SUBCOMMITTEE REPORT

TO

NATIONAL PETROLEUM COUNCIL'S

COMMITTEE ON SYNTHETIC LIQUID

FUELS PRODUCTION COST

October 15, 1951

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INDEX

	PAGE
SUBCOMMITTEE REPORT	1
ATTACHMENTS TO SUBCOMMITTEE REPORT	APPENDIX A
COAL HYDROGENATION RAW MATERIALS REPORT	APPENDIX B
SHALE OIL RAW MATERIALS REPORT	APPENDIX C
COAL HYDROGENATION PROCESS REPORT	APPENDIX D
SHALE OIL PROCESS REPORT	APPENDIX E
COAL HYDROGENATION ENGINEERING REPORT	APPENDIX F
SHALE OIL ENGINEERING REPORT	APPENDIX G
COAL HYDROGENATION ECONOMICS REPORT	APPENDIX H
SHALE OIL ECONOMICS REPORT	APPENDIX I

SUBCOMMITTEE REPORT
TO
NATIONAL PETROLEUM COUNCIL COMMITTEE
ON
SYNTHETIC LIQUID FUELS PRODUCTION COSTS

INTRODUCTION

This report presents the results of studies completed to date by the technical subcommittees of the National Petroleum Council's Committee on Synthetic Liquid Fuels Production Costs. These particular studies have been directed to the development of information on the production of marketable fuels plus some chemical by-products by the hydrogenation of coal and by the recovery and refining of oil from shale. To complete the Subcommittee's assignment, further work will be required.

ORIGIN OF THE PROJECT

This study of synthetic liquid fuels production costs was undertaken by the National Petroleum Council at the request of the Secretary of the Interior, the Honorable Oscar L. Chapman. The request was made in the Secretary's letter of April 21, 1950, to Mr. Walter S. Hallanan, Chairman of the National Petroleum Council. A copy of Mr. Chapman's letter is included in Appendix A.

After appropriate action by the Agenda Committee of the Council, Mr. Hallanan appointed the Committee on Synthetic Liquid Fuels Production Costs as covered by his letter of June 13, 1950, to Mr. W. S. S. Rodgers. A copy of Mr. Hallanan's letter, as well as the membership of the Committee, is presented in Appendix A.

SUBCOMMITTEE ORGANIZATION

Since it was readily apparent that a considerable amount of detailed technical effort would be required on the project, a subcommittee organization was established. The extensive memberships of the various subcommittees which have been active in this work to date are presented in Appendix A.

Specific functions of these various groups are indicated by their titles and will be apparent from the discussions to be presented in subsequent sections of this report. In the selection of the subcommittee members, an effort was made to obtain the most qualified people available for the various assignments. A large amount of work has been done in the synthetic liquid fuels and allied fields by the industrial organizations represented, and a vast amount of research and development, engineering and cost estimating experience on the subject has been brought to bear through the subcommittee members on the studies now being reported. Some important contributions to the work of the subcommittees were made by coal industry experts. It is also to be noted that most of the 47 subcommittee members obtained considerable assistance from associates ir their own organizations and from concerns not represented on the subcommittees. It has been estimated that some 105 technical men, in addition to subcommittee members, have been engaged in the work. In the course of the development of information necessary for the study, approximately 115 concerns, aside from those represented on the subcommittees, provided data. These firms are

listed in Appendix A. Their assistance was most valuable and is gratefully acknowledged.

SCOPE OF THE PROJECT

In his letter requesting that the synthetic fuels cost study be made, Secretary Chapman asked that the work cover:

1. A review of estimates made by the Bureau of Mines of the cost of producing synthetic liquid fuels, and its estimates of comparative costs of producing liquid fuels from crude oil.

2. Preparation of independent cost estimates.

3. Preparation of recommendations as to ways and means, if any, for improvement of future cost estimates by the Bureau of Mines.

It is to be noted that the concluding phrase of item #1 concerns the Bureau of Mines' estimates of costs of producing finished liquid fuels from crude oils. In an early meeting of the Subcommittee with Bureau of Mines' personnel, it was found that the Bureau had not developed a cost estimate on production of liquid fuels from crude oil which they were prepared to submit for review. It was, therefore, agreed that this phase would be omitted from the scope of the project.

Work by the Bureau of Mines in the synthetic fuels field has been in three categories:

1. Production of synthetic liquid fuels by hydrogenating coal.

2. Production of synthetic liquid fuels by gasifying coal and converting the resulting mixture of carbon monoxide and hydrogen to liquid fuels by some modification of the Fischer-Tropsch process.

3. Production of liquid fuels from oil shale.

As stated in the introduction, this report presents information on production of synthetic fuels by coal hydrogenation and from oil shale. The Bureau of Mines had prepared a design and estimate of the Fischer-Tropsch process, listed as category #2 above. Upon reviewing the process design, the Subcommittee found, and the Bureau agreed, that many of the assumptions involved could not be supported by data. The Bureau of Mines is now proceeding with a new design based on conditions which have been jointly agreed upon. At such time as the Bureau of Mines completes the development of the necessary data, a comparable study will be made of the Bureau's process for producing synthetic fuels from coal by the Fischer-Tropsch synthesis. It is also planned to make cost estimates for a coal hydrogenation operation and a shale oil operation in which certain modifications have been proposed by the Bureau. These additional studies outlined will be covered later by a separate report. On the basis of information now available, it is believed that these modifications will not significantly change the estimated gasoline costs from those reported here.

In order to conform with Secretary Chapman's request, this report (with only a few necessary exceptions) has been limited to study of those processes on which the Bureau has done work or for which the detailed results of work done by others has been made available to them. No attempt has been or will be made by the subcommittees to inject into the study any process

developments of private industry which have not been made available to the Bureau of Mines for their full study.

PROCEDURE

Although in the initial deliberations of the subcommittees it was assumed that the Bureau of Mines would have available detailed reports covering the process designs, investment cost estimates and final economic studies, it developed that this was not the case. It was, therefore, necessary for the various subcommittees to work out in detail, with the Bureau of Mines' personnel involved, the necessary information on which the synthetic liquid fuels production cost estimates presented at this time have been based.

In certain instances, process designs have had to be adjusted to bring equipment sizes into conformity with the throughputs proposed. In other cases, it was necessary to prepare designs for pieces of equipment, regarded as necessary to the operation, for which no provision had been made by the Bureau. In addition to the problems arising in connection with the operating units, a substantial amount of attention had to be given to "offsite" facilities, such as the provision of housing for certain of the plants which are located at some distance from centers of population.

To make the cost estimates significant, it was deemed necessary that all products be of equivalent quality to those now being marketed. Suitable provisions for processing facilities, treatment, and addition of tetraethyl lead have been made as appropriate.

In view of the considerable movement in prices and labor rates over the past several years, it was necessary to establish a base period for the study. This was selected as January, 1951, and all costs and labor rates were adjusted to fall as closely as possible to the levels for that time. Corrections for changes in the cost levels resulting from future inflationary or deflationary trends may be made as desired.

As a means of obtaining an independent appraisal of the methods of accounting employed by the subcommittees in arriving at the estimates presented in this report, experts from the firm of Price, Waterhouse and Company have reviewed the information in detail. They are prepared to support the suitability of the procedure in making the estimates and of the factors employed as related to data developed from actual experience in existing commercial operations.

The method of handling capital costs is of major importance. In deciding on the return on investment after income tax, consideration must be given to the experience of private industry, especially in related fields. The figure for the oil industry is currently about 12%, but this is still below the <u>average</u> of all other manufacturing industries. The recommendation of financial consultants is that earnings of not less than 15% should have been used in calculating costs of synthetic fuels. Such levels are considered the minimum needed to stand a chance of attracting the necessary private capital in view of the speculative nature of the ventures.

S U M M A R Y
SYNTHETIC LIQUID FUELS PRODUCTION COSTS

	COAL HYDROGENATION				OIL SHALE			
	SINGLE PLANT		MULTI PLANT		SINGLE PLANT		MULTI PLANT	
	Total	Per Daily Barrel of Liquid Production	Total	Per Daily Barrel of Liquid Production	Total	Per Daily Barrel of Liquid Production	Total	Per Daily Barrel of Liquid Production
Coal or Shale, Tons/CD	12,960	0.48	112,590	.52	76,800	1.93	384,000	1.91
Tons/Year	4,730,000	-	41,095,000	-	28,030,000	-	140,160,000	-
Products								
Gasoline, B/CD	19,490	0.72	163,830	.76	25,380	.64	126,900	.64
Diesel Fuel, B/CD					12,200	.31	62,360	.31
LPG, B/CD	6,390	0.24	52,170	.24	1,780	.04	8,920	.04
Residual Fuel, B/CD					340	.01	3,050	.01
Coke, Tons/CD					1,180		5,900	
Fuel Gas, MSCF/CD					24,830	-	124,150	-
Chemicals								
Phenols, B/CD	229	0.008						
Cresols, B/CD	383	0.012						
Xylenols, B/CD	508	0.018						
Ammonia, Tons/CD					92	-	460	-
Sulfur, Tons/CD					43	-	215	-
Total Liquid Production, B/CD	27,000	1.000	216,000	1.000	39,700	1.00	201,230	1.00
Investment, Dollars								
Mines	$ 12,700,000	470	$ 185,200,000	860	$ 26,000,000	650	$ 130,100,000	640
Plants	403,300,000	14,940	3,214,200,000	14,880	230,200,000	5,800	1,026,100,000	5,100
Other	56,900,000	2,110	426,800,000	1,970	48,900,000	1,230	209,200,000	1,040
Total ex Housing	$472,900,000	17,520	$3,826,200,000	17,710	$305,100,000	7,680	$1,365,400,000	6,780
Housing	60,000,000	2,220	247,900,000	1,150	27,500,000	690	152,100,000	760
Total Including Housing	$532,900,000	19,740	$4,074,100,000	18,860	$332,600,000	8,370	$1,517,500,000	7,540
Operating Manpower, Including Supervision and Administration, Men	5,900	0.22	53,800	0.25	3,420	.086	15,750	.078
Construction Labor, Man Hours								
Mine	1,900,000	70	13,400,000	60	4,600,000	120	23,000,000	110
Plant	37,900,000	1,400	291,900,000	1,350	16,000,000	400	72,000,000	360
Housing	11,200,000	420	49,400,000	230	5,100,000	130	28,400,000	140
Total	51,000,000	1,890	354,700,000	1,640	25,700,000	650	123,400,000	610
Metals Requirement, Including Equipment Construction, Short Tons								
Mines	3,700	.14	53,000	.24	13,200	.33	66,100	.33
Plant	211,600	7.83	1,639,000	7.59	162,900	4.10	616,300	3.07
Housing	4,500	.17	19,000	.09	2,100	.05	11,400	.05
Total	219,800	8.14	1,711,000	7.92	178,200	4.48	693,800	3.45
Operating, Short Tons/Year								
Mines	410	.02	6,200	.03	1,400	.04	7,010	.04
Plant	4,060	.15	32,800	.15	5,730	.14	26,630	.13
Total	4,470	.17	39,000	.18	7,130	.18	33,040	.17
Cost of Gasoline with 6% Return on Investment after Income Tax, Cents/Gal.	41.4		43.5		16.2		14.7	

Thus, in basing the calculations on a return of 6%, it is felt that the results are definitely on the low side, and that a return in the order of 15% would be more realistic.

CONCLUSIONS

The results of the investigation to date of the coal hydrogenation and shale oil processes, which are discussed in greater detail subsequently, are summarized in the opposite table.

In the opinion of the subcommittee, the cost estimates are the most reliable which have yet been prepared on these operations. Considerable care has been used in selecting low bids, avoiding the duplication of charges of any kind, and choosing the more optimistic premises. It is believed, therefore, that any error in the estimates is probably in the direction of their being low.

The results presented confirm previously-published conclusions that production of synthetic liquid fuels from coal by hydrogenation is uneconomical at present. Although some technological advance may be expected in the future, there is no indication at this time that any substantial improvement in the economics of the process will be effected.

It has been noted that effort is being made to promote coal hydrogenation as a source of aromatic chemicals, such as benzene, toluene, phenols, etc. Study of this proposal is not within the scope of this committee's assignment, and no opportunity has been provided for such study. Attention is directed, however, to the fact that the disadvantages of high investment

cost involved in the basic coal hydrogenation step will still be present and that additional investment will be required for the further processing, recovery and purification of the aromatics. Such aromatic chemicals could be produced from petroleum at much lower cost.

The oil shale phase of the synthetic fuels program is in a more favorable position. Excellent work has been done by the Bureau in the development of shale mining on a large scale. Although the resulting product costs are still significantly higher than those from petroleum, the levels are such that this source of fuel will continue to receive serious attention by the petroleum industry. The future trend of oil shale development will, of course, be affected by the cost of petroleum gasoline. An additional cost study involving other retorting and product finishing methods is in progress but is not expected to alter the estimated cost levels reported here to any substantial extent.

It has been estimated that known oil shale reserves will yield in excess of 100 billion barrels of oil or in excess of three times the present proven petroleum reserves. It is evident that oil shale will provide a considerable period of supply, when petroleum sources are exhausted, and that the employment of coal hydrogenation lies in the more distant future.

It is also noteworthy that estimates made by other investigators on the costs of producing gasoline from coal by the Fischer-Tropsch synthesis route have indicated that such costs

are somewhat greater than the shale cases reported herein and considerably lower than the coal hydrogenation cases.

All of this detailed work has required a large amount of effort and has taken much more time than was originally contemplated. Throughout this activity, it has been necessary to hold frequent meetings with Bureau of Mines' personnel at the various demonstration plants and in Washington. In all instances, the Bureau people have been most cooperative in working with committee representatives.

Although it has not been possible to obtain agreement between the Subcommittee and the Bureau in all instances, many of the individual parts of the estimates are in close agreement. In most of the instances for which the disagreement is significant, it has been possible to account for this on the basis of differences in basic judgment or sources of data.

During the course of this study, Bureau of Mines' personnel have had numerous opportunities to review in detail the methods employed by the industry organizations. With this experience to supplement their own background and with the information which is contained in the technical reports made available to them by the subcommittees, Bureau experts should be in a good position to prepare comparable cost estimates for any new process combinations.

COAL HYDROGENATION

The coal hydrogenation process, as its name implies, consists of adding hydrogen to coal to convert it into normal

oil products. The hydrogen used can be generated by reaction of additional coal (or coke therefrom) at high temperatures with steam and oxygen.

The Bureau of Mines has carried out extensive laboratory and pilot plant work on various phases of coal hydrogenation for a number of years. More recently, a "Demonstration Plant" has been erected and placed in operation at Louisiana, Missouri. This plant was designed to have a capacity of 200-300 barrels per day. Aside from some advances by the Bureau and others on production of hydrogen, the coal hydrogenation process is essentially in the same state as developed in Germany. The hydrogenation section of the plant in designs proposed by the Bureau is based almost entirely on German commercial and pilot plant operations.

The Bureau of Mines in Report RI-4564 has presented estimates of investments involved for a 30,000-barrels-per-day coal hydrogenation plant at several locations in the United States. These estimates were for a plant using designs and operations proven on a large scale in Germany as well as a plant incorporating certain engineering and process improvements. One of the assignments of the Subcommittee was to review these estimates and then prepare its own estimates for coal hydrogenation plants.

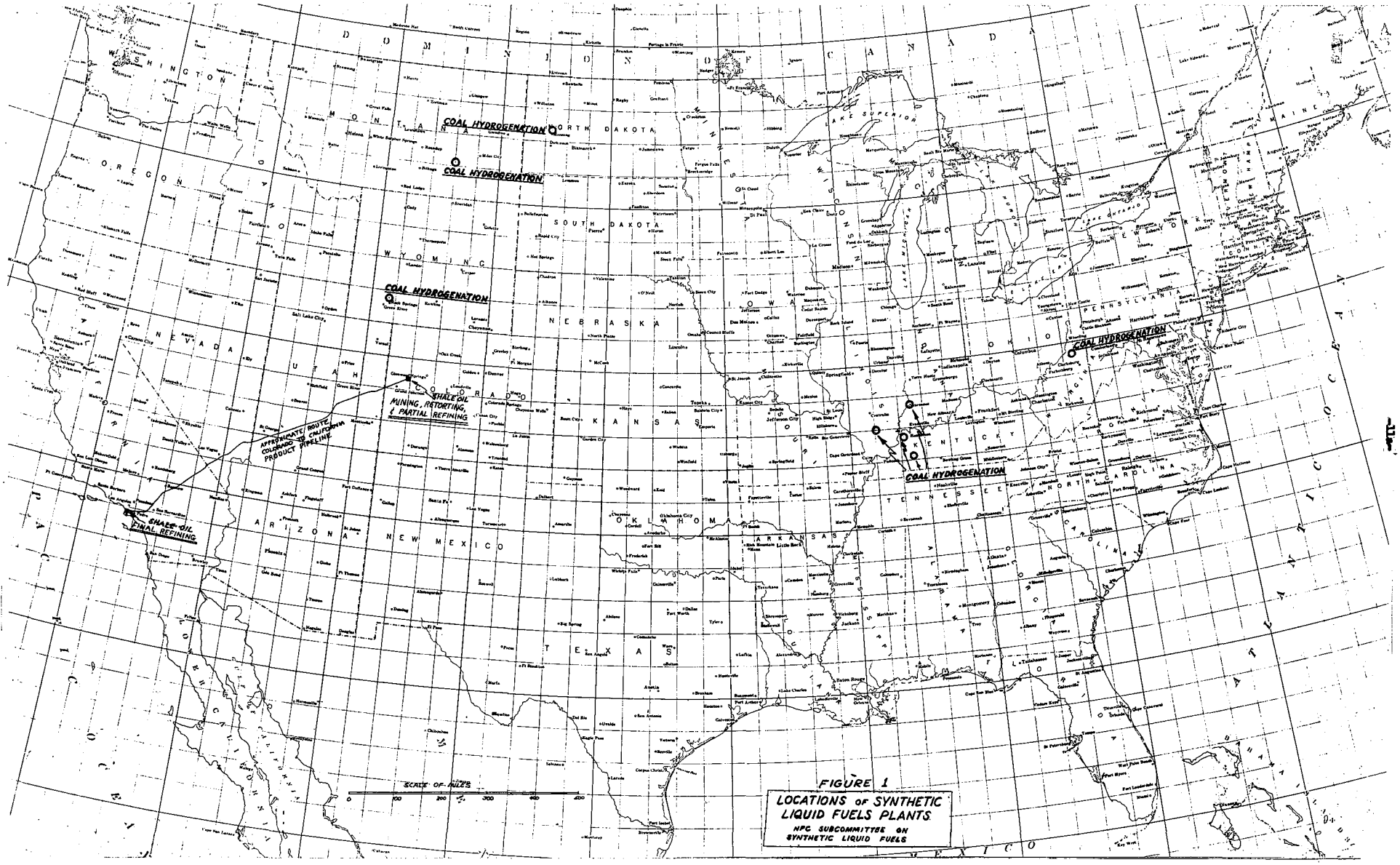
In initial discussions with the Bureau of Mines, it was agreed that a 30,000-barrels-per-day plant would be taken as the unit size and that a specific estimate for a single plant of

this capacity would be based on a location at Rock Springs, Wyoming. This plant would produce certain chemical by-products.

It was the feeling of the Subcommittee that if coal hydrogenation were practiced to the extent of producing a significant part of the oil product requirements of the United States, production of by-product chemicals would greatly exceed the demand for such materials so that a clearer picture of the possible future of coal hydrogenation would be obtained by converting by-product chemicals into gasoline. Further, it was felt that a more representative picture would result by considering a number of locations so that more of an average would be obtained for plant investments and production costs. In agreement with the Bureau of Mines, eight locations were chosen for 30,000-barrels-per-day coal hydrogenation plants. Since such plants do not operate all of the time due to necessity for shutting down for maintenance and other causes, actual liquid fuel production per calendar day is estimated at 27,000 barrels. Accordingly, the eight plants would produce a total of 216,000 barrels per calendar day (CD) of liquid fuels.

The eight locations picked as sites for coal hydrogenation plants and the type of coal involved are as follows:

County	State	Type of Coal
Sweetwater	Wyoming	Bituminous
Rosebud	Montana	Sub-Bituminous
Dunn	North Dakota	Lignite
Union	Kentucky	Bituminous
Franklin	Illinois	Bituminous
Knox	Indiana	Bituminous
Muhlenberg	Kentucky	Bituminous
Wetzel	West Virginia	Bituminous


COAL HYDROGENATION
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COAL HYDROGENATION
SHALE OIL MINING, RETORTING & PARTIAL REFINING
APPROXIMATE ROUTE, COLORADO TO CALIFORNIA PRODUCT PIPELINE
SHALE OIL FINAL REFINING
SCALE OF MILES
0 100 200 300 400 500
FIGURE 1
LOCATIONS OF SYNTHETIC LIQUID FUELS PLANTS
NPC SUBCOMMITTEE ON SYNTHETIC LIQUID FUELS

A map indicating these various locations is included as Figure 1.

Raw Materials

In order to determine locations for the eight coal hydrogenation plants and to determine raw material costs, a raw materials subcommittee of the Subcommittee was formed, which was further divided into subcommittees for eastern and western coal. The reports of the coal subcommittees are given in Appendix B.

The amount of coal required for a 27,000-B/CD coal hydrogenation plant varies mainly with its moisture and oxygen content. In general, approximately 100 million tons of bituminous coal will be required to supply one plant for 20 years. This corresponds to around 13,000 tons of coal per day and will involve a coal mining operation commensurate with the largest scale operation now being carried on in this country. For lignite, the quantity is roughly twice this and, for sub-bituminous coal, somewhere between. One of the duties of the raw materials subcommittees was to pick locations where adequate coal would be available for at least 20 years. All of the sites chosen meet this requirement, and certain of the sites could readily supply more than one plant. Further, the sites selected are ones not now dedicated to supplying other needs for coal.

A second consideration the subcommittees used in considering choice of sites was the availability of water for the coal hydrogenation plant as well as general accessibility of the

site. Another factor was the availability of communities close to the site to minimize the necessity of providing housing. In general, at western locations, there are no communities close to desirable sites.

In choosing sites, an attempt was made to select representative locations rather than the best possible. It is felt, however, that the sites chosen are representative of the best to be found in the United States rather than the average.

Process

In order to serve as a basis for subsequent investment and operating cost figures, a careful review was made of the process design proposed by the Bureau of Mines. This involved a review of the process data on which the design was based, size of equipment required, amount of coal needed, yield and quality of products, and power and labor requirements. This information is presented in detail in Appendix D.

Although the Bureau had two main designs available, the processing scheme is generally the same. Coal is de-ashed, when necessary, dried, pulverized, and fed in paste form with recycle oil to a liquid phase hydrogenation unit operating at 10,000 lbs./sq.in. pressure. The liquid product is distilled, and heavy fractions above gas oil are recycled to the liquid phase stage. Ash and catalyst are purged from the heavy oil recycle by withdrawing part of the stream for treatment by coking or distillation. The lighter portion of the liquid phase product passes to a second stage where it is hydrogenated at the

10,000 lbs./sq.in. pressure in the vapor phase to ultimate yield of motor fuel and LPG. If desired, phenols, cresols and xylenols may be extracted from the oil from the liquid phase stage prior to vapor-phase hydrogenation. Hydrogen for the process is obtained partly by gasification of coal with oxygen and steam, and partly by catalytic reformation of methane, ethane and propane made in the process.

As brought out above, the Bureau offered two designs, both based on a plant using Wyoming bituminous coal and located at Rock Springs, Wyoming - (a) "conventional" case, for which a more detailed design had been prepared, and (b) a "modernized" case, which differed from the conventional design mainly in that:

1. Coal gasification is carried out at 25 atmospheres pressure versus atmospheric in the conventional case.

2. The heavy oil purge stream from the liquid phase is processed by coking instead of flash distillation.

3. Spirally-wound or wrapped high pressure vessels are used to reduce investment.

4. Through use of complete automatic control, 10% greater throughput per volume of catalyst is taken.

Since the Subcommittee estimates were to be based on demonstrated operations, and since gasification under 25 atm. pressure had not been carried out by the Bureau, the Subcommittee decided to proceed on the general basis of the conventional design. However, it was felt that items 2, 3 and 4 above in the modernized case were sufficiently well established to be included in the Subcommittee estimate.

In addition to the above, the following major modifications to the Bureau's design were made in the course of the review:

1. The coal gasification design proposed by the Bureau was based on the Koppers slagging generator developed in Germany. Since an attempt to operate a large experimental unit of this type at Louisiana, Missouri, by the Bureau was unsuccessful, the process subcommittee rejected this process. The Bureau was unwilling to prepare a revised design. The process subcommittee, therefore, worked up a low pressure design partially based on data obtained by the Bureau at Morgantown, West Virginia. This is the design used in this report.

2. In the matter of throughputs, the subcommittee and the Bureau are in disagreement. The Bureau's design data were based on plant capacity of 30,000 barrels per stream day, and the design was reviewed on this basis by the subcommittee. The Bureau stated subsequently, however, that the equipment was designed sufficiently large so that with 90% service factor, the plant could produce 30,000 barrels per calendar day. Accordingly, a careful second review was made, a series of meetings were held with the Bureau, and a few items were adjusted. The subcommittee concluded from this review that the plant as designed would not be expected to have a capacity greater than 30,000 barrels per stream day. The Bureau still feels that a number of parts of the plant are suitable for 30,000 barrels per calendar day, equivalent to 33,000 barrels per stream day. Operating quantities for the Rock Springs plant in this report are thus as follows:

	Stream Day	Calendar Day
Raw Coal, Tons	14,400	12,960
Gasoline, Barrels	21,656	19,490
LPG, Barrels	7,100	6,390
Phenols, Barrels	254	229
Cresols, Barrels	426	383
Xylenols, Barrels	564	508
Total	30,000	27,000

No middle distillates or heavy fuels are produced in this type of operation.

Detailed process review was limited to the above case for Rock Springs, Wyoming. Using this design as a basis, flow streams were calculated with the help of the Bureau of Mines for the individual process steps involved in the plants at each of the other seven sites, taking into account differences in type of coal involved. Product quality, energy, water, and chemical requirements were likewise estimated. These quantities are shown in Appendix D. In the above cases, phenols, cresols, and xylenols were not extracted, but were permitted to pass to the second hydrogenation stage where they were converted to gasoline.

Each plant was sized for a total production of 27,000 barrels per calendar day. In view of the differences in type of coal, the relative proportions of gasoline and LPG varied in the different plants as follows:

Gasoline, B/CD	19,620 to 21,320
LPG, B/CD	7,380 to 5,680

Raw coal requirements ranged from 11,800 tons per calendar day for West Virginia bituminous to 16,600 tons per calendar day for Montana sub-bituminous coal, with the exception of North Dakota lignite which required 24,500 tons per calendar day mainly in view of its 40% moisture content.

Investment Costs

The investment costs of most of the facilities were based on the designs of the Bureau as modified by the review of the process subcommittee as previously described.

Separate and independent estimates of the construction costs of the base plant at Rock Springs were made by three different companies. The three estimates were then reviewed in conference to arrive at the average investment cost which is used in this report. It is noteworthy that the estimates of material and labor differed by only 4.4%.

The construction cost estimates of the plants at other locations were projected from the base estimate at Rock Springs. Cost adjustments were made for changes in process conditions due to differences in processing behavior of the various coals, elimination of chemical manufacture, construction labor rates, plant altitude and freight.

Every effort was made to accept designs, layouts, and other engineering factors proposed by the Bureau where information was available to clearly indicate the basis proposed. In those instances where details were not available, the subcommittee employed designs typical of the petroleum industry. One of the more important calculations made by the subcommittee was the preparation of utility requirements to facilitate the estimation of the costs of steam and power generation facilities. No details on these facilities were available from the Bureau.

In addition to investment costs of the plant proper, costs of other facilities that are necessary for operation, such as housing requirements, water supply, and transportation, were estimated. The development of these costs in addition to the investigation of probable methods of financing of the housing was

a task of some magnitude and advice on the matter was obtained from government housing authorities, insurance companies, construction concerns and other experts in this field.

Requirements of steel, construction and operating manpower, utilities, chemicals, coal, and other items necessary to portray the economics and the scope of the project were developed.

The Bureau of Mines was advised currently of the results of the subcommittees' investigations and an attempt was made to reconcile differences as the work proceeded. It is believed that a better understanding of both estimates by both parties has resulted from these exchanges. A comparison with the Bureau of Mines' estimates is included with other details of the estimate in Appendix F.

Economics

The economics of coal hydrogenation have been developed in the same manner as employed by the petroleum industry for the evaluation of new processes or projects.

The details and basis for the economic calculations are presented in Appendix H. A summary of these economics follows:

	Rock Springs, Wyoming		Eight Plants	
	$	$/B/CD	$	$/B/CD
Investment				
Plant	403,300,000	14,900	3,214,200,000	14,900
Mine	12,700,000	500	185,200,000	900
Housing	60,000,000	2,200	247,900,000	1,100
Other	56,900,000	2,100	426,800,000	2,000
Total	532,900,000	19,700	4,074,100,000	18,900

	Rock Springs, Wyoming	Eight Plants
Cost of Synthetic Gasoline with 6% return after taxes, ¢/Gallon	41.4	43.5
Present Average Refinery Bulk Price for Gasoline in Area, ¢/Gallon	11.2	12-13

The above investment-capacity ratios are based upon total liquid product (including the LPG produced) and in the case of the Rock Springs plant, the chemicals produced. In determining the cost of gasoline, all by-products are credited at their market value.

The above table corresponds to Case C developed in Appendix H wherein community facilities are provided and housing is supplied for 90% of the plant and mining employees at all locations west of the Mississippi River. Considerably less housing is provided for locations east of the Mississippi because plants are located closer to existing communities. It is the feeling of the subcommittee that the cases presented represent the minimum housing and community expense that can be anticipated. Credit for housing rental income is included in the calculations so that the net burden of housing on the cost of gasoline amounts to only approximately 2.3¢ per gallon. If it is necessary to finance commercial buildings and housing of the trades people, the cost of the gasoline would be increased by approximately 1 1/2¢ per gallon, and the investment increased by approximately $2,000 per barrel of daily capacity.

Cost of gasoline by coal hydrogenation at eight other locations varies from 41.0 to 48.5¢ per gallon, with an average of 43.5¢ per gallon. Detailed information is presented in Appendix H.

The cost of gasoline as developed above represents the price which must be realized at the plant in order to provide only 6% return after taxes on the investment. An income tax rate of 50% is used and excess profits' taxes neglected. The 6% return rate is comparable with returns in controlled, relatively low risk enterprises, such as the utilities, and is substantially lower than earnings on normal business capital. It is the opinion of the Subcommittee that for an enterprise as speculative as fuels production, 6% return is insufficient and that a return of not less than 15% after taxes is necessary to attract private capital.

With gasoline selling at today's prices, insufficient revenue is realized to pay direct operating costs without any capital charges.

OIL SHALE

Manufacture of liquid fuels from oil shale has been carried on commercially in Europe, particularly in Scotland, for many years, but there has never been the need for such a development in the United States. During the period when the yearly increase in national petroleum reserves declined immediately following World War I, attention was directed to extensive deposits of rich oil shale in northwestern Colorado as a possible supplemental source of petroleum products.

The U. S. Bureau of Mines and several oil companies undertook experimental work in mining, retorting and refining, and general interest in the whole subject developed, leading to formation of several Naval Oil Shale Reserve areas and acquisition of large shale holdings by companies and individuals. An upsurge in petroleum discoveries resulted in a national surplus of crude in the early 20's and active work on oil shale was discontinued.

More recently the Bureau of Mines, under a congressional appropriation, granted in 1944, opened up a new experimental mine and crushing plant near Rifle, Colorado, in order to develop and demonstrate mining methods and costs for commercial scale operations. Two batch retorts were later added, followed by a small scale experimental refinery.

Work is being continued by the Bureau of Mines on all the above phases, with particular emphasis on the development of a continuous, gas combustion type shale retort.

The work of the Bureau of Mines has been supplemented by research and development in retorting and refining methods carried on by several companies in the industry. The Bureau, as well as the various sub-committees responsible for the preparation of this report, has had full access to all of the data developed and used in the report.

Raw shale oil requires considerable refining to convert it into marketable products. The Subcommittee felt that to obtain a representative picture, the refining operation should be so carried out that the main products, namely gasoline and distillate oils, would be manufactured in a ratio corresponding to the present average of U. S. production.

Since there is a very small market outlet in the Rifle area, it is necessary to move liquid shale products to areas where markets are available. Chicago as a distribution center for the Mid-Continent district and Los Angeles for the West Coast district were alternate possibilities. For the purpose of this study Los Angeles was used because of the smaller petroleum reserves in California compared to the Mid-Continent district.

As alternate procedures the raw shale oil, after processing to reduce viscosity, could be piped to Los Angeles for refining, or the refining operation could be broken up into two steps, part being carried out at Colorado, and part at Los Angeles. This latter alternative was the one chosen by the Subcommittee after giving consideration to the cost of housing required for employees in Colorado, and the availability of fuel gas from the retorting operation to

supply part of the fuel needs for the over-all refining operations. On this basis the pipeline from Colorado to Los Angeles would transport partially refined products. By-product ammonia, sulfur, coke, and gas produced in Colorado would be sold from this location.

Estimates on production of oil products from oil shale that had been prepared by the Bureau contained some processing steps that have become outmoded due to more recent developments. As a consequence, it was necessary to work out with the Bureau a new basis for the Subcommittee's estimates. It was agreed that a base retorting plant to produce 12,500 barrels per calendar day of raw shale oil should be used. This would require 19,200 tons per calendar day of oil shale and this, therefore, represents the unit mine size.

The refining equipment required in Colorado for handling 12,500 barrels per day of raw shale oil is rather small, and to obtain more economic size refining equipment of 25,000 barrels per day is provided. From the standpoint of general facilities, such as power plants, shops and the like, it was felt investment per unit of capacity should be reduced by combining two refining units into a 50,000 barrels per day plant. The unit shale plant pictured for Colorado, therefore, consists of four base mining and retorting units, each of 12,500 barrels per calendar day raw shale oil capacity, and two units of 25,000 barrels per calendar day to partially refine the raw shale oil.

In preparing its estimates, the Subcommittee considered two cases. One was a single plant having a capacity of 50,000 barrels per calendar day of raw shale oil with a pipeline of like capacity to Los Angeles. The second case involved five such plants with a common pipeline to Los Angeles. The purpose of this case was to get a more representative picture. All plants were located in the vicinity of Rifle, Colorado. The Bureau of Mines was in agreement with this procedure.

Raw Materials

The Bureau of Mines has prepared adequate data to show the existence of extensive deposits of oil shale in Western Colorado. Mine sites may be located along the shale outcrop from which shale averaging 30 gallon per ton assay can be mined from beds 70 feet or more in thickness. Twenty-five sites have been designated as favorable, and others may be located as required.

It has been estimated, based on outcrop sampling and diamond drilling in the Rifle area that 1.4 square miles can produce 19,200 tons of shale per day for twenty years.

The cost of mining and crushing was developed by the Bureau of Mines in the demonstration mine at Rifle, Colorado. These cost estimates were revised by the raw materials sub-committee to conform to conditions prevailing in industrial operations. Cost estimates are shown in Appendix C.

Process

The retorting process selected by agreement between the Sub-committee and the Bureau of Mines was that developed by the Union Oil Company and demonstrated in a 50 ton per day pilot plant operation.

A retorting installation of 19,200 tons per calendar day throughput would be geared to the output of the unit mine, and would consist of individual kilns of 1,000 tons per stream day capacity charging thirty gallon per ton shale.

The retort is a continuous underfeed kiln requiring no water for cooling, and is self-sustaining with respect to utility requirements. Throughput rates are based on run of the mill particle sizes of maximum four-inch diameter.

A complete description of the process, including specifications, plant design, and product analysis, is included in Appendix E.

In the refining operations in Colorado, raw shale oil is first subjected to a coking operation to obtain material suitable for further processing. Overhead material from the coking operation is then split into a naphtha and a gas oil fraction. Coke obtained in the coking operation is a marketable product. Fuel gas is also obtained as a by-product.

Naphtha and gas oil fractions from the coking operation contain nitrogen compounds that impart a disagree-

able odor and offer difficulties in further refining operations. Both of these fractions are also quite unstable. The naphtha fraction is catalytically reformed, which removes nitrogen as ammonia, hydrogenates the more unstable compounds, and gives a desirable increase in octane number. The gas oil fraction is subjected to mild hydrogenation, which removes nitrogen by conversion to ammonia and, at the same time, upgrades the gas oil by making it more saturated. Ammonia is recovered and sold as such.

The combined sulfur present in the oil fed to these two steps is removed by conversion to hydrogen sulfide. This hydrogen sulfide is recovered and converted back into sulfur for sale as such.

Reformed naphtha and hydrogenated gas oil are piped to Los Angeles for further refining. In order to obtain the desired ratio (U. S. average) between gasoline and gas oil a portion of the gas oil is catalytically cracked. Other operations at Los Angeles involve polymerization of propylene and butylenes from catalytic cracking, rerunning, leading of gasoline, and blending.

The quantities of materials produced in the single plant shale oil case are listed in the following table:

Produced in Colorado	Per Calendar Day
Shale Used, Short Tons	76,800
Unfinished Gasoline piped to California, Barrels	17,340
Unfinished Gas Oil piped to California, Barrels	23,640
Fuel Gas, Thousand Cubic Feet	24,830
Coke, Short Tons	1,180
Ammonia, Short Tons	92
Sulfur, Short Tons	43
Produced in California	
Premium Gasoline, Barrels	12,690
Regular Gasoline, Barrels	12,690
Diesel Fuel, Barrels	12,200
Fuel Oil, Barrels	340
LPG, Barrels	1,780
Total Barrels	39,700

The multi-plant case differs from the single plant case so far as materials produced are concerned almost entirely in scale, showing above five times the production of each of the products.

The refining steps as outlined with the exception of catalytic reforming and mild hydrogenation are conventional refinery procedures. The processes for catalytic reforming and mild hydrogenation on which the estimates are based were developed by the Union Oil Company and have been well demonstrated on a pilot plant scale. The refining of raw shale oil has been discussed in detail with the Bureau of Mines and they are in agreement with the procedures used.

Investment Cost

Estimates of investment costs and related data were made by representatives of six oil companies on the West Coast thoroughly familiar with construction conditions in the area. The project was divided into various facilities and distributed among the participants. The estimates of these facilities were then reviewed in conference and assembled to obtain the totals for the whole project.

For estimating purposes, mines, retorts, refineries, and shipping facilities were assigned specific sites near the Colorado River in which the refineries are located in valleys beneath the shale bearing cliffs with the mines and retorts 1500 to 2000 feet above the refineries.

The cost of the shale retorts were estimated from detailed engineering designs and equipment quotations. The other processing units were estimated by projection from actual construction costs of similar units. A considerable amount of detailed engineering and estimating as well as use of past experience was required to develop the costs of such facilities as utilities, pipelines, shops, buildings, tankage, and other related general facilities. Housing costs were prorated from the estimate of the coal hydrogenation plant at Rock Springs, Wyoming.

The five plant case envisages the use of a certain amount of common facilities such as a common pipeline to California; inter-connection of electric power generation;

savings in space and cost of central shops, central warehouses, and shipping facilities; common pipeline terminal facilities in California employing catalytic cracking, catalytic polymerization and redistillation units. The use of a common pipeline to California was by far the largest factor in the savings due to these joint operations.

Additional details of this phase of the investigation are included in Appendix G.

Economics

The economics of synthetic liquid fuels from oil shale was developed in a similar manner to that discussed under coal hydrogenation.

The details and basis for the economic calculations are presented in Appendix I. A summary of these economics follows:

	One Plant		Five Plants	
	$	$/B/CD*	$	$/B/CD*
Investment, $				
Plant	230,230,000	5,800	1,026,110,000	5,100
Mine	26,020,000	700	130,100,000	600
Housing	27,500,000	700	152,100,000	800
Other	48,830,000	1,200	209,150,000	1,000
Total	332,580,000	8,400	1,517,460,000	7,500
Cost of Equivalent Gasoline from Shale with 6% Return After Taxes, ¢/Gal.	16.2		14.7	
Present Average Refinery Bulk Price for Gasoline in Los Angeles, ¢/Gallon	11.7		11.7	

* Based on total liquid product.

In determining gasoline costs, six of the eight separate products were treated as by-products, and only motor gasoline and diesel fuel were considered major products. Diesel fuel was reflected as gasoline at the ratio of 0.7 of a gallon per one gallon of gasoline. This factor is nothing more than the present ratio of market values. If diesel fuel were credited at today's price as a by-product, a higher cost of gasoline would result. By-products in the shale oil operation have been credited at present market value.

The figures presented in the above table correspond to Case C developed in Appendix I, wherein community facilities are provided and housing is supplied for 80-90% of the plant and mine employees. As discussed in the section under Coal Hydrogenation, it is the feeling of the Subcommittee that this case represents the minimum housing and community expense which can be anticipated. Credit for rental income is included in the cost of shale gasoline so that the net housing burden amounts to only approximately 0.7¢ per gallon. If it is necessary to finance commercial buildings and housing of the trades people, the cost of gasoline would be increased by approximately 1/2¢ per gallon, and the investment increased by $600 per barrel of daily capacity.

No depletion or royalty has been charged to the operation for the reason that the Subcommittee was unable

to determine the basis for such charges at the present time. There is ample mineable shale land owned in fee simple by the various companies who would be most interested in the development of a shale industry in Colorado. These lands are sufficient to provide tonnage of the magnitude contemplated in this report for many years in the future. The cost of acquisition and the carrying charges of the land have been nominal so that a depletion rate is of negligible consequence in the final cost and there is no royalty.

The cost of gasoline as developed above represents the price which must be realized at the plant in order to provide only 6% return after taxes on the investment. An income tax rate of 50% is used. The 6% return rate is comparable with returns in controlled, relatively low risk enterprises such as the utilities, and is substantially lower than earnings on normal business capital. It is the opinion of the committee that certainly for an enterprise as speculative as synthetic fuels, 6% return is insufficient and that a return of not less than 15% after taxes is necessary to attract private capital. Based on todays economics an oil shale plant marketing gasoline competitively would realize only 3 to 5% return per year on the capital.

Whereas cases have been developed for a 50,000 barrel per day crude shale oil plant and a shale oil industry of 250,000 barrel per day crude shale oil, the

first plant which might be built to operate on shale oil would probably be a much smaller size. It should be pointed out that the cost of gasoline from a smaller operation would be considerably higher than those presented herein. Certain benefits resulting from larger size and particularly those benefits which can be derived from pipeline transporation to market cannot be obtained until sufficient volume is available to justify such pipeline.

UNITED STATES
DEPARTMENT OF THE INTERIOR
OFFICE OF THE SECRETARY
Washington 25, D. C.

April 21, 1950

My dear Mr. Hallanan:

During and immediately after World War II when the problem of adequate supplies of liquid fuels was uppermost in the minds of Government and industry and while there was uncertainty as to whether this country possessed an adequate supply of petroleum in the event of another emergency, the Bureau of Mines, of the Department of the Interior, was charged by Congress with the responsibility for investigating and developing processes for producing synthetic liquid fuels from oil shale and coal.

One of the requirements was to construct and operate demonstration plants to enable Government to furnish industry with the necessary cost and engineering data for the development of a synthetic liquid fuels industry.

Since the Bureau of Mines experimental work is sufficiently advanced to enable it to furnish some of the data called for, the Bureau would now welcome a critical study of its cost data by the National Petroleum Council and will cooperate fully in furnishing its data for such a study.

Therefore, I request that the National Petroleum Council create a committee to: (1) review the estimates made by the Bureau of Mines for the cost of producing synthetic liquid fuels and its estimates of comparative costs of producing liquid fuels from crude oils, (2) prepare independent cost estimates, and (3) make recommendations as to ways and means, if any, for improvement of future cost estimates by the Bureau of Mines.

Sincerely,

/s/ Oscar L. Chapman

Secretary of the Interior

Mr. Walter S. Hallanan, Chairman
National Petroleum Council
1625 K Street, N. W.
Washington 6, D. C.

NATIONAL PETROLEUM COUNCIL
(Created by the Secretary of the Interior)
Suite 601, 1625 K Street, N. W.
Washington 6, D. C.

June 13, 1950

Mr. W. S. S. Rodgers, Chairman
of the Board
The Texas Company
135 East 42nd Street
New York 17, New York

Dear Mr. Rodgers:

It gives me pleasure to appoint you as Chairman of the National Petroleum Council's Committee on Synthetic Liquid Fuels Production Costs.

This appointment is made under the authorization for such appointments in the Council's Articles of Organization and the recommendation of the Agenda Committee in response to the request of the Secretary of the Interior, in his letter of April 21, 1950, (copy of which is enclosed for your information) that a committee be appointed to make estimates and recommendations relating to synthetic liquid fuels referred to in the said letter, and that such committee report its findings to the next meeting of the National Petroleum Council.

It is expected that technical subcommittees will be appointed by your Committee to assist in developing appropriate data on the subject as outlined by the Agenda Committee.

A copy of the letter containing the Agenda Committee's recommendation together with a list of the membership of your Committee is also enclosed.

It is hoped that the Committee will undertake the study on synthetic costs at an early date so that a report can be made at the earliest possible time.

I trust I may have your acceptance and cooperation in this important assignment.

Sincerely yours,

(Signed) Walter S. Hallanan

Walter S. Hallanan
C h a i r m a n

Enc.

NATIONAL PETROLEUM COUNCIL COMMITTEE ON SYNTHETIC LIQUID FUELS PRODUCTION COSTS

W. S. S. RODGERS Chairman	The Texas Company, New York
K. S. ADAMS	Phillips Petroleum Company, Bartlesville Oklahoma
HINES H. BAKER	Humble Oil & Refining Company, Houston
MAX W. BALL	Room 1001, 1025 Vermont Avenue, N. W. Washington, D. C.
*BRUCE K. BROWN	Military Petroleum Advisory Board, c/o Pan American Southern Corporation, P. O. Box 2, New Orleans 6, Louisiana
ROBERT L. FOREE	Texas Independent Producers & Royalty Owners Association, Dallas
JOHN M. LOVEJOY	Seaboard Oil Company of Delaware, New York
R. S. SHANNON	Pioneer Oil Corporation, Denver
REESE H. TAYLOR	Union Oil Company of California, Los Angeles
J. ED WARREN	Independent Petroleum Association of America, c/o Carl B. King Drilling Company, Midland, Texas
L. S. WESCOAT	The Pure Oil Company, Chicago
ROBERT E. WILSON	Standard Oil Company (Indiana), Chicago
J. W. FOLEY Secretary	The Texas Company, New York

* Mr. Brown resigned from the committee on November 22, 1950.

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***H. G. VESPER	California Research Corporation 200 Bush Street San Francisco 4, California

*Mr. Frame resigned from the committee on March 1, 1951
**Mr. Kemp was appointed chairman on March 1, 1951
***Mr. Vesper joined the committee on July 11, 1951

NATIONAL PETROLEUM COUNCIL SUBCOMMITTEE ON SYNTHETIC LIQUID FUELS PRODUCTION COSTS

RAW MATERIALS SUBCOMMITTEE

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*Resigned

NATIONAL PETROLEUM COUNCIL SUBCOMMITTEE ON SYNTHETIC LIQUID FUELS PRODUCTION COSTS

PROCESS SUBCOMMITTEE (Cont')

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NATIONAL PETROLEUM COUNCIL SUBCOMMITTEE ON SYNTHETIC LIQUID FUELS PRODUCTION COSTS

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** Deceased

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J. D. SNAKENBURG	Cities Service 60 Wall Tower New York 5, N. Y.

NPC Subcommittee on Synthetic Liquid Fuel Costs
Outside Companies Contacted for Information

1. Alabama Power Co.
2. Allis-Chalmers Mfg. Co.
3. American Air Filter Co.
4. American Blower Co.
5. American Cyanamid Co.
6. American Locomotive Co.
7. American Pipe and Construction Co.
8. Anaconda Copper Co.
9. Armco, Inc.
10. Automatic Electric Sales Co.
11. Babcock & Wilcox Co.
12. Baldwin Lima-Hamilton Corp.
13. Bechtel Corporation
14. Bell and Zoller Coal & Mining Co.
15. Bingham Pump Co.
16. Blaw-Knox Co.
17. C. F. Braun & Co.
18. Buell Engineering Co., Inc.
19. Burndy Equipment Co.
20. Caney Creek Mining Co.
21. Carthage Hydrocol, Inc.
22. Central Ohio Coal Co.
23. Chain Belt Co.
24. Chicago Bridge and Iron
25. Chicago, Wilmington & Franklin Coal Co.
26. Clark Bros. Co., Inc.
27. Combustion Engineering-Superheater, Inc.
28. Concrete Conduit Co.
29. Consolidated Western Steel
30. Cooper-Bessemer Corporation
31. Crane Co.
32. Duncan Coal Co.
33. Elliott Co.
34. Engineering Associates
35. Enco Collieries Co.
36. Equitable Life Insurance Co.
37. Ethyl Corporation
38. Farrell Birmingham Co.
39. Ford, Bacon and Davis
40. Foster Wheeler Corporation
41. Fluor Corporation
42. Gamewell Company
43. General Cable Company
44. General Electric Co.
45. The Girdler Corporation
46. F. W. Glitsch & Sons
47. B. F. Goodrich Co.
48. Graham Manufacturing Co.
49. V. Grinnell Co.
50. Hanna Coal Co.
51. Haskel Engineering & Supply Co.
52. Homestead Coal Co.
53. Hydrocarbon Research Corp.
54. Ingersoll-Rand Co.
55. Jeffrey Manufacturing Co.
56. Johns-Manville Corp.
57. The M. W. Kellogg Co.
58. Kennecott Copper Co.
59. Key Co.
60. Koppers Co., Inc.
61. Linde Air Products Co.
62. Link-Belt Co.
63. Lock Joint Concrete Pipe Co.
64. Lummus Co.
65. Maaco Corporation
66. Marley Co., The
67. Morgan Construction Co.
68. Morrison-Knudsen Co., Inc.
69. Nashville Coal Co.
70. National Valve & Mfg. Co.
71. Pacific Pumps, Inc.
72. R. M. Parsons Co.
73. Peabody Coal Co.
74. Peerless Pump Division - Food Machine & Chemical Corp.
75. Perlite Aggregates, Inc.
76. Permutit Co.
77. Petrochem Development Co.
78. Philadelphia Gear Co.
79. M. Pirnie, Engineers
80. Polymer Corp. of Canada
81. C. F. Pritchard Co.
82. Republic Flowmeter Co.
83. H. H. Robertson Co.
84. Rust Engineering
85. Semet-Solvay Co.
86. A. O. Smith Corp.
87. Snow Hill Coal Corp.
88. Southern California Edison Co.
89. Spaco Inc.
90. Sprout-Waldron Co.
91. Stacey Bros. Gas Const. Co.

92. Stevens Adamson Co.
93. Struthers Wells Co.
94. Sunny Hill Coal Co.
95. Truax-Traer Coal Co.
96. Turbine Equipment Co.
97. Ultrasonic Corporation
98. Union Diesel Engine Co.
99. Union Steam Pump Co.
100. Vickers, Inc.
101. Vogue Coal Co.
102. Wallace and Tierman Co.
103. Wellman Engineering Co.
104. Wierton Steel Co.
105. Westinghouse Electric Corp.
106. Wilson-Snyder Mfg. Div.
107. Worthington Pump & Mach. Co.

September 25, 1951

REPORT ON COAL MINING FOR THE COAL HYDROGENATION PROCESS BY THE RAW MATERIALS SUBCOMMITTEE

INTRODUCTION

The Raw Materials Subcommittee of the NPC Subcommittee on Synthetic Liquid Fuels Production Costs was assigned the task of determining suitable locations and raw materials costs for synthetic fuel plants based on the coal hydrogenation process. The primary assignment was (1) to develop coal and water availability and coal costs for the specific site, Rock Springs, Wyoming, which was selected by the U. S. Bureau of Mines for the detailed evaluation of the coal hydrogenation process, and (2) to develop coal and water availability and coal costs for enough additional locations, scattered geographically, to supply plants having a total production of finished products in excess of 200,000 B/CD.

The scope of this study did not include the estimation of the total liquid fuel potential of the United States based on our coal resources, nor did it include any special effort to select locations which are uniquely desirable. In selecting sites for the multi-plant (200,000 B/CD) case, the greatest emphasis was placed on selecting representative locations rather than optimum locations. The locations selected, however, are more nearly representative of the best to be found in the United States rather than the average. The Bureau of Mines participated in the selection of these locations.

The work of this subcommittee on coal availability and costs was divided between two groups who submitted reports, respectively, on Eastern Coal and Western Coal. These reports, appended hereto, also develop coal costs for the modified Fischer-Tropsch synthesis process, but we are not concerned with these costs in this report.

DISCUSSION

The work performed by the Eastern and Western Coal Groups included seven locations in addition to the Rock Springs, Wyoming, site. Each site chosen is capable of providing a 20-year supply of coal for a

coal hydrogenation plant having a capacity of 27,000 B/CD of liquid fuels. The results of these studies are as follows:

Location	Type of Coal	Mine Investment, $ per Annual Ton	Mining Cost, $/Ton
Eastern Coal Sites			
Muhlenberg Co., Ky.	Bitum.	$4.75	$3.25
Franklin Co., Ill.	Bitum.	6.75	4.20
Knox Co., Ind.	Bitum.	6.75	4.20
Union Co., Ky.	Bitum.	6.75	4.03
Wetzel Co., W. Va.	Bitum.	11.25	5.09
Western Coal Sites			
Rock Springs, Wyo.	Bitum.	$2.68	$2.16
Rosebud Co., Mont.	Subbit.	1.21	1.55
Dunn Co., N. Dak.	Lignite	1.23	1.25

The investment costs given above are expressed as dollars per annual ton of capacity. This unit cost method was employed since, at the time these data were prepared, the exact coal requirements were not known. It was known, however, that approximately 4,000,000 tons per year would be consumed by each plant using bituminous coal, and even larger tonnages of subbituminous coal and lignite. This capacity, 4,000,000 tons per year, probably is greater than that of any mine now producing coal, since a capacity of 1,000,000 tons per year is considered to be large. Thus, the unit costs developed in the appended reports can be applied to the actual coal requirements of the plants because, once a mine has been developed to a relatively large size, additional capacity will require a proportional increase in facilities and personnel.

The mining costs shown are exclusive of any profit but do include depreciation and cost depletion. The investment and mining costs should be considered as rough, rather than definitive, cost estimates since there are many factors involved in opening a new coal mine which cannot be determined beforehand, particularly in the absence of an extensive core drilling program.

The costs of the eastern coals are, without exception, higher than the western coals. This is due to two factors, the first of which is the availability of thicker seams and/or easy access to the seams from the surface. The second is that the eastern coals are thoroughly cleaned to prepare a low ash fraction for process consumption whereas the western coals are not cleaned. This latter is due to an inherent low ash content in the Rock Springs coal and the difficulty in cleaning low rank coals such as the Montana subbituminous and the North Dakota lignite.

It should be borne in mind that the mining costs, with few exceptions, were determined for locations in which the coal reserves are not controlled by an operating coal company nor dedicated to an electric utility or other such industry. These reserves are, therefore, usually

not the most desirable from a cost, quality, or transportation viewpoint. A realistic appraisal of the cost of mining more desirable reserves purchased from operating coal companies vs. mining somewhat less desirable reserves with their much lower cost of acquisition will, in the opinion of the subcommittee, indicate only negligible differences. The premise used herein is that the plant owner must acquire its coal reserves on the open market.

No specific information on coal reserves is offered by these reports. It is merely indicated that these specific sites have sufficient reserves to support a 30,000 B/CD synthetic fuel plant for 20 years. Although these sites are not specifically located within the county mentioned, a rough estimate of the distance to, and the name of, the nearest adequate water supply is given. Also, an indication is given concerning the adequacy of transportation and housing facilities at each location.

Since this summary report has dealt only with generalities and given a very brief presentation of the results of these two studies, the reader is referred to the appended reports for a more detailed presentation.

The Raw Materials Subcommittee wishes to acknowledge the assistance received from many people, both within and outside the organizations which are represented by the membership of this subcommittee, whose contributions have significantly improved this study.

By: A. L. Solliday, Chairman
Raw Materials Subcommittee

September 25, 1951

REPORT OF THE EASTERN COAL SUBGROUP OF THE RAW MATERIALS SUBCOMMITTEE OF NPC'S SUBCOMMITTEE ON SYNTHETIC FUELS PRODUCTION COSTS

The function of the Eastern Coal Subgroup was to evaluate a number of locations east of the Mississippi River as raw materials sources for a synthetic fuel industry based on coal. Information has been developed on coal availability and quality, mining and mine investment costs, and availability of water, for six plant sites. This information is summarized on Table I and additional details are given in the attached charts and Tables II through V.

The plant sites were originally selected at a meeting attended by the Raw Materials Subcommittee and the U.S. Bureau of Mines. Subsequent study, however, indicated that two of the original sites should be shifted to locations at which sufficient reserves of coal in the "Inactive Reserves" category were more readily available. These changes involved replacing the Harrison County, Ohio, No. 8 seam, strip mine with the Noble County, Ohio, No. 9 seam, strip mine, and shifting the West Virginia, Pittsburgh seam, underground mine from Monongalia County westward to adjacent Wetzel County.

Of the premises used in the selection of all six sites, the most important is the availability of sufficient coal reserves. Before discussing the individual sites, it is necessary to define the classification of coal reserves as used by the Eastern Coal Subgroup. They are:

a. Active Commercial Reserves. These are contiguous to existing commercial mining operations and are owned by commercial coal companies. Generally these reserves are the most readily available to rail and river transportation. Such reserves can be purchased at going prices. "Going Prices" can be defined as that price worked out by the owner based on his estimate of future earning power of the reserves discounted at a reasonable interest rate.

The shifting in plant sites mentioned above was due to the fact that the huge coal reserves in Harrison County, Ohio and Monongalia County, West Virginia are in the "active commercial reserves" category. The vast "commercial reserves" in these West Virginia and Ohio Counties would support several coal hydrogenation plants of the size contemplated, and these sites should be re-examined, whenever a more detailed survey might be made.

The Muhlenberg County, Kentucky site was selected in "Active Commercial Reserves." For this reason a royalty rate of $0.50 per ton on good active strip coal reserves was used. Since the good strip operators in this field are making at least this much profit, and probably more, we do not see why it could be leased for less.

b. Inactive Reserves. These are owned by farmers and land companies and, in general, are located some distance from active mines or transportation facilities. After looking over many areas east of the Mississippi River, it is reasonable to make the assumption

that private companies have already developed good quality reserves, closest to rail and water transportation with the most favorable mining conditions and the lowest cost operations. Therefore, one may expect that mining costs in the areas designated "inactive reserves" will be higher than costs in "commercial reserves." This explains, for example, why this group estimated a much higher cost for mining "inactive reserves" in Wetzel County, West Virginia, than the present costs in existing mines operating in "commercial reserves" in Northern West Virginia. All sites except Muhlenberg County, Kentucky were selected in "inactive reserves."

c. Captive Reserves. Steel companies, electric power utilities, and chemical companies mining their own coal must protect large plant investments with long-life reserves of coal. It can be stated categorically that such large reserves are not for sale any more than would be those acquired by a synthetic fuel plant for its own use.

As previously stated, the selection of the six sites used in this study was greatly affected by the problem of acquiring sufficient reserves. The production of approximately 30,000 B/D of liquid fuels at each location, using either the hydrogenation or Fischer-Tropsch synthesis process, requires reserves of 100 million tons, or more, of coal. The task of assembling contiguous blocks of "commercial" reserves to meet this required quantity presents some problems in most of the present coal mining areas. Also, since it is the opinion of this group that "commercial" reserves could only be purchased at a price reflecting the incremental profit which the present owner expects to make above mining poorer or "inactive" reserves, there are perhaps no particular long-range benefits to be obtained by attempting to study this whole problem on the basis that only "commercial" reserves would be used.

In line with this, three of the locations, viz. Wetzel County, West Virginia; Knox County, Indiana; and Union County, Kentucky, are based on "inactive" reserves. The Franklin County, Illinois location is also in this classification, even though most of the undeveloped reserves in this area are held by a steel company. There are no indications, however, that these reserves are in any way a vital factor in the continuing operation of this company, and they are thus classified as "inactive" reserves.

The Noble County, Ohio, location does not have sufficient "inactive" strip coal reserves to meet the requirements of a 30,000 B/D plant. Nevertheless, it has been included on the basis that it would supply coal to a 10,000 B/D plant of the Fischer-Tropsch type.

In the five locations discussed so far, all have been classified as "inactive" reserves and a consistent coal land price of 5 cents per ton has been used.

The final location, Muhlenberg County, Kentucky, is the only location in which "commercial" reserves are specified. There are approximately 150-million tons of strippable coal in this county, and essentially all is controlled by active strip operators. It was believed to be desirable to include one 30,000 B/D location at which the coal is strip mined, and this particular area represents one of the few remaining, east of the Mississippi, where large tonnages are available. Rather than attempt to estimate the price of these

properties under an outright purchase, it was decided to include a royalty payment of 50 cents per ton. This may or may not be adequate, but it does tend to put the mining costs at this location on a more realistic basis than if a cost depletion of 5 cents per ton were used.

Operating and Investment Costs. Calculations made to develop the data in this report were prepared on the best judgment of men experienced in coal mine operations. Obviously, much more exhaustive studies than could be made at that time by this subgroup committee would be required to remove all estimating uncertainties in these costs. Because in almost all instances this committee's report was based on using "inactive reserves" the exact physical characteristics of the coal in most of the areas is unknown and must be estimated. Obviously, such estimates can only be approximations. However, this aim of eliminating all uncertainties in estimating coal quality and coal mining costs is quite unrealistic, because the unpredictable factors involved in coal mining operations could more than offset any substantial differences in views between experienced operators on mining costs.

We do not believe sound business judgment would permit all the best single performance data for each item of coal mine operation to be accumulated and employed as a proper representation of total coal costs. Such idealistic figuring and forecasting are not the basis of requests by mine operators made to Boards of Directors for funds to open new properties. It is our belief that the costs reported here are in line with the thinking of most of the country's reliable operators and represent an approach to the problem similar to that used in commercial practice today.

According to one of this committee's prime premises based upon the experience of the members, it costs more to open and operate mines in "inactive reserves" than it does to open and operate mines in "active commercial reserves" in the same general area. Because of the future estimated earning power of certain "active commercial reserves" the present owners might not sell or lease them at a rate low enough to permit total cost from these "active commercial reserves" to be as low as total cost from production in "inactive reserves" in the same district. To say it another way: If "active commercial reserves" cost too much more to buy or lease than "inactive reserves," then it might be cheaper to buy and operate in "inactive reserve" areas. All this simply points out that it is a complex problem requiring a lot of study.

There is one other influence on coal mine operations which we feel must be brought out in this report, and this relates to unionization of areas surveyed by this committee. Except for West Kentucky, all mining areas surveyed are now operated by members of the United Mine Workers. If it should be decided to locate one or more large synthetic fuel plants in an unorganized area such as West Kentucky, it is our belief that full allowance should be made in cost analyses for this area to provide for the cost items that result from organization of the workers. Plants and mines of such huge magnitude would naturally attract the full attention of every major labor union in the country.

The mining and investment costs were based on providing a cleaned coal for the hydrogenation plants. It was assumed that the Fischer-Tropsch synthesis plants would also require a similar coal. We have recently been notified, however, that the latter process can suitably use raw coal and so the mining and investment costs have been adjusted for this process. Although the costs for raw coal appear to be on a more exact basis than the clean coal costs, this is merely the result of mathematical adjustments and the desire to keep clean and raw coal costs on a consistent basis at each location.

In summary, a detailed analysis of Eastern areas for possible synthetic fuel sites based on coal should consider these possible means for adquiring the necessary coal: (1) the purchase of coal from existing mines; (2) the purchase and expansion of existing mines and contiguous "commercial reserves," to provide for this large new demand; (3) possible opening of new mines in "commercial reserves" dedicated to the synthetic fuel plant; and (4) the opening of mines in "inactive reserve" areas. Under conditions of world tension, materials needed for the opening and equipping of whole new mines are very scarce. Good, efficient manpower for fully mechanized mines is also scarce. In fact, manpower could be much scarcer than materials. We, therefore, believe that if a synthetic fuel program were to be initiated now that coal probably could be supplied most advantageously by routes (1) and (2) noted above.

This committee has reviewed the report of coal analyses and sizing at the sites in question prepared by Mr. William Crentz of the Bureau of Mines, sent along with a letter to G. C. Gambs, dated July 3, 1951. While there are some points of difference, we did not believe any estimates of what coal analyses or sizing will be from mines as yet unopened are subject to much discussion unless the differences are quite substantial. It should be thoroughly understood, and we repeat for emphasis, that such estimates are truly "guesstimates."

We also wish to offer a general word of caution about cleaning coal at very low specific gravities such as 1.30, 1.32, 1.33, and 1.35, to produce super-clean feedstocks for hydrogenation plants. Such separations can be made but at great sacrifices in cleaning capacity of any given size cleaning unit.

Thus, "super-cleaning plants," of the capacities required for synthetic fuel plants, will undoubtedly have to contain a large number of cleaning vessels or units. Such cleaning plants are expensive to build and to operate.

With these remarks on the record, and in the interests of saving time we have not changed Mr. Crentz's sizing or analytical data, and we have not changed our costs.

N.P.C. EASTERN COAL SUBGROUP

/s/ Joseph Pursglove, Jr.
Joseph Pursglove, Jr.
Chairman

Committee Members:

Clayton G. Ball
I. S. Salnikov
Stephen Krickovic

TABLE I

NPC COMMITTEE ON SYNTHETIC FUELS PRODUCTION COSTS
RAW MATERIALS SUBCOMMITTEE - EASTERN COAL SUBGROUP

Summary of Information on Coal Supply for Synthetic Fuel Plant Sites East of Mississippi River

Location												
State	Ohio		Western Kentucky		Illinois		Indiana		Western Kentucky		West Virginia	
County	Noble		Muhlenberg		Franklin		Knox		Union		Wetzel	
Reserves												
Classification of Coal	Bituminous		Bituminous		Bituminous		Bituminous		Bituminous		Bituminous	
Tons Recoverable at Specified Cost	Sufficient for 10,000 B/D Plant		Sufficient for 30,000 B/D Plant		Sufficient for 30,000 B/D Plant		Sufficient for 30,000 B/D Plant		Sufficient for 30,000 B/D Plant		Sufficient for 30,000 B/D Plant	
Mine Characteristics												
Type of Opening	Strip		Strip		Underground-500' Shaft		Underground-400' Shaft		Underground-300' Shaft		Underground-1,000' Shaft	
Average Thickness of Minable Seams	48"		66" and 54"		72" to 78"		60"		59" and 66"		72"	
Identification of Seams	#9		#11 and #12		#6		#5		#9 and #11		Pittsburgh	
Dip of Seams	Less than 1°		Less than 1°		Less than 1°		Less than 1°		Less than 1°		Less than 1°	
Quality of Coal as Rec'd at Plant	Hydro	F.T. Syn.	Hydro	F.T. Syn.	Hydro	F.T. Syn.	Hydro	F.T. Syn.	Hydro	F.T. Syn.	Hydro	F.T. Syn.
Hydrogenation Coal												
Moisture	-	-	9.5%	-	11.0%	-	12.0%	-	9.1%	-	4.5%	-
Ash	-	-	4.9%	-	3.7%	-	5.3%	-	4.2%	-	6.4%	-
Heating Value (as Rec'd), Btu/Lb	-	-	12,400	-	12,400	-	12,000	-	12,600	-	13,450	-
Gasification Coal												
Moisture	-	5.0%	8.5%	7.5%	10.3%	9.0%	11.4%	10.0%	8.0%	7.1%	2.7%	2.5%
Ash	-	16.9%	17.4%	14.9%	11.6%	9.2%	11.8%	11.7%	14.6%	14.5%	11.6%	12.7%
Heating Value (as Rec'd), Btu/Lb	-	11,320	10,750	11,200	11,300	11,900	11,100	11,300	11,300	11,400	12,940	12,800
Mine Equipment, Facilities, and Development												
Cost, $/Yearly Ton of Production	$4.31		$4.75	$3.16	$6.75	$5.37	$6.75	$5.14	$6.75	$5.04	$11.25	$9.28
Construction Manhours per Yearly Ton	0.5		0.5	0.5	0.533	0.533	0.725	0.725	0.427	0.427	0.492	0.492
Tons of Metals per Yearly Ton												
Steel	.00215		.00215	.00215	.00077	.00077	.00077	.00077	.00077	.00077	.00077	.00077
Copper and Others	.000015		.000015	.000015	.000005	.000005	.000005	.000005	.000005	.000005	.0000057	.0000057
Mining Labor and Costs												
Labor Efficiency, Tons/Man/Shift	23.5		25	31.6	9	9.7	9	10.3	9	10.5	7	7.9
Mining Cost Incl. Depreciation, $/Ton	$2.72		$3.25	$2.83	$4.20	$3.89	$4.20	$3.69	$4.03	$3.47	$5.09	$4.54
Effect of 10% per Year Return (before Taxes) on Investment, $/Ton	$0.43		$0.48	$0.32	$0.68	$0.54	$0.68	$0.51	$0.68	$0.50	$1.13	$0.93
Other Factors												
Water Supply	25 Miles West to Muskingum River or 25 Miles So. to Ohio R.		15 Miles East to Green River or 50 Miles North to Ohio River.		40 Miles SW to Mississippi R. or 45 Mi. E. to Wabash River.		10 Miles West to Wabash River.		5 Miles West to Ohio River.		30 Miles East to Monongahela R. or 30 Miles W. to Ohio R.	
Transportation Facilities	No Major Railroad Construction Required		No Major Railroad Construction Required		No Major Railroad Construction Required		No Major Railroad Construction Required		No Major Railroad Construction Required		No Major Railroad Construction Required	
Distance From Plant Site to Mine	Reasonably Close		Reasonably Close		Reasonably Close		Reasonably Close		Reasonably Close		Reasonably Close	
Cost of Transporting Coal to Plant Site	Minor Expense		Minor Expense		Minor Expense		Minor Expense		Minor Expense		Minor Expense	
Housing Requirements as % of Labor Force	No Problem		No Problem		No Problem		No Problem		No Problem		No Problem	

DATA ON COAL FOR HYDROGENATION PLANT

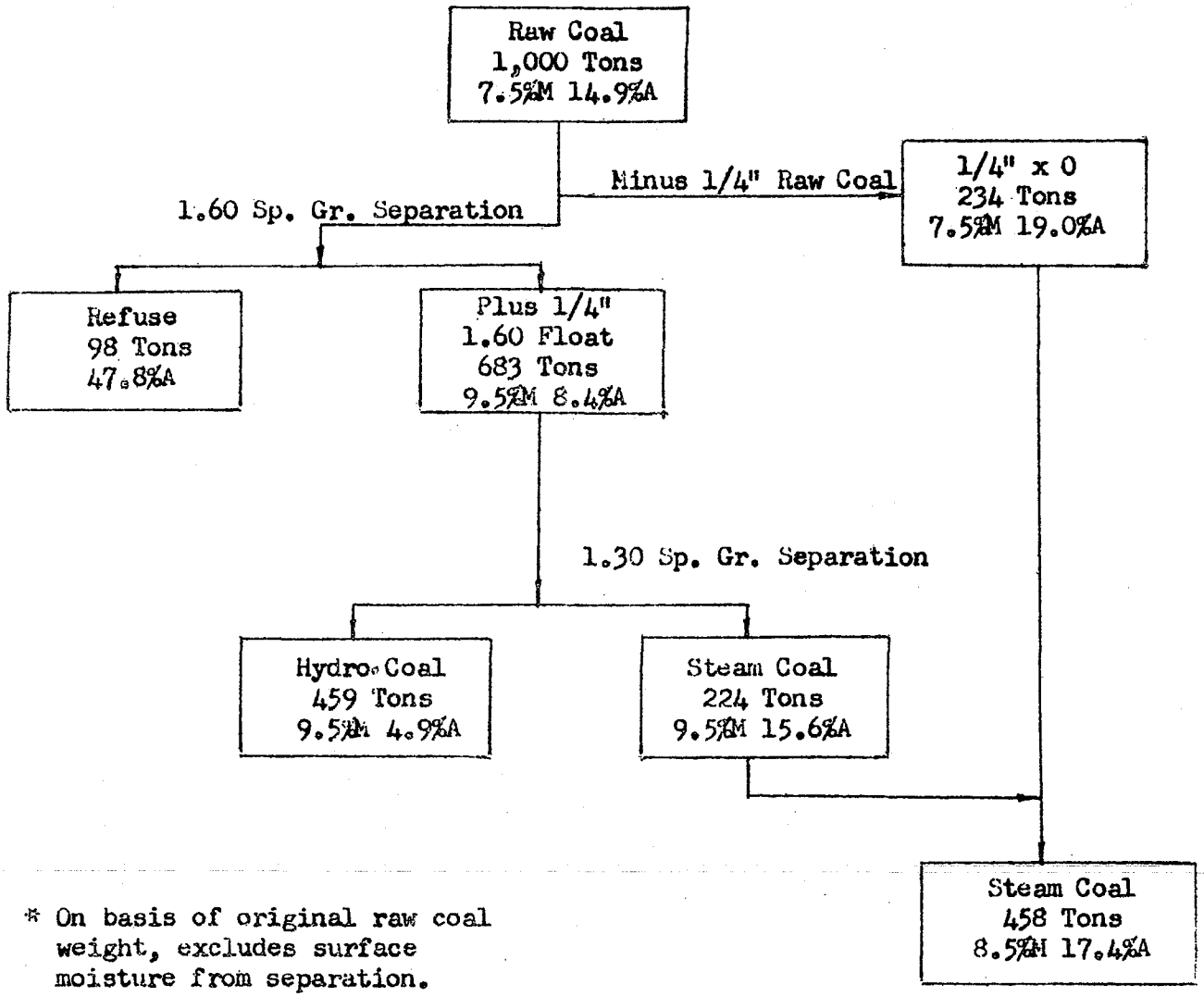
1. State: Kentucky
2. County: Muhlenberg
3. Seam: #11 and #12
4. Type Mining: Strip
5. Type Plant: Hydrogenation
6. Heating value of coal on M & A free basis:

Bed	H.V.	M	Thickness
#11	14,550 Btu	7%	66"
#12	14,400 Btu	8%	54"
Av	14,490 Btu	7.5%	

7.

Analysis	Raw Coal	Cleaning Pl. Refuse	Clean Coal to Hydrogenation Pl.	Middlings to Power Pl.	Fines to Power Pl.
Ash	14.9	47.8	4.9	15.6	19.0
Moisture	7.5	9.5	9.5	9.5	7.5
Btu	11,200	—	12,400	10,900	10,600
% of Total*	100.0	9.6	45.0	22.0	23.4

8. Estimated mine operating days per year: 220 days.
9. Flow Sheet:



* On basis of original raw coal weight, excludes surface moisture from separation.

DATA ON COAL FOR HYDROGENATION PLANT

1. State: Illinois
2. County: Franklin
3. Seam: #6
4. Type Mining: Underground
5. Type Plant: Hydrogenation

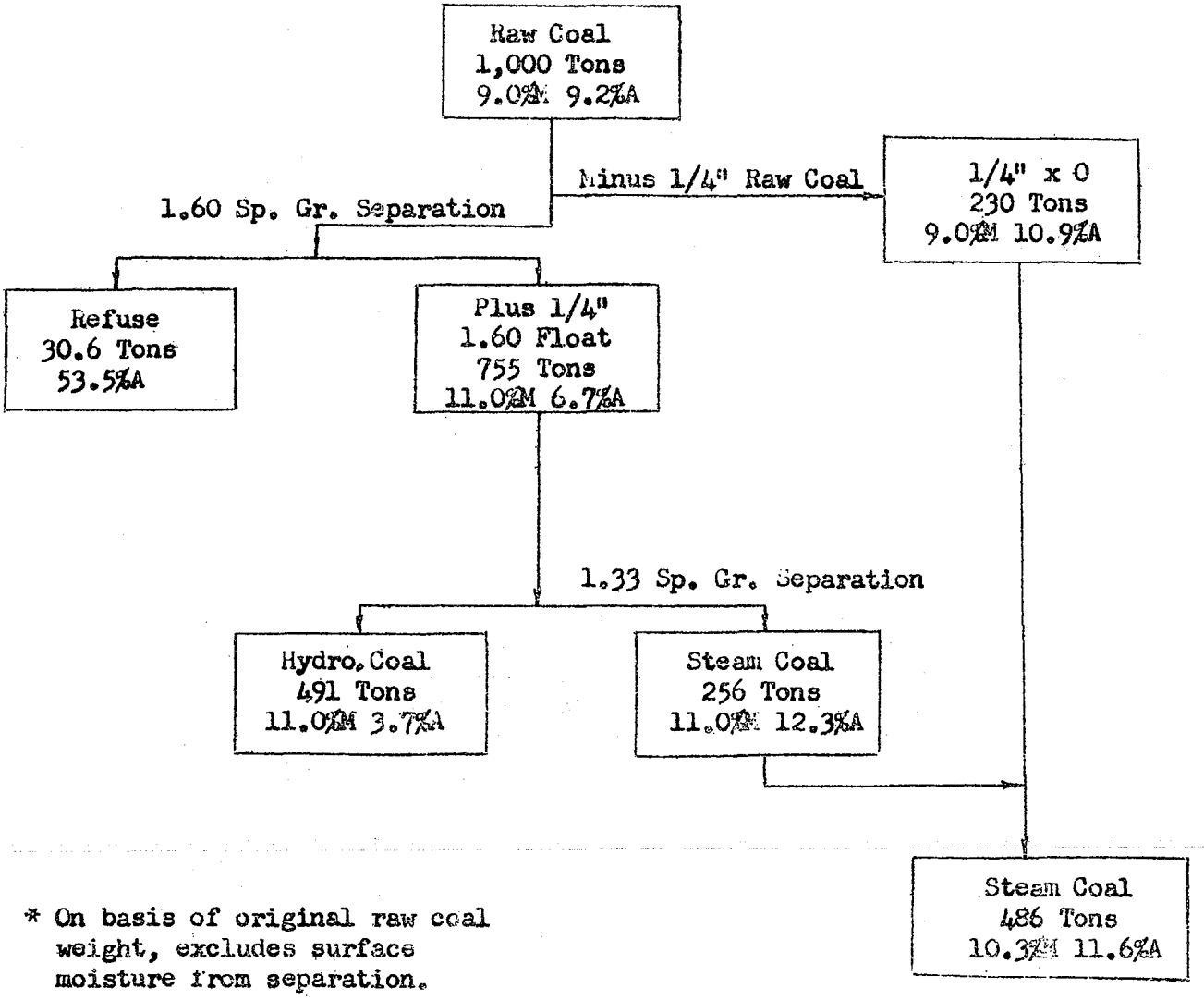
Bed Moisture: 9%

6. Heating value of coal on M & A free basis: 14,500 Btu

7.

Analysis	Raw Coal	Cleaning Pl. Refuse	Clean Coal to Hydrogenation Pl.	Middlings to Power Pl.	Fines to Power Pl.
Ash	9.2	53.5	3.7	12.3	10.9
Moisture	9.0	11.0	11.0	11.0	9.0
Btu	11,900	--	12,400	11,100	11,600
% of Total*	100.0	3.0	48.5	25.5	23.0

8. Estimated mine operating days per year: 220 days.
9. Flow Sheet:



* On basis of original raw coal weight, excludes surface moisture from separation.

DATA ON COAL FOR HYDROGENATION PLANT

1. State: Indiana
2. County: Knox
3. Seam: #5
4. Type Mining: Underground
5. Type Plant: Hydrogenation

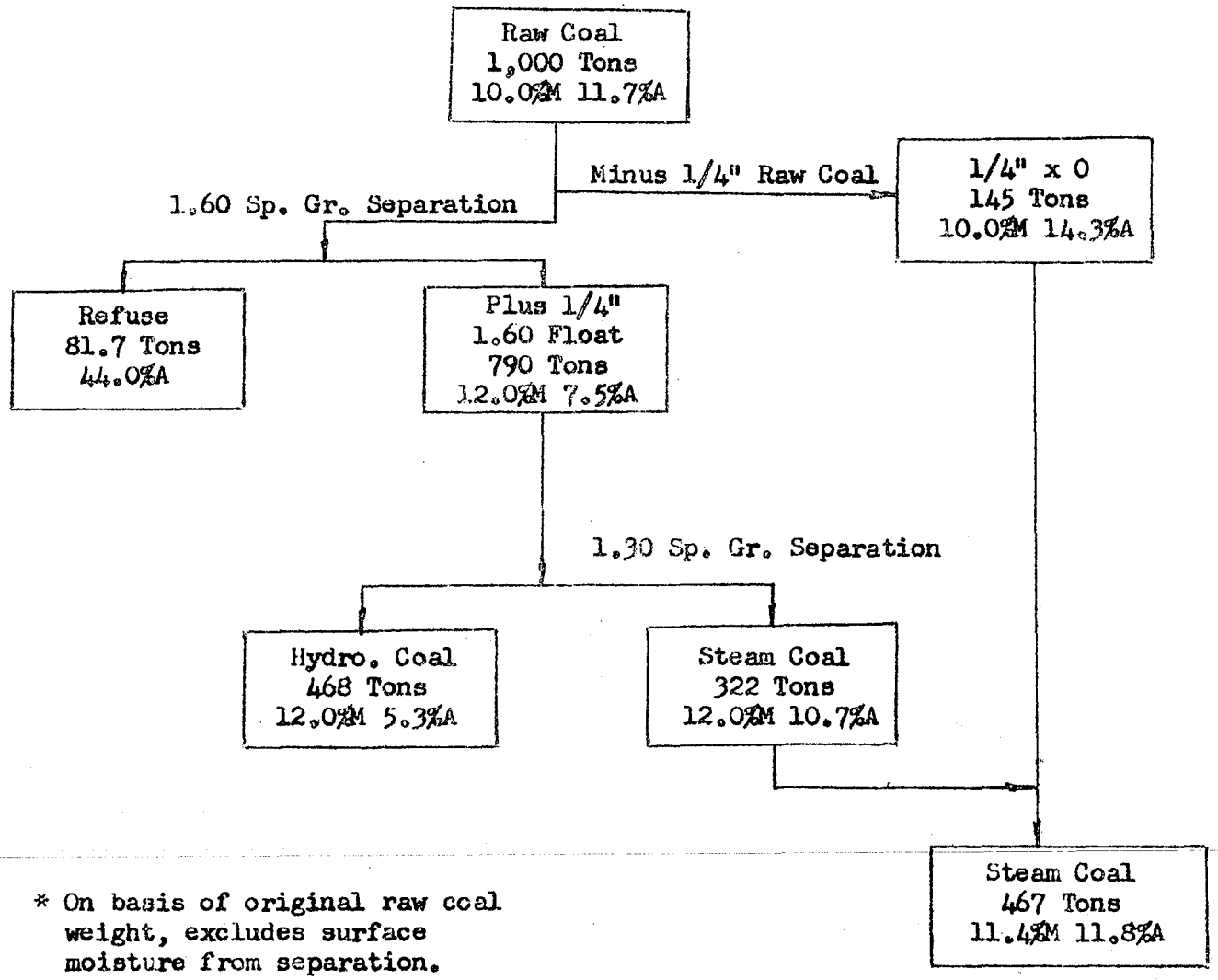
Bed Moisture: 10%

6. Heating value of coal on M & A free basis: 14,500 Btu

7.

Analysis	Raw Coal	Cleaning Pl. Refuse	Clean Coal to Hydrogenation Pl.	Middlings to Power Pl.	Fines to Power Pl.
Ash	11.7	44.0	5.3	10.7	14.3
Moisture	10.0	12.0	12.0	12.0	10.0
Btu	11,300	—	12,000	11,200	11,000
% of Total*	100.0	8.0	46.0	31.5	14.5

8. Estimated mine operating days per year: 220 days.
9. Flow Sheet:



* On basis of original raw coal weight, excludes surface moisture from separation.

DATA ON COAL FOR HYDROGENATION PLANT

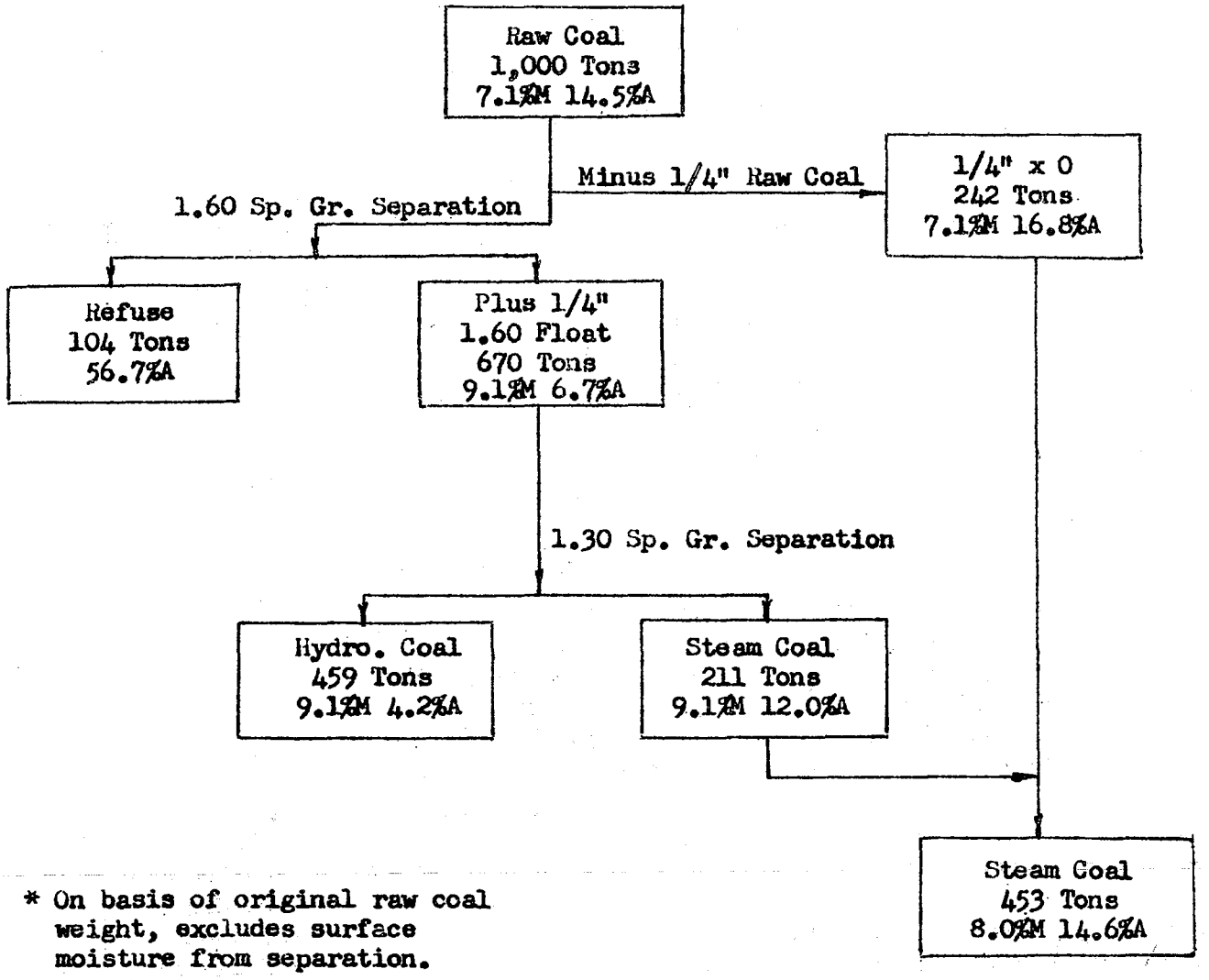
1. State: Kentucky
2. County: Union
3. Seam: #9 and #11
4. Type Mining: Underground
5. Type Plant: Hydrogenation
6. Heating value of coal on M & A free basis:

Bed	H.V.	M	Thickness
# 9	14,800 Btu	5%	59"
#11	14,400 Btu	11%	66"
Av	14,600 Btu	7%	

7.

Analysis	Raw Coal	Cleaning Pl. Refuse	Clean Coal to Hydrogenation Pl.	Middlings to Power Pl.	Fines to Power Pl.
Ash	14.5	56.7	4.2	12.0	16.8
Moisture	7.1	9.1	9.1	9.1	7.1
Btu	11,400	—	12,600	11,500	11,100
% of Total*	100.0	10.2	44.9	20.7	24.2

8. Estimated mine operating days per year: 220 days.
9. Flow Sheet:



* On basis of original raw coal weight, excludes surface moisture from separation.

DATA ON COAL FOR HYDROGENATION PLANT

1. State: West Virginia
2. County: Monongalia & Wetzel
3. Seam: Pittsburgh
4. Type Mining: Underground
5. Type Plant: Hydrogenation

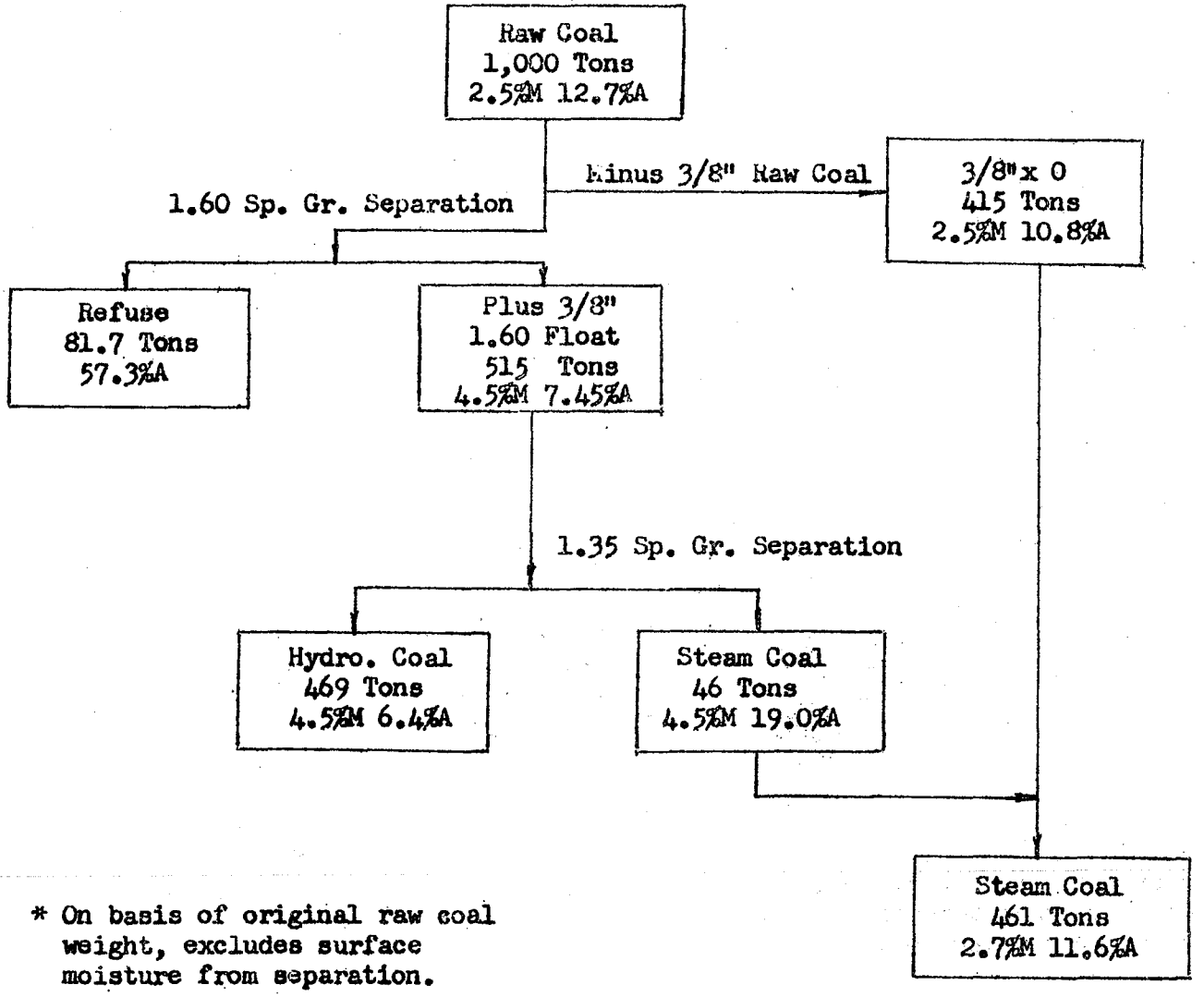
Bed Moisture: 2.5%

6. Heating value of coal on M & A free basis: 15,100 Btu

7.

Analysis	Raw Coal	Cleaning Pl. Refuse	Clean Coal to Hydrogenation Pl.	Middlings to Power Pl.	Fines to Power Pl.
Ash	12.7	57.3	6.4	19.0	10.8
Moisture	2.5	4.5	4.5	4.5	2.5
Btu	12,800	--	13,450	11,500	13,100
% of Total*	100.0	8.0	46.0	4.5	41.5

8. Estimated mine operating days per year: 220 days.
9. Flow Sheet:



* On basis of original raw coal weight, excludes surface moisture from separation.

TABLE II

RAW COAL MOISTURE AND ASH AND MAF HEATING VALUE

Site	State	County	Type Mining	Seam	Raw Coal, Wt% Moisture	Raw Coal, Wt% Ash	HV (M & A Free)
1	Ohio	Noble	Strip	#9	5	16.9	14,500
2	Kentucky	Muhlenberg	Strip	#11	7	13.1	14,550
				#12	8	16.9	14,400
3	Illinois	Franklin	Under.	#6	9	9.2	14,500
4	Indiana	Knox	Under.	#5	10	11.7	14,500
5	Kentucky	Union	Under.	#9	5	17.1	14,800
				#11	9	11.7	14,400
6	W. Virginia	Wetzel	Under.	Pittsburgh	2.5	12.7	15,100

TABLE III

INVESTMENT COST IN DOLLARS PER TON OF ANNUAL CAPACITY

Note: All costs are per ton of coal delivered to synthetic fuel plant

Site	State	County	Seam	Depth to Seam	Type of Mine	Investment, $/Annual Ton							
						Mine		Coal Lands		Cleaning Plant		Total	
						Syn.	Hydro.	Syn.	Hydro.	Syn.	Hydro.	Syn.	Hydro
1	Ohio	Nobel	#9	0	Strip	$3.31	$ -	$1.00	$ -	-	$ -	$4.31	$ -
2	Ky	Muhlenberg	#11 & 12	0	Strip	3.16	3.50	-	-	-	1.25	3.16	4.75
3	Ill.	Franklin	#6	500'	Under.	4.37	4.50	1.00	1.00	-	1.25	5.37	6.75
4	Ind.	Knox	#5	400'	Under.	4.14	4.50	1.00	1.00	-	1.25	5.14	6.75
5	Ky	Union	#9 & 11	300'	Under.	4.04	4.50	1.00	1.00	-	1.25	5.04	6.75
6	W. Va.	Wetzel	Pitts.	1,000'	Under.	8.28	9.00	1.00	1.00	-	1.25	9.28	11.25

TABLE IV

BREAKDOWN OF COAL MINE OPERATING COSTS

Note: All costs are per ton of coal delivered to synthetic fuel plant

Site	State	County	Seam	Type of Mine	Per Man-Shift		Operating Costs, $/Ton								
					Wages	Productivity, Tons	Direct Labor	U.M.W. Welfare Fund	Vacations, etc.	Total Labor	Supplies, etc.*	Depreciation**	Cost Depletion	Royalty	Total Costs
A - COAL HYDROGENATION PLANTS															
1	Ohio	Noble	#9	Strip	-	-	-	-	-	-	-	-	-	-	-
2	Ky	Muhlenberg	#11 & 12	Strip	$18.00	25	$0.72	$0.30	$0.03	$1.05	$1.25	$0.45	-	$0.50	$3.25
3	Ill.	Franklin	#6	Under.	18.00	9	2.00	0.30	0.05	2.35	1.25	0.55	$0.05	-	4.20
4	Ind.	Knox	#5	Under.	18.00	9	2.00	0.30	0.05	2.35	1.25	0.55	0.05	-	4.20
5	Ky	Union	#9 & 11	Under.	16.50	9	1.83	0.30	0.05	2.18	1.25	0.55	0.05	-	4.03
6	W. Va.	Wetzel	Pitts.	Under.	16.25	7	2.32	0.30	0.05	2.67	1.40	0.97	0.05	-	5.09
B - FISCHER-TROPSCH SYNTHESIS PLANTS															
1	Ohio	Noble	#9	Strip	$20.00	23.5	$0.85	$0.30	$0.03	$1.18	$1.18	$0.31	$0.05	-	$2.72
2	Ky	Muhlenberg	#11 & 12	Strip	18.00	31.6	0.57	0.30	0.03	0.90	1.13	0.30	-	$0.50	2.83
3	Ill.	Franklin	#6	Under.	18.00	9.7	1.86	0.30	0.05	2.21	1.21	0.42	0.05	-	3.89
4	Ind.	Knox	#5	Under.	18.00	10.3	1.75	0.30	0.05	2.10	1.15	0.39	0.05	-	3.69
5	Ky	Union	#9 & 11	Under.	16.50	10.5	1.57	0.30	0.05	1.92	1.12	0.38	0.05	-	3.47
6	W. Va.	Wetzel	Pitts.	Under.	16.25	7.9	2.06	0.30	0.05	2.41	1.29	0.79	0.05	-	4.54

* This column includes supplies, power, taxes and insurance, and administrative overhead.

** Depreciation charges calculated by using 12.5% rate on 60% of investment and 5% rate on remainder, giving overall rate of 9.5%. Investment for coal lands written off as cost depletion at 5% rate.

TABLE V

BASIS FOR CALCULATIONS OF CONSTRUCTION MANHOURS AND TONS OF METAL FOR MINE EQUIPMENT, FACILITIES AND DEVELOPMENT - BASED ON MPAC STUDY OF MARCH 15, 1948

I. MPAC Study March 1948

State County	Illinois Hamilton	Indiana Vigo & Sullivan	W. Kentucky Union	W. Virginia Monongalia
T/D Coal	25,700	26,400	25,700	21,700
HV Btu	11,000	10,700	11,000	13,000
Annual Capacity (T/D x 365)	9,380,500	9,650,000	9,380,500	7,920,500
Type Mining	Underground	Underground	Underground	Underground
1. Tons Steel	7,200	7,400	13,700	6,100
T Steel/Annual Ton Capacity	.00077	.00077	.00146	.00077
2. Tons Copper	50	50	95	45
T Copper/Annual Ton Capacity	.00000533	.00000518	.0000101	.00000568
3. Construction Labor Million Man Hours	5.0	7.0	4.0	3.9
Man Hours/Annual Ton Capacity	.533	.725	.427	.492

II. MPC Study October 1950

State County Type Mining	Ohio Noble Strip	W. Kentucky Muhlenberg Strip	Illinois Franklin Underground	Indiana Knox Underground	W. Kentucky Union Underground	W. Virginia Wetzel & Monongalia Underground
1. Tons Steel/Annual Ton	.00215*	.00215*	.00077	.00077	.00077	.00077
2. Tons Copper/Annual Ton	.00001465	.00001465	.00000533	.00000518	.000005	.00000568
3. Man Hours/Annual Ton	.5 (est.)	.5 (est.)	.533	.725	.427	.492

* Based on factor of 0.56 tons of steel per daily ton of production for strip mines.

REPORT OF THE WESTERN COAL SUB-GROUP OF THE RAW MATERIALS SUB-COMMITTEE OF THE NPC'S SUB-COMMITTEE ON SYNTHETIC LIQUID FUELS PRODUCTION COSTS

The assignment of the Western Coal Sub-Group of the Raw Materials Subcommittee was to evaluate several raw material sources west of the Mississippi River as locations for synthetic fuel plants. Information was to be developed on coal availability and quality, mining costs, and availability of water.

At a meeting attended by the Raw Materials Subcommittee and the U. S. Bureau of Mines on September 25 and 26, in Washington, D.C., four sites were tentatively selected for evaluation by the Western Coal Sub-Group. These sites included the specific location in the Rock Springs Field, Wyoming, on which the U.S.B.M. based their estimate of the 30,000 B/D coal hydrogenation plant. The three remaining sites included one in the North Dakota lignite region, one in the Montana sub-bituminous region, and one in the Kemmerer Field, Wyoming, which coal ranks slightly above sub-bituminous. This Kemmerer Field location, however, was eliminated since its advantage, over the Rock Springs location, of a lower mining cost would be offset by lower quality and a more difficult water supply.

The information on the attached table summarizes the evaluations for the three locations finally considered. It will be noted that no specific quantity of coal reserves are given except to mention that they are sufficient for a 30,000 B/D plant. Actually, at each of these locations, it is possible that several more plants could be located within a radius of 10 miles. The major limitations in these regions are water and labor supply and a market for the products.

Inasmuch as the proposed mine sites in the Rock Springs and Rosebud Fields are near the present mining operations in these areas, it was assumed that the coal will be of the same quality as that currently being mined. The lignite beds in North Dakota will vary rather widely in moisture and mineral content, so in the absence of any samples from the particular area chosen, an average composition was used.

Due to the weathering characteristics of lignite and sub-bituminous coals, these materials are never wet-cleaned. In the opinion of this group, the only feasible operation for preparing these coals for consumption in a hydrogenation plant would involve crushing to a minus 3" or 4" size followed by a screening or sizing operation to obtain roughly equal portions of coarse and fine material. The coarse coal would be the cleaner and would serve as the raw material for the hydrogenation reaction; leaving the finer for use in steam generation and hydrogen manufacture. Only the crushing operation would be required to prepare the raw material for the Fischer-Tropsch synthesis plant.

The Rock Springs bituminous coal can be wet-cleaned, but the ash content is inherently low so that little benefit could be obtained by installing a cleaning plant. It was therefore decided that this coal would be handled in the same manner as the lignite and sub-bituminous coals.

The sulfur content of these coals, corresponding to the analysis shown on the table under the heading "Fischer-Tropsch Synthesis", is as follows:

Location	% Sulfur
Rock Springs Bituminous	0.9
Montana Sub-bituminous	1.0
North Dakota Lignite	0.7

The mine investment costs for the bituminous and sub-bituminous coals are based on the approximate tonnage required to supply a 30,000 B/D plant. The lignite mine costs are based on an optimum-sized pit of which about three would be required to supply a 30,000 B/D plant. These investment costs include the purchase of mineral and surface rights where necessary and all equipment, facilities, and development costs required to mine, crush, and deliver the coal to stockpiles at an adjacent plant. If it is decided to locate the plant near the water supply rather than at the mine location; coal transportation costs must be added to this estimate.

The mining costs include all direct and indirect charges, such as depreciation, depletion, royalty, property taxes, administrative overhead, etc., but exclude any return on investment. An important item in the mining costs for each of these mines is the 30¢ per ton payment to the UMW Welfare Fund. If it were assumed that these mines would not be organized under the UMW, reductions of 15 to 25¢ per ton would result even with very liberal labor benefits. The UMW, however, represents the majority of miners in Wyoming and North Dakota, and the mining costs must include these Welfare Fund payments to be realistic.

The water supply for the Rock Springs location may be obtained from several sources. The Bureau of Mines, in their detailed estimate of a 30,000 B/D coal hydrogenation plant, assumed that a 100 mile flow line carrying water from Fremont Lake was the best source for this project. This group, however, is of the opinion that the Green River, 33 miles southwest of the mine site, might be more economical. The minimum flow from the Green River is many times the amount of water required for a synthetic fuel plant, and the unallocated water in the New Fork River is in excess of that required for a synthetic fuel plant.

For the Montana sub-bituminous site, we have assumed that sufficient water would be obtained from the Yellowstone River, 35 miles north of the mine location. This may be somewhat optimistic since the runoff during certain periods of the year is rather small. However, the water supply problem for one plant should not be critical, but two or more plants would probably require the construction of storage basins.

The North Dakota lignite mine site lies about 30 miles south of the artificial lake created by the Garrison Dam. It is reasonable to assume that sufficient water for one plant could be obtained from this reservoir. Additional sources of water in the future will be made available by proposed dams on the Knife and Little Missouri Rivers.

Additional railroad trackage will be required for both the Rock Springs and Montana mine sites. If, in either case, it is desired to transport the coal over this trackage to the plant site, or if the plant products are to be moved by rail from near the mine site, it is probable that the railroad companies will install the tracks. If, however, the freight movement over these tracks is negligible, the cost must be included in the investment cost for the total project.

In all cases, these mine locations are in sparsely settled country and it will be necessary to provide housing and perhaps develop whole new communities.

This, to our knowledge, concludes the work of the Western Coal Group, but if we can be of further assistance we will cooperate willingly.

/s/ I. N. Bayless

I. N. Bayless, Chairman
Western Coal Sub-Group

J. H. Poore
R. L. Baldner

February 12, 1951

NPC COMMITTEE ON SYNTHETIC FUEL COSTS
RAW MATERIALS SUBCOMMITTEE - WESTERN COAL SUB-GROUP

Summary of Information on Coal Supply for Synthetic Fuel Plant Sites West of Mississippi River

Location						
State	Wyoming		Montana		North Dakota	
County	Sweetwater		Rosebud		Dunn	
Field	Rock Springs		Rosebud		(Near Dunn Center)	
Reserves						
Classification of Coal	Bituminous		Sub-bituminous		Lignite	
Tons Recoverable at Specified Cost	Sufficient for 30,000 B/D Plant		Sufficient for 30,000 B/D Plant		Sufficient for 30,000 B/D Plant	
Mine Characteristics						
Type of Opening	Underground - Slope		Strip		Strip	
Average Thickness of Minable Seams	Approx. 7' each		24'		14.5'	
Identification of Seams	Nos. 3, 1, and 7½		(one seam)		(one seam)	
Dip of Seams	4°		Flat		Flat	
Quality of Coal as Rec'd at Plant	**Hydro**	**F.T. Syn.**	**Hydro**	**F.T. Syn.**	**Hydro**	**F.T. Syn.**
Hydrogenation Coal						
Moisture	10.0%	--	25.8%	--	40.0%	--
Ash	3.3%	--	6.6%	--	4.5%	--
Heating Value (as rec'd), BTU/Lb	12,050	--	8,960	--	6,680	--
Gasification Coal						
Moisture	10.0%	10.0%	25.8%	25.8%	40.0%	40.0%
Ash	4.9%	4.1%	10.0%	8.3%	6.7%	5.6%
Heating Value (as rec'd), BTU/Lb	11,830	11,940	8,510	8,740	6,420	6,550
Mine Equipment, Facilities, and Development						
Cost, $/Yearly Ton of Production	$2.68		$1.21		$1.23	
Construction Manhours per Yearly Ton	0.4		Negligible		Negligible	
Tons of Metals per Yearly Ton						
Steel	.00077		.000666		.000666	
Copper and Others	.000005		.000005		.000005	
Mining Labor and Costs						
Labor Efficiency, Tons/Man/Shift	27		80		68	
Mining Cost Including Depreciation, $/Ton	$2.16		$1.55		$1.25	
Effect of 10% per Year Return (Before Taxes) on Investment, $/Ton	$0.27		$0.12		$0.12	
Other Factors						
Water Supply	100 Miles North to Freemont Lake or 33 Mi. SW to Green River.		35 Miles North to Yellowstone River.		30 Miles North to Garrison Dam Reservoir, Future dams may provide alternate sources.	
Transportation Facilities	Site Requires 14 Miles of additional Railroad.		Site Requires 50 Miles of additional Railroad.		Railroad available.	
Distance from Plant Site to Mine	Reasonably Close.		0 - 50 Railroad Miles.		Reasonably Close.	
Housing Requirement as % of Labor Force	100%		100%		100%	

September 25, 1951

REPORT ON OIL SHALE MINING BY THE RAW MATERIALS SUBCOMMITTEE

INTRODUCTION

The Raw Materials Subcommittee of the NPC Subcommittee on Synthetic Liquid Fuels Production Costs was assigned the task of determining suitable locations, shale mining costs, and water availability for synthetic fuel plants based on processing oil shale. This assignment involved the estimation of costs for two different mines; (1) one representing an initial mine in a uniquely favorable situation, and (2) a mine representing average conditions in the development of enough mines to supply shale for a production of 250,000 B/D of liquid fuels.

The scope of this study did not include the estimation of the total liquid fuel potential of the United States based on our reserves of oil shale, nor did it include the estimation of mining costs in shale deposits for regions other than the area near Rifle, Colorado, in which the U.S. Bureau of Mines' demonstration mine is located.

The details of this study are presented in the report of the oil shale mining group, appended hereto.

DISCUSSION

The cost estimates prepared by the oil shale mining group are based on the U.S. Bureau of Mines experience obtained at their demonstration mine. Costs were determined for two mines, one representing an initial mine in a favorable location, the other representing average conditions. The costs are as follows:

	Initial Mine	Average Mine
Investment, $/Annual Ton	$0.85	$0.96
Mining Cost, Including Depreciation, $/Ton	$0.56	$0.54

The "initial" mine shows a higher mining cost due to the assumption that it is the only mine in operation and consequently bears higher supervision and administrative expenses. Adjusting these two items to a comparable basis with the "average" mine would yield costs of $0.53 per ton. This indicates that there are only slight differences due to the actual location of the mines.

The purchase of shale lands has not been included in these costs. This is primarily due to the reluctance on the part of this subcommittee to estimate the future trend in the price of mineral rights or land in this area. To date, however, it appears that oil companies and other interested parties have been acquiring these properties at a price that would not appreciably alter this cost estimate.

The costs developed for mining of oil shale agree quite well with those developed by the U.S. Bureau of Mines except with regard to the labor rate which would be effective. The Oil Shale Mining Group used the coal mining rates in the area, whereas the Bureau of Mines used rates comparable to the average hourly wages for the total mining industry as compiled by the Bureau of Labor Statistics. It is our opinion that because of the sparsity of the population and the lack of skilled workers, incentives in the form of higher wages would be required to obtain an adequate labor force. The plants located near the mine sites will be competing for the region's labor supply, and due to the hazards associated with the mining industry, it is felt that the mine employees will require higher wages than the plant employees. It is the feeling of the Oil Shale Mining Group that the wages used in this study are essentially correct.

The water supply for a Colorado oil shale industry is ably discussed by Judge Clifford H. Stone, Director of the Colorado Water Conservation Board, whose comments are appended to the report of the Oil Shale Mining Subgroup. The current water supply situation is favorable, but there is a continual growth in demand for water from the Colorado River system which conceivably could equal the supply by the end of this century.

Since this summary report has dealt only with generalities and gives only a brief treatment of the results of this study, the reader is referred to the appended report for a more detailed presentation of the work of this subcommittee.

The Raw Materials Subcommittee wishes to acknowledge the assistance received from many people, both within and outside the various organizations which are represented by the membership of this subcommittee, whose contributions have significantly improved this study.

By: A. L. Solliday, Chairman
Raw Materials Subcommittee

March 5, 1951

REPORT OF THE OIL SHALE MINING SUB-GROUP OF THE RAW MATERIALS SUBCOMMITTEE OF THE NATIONAL PETROLEUM COUNCIL COMMITTEE ON SYNTHETIC LIQUID FUELS PRODUCTION COST

The oil shale mining sub-group is assigned to report to Mr. A. L. Solliday, Chairman of the Raw Materials Group, the availability and cost of oil shale at the recommended Bureau of Mines plant sites. The availability of water for the plants also is the responsibility of the group.

1. Availability of oil shale

The Bureau of Mines has obtained adequate data to show that a thick rich flat-lying deposit of oil shale exists in Western Colorado, north of the Colorado River between Rifle and Debeque. These data show that numerous mine sites can be chosen along the outcrop of the deposit, from which 30 gallon per ton oil shale can be mined from beds 70 or more feet in thickness. A list of the locations of 25 sites is attached. The first four of these sites may be considered specific sites, the remainder average sites. The mining conditions at each of the sites are expected to be similar to the conditions at the Bureau's mine at Anvil Points.

2. Cost of oil shale

The Bureau has made an analysis of the cost of mining oil shale on a commercial scale based on the methods developed and the costs and conditions presently applicable at the Bureau of Mines Oil Shale Mine at Rifle, Colorado. These cost estimates were submitted to the oil shale mining group who revised them in light of labor and material costs and conditions that prevailed in commercial operation on January 1, 1951. The revised figures show that the capital cost for a specific 19,200-ton per day plant will be $5,940,000 or $310 per daily ton and for an average plant will be $6,710,000 or $350 per daily ton. The cost per ton of delivering crushed oil shale to the retorts is calculated at 56 cents per ton for the specific mine and 54 cents per ton for the mines to produce 250,000 barrels per day. The costs include depreciation, taxes, administrative overhead, but do not include any charges for land for the plant or for oil shale land. Cost estimates are shown in the attached tables.

3. Availability of water

Adequate water is available in Western Colorado for the development of an oil shale industry of any conceivable size and for the use of the population and industry that will result because of the establishment of the oil shale industry. The complete explanation of the water supply situation in Western Colorado is contained in the attached letter from Judge Clifford Stone, Chairman, Colorado Water Conservation Board. This information has been verified from other authoritative sources.

Submitted by:

OIL SHALE MINING SUB-GROUP

Tell Ertl, Chairman
P. R. Schultz
I. N. Bayless

Signed by:

Tell Ertl, Chairman

Table 1. - Site Locations for Oil Shale Mines and Plants*

Site	Location			Remarks
	Section	Township	Range	
I	12	6S	95 W	Present Bureau of Mines Anvil Points Mine
II	14	6S	95 W	Bureau's proposed mine site
III	20	5S	95 W)	
IV	21	5S	95 W)	
V	22	5S	95 W)	MPAC Mine Sites
VI	24	5S	96 W)	
VII	14	5S	96 W)	
VIII	10	5S	96 W)	
IX	18-19	6S	95 W	
X	14	6S	96 W	
XI	15-22	6S	96 W	
XII	3-4	6S	96 W	
XIII	6	6S	96 W	
XIV	1-12	6S	97 W	
XV	27-34	6S	97 W	
XVI	16	6S	97 W	
XVII	17	6S	97 W	
XVIII	1-12	6S	98 W	
XIX	11	6S	98 W	
XX	3	6S	98 W	
XXI	21	5S	98 W	
XXII	30	6S	97 W	
XXIII	1	7S	98 W	
XXIV	26	6S	98 W	
XXV	24	6S	97 W	

* A site of 1.4 square miles can yield 19,200 tons of oil shale for 20 years

Table 2. - Capital Cost for preparing an oil-shale mine to produce, crush and convey 19,200 tons per calendar day

Item	Specific Mine	Average Mine
Excavations	$ 468,000	$ 1,400,000
Installations	2,132,000	2,000,000
Start up expense	400,000	300,000
Sub-total	3,000,000	3,700,000
Mining equipment	2,400,000	2,400,000
Sub-total	5,400,000	6,100,000
Contingencies 10%	540,000	610,000
Total	$ 5,940,000	$ 6,710,000
Total capital expenditures as $ per yearly ton of production	$0.85	$0.96

Table 3. - Operating costs for mining, crushing, and conveying 19,200 tons of oil shale per calendar day

	COST PER DAY		COST PER TON	
	Specific Mine	Mines to produce oil shale for 250,000 b/d	Specific Mine	Mines to produce oil shale for 250,000 b/d
Labor				
Underground	$ 1,858	$ 1,858	$ .0968	$ .0968
Maintenance, Service, and Surface	1,466	1,466	.0764	.0764
Supervision, Engineering, and Administration	570	455	.0297	.0237
Labor Benefits *	687	675	.0358	.0352
Supplies				
Operating	3,040	3,040	.1583	.1583
Maintenance and Repair	464	458	.0242	.0239
Depreciation				
Mining Equipment	1,101	1,101	.0573	.0573
Installation, Excavation, and Development	411	507	.0214	.0264
Contingency at 10% of Capital Investment **	151	161	.0079	.0084
Taxes				
Ad Valorem Tax on 50% of Capital Investment @ $21.51 per $1,000	175	198	.0091	.0103
Administrative Overhead ***	916	445	.0477	.0232
Total Cost	$10,839	$10,364	$ .5646	$ .5399
Effect of 10% per Year Return (Before Taxes) on Investment	$ 1,627	$ 1,838	$ .0847	$ .0957
Land Cost ****	---	---	---	---

* Based on 19% labor benefits for all employees except supervisory, engineering, and administrative on which a 10% rate applies.

** Contingency on capital expenditures depreciated at average rate for equipment, installation, excavation, and development.

*** Based on 20% of labor for specific plant and 10% of labor for average plant.

**** The determination of cost of land was felt to be a matter for the policy committee.

Table 4. - Total personnel requirements for specific plant *

Classification	No. required per day	Total for 7-day week	Cost per day
Underground labor	98	147	$ 2,210
Maintenance, service and surface	82	120	1,744
Supervision, engineering and administration	27	27	627
Total	207	294	$ 4,581

* For details see Backup Sheets I, II, III in Appendix

** Average plant is estimated to have a supervision charge of 80 per cent of that charged for specific plant ($455 per day) because of unitized operations.

Table 5. - Operating Supplies

Item	Basis for Calculation	Cost per day	Cost per ton
Drill rods	Top level 397 lb./day Bench level 288 lb./day		
	Total 685 lb./day @ 20¢/lb.	$ 137.00	$0.0071
Drill bits	Top level 4608 ft. of drilling Bench level 2240 ft. of drilling		
	Total 6848 feet @ 0.75¢/foot	51.36	0.0026
Explosives	Top level 3840 lb./day Bench level 2400 lb./day		
	Total 6240 lb. @ $15.50/cwt.	967.20	0.0503
Detonators	Top level 288 with 20-foot leads @ 23.40¢	67.39	0.0035
	Top level 64 with 40-foot leads @ 42.90¢	27.45	0.0014
Blasting wire and accessories	Total 500 ft./day @ 2.75¢/ft.	13.75	0.0007
Fuels and lubricants	1100 gal. Diesel fuel 50 gal. gasoline 25 gal. lubricants	234.00	0.0122
Haulage truck tires	Estimated tire life 5000 hr.	187.00	0.0098
Water	52,000 gal./day @ 26.4¢/1000 gal.	13.73	0.0007
Power	60,000 kw.-hr. @ 0.925¢/kw.-hr.	555.00	0.0289
Office supplies		6.00	0.0003
Travel		30.00	0.0015
Communications		5.00	0.0003
Miscellaneous Tools, Bar stock, Pipe and fittings Air and water hose Electrical supplies Non-ferrous metals, etc.		350.00	0.0183
Research supplies		120.00	0.0063
Sub-Total		$2,764.88	$0.1439
Contingencies 10%		276.49	0.0144
Total		$3,041.37	$0.1583

Table 6. - Maintenance and Repair Supplies *

Item	Cost per day		Cost per ton	
	Specific Mine	Average Mine	Specific Mine	Average Mine
Mining Equipment	$367.05	$367.05	$.0191	$.0191
Crusher, conveyor and other installations	97.35	91.32	.0051	.0048
Total	$464.40	$458.37	$.0242	$.0239

* Maintenance and repair supplies were calculated at 33% of the depreciation of capital expenditures for equipment and installations.

Table 7. - Mining equipment depreciation schedule

Item	In use	Stand by	Total	Unit Cost	Total cost	Life in shifts	Life in yrs	Cost per day
Drilling equipment BL	1	1	2	$ 50,000	$ 100,000	2920	4	$ 68.49
Drilling equipment TL	2	2	4	50,000	200,000	2920	4	136.99
Compressor assembly	3	1	4	55,000	220,000	7300	10	60.27
Shovels	4	1	5	100,000	500,000	7300	10	136.99
22-ton trucks	13	5	18	35,000	630,000	2920	4	431.51
Bulldozers	3	2	5	24,000	120,000	2920	4	82.19
Overhead loaders	1		1	38,000	38,000	2920	4	26.03
Motor patrols	1		1	15,000	15,000	3650	5	8.22
Lift trucks	4	2	6	15,000	90,000	7300	10	24.66
Water trucks	2		2	10,000	20,000	2920	4	13.70
Explosive trucks	1		1	3,000	3,000	3650	5	1.64
Service trucks	1		1	16,000	16,000	3650	5	8.77
Electrician trucks	1		1	9,000	9,000	3650	5	4.93
Supply trucks	2	1	3	4,000	12,000	3650	5	6.58
Staff cars	10		10	2,200	22,000	2190	3	20.09
Pickup trucks	3		3	3,000	9,000	2190	3	8.22
Ambulances	1		1	4,000	4,000	2190	3	3.65
Personnel buses	5	2	7	6,000	42,000	2190	3	38.36
Sub-total					$2,050,000			
Stock of Maintenance and Repair parts (not depreciable)					205,000			
Equipment on trial and under development *					145,000		20	19.86
Total					$2,400,000			$1,101.15
								5.73¢/ton

* This equipment in actual practice could be depreciated in the first year. There may be additional expenditures of this nature which would increase depreciation charges, but such expenditures should result in decreased operating costs thereby compensating for additional depreciation charges.

Table 8. - Depreciation schedule on installations, excavations, and development

Item	Cubic yards: Specific Mine	Cubic yards: Average Mine	Unit Cost	Total Cost: Specific	Total Cost: Average	Life	Cost per day: Specific	Cost per day: General
Excavations	624,000	1,872,000	$0.75	$ 468,000	$1,400,000	20 years	$ 64.11	$191.78
Installations				2,132,000	2,000,000	20 years	292.05	273.97
Start up expenses				400,000	300,000	20 years	54.80	41.10
Total				$3,000,000	$3,700,000		$410.96	$506.85

Table 9. - Utility requirements per day (16 hours)

Electric power	60,000 KWH
Water	52,000 gallons
Fuel	1,100 gallons diesel fuel 50 gallons gasoline 25 gallons lubricants

Table 10. - Material and Construction Manpower Requirements for 19,200 ton/CD Oil Shale Mine

Steel	3,000 tons
Alloy Steel	400 tons
Copper	40 tons
Other Metals	2 tons
Rubber	100 tons
Construction Labor	1,200,000 manhours
Construction Period	15 months
Time to Reach Full Production	18 months

Backup Sheet I. - Underground Labor

Classification	No. and Wage	$/CD *
Mine Shift Boss	9 @ $2.80/hr	$ 144
Miners		
Drillers	18 @ $2.10/hr	216
Blaster-scalers	18 @ $2.10/hr	216
Scalers	12 @ $2.10/hr	144
Compressor Operators	9 @ $2.10/hr	108
Bulldozer Operators	9 @ $2.05/hr	106
Shovel Operators	12 @ $2.66/hr	183
Shovel Oilers	12 @ $2.41/hr	165
Truck Drivers	36 @ $2.10/hr	432
Groundmen	12 @ $2.10/hr	144
Total Wages	147 ($2.21/hr)	$1,858
Labor Benefits @ 19%		352
Total Wages and Benefits		$2,210

* $\frac{\text{No. of men} \times \text{hourly wage} \times 40}{7}$

Backup Sheet II. - Maintenance, Service, and Surface Labor

Classification	No. and Wage	$/CD *
Master Mechanic	1 @ $2.80/hr	$ 16
Mechanic Foreman	3 @ $2.50/hr	43
Mechanic	12 @ $2.20/hr	151
Mechanic Helper	12 @ $2.03/hr	139
Maintenance Foreman	3 @ $2.50/hr	43
Blacksmith	3 @ $2.20/hr	38
Welder	4 @ $2.20/hr	50
Welder Helper	4 @ $2.03/hr	46
Machinist	1 @ $2.20/hr	13
Millwright	1 @ $2.20/hr	13
Carpenter	3 @ $2.20/hr	38
Mixed Gang Foreman	3 @ $2.50/hr	43
Operator General	3 @ $2.10/hr	36
Truck Driver	3 @ $2.05/hr	35
Powder Man	3 @ $2.15/hr	37
Explosive Truck Driver	3 @ $2.05/hr	35
Filling Station Man	6 @ $2.03/hr	70
Labor Gang	12 @ $1.85/hr	127
Crushing Plant Foreman	3 @ $2.50/hr	43
Crushing Operator	6 @ $2.03/hr	70
Conveyor Operator	3 @ $2.03/hr	35
Warehouseman	3 @ $2.50/hr	43
Stock Clerk	3 @ $2.03/hr	35
Stock Clerk Helper	3 @ $1.85/hr	32
Supply Truck Driver	4 @ $2.05/hr	47
Electrician Foreman	3 @ $2.50/hr	43
Electrician	6 @ $2.20/hr	75
Electrician Helper	6 @ $2.03/hr	70
Total Wages	120 ($2.14/hr)	$1,466
Labor Benefits @ 19%		278
Total Wages and Benefits		$1,744

* $\frac{\text{No. of men} \times \text{hourly wage} \times 40}{7}$

Backup Sheet III. - Supervision, engineering, and administrative personnel for specific plant

Classification	Number required	Annual Rate	Total annual cost
General superintendent	1	$25,000.00	$ 25,000.00
Secretary	1	5,000.00	5,000.00
Mine foreman	3	15,000.00	45,000.00
Chief engineer	1	15,000.00	15,000.00
Surveyor	2	5,000.00	10,000.00
Draftsman	1	5,000.00	5,000.00
Mechanical engineer	1	10,000.00	10,000.00
Draftsman	1	5,000.00	5,000.00
Electrical engineer	1	10,000.00	10,000.00
Safety engineer	1	10,000.00	10,000.00
Industrial nurse	3	5,000.00	15,000.00
Research engineer	1	10,000.00	10,000.00
Assistant research engineer	2	6,000.00	12,000.00
Chief clerk	1	6,000.00	6,000.00
Statistical clerk	2	4,000.00	8,000.00
Stenographers	2	4,000.00	8,000.00
Timekeepers	3	3,000.00	9,000.00
Total	27		$208,000.00
Cost per day			$ 569.86

COLORADO WATER CONSERVATION BOARD
212 State Office Building
Denver 2, Colorado

Tabor 5853
KEystone 1171, Ext. 432

February 9, 1951

Mr. Tell Ertl, Chairman
Oil Shale Raw Materials Sub-Group
Ohio State University
Columbus 10, Ohio

Dear Mr. Ertl:

In answer to your letter of December 1, 1950, respecting available water supplies for synthetic fuel processing in Western Colorado, may I suggest that I do not attempt to cover this subject in the detail and to the extent suggested by your letter. For instance, you state: "We want the true water supply situation as it exists in Western Colorado". If I were to cover the subject to that extent, it would require many pages of a reply and much of such a discussion would have to be based on tentative plans and programs which are not yet fully formulated. It would involve basin plans and estimates which must be evolved over a period of years.

The statements in this letter are restricted to synthetic fuel processing from oil shales and are not intended to cover such processing from coal reserves which are found in abundance in Western Colorado.

May I call your attention to the section on water found in the summary report to the United States Bureau of Mines on Areas Suitable for Synthetic Liquid Fuel Plants in Western Kentucky, Northwestern Colorado, and Southeastern Texas. This report is dated May 1949. The section on water is that found on pages 18 to 21, inclusive. I assume that a copy of this report is available to you, but for completeness of reply, I attach hereto a copy of the section of the report, to which reference is here made. Later in this letter I shall quote from pertinent portions of that water section.

The attached section on water, to which I have just referred, was prepared after consultation with engineering and legal members of the staff of the Colorado Water Conservation Board; and the statements contained in that section reflect the Colorado views on the subject of synthetic liquid fuel processing from oil shale so far as such views may now be formulated in the absence of further studies and investigations which are now being made in the area here under discussion, as well as in other areas of the United States.

First, may I call your attention to paragraph 68, entitled "Water rights" of the attached water section of the above-mentioned report, wherein it is stated:

> "68. Water rights.--According to the Constitution of the State of Colorado "The right to divert the unappropriated waters of any natural stream to beneficial uses shall never be denied. Priority of appropriation shall give the better

right as between those using the water for the same purpose; but when the waters of any natural stream are not sufficient for the service of all those desiring the use of the same, those using the water for domestic purposes shall have the preference over those using the same for manufacturing purposes." The principal use made to date of the preferential right mentioned in the Constitution has been where a municipality has condemned an agricultural right for domestic use with adequate compensation to the owner of the agricultural right.

"69. The constitutional right to appropriate water for beneficial uses applies to water required for synthetic liquid fuels and the right is subject only to the availability of water and to uses that are senior regardless of whether they are for domestic, agricultural, power, or other industrial uses."

The sections quoted above are important in consideration of the matter mentioned in your letter. I believe you understand their import. They indicate the right of those who seek water supplies to process shale oils to seek appropriation under the Constitution and statutes of Colorado. It must be borne in mind that such appropriation for this purpose, as well as for all other uses in Colorado, must be within the share of water allocated to this State under the Upper Colorado River Basin Compact. Reference is also made to the quoted sections from the Colorado River Compact of 1922 and the Upper Colorado River Basin Compact of 1948, appearing on page 19 of the above-mentioned report. Any analysis of the availability of water to process synthetic fuel is to be considered in the light of these compact provisions.

As to the availability of water for oil shale processing, I call your particular attention to paragraphs 76, 77, 78, 79, 80 and 81 of the attached document, which read as follows:

"76. Availability of water.--If it is assumed that Arizona will utilize the full 50,000 acre-feet of water mentioned in Article III of the Upper Colorado River Basin Compact, and if it is assumed that none of the restrictive provisions of Article III of the Colorado River Compact will reduce the beneficial consumptive use by the Upper Basin below 7,500,000 acre-feet per year, there will be available for the State of Colorado under the Upper Colorado River Basin Compact 3,855,375 acre-feet per year for man-made depletions of the virgin flow at Lee Ferry. This quantity of water includes the man-made depletions being caused by Colorado of the virgin flow at Lee Ferry under present conditions. The aggregate of the man-made depletions at the points of use in Colorado may well exceed the 3,855,373 acre-feet because of the placing to beneficial use by man of some water which was lost in the state of nature and which never did reach Lee Ferry under virgin conditions.

"77. It is estimated that the present depletions of the virgin flow at Lee Ferry made by man in Colorado together with the depletions that will be caused by projects under construction, and together with depletions by projects not under construction for which water rights are claimed and might be obtained, amount to approximately 1,600,000 acre-feet annually. There remains therefore at the present time unappropriated a quantity of water available in Colorado to increase by man's activities in Colorado the depletions at Lee Ferry by approximately 2,255,375 acre-feet annually. The aggregate permissible depletion at the points of use may well be materially in excess of this quantity. All of this water is subject to appropriation for beneficial use by anyone.

"78. The present development in Colorado which will deplete the flow at Lee Ferry by the above estimated 1,600,000 acre-feet annually has taken place within the past 100 years. Because of the consummation of the Upper Colorado River Basin Compact and the growing need for hydroelectric energy in the Intermountain Region and for the development of irrigation projects in that area, it is anticipated that the development of projects to utilize Colorado River water will be accelerated. It is not known where or how the waters of the Colorado River will be used, what the pattern of development will be, or at what rate it will proceed. For the purposes of this report, however, it is assumed that by 1963 rights will be perfected by uses in addition to those for the processing of synthetic fuels which, together with necessary evaporation losses chargeable to Colorado, will deplete the flow of the Colorado River and its tributaries at the points of use in Colorado by 1,600,000 additional acre-feet annually.

"79. On the basis of these estimates there will remain in 1963 over 600,000 acre-feet of Colorado River water apportioned to Colorado subject to appropriation for beneficial use less the amounts that may have at that time already been appropriated for the processing of synthetic fuel or other industrial uses. Because of the provision of the Colorado River Compact Article III (f) and III (g) quoted above for the apportionment of unapportioned water after 1963 there is no firm basis for estimating the quantity of such unapportioned water which may be allocated either to the Upper Basin or to Colorado. Therefore, no effort has been made to appraise the availability of such water.

"80. It must be made clear that even under present conditions in most instances storage will be required to permit the processing of any large amounts of synthetic fuel even though there is a large amount of unappropriated water in the stream. This is because, in some instances during periods of low water supply, the water in the stream is fully appropriated by existing uses.

"81. At some time in the future (possibly by the end of this century*) it is reasonable to assume that all water of the Colorado River available for use in Colorado under pertinent compacts will be appropriated and consumed, and at that time the amount of this available water which is utilized by synthetic liquid fuel plants and their communities will depend on the rate of growth of the synthetic liquid fuels industry and the perfecting of water rights for these plants in relationship to the growth and perfecting of water rights for other uses in accordance with the laws of the State of Colorado."

You "call particular attention" to specific details on the availability of water in the Colorado and White Rivers in Colorado. On this phase of the subject I include herein a statement showing outflows near the Colorado state line, based upon the 1914-1945 average of principal tributaries of the Colorado River arising in this State. These are as follows:

	1914-1945 average Outflow near State Line
Yampa	1,173,000
White	576,000
Colorado (excluding the Gunnison River)	3,450,000
Gunnison	2,020,000
Dolores	760,000
San Juan and Tributaries	2,160,000

The compact allocation of Colorado River water to Colorado will average 3,855,375 acre-feet a year. It is estimated that the present uses of water including those under authorized projects in Colorado will amount to approximately 1,600,000 acre-feet a year. This leaves a balance of 2,255,375 acre-feet for future development.

In order that you may better appraise the above outflow figures, may I state that it is estimated that the present uses and those contemplated under authorized projects from the main stem of the Colorado River and the Gunnison River are approximately 800,000 acre-feet and those for the White River are estimated to approximate 34,000 acre-feet a year.

Without going into a great mass of detail with many ramifications, I believe the foregoing, together with the attached water section from the report to which I have made reference**, will provide you with the information which you desire.

Yours very truly,

/s/ Clifford H. Stone

Clifford H. Stone, Director
Colorado Water Conservation Board

chs/gnb/rep

* Added by Corps of Engineers

** Not included as an exhibit in this report. T.E.

NATIONAL PETROLEUM COUNCIL
COMMITTEE ON SYNTHETIC FUELS
PRODUCTION COSTS

REPORT

OF

PROCESS SUBCOMMITTEE
ON
COAL HYDROGENATION

PROCESS SUBCOMMITTEE: E. V. Murphree, Chairman

COAL HYDROGENATION PROCESS SUBCOMMITTEE

L. E. Carlsmith (Chairman)
F. T. Barr
C. Holloway
B. J. Mayland
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TABLE OF CONTENTS

		Page No.
INTRODUCTION		1
DESTRUCTIVE HYDROGENATION		2
BUREAU OF MINES COAL HYDROGENATION PROCESSES		3
CONVENTIONAL PLANT - MODIFICATIONS OF NPC SUBCOMMITTEE		4
General		4
Paste Preparation Unit		6
Liquid-Phase Hydrogenation Unit		7
Liquid-Phase Products Distillation		8
Vapor-Phase Hydrogenation Unit		8
Vapor-Phase Products Distillation		9
Delayed Coking of HOLD		9
Phenols Recovery Unit		9
Hydrogen Recovery Unit (Linde)		10
Hydrocarbon-Steam Cracking Unit		10
Hydrogen Purification and Compression		10
Coal Gasification Unit		11
Oxygen Plant		11
EIGHT-PLANT CASE		12
FIGURES 1 - 9, TABLES I - XIX	Following	13

INTRODUCTION

This report presents a review of the process designs proposed by the Bureau of Mines for coal hydrogenation plants together with the designs modified by the Process Subcommittee. The study is a part of the review by the National Petroleum Council of the Bureau of Mines' estimates of the costs of producing synthetic liquid fuels. The report outlines in detail the processes of the Bureau and the changes deemed essential by the subcommittee to give a workable process. The report contains the information necessary for detailing and sizing the equipment for the various steps of the hydrogenation process; it also gives the requirements for labor, materials, and energy for the plants. The data are, therefore, the bases for the estimates of investments made by the Engineering Subcommittee and operating costs made by the Economics Subcommittee.

To initiate this study the Process Subcommittee visited the Bureau of Mines Station at Louisiana, Mo. where a 200-300 bbl./day coal hydrogenation demonstration plant is located. Several days were devoted to going over the processes of the Bureau very carefully with members of the staff of the station, who were most cooperative.

The main Process Subcommittee decided that the following conditions should govern the work of the subcommittee. Where possible, the subcommittee should use the steps in the process as designed by the Bureau, enlarging or modifying equipment whenever, in their opinion, the design of the Bureau was inadequate. If sections of the process (gasification, flash distillation, etc.) were not acceptable to the subcommittee, because believed to be unworkable, the Bureau should be requested to submit another process. Any conventional established process could be used. The Bureau should be advised of any changes and an attempt made to obtain their agreement. The subcommittee was requested to check in detail the design of a single hydrogenation plant modified as necessary. In addition a case involving 8 plants was to be submitted, the design of the additional plants not necessarily being made in complete detail. The sites for the additional plants were furnished by the Raw Materials Subcommittee.

As the work of checking and altering the designs of the Bureau's process proceeded, the subcommittee furnished the Engineering, Raw Materials, and Economics Subcommittees with information as it became available. The Bureau of Mines was likewise continuously apprised of the developments. The result was a cooperative venture which permitted simultaneous working up of the assignments to the several groups concerned.

The work of the Process Subcommittee has been limited to the functional design and layout of the equipment for the strictly process steps, together with the labor, materials, and power requirements for these. Information of a specialized nature including the quantities and qualities of all materials handled was also supplied. The power plant, coal mining and cleaning, water system, shops, offsites, and other auxiliary facilities were designed by other subcommittees.

DESTRUCTIVE HYDROGENATION

Like crude petroleum coals consist largely of a complex mixture of chemical compounds of carbon and hydrogen. The ratio of carbon to hydrogen in the case of coals is considerably higher than for the liquid fuels. The hydrogenation process is a means of converting the higher molecular weight compounds such as coal into hydrocarbon oils by reacting hydrogen with them under high pressure and temperature in the presence of suitable catalysts. The chemical reactions involved are complex. Essentially what occurs is that under the operating conditions the primary products of cracking become saturated with hydrogen as soon as they are formed. Thus, polymerization to higher boiling compounds, or eventually to carbon is avoided. Satisfactory hydrogenation depends on the proper choice of temperature, hydrogen pressure, reaction time, and catalysts. In the case of raw materials such as coal which contain oxygen, nitrogen, and sulfur, these impurities at the same time are removed by being hydrogenated to water, ammonia, and hydrogen sulfide. The outstanding characteristic of the destructive hydrogenation process is that it is effected at high pressure, 300 to 700 atmospheres. Developed and applied originally in Germany hydrogenation of coal and tars has been more widely used there than elsewhere. During the last war most of the aviation gasoline used by the Germans came from this source.

There are two general types of destructive hydrogenation, liquid-phase and vapor-phase. In liquid-phase hydrogenation coal is usually cleaned, dried, pulverized, mixed with a small amount (2-3%) of catalyst, usually compounds of tin or iron, and then made into a paste with some of the heavier oils recycled in the process. The paste or slurry of coal and oil is pumped into converters - vertical tubular vessels - where it is contacted with hydrogen at the chosen operating conditions. The products of hydrogenation are separated by distillation. The heavier oils are returned for pasting the raw coal and further hydrogenation. The lighter products are further processed, those suitable being purified and marketed as such. A stream of the recycled oil is purged to remove ash, catalyst, and unreacted organic components of the coal. Certain components of coal, particularly fusain and certain asphaltic components are difficult to hydrogenate and so are discarded with the ash.

Vapor-phase hydrogenation is carried out in similar vessels but they are filled with granular or pelleted catalysts, and the feed enters the reactor in the vapor phase essentially free of ash, heavy tars, etc. Molybdenum or tungsten sulfides usually are the active components of the catalysts. As in the liquid-phase process, the products of reaction are separated by fractionation and the heavier oils returned for further hydrogenation. By choice of proper operating conditions and extent of recycling a variety of products from methane to heavy oils may be produced. The feed to vapor-phase hydrogenation plants may be middle and light oils from the liquid-phase hydrogenation units or any tars, pitches, petroleum residues, or other fraction oils. Certain kerosenes may be hydrogenated to choice aviation blending stocks. In Germany during the war a great deal of tar from the carbonization of coal was hydrogenated, especially the products of low-temperature carbonization of lignite. The throughputs of the plants are higher and the hydrogen consumptions lower for these oils than for heavier oils or coals. In commercial practice vapor-phase hydrogenation of tars or middle oils, especially those containing oxygenated or nitrogenous compounds are often given a prehydrogenation at milder conditions to saturate and purify them, the oxygen, nitrogen, and sulfur being converted to volatile materials.

The products of hydrogenation are saturated (no olefins). The materials boiling in the gasoline range are generally naphthenic, but may contain up to 45% aromatics with some paraffins.

BUREAU OF MINES COAL HYDROGENATION PROCESSES

The Bureau of Mines has designed in considerable detail several plants for hydrogenating various types of coal to liquid fuels. These are described in their report RI-4564*. In addition a report with flow sheets prepared by the Bechtel Corporation and USBM report L-71 supplement RI-4564. Other reports, memoranda, and prints dealing with individual aspects of the process were furnished the subcommittee.

The coal hydrogenation process offered by the Bureau of Mines is based primarily on a combination and extrapolation of best available German commercial practice, pilot-plant research, and laboratory tests. The Bechtel Corporation was hired to make an engineering estimate (about 40,000 man hours) for the process and to make the designs for offsites, distillation equipment, buildings, and other conventional auxiliary facilities. The Bureau of Mines staff added some modifications to the process, especially for the Modernized case.

Processwise the hydrogenation plants projected by the Bureau fall into the following scheme. Coal is partially deashed, dried, pulverized, mixed with iron oxide catalyst, and fed to a liquid-phase hydrogenation unit operating at 700 atmospheres pressure. The liquid-phase output is distilled. The higher molecular weight products of hydrogenation are recycled back to the unit and the balance (C_4 and lighter excepted) is then hydrogenated at 700 atm. in a vapor-phase unit over Welheim-type catalyst (Mo, Cr, Zn on activated clay). The fraction containing tar acids is extracted with methanol to recover phenol, cresols, and xylenols before being processed in the vapor-phase hydro step. Ash and catalyst are purged from heavy recycle oil by coking or flash distillation. The vapor-phase hydrogenation is operated to give an ultimate yield of motor fuel and LPG, all plants yielding a total production of 30,000 B/D. Lean gas from the unit (60% H_2) is distilled at low temperature to recover the hydrogen. Methane, ethane, and part of the propane are cracked with steam over reforming catalyst to produce more hydrogen. Hydrogen requirements over and above these two sources are made by gasification of powdered coal with steam and 95% oxygen.

Two general cases are proposed, a Conventional case (detailed in the Bechtel Corp. Report) and a Modernized case (RI-4564 is largely devoted to this case). The first case is designed to involve steps proven in commercial practice and hence, should not be subject to question as to operability. Actually, this was not the case for this design. The Modernized version includes some process steps which require further development for application. They are expected to result in savings in plant investment and operating costs. The chief differences between the Bureau's Conventional and Modernized cases are the following: (1) The Modernized plant involves gasification of particulate coal under 25 atm. pressure vs. approximately atmospheric pressure. (2) In the Modernized plant the HOLD purge stream is processed by delayed coking instead of by flash distillation to recover hydrocarbons in the discarded ash and catalyst.

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*Report of Investigations 4564, "Estimated Plant and Operating Costs for Producing Gasoline by Coal Hydrogenation" by L. L. Hirst, L. S. Skinner, R. W. Dougherty, and E. E. Donath. 83p + 23 figures.

(3) The hydrogenation sections of the Modernized version are more completely instrumented for automatic control which is claimed will allow about 10% greater throughput per volume of catalyst. (4) Spirally-wound high-pressure vessels not currently made in this country are used to reduce investment costs.

For their base case for coal hydrogenation the Bureau of Mines selected Wyoming bituminous coal from the Rock Springs seam in Sweetwater County, Wyoming as the principal raw material (see Table I for analysis of the coal). The plant designed by the Bechtel Corporation for obtaining basic investment and operating costs is to be located at Rock Springs, Wyo. Four other coals and locations also were proposed by the Bureau. Cost estimates for fuels from these coals also are presented in RI-4564. These include North Dakota lignite, Montana subituminous coal, Illinois bituminous coal, and Pittsburgh seam coal.

CONVENTIONAL PLANT - MODIFICATIONS OF THE NPC SUBCOMMITTEE

General

Conforming to the Bureau's selection of coal for a base case, the Process Subcommittee chose the Rock Springs, Wyoming site for a hydrogenation plant for its detailed check of the Bureau's process. It is the principal subject of this report. A case comprising eight hydrogenation plants located in different parts of the country, however, also has been worked up and is presented. The following modifications of the Bureau's process, were agreed upon by the main Process Subcommittee.

1) Since any plant built in the United States would be equipped with the best available instrumentation, the more automatic control of the Bureau's Modernized case would be used. The 10% increase in throughput gained by this modification is based on data obtained by the I. G. Farben Industrie of Germany.

2) Delayed coking, used in the Bureau's Modernized case, would be employed in the Conventional case because it was believed to have as good a chance of operation as the flash distillation step which had proved troublesome in the demonstration plant at Louisiana, Mo. This coking unit was designed completely for the Bureau by the subcommittee.

3) The high-pressure vessels were to be made by wrapped, laminated or other construction rather than forgings, if the Engineering Subcommittee found that this was feasible. Thus, three of the steps used only in the Modernized case of the Bureau were adopted as sufficiently well established by the subcommittee to use in the Conventional case.

4) Credit was to be taken for phenol, cresols, and xylenols in the base case only. The eight plant case is more representative of a substantial liquid fuels project where the marketable chemicals would be negligible. Therefore, the tar acids are all hydrogenated to fuels.

5) The coal gasification plant in the Bureau's scheme was rejected by the subcommittee as unacceptable. The coal gasification plant originally recommended by the Bureau was an adaptation of the powdered coal, oxygen, steam, high temperature, slagging-type generator developed by Heinrich Koppers of Germany. No commercial units of this type were ever built. An attempt to operate a large experimental unit at Louisiana, Mo. by a co-operative effort of the Bureau of Mines and Koppers Company

was unsuccessful. The Bureau then offered a gasification process under development by the Texas Company. They were unable; however, to furnish any details of operation or experimental results to the subcommittee; so this, too, was rejected. The Bureau did not feel that they were in a position to design a low-pressure coal-oxygen gasification unit at the time; so the Coal Synthesis Subcommittee designed one for them. Data obtained from experimental work conducted at the Morgantown Station of the Bureau of Mines were used in the design. This is the process used in this report. It has no counterpart in commercial operation.

6) The exact designs of the Bureau for the oxygen plant and low-temperature hydrogen separation (Linde type) plant were not checked in detail by the subcommittee, but several vendors of this type of equipment were asked to submit estimates for these plants. Based on these estimates and operation and costs of tonnage oxygen plants in the country and abroad the Process and Engineering Subcommittees estimated the investments, labor requirements, and energy requirements for these two units.

The check of the process steps other than those mentioned above resulted in relatively few modifications to the processes or equipment proposed by the Bureau. Occasional changes in sizes or capacities were recommended; some additions in equipment were made.

In the matter of throughputs, however, the subcommittee and the Bureau are in disagreement. In the Bureau's report throughputs and other figures are given on a stream-day basis. They state, however, that the equipment is designed sufficiently large so that with a 90% service factor the plant can produce 30,000 barrels per calendar day. This difference was not fully appreciated by the Bureau until several months ago when they noted that all checks by the NPC group were on a 30,000 B/SD basis. A number of meetings have been held with the representatives of the Bureau to discuss this question. The differences have not been wholly reconciled. Since the plants designed by the NPC engineers are on a basis of 30,000 B/SD and because most of the units checked were found to be adequate in capacity only for a production corresponding to 30,000 barrels per stream day, the subcommittee has put the plant on the latter basis. The position of the subcommittee in this matter is further amplified below.

A not inconsiderable portion of the plant including the coal gasification unit, the delayed coking unit, the oxygen plant, and low-temperature hydrogen recovery plant were all designed by or specified by the subcommittee on the stream-day basis. The subcommittee found that the hydrocarbon-steam cracking unit as designed by the Bureau was barely large enough to process only part of the gas from a 30,000 B/SD plant. The subcommittee found the hydrogen purification unit as a whole large enough for 30,000 B/SD only, although some elements of equipment in it could handle a little more product. The two distillation units deliberately were designed oversize by the Bureau. After the alterations to some of the equipment by the NPC group, they are slightly oversize, but the Bureau's original approach to this problem was accepted. Little change in cost of products will come from redesigning the distillation sections because they represent a small part of the investment anyway. The phenols extraction unit appears to the subcommittee to be adequate from a stream-day basis, but it is difficult to say whether or not it could be forced to a higher throughput. Likewise, the paste preparation unit might process 33,000 B/SD but it is difficult closely to rate this type of equipment. Both these units represent a relatively small investment.

The vapor-phase hydrogenation unit, after the heat exchanger surface had been increased by the subcommittee on the basis of heat transfer coefficients submitted by the Bureau's consultants, is calculated to be large enough for a 30,000 B/SD plant only. After the heat transfer surface for the liquid-phase unit was increased and the compressors and boosters, etc. sized to a 30,000 B/SD unit, it was found that the converter capacity was oversize; so the number of reactors was reduced from 20 to 18, thus making it a 30,000 B/SD unit.

In view of these considerations the Process Subcommittee feels that a plant meeting requirements set forth in the design herein submitted could not be expected to produce more than 30,000 barrels of products per stream day (27,000 barrels per calendar day) over an extended period of time.

The matter of service factor has also been a subject of considerable discussion with members of the Bureau. The subcommittee feels that it has leaned over backwards in accepting a 90% service factor. This may be possible if an organization of skilled administrative, technical, operating, and mechancial personnel is available to run the plant. Many sections of this plant are among the most complicated and difficult type to operate to be found in industry. Some, as the coal gasification unit and part of the hydrogenation units, are not backed by commercial experience. In general, it is felt that the plant is rather closely designed. Also, no provision has been made for losses of liquids or hydrogen in the process. Unaccounted for losses can amount to several per cent in refineries. Hydrogen leaks may run 5 to 10%. It is conceivable that such a plant ordered today might not attain a 90% service factor by 1960.

The Bureau's base case Conventional process coal hydrogenation plant as modified by the NPC Process Subcommittee will now be described. The proposed location is in Sweetwater County, Wyoming where Rock Springs seam bituminous coal will be obtained by underground mining.

Reference is made to Figure 1, the overall schematic process flow sheet for the plant. More detailed flow sheets are presented for individual sections of the plant. The most important flows of materials are indicated on the various flow sheets. Further data on flows of materials are given in Table I under Case III-A, which is the number designating the Rock Springs, Wyoming base case in subsequent tables. Summarized lists of the principal items of equipment used together with the most critical specifications are presented for each section of the plant in Tables II through X. The flow sheets for the individual units also give considerable information on equipment and on energy requirements. The consumption and production of steam for the plant are given in Tables XIII, XIV, and XV. Electric power requirements appear in Table XVII. A fuel balance is presented in Table XIII. The chemicals needed to operate the various units of the plant are listed in Table XII. Estimated process operating labor for the Rock Springs, Wyoming case is presented by individual sections of the plant in Table XI.

Figure 1 indicates that this plant follows the general scheme outlined in the introduction with the modifications referred to subsequently. The plant is designed to produce 21,670 bbl. of motor fuel, 7,100 bbl. of LPG (C_3-C_4) and 1,230 bbl. of tar acids, a total of 30,000 bbls. of products per stream day. This requires a consumption of 14,400 tons per stream day of raw coal (15,600 maximum rate) 45% of which is hydrogenated directly.

Paste Preparation Plant

Coal dried to 1.5% water and ground 90% through 60 mesh, 65%

through a 200-mesh screen with the finest 5% of the latter rejected as fuel, is mixed continuously with recycled medium and heavy oils in three 2500-gal. agitated heated tanks. The mixed oil is blended to insure uniformity of composition of the feed to the hydrogenation unit, a very critical matter in regard to operation of the high-pressure exchangers and heaters. Twenty-seven pumps, a number of tanks, and 10 HOLD letdown receivers, together with solids handling equipment, including coal and catalyst weighers, are involved in the operation of this unit. Iron oxide catalyst for the liquid-phase hydrogenation operation is introduced in this unit at a rate of 111 tons/SD (equivalent to 2% by weight of the coal) together with all the coal to be hydrogenated, 5568 tons/SD, m.a.f. basis.

The design for this unit is substantially the same as that originally submitted by the Bureau. It is difficult to estimate the exact capacity of such a unit in the absence of any data on mixing and blending characteristics of the coals. It has been accepted as being capable of handling streams corresponding to 30,000 B/SD of products, but the mixing times appear very short (a couple of minutes) and blending tank recycle rates very long (several hours turnover per tank). No special flow sheet is included for this plant because of the simplicity of the layout. The principal items of equipment required for the unit are listed in Table II.

Liquid-Phase Hydrogenation Unit

This plant is patterned after the most modern German liquid-phase hydrogenation practice as exemplified by the plants started during the war in Germany at Wesseling, Gelsenberg, Stettin-Poelitz, and Bleckhammer, which operate at 700 atm. pressure, an advantage for more complete hydrogenation of coal. The reactors proposed here are larger than those used abroad. Also paste-product heat exchangers instead of fired preheaters are specified. This introduces difficulties of operation. Paste-product exchangers, however, have been used in Germany in a couple of instances - at Leuna (300 atm.) and Poelitz (700 atm.). Fired preheaters are used at Louisiana, Mo. The liquid-phase hydrogenation unit, of course, is the most expensive in the plant, and the heart of the process. Figure 2 is a flow sheet of the unit. The impressive equipment is listed in Table III.

The estimates for the space-time yields, product distribution and quality, and other characteristics of the plant, as outlined in report L-71, have been accepted by the subcommittee. T.O.M. reels and BIOS reports were consulted by the subcommittee to check the design. Several German engineers visiting the country have been consulted on the problem. The plant designed by the Bureau and the original check by the subcommittee stipulated the use of 20 converters (reactors). Subsequently, the Bureau revealed that at the Louisiana, Mo. plant it was found that the inside insulation of the reactors could be decreased in thickness about 3/4 of an inch, which resulted in an increase in the effective volume of the reactors from 705 to 750 cubic feet (5-6%). If advantage of the 10% increase in throughput due to more instrumentation is taken, a stream-day capacity of nearly 34,000 barrels was calculated for the unit. The subcommittee, therefore, reduced the number of reactors from 20 to 18 to make this unit consistent with the rest of the plant at 30,000 barrels per stream day.

The matter of heat transfer coefficients for the exchangers and coolers in this unit is important because of the high cost of the equipment. The subcommittee carefully reviewed the literature and then went over the original design in great detail with the representatives of the Bureau of Mines, including the German engineers at the Bureau who designed the heat transfer facilities. The heat transfer coefficients had been based on extrapolations of German pilot plant data and laboratory tests as well as on commercial operations. As a result of this extensive study, the product coolers were increased by 17 per cent and the gas

coolers 46 per cent in total area.

For further study of the details of the process the reader is referred to the flow sheets and tables. It should be pointed out that because of the very high pressure, the process is complicated mechanically and requires skilled operators and supervisors. The high-pressure fuel pumps are especially difficult to maintain in good operating condition.

Liquid-Phase Products Distillation

The products from the hydrogenation unit are separated by flashing and distillation to streams to be recycled to the unit or otherwise processed. Light hydrocarbons are sent to LPG, hydrogen recovery, or steam-cracking. Heavy oils are recycled to paste preparation eventually to receive further hydrogenation. A purge stream (HOLD) is depressured and coked to get rid of ash, catalyst, and hydrogenation-resisting constituents of the coal. The rest is processed in the vapor-phase hydrogenation unit. Figures 4-A and 4-B are flow sheets for the unit. The equipment is listed in Table IV. Conventional fractionation and absorption facilities are employed. The unit was designed largely by the Bechtel Corporation and is somewhat oversize. The engineers at the Bureau early explained that the overdesign was desired for flexibility, and as it represented only a small part of the total investment (3% for both distillation units) it did not warrant a close design. The subcommittee accepted this approach and left the unit essentially as designed, although the design of this unit is not one which they would have recommended. It is, however, quite operable. The subcommittee increased the number of trays in the absorber deethanizer from 35 to 64 and the tower height from 70 to 105 ft.; added a caustic pump; increased the area of the exchangers by a total of 2,160 sq. ft.; and increased the power of the pumps by a total of 388 horsepower.

Vapor-Phase Hydrogenation Unit

The middle oils and naphtha streams from the liquid-phase unit are further hydrogenated over fixed-bed catalyst at 700 atm. pressure in the vapor phase to an ultimate yield of motor fuel and LPG.

Again, the latest German practice is adopted. The accompanying vapor-phase section flow sheet (Figure 3) and overall flow sheet (Figure 1) indicate the nature of the process. It is noteworthy that vapor-phase hydrogenation at 700 atm. of middle oils from liquid-phase coal hydrogenation plants was not commercially practiced in Germany. Hydrogenation at 700 atm. of petroleum fractions, low-temperature carbonization tars and certain pitches was carried out at Welheim. A 700-atm. vapor-phase plant was also located at Lutzkendorf. Pilot plant data obtained at Ludwigshafen (I. G. Farben) indicate that hydrogenation of hydro middle oils is practicable. The time-space throughputs for this unit are based on the pilot plant data. Commercial throughputs at Welheim for tars were 13-14% lower; so the design for this unit may be considered optimistic.

The catalyst developed at Welheim for this operation consists of 0.6% Mo, 2% Cr, 5% Zn on activated clay. It is claimed that it is sufficiently rugged so that the usual supporting catalyst trays and cooling gas distributors may be eliminated, and the whole volume of the reactor then used. Normally, German vapor-phase hydro reactors are 73% filled (less for those at Louisiana, Mo.) due to the internals. After much discussion of this subject with engineers of the Bureau and visitors from Germany, the subcommittee decided that 90% filling was the maximum permissible for the unit. On this basis and allowing for the reduced internal insulation and the increased capacity for extra instrumentation, the subcommittee estimates that with 12 reactors the unit is just big enough to process feed corresponding to 30,000 B/SD of products with a 90% service

factor. The feed-product heat exchangers on this unit were increased 33% in area, and the product coolers 25% over the original estimate of the Bureau.

The quality of the products as specified by the Bureau has been accepted by the subcommittee, although it would be desirable to have more data on the relationship between throughputs, and other operating conditions with the aromatic content of the motor fuel. The German correlations between aromaticity and octane numbers have roughly been confirmed by laboratories of oil companies. Gasoline manufactured at the plant at Louisiana, Mo. from Rock Springs coal has been tested for octane rating and the correspondence of octane number with aromaticity tends to confirm the German estimates. The data on anticipated product quality appear on the second sheet of Table I.

Vapor-Phase Products Distillation

Figures 5-A and 5-B portray this unit which like the liquid-phase products distillation unit may be larger than necessary in some parts. It involves conventional equipment (see Table V) and offers no serious problems. The subcommittee increased the diameter of one absorber from 4 feet to 5 feet and one of the exchangers 100% in area. Four pumps were altered to increase the power requirements by 320 brake horsepower. One of these had to have the discharge rating increased from 110 to 275 p.s.i.g. pressure. The two furnaces are barely adequate for a stream-day capacity of 30,000 barrels of product.

Delayed Coking of HOLD

The delayed coking unit was entirely designed by engineers of the Standard Oil Company (Indiana) based on their experience with coking of petroleum and information in the literature. Of course, experimental work should be done to ascertain whether or not the HOLD (hot oil letdown) stream has any peculiar qualities which result in abnormal coking characteristics or involve difficult mechanical problems in handling coke. It was felt that the probability of successfully effecting the operation without too extensive later modification of the equipment was good. The flow sheet (Figure 6 - one of three identical units) indicates that the process is fairly straightforward. The investment for the unit amounts to less than 2% of the whole plant. This unit was designed to process the HOLD stream for a 30,000 B/SD plant. The principal items of equipment required are listed in Table VI.

Phenols Recovery Unit

The fraction of oil from the liquid-phase products distillation unit containing tar acids is processed in a phenols recovery unit to extract these compounds. A flow sheet of it (Figure 7) and an equipment list (Table VII) are attached. The tar acids are extracted with methanol first. The methanol-phenols extract contains some neutral oil which is then extracted by naphtha. Methanol is separated from the tar acids which are fractionated into phenol, o-cresol, m,p-cresols and xylenols fractions. This process is based on data from German pilot plants. It was previously pointed out that the phenol, cresols, and xylenols are recovered in this case for credit, but not for the other eight cases.

The methanol-middle oil extraction tower specified by the Bureau was found to be too small to handle the vapor load; so the cross-sectional area was doubled by the subcommittee. A few other minor revisions were incorporated.

Hydrogen Recovery Unit (Linde)

The lean off gases (around 60% H_2) from the wash oil scrubbers in the hydrogenation units and from the letdown vessels contain about 15% of the total hydrogen required. The hydrogen in this gas is recovered (ca. 95%) at low-temperature (liquid nitrogen), fractionated, and returned to the hydrogenation units. The CO_2, H_2S and NH_3 are removed prior to entering the low-temperature equipment by caustic scrubbing. The N_2 and CO are discarded from the unit and the hydrocarbons, largely methane and ethane, are sent to the hydrocarbon-steam cracking unit.

Although the Bureau's report contains a detailed design of this unit, it was not checked, because this unit is comprised of highly specialized equipment which would involve consulting engineers practicing in that field. On the other hand, this type of equipment is widely used commercially, especially abroad. There is no question whatsoever about the operability of the process. The subcommittee, therefore, obtained estimates from vendors for the investment and utilities and labor requirements for this unit. The vendors supplied data for units to process the gases for a 30,000 barrels per stream day plant. No flow sheet or equipment list is furnished for this unit.

Hydrocarbon-Steam Cracking Unit

Absorber off gases and the Linde unit discard contains sufficient hydrocarbons to furnish almost 40% of the hydrogen requirements of this hydrogenation plant. This gas is cracked with steam and shifted to produce hydrogen. The process is well known and widely used. An equipment list (Table VIII), but no flow sheet, is furnished for this process.

When the review of the process was made, it was found that the material balance did not check. The input exceeded the output. The subcommittee then checked the unit on an output basis and found the equipment to be barely adequate in size to handle output. It was understood that the Bureau was aware of this and preferred to divert the excess to fuel, which was equivalent to about 15% more hydrogen than made. This was, therefore, done for Case III-A. For all the other cases the equipment is scaled up to take all the rich gas available and none is sent to fuel. This results in a relatively larger fuel coal requirement for the other plants. The 310 metal tubes in this unit are fired with clean producer gas. The figures for the producer gas plant were obtained by the Engineering Subcommittee. Clean gas was specified because ash in uncleaned gas might get on the costly alloy tubes and damage them.

There is no question of the operability of this process. The equipment for Case III-A is adequate to process only part of the available gas in a 30,000 B/SD plant.

Hydrogen Purification and Compression

Representing about 15% of the total plant investment, the most expensive unit in the plant except the liquid-phase hydrogenation unit and powerhouse, the hydrogen purification and compression facilities convert the raw hydrogen to 98% pure gas and deliver it at 700 atm. (10,000 p.s.i.) pressure to the two hydrogenation units.

A flow sheet (Figure 8) and equipment summary (Table IX) present a picture of this unit. The gas from the coal gasification unit is shifted in this unit, e.g., the carbon monoxide is converted to CO_2 and hydrogen by reacting with steam over catalyst. (The gas shift equipment for the hydrogen from rich absorber off gas is in the steam-hydrocarbon cracking unit.) The CO_2 in the hydrogen is removed by scrubbing with water under

pressure (ca. 170 p.s.i.g.) between stages of compression to the high pressure. The last traces of carbon monoxide in the gas are scrubbed out in copper ammonium formate solution at around 1300 p.s.i. pressure. The copper solution is continuously regenerated. 250,000 gallons of solution containing 187.5 tons of copper and of ammonia and 94 tons of formic acid are required to charge the system. Gas is compressed at 10,000 p.s.i. in a series of multi-stage compressors.

Only minor modifications were made to the unit by the subcommittee which found that the purification equipment, especially the CO_2 scrubbing and degassing equipment, is barely large enough for a 30,000 B/SD plant. A few items possibly the CO removal towers are conservatively sized. The compressor requirements have been rechecked by the Engineering Subcommittee. The horsepower figures in the equipment listing are from the Engineering Subcommittee.

Coal Gasification Unit

The hydrogen not obtained from off gases is produced by the gasification of coal with steam and 95% oxygen. This amounts to 45% of the total hydrogen requirement for the base case.

It was explained earlier that the Bureau did not furnish an acceptable gasification process and would not design a low-pressure coal gasification process, the only type the NPC Subcommittee would consider for a conventional plant. The NPC Synthesis Process Subcommittee, therefore, designed the plant shown in Figure 9. Table X is a summarized list of the principal items of equipment for the unit. This unit uses fuel-type coal (higher ash content than the cleaned coal for the hydro unit) which is dried to 5% moisture in the pulverizers on the unit. Gasification is effected at 2400°F in a refractory-lined vessel. The coal is dispersed in the gases and the fused ash drops to the bottom of the vessel where it enters a basin to be quenched with water to decrepitate it. The reaction conditions and yields were based in part on data obtained from an experimental unit of the Bureau of Mines at Morgantown, West Virginia.

No commercial counterpart of this process is in operation. It was decided, however, that there is a good probability that the process as here presented is operable. Oxygen coal gasification processes have been operated abroad, although none of these is exactly like this one. They are limited by the type of coal that can be processed, highly coking coals - as Pittsburgh seam - being unsuitable. This unit should process any type coal. The use of conventional water gas generators (employed in most German hydrogenation units and for all German Fischer-Tropsch plants) would be very costly and necessitate the manufacture or purchase of coke as a raw material.

This unit will be complicated to operate and may require modification before a suitable service factor is attained. It is designed for supplying the hydrogen for a 30,000 B/SD plant.

Oxygen Plant

As in the case of the low-temperature fractionation plant, the design of the oxygen plant submitted by the Bureau was not checked in detail. Vendors of oxygen plants were requested to submit estimates of investment for the units. There are a number of different cycles used in various oxygen processes offered for sale. These are competitive and the differences in cost are small. All are based on the fractionation of air precooled to very low temperature by elaborate heat exchange and obtaining refrigeration by expansion of air or its components in engines, nozzles, or both. All operate at about 100 p.s.i.g. pressure. All make 95 to 98% pure oxygen.

The cost estimate was based on quotations from the vendors and from costs of several tonnage oxygen plants operating in this country. The evaluation of this plant was a joint venture of the Process and Engineering Subcommittees. After a careful study of the matter, it was decided that a 450-ton/day plant was the largest single unit advisable at present. Four such units were recommended. It was also decided that a 72% efficiency for air compressors was realistic, radial flow compressors being used.

A review of the records of oxygen plants operating in this country and abroad and study of vendors' estimates indicated that a power requirement of 448 horsepower-hours per ton of 100% oxygen produced represents the lowest energy consumption that can be expected from the best designed and operated oxygen plants today. This figure is based on the use of compressors operating at 72% efficiency.

EIGHT-PLANT CASE

It was indicated earlier that in addition to checking the base case (Rock Springs, Wyo.) the subcommittee should evaluate a case which included eight plants situated in different localities and processing widely different types of coals. Each plant produces 30,000 B/SD of total products. For this case, however, complete separate detailed designs for each plant were not deemed necessary. The subcommittee has submitted such a case.

The eight-plant case is based on the use of coal from eight sites chosen by the Raw Materials Subcommittee. These are lignite from Dunn County, North Dakota; subituminous coals from Knox County, Indiana; from Muhlenberg County, Kentucky; from Union County, Kentucky; from Franklin County, Illinois; and from Monongalia County, West Virginia (Pittsburgh seam coal). Rock Springs, Wyoming is the eighth site. Strip mining will be employed in the Muhlenberg County, Kentucky, Montana, and North Dakota sites. All others will involve underground mining. The analyses of these coals are given in Table I.

From correlations based on the hydrogenating characteristics of coals the subcommittee working with representatives of the Bureau of Mines worked up the coal requirements, hydrogen consumptions, products yields, and hydrogenation reactor volumes for each of these coals. The correlations and workups are based on the analyses of the coals. From these streams and qualities it was possible to estimate from the base case the sizes of the different plants and the materials and energy requirements for each plant by individual sections of the plant. Most of the latter requirements could be approximated by proper proration from the base case. For some values, however, a considerable amount of direct computation had to be made.

The principal streams involved in each step together with process and fuel coal requirements, hydrogen consumption, utilities, and product distribution and quality are given for each case in Table I. Detailed utilities, chemicals, and fuels requirements for all the plants are presented in Tables XIII through XVII.

Two cases are given for the Rock Springs, Wyoming coal, Case III and III-A, the base case. They differ in two respects. No phenols are recovered in Case III. Also, all the rich off gas is processed in the steam-hydrocarbon cracking unit which is correspondingly larger. In Case III-A about 10% of this is by-passed to fuel backing out some coal, but resulting in larger coal gasification unit.

Tables XVIII and XIX list the proportioning factors used to prorate the values from the base case to the other cases for those values when proration may be used. The basis for the prorating factors are also indicated. The principal streams, raw materials, and hydrogen consumption, and product quality and distribution were, of course, worked up individually for each case from basic correlations. The Engineering Subcommittee was able to make investment estimates from the seven additional cases by prorating from Case III-A on the basis of stream sizes and utilities and fuels balances presented here.

A study of Table I will indicate the wide range of types of coals covered by the study. For the coals ash contents range from 5 to 16%, moisture contents from 2.5 to 40%, oxygen content from 6.1 to 22%, carbon from 71 to 84%, heating value from 12,000 to 15,100 B.t.u./lb. To make 30,000 B/SD of products the different plants process between 6,000 and 10,500 tons/day of wet coal for hydrogenation, between 13,000 and 30,000 tons/day of coal for all purposes; consume between 230 and 248 million cubic feet per day of hydrogen; send to the power plants between 700 and 1,200 tons per day of coke; and produce between 21,600 and 23,700 B/SD of gasoline, which varies from 25 to 42% in aromatics content and between 78 and 88 octane number (Research clear). These figures indicate what can be expected from processing a fairly representative cross section of coals available in the United States.

TABLE I

EIGHT-PLANT CASE FOR 30,000 B/SD COAL HYDROGENATION PLANTS

CRITICAL THROUGHPUTS FOR VARIOUS SECTIONS OF EACH PLANT

Case	Units	I	II	III	III-A	IV	V	VI	VII	VIII
Coal:										
State		North Dakota	Montana	Wyoming	Wyoming	Indiana	Kentucky	Kentucky	Illinois	West Virginia
County		Dunn	Rosebud	Sweetwater	Sweetwater	Knox	Muhlenberg	Union	Franklin	Monongalia
Seam		-	Colstrip	Rock Springs	Rock Springs	5	11-12	9-11	6	Pittsburgh
Ultimate Analysis (m.a.f.)										
C	Wt. %	71.0	77.7	78.6	78.6	79.9	80.5	80.6	81.5	84.1
H	Wt. %	4.4	5.2	5.6	5.6	5.4	5.6	5.4	5.4	5.6
O	Wt. %	22.0	14.5	13.0	13.0	9.1	8.3	7.4	9.7	6.1
N	Wt. %	1.3	1.1	1.7	1.7	1.6	1.6	1.7	1.7	1.6
S	Wt. %	1.3	1.5	1.1	1.1	4.0	4.0	4.9	1.7	2.6
Proximate Analysis										
Volatile Matter	Wt. %	49.2	41.4	45.0	45.0	47.9	46.5	44.9	42.0	42.1
Fixed Carbon	Wt. %	50.8	58.6	55.0	55.0	52.1	53.5	55.1	58.0	57.9
Heating Value	BTU/Lb.	12,000	13,300	13,900	13,900	14,500	14,490	14,600	14,500	15,100
Per Cent Ash (Moisture-free)										
Raw Coal	Wt. %					13.0	16.1	15.6	10.1	13.0
Steam & Gasification Coal	Wt. %	11.2	13.5	5.4	5.4	13.4	18.9	15.8	12.9	11.9
Hydrogenation Coal	Wt. %	7.5	8.9	3.7	3.7	6.0	5.4	4.7	4.2	6.7
Per Cent Moisture (As Rec'd.)										
Raw Coal	Wt. %	40.0	25.8	10.0	10.0	10.0	7.5	7.1	9.0	2.5
Steam & Gasification Coal	Wt. %	40.0	25.8	10.0	10.0	11.4	8.5	8.0	10.3	2.7
Hydrogenation Coal	Wt. %	40.0	25.8	10.0	10.0	12.0	9.5	9.0	11.0	4.5
Per Cent Ash (As Rec'd.)										
Raw Coal	Wt. %	-	-	-	-	11.7	14.9	14.5	9.2	12.7
Steam & Gasification Coal	Wt. %	6.7	10.0	4.9	4.9	11.8	17.4	14.6	11.6	11.6
Hydrogenation Coal	Wt. %	4.5	6.6	3.3	3.3	5.3	4.9	4.3	3.7	6.4
Coal Cleaning Plant Recovery	Per Cent	-	-	-	-	92.0	90.4	89.8	97.0	92.0
Hydrogenation Plants										
Coal - (m.a.f.)	Tons/SD	5,820	5,550	5,400	5,568	5,320	5,270	5,260	5,200	5,480
	Tons/Hr.	243	231	225	232	222	220	219	217	228
Coal - (As Rec'd.)	Tons/SD	10,486	8,210	6,228	6,422	6,433	6,157	6,067	6,096	6,150
Hydrogen	MMSCF/D	248	236	237	239	234	231	235	234	230
Paste Preparation Unit										
Dry Coal in Feed	Tons/SD	6,280	6,100	5,606	5,740	5,670	5,570	5,520	5,430	5,880
Catalyst in Feed	Tons/SD	117	111	113	111	107	105	105	104	165
Water in Feed	Tons/SD	94	91	91	86	85	83	82	81	88
Pasting Oil in Feed	Tons/SD	7,460	7,020	6,500	7,520	7,100	7,100	7,100	7,120	7,900
Total Paste	Tons/SD	13,951	13,322	12,310	13,257	12,962	12,858	12,807	12,735	14,033
Liquid Phase Hydrogenation										
Paste Fed		See above								
Recycle Gas	MMSCF/D	868	825	828	840	820	808	825	820	805
Calculated Reaction Space	Cu.Ft.	9,040	12,180	13,500	13,500	13,600	13,920	13,910	14,550	16,520
No. of Reactors (750 Cu.Ft.)	-	12	16	18	18	18	19	19	19	22
Delayed Coking of HOLD*										
Feed to Delayed Coking Unit	Tons/SD	1,900	2,750	1,530	1,565	2,220	2,020	1,960	1,920	3,130
Quantity of Coke (m.a.f.)	Tons/SD	322	540	391	337	495	487	481	480	704
Quantity of Ash in Coke	Tons/SD	505	653	321	325	446	406	366	332	560
Total Dry Coke	Tons/SD	827	1,193	712	662	941	893	847	812	1,264
Heat Content of Off-Gas.	MMBTU/SD	1,050	1,760	1,270	1,210	1,610	1,580	1,560	1,560	2,280
Vapor Phase Hydrogenation										
Oil Feed	Tons/SD	3,540	3,620	3,670	3,598	3,590	3,580	3,580	3,530	3,450
Calculated Catalyst Volume	Cu.Ft.	7,505	8,442	8,250**	7,790**	8,344	8,312	8,279	8,182	8,577
Number of Reactors***	Cu.Ft.	11	12	12	12	12	12	12	12	13
Recycle Gas	MMSCF/SD	576	576	576	576	576	576	576	576	576
Distillation of Liquid Phase Product										
Middle Oil & Gasoline from Liq. Ph. Hydro.	Tons/SD	3,540	3,620	3,670	3,508	3,590	3,580	3,580	3,530	3,450
Light Oil Bottoms	Tons/SD	5,730	5,000	4,950	4,650	4,850	4,830	4,830	4,760	5,140
Total Feed (C_4-free)	Tons/SD	9,270	8,620	8,620	8,110	8,440	8,410	8,410	8,290	8,590
Products:										
Gasoline	Tons/SD				672					
Lt. Middle Oil to Tar Acids Rec.	Tons/SD				1,116					
Hvy. Middle Oil to Tar Acids Rec.	Tons/SD				1,920					
Bottoms to Pasting Oil + Flush Oil	Tons/SD				4,650					
C_1-C_4	Tons/SD			768	724					

* "Hot Oil Let Down"; e.g. the purge from the heavy oil recycle stream in hydro plant in which is the rejected ash and unhydrogenated coal.

** USBM early estimate. Later estimate 1.5% higher e.g. 8,377 and 7,910.

*** 750-cu.ft. reactors 90% filled = 675 cu.ft. catalyst volume per reactor.

TABLE I (Continued)

Case	Units	I	II	III	III-A	IV	V	VI	VII	VIII
		North Dakota	Montana	Wyoming	Wyoming	Indiana	Kentucky (M)	Kentucky (U)	Illinois	West Virginia
Low-Temperature (Linde) Fractionation Unit										
Hydrogen in Off Gas	MMSCF/SD	51.6	48.0	42.5	-	47.6	47.6	48.7	48.7	47.7
Hydrogen Recovered	MMSCF/SD	47.8-	44.5-	40.4-	38.1-	44.1-	44.1-	45.1-	45.1-	44.1-
Hydrocarbon-Steam Cracking										
Off Gas - C_1-C_4 (Feed)	Tons/SD	574	600	626	672*	644	657	662	681	762
Hydrogen Produced	MMSCF/SD	93.5-	97.7-	101.5-	92.8-	104.9-	107.0-	107.8-	110.9-	124.1-
Coal Gasification Unit										
Coal to Unit (m.a.f.)	Tons/SD	2,002	1,588	1,525	1,776	1,320	1,242	1,266	1,211	920
Coal to Unit (As Rec'd.)	Tons/SD	3,744	2,472	1,800	2,088	1,680	1,680	1,632	1,560	1,080
Low-Pressure Steam Consumed	M Lbs./SD	2,734	2,403	2,424	2,810	2,178	2,047	2,103	1,998	1,581
95% Oxygen Consumed	Tons/SD	1,804	1,431	1,377	1,600	1,190	1,119	1,140	1,091	829
Hydrogen Produced	MMSCF/SD	106.7-	93.8-	95.1-	108.1-	85.0-	79.9-	82.1-	78.0-	61.7-
Total Hydrogen Required	MMSCF/SD	248	236	237	239	234	231	235	234	230
Distillation of Vapor Phase Hydrogenation Unit Product										
Gasoline	BBL./SD	23,690	23,260	22,600	21,670	22,880	22,690	22,650	22,470	21,800
LPG	BBL./SD	6,310	6,740	7,400	7,100	7,120	7,310	7,350	7,530	8,200
Phenol**	BBL./SD				252					
O-Cresol	BBL./SD				84					
M-and P-Cresol	BBL./SD				347					
Xylenols	BBL./SD				547					
Total	BBL./SD	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
Aromatics in Gasoline	Wt. %	25	30	40	40	40	40	40	40	42
Octane No. of Gasoline - Clear	MM	72	74	77	77	77	77	77	77	78
Octane No. of Gasoline - Clear	Res.	78	81	85	85	85	85	85	85	88
Octane No. of Gasoline + 1 cc. TEL	Res.	86	88.5	91.5	91.5	91.5	91.5	91.5	91.5	95
Utilities										
1400-PSIG Steam Generation - Avg.	M Lbs./Hr.	3,384	3,123	3,082	3,230	3,016	2,983	2,999	3,002	2,993
1400-PSIG Steam Generation - Max.	M Lbs./Hr.	4,291	3,879	3,792	3,978	3,734	3,690	3,690	3,709	3,708
Process Steam***										
350-PSIG - Total Demand - Avg.	M Lbs./Hr.	1,566	1,489	1,419	1,573	1,422	1,396	1,409	1,402	1,387
From Waste Heat - Avg.	M Lbs./Hr.	450	445	393	447	391	365	369	353	352
45-PSIG - Total Demand - Avg.	M Lbs./Hr.	1,677	1,543	1,612	1,623	1,617	1,602	1,581	1,620	1,694
From Waste Heat - Avg.	M Lbs./Hr.	1,041	1,075	1,005	998	1,031	1,026	1,003	1,042	1,104
Electric Power										
Avg.	KW	255,211	239,640	225,847	233,600	223,690	220,753	221,095	220,984	223,083
Max.	KW	290,375	272,015	255,840	264,328	253,499	250,232	250,446	250,409	252,535
Cooling Water										
Avg.	GPM	331,400	305,000	310,500	333,360	310,240	308,160	308,600	309,580	309,290
Max.	GPM	387,730	358,040	363,500	390,700	363,640	361,240	361,590	364,160	363,270
Fresh Water										
Avg.	GPM	17,500	16,100	16,420	16,870	16,170	15,960	16,160	16,130	15,850
Max.	GPM	22,730	21,850	20,930	21,650	21,370	21,040	21,180	21,060	21,760
Producer Gas****	MMBTU/Hr.	637	646	663	624	684	680	636	720	771
Coal: Average Demand - (As Rec'd.)										
Process Coal - Hydrogenation	Tons/SD	10,486	8,210	6,228	6,422	6,433	6,157	6,067	6,096	6,150
Gasification	Tons/SD	3,744	2,472	1,800	2,088	1,680	1,680	1,632	1,560	1,080
Fuel Coal*****	Tons/SD	12,480	7,512	5,184	5,304	5,400	5,496	5,160	5,400	4,540
Losses	Tons/SD	490	306	288	586	263	267	269	264	250
Total Cleaned Coal	Tons/SD	27,200	18,500	13,500	14,400	13,776	13,600	13,128	13,320	12,020
Coal: Maximum Demand (As Rec'd.)										
Fuel Coal	Tons/SD	15,432	9,384	6,312	6,480	6,768	6,864	6,336	6,504	5,664
Losses	Tons/SD	598	404	280	610	289	299	290	290	281
Total Cleaned Coal	Tons/SD	30,260	20,470	14,620	15,600	15,170	15,000	14,325	14,450	13,175
Total Raw Coal Before Cleaning (As Rec'd.) Average Demand	Tons/SD	27,200	18,500	13,500	14,400	15,000	15,000	14,600	13,700	13,100
Maximum Demand	Tons/SD	30,300	20,500	14,600	15,600	16,500	16,500	16,000	14,900	14,300

* About 15% by-passed to fuel.

** All phenol and half other tar acids listed as given in the Bechtel Report.

*** From turbine bleeds and waste heat boilers.

**** Maximum demand ca. 110-112%

***** Includes coal for steam raising, producer gas mfg., furnace firing, and driers.

TABLE II

30,000 B/SD COAL HYDROGENATION PLANT, ROCK SPRINGS, WYO.
CASE III-A

PRINCIPAL ITEMS OF EQUIPMENT IN PASTE PREPARATION UNIT

3 Coal Silos	- Reinforced concrete 30 ft. dia. x 50 ft. high; 9-inch walls; 830 tons coal each.
2 Catalyst Silos	- Reinforced concrete 20 ft. dia. x 50 ft. high; 7-inch walls; 700 tons catalyst each.
2 Catalyst Pulverizers	- Roller mills plus drives, etc.; 5 tons/hr.
8 Weighing Feeders	- For coal and catalyst.
4 Paste Mixing Tanks	- 2500-gal. tanks with turbine-driven agitators.
15 Oil Pumps	- 50 to 800 g.p.m. each.
12 Paste Pumps	- 250 g.p.m.; 70 h.p. each.
2 Blend Tanks	- 48 ft. dia. x 24 ft. high.
11 Coal Paste Mixing Tanks	- 7 ft. dia. x 10 ft. high, steam-jacketed, baffled.
12 Storage Tanks	- 20 to 48 ft. dia.; 18 to 24 ft. high; heated.
10 HOLD Receivers	- 7 ft. dia. x 10 ft. high; 100 p.s.i.g.

Conveyors for coal and catalyst; piping; instruments; main building, 2-story 45,000 sq. ft.; tank farm; pump house.

TABLE III

30,000 B/SD COAL HYDROGENATION PLANT, ROCK SPRINGS, WYO.
CASE III-A

PRINCIPAL ITEMS OF EQUIPMENT IN LIQUID- AND VAPOR-PHASE HYDROGENATION UNITS

24	Coal Paste Pumps (LP)*	-	10,500 p.s.i. operating pressure; 616 b.h.p. each; 100 g.p.m.; motor drive.
2	Flushing Oil Pumps (LP)	-	10,500 p.s.i. operating pressure; 263 b.h.p. 100 g.p.m.; motor drive.
3	Water Injection Pumps (LP)	-	10,500 p.s.i. operating pressure, 489 b.h.p. 100 g.p.m.; motor drive.
4	Oil Letdown Engines (LP)	-	10,500 p.s.i.
15	Vap.-Ph. Feed Pumps (VP)*	-	10,500 p.s.i. operating pressure, 622 b.h.p. 100 g.p.m.
6	Recycle Compressors (LP)	-	10,500 p.s.i.; 1000 p.s.i. ΔP; 350 cu.ft. 1650 b.h.p.
5	Recycle Compressors (VP)	-	Same, but 1410 b.h.p.
18	Convertors (LP)	-	56 in. i.d., 80 in. o.d., 60 ft. long, 10,300 p.s.i. operating pressure; 900°F.; 750 cu. ft. volume.
4	Hot Catchpots (LP)	-	56 in. i.d. x 80 in. o.d. x 41 ft. long, 10,300 p.s.i.; 900°F.
4	Cold Catchpots (LP)	-	56 in. i.d., 80 in. o.d. x 27 ft.; 10,300 p.s.i.; 150°F.
5	Wash Oil Scrubbers (LP)	-	56 in. i.d., 80 in. o.d. x 60 ft.; 10,300 p.s.i.; 150°F.
2	Compressor Traps (LP)	-	56 in. i.d. x 80 in. o.d. x 27 ft.; 10,300 p.s.i.
1	Startup Trap (LP)	-	32 in. i.d.; 49.5 in. o.d.; 6 ft. long, 10,300 p.s.i.; 100°F.
1	Water Injection Surge (LP)	-	32 in. i.d.; 49.5 in. o.d. 12.5 ft. long, 10,300 p.s.i.; 100°F.
3	Oil, N_2, Surge, K.O. Drum (LP)	-	56 in. i.d., 80 in. o.d.; 12 ft. long, 10,300 p.s.i.
4	Wash Oil Pumps (LP)	-	10,300 p.s.i. 666 b.h.p. 100 g.p.m.

*(LP) denotes used in liquid-phase hydrogenation unit.
(VP) denotes used in vapor-phase hydrogenation unit.

TABLE III

(Continued)

2	Emergency Letdowns (LP)	-	atm. press. 900°F. 3 sections 33 ft., 20 ft., 6 ft., x 20 ft. long.
12	Convertors (VP)	-	56 in. i.d.; 80 in. o.d.; 60 ft., 10,300 p.s.i.; 930°F. oper. temp. alloy internals.
3	Cold Catchpots (VP)	-	56 in. i.d.; 80 in. o.d.; 27 ft. long, 10,300 p.s.i.; 100°F.
2	Compressor Traps (VP)	-	56 in. i.d.; 80 in. o.d.; 27 ft. long, 10,300 p.s.i.; 100°F.
1	Startup Trap (VP)	-	32 in. i.d.; 49.5 in. o.d.; 6 ft., 10,300 p.s.i.
1	Gantry Crane	-	85-ft. span; 85-ft. lift; 400-ton cap.
28	Paste-Pdt. Exchangers (LP)	-	22 in. i.d.; 30 in. o.d.; 60 ft. long shell; 283 tubes 3/4 in.; 2,560 sq.ft. each, 10,300 p.s.i.; 900°F.
28	Product Coolers (LP)	-	50 tubes 3/4 in. i.d. x 1-3/8 in. o.d., 10,300 p.s.i.; 420°F.
28	Recycle Gas Coolers (LP)	-	Same, 150°F.
24	Feed-Pdt. Exchangers (VP)	-	Same as liquid-phase paste-pdt.
30	Product Coolers (VP)	-	Same as for LP.
4	HOLD Coolers (LP)	-	Double tubes - oil side 3 in. i.d.; 4 in. o.d., 860 ft.; 10,300 p.s.i.; 900°F.
2	Recycle Comp. Breakin Coolers (LVP)	-	Double tube; oil side 3 in. i.d., 4 in. o.d., 270 ft. long; 10,300 p.s.i.; 200°F.
4	Preheaters, gas-fired (LP)	-	5 in. i.d. tubes; 20 10^6 B.t.u./hr.
3	Preheaters, gas-fired (VP)	-	6 in. i.d. tubes; 12 x 10^6 B.t.u./hr.
2	Tanks	-	25,000 bbl. (LP) 10,000 bbl. (VP).

Building - (see Engineering Subcommittee Report) Large control houses, a pump house of the order of 160 ft. x 630 ft. is involved, and a building possibly 100 x 200 ft. is required for the recycle compressors.

TABLE IV

30,000 B/SD COAL HYDROGENATION PLANT, ROCK SPRINGS, WYO.
CASE III-A

PRINCIPAL ITEMS OF EQUIPMENT
IN LIQUID-PHASE HYDRO PRODUCTS DISTILLATION UNIT

Towers, Vessels, Drums, Etc.

No. Req'd.	Service	Dia. ft.	Length ft.	Des. Press. p.s.i.g.	Trays No.	Remarks
1	Wash Water Tower	8	50	80	-	30 ft. packing
1	Absorber-Deethanizer	4-6	105	240	64	2 sections
1	Debutanizer	8	85	190	42	
1	Depropanizer	5	66	290	34	
1	Still	18.5	102	30	32	
4	Middle Oil Stripping	6	30	30	6	
1	Still	18.5	102	90	32	
10	Feed Flash Drums	7	20	385	-	Horizontal
10	Feed Flash Drums	7	20	95	-	Horizontal
2	Feed Flash Drums	12	40	30	-	Horizontal
1	Feed Flash Drums	11.5	38	30	-	Horizontal
1	Comp. K.O. Drum	5	14	30	-	Vertical
1	Comp. K.O. Drum	5	14	80	-	Vertical
1	Deb. Reflux Drum	8.5	30	190	-	Horizontal
1	Deprop. Reflux Drum	6	22	290	-	Horizontal
1	Still Reflux Drum	11	36	30	-	Horizontal
1	Still Reflux Drum	11	36	90	-	Horizontal
1	NaOH Wash Tower	3	34	225	-	Vertical

Exchangers, Coolers, Reboilers, Etc.

No. Req'd.	Service	Design Pressure p.s.i.g. Tube	Design Pressure p.s.i.g. Shell	Total Area sq. ft.	No. of Shells Per Unit	Remarks
1	Comp. Intake Cooler	-	30	285	1	
1	Comp. Intercooler	-	100	1270	1	
1	Comp. After Cooler	-	275	1650	1	
1	Absorber Intercooler	-	280	650	1	
1	Absorber Reboiler	175	240	3750	1	
1	Deb. Feed Heater	425	240	1700	1	
1	Deb. Condenser	-	190	5950	2	
1	Deb. Reboiler	175	190	4750	1	
1	Deprop. Preheater	70	290	380	1	
1	Deprop. Condenser	-	290	1600	1	
1	Deprop. Reboiler	70	290	390	1	
1	Deprop. Cooler	-	290	165	1	
2	Still Feed Exchanger	285	90	7510	2	eg. 4 shells total
2	Still Condenser	-	90	23250	6	eg. 12 shells total
2	Still Reflux Exchanger	250	65	4340	2	
2	Still LMO Exchanger	350	285	2340	2	
2	Still HMO Exchanger	150	285	3460	2	
2	Still LOB Exchanger	175	285	15900	4	
1	LMO Cooler	-	350	4330	2	
1	HMO Cooler	-	150	1375	1	
1	LOB Cooler	-	175	580	1	

Pumps (Motor Drive)

No.Req'd. (Incl. Spare)	Service	Capacity g.p.m.	Disch. Press. p.s.i.g.	Effic'y. %	Drive Rating b.h.p.
2	Comp. Precooler Liq. (Steam drive, reciprocating)	50	100	43	-
2	Comp. Interstage Liq.	139	275	58	40
2	Deprop. Reflux and Product	220	310	64	10
2	Deb. Reflux and Product	585	290	74	60
3	Still Charge	1255	250	78	250
2	Scrubber Oil Return	2700	500	78	1000
1	Still Reflux	938	100	77	100
3	Heavy Middle Oil	308	150	67	50
3	Light Oil Bottoms	781	175	76	125
3	Still Intermed. Reflux	412	65	70	15
2	Still Reflux and Product	938	250	77	135
2	Absorber Intercooler Circulator	256	280	67	10
2	Caustic Pump	10	230	12	2.5
3	Light Middle Oil	319	350	67	100

Compressors

2	Absorber Feed 1st Stage	5050*	65	72	850
2	Absorber Feed 2nd Stage	1430*	235	72	840

Furnaces

2	Still Feed (13,400 sq. ft.)	629165**	285	-	94 MM B.t.u./hr.

* cu. ft./min. at suction conditions.
** lb./hr. to 600°F.

TABLE V

30,000 B/SD COAL HYDROGENATION PLANT, ROCK SPRINGS, WYO.
CASE III-A

PRINCIPAL ITEMS OF EQUIPMENT
IN VAPOR-PHASE HYDRO PRODUCTS DISTILLATION UNIT

Towers, Vessels, Drums, Etc.

No. Req'd.	Service	Dia. ft.	Length ft.	Design Press. p.s.i.g.	Trays No.	Remarks
1	Water Wash	6	50	255	-	30 ft. Packing
1	Absorber	5	56	240	27	
1	Stripper	10	32	240	8	
1	Debutanizer	11.5	130	200	45	
1	Depropanizer	6.5	66	290	34	
1	Still	15.7	75	90	20	
1	Gasoline-Lean Oil Splitter	21.3	110	35	30	
1	Deisobutanizer	8	165	135	100	
1	H_2S Absorber	4.5	50	285	24	
1	Amine Reactivator	2	34	35	12	
4	Feed Flash Drums	8	23	385	-	Horizontal
1	Feed Flash Drum	12	42	95	-	Horizontal
1	Comp. Intake Drum	2.5	8	80	-	Vertical
1	Deb. Reflux Drum	12	42	200	-	Horizontal
1	Deprop. Reflux Drum	7.5	16	290	-	Horizontal
1	Still Reflux Drum	12	42	90	-	Horizontal
1	Gasoline-Lean Oil Splitter	11.5	34	35	-	Horizontal
1	Deisobutanizer Ref. Drum	8.5	26	135	-	Horizontal
1	Propane Drum	6.5	16	285	-	Horizontal

TABLE V

(Continued)

Exchangers, Coolers, Reboilers, Etc.

No. Req'd.	Service	Design Pressure p.s.i.g. Tube	Shell	Total Area sq. ft.	No. of Shells
1	Still Overhead - Condenser	150	90	22500	6
1	Still Feed - Btms. Exchg.	100	285	6000	2
1	Still Btms. Cooler	150	100	3760	2
1	Comp. Aftercooler	150	250	920	1
1	Absorber Intercooler	150	285	1150	1
1	Rich Oil Reboiler	410	240	7060	2
1	Debutanizer Condenser	150	200	13080	4
1	Splitter Overhead Condenser	150	35	12500	4
1	Depropanizer Feed Heater	70	290	2800	1
1	Depropanizer Overhead Condenser	150	290	2800	1
1	Depropanizer Reboiler	375	290	710	1
1	Splitter Btms. Cooler	150	275	3000	1
1	Lean Oil Cooler	150	275	220	1
1	Deisobutanizer Condenser	150	135	4600	2
1	Deisobutanizer Reboiler	70	135	1000	1
1	Deisobutanizer Btms. Cooler	150	135	210	1
1	H_2S Absorber Heater	70	310	830	1
1	Amine Sol'n. Cooler	150	300	160	1
1	H_2S Absorber Condenser	150	285	1100	1
1	Amine Exchanger	300	285	900	1
1	Reactivator Reboiler	70	35	270	1
1	Reactivator Overhead Cooler	150	35	140	1
1	Still Feed-Product Exchanger	285	90	7050	2

TABLE V

(Continued)

Pumps, Compressors (Motor Drive)

No. Req'd. (Incl. Spare)	Service	Capacity g.p.m.	Dischg. Press. p.s.i.g.	Effic'y. %	Drive Rating b.h.p.
2	Feed Pump	1440	285	78	250
2	Still Bottoms	620	100	74	20
2	Still Overhead	1550	250	78	250
2	Comp. Intake Drum (steam-drive reciprocating)	50	250	43	-
2	Rich Oil Absorber	390	265	69	20
3	Debutanizer Furn.Recycle & Btms.	1980	290	78	200
2	Debutanizer Overhead	1275	290	78	150
2	Splitter Furnace Recycle & Btms.	2500	275	78	500
2	Splitter Overhead	1280	104	78	100
2	Depropanizer Overhead	430	310	70	20
2	Deisobutanizer Overhead	575	160	73	25
2	H_2S Absorber Overhead	195	290	62	7.5
2	Lean Amine Circulation	150	300	59	50
2	Absorber Side Stream	340	285	68	15
2	Comp. - Vapor Recovery	392 c.f.m.	250	80	300

Furnaces

		Flow lb./hr.	Dischg. Press. p.s.i.g.	Area M sq. ft.	MM B.t.u./hr.
1	Still Reboiler	542990	285	11.6	89
1	Debutanizer Reboiler	823000	290	7.5	56.2
1	Splitter Reboiler	690000	275	4.9	37

TABLE VI

30,000 B/SD COAL HYDROGENATION PLANT, ROCK SPRINGS, WYO.
CASE III-A

PRINCIPAL ITEMS OF EQUIPMENT
IN UNIT FOR DELAYED COKING OF HOLD

Drums, Vessels

No. Req'd.	Service	Diameter ft.	Length ft.	Design Press. p.s.i.g.	Design Temp. °F.
6	Coke Drums	17	60	55	950
3	Heat Exchange Towers	9	30	45	850
3	Separators	8	30	35	250
3	Accumulators	4	12	30	180
1	Blow-down Drum	8	20	50	850

Exchangers, Coolers, Etc.

No. Req'd.	Service	Design Pressure p.s.i.g. Tube	Design Pressure p.s.i.g. Shell	Total Area sq. ft.	Duty MM B.t.u./hr.
3	Waste Heat Boilers	425	75	3320	
3	Condenser	150	40	2500	
3	Condenser (secondary)	35	60	60	
3	Coolers	45	120	120	
3	Recycle Gas Furnaces				
	Radiant Section	75		1820	25.5
	Convection Section	500		3070	13.8

Pumps and Compressors

No. Req'd.	Service	Capacity g.p.m.	Press. p.s.i.g.	Effic'y. %	Drive b.h.p.	Drive Type
6	Exchange Tower Btms. Pump	620	75	15	2.5	Steam
6	Circulating Oil Pump	20000	55	63	13.8	Motor
6	Distillate (from Sep.)	2840	65	40	4.2	Motor
6	Distillate (from Acc.)	85	65	15	0.5	Steam
2	Decoking Jet	42000	1900	71	1095	Steam
2	Coke Cooling Water	90000	80	85	72.5	Motor
2	Drum Condensate	10200	125	-	10.0*	Steam
2	Blow-down Pump	27000	125	-	33*	Steam
1	Water Return	130000	30	-	38*	Motor
3	Rec. Gas Compressors	11000 c.f.m.	55	75	1800	Motor

(*) Theoretical horsepower

TABLE VII

30,000 B/SD COAL HYDROGENATION PLANT, ROCK SPRINGS, WYO.
CASE III-A

PRINCIPAL ITEMS OF EQUIPMENT
IN PHENOLS (TAR ACIDS) RECOVERY UNIT

Columns, Towers, Etc.

No. Req'd.	Service	Dia. ft.	Length ft.	Design Press. p.s.i.g.	No. of Trays
1	Naphtha-MO* Fractionator	10	40	9	12
1	Methanol-Phenols Fractionator	12	40	9	12
1	Phenol Fractionator	7	65	200 mm.**	30
1	o-Cresol Fractionator	5	72	200 mm.	34
1	Methanol-MO Extractor	9	37	55	Packed
1	Naphtha-Methanol Extractor	9	44	28	Packed
1	m,p-Cresol-Xylenol Fractionator	8	62	200 mm.	28
1	Xylenols Fractionator	8	52	100 mm.	25
	Vessels				
2	Horizontal Drums	8	23	9	-
1	Horizontal Drum	5.5	15	200 mm.	-
1	Horizontal Drum	3.5	11	200 mm.	-
1	Horizontal Drum	5	15	200 mm.	-
1	Horizontal Drum	5	15	100 mm.	-

*MO denotes middle oil.
**200 mm. Hg vacuum.

Exchangers, Coolers, Etc.

No. Req'd.	Service	Capacity MM B.t.u./hr.	Area sq. ft.	Pressure p.s.i.g.
1	Naphtha-MO Heater	12.0	753	370
1	MO Reboiler	14.7	1474	370
1	Naphtha Condenser	22.5	3220	-
1	Naphtha Overhead Cooler	2.8	1680	-
1	MO Bottoms Cooler	1.0	192	-
1	Methanol-Phenols Heater	21.8	800	370
1	Methanol Condenser	84.3	4530	-
1	Methanol Cooler	5.9	1470	-
1	Phenol Condenser	8.9	580	-
1	Phenol Cooler	0.2	28	-
1	Cresols-Xylenols Reboiler	8.1	850	370
1	o-Cresol Condenser	3.8	231	-
1	o-Cresol Cooler	0.2	10	-
1	Cresols-Xylenols Reboiler	3.6	348	370
1	Xylenols Reboiler	8.7	932	370
1	m,p-Cresols Condenser	8.6	480	-
1	m,p-Cresols Cooler	0.3	50	-
1	Tar Acids Reboiler	5.2	475	370
1	Xylenols Condenser	5.5	319	-
1	Xylenols Cooler	0.5	77	-
1	Tar Acids Bottoms Cooler	0.3	36	-
1	Phenols Reboiler Furnace	60.8	8700	*

*12% Cr tubes.

Pumps

No. Req'd.	Service	Capacity gal./hr.	Pressure p.s.i.g.	Drive b.h.p.	Drive Type
1	MO to Vapor Phase	9060	100	11.5	Motor
1	Methanol Extractor	14620	100	8.3	Motor
1	MO from Fractionator	1175	75	1.1	Motor
1	Naphtha Overhead	22600	50	12.8	Motor
1	Methanol Fractionator Overhead	18300	75	16.8	Motor
1	Furnace Recycle	61700	110	87.5	Motor
1	Phenol Fractionator Overhead	4870	50*	4.2	Motor
1	Phenol Fractionator Bottoms	2114	10*	0.6	Motor
1	o-Cresol Fractionator Overhead	2240	50*	1.9	Motor
1	o-Cresol Fractionator Bottoms	1968	10*	0.6	Motor
1	Cresols-Xylenols Fr. Overhead	5360	50*	4.6	Motor
1	Cresols-Xylenols Fr. Bottoms	1350	10*	0.4	Motor
1	Xylenols-T.A. Overhead	3460	50*	3.1	Motor
1	Xylenols-T.A. Bottoms	593	75*	0.8	Motor

*Also, 250 mm. Hg vacuum on suction.

TABLE VIII

30,000 B/SD COAL HYDROGENATION PLANT, ROCK SPRINGS, WYO.
CASE III-A

PRINCIPAL ITEMS OF EQUIPMENT
IN HYDROCARBON-STEAM CRACKING UNIT

Towers, Vessels, Etc.

No. Req'd.	Service	Dia. ft.	Length ft.	Press. p.s.i.g.	Remarks
4	Pdt. Gas Cooling Tower	12	20	-	Packed; bricklined
1	Methane, Ethane Gas Holder				250,000 cu. ft. capacity
8	CO Shift Converters	15	12	2.5	Bricklined
1	H_2S and CO_2 Absorber*	5	50	285	24 Trays
1	Amine Reactivator*	3.3	34	35	12 Trays

Exchangers, Heaters, Coolers, Etc.

No. Req'd.	Service	Heating Area sq. ft.	Duty MM B.t.u./hr.	Press. p.s.i.g.	Temp., °F.
4	Air Preheaters	3250	4.2	11.3	400
4	Flue Gas Waste Ht. Boiler	11300	63	50	1900
8	Pdt. Steam Superheater	1320	5.5	50	1260
8	Pdt.-Feed Exchanger	725	3.7	50	1260
4	Pdt. Waste Ht. Boiler	4400	32.8	50	960
1	Lean Amine Sol'n Cooler	430	4.3	-	150
1	Lean-Rich Amines Exchg.	2346	9.3	-	230
1	Reactivator Overhead Cooler	370	4.8	-	-
1	Reactivator Reboiler	715	8.7	50	-

Pumps, Compressors, Etc.

No. Req'd.	Service	Capacity c.f.m.**	Press. p.s.i.g.	Drive b.h.p.	Drive Type	Remarks
4	Air Blower	26400	***	-	Motor	60°F.
4	Flue Gas Blower	75000	***	-	Motor	400°F. Gas
4	Linde Gas Compressors	4250	50	-	-	100°F.
1	Lean Amine Circ. Pump	343 g.p.m.	300	130	Motor	59% Eff.

Special Equipment

No. Req'd.	Description	
8	Gas Producers:	To manufacture 530 MSCFH Clean 125 B.t.u./cu. ft. Gas.
8	Hydrocarbon-Steam Cracking Furnaces:	Each unit contains 12 cells of 4 tubes (384 tubes in all); tubes are 8 in. dia. by 33 ft. 3 in. long for 30 p.s.i.g. pressure at 1800°F. made of 310 metal. Tubes vertically hung in fire box heated with clean producer gas - wall temperature 2200°F. Hercules type standard unit or equivalent may be used.

*Part of Girbotol Unit.
**At suction conditions - see remarks.
***8 inches $H_2O \Delta P$.

TABLE IX

30,000 B/SD COAL HYDROGENATION PLANT, ROCK SPRINGS, WYO.
CASE III-A

PRINCIPAL ITEMS OF EQUIPMENT
IN HYDROGEN PURIFICATION UNIT

Vessels, Towers, Drums, Etc.

No. Req'd.	Service	Dia. ft.	Length ft.	Press. p.s.i.g.	Remarks
2	Cu Liquor CO Scrubber	4	60	1350	Packed, 48 ft.
2	Cu Liquor Regen. Tower	8	24	15	Packed, 14 ft.
		11	37	45	1500 sq. ft. 3" Tubes
9	Water CO_2 Scrubber	12	70	200	Packed, 70 ft.
24	Shift Gas Coolers, Water Scrubbers	8	20	200	Packed, 14 ft.
19	CO_2 Degassing Towers	(64 x 24)	25	15	Carbon Steel
31	CO_2 Degassing Towers	(64 x 24)	25	15	Monel Trim
2	Gas Holder - Raw H_2	143	96	-	1.5 MM cu. ft.
1	Gas Holder - N_2	67	45	-	150,000 cu. ft.
28	Traps and K.O. Drums	3	5	200	--
1	Compressor K.O. Drum	12	20	200	--
2	Cu Liquor Regenerator	12	40	15	--
1	Compressor K.O. Drum	3	20	1350	--
7	Shift Reactors	12	16	200	5% Cr Steel
4	Ammonia Receiver	-	-	250	2,000 Gal.
2	Cu Liquor Storage Tanks	8	12	-	Rubber-lined; 304 metal coil.

Exchangers, Heaters, Coolers, Etc.

No. Req'd.	Service	Design Press. p.s.i.g. Tube	Design Press. p.s.i.g. Shell	Area sq. ft.	Heat Load MM B.t.u./hr.	Remarks
2	Cu Liquor Exchangers	100	100	1800	10.8	
2	Cu Liquor Coolers	100	-	2150	19.4	
2	Cu Liquor-Ammonia Cooler	100	50	2180	14.3	
7	Shift Gas Waste Ht. Exchg.	200	200	11800	112.0	
6	Cu Liq. Exchg. + Coolers	200	200	11800	112.0	
1	Shift Startup Heater	200	-	-	20.0	7% Cr Steel Tubes
4	Ammonia Condenser	250	-	7150	18.0	

Pumps

No. Req'd.	Service	Capacity g.p.m.	Press. p.s.i.g.	Drive b.h.p.	Drive Type	Remarks
9	CO_2 Scrubber Water Pump	9000	220	750	Motor	Pelton Wheel
10	CO Scrubber Cu Liquor	575	1350	-	-	Let-down Pump
3	CO Scrubber Cu Liquor	230	1350	330	Motor	
1	Aerated Water Return	108000	15	1150	Motor	Bronze-enamel
15	CO_2 Scrubber	9000	220	720	Motor	Pelton Wheel
1	CO_2 Scrubber Building	160 x 660 x 30 or larger, steel and transite.				

Compressors

No. Req'd.	Service	Capacity SCFM	Press. atm.	Stages	Total Installed b.h.p.
1	Turbo-Comp. Reformed H_2	90400	1-4	2	16030
2	Turbo-Comp. Gasif. H_2	98700	1-6	2	47410
2	Turbo-Comp. Gasif.	98700	6-13	1	16490
4	H_2 Recip. Comp.	30150	4-11.5	1	14000
4	H_2 Hyper. Comp. I	23800	11-88	2	21000
4	H_2 Hyper. Comp. II	21500	88-710	2	21000
5	H_2 Hyper. Comp. I	21500	11-88	2	24500
4	H_2 Hyper. Comp. II	26000	88-710	2	24000
2	H_2 Hyper. Comp. I	26900	25-88	1	6000
1	H_2 Hyper. Comp. II	26900	88-710	2	7500
2	N_2 Compressor	840	1-915	7	1400
5	Ammonia Comp.	33000 lb./hr. NH_3 to 200 p.s.i.g.			7500
	Total Compressor Horsepower				126900

Compressor Building at least 160 x 660 ft. x 30 ft. high.

TABLE X

30,000 B/SD COAL HYDROGENATION PLANT, ROCK SPRINGS, WYO.
CASE III-A

PRINCIPAL ITEMS OF EQUIPMENT FOR COAL GASIFICATION UNIT

Vessels, Towers, Drums, Special Equipment, Etc.

No. Req'd.	Service	Dia. ft.	Length ft.	Press. p.s.i.g.	Temp. °F.	Remarks
3	Coal Hoppers	-	36	atm.	-	20 ft. x 40 ft.; 350 tons coal
3	Fluidized Coal Feed Tanks	16	36	20	-	Conical Btms.
6	Cyclone Collectors	12-1/2	-	-	-	
4	Bag Filter Cases	12	20	-	-	Approx. Dimen.
3	Gas Scrubbers	12	52	-	150	Packed
1	Settling Basin	120 x 60 x 5		-	-	
3	Steam Drums	6	10	375	-	
3	Reactors	19	95	10	2500	Carbon Steel Shell (600°F.), 25 inches internal refractory lining, water-cooled wall, overhead steam drum, 8-6 in. EH pipe nozzles for O_2; 8-8 in. EH nozzles for steam; 8 ft. x 12 ft. slag removal basin on bottom.
4	Coal Pulverizers:	DJ-7 ball mills, 750 h.p. motor drive.				
4	Exhauster (fans):	250 h.p. motor drive; 900,000 SCFM.				
8	Coal Feeder:	Size #4 Table Type.				
2	Air Heaters:	Direct-fired air mixing heater; 3.65 MM B.t.u./hr., 1200°F. outlet.				
4	Bag Filter Mechanisms:	Includes filter, rapping mechanism, rotary valves, air locks, controls, etc.				
4	Air Heater Fans:	170,000 SCF/hr.				
4	Oxygen Plant:	450 Tons/SD 95% oxygen each.				

Exchangers, Coolers, Heaters, Etc.

No. Req'd.	Service	Duty MM B.t.u./hr.	Press. p.s.i.g.	Temp. °F.	Area sq. ft.	Remarks
3	Steam Superheaters	13.4	50	1000	1110	Prod. Gas-fired
3	Waste Heat Boilers	110	375	-	11800	Prod. Gas
3	Boiler Feedwater Heater	16.2	375	-	9600	
3	Scrubber Tower Cooler	29.3	-	140	9600	-

In addition this plant involves extensive installations of conveyors, ducts, instruments, large piping, safety controls, valves, insulation, ditches, etc.

TABLE XI

30,000 B/SD COAL HYDROGENATION PLANT, ROCK SPRINGS, WYO.
CASE III-A

PROCESS LABOR REQUIREMENTS - OPERATING ONLY

Unit	Men per Shift	
Coal Handling and Storage*	9	
Coal Preparation Unit*	7	
Paste Preparation Unit	5	
Hydrogenation Units (Liquid-and Vapor-Phase)	64	
Distillation Units	10	
Delayed Coking Unit	13	
Phenols Recovery Unit	6	
Coal Gasification Unit	7	
Hydrocarbon-Steam Cracking - incl. Prod. Gas.	16	
Oxygen Plant	7	
Hydrogen Recovery Unit (Linde Low-Temp. Distill.)	8	
Hydrogen Purification, Gas Shifting	21	
Total Process Operating Labor		173
Services Labor		
Catalyst Manufacture	5	
Plant Producer Gas**	3	
Steam and Power**	29	
Water System**	10	
Waste Disposal**	5	
Tankage and Loading**	13	
		65
Total Without Supervision		238

*Estimated by Raw Materials Subcommittee.
**Estimated by Engineering Subcommittee or Offsites Subcommittee.

TABLE XII

30,000 B/SD COAL HYDROGENATION PLANTS - EIGHT-PLANT CASE

CHEMICALS REQUIREMENTS

Case	Units	I	II	III	III-A	IV	V	VI	VII	VIII
Coal: State		North Dakota	Montana	Wyoming	Wyoming	Indiana	Kentucky	Kentucky	Illinois	West Virginia
County		Dunn	Rosebud	Sweetwater	Sweetwater	Knox	Muhlenberg	Union	Franklin	Monongalia
Coal Preparation		Information to be furnished by Raw Materials Subcommittee. Magnetite may be required for wet cleaning of coal.								
Paste Preparation Unit										
Ferric Oxide (Catalyst)	Tons/SD	117	111	108	111	107	105	105	104	165
Vapor Phase Hydrogenation*										
Untreated Fuller's Earth	Tons/yr.	202	220	220	220	220	220	220	220	238
Zinc Oxide (Tech. Grade)	Tons/yr.	7.5	8	8	8	8	8	8	8	8.5
Chromic Acid (Tech. Grade)	Tons/yr.	6.	6.5	6.5	6.5	6.5	6.5	6.5	6.5	7.
Sulfur (Flowers)	Tons/yr.	14.5	16.	16.	16.	16.	16.	16.	16.	17.5
Ammonium Thiomolybdate - $(NH_4)_2$ MoS_4 -	Tons/yr.	3.2	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.8
Activated Fuller's Earth	Tons/yr.	53	64	64	64	64	64	64	64	70
Hydrofluoric Acid	Tons/yr.	9	10	10	10	10	10	10	10	11
Ammonia - 25% - Tech.	Tons/yr.	38	41	41	41	41	41	41	41	45
Low-Temp. Fractionation Unit										
Sodium Hydroxide	Tons/yr.	825	770	700	660	765	765	780	780	765
Ammonia (Anhydrous)		1.5	1.5	1.5	1.2	1.5	1.5	1.5	1.5	1.5
Hydrocarbon-Steam Cracking Unit	Tons/yr.									
Cracking Catalyst	Tons/yr.	29	31	32	29	33	34	34	35	39
Shift Catalyst	Tons/yr.	95	99	103	94	106	108	109	112	125
Monoethyanolamine	Tons/yr.	11	11.5	12	11	12.5	13	13	13	14.5
Oxygen Plant										
**Ammonia - (Refrigeration)	Tons/yr.	1	1	1	1	1	1	1	1	1
Hydrogen Purification & Comp.										
Formic Acid	Tons/yr.	30	28	29	30	28	28	28	28	27.5
Acetic Acid	Tons/yr.	7	7	7	7	7	7	7	7	6.5
Copper	Tons/yr.	14	13	14	14	13	13	13	13	12.5
Shift Catalyst	Tons/yr.	52	45	46	52	40	38	39	38	30
Ammonia	Tons/yr.	45	43	44	45	42	42	43	42	41
Tar Acids Recovery										
Methanol	Gal./yr.	0	0	0	230,000	0	0	0	0	0

*Chemicals for Catalyst estimated to nearest 1/2 ton.

**Equivalent Freon may be used. If Linde-Frankl or Air Liquide plants with 5-6% air compressed to 200± atm. is used 200 to 300 tons/yr. caustic will be required.

TABLE XIII

30,000 B/SD COAL HYDROGENATION PLANT - EIGHT-PLANT CASE

I - FUEL BALANCES

Case		I		II		III		III-A*		IV		V		VI		VII		VIII	
	Units																		
Coal: State		North Dakota		Montana		Wyoming		Wyoming		Indiana		Kentucky		Kentucky		Illinois		West Virginia	
County		Dunn		Rosebud		Sweetwater		Sweetwater		Knox		Muhlenberg		Union		Franklin		Monongalia	
**Per Cent Ash - As Rec'd.	Wt. %	6.7		10.0		4.9		4.9		11.9		17.4		14.6		11.6		11.6	
**Per Cent Water - As Rec'd.	Wt. %	40.0		25.8		10.0		10.0		11.4		8.5		8.0		10.3		2.7	
Heating Value Gross - As Rec'd.	B.t.u./lb.	6,400		8,540		11,830		11,830		11,120		10,750		11,320		11,320		12,940	
		Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum
Fuel Consumed																			
Drying Coal to 10% H_2O	MM B.t.u./Hr.	742	890	265	318	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Preparation Unit	MM B.t.u./Hr.	104	125	100	120	97	115	***81	***97	117	140	88	106	82	99	102	122	45	54
Hydrogenation Units	MM B.t.u./Hr.	+27.6	+48	+26.8	+47	+25.3	+44	+26.7	+46.5	+26.2	+46	+26	+45	+26	+45	+26	+45	+27.7	+48
Delayed Coking Unit	MM B.t.u./Hr.	210	231	304	335	169	186	173	190	246	270	224	236	216	238	212	234	344	378
Liquid-Phase Distillation	MM B.t.u./Hr.	290	316	269	293	269	293	253	276	262	285	261	284	261	284	258	231	268	293
Vapor-Phase Distillation	MM B.t.u./Hr.	179	199	179	199	179	199	179	199	179	199	179	199	179	199	179	199	179	199
Phenols Recovery Unit	MM B.t.u./Hr.							++94	++104										
Hydrocarbon-Steam Cracking Unit	MM B.t.u./Hr.	808	900	840	935	872	972	800	880	903	1010	920	1025	848	945	952	1060	1072	1195
Coal Gasification - Steam Heater+	MM B.t.u./Hr.	+49.6	+76	+43.6	+66	+44.1	+64	+51	+68.8	+39.5	+63	+37	+51	+38.2	+51	+36.3	+53	+28.7	+32
Drying+	MM B.t.u./Hr.	+18.7		+15.3		+13.5		+11		+17.0		+3.5		+7.1		11.9		0	0
Producer Gas Unit****	MM B.t.u./Hr.	144	158	128	141	124	136	133	146	124	136	107	118	107	118	111	122	85	94
Process Fuel - Sub-Total	MM B.t.u./Hr.	2,477	2,819	2,085	2,341	1,720	1,901	1,713	1,892	1,831	2,040	1,779	1,968	1,693	1,883	1,811	2,018	1,993	2,213
Steam Dept.	MM B.t.u./Hr.	4,560	5,760	3,900	4,850	4,740	4,740	4,071	4,994	3,770	4,660	3,730	4,610	3,750	4,610	3,750	4,630	3,740	4,640
Total	MM B.t.u./Hr.	7,037	8,579	5,985	7,191	5,570	6,691	5,784	6,886	5,601	6,700	5,509	6,578	5,443	6,493	5,664	6,648	5,733	6,853
Fuel Produced																			
Delayed Coking Unit	MM B.t.u./Hr.	384	346	643	580	460	414	413	372	590	431	580	422	573	517	572	515	837	753
Distillation Unit Off Gas	MM B.t.u./Hr.							150	135										
	MM B.t.u./Hr.							563	507										
Net Fuel Required	MM B.t.u./Hr.	6,653	8,233	5,342	6,611	5,110	6,227	5,221	6,379	5,011	6,269	4,929	6,156	4,870	5,976	5,092	6,133	4,896	6,100
Fuel Coal - As Rec'd.	Tons/Hr.	520	643	313	391	216	263	221	270	225	282	229	286	215	264	225	271	189	236
II - 1400-PSIG STEAM BALANCE																			
1400-psig Steam Demand																			
Bleed to 370-psig Steam	M Lb./Hr.	1,116	1,569	1,044	1,486	1,026	1,436	1,126	1,571	1,031	1,448	1,031	1,437	1,039	1,447	1,048	1,454	1,035	1,447
Bleed to 45-psig Steam	M Lb./Hr.	636	1,004	468	834	606	972	624	987	585	953	575	945	578	939	578	950	550	933
Direct to Process Turbo Compressors	M Lb./Hr.	289	318	273	300	299	321	306	337	254	280	249	274	254	268	252	277	248	273
Supply to 1400-psig Steam System	M Lb./Hr.	1,343	1,400	1,338	1,259	1,151	1,063	1,174	1,083	1,146	1,053	1,128	1,034	1,128	1,036	1,124	1,028	1,160	1,055
Total	M Lb./Hr.	3,384	4,291	3,123	3,879	3,082	3,792	3,230	3,978	3,016	3,734	2,983	3,690	2,999	3,690	3,002	3,709	2,993	3,708
Power Generation																			
From 370-psig Steam @27.6 lb./k.w.	k.w.	40,500	41,900	37,900	53,800	37,200	52,100	40,800	57,000	37,400	52,500	37,400	52,100	37,700	52,500	38,000	52,800	37,500	52,500
From 45-psig Steam @13.9 lb./k.w.	k.w.	45,700	72,400	33,600	60,000	43,700	70,000	44,900	71,100	42,100	68,600	41,400	68,100	41,600	67,600	41,600	68,400	39,600	67,200
From 1400-psig Steam @7.95 lb./k.w.	k.w.	169,011	176,075	168,140	158,215	144,947	133,740	147,900	136,228	144,190	132,399	141,953	130,032	141,975	130,346	141,384	129,209	145,983	132,835
Total Power Demand	k.w.	255,211	290,375	239,640	272,015	225,847	255,840	233,600	264,328	223,690	253,499	220,753	250,232	221,095	250,446	220,984	250,409	223,083	252,535
Fuel Demand for Steam Dept. - 1250 B.t.u./Lb. @85% Boiler Efficiency; except case I @79%	MM B.t.u./Hr.	4,560	5,760	3,900	4,850	3,850	4,740	4,071	4,994	3,770	4,660	3,730	4,610	3,750	4,610	3,750	4,630	3,740	4,640

*Base Case; **Fuel and Gas Coal; ***Figures of Eng. Subcom. Proc. Subcom. Estimate 100 and 1120; ****Used 66.6% Efficiency; +Represents Producer Gas accounted for under this item. Do not include to obtain total; ++From light ends gas not used in steam cracking to H_2.

TABLE XV

EIGHT-PLANT CASE FOR 30,000 B/SD COAL HYDROGENATION PLANTS

CONSUMPTION AND PRODUCTION OF 370-PSIG STEAM

Case	Units	I		II		III		III-A		IV		V		VI		VII		VIII	
Coal:																			
State		North Dakota		Montana		Wyoming		Wyoming		Indiana		Kentucky		Kentucky		Illinois		West Virginia	
County		Dunn		Rosebud		Sweetwater		Sweetwater		Knox		Muhlenberg		Union		Franklin		Monongalia	
Seam		-		Colstrip		Rock Springs		Rock Springs		5		11-12		9-11		6		Pittsburgh	
		Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum
370-PSIG STEAM CONSUMPTION																			
Delayed Coking	Lbs./hr.	(Note: 370-PSIG Steam Production shown below is net production)																	
Liquid Phase Distillation	Lbs./hr.	13,300	15,000	12,350	13,900	12,350	13,900	11,600	13,070	12,050	13,600	12,000	13,500	12,000	13,500	11,850	13,350	12,300	13,850
Vapor Phase Distillation	Lbs./hr.	78,500	88,300	78,500	88,300	78,500	88,300	78,500	88,300	78,500	88,300	78,500	88,300	78,500	88,300	78,500	88,300	78,500	88,300
H_2 Purification Unit	Lbs./hr.	124,000	139,500	109,000	123,000	111,000	125,000	126,000	142,000	99,000	112,000	93,000	105,000	95,500	107,500	90,800	102,500	71,800	81,000
General Plant	Lbs./hr.	8,000	10,000	8,000	10,000	8,000	10,000	8,000	10,000	8,000	10,000	8,000	10,000	8,000	10,000	8,000	10,000	8,000	10,000
Fire Pumps	Lbs./hr.	-	15,600	-	15,600	-	15,600	-	15,600	-	15,600	-	15,600	-	15,600	-	15,600	-	15,600
Boiler Feed Pumps to Waste Heat Boilers	Lbs./hr.	24,000	32,000	24,000	32,000	24,000	32,000	24,000	32,000	24,000	32,000	24,000	32,000	24,000	32,000	24,000	32,000	24,000	32,000
Plant & Instrument Air Supply	Lbs./hr.	10,500	21,000	10,500	21,000	10,500	21,000	10,500	21,000	10,500	21,000	10,500	21,000	10,500	21,000	10,500	21,000	10,500	21,000
Cooling Towers & Pumps	Lbs./hr.	243,000	300,000	239,000	295,000	230,000	284,000	236,820	293,000	235,000	290,000	232,000	287,000	235,000	290,000	233,000	288,000	236,800	293,000
Phenol Recovery	Lbs./hr.	-	-	-	-	-	-	94,820	106,500	-	-	-	-	-	-	-	-	-	-
Sub Total	Lbs./hr.	501,300	621,400	481,350	598,800	474,350	589,800	590,240	721,470	467,050	582,500	458,000	572,400	463,500	577,900	456,650	570,750	441,900	554,750
Steam Dept.	Lbs./hr.	1,065,000	1,318,000	1,008,000	1,246,000	945,000	1,170,000	983,000	1,219,000	955,000	1,182,000	938,000	1,161,000	945,000	1,170,000	945,000	1,170,000	945,000	1,170,000
Grand Total	Lbs./hr.	1,566,300	1,939,400	1,489,350	1,844,800	1,419,350	1,759,800	1,573,240	1,940,470	1,422,050	1,764,500	1,396,000	1,733,400	1,408,500	1,747,900	1,401,650	1,740,750	1,386,900	1,724,750
370-PSIG STEAM PRODUCTION																			
Delayed Coking	Lbs./hr.	85,500	59,500	124,000	86,300	68,800	48,000	70,500	49,100	100,000	69,700	91,000	63,300	88,200	61,500	86,300	60,000	140,000	97,500
Coal Gasification Plant	Lbs./hr.	365,000	311,000	321,000	273,000	324,000	276,000	376,200	320,000	291,000	247,000	274,000	233,000	281,000	239,000	267,000	227,000	212,000	180,500
Total	Lbs./hr.	450,500	370,500	445,000	359,300	392,800	324,000	446,700	369,100	391,000	316,700	365,000	296,300	369,200	300,500	353,300	287,000	352,000	278,000
NET 370-PSIG STEAM PRODUCTION																			
370-PSIG Steam Consumption	Lbs./hr.	1,566,300	1,939,400	1,489,350	1,844,800	1,419,350	1,759,000	1,573,240	1,940,470	1,422,050	1,764,500	1,396,000	1,733,400	1,408,500	1,747,900	1,401,650	1,740,750	1,386,900	1,724,750
370-PSIG Steam Production	Lbs./hr.	450,500	370,500	445,000	359,300	392,800	324,000	446,700	369,100	391,000	316,700	365,000	296,300	369,200	300,500	353,300	287,000	352,000	278,000
Net 370-PSIG Steam Consumption	Lbs./hr.	1,115,800	1,568,900	1,044,350	1,485,500	1,026,550	1,435,800	1,126,540	1,571,370	1,031,050	1,447,800	1,031,000	1,437,100	1,039,300	1,447,400	1,048,350	1,453,750	1,034,900	1,446,750

TABLE XIV

EIGHT-PLANT CASE FOR 30,000 B/SD COAL HYDROGENATION PLANTS

CONSUMPTION AND PRODUCTION OF 45-PSIG STEAM

Case	Units	I		II		III		III-A		IV		V		VI		VII		VIII	
Coal:																			
State		North Dakota		Montana		Wyoming		Wyoming		Indiana		Kentucky		Kentucky		Illinois		West Virginia	
County		Dunn		Rosebud		Sweetwater		Sweetwater		Knox		Muhlenberg		Union		Franklin		Monongalia	
Seam		-		Colstrip		Rock Springs		Rock Springs		5		11-12		9-11		6		Pittsburgh	
		Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum
45-PSIG STEAM CONSUMPTION																			
Paste Preparation	Lbs./hr.	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Liquid Phase Distillation	Lbs./hr.	64,300	72,500	59,800	67,500	59,800	67,500	56,170	63,300	58,500	65,800	58,200	65,500	58,200	65,500	57,300	64,500	59,600	67,100
Vapor Phase Distillation	Lbs./hr.	29,600	33,300	29,600	33,300	29,600	33,300	29,600	33,300	29,600	33,300	29,600	33,300	29,600	33,300	29,600	33,300	29,600	33,300
Low Temp. Off Gas Separation	Lbs./hr.	3,150	3,530	2,920	3,270	2,650	2,970	2,500	2,800	2,900	3,250	2,900	3,250	2,960	3,310	2,960	3,310	2,900	3,250
Hydrocarbon Steam Cracking Plant	Lbs./hr.	344,000	388,000	358,000	403,000	372,000	418,000	341,130	384,000	385,000	433,000	392,000	442,000	361,000	407,000	406,000	457,000	457,000	515,000
Coal Gasification Plant	Lbs./hr.	114,000	128,500	100,000	113,000	101,000	114,000	117,000	132,000	90,700	102,000	85,300	96,200	87,500	98,600	83,300	93,800	66,000	74,300
H_2 Purification Unit	Lbs./hr.	134,000	151,000	128,000	144,000	131,500	148,000	134,560	151,500	127,000	143,000	125,000	141,000	127,200	143,200	126,000	142,000	124,000	139,700
General Plant	Lbs./hr.	200,000	400,000	200,000	400,000	200,000	400,000	200,000	400,000	200,000	400,000	200,000	400,000	200,000	400,000	200,000	400,000	200,000	400,000
Sub Total	Lbs./hr.	891,050	1,178,830	783,200	1,080,320	898,550	1,185,770	882,960	1,168,900	895,700	1,182,350	895,000	1,183,250	868,460	1,152,910	907,160	1,195,910	941,100	1,234,650
Steam Dept.	Lbs./hr.	786,000	979,000	760,000	945,000	713,000	887,000	740,000	920,000	721,000	897,000	707,000	880,000	713,000	887,000	713,000	887,000	713,000	887,000
Grand Total	Lbs./hr.	1,677,050	2,157,830	1,543,200	2,025,320	1,611,550	2,072,770	1,622,960	2,088,900	1,616,700	2,079,350	1,602,000	2,063,250	1,581,460	2,039,910	1,620,160	2,082,910	1,654,100	2,121,650
45-PSIG STEAM PRODUCTION																			
Liquid & Vapor Phase Hydro.	Lbs./hr.	39,800	33,800	38,700	32,800	36,500	31,000	38,500	32,700	37,700	32,000	37,500	31,800	37,400	31,700	37,100	31,500	39,900	33,900
Delayed Coking	Lbs./hr.	10,350	10,800	15,000	15,600	8,350	8,700	8,550	8,900	12,150	12,650	11,000	11,450	10,700	11,150	10,470	10,900	17,000	17,700
Hydrocarbon Steam Cracking Plant	Lbs./hr.	328,000	279,000	341,000	290,000	354,000	301,000	325,200	276,000	367,000	311,000	374,000	317,000	345,000	293,000	386,000	328,000	435,000	369,000
Boiler Feed Pumps to Waste Heat Boilers	Lbs./hr.	22,800	30,400	22,800	30,400	22,800	30,400	22,800	30,400	22,800	30,400	22,800	30,400	22,800	30,400	22,800	30,400	22,800	30,400
Plant & Instrument Air Supply	Lbs./hr.	9,500	19,000	9,500	19,000	9,500	19,000	9,500	19,000	9,500	19,000	9,500	19,000	9,500	19,000	9,500	19,000	9,500	19,000
Cooling Towers & Pumps	Lbs./hr.	231,000	285,000	270,000	334,000	219,000	271,000	224,770	278,290	223,000	276,000	220,000	272,000	223,000	276,000	221,000	273,000	224,770	278,290
Sub Total	Lbs./hr.	641,450	658,000	697,000	721,800	650,150	661,100	629,320	645,290	672,150	681,050	674,800	681,650	648,400	661,250	686,870	692,800	748,970	748,290
Steam Dept.	Lbs./hr.	400,000	496,000	378,000	469,000	355,000	440,000	369,000	457,000	359,000	445,000	352,000	437,000	355,000	440,000	355,000	440,000	355,000	440,000
Grand Total	Lbs./hr.	1,041,450	1,154,000	1,075,000	1,190,800	1,005,150	1,101,100	998,320	1,102,290	1,031,150	1,126,050	1,026,800	1,118,650	1,003,400	1,101,250	1,041,870	1,132,800	1,103,970	1,188,290
Net 45-PSIG STEAM CONSUMPTION																			
45-PSIG Steam Consumption	Lbs./hr.	1,677,050	2,157,830	1,543,200	2,025,320	1,611,550	2,072,770	1,622,960	2,088,900	1,616,700	2,079,350	1,602,000	2,063,250	1,581,460	2,039,910	1,620,160	2,082,910	1,654,100	2,121,650
45-PSIG Steam Production	Lbs./hr.	1,041,450	1,154,000	1,075,000	1,190,800	1,005,150	1,101,100	998,320	1,102,290	1,031,150	1,126,050	1,026,800	1,118,650	1,003,400	1,101,250	1,041,870	1,132,800	1,103,970	1,188,290
Net 45-PSIG Steam Consumption	Lbs./hr.	635,600	1,003,830	468,200	834,520	606,400	971,670	624,640	986,610	585,550	953,300	575,200	944,600	578,060	938,660	578,290	950,110	550,130	933,360

TABLE XVI

EIGHT-PLANT CASE FOR 30,000 B/SD COAL HYDROGENATION PLANTS

CONSUMPTION OF ELECTRIC POWER - Kilowatts

Case	I		II		III		III-A		IV		V		VI		VII		VIII	
Coal:																		
State	North Dakota		Montana		Wyoming		Wyoming		Indiana		Kentucky		Kentucky		Illinois		West Virginia	
County	Dunn		Rosebud		Sweetwater		Sweetwater		Knox		Muhlenberg		Union		Franklin		Monongalia	
Seam	-		Colstrip		Rock Springs		Rock Springs		5		11-12		9-11		6		Pittsburgh	
	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum
Coal Preparation	10,790	13,300	8,460	10,450	4,880	6,025	5,025	6,200	5,000	6,170	4,810	5,940	4,750	5,860	4,770	5,880	4,820	5,940
Paste Preparation	1,485	1,620	1,410	1,540	1,310	1,430	1,415	1,545	1,380	1,510	1,370	1,495	1,365	1,490	1,360	1,485	1,500	1,635
Liquid & Vapor Phase Hydro.	34,500	37,000	33,400	35,800	31,500	33,700	33,300	35,700	32,700	35,000	32,500	34,800	32,400	34,700	32,100	34,400	34,500	37,000
Delayed Coking	6,140	7,060	8,920	10,250	4,940	5,680	5,070	5,830	7,200	8,300	6,530	7,380	6,330	7,280	6,210	7,150	10,100	11,600
Liquid Phase Distillation	3,640	3,920	3,380	3,640	3,380	3,640	3,180	3,436	3,300	3,560	3,290	3,550	3,290	3,550	3,240	3,490	3,270	3,520
Vapor Phase Distillation	1,855	1,990	1,855	1,990	1,855	1,990	1,855	1,990	1,855	1,990	1,855	1,990	1,855	1,990	1,855	1,990	1,855	1,990
Phenol Recovery	-	-	-	-	-	-	150	170	-	-	-	-	-	-	-	-	-	-
Low Temp. Off Gas Separation	16,600	17,380	15,400	16,110	13,970	14,610	13,170	13,790	15,280	16,000	15,280	16,000	15,590	16,300	15,590	16,300	15,280	16,000
Hydrocarbon Steam Cracking Plant	6,720	7,420	6,980	7,720	7,240	8,000	6,650	7,350	7,500	8,280	7,650	8,450	7,040	7,770	7,900	8,720	8,900	9,830
Coal Gasification Plant	2,510	2,670	2,200	2,340	2,220	2,370	2,580	2,750	1,990	2,120	1,880	2,000	1,930	2,060	1,830	1,950	1,450	1,550
Oxygen Plant	31,200	37,500	24,700	29,700	23,700	28,500	27,600	33,200	20,500	24,700	19,300	23,200	19,600	23,600	19,800	23,800	14,300	17,200
H_2 Purification Unit	98,800	109,000	94,000	103,500	93,300	102,500	95,080	104,350	93,100	102,200	91,800	101,000	93,500	102,700	93,000	102,200	91,500	100,500
Producer Gas Unit	400	525	400	525	400	525	400	525	400	525	400	525	400	525	400	525	400	525
Plant Make-Up Water Supply	5,640	7,160	5,550	7,060	5,350	6,820	5,500	7,000	5,450	6,940	5,400	6,880	5,450	6,940	5,420	6,900	5,500	7,000
Mines	4,000	5,000	3,000	3,750	2,810	3,660	2,400	3,100	4,330	5,450	5,250	6,600	4,050	5,120	4,000	5,100	6,000	7,500
Shipping, Blending, & R.P.&S.	515	2,025	515	2,025	515	2,025	515	2,025	515	2,025	515	2,025	515	2,025	515	2,025	515	2,025
Service Water Pumps	130	180	130	180	130	180	130	180	130	180	130	180	130	180	130	180	130	180
General Plant	4,000	4,660	4,000	4,660	4,000	4,660	4,000	4,660	4,000	4,660	4,000	4,660	4,000	4,660	4,000	4,660	4,000	4,660
Fire Pumps	-	440	-	440	-	440	-	440	-	440	-	440	-	440	-	440	-	440
Plant & Instrument Air Supply	165	250	165	250	165	250	165	250	165	250	165	250	165	250	165	250	165	250
Cooling Towers & Pumps	6,910	8,330	6,800	8,200	6,570	7,920	6,745	8,140	6,700	8,080	6,600	7,960	6,680	8,060	6,650	8,020	6,745	8,140
Electric Department	12,421	14,075	11,645	13,165	10,952	12,355	11,970	13,047	11,125	12,539	10,978	12,377	10,995	12,386	10,989	12,384	11,093	12,490
Sub Total	248,421	281,505	232,910	263,295	219,187	247,280	226,900	255,678	222,620	250,919	219,703	247,702	220,035	247,886	219,924	247,849	222,023	249,975
City Power (Offsites)	5,600	6,000	5,600	6,000	5,600	6,000	5,600	6,000	-	-	-	-	-	-	-	-	-	-
Steam Department	1,190	2,870	1,130	2,720	1,060	2,560	1,100	2,650	1,070	2,580	1,050	2,530	1,060	2,560	1,060	2,560	1,060	2,560
Grand Total	255,211	290,375	239,640	272,015	225,847	255,840	233,600	264,328	223,690	253,499	220,753	250,232	221,095	250,446	220,984	250,409	223,083	252,535

TABLE XVII

EIGHT-PLANT CASE FOR 30,000 B/SD COAL HYDROGENATION PLANTS

WATER REQUIREMENTS - Gallons Per Minute

Case	I		II		III		III-A		IV		V		VI		VII		VIII	
Coal:																		
State	North Dakota		Montana		Wyoming		Wyoming		Indiana		Kentucky		Kentucky		Illinois		West Virginia	
County	Dunn		Rosebud		Sweetwater		Sweetwater		Knox		Muhlenberg		Union		Franklin		Monongalia	
Seam	-		Colstrip		Rock Springs		Rock Springs		5		11-12		9-11		6		Pittsburgh	
	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum
COOLING WATER REQUIREMENTS																		
Liquid & Vapor Phase Hydro.	36,200	45,100	35,200	43,900	33,100	41,300	34,900	43,500	34,200	42,600	34,100	42,500	34,000	42,400	33,600	41,900	36,200	45,100
Delayed Coking	4,060	5,430	5,850	7,820	3,500	4,680	3,240	4,330	4,620	6,180	4,880	6,530	4,150	5,550	3,980	5,320	6,200	8,290
Liquid & Vapor Phase Distillation	32,500	40,300	32,500	40,300	32,500	40,300	32,250	40,300	32,500	40,300	32,500	40,300	32,500	40,300	32,500	40,300	32,500	40,300
Phenol Recovery	-	-	-	-	-	-	9,650	12,000	-	-	-	-	-	-	-	-	-	-
Low Temp. Off Gas Separation	4,860	6,070	4,510	5,630	4,080	5,100	3,850	4,800	4,470	5,580	4,470	5,580	4,560	5,700	4,560	5,700	4,470	5,580
Hydrocarbon Steam Cracking Plant	13,130	16,410	13,650	17,080	14,180	17,700	13,000	16,250	14,690	18,350	14,950	18,690	13,790	17,230	15,480	19,330	17,410	21,800
Coal Gasification Plant	3,840	4,830	3,380	4,250	3,430	4,310	3,900	4,900	3,070	3,860	2,880	3,620	2,960	3,720	2,810	3,530	2,230	2,680
Oxygen Plant	11,880	13,490	9,410	10,760	9,040	10,330	10,500	12,000	7,810	8,930	7,360	8,420	7,500	8,580	7,170	8,200	5,150	6,230
H_2 Purification Unit	73,100	85,000	69,300	80,500	69,000	80,100	70,180	81,500	68,800	79,900	67,800	78,700	69,100	80,200	68,700	80,000	67,500	78,400
Producer Gas Unit	1,870	1,100	1,700	1,000	1,680	1,000	1,890	1,120	1,580	940	1,520	900	1,540	910	1,480	880	1,330	790
Sub Total	181,440	217,730	175,500	211,240	170,510	204,820	183,360	220,700	171,740	206,640	170,460	205,240	170,100	204,590	170,280	205,160	173,290	209,170
Steam Dept.	150,000	170,000	129,500	146,800	140,000	158,700	150,000	170,000	138,500	157,000	137,700	156,000	138,500	157,000	139,300	159,000	136,000	154,100
Grand Total	331,440	387,730	305,000	358,040	310,510	363,520	333,360	390,700	310,240	363,640	308,160	361,240	308,600	361,590	309,580	364,160	309,290	363,270
FRESH WATER REQUIREMENTS																		
Coal Preparation	410	410	320	320	245	245	250	250	250	250	240	240	235	235	240	240	240	240
Paste Preparation	210	260	200	250	185	230	200	250	195	245	195	245	195	245	190	240	210	260
Liquid & Vapor Phase Hydro.	145	180	140	175	130	160	140	175	135	170	135	170	135	170	135	170	145	180
Delayed Coking	95	1,900	135	2,700	80	1,600	75	1,500	105	2,100	100	2,000	95	1,900	90	1,800	145	2,900
Liquid & Vapor Phase Distillation	85	105	85	105	85	105	85	105	85	105	85	105	85	105	85	105	85	105
Coal Gasification Plant	270	350	235	305	235	305	270	350	210	270	200	260	205	265	195	255	155	200
Oxygen Plant	280	280	225	225	215	215	250	250	185	185	175	175	180	180	170	170	130	130
H_2 Purification Unit	1,210	1,510	1,145	1,430	1,140	1,425	1,160	1,450	1,140	1,425	1,120	1,400	1,140	1,425	1,135	1,420	1,115	1,395
Plant Make-Up Water Supply	200	250	200	250	200	250	200	250	200	250	200	250	200	250	200	250	200	250
General Plant	350	500	350	500	350	500	350	500	350	500	350	500	350	500	350	500	350	500
Boiler Feed Pumps to Waste Heat Boilers	5,320	6,026	4,600	5,210	4,960	5,620	5,320	6,026	4,910	5,560	4,880	5,530	4,910	5,560	4,940	5,600	4,820	5,450
Cooling Towers & Pumps	8,850	10,890	8,400	10,320	8,350	10,210	8,500	10,475	8,340	10,240	8,210	10,100	8,360	10,280	8,330	10,240	8,190	10,080
Sub Total	17,425	22,661	16,035	21,790	16,175	20,865	16,800	21,581	16,105	21,310	15,890	20,975	16,090	21,115	16,060	20,990	15,785	21,690
Steam Dept.	70	70	60	60	65	65	70	70	65	65	65	65	65	65	65	65	65	65
Grand Total	17,495	22,731	16,095	21,850	16,240	20,930	16,870	21,651	16,170	21,365	15,955	21,040	16,155	21,180	16,125	21,055	15,850	21,755

TABLE XVIII

PROPORTIONING FACTORS USED TO DETERMINE SIZES OF VARIOUS STREAMS FOR EIGHT PLANTS FROM BASE CASE

Plant	Electrical Power	45-PSIG Steam Production	45-PSIG Steam Consumption	370-PSIG Steam Production	370-PSIG Steam Consumption	1400-PSIG Steam Consumption	Cooling Water Consumption	Fresh Water Consumption	Fuel Consumption
Coal Preparation	Note 1	-	-	-	-	-	-	15	Note 7
Paste Preparation	2	-	1	-	-	-	-	2	-
Liquid & Vapor Phase Hydro.	3	3	-	-	-	-	3	3	3
Delayed Coking	4	4	-	4	-	-	14	14	4
Liquid Phase Distillation	5	-	5	-	5	-	1	1	5
Vapor Phase Distillation	1	-	1	-	1	-	1	1	1
Low Temp. Off Gas Separation	6	-	6	-	-	-	6	-	-
Hydrocarbon Steam Cracking	7	7	7	-	-	-	7	-	7
Coal Gasification Plant	8	-	-	13	-	-	13	13	Note 8
Oxygen Plant	9	-	-	-	-	-	9	9	-
H_2 Purification Unit	10	-	12	-	13	-	10	10	-
Producer Gas Unit	1	-	-	-	-	-		-	Note 9
Plant Make-Up Water Supply	11	-	-	-	-	-	-	1	-
Mines	Note 2	-	-	-	-	-	-	-	-
Shipping, Blending, & R.P.&S.	1	-	-	-	-	-	-	-	-
Service Water Pumps	1	-	-	-	-	-	-	-	-
General Plant	1	-	1	-	1	-	-	1	-
Fire Pumps	1	-	-	-	1	-	-	-	-
Boiler Feed Pumps to Waste Heat Boilers	-	1	-	-	1	-	-	1	-
Plant & Instrument Air Supply	1	1	-	-	1	-	-	-	-
Cooling Towers & Pumps	11	11	-	-	11	-	-	10	-
Electric Department	Note 3	-	-	-	-	-	-	-	-
Steam Department	17	17	17	-	17	-	16	16	-
City Power (Offsites)	Note 4	-	-	-	-	-	-	-	-
1400-PSIG Steam to Turbo Comp.	-	-	-	-	-	19	-	-	-
Coal Drying	-	-	-	-	-	-	-	-	Note 6

*Maximum utility requirements calculated for each item by using ratio of maximum to average requirements for base case used by Engineering Subcommittee.

Notes:

(1) Used Bechtel requirements of 6,825 (avg.) and 8,420 (max.) KW as the base for Cases I & II. These were proportioned on the basis of as received hydro coal to Bechtel m.a.f. coal. (See factor 18) The ratio of as received hydro coal to the same quantity for the base case (III-A) was used in proportioning base case requirements to requirements for cases III through VIII (See factor 18).

(2) Total as received coal required was estimated on the basis of the sum of as received hydrogenation and gasification coal. The conversion factor of KWH/ton for each case was obtained from letter of P.R.S. of 3/1/51. The estimated coal requirements used were:

Cases	I	II	III	III-A	IV	V	VI	VII	VIII
Tons/SD	24,000	18,000	13,500	14,400	13,700	13,200	13,000	12,900	12,040

(3) Electrical department power requirements were taken as 5% of the sub-total of electrical power required as per procedure used in base case (III-A) calculations.

(4) City power (offsites) requirements were taken as the same for the base case (III-A) for cases I, II and III. It was assumed to be negligible for all other cases.

(5) 1400-PSIG steam requirements for turbo compressors in the H_2 purification unit were adjusted for the following elevations:

Case I - 2500 ft. Cases III, III-A - 7000 ft.
Case II - 3230 ft. All others - sea level

(6) Coal was dried to 10% moisture using 65% dryer efficiency. Coal was heated from 75° to 150°F. and the moisture from 75° to 200°F. in order to evaluate fuel requirements for coal drying in cases I and II.

(7) Fuel requirements calculated for evaporating moisture (to 1.5%) and heating coal to 150°F. using 65% dryer efficiency. Initial moisture content of 10% used for cases I and II.

(8) Fuel required for coal gasification calculated in two parts.

(a) Steam to superheater based on L.P. steam to gasifier (See factor 8).

(b) To dry coal to 5% moisture and heat to 150°F. using a dryer efficiency of 65%.

(9) Fuel required for producer gas unit to supply producer gas to gasification unit steam superheater and dryer, and to coal preparation plant dryer. Producer thermal efficiency of 66.7% used.

TABLE XIX

PROPORTIONING FACTORS USED TO DETERMINE UTILITIES REQUIREMENTS OF EIGHT PLANTS FROM BASE CASE (III-A)

Factor No.	I	II	III	III-A	IV	V	VI	VII	VIII	Basis of Calculation
1	1.000	1.000	1.000	-	1.000	1.000	1.000	1.000	1.000	Assumed no change from base case (III-A).
2	1.050	0.995	0.927	-	0.975	0.968	0.965	0.960	1.060	Quantity of paste.
3	1.035	1.005	0.947	-	0.980	0.975	0.972	0.963	1.036	Sum of feed to liquid & vapor phase hydro.
4	1.210	1.760	0.975	-	1.420	1.290	1.250	1.225	1.990	Feed to delayed coking.
5	1.143	1.063	1.063	-	1.040	1.035	1.035	1.020	1.060	Total feed to distillation units.
6	1.260	1.170	1.060	-	1.160	1.160	1.182	1.182	1.160	H_2 produced in Linde plant.
7	1.010	1.050	1.090	-	1.130	1.150	1.060	1.190	1.340	H_2 produced in hydrocarbon steam cracking plant.
8	0.972	0.855	0.863	-	0.775	0.728	0.748	0.712	0.563	Low Pressure steam to gasifier.
9	1.130	0.895	0.860	-	0.743	0.700	0.712	0.682	0.518	95% O_2 required.
10	1.040	0.987	0.982	-	0.980	0.965	0.983	0.978	0.962	Total H_2 required.
11	1.025	1.010	0.973	-	0.993	0.980	0.990	0.985	1.000	Amount of cooling water circulation (See B.J.M. calculation).
12	0.995	0.952	0.977	-	0.945	0.929	0.945	0.938	0.923	Total H_2 from hydrocarbon steam cracking & coal gasification.
13	0.986	0.867	0.878	-	0.785	0.737	0.758	0.720	0.570	H_2 from coal gasification.
14	1.251	1.805	1.078	-	1.425	1.350	1.280	1.228	1.911	Quantity of total dry coke.
15	1.630	1.282	0.973	-	1.003	0.959	0.946	0.951	0.962	As received hydro coal.
16	1.000	0.864	0.934	-	0.923	0.917	0.923	0.929	0.906	Sum of net 370-PSIG and 45-PSIG steam consumption.
17	1.085	1.025	0.962	-	0.972	0.955	0.962	0.962	0.962	Sub-total of electrical power required.
18	1.580	1.240	0.972	-	0.996	0.957	0.946	0.950	0.960	See note 1.
19	0.952	0.952	0.977	-	0.945	0.929	0.945	0.938	0.923	Same as factor 12 with altitude correction - See note 2.

Note 1 - Used Bechtel requirements of 6,825 (avg.) and 8,420 (max.) KW as the base for Cases I & II. These were proportioned on the basis of as received hydro coal to Bechtel m.a.f. coal. (See factor 18) The ratio of as received hydro coal to the same quantity for the base case (III-A) was used in proportioning base case requirements to requirements for cases III through VIII (See factor 18).

Note 2 - 1400-PSIG steam requirements for turbo compressors in the H_2 purification unit were adjusted for the following elevations:

Case I	- 2500 ft.	Cases III, III-A	- 7000 ft.
Case II	- 3230 ft.	All others	- sea level

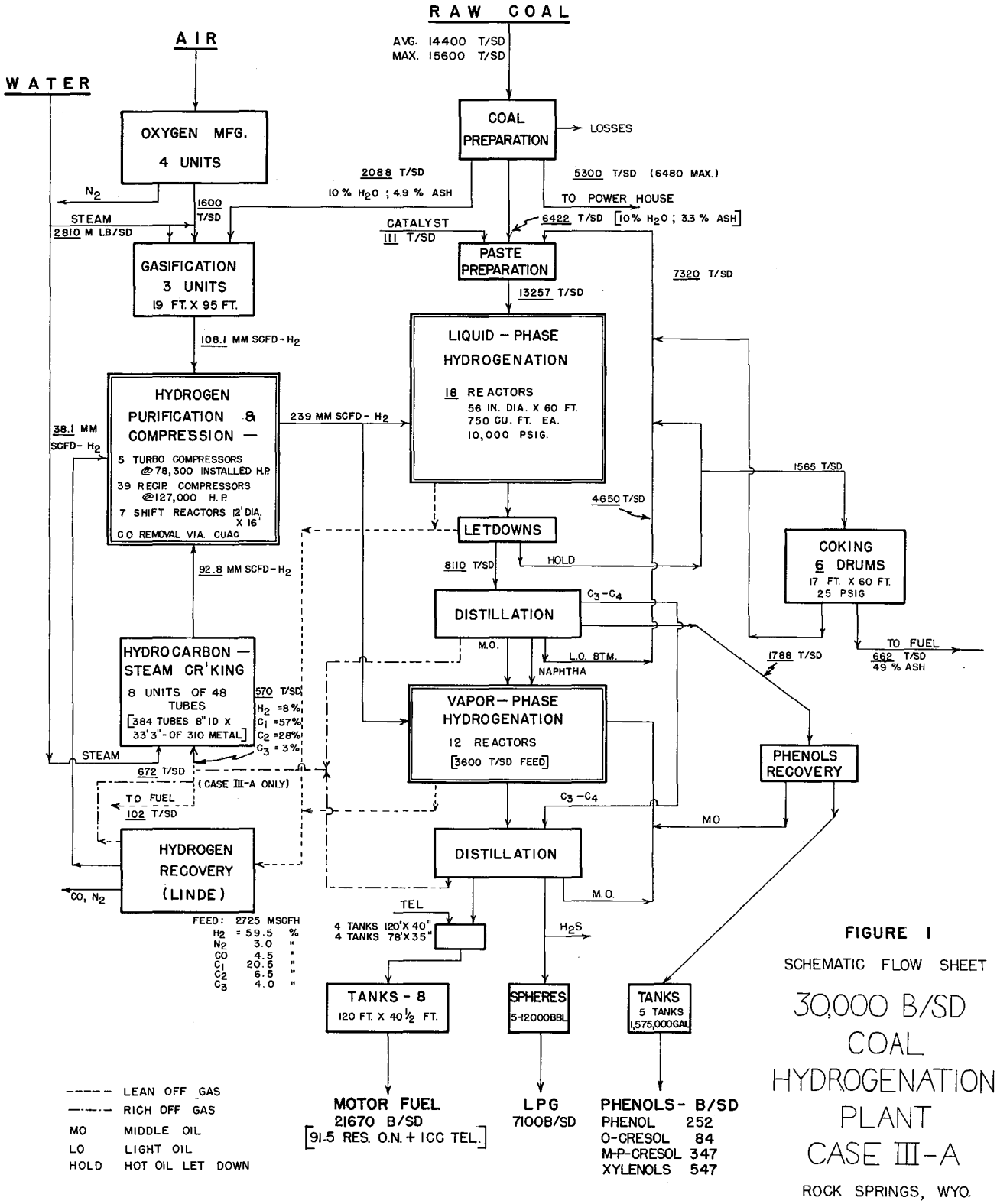


FIGURE I

SCHEMATIC FLOW SHEET

30,000 B/SD COAL HYDROGENATION PLANT CASE III-A

ROCK SPRINGS, WYO.

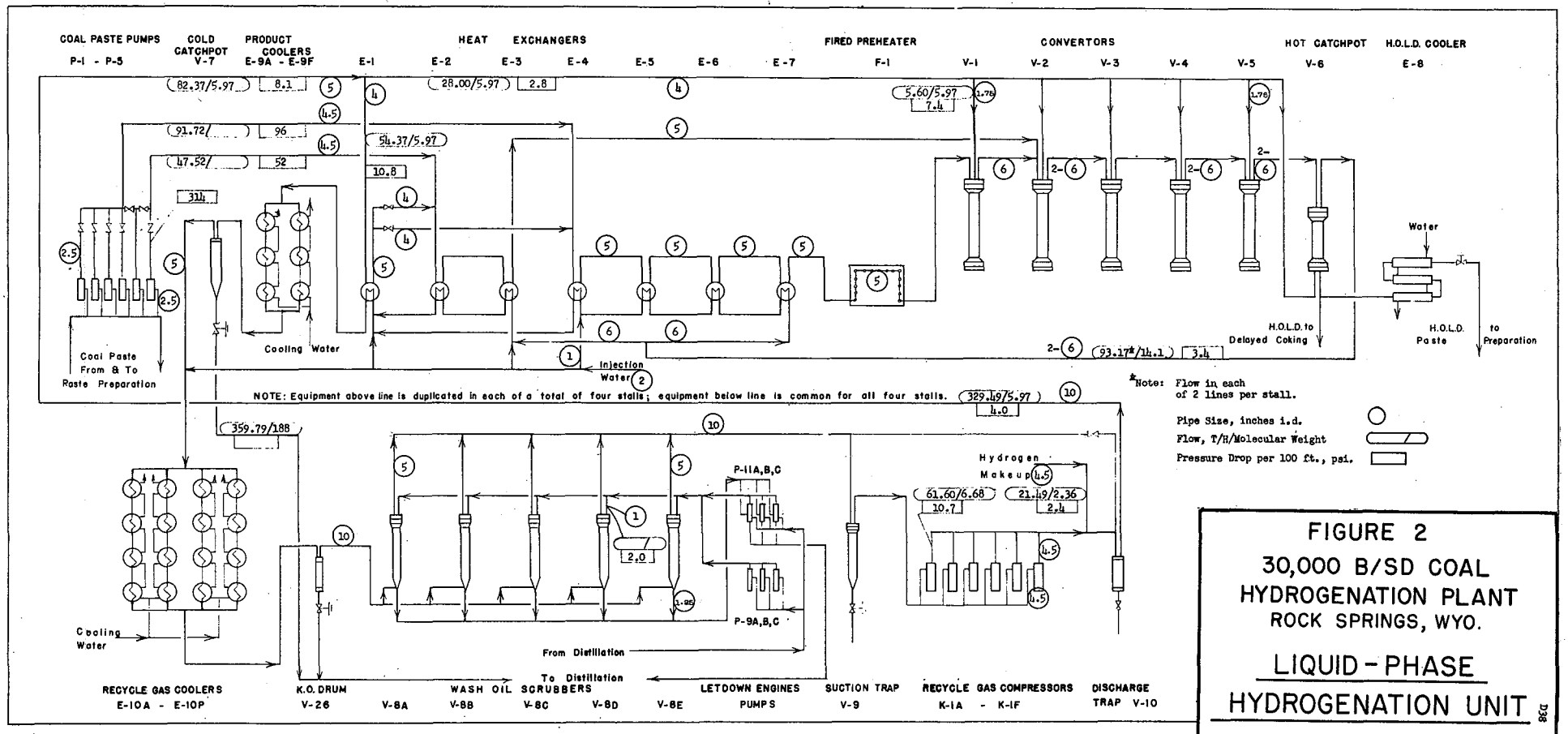


FIGURE 2

30,000 B/SD COAL HYDROGENATION PLANT
ROCK SPRINGS, WYO.

LIQUID-PHASE HYDROGENATION UNIT

D38

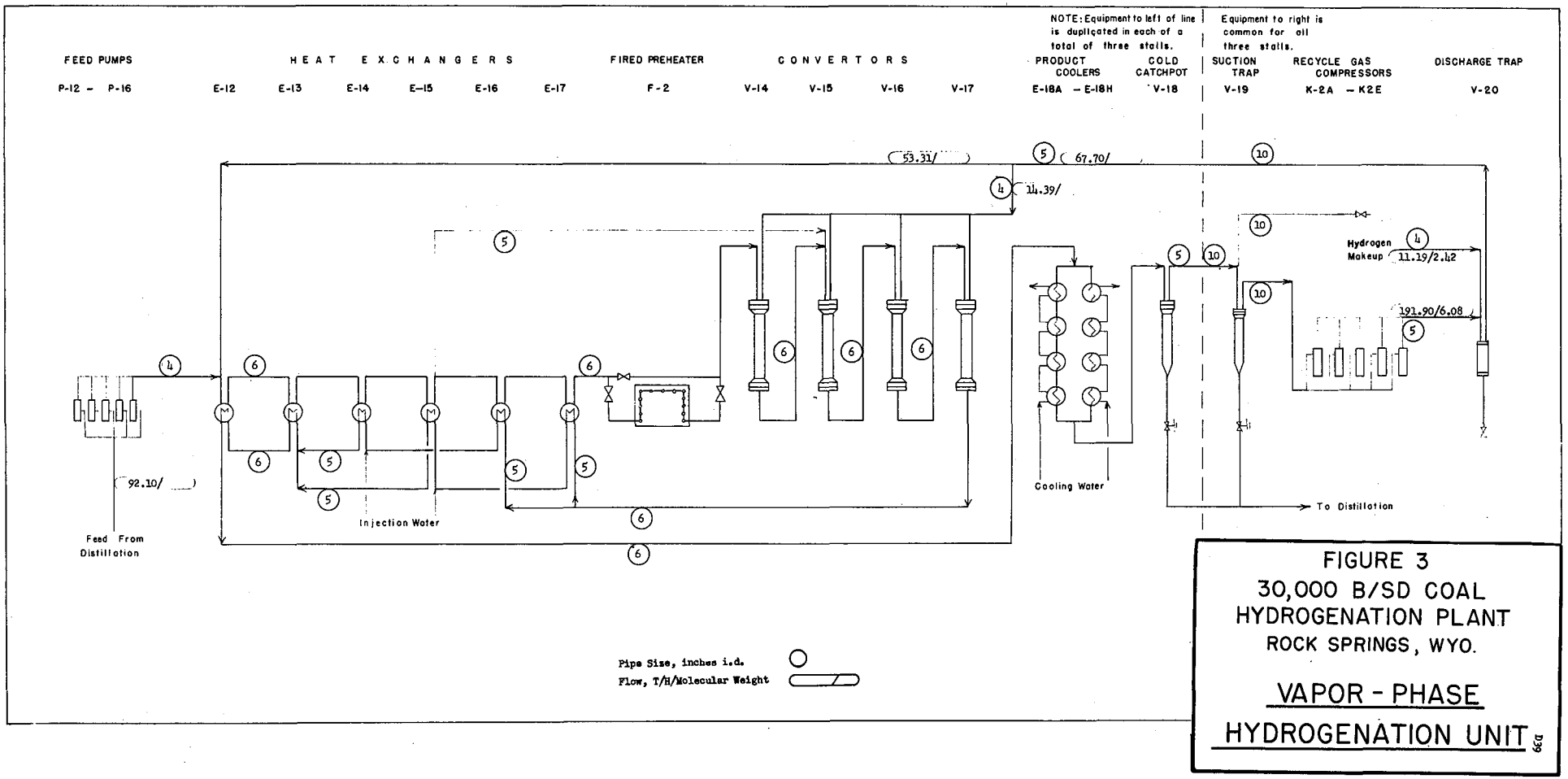


FIGURE 3
30,000 B/SD COAL HYDROGENATION PLANT
ROCK SPRINGS, WYO.

VAPOR - PHASE HYDROGENATION UNIT

D39

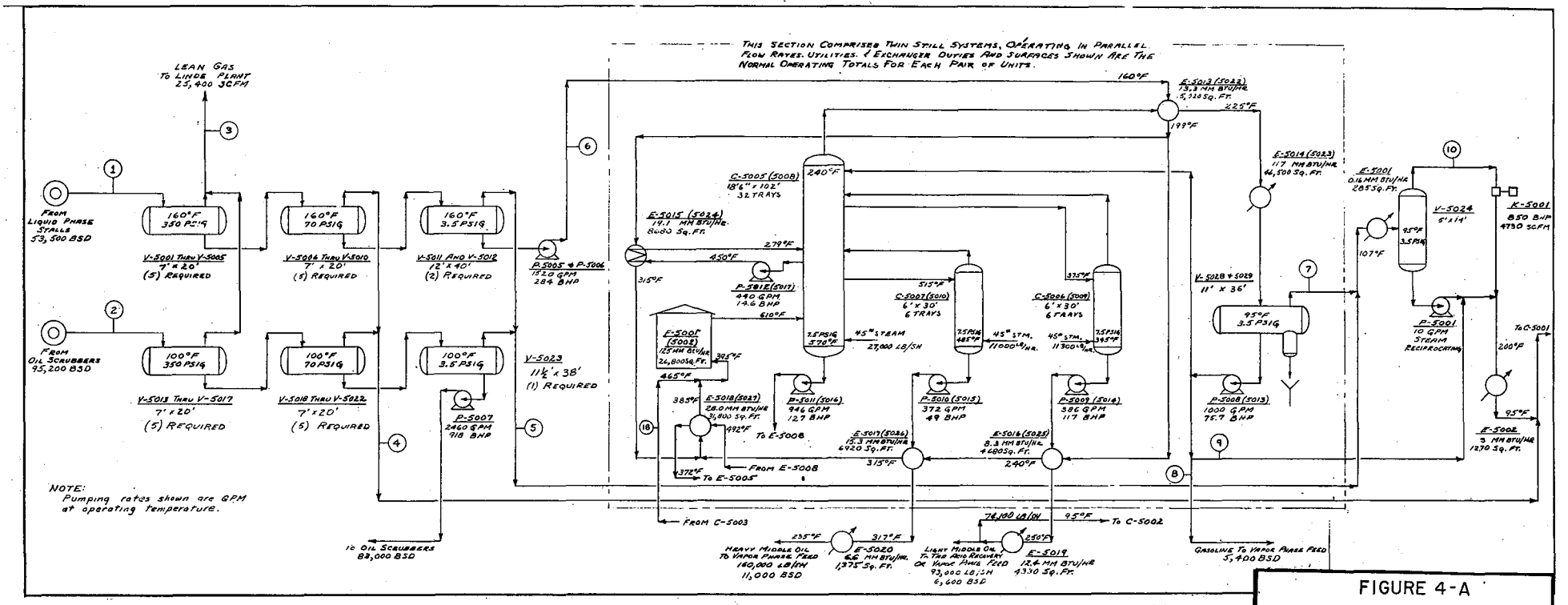


FIGURE 4-A

30,000 B/SD COAL HYDROGENATION PLANT

ROCK SPRINGS, WYO.

LIQUID - PHASE PRODUCTS DISTILLATION UNIT

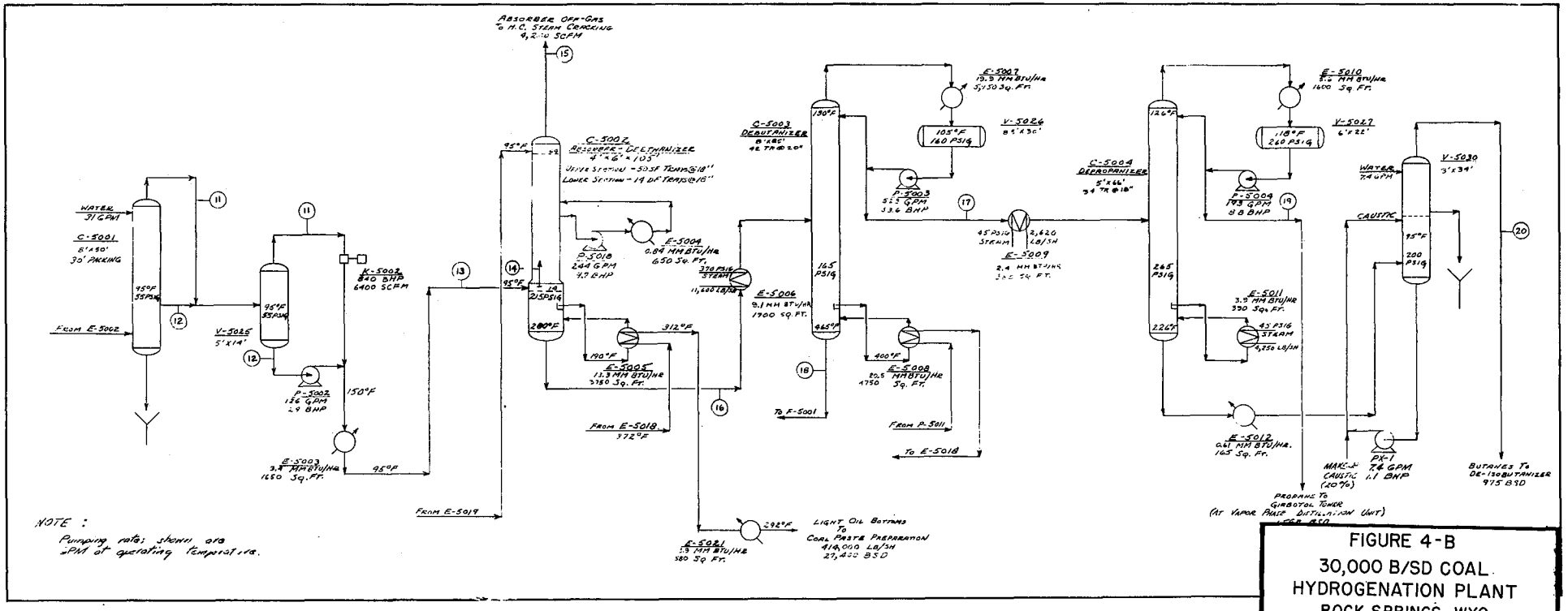


FIGURE 4-B

30,000 B/SD COAL HYDROGENATION PLANT

ROCK SPRINGS, WYO.

LIQUID-PHASE PRODUCTS DISTILLATION UNIT — CONTINUED

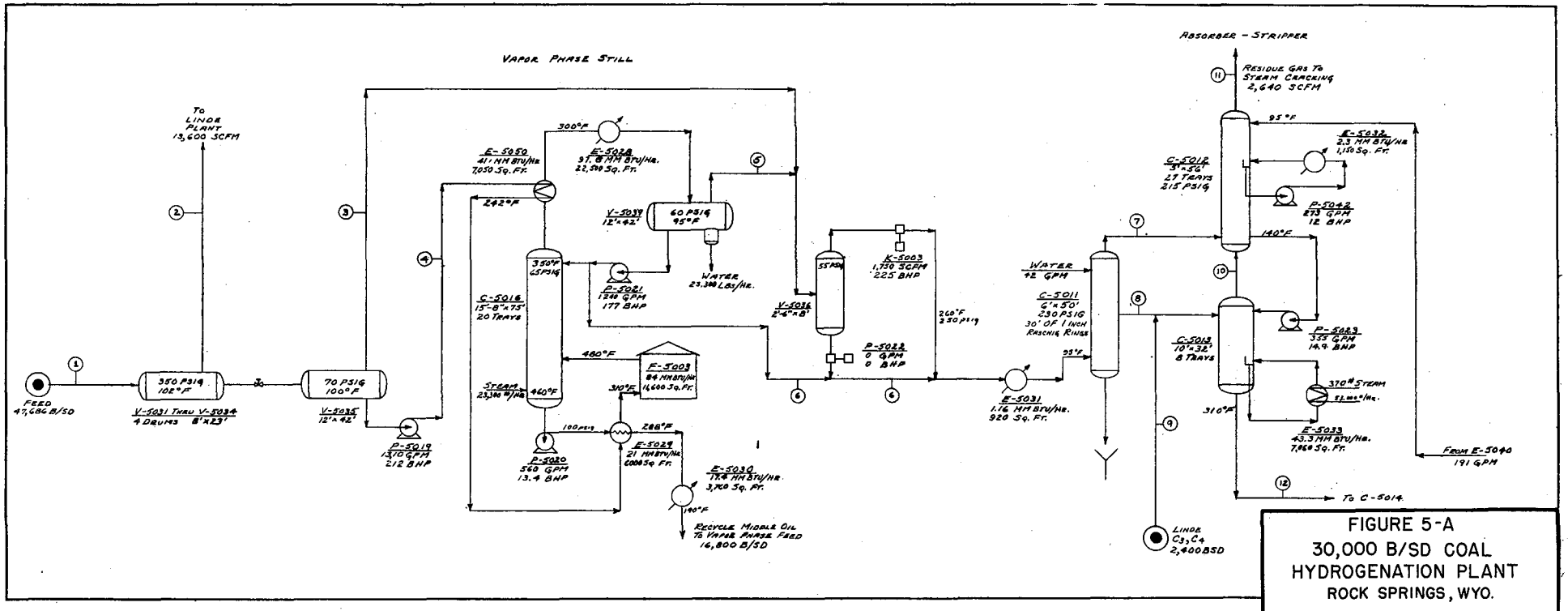


FIGURE 5-A
30,000 B/SD COAL HYDROGENATION PLANT
ROCK SPRINGS, WYO.
VAPOR - PHASE PRODUCTS DISTILLATION UNIT

1142

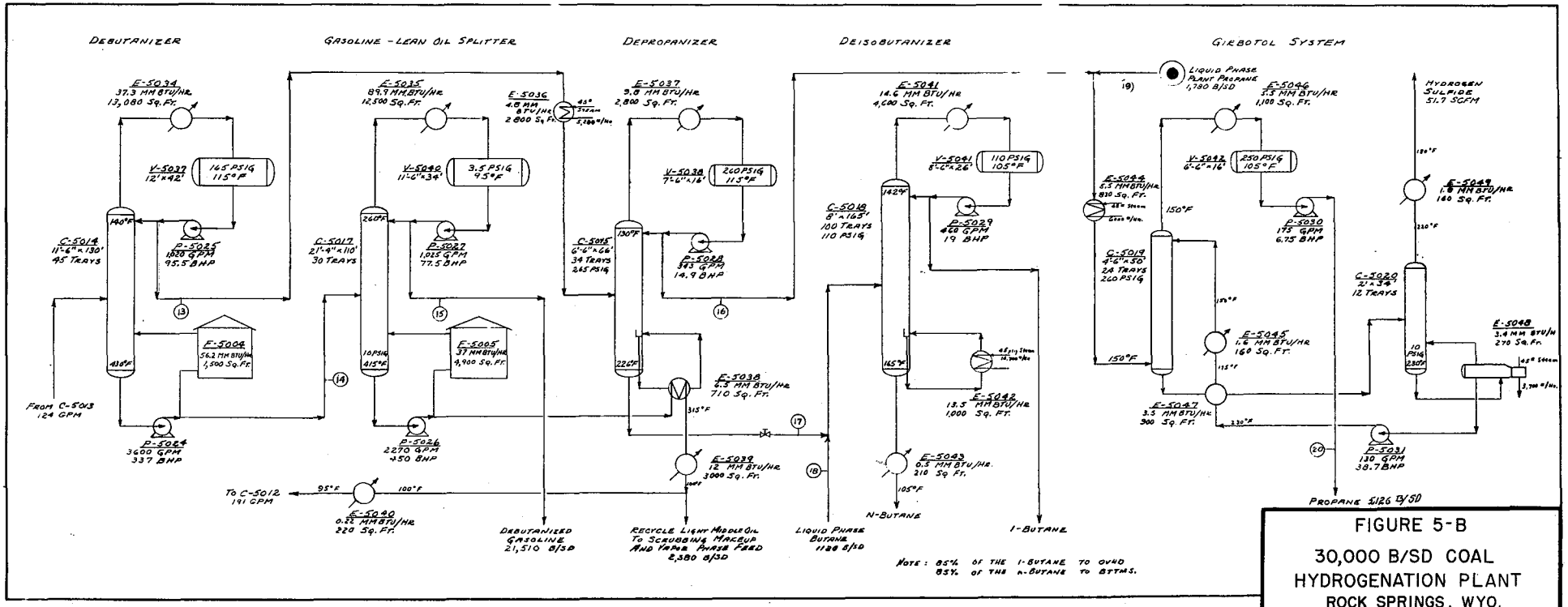


FIGURE 5-B

30,000 B/SD COAL HYDROGENATION PLANT
ROCK SPRINGS, WYO.

VAPOR-PHASE PRODUCTS DISTILLATION UNIT - CONTINUED

5-13

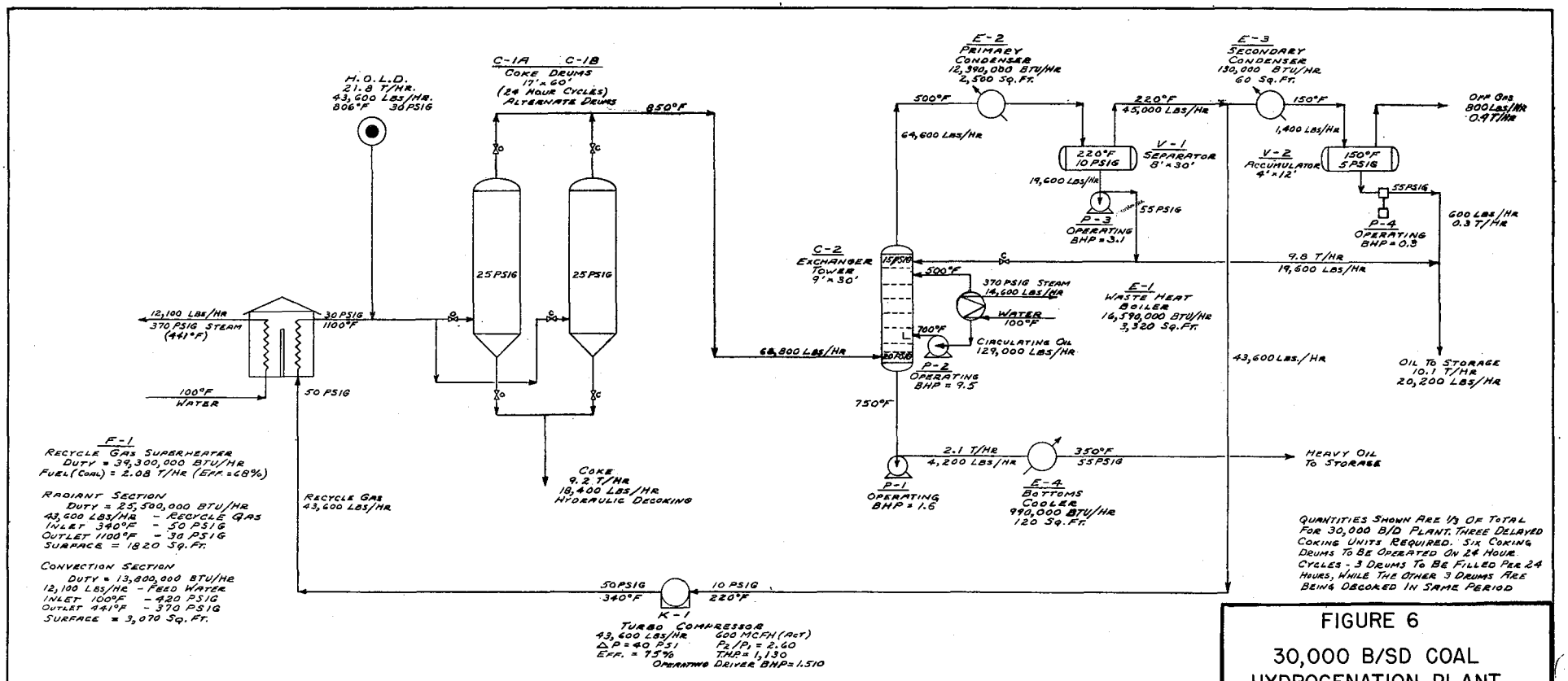


FIGURE 6

30,000 B/SD COAL HYDROGENATION PLANT

ROCK SPRINGS, WYO.

DELAYED COKING UNIT

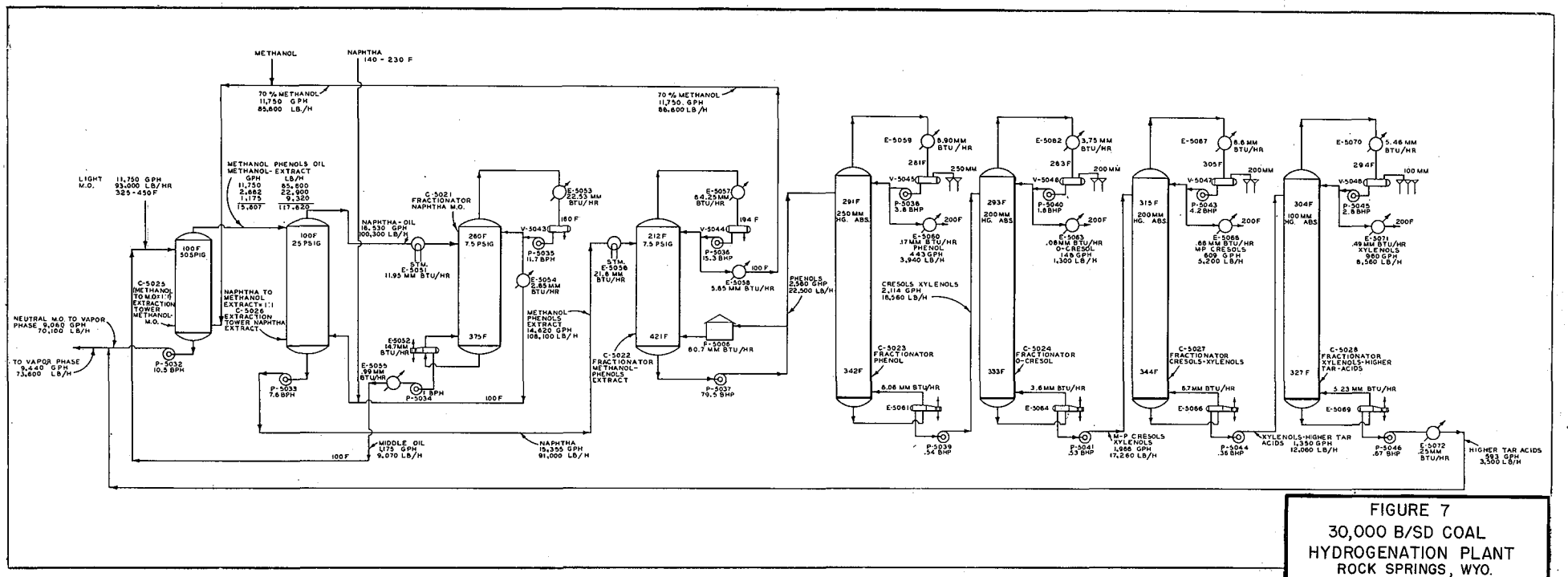


FIGURE 7
30,000 B/SD COAL
HYDROGENATION PLANT
ROCK SPRINGS, WYO.

TAR ACIDS
RECOVERY UNIT

345

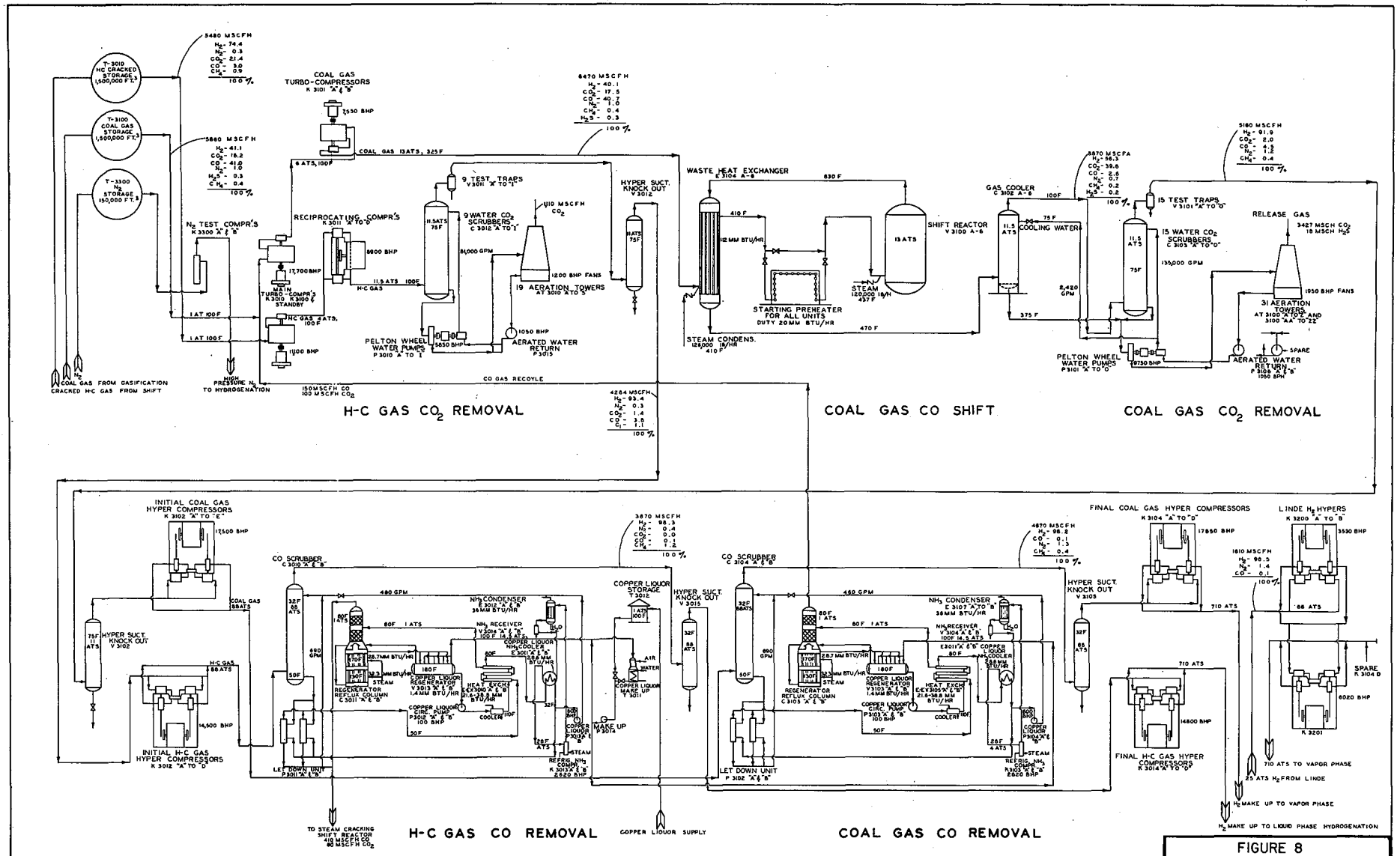


FIGURE 8

30,000 B/SD COAL HYDROGENATION PLANT

ROCK SPRINGS, WYO.

HYDROGEN PURIFICATION AND COMPRESSION UNIT

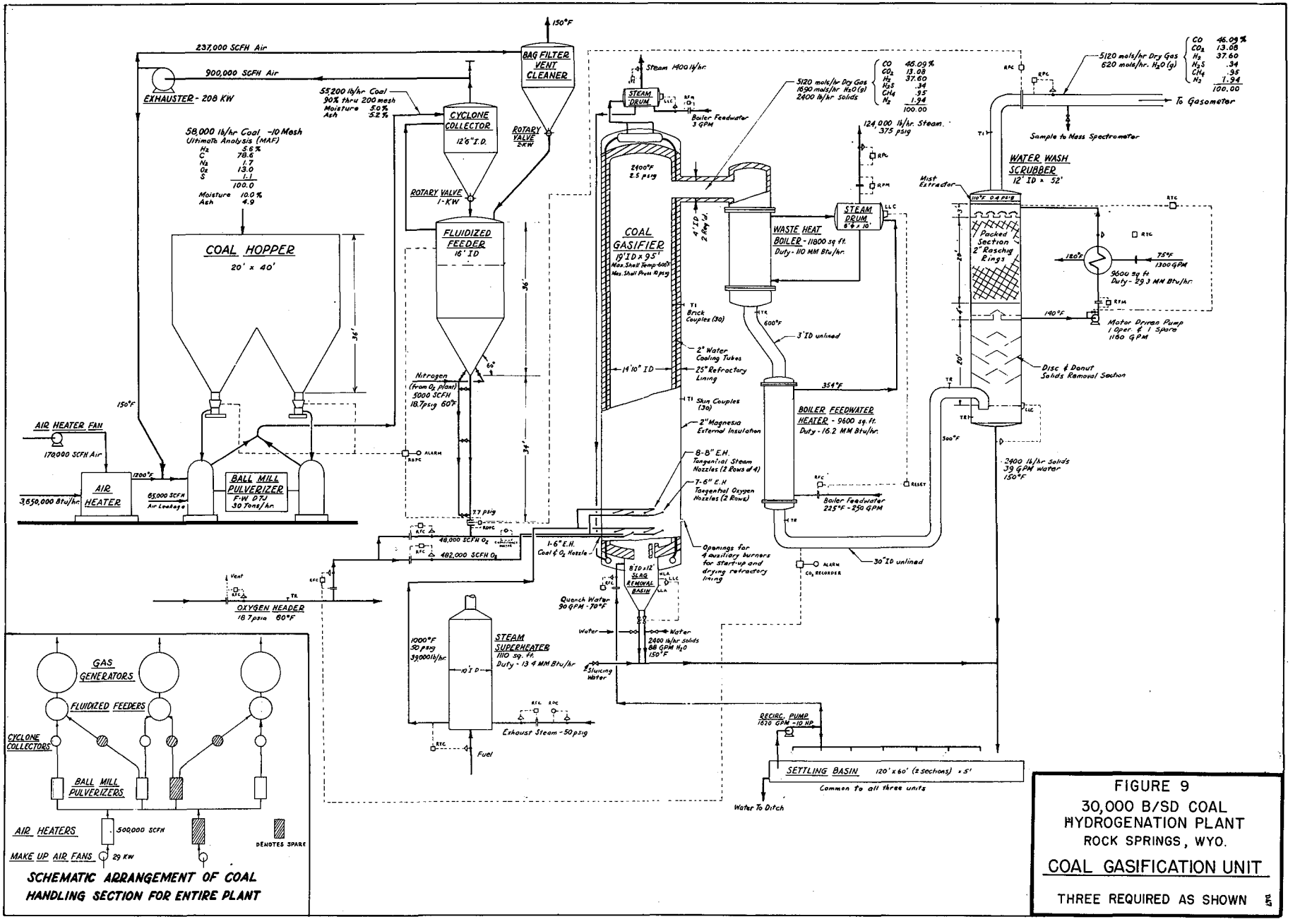


FIGURE 9

30,000 B/SD COAL HYDROGENATION PLANT

ROCK SPRINGS, WYO.

COAL GASIFICATION UNIT

THREE REQUIRED AS SHOWN

NATIONAL PETROLEUM COUNCIL
COMMITTEE ON SYNTHETIC FUELS
PRODUCTION COSTS

SHALE OIL RETORTING
AND REFINING FACILITIES

E. V. Murphree, Chairman Process Subcommittee

SHALE OIL PROCESSING SUBCOMMITTEE:
Clyde Berg, Chairman
Joel Hirsch
J. E. Latta
H. J. Ogorzaly

September 15, 1951

TABLE OF CONTENTS

PART I - Process and Engineering Design of Shale Retorting Plant

PART II - Shale Retort Gas Pipe Line Design

PART III - Process and Engineering Design of Shale Oil Refinery

PART IV - Overall Utility Requirements of Colorado Facilities

PART V - Shale Oil Refining Facilities at Pipe Line Terminal

NATIONAL PETROLEUM COUNCIL COMMITTEE ON
SYNTHETIC FUELS PRODUCTION COSTS

REPORT OF THE COMMITTEE ON SHALE OIL PROCESSING

This report presents the design of the facilities required to produce gasoline and middle distillates from Colorado shale on a commercial basis, with quality comparable to products now being produced from crude oil, and with a ratio of gasoline to middle distillates corresponding to the nationwide industry average. The processes envisioned in this report have either been demonstrated by industrial use or their practicality has been established by pilot plant operations. The particular processing sequence employed was chosen by the National Petroleum Council's Subcommittee on Shale Oil Processing, with the concurrence of the Office of Synthetic Liquid Fuels, Bureau of Mines, Department of the Interior.

Plan of Shale Retorting and Refining Facilities

The over-all plan calls for the production of 250,000 barrels per calendar day of crude shale oil. This production is accomplished by twenty mines feeding twenty retorting plants. Each retorting plant consists of twenty-one retorts. The retorting plants are located as close as possible to the mines and the shale is transported by conveyors. The major portion of the refining is conducted at four sites in the vicinity

of the retorting plants. The retorting plants feed each refinery with retort gas as well as crude shale oil. The refining steps conducted at this location are coking, 1100 psig hydrogenation and catalytic reforming. The retort gas provides the energy to run the refineries, the retorts and the mines. The liquid hydrocarbon products are transported via pipe line to three refiners on the West Coast where the refining steps consist of distillation of the pipe line effluent, catalytic cracking, catalytic polymerization, and blending of finished products. The production ratio of gasoline to middle distillates is 1.95.

Scope of Report

There are five parts to this report dealing with different phases of the processing. Part I contains the design of a complete retorting plant to process 19,200 tons per calendar day of shale. Twenty such plants are required to produce 250,000 barrels per calendar day of crude shale oil. Part II contains the design of the retort gas transmission systems from the retorting plants to the refineries. Part III contains the design of a 25,000 barrel per stream day refinery, eleven of which may be utilized to make up the 250,000 barrel per calendar day capacity, allowing approximately a 90 per cent operating factor. Part IV contains the over-all utility requirements of all the shale oil facilities in Colorado for processing 250,000 barrels per calandar day. Part V specifies the process requirements of the facilities on the West Coast.

Refined Products

The salable products from the West Coast refineries are tabulated below:

Gasoline		
Premium	63,450 Bbl./CD	
Regular	63,450 Bbl./CD	
Total Gasoline		126,900 Bbl./CD
Middle Distillates		65,100 Bbl./CD *
Fuel Oil (Net Production)		3,000 Bbl./CD
Liquid Petroleum Gases		8,925 Bbl./CD
Total Liquid Products		203,925 Bbl./CD

The fuel gas and part of the fuel oil produced by catalytic cracking are consumed in processing.

The salable products from the Colorado refineries are tabulated below:

Coke	5,900 Tons/CD
Fuel Gas (1060 Btu net)	125,300 MSCF/CD
Anhydrous Liquid Ammonia	460 Tons/CD
Sulfur	215 Tons/CD

Nearly all of the Colorado refinery coke and fuel gas production is salable due to the utilization of the retort gas energy to run the mines, retorts, and refineries.

* Includes 2740 B/CD which is actually consumed as pipe-line fuel. Net availability for sale = 62,360 B/CD

I. RETORTING

PROCESS AND ENGINEERING DESIGN
SHALE RETORTING PLANT

1. SUMMARY

This section of the report presents detail engineering design for a complete shale retorting unit with a capacity of 12,600 bbls. per calendar day of product shale oil. The design is based upon two years of semi-works operating experience with the Union Oil Company's underfeed retort culminating in a demonstration run during February, 1950, which was witnessed by representatives of the Bureau of Mines, United States Army, etc. This retorting process was selected for the current study by agreement between the Shale Processing Committee and the Office of Synthetic Liquid Fuels, Bureau of Mines.

The plant is entirely self-sustaining with respect to power and utility requirements. The retorting unit has a capacity of 19,200 tons of 4.0 inch diameter full range shale per calendar day and contains multiple feeders operating in parallel. The retorting rates were based on extensive operating data and represent conservative design conditions. A hydrocarbon recovery amounting to 100% of assay value is obtained as liquid and gaseous products from the plant.

The total daily personnel requirement for the retorting plant is 42 including all service personnel.

II. BASIS OF PLANT DESIGN

The process conditions employed for the proposed retorting operation were confirmed by the demonstration run previously referred to. The individual kilns were sized to handle 1,000 tons/stream day of 30.0 gallon per ton shale having the following assay:

Shale Oil	30.0 gallons/ton
Moisture	1.5%
Bound Water	1.5 gallons/ton
Gas Loss	2.2%

The liquid yield figure upon which the proposed plant is based is 94.1 weight percent or 91.6 volume percent of the assay value which represents a conservative design value.

The shale oil produced from the underfeed retorts is characterized by relatively constant quality with little variation due to fluctuations in operating conditions. Typical properties of the shale oil are presented below:

Properties of Shale Oil

Gravity, °API @ 60°F.	20.7
Specific Gravity @ 60°F.	0.930
Distillation (50 mm.vac.)°F.	
Initial	402
10%	536
20%	622
30%	692
40%	764
50%	814
60%	836
70%	865
80%	889
90%	Cracked
Water, %	0.1
Ash, wt. %	0.03
Conradson carbon, %	4.57
Viscosity, SSU @ 100°F.	223
Viscosity, SSU @ 210°F.	46
Pour Point, °F.	90
Sulfur, wt. %	0.77
Nitrogen, wt. %	2.01

Of particular interest are the exceptionally low water and ash contents, averaging approximately 0.2 wt. percent for the former, and 0.03 wt. percent for the latter. Such effective removal of contaminants is a distinct advantage in simplifying primary refining techniques. The balance of the oil properties is typical of shale oil produced from Green River shale. In comparison with domestic crude oils of similar gravity, the following characteristics of the shale oil are most notable:

1. High nitrogen content
2. High pour point
3. Substantial unsaturation
4. Relative absence of low boiling fractions.

The gas produced amounts to 13,490 SCF/Ton (dry) and has the following composition:

Component	Mol %
Air	2.0
Nitrogen	57.5
Argon	0.6
Carbon Monoxide	4.7
Carbon Dioxide	29.7
Hydrogen	2.2
Hydrogen Sulfide	0.1
Methane	1.0
Ethylene	0.6
Ethane	0.4
Propylene	0.5
Propane	0.2
Butylene	0.3
Butane	0.1
Pentenes	0.1
	100.0
Average Molecular Weight	32.44
Gross Heating Value	83.3 Btu/SCF

The ash produced amounts to 62.8 weight percent of the fresh shale.

Based on the above process conditions, and an operating factor of approximately 91% the major flow rates for the proposed plant become:

Shale Feed (21 Kilns)	19,200 Tons/CD
Shale Oil Product	12,600 Bbls/CD
Gas Production (Dry, Total)	259,000 MSCF/CD
Shale Ash	12,000 Tons/CD
Air Rate to Kilns	195,000 MSCF/CD

The design yields of shale oil and gas tabulated above represent a hydrocarbon recovery of 100 percent based on weight of oil and hydrocarbon gases from assay. Such recoveries are typical of the performance obtained with the semi-commercial retort. Heat efficiency for the process is high and total energy requirements for operation of the retort amount to only 7 percent of the gas yield or less than 2 percent of the energy value of total retort products. The retort gas provides a convenient fuel for the mining, retorting, and refining operations of an integrated shale program.

III. DISCUSSION OF PROCESS FLOW

The process flow, plot plan, and structural detail of the proposed 12,600 Bbl./Day shale retorting plant are presented in the appended figures. It will be noted that the unit comprises essentially three main sections; the cylindrical kilns, four hydraulically operated underfeed mechanisms per kiln, and the oil recovery facilities. The shale is fed to the retorting plant surge hopper by a 48" belt transport conveyor 830 feet long. From the surge hopper, two feeder belt conveyors move the shale to line hoppers from where it is conveyed and fed to the kilns. Fourteen kilns are fed by a 48" belt conveyor 335 feet long equipped with seven stationary three-way trippers and seven kilns are fed by a 36" belt conveyor 335 feet long equipped with seven stationary two-way trippers. The shale is gravity fed from the conveyors to the shale feeders. Movement of the shale is upward with spent ash overflow at the top. The diameter of the kiln expands gradually upward, minimizing restriction to movement of the solids.

A. Retorting Section

The twenty-one kilns, each with a capacity of 1,000 tons of 4" diameter full range shale per stream day, are operated in parallel and have a maximum diameter of 28.5 ft. Each kiln is equipped with four underfeed mechanisms each having a stroke of 2.0 ft. with a 3.0 ft. diameter bore. This mechanism is actuated by two hydraulic cylinders, a 10" bore cylinder for the upwards feeder stroke and a 5" bore unit for the radial loading stroke. The kiln is supported by the four feeder cases. The kiln is provided with four inch fins spaced every inch around the circum-

ference and an external cowling to direct air flow and control the shell temperature. Two 2.0 ft. diameter secondary stacks per kiln provide atmospheric draft through the cowling section. Cooling of the shell by this arrangement will maintain a maximum metal wall temperature of 750°F. at the burning zone. The upper conical sections of the four feeders are slotted and provide the disengaging area for the shale oil and gas from the unit. An external cowling surrounds the slotted disengaging section from which the gas and oil pass to the oil recovery facilities through large diameter headers which handle the production from all twenty-one kilns.

Overhead removal of spent ash is accomplished by three sodium-cooled plows which extend five feet into the shale bed. The plows are supported by a 32 ft. diameter race equipped with dogs and actuated by three four inch hydraulically operated cylinders each having a stroke of 34.0 inches. The formation of large clinkers from fused ash in the kiln is prevented, since the plastic ash zone is exposed to the free action of the plows. The five foot depth of stirring effects improved air distribution which is necessary for high operational efficiency. The shale ash is swept into a disposal chute loading two 42" glass fiber belt conveyors, 300 ft. long. These conveyors feed the spent shale to a 48" glass fiber belt conveyor, 200 ft. long, which carries the ash to the canyon. The disposal conveyor is cantilevered to provide an easy means of unloading the ash. A small portable belt conveyor may be utilized to extend the radius of ash disposal when needed.

B. Underfeed Mechanism

As previously described, the four shale underfeeders at the base of the unit consist of a piston and cylinder assembly mounted on an oscillating carriage. Both the feed piston (10"bore) and the piston moving the carriage (5" bore) are hydraulically operated. Construction of the feed hopper is such that any fines falling through the slots in the disengaging section above are reintroduced to the unit with the fresh feed. Thus, plugging due to accumulation of fines in the gas and oil collecting housing is avoided. The entire feeding mechanism is filled with shale oil to a level just below the disengaging slot edges, providing a liquid seal which prevents the blower from pulling air in through the feed hopper. Lubrication of the moving parts in contact with the shale is also provided by the oil submergence.

C. Oil Recovery Facilities

The oil and gas from the kilns passes through the product headers to the precleaner hopper equipped with two drag chain sludge conveyors. The precleaner hopper serves the three product headers effecting a separation between the oil, sludge, and gas from the retorts. The sludge is removed by means of two drag chain conveyors which carry the sludge to the raw shale conveyor for recycle back to the units. The amount of sludge handled is approximately 1760 pounds per hour. Draw-off lines for the removal of the liquid shale oil are located on the downstream side of the precleaner. The gas from the precleaner hopper discharges through a connecting duct into a common header located outside the Rotoclone Blower house. From the common header four

connecting lines are provided to four type "T", arrangement "A", size 45 Rotoclones. Each Rotoclone develops a head of 9.2 inches of H_2O and is required to handle 54,700 SCFM at 7200 ft. altitude. Each unit is equipped with oil sprays and is powered with a 550 hp. electric motor drive. The four Rotoclone Blowers and drives are housed in a 120 ft. by 35 ft. building.

The recovered oil from the Rotoclone is gravity fed back to the precleaner hopper from which it is removed to production. The Rotoclone building is located at a sufficient height above the precleaner site to allow the gravity flow. The gas from the discharge of the four Rotoclone Blowers is piped to four Ultrasonic wet entrainment separators in parallel for final mist removal. These final separators have the following approximate collection efficiencies which will effectively remove all traces of oil from the product gas:

Diameter Droplets, microns	% Removal
4.0	99.7
2.0	96.5
1.0	39.0

The effluent gas from the final mist extractors proceeds to a collection header and a booster blower takes suction from this header. The booster blower is provided to furnish the required pressure head in combination with the Rotoclone Blower. A mounted booster blower is provided as a spare.

The shale oil product from the precleaner hoppers is pumped to a surge tank 35 ft. in diameter by 30 ft. high. From this tank the shale oil is gravity fed to the refining facilities in the valley. The tank is insulated with 2" of Banroc board and contains a Surface Combustion Corp. immersion burner to maintain the shale at 120°F.

D. Instrumentation

Operation of the shale kilns is entirely automatic and air rate and shale feed are the primary control elements. Flow of air is adjusted to maintain a constant differential pressure across the kilns. Operation with the differential held constant exerts a stabilizing effect on the overall process.

Rate of shale feed is varied by the hydraulic feeder and is controlled by an automatic temperature controller to maintain the burning zone approximately seven feet above the lower edge of the retorting section. The instrument is actuated by thermocouples attached to the retort shell. By holding the burning zone at this level, optimum heat transfer conditions in the bed are established, and an exact balance of shale feed rate with respect to air input is obtained.

An additional control element of importance in the retorting operation is the rotational speed of the plows. Their speed is proportioned to the rate of shale feed by an auxiliary control device on the automatic temperature controller.

The balance of the retort instrumentation includes flow recorders for the stack gas and product oil, a level indicator for the product oil surge tank, multipoint temperature recorders and various indicating gauges.

E. Material and Equipment Specifications

Tables presenting pertinent dimensions, sizing, equipment specifications etc., for all major items in the shale retorting plant, including housing, foundation, major piping and instrumentation, have been deleted from this report. These tables may be found in the complete NPC processing report.

IV. POWER AND UTILITY REQUIREMENTS

All power required to operate the shale retorting plant will be produced from the 80 Btu/cu. ft. product gas. The use of gas turbine or steam power generating units is assumed with the selection of optimum size, type and location of the facilities to be determined by the Engineering Subcommittee. Electric motor drives are specified throughout the plant in this design. Four 550 BHP motors are employed to drive the four Roto-clone Blowers and one 2900 BHP motor is required to drive the Buffalo Forge Booster Blower. Four 400 BHP motors are required to drive Vickers variable delivery piston type hydraulic pumps. These hydraulic pumps supply the power requirements in the plant for plows and shale feeders. Miscellaneous electric drives are supplied for convyeor drives, pumps, air compressors, etc. The use of stand-by electric power for start-up and emergency use is stipulated. A small Babcock-Wilcox gas fired steam boiler is required to furnish seasonal steam tracing for the sludge drag chain conveyors and for heating buildings. A Surface Combustion immersion burner is employed to maintain the product oil surge vessel at 120°F.

A. Power

The power demand for the retorting plant is 4675 KW. A conversion factor of 16,100 Btu/KW.-hr. was used to determine the fuel equivalent which is 75.2 MMBtu/hr.

B. Fuel

Retort gas is used as fuel for the immersion burner. The demand is 33 MSCF/SD which has a fuel gas equivalent of 0.1 MMBtu/hr.

C. Water

The water consumption rate for the retorting plant is 6,000 Gal./Day and includes water make-up for the boiler plant, sewage and drinking requirements, cooling water for bearings and dust wet-down requirements. 10% of the total steam usage rate, assumed non-recoverable, is the make-up water rate to the boilers. This rate amounts to 50 Gal/hr.

D. Steam

The steam consumption rate for the retorting plant is 4,000 Lbs./hr. Steam pressure of 15 psig is sufficient to meet heating and line tracing requirements. The heating efficiency is 72% net for the boiler and the retort gas consumption rate is 4.7 MMBtu/hr.

A summary of over-all utilities and their retort fuel gas equivalents is given in Table 1.

TABLE 1

SUMMARY OF UTILITIES AND POWER REQUIREMENTS

ITEM	RATE	EQUIVALENT RETORT GAS RATE, MMBtu/hr.
Electricity	KW	
Booster Blower	1930	
Rotoclone Blowers	1250	
Shale Feeders	815	
Shale Plows	245	
Shale Conveyor System	220	
Ash Conveyor System	45	
Sludge Conveyors	10	
Wash Oil Pump	35	
Product Pump	5	
Shop	60	
Lighting	45	
Instruments	10	
Air Compressor	5	
TOTAL	4675 KW/hr.	75.2
Steam	4,000 Lbs/hr.	4.7
Water	6,000 Gals/Day	-
Fuel	33 MSCF/Day	0.1
TOTAL RETORT GAS REQUIRED		80.0

TABLE 2

SUMMARY OF DAILY PERSONNEL REQUIREMENTS

Superintendent	1
Assistant Superintendent	
Operations	1
Maintenance	1
Foreman, Operations	3
Foreman, Maintenance	1
Craftsmen	
A. Pipefitters	3
B. Electricians	3
C. Instrument and Valve Man	1
D. Painter	1
E. Machinist	1
Machinist Helper	1
F. Riggers	2
G. Laborers	2
Operations	
A. Conveyor Men	6
B. Retort Men	9
C. Pumpers	6
TOTAL	42

TABLE 3

PRESSURE BALANCE

	Pressure Loss Inches H_2O	Pressure Gain Inches H_2O	Pressure[c] Psia
Retort Shale Bed	23.1		10.27
Line Losses to Precleaner[a]	0.97		10.23
Precleaner[b]	0.42		10.21
Line Losses to Rotoclones[a]	0.43		10.19
Rotoclones	-	9.2	10.52
Line Losses to Wet Entrainment Separators[a]	0.12		10.52
Wet Entrainment Separators[b]	6.0		10.30
Line Losses to Booster Blower[a]	0.13		10.30
Booster Blower	-	32.0	11.46
	31.2	41.2	

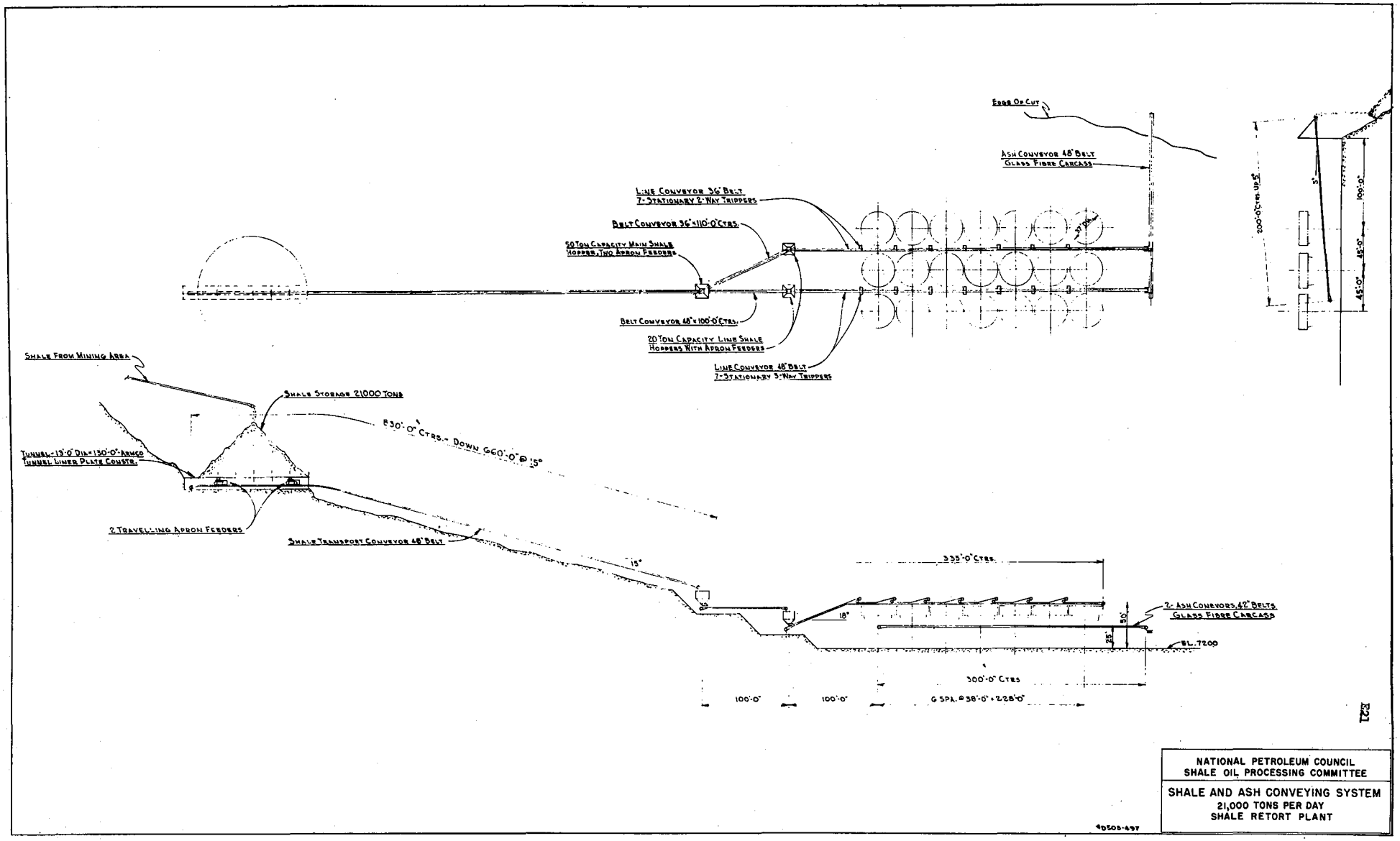
Fuel Gas Pressure Available at Retorting Facilities = 10.0" w.g.

(Gas Pipe Line is sized for 5" w.g. pressure drop)

a. Includes losses due to friction, enlargement, contraction, etc.

b. Total pressure loss including design pressure drop, enlargement and contraction losses.

c. Atmospheric pressure taken as 11.10 psia.

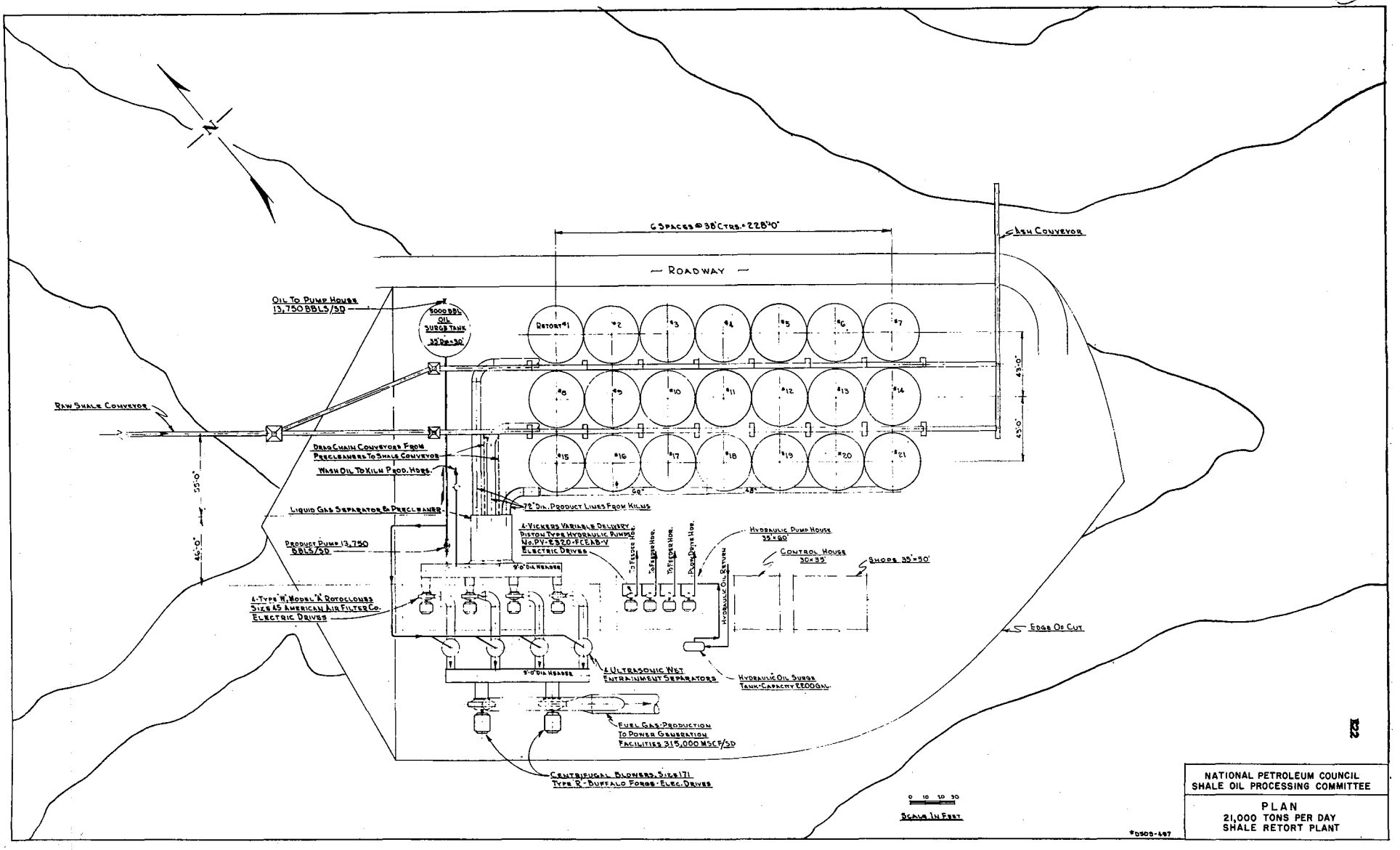


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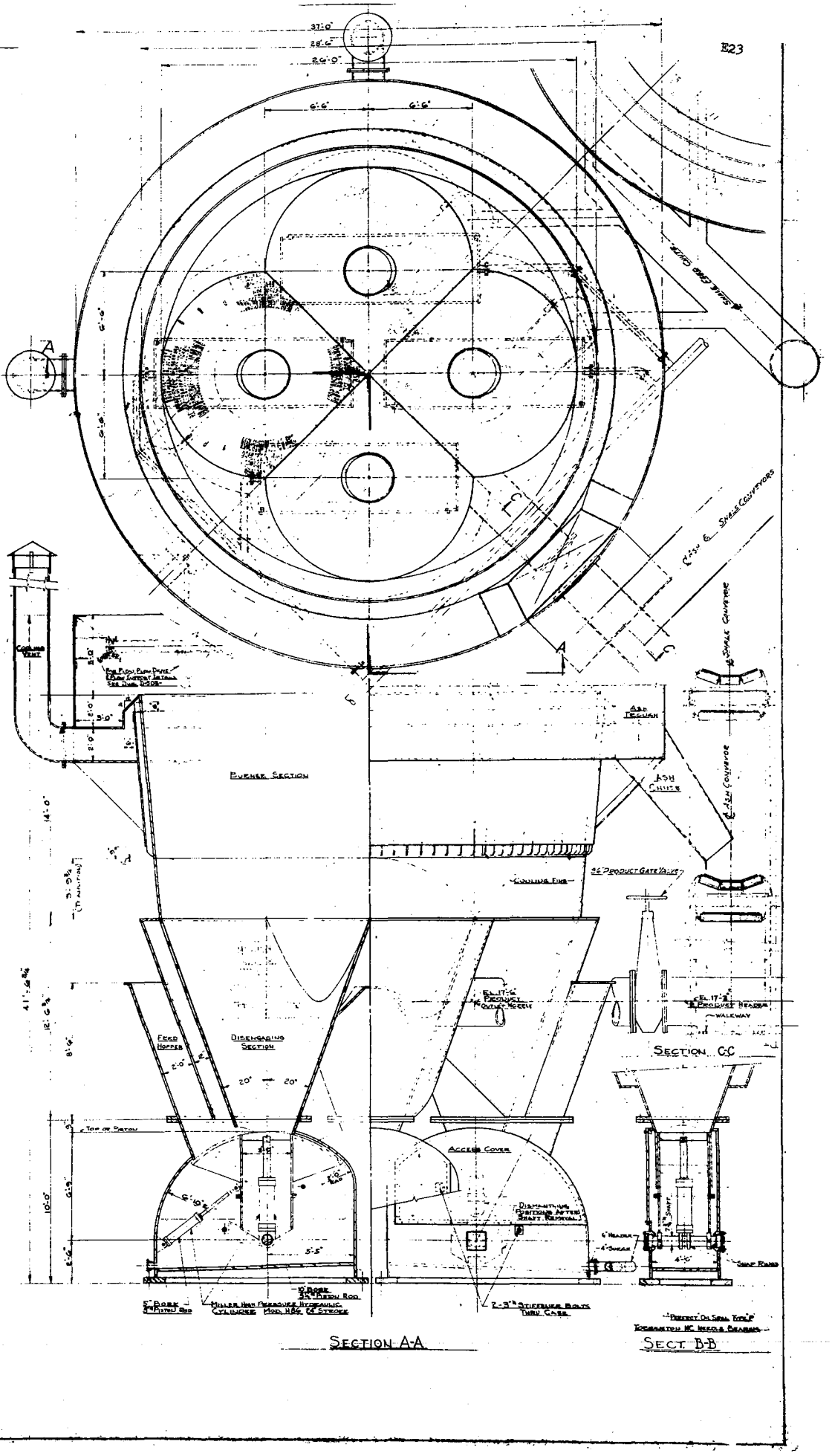
SHALE AND ASH CONVEYING SYSTEM
21,000 TONS PER DAY
SHALE RETORT PLANT

4D508-697



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SHALE OIL PROCESSING COMMITTEE

PLAN
21,000 TONS PER DAY
SHALE RETORT PLANT



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SHALE OIL PROCESSING COMMITTEE

PLAN AND SECTIONS
21,000 TONS PER DAY
SHALE RETORT PLANT

NUMBER D-SC/SR-409

REFERENCE DRAWINGS
PUSHER PLOW DRIVE DETAIL-SHALE RETORT

II. GAS PIPE LINE

SHALE RETORT GAS PIPE LINE DESIGN

I. SUMMARY

In connection with the process and engineering design studies for the retorting and refining 250,000 B/CD of shale oil, a study has been made which covers the transportation of the retort gas to the refinery sites. The total utility requirement for mining, retorting and refining[1] is supplied by burning about 86.5% of the net retort gas production. Nearly all high BTU content gas and coke production from the refinery is then realized as a salable product.

The process and engineering design has been prepared for the retort gas pipe line system to handle 6,300,000 MSCF per day of 80 Btu/cu. ft. gas for 250,000 Bbl./D shale oil refining, between the retorting areas and four refinery sites selected by the Shale Oil Engineering Subcommittee.

II. DISCUSSION OF DESIGN

The retort gas at the retorting area is available at approximately ten inches of water pressure. The pipe line system is sized to give only five inches of water pressure drop, thus providing gas at a pressure of 5.0 inches of water at the refinery end. The mining and refining sites were selected by the Engineering Subcommittee. Profiles were prepared for each of the selected sites to obtain actual pipe line lengths required.

---

1. Excludes catalytic cracking facilities located on the West Coast.

Two basic pipe line sizes, 13.0 and 18.0 ft. (pipe diameter) are required. This system is believed to be the most economical means of transporting the retort gas from the retorting plant sites to the steam power generating facilities located within the refinery boundaries.

The pipe lines are constructed from light gauge Armco Tunnel Liner Plates. The inner surface of the pipe is given a 1/2" coating of gunite to maintain a gas tight construction. Auxiliary equipment consists of heating units spaced along the pipe line which employ a small fraction of the pipe line gas as fuel and fire into the line to maintain a minimum of 40°F. in the line during cold weather. The outside of the line is aluminum painted to minimize heat losses.

The design of the heating units is based on an ambient temperature of -20°F. and a gas temperature which is a maximum of 50°F. at a firing point and drops to 40°F. before contacting the next heater. Under these conditions the amount of heat loss from the line amounts to 3,980 MBtu/hr./1000 ft., 13.0 ft. diameter pipe and 5510 MBtu/hr./1000 ft., 18.0 ft. diameter pipe. The amount of pipe line gas utilized to maintain the line at a minimum of 40°F. amounts to approximately 5.0% of the total gas.

At periodic intervals, ball float drainers are installed to remove pipe line condensate.

The tables presenting specifications and costs for the major equipment involved in the pipe line system have been deleted from this report. They may be found in the complete NPC processing report.

III. COLORADO REFINING

TABLE OF CONTENTS

		Page No.
I.	Summary	E28
II.	Introduction	E30
III.	Over-all Refinery Plan	E31
	A. Location	E31
	B. Over-all Flow Sheet	E31
	C. Storage Facilities	E32
IV.	Coking Unit	E35
V.	Hydrogenation Unit	E39
	A. Chemical Reactions	E39
	B. Reactor Design Conditions	E39
	C. Flow Sheet, Material Balance and Operational Requirements	E44
	D. Equipment Specifications	E47
VI.	Catalytic Reforming Unit	E48
	A. Chemical Reactions	E48
	B. Reactor Design Conditions	E48
	C. Flow Sheet, Material Balance and Operational Requirements	E52
	D. Equipment Specifications	E57
VII.	Hydrogen Plant	E58
VIII.	Ammonia Recovery Unit	E61
IX.	Sulfur Plant	E64
X.	Utilities and General Plant Facilities	E67
	A. General Facilities	E67
	B. Utilities	E67
XI.	Diesel and Gasoline Specifications	E69

PROCESS AND ENGINEERING DESIGN
25,000 BBL/SD SHALE OIL REFINERY

1. SUMMARY

This report presents the design of a 25,000 Bbl/SD shale oil refinery for the production of gasoline and diesel oil. The refinery consists of a coking unit, a hydrogenation unit, a reforming unit, a hydrogen plant, an ammonia recovery unit, a sulphur plant, a boiler plant and a power plant. The hydrogenation and reforming units which require special equipment have been designed in detail, whereas the remaining units are of standard design such that cost estimates may be obtained from process requirements which are presented.

The refinery is located near the Colorado River and the crude shale oil and retort gas are piped approximately 2 miles to the refinery. The retort gas fulfills all refinery fuel and power requirements. The coke and cracked gas produced are sold to outside consumers.

The salable products are tabulated below for 25,000 Bbl./SD crude shale oil feed.

Diesel	11,820 Bbl/SD
Gasoline	8,670 Bbl/SD
Coke	590 Tons/SD
Fuel Gas (1060 BTU net)	12,530 MSCF/SD
Anhydrous Liquid Ammonia	46 Tons/SD
Sulphur	21 Tons/SD

The diesel and gasoline are piped in slugs to refiners in the market area.

This gasoline stock has an octane rating of about 83, Research Method + 3 cc TEL, and the diesel has a cetane number of about 55.

The total daily personnel requirement for the refinery is 351 including all service groups.

II. INTRODUCTION

Previous studies on the refining of shale oil have been directed toward the production of diesel and jet fuel. The refinery design presented herein is for the production of diesel and gasoline rather than jet fuel. The gasoline produced from coking and hydrogenation has a very low octane rating and must be reformed in order to produce a gasoline that is comparable to "regular" gasolines now being produced from crude oil sources. The addition of the catalytic reforming unit is the major difference between this and previous studies.

The purpose of this preliminary design is to present the most likely scheme to be employed in refining shale oil in light of existing processes, and to give enough information for economic evaluation, i.e., determination of capital investment and operating charges.

III. OVER-ALL REFINING PLAN AND STORAGE FACILITIES

The over-all refining flow diagram and tankage facilities are presented in Figure 1.

A. Location

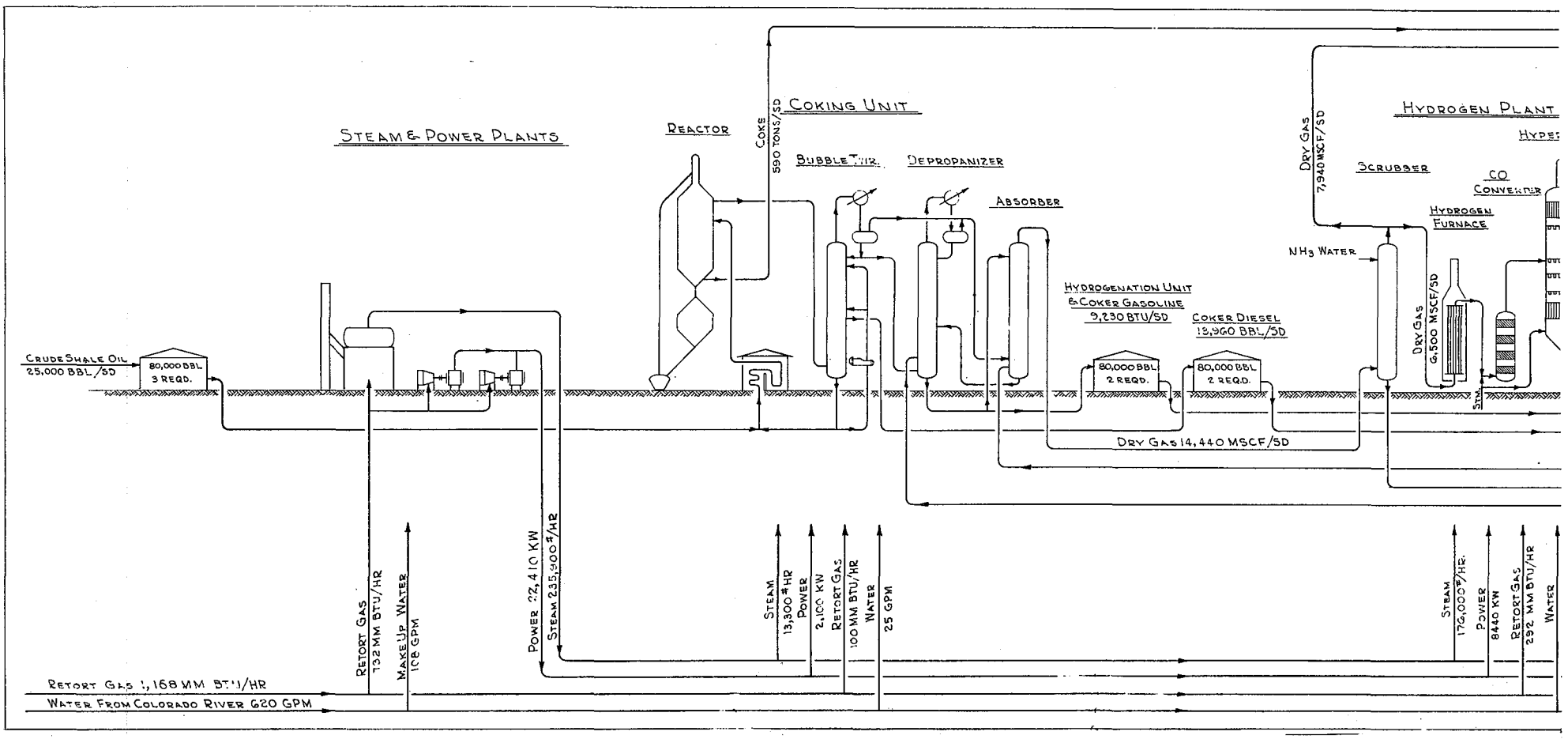
The refinery is to be located near the Colorado River. Two miles of insulated pipe line to the retorting site is required for the crude shale oil and a second line of the same length is required for the retort gas. Due to the shortage of water in this area, Fin-Fan cooling is used wherever possible throughout the refinery. The diesel and gasoline produced is transported by pipe line to refiners in other areas. The diesel produced is a finished product which may be sold as such or catalytically cracked, whereas the depropanized gasoline is rerun, blended and leaded by refiners in the market areas. This scheme appears to be the most economical.

B. Over-All Flow Sheet

The refinery has been sized to process 25,000 Bbl/SD of crude shale oil. The oil is first coked by the contact coking process to produce a 700°F. end point coker distillate. The coker distillate is fractionated to produce a C_4 - 400°F. gasoline cut and a 400-700°F. diesel cut.

The hydrogen plant employs the steam-methane reaction for the production of hydrogen and hypersorption for the purification of the hydrogen. The dry gas from the coking unit is the feed to this plant.

The diesel cut from the coker is the feed to the hydrogenation plant employing cobalt-molybdate catalyst. Here, in the presence of hydrogen, at 1100 psig. and about 820°F., virtually complete conversion

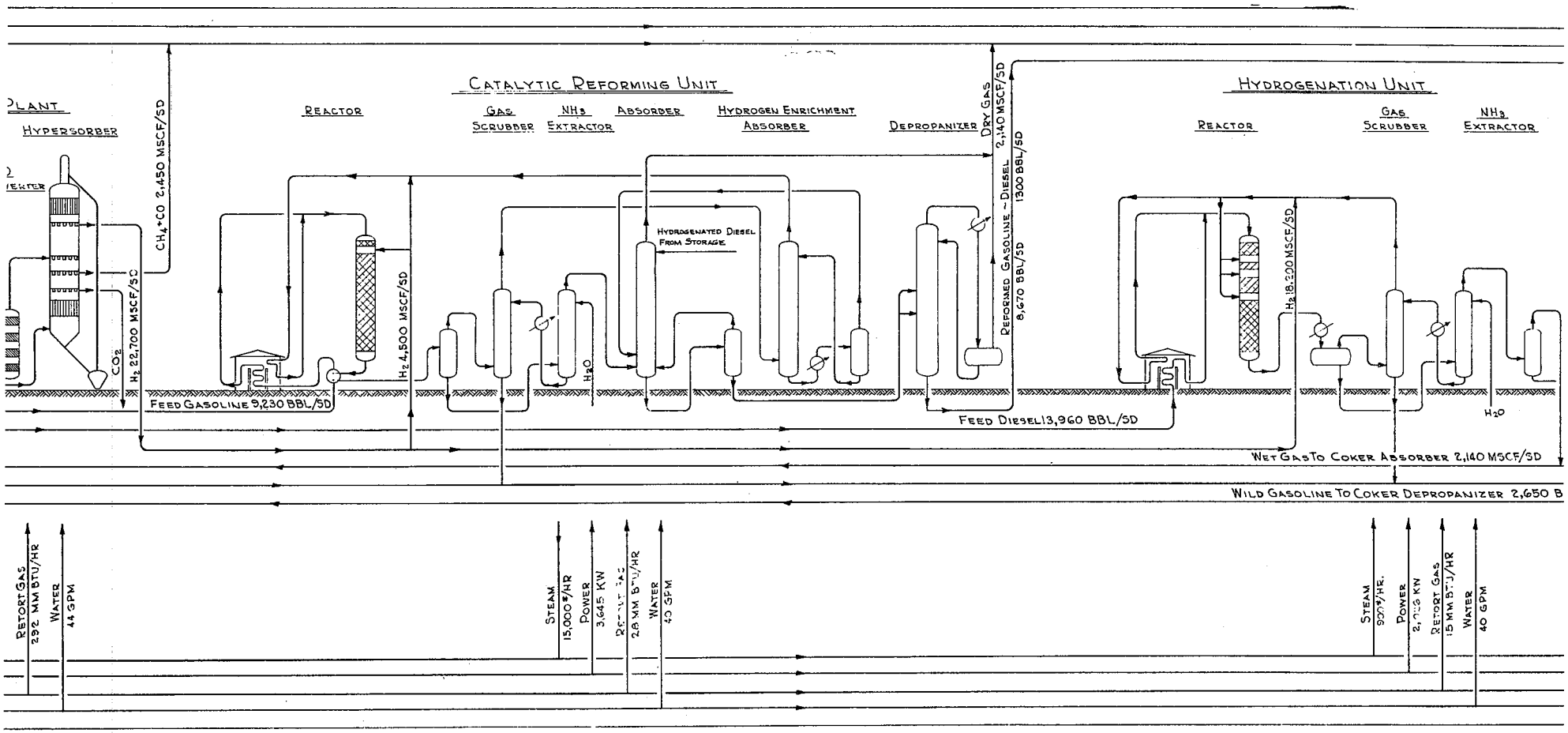


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FIGURE-1

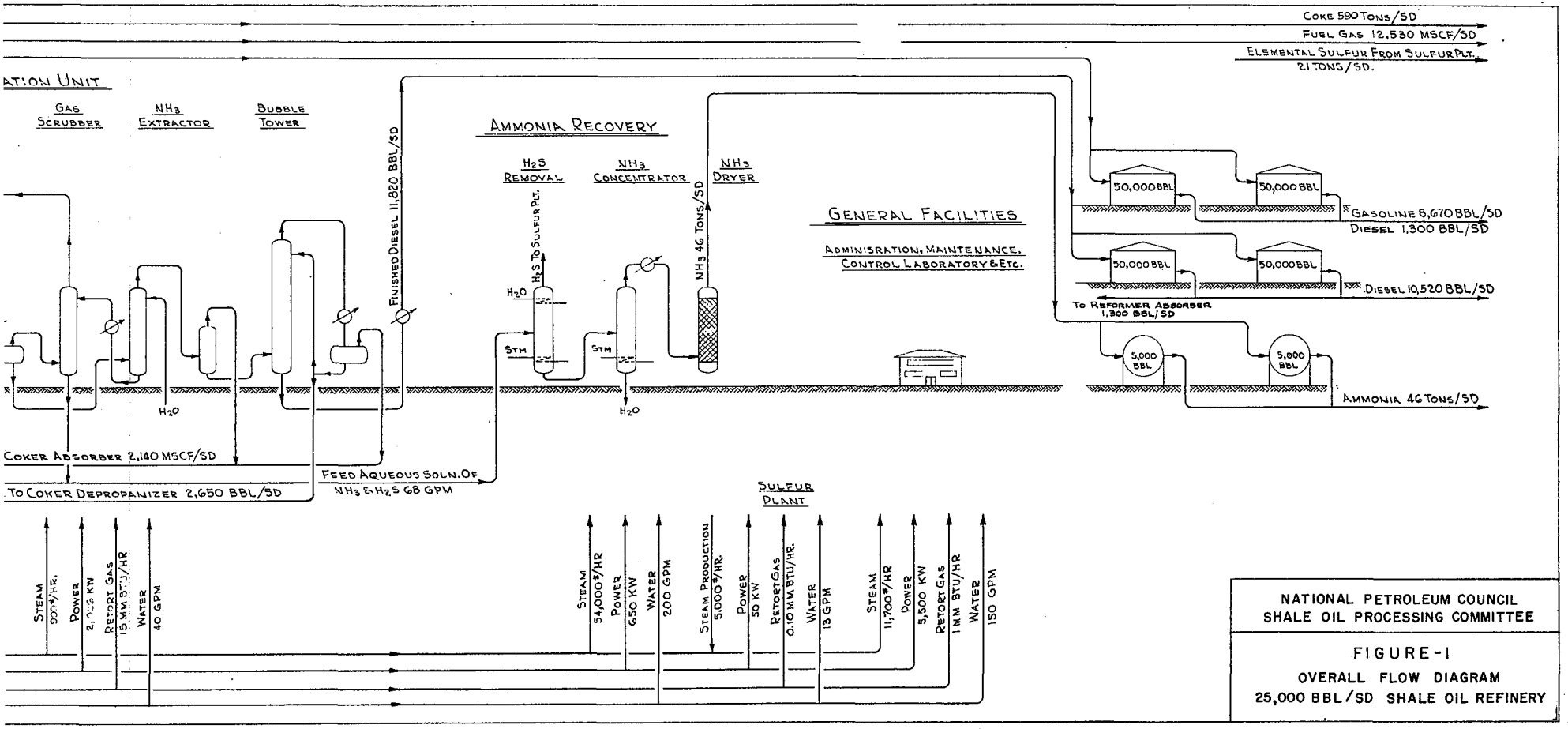
OVERALL FLOW DIAGRAM
25,000 BBL/SD SHALE OIL REFINERY

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FIGURE-1
OVERALL FLOW DIAGRAM
25,000 BBL/SD SHALE OIL REFINERY



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FIGURE-1
OVERALL FLOW DIAGRAM
25,000 BBL/SD SHALE OIL REFINERY

E31a

of the nitrogen and sulfur compounds to paraffin type hydrocarbons and NH_3 and H_2S is obtained and the olefins are hydrogenated. The H_2S and NH_3 are scrubbed out of the system with water. The conditions required in the reactors for the removal of nitrogen and sulfur from the oil are severe enough to cause considerable hydrocracking which produced some gas and considerable gasoline. The hydrogenated liquid product is fractionated to produce a gasoline cut and a finished diesel product. The gasoline cut is depropanized with the gasoline produced in the coking operation and this combined naphtha is the feed to the catalytic reforming unit.

The gasoline reforming unit also employs cobalt-molybdate catalyst. Here in the presence of hydrogen at 400 psig. and about 900°F., the sulfur and nitrogen compounds carried over by the coker gasoline are converted to paraffin type hydrocarbon and H_2S and NH_3, the olefins are hydrogenated, the naphthenes are converted to aromatics, and there is considerable hydrocracking and isomerization. The aromatization, isomerization and cracking are the reforming reactions which are responsible for the increase in knock rating. The H_2S and NH_3 are scrubbed out of the system with water as before. The reformed gasoline mixed with hydrogenated diesel absorption oil is depropanized and pumped to storage.

The ammonia - H_2S water solution produced from the hydrogenation and reforming units is fed into a series of towers for separation of the ammonia, which is compressed and liquified for shipment by tank car. The H_2S from the ammonia plant is fed to a sulfur plant where elemental sulfur is produced.

C. Storage Facilities

The storage facilities are shown on the Over-All Refinery Flow Sheet, Figure 1, and the capacities and residence times are summarized

in Table 1. Long residence times are not necessary for the diesel and gasoline since they are being transported by pipe line to refiners in the market area.

TABLE 1

REFINERY STORAGE FACILITIES

	Capacity Bbl.	Residence Time, Days
1. Crude Shale Oil	240,000	9.6
2. Coker Diesel Oil	160,000	11.5
3. Finished Diesel Oil	160,000	14.0
4. Coker Gasoline	100,000	10.8
5. Reformed Gasoline	100,000	11.5
6. Liquid Ammonia	10,000	22.2

IV. COKING UNIT

The "Continuous Contact Coking" process is employed using a "Mass Flow" lift line for the circulation of coke. This process has been successfully demonstrated by a semi-commercial plant and offers many advantages over the "Delayed Coking" process for this particular application.

The feed to the coker is 25,000 Bbl/SD or the total crude shale oil feed to the refinery. The coker is operated to produce a 700° F. end point material by recycling all heavier material to the reactor. The selection of 700° F. for the end point of the coker distillate was based on two factors. First, more gasoline production is desirable than that obtained by coking to a 750° F. end point and secondly the diesel obtained experimentally by coking to a 750° F. end point and hydrogenation had a fairly high pour point, and by coking to a 700° F. end point, a pour point of about 0°F. is obtainable.

The coking unit is operated to produce a depropanized gasoline cut with a minimum loss of butanes, so that the distillation section consists of a combination bubble tower, an oil absorber, and a depropanizer. The depropanizer also serves the gasoline stream produced by the hydrogenation unit so as to cut down losses in intermediate storage before reforming. The total feed to the depropanizer tower is 9,230 Bbl/SD when both plants are operating, and 6,580 Bbl/SD when only the coker is operating. The absorber also serves the hydrogenation plant wet gas which means an additional 2,140 MSCF/SD feed to this tower. The feed gas to this tower from the coker is approximately 12,300 MSCF/SD

"Continuous contact Coking" is a Lummus Company process and a capital investment estimate can be obtained from this company. Table 2

presents the material balance for this unit, and Table 3 presents the utility and personnel requirements.

TABLE 2

COKING UNIT MATERIAL BALANCE

Feed	Bbl/SD	°API	Lbs/Bbl.	M Lbs/Hr.	Vol.%	Wt.%
Crude Shale Oil	25,000	20.5	325.6	338.5	100	100
Product						
Dry Gas (M.W.=20)	-	-	-	27.1	-	8.0
Butane-Butylene	624	-	200	5.2	2.5	1.5
C_5 - 400°F. E.P.	5,960	51.0	271.1	67.3	23.8	19.9
Diesel (400-700°F.)	13,960	28.8	308.7	179.7	55.8	53.1
Coke	-	-	-	49.1	-	14.5
Burned in Reheating				10.1	-	3.0
				338.5	82.1	100.0

TABLE 3

COKING UNIT

UTILITY REQUIREMENTS	
Electricity, KW	2,100
Steam, Lbs./hr.	13,300
Water, GPM	25
Fuel, MMBtu/hr.	100
PERSONNEL REQUIREMENTS (PER DAY)	
Plant Operators	12
Plant Foremen	3

V. HYDROGENATION UNIT

The feed to the hydrogenation unit is the 400-700°F. diesel cut from the coking unit. The primary purpose of the hydrogenation of this stock is the removal of the large quantities of chemically combined nitrogen and sulfur it contains. The Union Oil Co. of Calif. "cobalt-molybdate" hydrogenation process, which has been used in previous economic studies by the Bureau of Mines and which has given excellent results in pilot plant operations, will be employed for this study.

A. Chemical Reactions

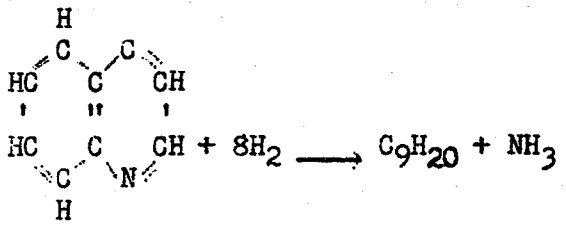
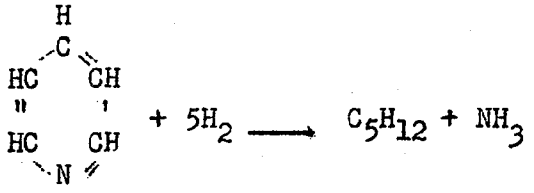
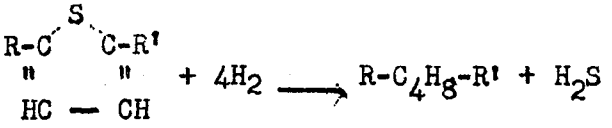
Analysis of the data available on shale oil and its hydrogenation indicate that the nitrogen is present largely in the form of quinoline-pyridine type compounds and the sulfur is the form of thiophene type compounds. Typical reactions and their heats of reaction are given in Table 4. The feed stock is highly olefinic so that the hydrogenation of olefin reaction, reaction 4, is of major importance. Kinetic studies have shown that the reactions of the nitrogen compounds are slower and therefore rate controlling. Operating conditions required for the removal of nitrogen are severe enough to produce considerable hydrocracking, so reaction 5 is also of major importance and accounts for the gasoline and gas produced.

B. Reactor Design Conditions

Fixed bed reactors are used and their operation is cyclic in that periodic regeneration of the catalyst by burning off the coke is required. Pilot plant data indicates that at the operating conditions chosen for design, an on stream time per reactor of 96 hours could be obtained readily with little loss of catalyst activity. On this basis, and with kinetic data on coke burnoff, a five reactor system has been

TABLE 4

HYDROGENATION REACTIONS

		ΔH @ 700°F. BTU/lb. mol.
1.		
2.		- 140,000
3.		- 112,000
4.	$R{=}R' + H_2 \longrightarrow R - R'$	- 53,000
5.	$R\text{-}R' + H_2 \longrightarrow R + R'$	- 22,400

designed such that four reactors are on stream at all times, and one on regeneration. The reactor time cycle employed is given in Table 5.

The design conditions for the reactors are given in Table 6. It will be observed from the heats of reaction, given in Table 4 in the previous section, that all reactions are highly exothermic. The feed enters the reactors at a temperature of 680°F. and rises to 835°F. in the first bed section. The effluent from the first bed section is quenched to 800°F. by cold hydrogen injection. The temperature rises to 835°F. in the second bed section and the effluent is quenched again with cold hydrogen to 800°F. The temperature rises again to 835°F. in the third bed section and is quenched again to 800°F. The temperature rises to 836°F. in the fourth and final bed section. The coke laydown in 96 hours of operation is 3.5 wt.% of the catalyst charge. The total hydrogen consumption is 1300 SCF/Bbl. of feed. The nitrogen reactions account for 76% of this hydrogen consumption due to the high nitrogen content of the feed.

The regeneration conditions are also given in Table 6. The regeneration is conducted by passing a controlled mixture of flue gas and air through the bed such that a temperature of 1100°F. is not exceeded by the exothermic coke burning reaction, as permanent loss of catalyst activity results above this temperature. The inlet temperature of the gas must be sufficiently high to start the reaction at a reasonable rate, and for most of the regeneration period all of the oxygen in the feed gas is consumed in the reactor so that the inlet and outlet temperature specified, control the allowable oxygen concentration of the inlet gas.

TABLE 5

HYDROGENATION UNIT
REACTOR TIME CYCLE

	Operation	Time, Hrs.
1.	Reaction	96
2.	Recycle Gas Purge	1.0
3.	Depressuring	0.5
4.	Inert Gas Purge	0.5
5.	Regeneration	20.5
6.	Inert Gas Purge	0.5
7.	Recycle Gas Purge	0.5
8.	Repressuring	0.5
	TOTAL	120.0

TABLE 6

HYDROGENATION UNIT
REACTOR DESIGN CONDITIONS

Reaction

1.	Feed rate to each reactor	--	3,490	Bbl/SD
2.	Pressure	--	1,100	psig.
3.	Liquid hourly space velocity	--	0.72	
4.	Catalyst bed volume per reactor	--	1,130	cu. ft.
5.	First bed section inlet temperature	--	680	°F.
6.	First bed section outlet temperature	--	835	°F.
7.	First bed section recycle gas rate	--	2,500	SCF/Bbl.
8.	First bed section volume	--	340	cu. ft.
9.	Quench gas rate to first quench section	--	770	SCF/Bbl.
10.	Second bed section inlet temperature	--	800	°F.
11.	Second bed section outlet temperature	--	835	°F.
12.	Second bed volume	--	85	cu. ft.
13.	Quench gas rate to second quench point	--	770	SCF/Bbl.
14.	Third bed section inlet temperature	--	800	°F.
15.	Third bed section outlet temperature	--	835	°F.
16.	Third bed section volume	--	141	cu. ft.
17.	Quench gas rate to third quench point	--	770	SCF/Bbl.
18.	Fourth bed section inlet temperature	--	800	°F.
19.	Fourth bed section outlet temperature	--	836	°F.
20.	Fourth bed section volume	--	564	cu. ft.
21.	Pressure drop	--	2.0	psi.
22.	Coke laydown in 96 hours	--	3.5	wt.% of catalyst
23.	Hydrogen consumption	--	1,300	SCF/Bbl.

Regeneration

1.	Pressure at reactor inlet	--	30	psig.
2.	Inlet temperature	--	700	°F.
3.	Outlet temperature	--	1,100	°F.
4.	Regeneration gas rate	--	276	MSCF/Hr.
5.	Oxygen concentration of feed gas	--	1.97	mol.%
6.	Pressure drop	--	4.5	psi.

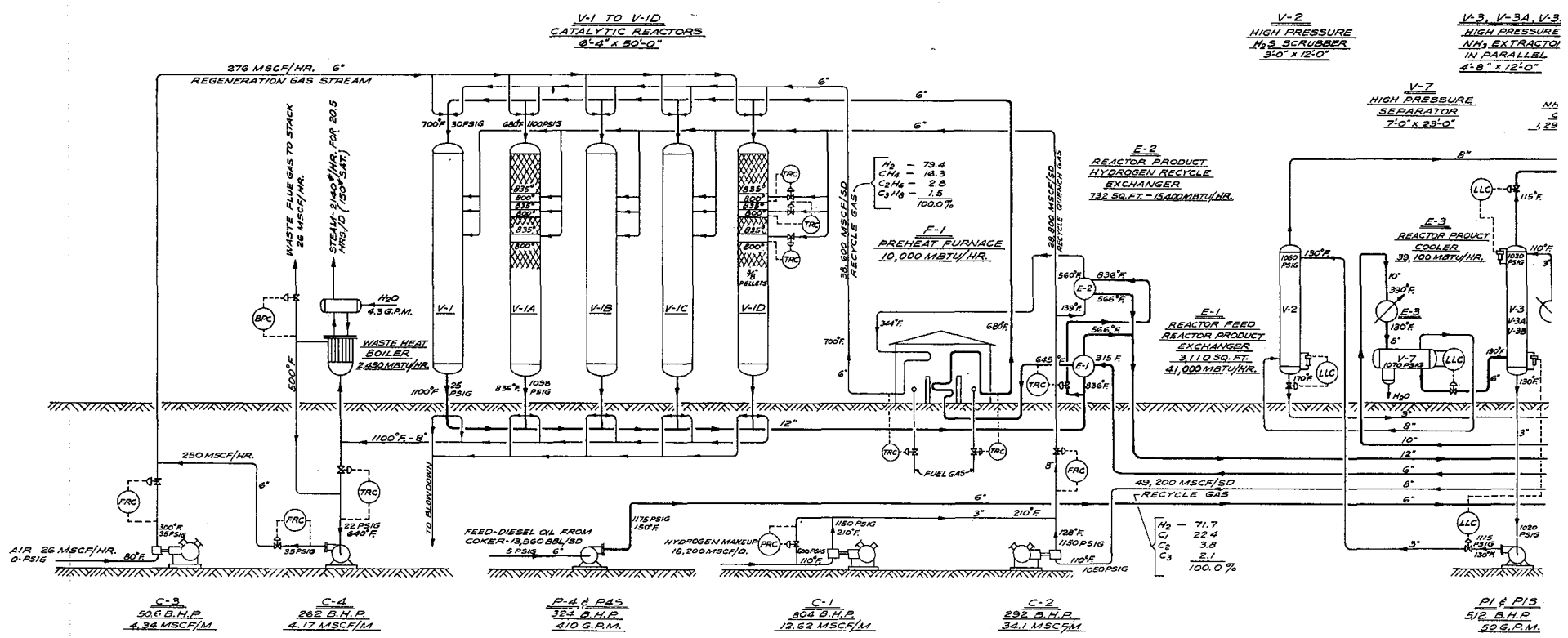
The reactors have been designed for low pressure drops on both reaction and regeneration to minimize blower requirements.

C. Flow Sheet, Material Balance and Operation Requirements

The process flow sheet is presented by Figure 2, the over-all material balance by Table 7, and the utility and operating personnel requirements by Table 8. The Flow Sheet contains all the major vessels, exchangers, pumps, compressors, instruments and lines.

Referring to the Flow Sheet, the coker Diesel oil feed is pumped by P-4 through exchanger E-8, exchanger E-1 and fired heater F-1 to heat it to the desired reactor inlet temperature of 680°F. At the top of the reactors it is mixed with the recycle hydrogen and the mixture passes down through four reactors operating in parallel at 1100 psig. The reactor effluent passes through exchangers E-1 and E-2 operating in parallel, the bubble tower feed preheater exchanger E-5, cooler E-3 and finally into the high pressure separator V-7. The liquid oil from V-7 is pressured through the high pressure ammonia extractors V-3, V-3A and V-3B operating in parallel where the ammonia and hydrogen sulfide are removed by water. From V-7 the liquid oil is pressured to the low pressure flash drum V-5 where the lighter components are flashed off at 30 psig. and go to the coker absorber. The liquid oil from V-5 is pressured through exchanger E-5 to the bubble tower V-4 where it is fractionated to produce gasoline and Diesel. The Diesel is pumped through exchanger E-8 and cooler E-6 to final storage, and the gasoline is pumped to the coker depropanizer tower.

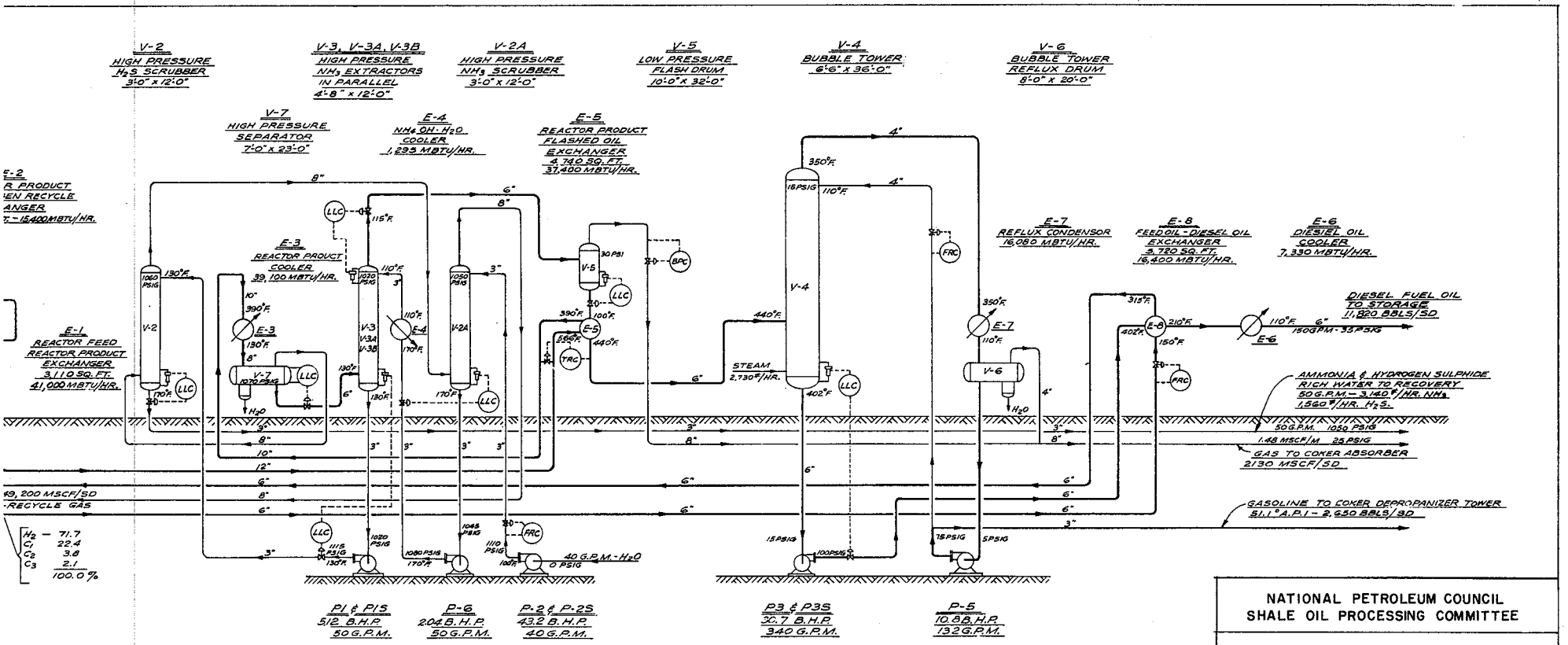
The hydrogen recycle stream is circulated through the system by blower C-2. The necessary hydrogen make up which is available at 600 psig.



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FIGURE-2

FLOW DIAGRAM OF HYDROGENATION UNIT
25,000 BBL/SD SHALE OIL REFINERY



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FIGURE-2

FLOW DIAGRAM OF HYDROGENATION UNIT
25,000 BBL/SD SHALE OIL REFINERY

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TABLE 7

HYDROGENATION UNIT
MATERIAL BALANCE

Feed	Bbl/SD	MSCF/SD	°API	M.W.	Lbs/Hr.	Liquid Vol. %	Wt.%
Coker Diesel	13,960	-	28.8	-	179,700	100.0	-
Hydrogen	-	18,200	-	2.0	4,000	-	-
				TOTAL	183,700		
Product							
Dry Gas	-	2,140	-	21	4,900	-	2.69
C_4 - 400° E.P. (Gasoline)	2,650	-	51.1	-	30,000	19.0	16.24
Diesel (400-700°F.)	11,820	-	38.0	-	144,000	84.7	78.45
Coke	-	-	-	12	100	-	.06
NH_3	-	-	-	17	3,140	-	1.71
H_2S	-	-	-	34	1,560	-	.85
				TOTAL	183,700		100.0

TABLE 8

HYDROGENATION UNIT

UTILITY REQUIREMENTS

Electricity, KW	2,026[a]
Steam, Lbs./hr.	900[b]
Water, GPM	40
Fuel, MM BTU/hr. (Net)	15

PERSONNEL REQUIREMENTS (PER DAY)

Plant Operators	15
Plant Foremen	3

a. Includes Fin-Fan power.

b. Steam required by Bubble Tower = 2,730 Lbs./hr.
Steam produced by waste heat Boiler = 1,830 Lbs./hr.

from the hyperscrber is added to the system by compressor C-1 and joins the recycle stream at the recycle gas compressor outlet. A part of this combined stream goes directly to the reactors as intermediate quench, while the bulk of it passes through exchanger E-2 and heater F-1, where it is heated to 700°F. and then mixed with the oil at the reactor inlet. The hydrogen remains mixed with the oil in the system previously described up to the high pressure separator V-7 where it is separated. The hydrogen recycle stream is then pressured through water scrubbers V-2 and V-2A where the ammonia and hydrogen sulfide are scrubbed out. From the top of scrubber V-2A the hydrogen recycle stream is picked up by the suction of the recycle blower C-2 and the cycle is completed.

The regeneration system is shown on the flow sheet with reactor V-1 being regenerated. The regeneration is conducted at an average pressure of about 28 psig. Blower C-4 circulates the inert gases through the system while compressor C-3 furnishes air to the system. The oxygen concentration of the feed gas stream controls the temperature rise across the reactor, and the waste heat boiler controls the inlet temperature by generating steam with the reactor effluent to remove the heat of reaction.

The liquid product and recycle gas scrubbers are arranged such that the water stream is pumped through towers V-2A, V-3, V-3B and V-2. The liquid extractors, V-3, V-3A, and V-3B in parallel are between the two gas scrubbers so that the water stream to the extractors is rich in ammonia which is required for effective hydrogen sulfide extraction.

D. Equipment Specifications

The specifications for vessels, exchangers, pumps, compressors, fired heaters, and pipe lines may be found in the complete NPC Processing Committee Report.

The total catalyst charge to the five reactors is 353,000 lbs. of 3/8" pelleted "Cobalt-Molybdate" catalyst.

VI. CATALYTIC REFORMING UNIT

The feed to the reforming unit is the C4-400°F. cuts from the coking and hydrogenation units. The purpose of reforming this stock is to increase the knock rating and to remove the nitrogen and sulfur it contains. The reactors are charged with "Cobalt-Molybdate" catalyst.

A. Chemical Reactions

The major reactions in catalytic reforming are presented in Table 9. The first four reactions which are aromatization of cyclohexanes, isomerization of cyclopentanes, isomerization of paraffins, and hydrocracking, all tend to upgrade the knock rating of the gasoline. The reactor design conditions have been chosen to give an optimum balance of these reactions based on kinetic studies and with due consideration to coke laydown and liquid yields.

B. Reactor Design Conditions

The reactors have been designed to give an optimum octane-yield relationship with provision for flexibility of operation depending on octane demand.

Fixed bed reactors are used and their operation is cyclic in that periodic coke burnoff is required. The reactor time cycle employed is given in Table 10. A three reactor system is employed such that two reactors are on stream at all times with one regenerating.

The design conditions for the reactors are given in Table 11. From Table 9 it may be seen that all the reactions, except aromatization, are exothermic and the net heat of reaction is exothermic. The feed enters the reactors at 750°F. and the temperature rises to 905°F. in the first short bed section. The effluent from the first bed section is quenched with cold

TABLE 9

REFORMING REACTIONS

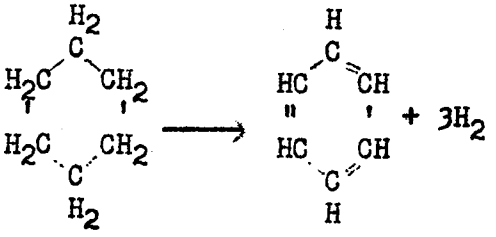
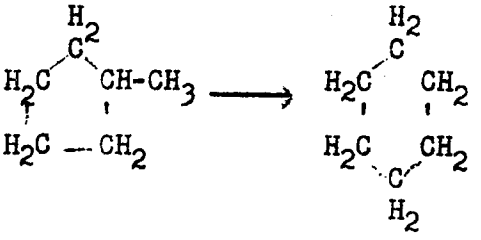
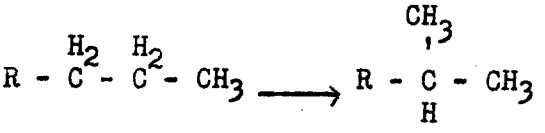
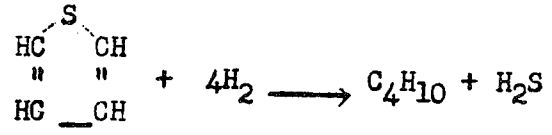
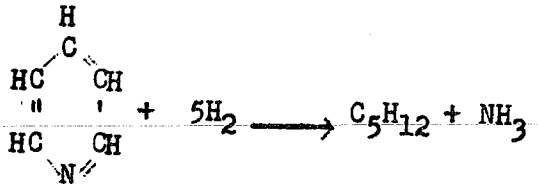
		ΔH @ 700°F. BTU/lb. mol
1.		+ 88,800
2.		
3.		
4.	$R - R' + H_2 \longrightarrow R + R'$	- 22,400
5.	$R = R' + H_2 \longrightarrow R - R'$	- 53,000
6.		- 112,000
7.		- 140,000

TABLE 10

REFORMING UNIT
REACTOR TIME CYCLE

	Operation	Time Hrs.	Min.
1.	Reaction	8	0
2.	Recycle Gas Purge		6
3.	Inert Gas Purge		9
4.	Regeneration	3	20
5.	Inert Gas Purge		9
	Valve Operation		10
		12	0

TABLE 11

REFORMING UNIT
REACTOR DESIGN CONDITIONS

Reaction

1.	Feed rate to each reactor	4617	Bbl/SD
2.	Pressure	400	psig
3.	Liquid hourly space velocity	0.5	
4.	Catalyst bed volume per reactor	2,200	cu. ft.
5.	First bed section inlet temperature	750°	F.
6.	First bed section outlet temperature	905°	F.
7.	First bed section recycle gas rate	3,000	SCF/Bbl
8.	First bed section volume	250	cu. ft.
9.	Quench gas rate to quench section	600	SCF/Bbl
10.	Second bed section inlet temperature	870°	F.
11.	Second bed section outlet temperature	900°	F.
12.	Second bed section volume	1,950	cu. ft.
13.	Pressure drop	0.6	psi
14.	Coke laydown in 8 hours	2.2	wt. % of catalyst
15.	Hydrogen consumption	470	SCF/Bbl
16.	Liquid yield	94	Vol. %
17.	Octane rating of product	83	F-1 + 3cc TEL

Regeneration

1.	Pressure at reactor inlet	400	psig
2.	Inlet temperature	800°	F.
3.	Outlet temperature	1,100°	F.
4.	Regeneration gas rate	4,860	MSCF/hr
5.	Oxygen concentration of feed gas	1.4	mol. %
6.	Pressure drop	2.5	psi

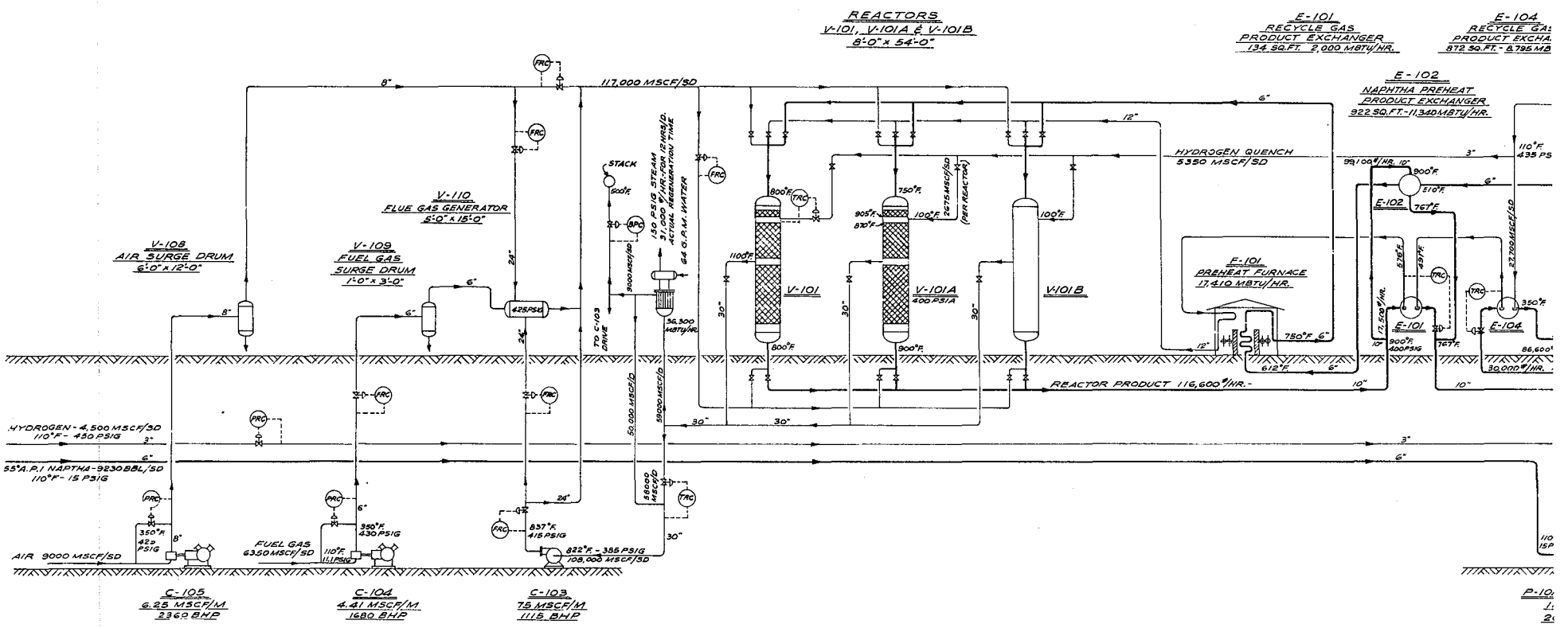
hydrogen to a temperature of 870°F. The temperature rises gradually in the second bed section to a reactor outlet temperature of 900°F. The total hydrogen consumption is 470 SCF/Bbl. of feed and the coke laydown at the end of 8 hours of operation is 2.2 wt. % of the catalyst charge. The liquid yield is 94 vol. % when operating at optimum conditions and the octane rating of the product is 83, F-1 plus 3 cc TEL. A higher octane product may be produced if so desired, however, this is attained at the expense of liquid yield. The pressure drop across the reactor is 0.6 psi.

The regeneration pressure is 400 psig. and the reactors are designed such that the feed gas enters at both ends with the outlet at the center of the reactor to reduce the pressure drop. The pressure drop across the reactor while on regeneration is 2.5 psi. The oxygen concentration of the feed gas for regeneration is 1.4 mol %.

C. Flow Sheet, Material Balance and Operational Requirements

The process flow sheet is presented by Figure 3, the over-all material balance by Table 12, and the utility and operating personnel requirements by Table 13. The flow sheet contains all the major vessels, exchangers, pumps, compressors, instruments and lines.

Referring to the Flow Sheet, the naptha feed is pumped by P-101 through exchanger E-105, exchanger E-102 and fired heater F-101 to heat it to the reactor inlet temperature of 750°F. At the top of the reactors it is mixed with the recycle hydrogen and the mixture passes down through the two reactors operating in parallel at 400 psig. The reactor effluent passes through exchangers E-101 and E-102 operating in parallel, and then through the depropanizer reboiler, E-114, then through exchangers

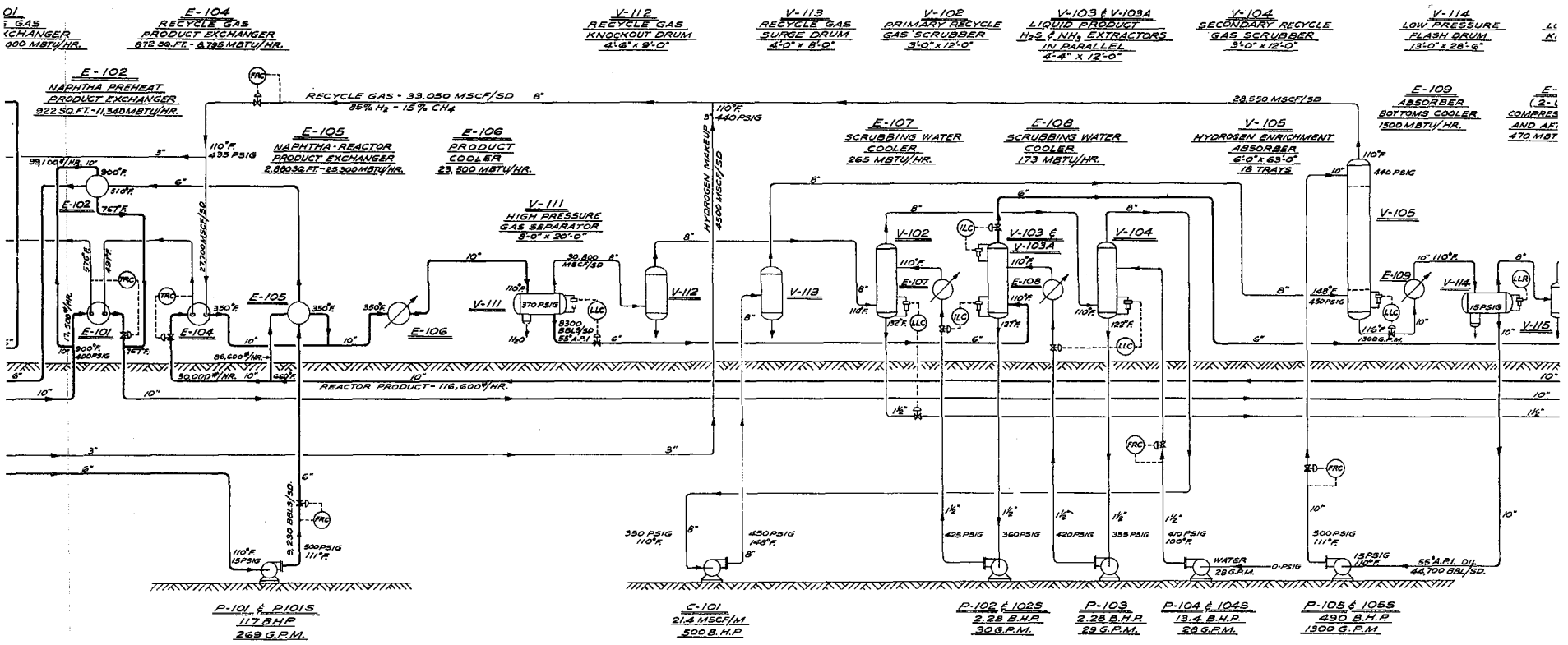


NATIONAL PETROLEUM COUNCIL
SHALE OIL PROCESSING COMMITTEE

FIGURE -3

FLOW DIAGRAM OF CATALYTIC REFORMING UNIT
25,000 BBL/SD SHALE OIL REFINERY

852a

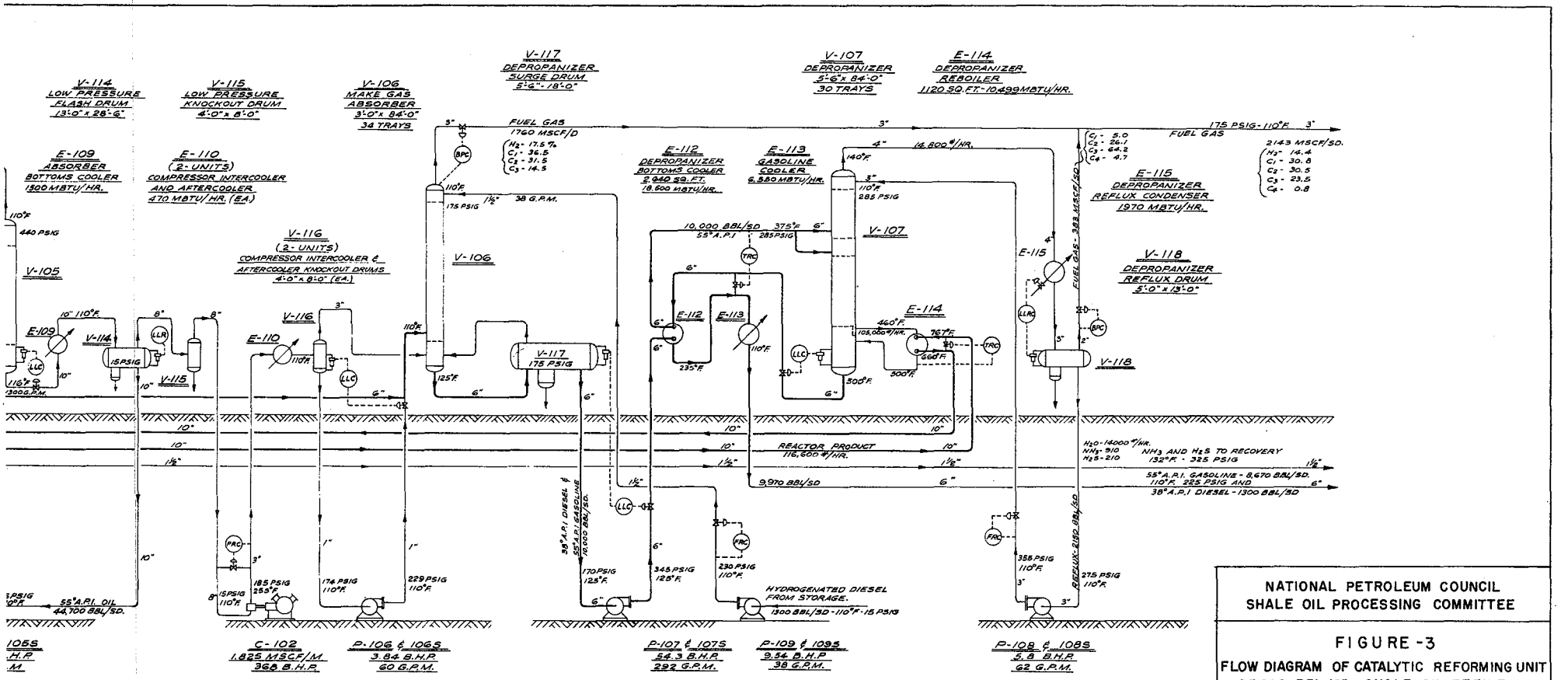


NATIONAL PETROLEUM COUNCIL
SHALE OIL PROCESSING COMMITTEE

FIGURE -3

FLOW DIAGRAM OF CATALYTIC REFORMING UNIT
25,000 BBL/SD SHALE OIL REFINERY

5529



NATIONAL PETROLEUM COUNCIL
SHALE OIL PROCESSING COMMITTEE

FIGURE - 3

FLOW DIAGRAM OF CATALYTIC REFORMING UNIT
25,000 BBL/SD SHALE OIL REFINERY

B52c

TABLE 12

REFORMING UNIT MATERIAL BALANCE[a]

Feed	Bbl/SD	MSCF/SD	°API	MW	Lbs./Hr	Liquid Yield Vol. %	Wt. %
Naphtha	9,230	-	55	-	102,472		99
Hydrogen	-	4,500	-	2	988		1
TOTAL					103,460		100
Products							
Dry Gas	-	2,140	-	25	5,885		5.66
C_4-400°F. Gasoline	8,670	-	55	-	95,700	94	92.53
Coke on Catalyst					755		0.73
NH_3					910		0.88
H_2S					210		0.20
TOTAL					103,460		100.00

a. Not including 1300 Bbl/SD hydrogenated diesel used as absorption oil and leaving unit mixed with product gasoline.

TABLE 13

GASOLINE REFORMING UNIT

UTILITY REQUIREMENTS

Electricity, KW	3,645[a]
Steam, Lbs./hr	0[b]
Water, GPM	40
Fuel, MMBtu/hr. (Net)	28[c]

PERSONNEL REQUIREMENTS (PER DAY)

Plant Operators	15
Plant Foremen	3

a. Included Fin-Fan power and represents average load (compressor C-104 operates for 108 min. per day).

b. Steam produced by waste heat boiler = 15,500 Lbs./hr (average production)

Steam required by unit = 500 Lbs./hr

Net steam production to Refinery = 15,000 Lbs./hr

c. Represents average load (inert gas generator operates for 108 min per day.)

E-104 and E-105 operating in parallel, then through cooler E-106 to the high pressure separator V-111. The liquid oil from V-111 is pressured through the ammonia hydrogen sulfide extractors V-103 and V-103A operating in parallel and employing water as the solvent. From V-103 and V-103A, the oil is pressured to the bottom of the make gas absorber, V-106, employing hydrogenated diesel absorption oil, where the pressure is reduced to 175 psig. and the light components flash off and C_1 - C_3 is produced overhead for fuel gas. The liquid from the make as a sorber collects in depropanizer feed surge drum V-117, which also serves as a secondary flash drum, and the liquid from V-117 is pumped through preheat exchanger E-112 to the depropanizer tower V-107. The depropanizer tower bottoms which are a mixture of gasoline and diesel are pressured through exchanger E-112 and cooler E-113 to final storage. The overhead from the depropanizer goes to fuel gas.

The hydrogen recycle is circulated through the system by blower C-101. The blower discharge passes through surge drum V-113 to the hydrogen enrichment absorber tower V-105, operating at 440 psig. The purpose of this tower is to keep the hydrogen concentration of the recycle gas up to 85%, and it is necessary to absorb a considerable amount of the methane produced by the reactions to accomplish this so a high absorber oil rate is necessary. If the hydrogen enrichment absorber were not used, the equilibrium hydrogen concentration of the recycle gas would drop to about 60% and much of the beneficial effect of pressure on coke laydown would be lost. The recycle gas from the top of the absorber joins the hydrogen make up stream available at

600 psig. from the hydrogen plant hypersorber. Part of this combined stream goes directly to the reactors as intermediate quench, while the bulk of it passes through preheat exchangers E-104 and E-101 and then through fired heater F-101 where it is heated to 750°F. and then mixed with the naphtha at the reactor inlet. The hydrogen remains mixed with the naphtha in the system previously described, until it is separated in vessel V-111. The gas from V-111 is pressured to knockout drum V-112 where entrained oil is separated. From V-112 the gas is pressured to two scrubbers connected in series, V-102 and V-104, where water is employed to scrub out ammonia and hydrogen sulfide. From the top of V-104 the recycle gas stream is picked up by the suction of the recycle gas blower and the cycle is completed.

The absorption oil from the hydrogen-enrichment absorber, V-105, operating at 440 psig., is pressured through cooler E-109 to the low pressure flash drum V-114 where at atmospheric pressure the light absorbed gases are flashed off. The absorption oil is circulated by pump P-105. The gases from V-114 pass through a knockout drum V-115 to compressor C-102. The discharge from the compressor passes through cooler E-110 and knockout drum V-116 to the make gas absorber V-106, where dry gas is produced overhead to fuel gas.

The regeneration system is shown on the flow sheet with reactor V-101 being regenerated. The regeneration is conducted at 400 psig. and, as previously mentioned, the reactors are designed such that the feed gas enters at both ends with the outlet at the center to reduce pressure drop. Otherwise the system is very similar to the hydrogenation unit system.

The flue gas is recirculated by blower C-103. The air compressor C-105 furnishes the oxygen for combustion. The fuel gas for the inert gas generator is compressed by C-104 and retort gas is used. The high rate of fuel gas shown on the flow sheet is for the duration of the inert gas purges which is 108 minutes per day.

The liquid product and recycle gas scrubbers are arranged in the same manner as the hydrogenation unit, with the liquid product extractors between the two gas scrubbers, so that the water stream to the extractors is rich in ammonia which is required for effective hydrogen sulfide extraction.

D. Equipment Specifications

The specifications for vessels, exchangers, pumps, compressors, fired heaters and pipe lines may be found in the complete NPC Processing Committee Report.

The total catalyst charge to the three reactors is 412,000 lbs. of 3/8" pelleted "Cobalt-Molybdate" catalyst.

VII. HYDROGEN PLANT

The coker dry gas which contains about 15% hydrogen is used as feed to the hydrogen plant. This gas must be purified to remove sulfur compounds and ammonia water scrubbing is used for this purpose. The ammonia water is available from the hydrogenation and reforming units. Conventional steam methane reaction over nickel catalyst followed by one stage carbon monoxide conversion over iron oxide catalyst followed by hypersorption for hydrogen purification, are the main steps of the process employed.

Cost data on all these operations are available so that no detail design will be presented here. Table 14 gives the material balance for this unit, and Table 15 gives the estimated utility and personnel requirements.

TABLE 14

HYDROGEN PLANT
MATERIAL BALANCE

Feed	MSCF/SD	M.W.	Lbs/Hr.	Wt.%
Coker Dry Gas	6,500	18.4	13,100	36.7
Theoretical Steam	11,400	18	22,600	63.3
		TOTAL	35,700	100.0
Product				
Hydrogen	22,700	2.0	5,000	14.0
Fuel Gas Stream		21.5	5,800	16.2
CH_4	1,670			
CO	530			
CO_2	250			
CO_2 Stream	5,150	44	24,900	69.8
		TOTAL	35,700	100.0

TABLE 15

HYDROGEN PLANT

UTILITY REQUIREMENTS

Electricity, KW	8,440
Steam, Lbs./hr.	176,000
Water, GPM	44
Fuel, MMBtu/hr.	292

PERSONNEL REQUIREMENTS (PER DAY)

Plant Operators	15
Plant Foremen	3

VIII. AMMONIA RECOVERY UNIT

The feed to this unit is the aqueous solution of ammonia and hydrogen sulfide from the hydrogenation, reforming and coking units. The ammonia is recovered, dried and liquified for sale as a byproduct. The unit consists of several towers for hydrogen sulfide removal, ammonia concentration and ammonia drying. Compressors and Fin-Fan coolers for the liquification of the anhydrous ammonia are also part of this unit.

Units of this type are used for ammonia recovery in the destructive distillation of coal and the design is conventional. Table 16 gives the material balance and Table 17 gives the utility and personnel requirements.

TABLE 16

AMMONIA RECOVERY UNIT
MATERIAL BALANCE

Feed	Bbl/SD	MSCF/SD	Mol.%	MW	#/Hr.	Wt.%
$(NH_4)_2S$	-	-	3.2	-	4,410	11.0
NH_3	-	-	5.0	-	1,743	4.3
H_2O	-	-	91.8	-	34,011	84.7
TOTAL					40,164	100.0
Product						
H_2S Stream		595		32.8		5.4
H_2S			93.3	-	2,076	
NH_2			1.9	-	22	
H_2O			4.8		58	
NH_3 Stream	450					9.8
NH_3			99.7	17.0	3,910	
H_2O			.3		12	
Water Stream						84.8
H_2O			99.75	18.0	33,941	
H_2S			.20		128	
NH_3			.05		17	
		TOTAL			40,164	100.00

TABLE 17

AMMONIA RECOVERY UNIT

UTILITY REQUIREMENTS	
Electricity, KW	650
Steam, Lbs./hr.	54,000
Water, GPM	200
Fuel, MMBtu/hr.	0
PERSONNEL REQUIREMENTS (PER DAY)	
Plant Operators	9
Plant Foremen	0

IX. SULFUR PLANT

The feed to this unit is the hydrogen sulfide stream from the ammonia recovery unit. The unit consists of an ammonia scrubber where dilute sulfuric acid is used to remove traces of ammonia, a hydrogen sulfide burning chamber, two catalytic converters in series with an intermediate sulfur condenser, a sulfur scrubber and a tail gas burner. This is well established standarized process so no detail is necessary.

Table 18 gives the material balance and Table 19 gives the utility and personnel requirements.

TABLE 18

SULFUR PLANT
MATERIAL BALANCE

Feed	Lbs./Hr.	Wt.%
H_2S	2,076	96.3
NH_3	22	1.0
H_2O	58	2.7
Total	2,156	100.0
Products		
Recovered Sulfur	1,775	
Tail Gas Sulfur (as So_2)	185	

TABLE 19

SULFUR PLANT

Utility Requirements	
Electricity, KW	50
Steam, Lbs./hr.	-5,000[1]
Water, GPM	13
Fuel, MMBtu/hr.	0.10
Personnel Requirements (Per Day)	
Plant Operators	3
Plant Foremen	0

1. Net Steam Production

X. UTILITIES AND GENERAL PLANT FACILITIES

A. General Facilities

Tables listing administrative, maintenance, laboratory, utilities production and miscellaneous personnel are given in the complete processing report. The buildings required to house these groups and their utilities consumption have also been estimated. The cost of the following miscellaneous facilities must be estimated on the basis of previous experience: Fire protection system, compressed air system, rolling stock, yard sewers, waste water disposal, roads and railroads.

B. Utilities

The overall utilites requirement for the 25,000 B/SD shale oil refinery is as follows:-

1. Water

The total usage rate is 620 GPM and the total rate of return to the river is 466 GPM, leaving a net consumption rate from river to 154 GPM.

Of the true water consumption rate for the refinery of 154 GPM the one principal consumption is by the water gas reaction for the production of hydrogen which accounts for 63 GPM. The remainder is an estimated value for unavoidable losses such as blowdown steam, steam for cleaning purposes, water vapor in fuel gas produced from hypersorber, water for wetting down areas and general evaporation losses.

2. Steam

The steam consumption rate for the refinery is 235,900 lbs./hr. Steam pressure of 150 psig. is sufficient to meet all process

requirement and higher pressures are not warranted as steam turbines are not used. The make up water rate to the boilers is 108 GPM. Retort gas is used as fuel for the boilers and air preheat and producer gas burners are employed. Under these conditions the heating efficiency is 74% net for the boilers and the retort gas consumption rate is 372 MMBtu/hr.

3. Power

The power demand for the refinery is 22,410 KW. The power plant employs combustion gas turbine drives with retort gas fuel. A conversion factor of 16,100 Btu/KW-hr. was used to determine the fuel equivalent which is 360 MMBtu/hr.

4. Fuel

Retort gas is used as fuel throughout the refinery. The fired heaters employ air preheat and producer gas burners and their net heating efficiency is 69% net, under which conditions the retort gas consumption for refinery fuel is 436 MMBtu/hr. The total fuel demand including steam and power is 1,168 MMBtu/hr., which is about 71% of the total retort gas.

XI. DIESEL AND GASOLINE SPECIFICATIONS

The properties of the diesel fuel and gasoline produced were estimated from bench scale and pilot plant data available on the hydrogenation of shale oil coker distillate and the hydrogenation and catalytic reforming of Santa Maria Valley coker distillate which is similar in characteristics.

The diesel fuel is compared to U. S. Navy specifications in Table 20 and the gasoline is compared to "regular" gasoline from crude oil sources in Table 21.

TABLE 20

DIESEL FUEL SPECIFICATIONS

Test	Shale Oil Hydrogenated Diesel	U.S. Navy Diesel Specification 7-0-2e
Flash point, closed cup, minimum, °F.	160	150
Pour Point, maximum, °F.	0	0
Cloud point, maximum	10	10
Viscosity at 100°F., SSU	37	35-45
Water and Sediment, maximum, %	Nil	Trace
Total sulfur, maximum, %	0.02	1.00
Total nitrogen, maximum, %	0.002	-
Carbon residue, on 10% bottoms, maximum, %	0.05	0.20
Ash, minimum, %	Trace	0.01
Corrosion at 212°F. copper strip	Pass	Pass
90% distillation temperature, Maximum, °F	610	675
Color, maximum		5
Ignition quality, minimum, cetane number	55	50

TABLE 21

GASOLINE SPECIFICATIONS

Test	Shale Oil Refined Gasoline	Typical "Regular" Gasoline
Bromine number	0	35
Nitrogen, wt. %	Nil	.005
Sulfur, wt. %	Nil	.15
ASTM gum, mg/100 ml	0.5	0.8
Copper dish gums, mg/100 ml	2.0	4.0
Accelerated gums, mg/100 ml	3.2	7.0
Knock rating, research method + 3 cc TEL	83	83
End Point	400	400
Induction period, minutes	500+	500+

IV. OVER-ALL COLORADO UTILITIES

OVER-ALL UTILITY REQUIREMENTS OF COLORADO FACILITIES FOR 250,000 BBL./CD SHALE OIL PROCESSING

Tables 1 through 4 summarize the over-all utility requirements of all the shale oil facilities in Colorado. These facilities comprise the mining, retorting and refining equipment for the production and processing of 250,000 Bbl./CD crude shale oil.

The utilities for the mining operations were obtained from the "Report of the Oil Shale Mining Sub-Group of the Raw Materials Sub-Committee of the National Petroleum Council Committee on Synthetic Liquid Fuels Production Costs" issued March 5, 1951.

The utilities for the retorting and refining operations were detailed from the accompanying reports. The cost of boiler plants, power plants, water facilities, and sewage facilities may be estimated from these figures.

TABLE 1

OVER-ALL STEAM REQUIREMENTS
OF COLORADO FACILITIES
FOR 250,000 BBL./CD SHALE OIL PROCESSING

	Steam Consumption[a] Lbs./Hr.
Mining	0
Retorting	80,000
Refining	
Coking	133,000
Hydrogenation	9,000
Reforming	0
Hydrogen Production	1,760,000
Ammonia Recovery	540,000
Miscellaneous Facilities	117,000
Total Consumstion	2,639,000
Reforming Production	150,000
Sulfur Plant Production	50,000
Boiler Plant Capacity	2,439,000

Boiler Plant Retort Gas Requirement
Assuming 74% Net Heating Efficiency = 3,790 MMBtu/Hr.

a. Rates shown are per calendar day.

TABLE 2

OVER-ALL ELECTRICITY REQUIREMENTS
OF COLORADO FACILITIES
FOR 250,000 BBL./CD SHALE OIL PROCESSING

	Electricity[c] KW
Mining[a]	50,000
Retorting	93,500
Refining	
Coking	21,000
Hydrogenation	20,260
Reforming	36,450
Hydrogen Production	84,400
Ammonia Recovery	6,500
Sulfur Plant	500
Miscellaneous Facilities	55,000
Total Process Requirements	367,610
Line and Transformer Losses (5%)	19,300
Plant Output	386,910
Power Plant Auxiliary Requirements (10%)	38,690
Normal Process Power Generation	425,600
Excess Capacity for Peak Loads and First Pipe line Pumping Station[b]	69,650
Total Power Plant Capacity	495,250
Power Plant Retort Gas Requirement Assuming 16,100 Btu/KW/hr. = 7,967 MMBtu/Hr.	

a. Rate shown is average for 24 hours. Mines operate 16 hours per day.
b. Retort gas balance given in Table 3. Seasonal heating requirements of retort gas pipe lines not included so excess power will be lower than 69,650 KW during winter months.
c. Rates shown are per calendar day.

TABLE 3

OVER-ALL RETORT GAS REQUIREMENTS OF COLORADO FACILITIES FOR 250,000 BBL./CD SHALE OIL PROCESSING

	Retort Gas[a] MMBtu/Hr. Net
Mining	0
Retorting	2
Refining	
Coking	1,000
Hydrogenation	150
Reforming	280
Hydrogen Production	2,920
Ammonia Recovery	0
Sulfur Plant	1
Miscellaneous Facilities	10
Boiler Plant	3,870
Power Plant	7,967
Total Consumption	16,200
Total Retort Gas Production	16,200

a. Rates shown are per calendar day.

TABLE 4

OVER-ALL WATER USAGE AND DRAINAGE RATES
OF COLORADO FACILITIES
FOR 250,000 BBL./CD SHALE OIL PROCESSING

	Water Usage[b] GPM	Water Drainage[b] GPM
Mining[a]	720	300
Retorting	80	40
Refining		
Coking	250	200
Hydrogenation	400	350
Reforming	400	350
Hydrogen Production	440	350
Ammonia Recovery	2,000	1,900
Sulfur Plant	130	100
Miscellaneous Facilities	1,500	1,300
Boiler Plant		
Reacted in H_2 Plant	630	0
Blowdown	110	110
Mon-Recoverable Losses	340	0
Total	7,000	5, 000
Net Consumption or Net Take from River (7000 - 5000)	2,000 GPM	

a. Rate shown is average for 24 hours. Mines operate 16 hours per day.
b. Rates shown are per calendar day.

V. PIPE LINE TERMINAL FACILITIES

TABLE OF CONTENTS

		Page No.
I.	Summary	E78
II.	Over-all Plan	E80
	A. Location	E80
	B. Process Plan	E80
	C. Storage Facilities	E82
III.	Catalytic Cracking Units	E84
IV.	Catalytic Polymerization Units	E88
V.	Distillation Units	E91
VI.	Final Products and Their Specifications	E94
	A. Over-all Material Balance	E94
	B. Gasoline	E94
	C. Diesel	E94
	D. Gasoline Blending Facilities	E98
VII.	Utilities and General Plant Facilities	E99
	A. General Facilities	E99
	B. Utilities	E99

SHALE OIL REFINERY FACILITIES AT PIPE LINE TERMINAL 250,000 BBL/CD SHALE OIL REFINING

1. SUMMARY

Previous sections of this report have presented facilities at or near the mining area, which consist of the retorting plants and part of the refining facilities. This section presents the facilities in the market area which has been taken as the West Coast, with the pipe line terminal in Los Angeles.

The basis for the West Coast facilities is 250,000 Bbl./CD of crude shale oil from the retorts, so that the materials received via pipe line from the refineries in Colorado consist of 118,200 Bbl./CD of hydrogenated diesel and 86,700 Bbl./CD of reformed gasoline.

The West Coast facilities consist of expansions to three existing refineries with each expansion consisting of a 33,800 Bbl./CD catalytic cracking unit, a 5,970 Bbl./CD catalytic polymerization unit, a 33,230 Bbl./CD distillation unit, and the required tankage and miscellaneous facilities. Hydrogenated diesel is fed to the catalytic cracking units and the catalytic cracking and catalytic polymerization units have been sized such that the ratio of the total gasoline production to the middle distillate production is 1.95, which is the national average forecast for 1951[1].

1. E. T. Knight, Oil and Gas Journal, January 25, 1951.

The salable products for the West Coast area are tabulated below:

Gasoline	
Premium	63,450 Bbl./CD
Regular	63,450 Bbl./CD
Total	126,900 Bbl./CD
Diesel	65,100,Bbl./CD *
Liquid Petroleum Gases	8,925 Bbl./CD
Fuel Oil	3,000 Bbl./CD

The gasoline and diesel produced by this scheme of processing are superior in their properties to the present West Coast products from crude oil sources and the over-all refining scheme offers flexibility to meet changing market demands.

* Includes 2740 Bbl./CD which is actually consumed as pipeline fuel. Net availability for West Coast sale = 62,360 Bbl./CD

II. OVER-ALL PLAN

The over-all plan for the shale oil facilities at the pipe line terminal is presented by Figure 1 for one of three required refinery expansions.

A. Location

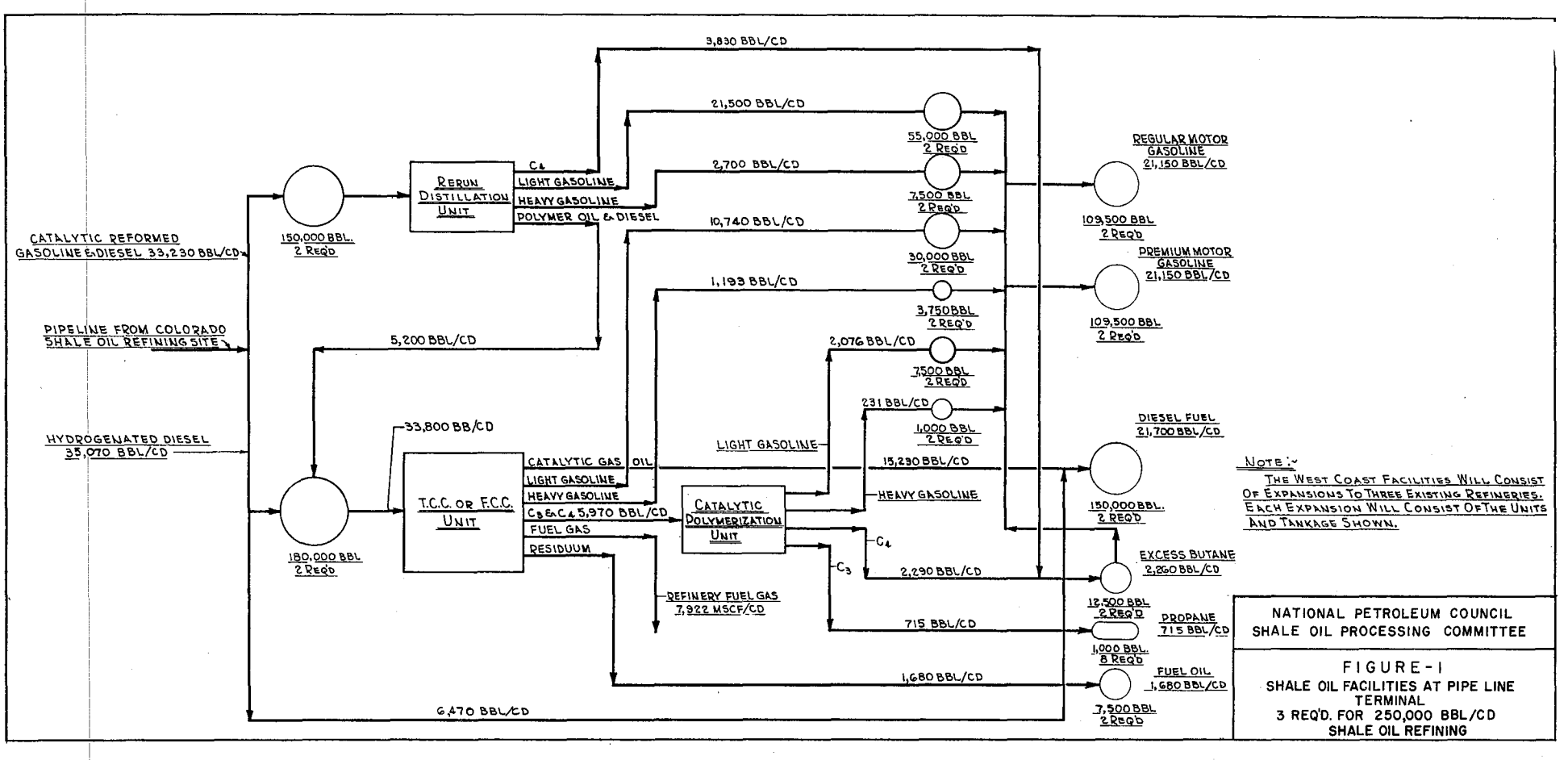
The area chosen for the marketing of the finished shale oil products is the West Coast with the pipe line terminal for the partially refined oils from Colorado at Los Angeles. The distance between the Colorado refinery site and Los Angeles is approximately 850 miles.

B. Process Plan

Three refineries in Los Angeles will receive 86,700 Bbl./CD of raw catalytic reformed gasoline and 118,200 Bbl./CD of hydrogenated diesel from the refining facilities in Colorado. These two stocks will be received in slugs through the pipe line and since the gasoline must be rerun to remove diesel and polymer oil, both ends of each diesel slug will be cut into the raw gasoline storage to allow for some mixing in transit.

The raw catalytic reformed gasoline is fed to distillation units and fractionated to produce a light gasoline cut, a heavy gasoline cut, a butane cut and a diesel and polymer oil cut. The butanes are sent to storage to be used for gasoline blending and as LPG production. The light and heavy gasoline cuts are sent to storage for blending and the diesel and polymer oil cut is sent to storage for cracking stock feed.

Part of the hydrogenated diesel from the pipe line and all the diesel and polymer cut from the distillation unit is fed to the catalytic cracking units. The remainder of the hydrogenated diesel goes directly to diesel production and may be sold as a premium diesel or blended. The



NOTE :-
THE WEST COAST FACILITIES WILL CONSIST OF EXPANSIONS TO THREE EXISTING REFINERIES. EACH EXPANSION WILL CONSIST OF THE UNITS AND TANKAGE SHOWN.

NATIONAL PETROLEUM COUNCIL
SHALE OIL PROCESSING COMMITTEE

FIGURE-1
SHALE OIL FACILITIES AT PIPE LINE TERMINAL
3 REQ'D. FOR 250,000 BBL/CD
SHALE OIL REFINING

881

gasoline produced by catalytic cracking is fractionated to produce light and heavy cuts and these are sent to storage for blending. The catalytic diesel and fuel oil produced are sent to storage as final products. The butane-butylene propane-propylene cut is sent to catalytic polymerization units.

In the catalytic polymerization units the olefins are polymerized to produce more gasoline. This gasoline is fractionated to produce light and heavy fractions which are sent to storage for blending. The saturated butanes and propanes from this unit are fractionated and the butane is sent to storage to be used for gasoline blending and as LPG production, while the propane is sent to storage as LPG production.

The gasoline cuts are blended, leaded and dyed to produce premium and regular grades and sent to storage as finished products.

C. Storage Facilities

The storage facilities for one of the three refinery expansions are shown on the over-all plan flow sheet, Figure 1, and the capacities and residence times for all three expansions are summarized in Table 1.

TABLE 1

OVER-ALL STORAGE FACILITIES

		Capacity Barrels	Residence Time, Days
1.	Reformed Gasoline from Pipe Line	900,000	9.2
2.	Hydrogenated Diesel from Pipe Line	1,080,000	10.6
3.	Light Reformed Gasoline	330,000	5.1
4.	Heavy Reformed Gasoline	45,000	5.6
5.	Light Cracked Gasoline	180,000	5.6
6.	Heavy Cracked Gasoline	22,500	6.28
7.	Light Cat. Poly Gasoline	45,000	7.23
8.	Heavy Cat. Poly Gasoline	6,000	8.65
9.	Blended Regular Gasoline	659,000	10.3
10.	Blended Premium Gasoline	659,000	10.3
11.	Finished Diesel Oil	900,000	13.8
12.	Fuel Oil	45,000	8.9
13.	Butane	75,000	11.1
14.	Propane	24,000	11.2

III. CATALYTIC CRACKING UNITS

The "Fluid Catalytic Cracking Process, Standard Oil Company of New Jersey, Type IV", or the "Thermofor Catalytic Cracking Process" equivalent is employed to obtain the required additional gasoline from diesel to meet the national gasoline to middle distillate ratio of 1.95.

The feed to the three catalytic cracking units is made up of two materials; 85,800 Bbl./CD hydrogenated diesel from the Colorado refining site and 15,600 Bbl./CD diesel and polymer oil obtained from rerunning the reformed gasoline. This represents 85% of the total diesel available for feed. With this quantity of feed a conversion level of 48.5 volume per cent is required to yield the desired over-all gasoline to middle distillate ratio and is obtained by employing the process conditions given in Table 2.

The products from the three catalytic cracking units include 35,800 Bbl./CD gasoline stocks utilized for both regular and premium motor gasolines, 45,700 Bbl./CD diesel fuel and 17,920 Bbl./CD propane-propylene butane-butylene utilized as feed to the catalytic polymerization units. In addition 5,040 Bbl./CD of fuel oil and 23,766 MSCF/CD of dry gas are produced and consumed as a portion of the total processing fuel requirements. The feed to the catalytic polymerization unit and the fuel gas production are based on 80% recovery of propanes with the remaining 20% going to fuel gas. A complete material balance is shown in Table 3 for all three cracking units.

The catalytic cracking units are operated to produce two debutanized gasoline stocks and the distillation sections each consist of a combination bubble tower, an oil absorber, and a debutanizer.

Utility and personnel requirements for these units are shown in Table 4.

TABLE 2

CATALYTIC CRACKING OPERATING CONDITIONS

Temperature, Average Bed °F.	900
Catalyst-Oil Ratio, wt./wt.	4.0
Recycle Oil Rate, vol./vol.	0
Space Rate, wt./wt. (Total Reactor Feed)	1.1
Conversion, vol. %	48.5

TABLE 3

THREE CATALYTIC CRACKING UNITS
OVER-ALL MATERIAL BALANCE

Feed	Bbl./CD	°API	Lbs/Bbl	Lbs./Hr.	Vol. %	Wt. %
Middle Distillates and Polymer Oil	101,400	38	292	1,234,000	100	100
Products[a]						
Gasoline RVP = 6.7	35,800	62	254	378,810	35.3	30.70
Middle Distillates	45,700	35	297	562,720	44.9	45.60
Butanes	6,250		204	53,100		4.30
Butylenes	6,060		210	53,100		4.30
Propane	2,160		178	16,040		1.30
Propylene	4,850		183	37,000		3.00
Hydrogen				2,590		.21
Methane				12,200		.99
Ethane				2,590		.21
Ethylene				6,050		.49
Coke				37,000		3.00
Fuel Oil	5,040	11	347	72,800	5.0	5.90
TOTAL				1,234,000		100.00

a. Dry gas stream contains all the ethanes and lighter plus 20 mol. % of the propanes and has a net heating value of 790 Btu./SCF.

TABLE 4

THREE CATALYTIC CRACKING UNITS

OVER-ALL UTILITY REQUIREMENTS (PER CALENDAR DAY)

Electricity, KW	1,410
Steam, Lbs./Hr.	320,000
Water Consumption, GPM	1,500
Fuel, MMBtu/Hr.	363

OVER-ALL PERSONNEL REQUIREMENTS (PER DAY)

Plant Operators	90
Plant Foremen[a]	15

a. Assume charge of Catalytic Polymerization Units also.

IV. CATALYTIC POLYMERIZATION UNITS

The Universal Oil Products Company "Phosphoric Acid Catalytic Polymerization Process" is employed. The feed to these three units is the 17,920 Bbl./CD butane-butylene propane-propylene stream from the catalytic cracking units which assumes 80% recovery of the propanes. Three units are employed such that each operates in conjunction with a catalytic cracking unit.

These units are operated to produce light and heavy debutanized gasoline cuts, butane and propane so that three towers are required in the distillation section. The total debutanized polymer gasoline production is 6,920 Bbl./CD. The butane production is 6,860 Bbl./CD and the propane production is 2,145 Bbl./CD. A conversion of 90% olefins was assumed.

The material balance for all three units is given in Table 5. The utilities and operating personnel for all three units are given in Table 6.

TABLE 5

THREE CATALYTIC POLYMERIZATION UNITS
OVER-ALL MATERIAL BALANCE

Feed	Bbl/CD	°API	Lbs/Bbl	Lbs/Hr	Vol. %	Wt. %
Butane-Butylene and Propane-Propylene from Catalytic Cracking	17,920[a]		199	148,700	100	100
Products						
Polymer Gasoline (RVP = 2.0)	6,920	60.1	258	74,400	38.6	50.0
Butane	6,860		204	58,400	38.3	39.3
Propane	2,145		178	15,900	12.0	10.7
	TOTAL			148,700		100.0

a. Assumes 80% recovery of propanes in distillation section of catalytic cracking unit.

TABLE 6

THREE CATALYTIC POLYMERIZATION UNITS

OVER-ALL UTILITY REQUIREMENTS (PER CALENDAR DAY)

Electricity, KW	254
Steam, Lbs./hr.	135,000
Water Consumption, GPM	195
Fuel, MMBtu/hr.	14.5

OVER-ALL PERSONNEL REQUIREMENTS (PER DAY)

Plant Operators	27

V. DISTILLATION UNITS

The catalytic reformed gasoline mixed with some of the diesel transported via pipe line from Colorado is processed at these facilities to produce both light and heavy gasoline blending stocks, a diesel and polymer oil stock and butanes. The three units process a total of 99,700 Bbl./CD of feed. Each unit consists of a debutanizer and a bubble tower.

The products from these three units are 64,500 Bbl./CD of light gasoline, 8,100 Bbl./CD of heavy gasoline, 15,600 Bbl./CD of diesel and polymerized oil and 11,500 Bbl./CD of butane. Table 7 presents the material blanace for all three units.

Utility and personnel requirements for all three units are given in Table 8.

TABLE 7

THREE DISTILLATION UNITS
OVER-ALL MATERIAL BALANCE

Feed	Bbl/CD	°API	Lbs/Bbl	Lbs/Hr	Vol. %	Wt. %
Reformed Gasoline	86,700	55	265	957,000	87.0	85.7
Hydrogenated Diesel	13,000	38	292	158,000	13.0	14.3
Totals	99,700			1,115,000	100.0	100.0
Products						
Light Gasoline	64,500	52	270	725,200	64.8	65.2
Heavy Gasoline	8,100	34	299	101,000	8.1	9.1
Butane	11,500		204	97,800	11.5	8.8
Polymer Oil	2,600	32	303	33,000	2.6	3.7
Diesel	13,000	38	292	158,000	13.0	14.2
Totals	99.700			1.115,000	100.0	100.0

TABLE 8

THREE DISTILLATION UNITS

OVER-ALL UTILITY REQUIREMENTS (PER CALENDAR DAY)

Electricity, KW	126
Steam, Lbs./hr.	58,400
Water, GPM	356
Fuel, MMBtu/hr.	161

OVER-ALL PERSONNEL REQUIREMENTS (PER DAY)

Plant Operators	18

VI. FINAL PRODUCTS AND THEIR SPECIFICATIONS

A. Over-all Material Balance

The products from the over-all refining of 250,000 Bbl./CD of crude shale oil are presented in Table 9. Yields of 50.8 volume per cent 10 RVP gasoline and 26.0 volume per cent middle distillates are realized on the crude shale oil charge.

B. Gasoline

Two grades of finished motor gasoline are produced and the inspection of both regular and premium grades are shown in Table 10. The knock ratings of both premium and regular gasoline are somewhat higher than the typical West Coast averages at the present time. The sulfur content and the nitrogen content of the finished gasolines are much lower than West Coast averages as a result of the catalytic reforming and hydrodesulfurization processing at the Colorado refining site. An appreciable reduction in gum forming tendencies as compared with the West Coast average is also shown. The quantities of the blended gasolines are as follows:

"Regular" Motor Gasoline	63,450 Bbl./CD
"Premium" Motor Gasoline	63,450 Bbl./CD
Total Motor Gasoline	126,900 Bbl./CD

C. Diesel

The diesel fuel specifications are given in Table 11. In comparison with the typical West Coast average diesel, the shale oil diesel produced with these facilities has a lower pour point, a much lower sulfur content and a higher cetane number. The shale oil diesel can always be used as regular diesel fuel and in most cases as premium diesel fuel. The quantity produced is 65,100 Bbl./CD* as shown in Table 9.

* Less 2740 Bbl./CD consumed as pipe-line fuel

TABLE 9

PRODUCTS FROM OVER-ALL REFINING
OF 250,000 BBL/CD OF CRUDE SHALE OIL

	Bbl/CD
Gasoline (10 RVP)	
Catalytic Reformed	81,000
Catalytic Cracked	37,600
Catalytic Polymerized	8,300
Total Production	126,900
Middle Distillates	65,100 *
Fuel Oil (Net Production)	3,000
Liquid Petroleum Gases	
Butanes	6,780
Propanes	2,145
Total LPG	8,925
Fuel Gas, MSCF/CD	125,300[a]
Anhydrous Liquid Ammonia, Tons/CD	460
Coke, Tons/CD	5,900
Sulfur, Tons/CD	215

a. Fuel gas produced and sold at Colorado refining site. All fuel gas and part of fuel oil produced at California refining site consumed in processing.

* Less 2740 Bbl./CD consumed as pipe-line fuel

TABLE 10

GASOLINE SPECIFICATIONS

Test	Shale Oil		Typical West Coast	
	Regular	Premium	Regular	Premium
Knock Rating, F-1 + 3 cc TEL	85	96	83.5	91
Knock Rating, F-2 + 3 cc TEL	80	85	76.5	82
Engler, End Point °F.	400	380	400	390
Engler, 90% Point °F.	350	340	350	340
Nitrogen, Wt. %	.001	.003	.008	.003
Sulfur, Wt. %	.01	.05	.15	.20
Induction Period, minutes	500+	500+	500+	500+
ASTM Gums, mg/100 ml	1.0	1.0	2.0	1.6
Copper Dish Gums, mg/100 ml	3.0	8.0	8.0	10.0
Accelerated Gums, mg/100 ml	4.0	4.0	5.5	5.0

TABLE 11

DIESEL FUEL SPECIFICATIONS

Test	Shale Oil Diesel	Typical West Coast Diesel Specs.
Gravity, °API at 60°F.	35	32
Flash Point, PMCC, °F.	160	180
Pour Point, °F.	0	10
Viscosity, SSU at 100°F., sec.	36	38
Carbon Residue on 10% Botts, wt. %	.03	.08
Ash, wt. %	Trace	Trace
Sulfur, wt. %	.08	.40
Nitrogen, wt. %	.01	.05
Cetane No., CFR	47	43
Engler Distillation,		
10%, °F.	460	460
50%, °F.	540	540
90%, °F.	610	615
Max.	640	675

D. Gasoline Blending Facilities

Conventional blending components include a pump house, dye plant and leading facilities. Six gasoline stocks are available for blending including light and heavy cracked gasoline, light and heavy catalytic polymerized gasoline, and light and heavy reformed gasoline. Utility and personnel requirements for the gasoline blending facilities are included in overall tabulations appended to the complete processing report.

VII. UTILITIES AND GENERAL PLANT FACILITIES

A. General Facilities

Tables listing administrative, maintenance, laboratory, utility production and miscellaneous personnel for the three refinery expansions are given in the complete processing report. The utilities consumption associated with these groups have also been estimated. Facilities employed in fire protection, the compressed air system, sewage and water disposal, rolling stocks, roads and railroads must be estimated from previous experience.

B. Utilities

The over-all utility requirements and their fuel gas equivalents for these refinery expansions are as follows:-

1. Steam

The steam consumption rate for the three refinery expansions is 540,300 Lbs./hr. Steam pressure is 400 psig. since steam turbines are used as primary drives. The make-up water rate to the boilers is 119 GPM. Industrial fuel gas in combination with fuel oil is used as fuel for the boilers. The fuel consumption rate of the boiler plants is 756 MMBtu/hr.

2. Water

The process water consumption rate is 2,360 GPM. Since there is an abundance of water in the pipe line terminal area, steam turbines rather than electric motors are used primarily as drives, and fresh water is used for cooling with circulating systems and cooling towers.

VII. UTILITIES AND GENERAL PLANT FACILITIES (CONT'D)

3. Power

The power demand for all three refinery expansions is 4,790 KW. This power will be purchased from local power plants.

4. Fuel

Industrial fuel gas is used in combination with fuel oil as fuel throughout and the total demand for all three refinery expansions is 1,296 MMBtu/hr. The cracking units produce 2,057 MMBtu/hr. of fuel gas and fuel oil, and therefore, the net fuel oil production is 761 MMBtu/Hr or 3,000 Bbl/CD.

NATIONAL PETROLEUM COUNCIL
COMMITTEE ON SYNTHETIC FUELS
PRODUCTION COSTS

REPORT
OF
ENGINEERING SUBCOMMITTEE
ON
COAL HYDROGENATION

L. C. Kemp, Jr., Chairman

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TABLE OF CONTENTS

		Page
I.	SUMMARY	1
II.	BASE CASE	4
	Description of	4
	Design Data	7
	Summary	10
	Utility Consumption	12
	Method of Estimating	15
	Coal Preparation Unit	17
	Paste Preparation Unit	20
	Liquid Phase Hydrogenation Unit	22
	Delayed Coking Unit	29
	Vapor Phase Hydrogenation Unit	34
	Product Distillation Unit	38
	Tar Acid Recovery Unit	48
	Low Temperature Off-Gas Separation	52
	Hydrocarbon Steam Cracking and Girbotol Unit	54
	Coal Gasification Unit	58
	Oxygen Plant	62
	Hydrogen Purification and Compression Unit	64
	Tankage, Field Lines and Shipping	69
	Steam and Power Plant	72
	Plant Utilities	84
	General Plant Facilities	87
	Water Supply	88
	Temporary Construction Housing	90
	Permanent Housing	93
	Metal Requirements	96
	Chemical Consumption	98
III.	INDUSTRY CASES	99
	Description	99
	Summary	104
	Locations	
	Sweetwater County, Wyoming	105
	Dunn County, North Dakota	106
	Rosebud County, Montana	107
	Knox County, Indiana	108
	Muhlenberg County, Kentucky	109
	Union County, Kentucky	110
	Franklin County, Illinois	111
	Wetzel County, West Virginia	112

INDUSTRY CASES

ENGINEERING SUBCOMMITTEE REPORT ON COAL HYDROGENATION

SUMMARY

The Engineering Subcommittee of the National Petroleum Council Committee on Synthetic Liquid Fuels Production Costs has developed the investment costs and related data for the Coal Hydrogenation plant as designed by the Bureau of Mines and presented in their report Rl 4564 entitled "Estimated Plant and Operating Costs for Producing Gasoline by Coal Hydrogenation."

Inasmuch as the Bureau selected Rock Springs, Wyoming as a specific location for its detailed investigation and development of investment cost, the Committee also adopted this site as the base case to be investigated in detail. However, the base case of the Committee differs somewhat from that of the Bureau's in the subject report in that the Committee has incorporated some (but not all) of the changes suggested by the Bureau as improvements over the commercially proven German practices of coal hydrogenation. Further, the Process Subcommittee has suggested certain modifications to the equipment proposed by the Bureau which from an investment cost standpoint were of minor effect.

In addition, estimates were made for plants located at seven other sites which were selected by the Raw Materials Subcommittee as adequately representing probable conditions existing for a synthetic fuel industry of significant proportions. Estimates for these sites were made by projection of the data developed for the Rock Springs base estimate The Rock Springs base estimate was also recalculated in a similar manner to obtain an estimate for an "Industry" case in which tar acids were not recovered and corrections were made for minor process discrepancies occurring in the Bureau's calculations of the base case. For purposes of identification, this case is referred to as the Sweetwater, Wyoming location.

Since the Committee found that the Bureau was somewhat inconsistent in the capacity of various sections of the plant, adjustments have been made in the Committee's estimate to a consistent basis of 30,000 barrels per stream day capacity which is equivalent to 27,000 barrels per calendar day at 90% operating time.

The Subcommittee estimate of the Rock Springs, Wyoming location are compared with those prepared by the Bureau and attempt has been made to reconcile the major differences between estimates. The Subcommittee is of the opinion that most of the

30,000 B/SD COAL HYDROGENATION PLANTS
SUMMARY

	Base Case Rock Springs, Wyoming	Sweetwater County, Wyoming	Dunn County, N. Dakota	Rosebud County, Montana	Knox County, Indiana	Muhlenberg County, Kentucky	Union County, Kentucky	Franklin County, Illinois	Wetzel County, W. Virginia
Liquid Production -									
Barrels/Operating Day	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
Barrels/Calendar Day	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000
Coal Requirements -									
Tons/Calendar Day	12,960	12,150	24,500	16,600	13,500	13,350	13,100	12,300	11,800
Tons/Year	4,730,000	4,430,000	8,950,000	6,060,000	4,930,000	4,870,000	4,780,000	4,500,000	4,300,000
Investment - Dollars									
Plant Cost	403,300,000	395,400,000	415,000,000	406,900,000	390,400,000	385,200,000	397,400,000	404,400,000	419,500,000
Per Barrel of Daily Production	14,900	14,600	15,400	15,100	14,400	14,300	14,800	15,000	15,500
Housing and Community Costs	79,800,000	79,800,000	79,800,000	79,800,000	15,100,000	15,100,000	15,100,000	15,100,000	15,100,000
Per Barrel of Daily Production	2,960	2,960	2,960	2,960	560	560	560	560	560
Metal Requirements - Short Tons									
Plant	211,600	205,300	212,600	210,900	200,200	199,500	197,600	204,300	208,800
Housing and Community	5,980	6,000	6,000	6,000	1,200	1,200	1,200	1,200	1,200
Total	217,580	211,300	218,600	216,900	201,400	200,700	198,800	205,500	210,000
Tons/Barrel of Daily Production	8.1	7.8	8.1	8.0	7.5	7.4	7.4	7.6	7.8
Construction Labor (Manhours)									
Plant	37,880,000	37,100,000	38,600,000	39,900,000	35,000,000	34,800,000	34,600,000	35,900,000	36,000,000
Housing and Community	14,900,000	14,900,000	14,900,000	14,900,000	2,800,000	2,800,000	2,800,000	2,800,000	2,800,000
Total	52,780,000	52,000,000	53,500,000	54,800,000	37,800,000	37,600,000	37,400,000	38,700,000	38,800,000

discrepancies have been explained. A considerable portion of the differences is due to the increase in construction costs since preparation of the Bureau's estimates during 1947 and 1948. The estimates of this subcommittee were based on prices prevailing during the first part of 1951.

Estimates of the Rock Springs base case compares with the estimate of the Bureau as follows:

	NPC	Bureau
Investment Cost of Plant	$403,300,000	$288,419,000
Housing & Community Facilities	$ 79,300,000	-
Construction Labor-Man-hours		
Plant	37,880,000	25,200,000
Total (including community)	52,780,000	
Steel Requirements (including equipment)-Short Tons		
Plant	211,600	202,800
Total (including community)	217,580	
Coal Requirements Tons/SD	14,400	13,440
Tons/Yr.	4,730,000	-

Summary of the data developed for the "industry" location is presented in the opposite table. The data appearing in this table do not include any information pertaining to the mines nor have steel requirements for maintenance during operation of the plant been included. Community facilities have been estimated using the number of employees developed by the Bureau of Mines (4109). Adjustment by direct proportion should be made if a different estimate is developed by other Subcommittees.

ENGINEERING SUBCOMMITTEE REPORT ON 30,000 B/SD COAL HYDROGENATION PLANT ROCK SPRINGS, WYOMING

This section of the report contains the estimates of the Engineering Subcommittee on investment costs and construction requirements for a 30,000 barrels per stream day (27,000 barrels per calendar day) Coal Hydrogenation Plant at Rock Springs, Wyoming. Comparisons are made with the estimates of the Bureau of Mines as presented in their report R. I. 4564 entitled "Estimated Plant and Operating Costs for Producing Gasoline by Coal Hydrogenation."

This site was selected by the Bureau for its detailed investigation and development of the basic investment costs. From these detailed estimates projections were made to obtain costs at other locations as well as costs for the so-called modernized plant designs incorporating some features which have not been commercially demonstrated.

Accordingly, the Committee also selected Rock Springs, Wyoming as its base plant, however, it differs somewhat from the base or "conventional" plant of the Bureau in that certain modifications proposed by the Bureau for the speculative case were accepted by the Committee as sufficiently demonstrated to include in the base case. Specifically the base case of the Committee contains the following features of the modernized design case of the Bureau:

1. Substitution of delayed coking for flash distillation of part of the heavy liquid from the liquid phase hydrogenation unit for disposal of unconverted solids.

2. An allowance for higher capacity due to increased instrumentation of the hydrogenation section compared to conventional German practice.

3. Use of wound or wrapped vessels instead of the more expensive forged construction in the hydrogenation section.

The investigation has been based on various reports of the Process Subcommittee in which a review of the process design proposed by the Bureau of Mines was made.

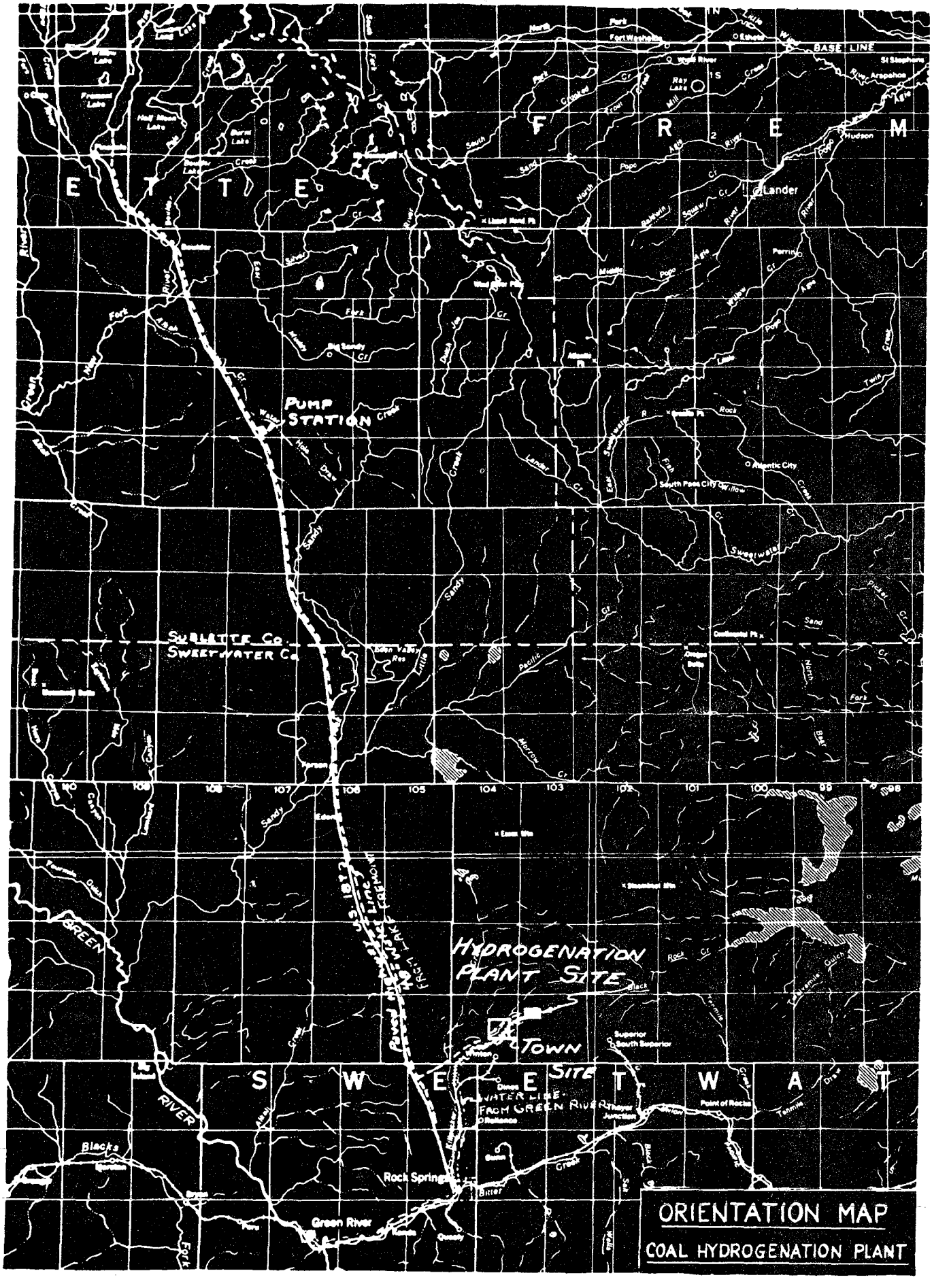
In general every effort has been made to follow the basis of the Bureau's estimate with respect to layout, construction standards or other features affecting costs when details were available to the Subcommittee to clearly indicate the basis proposed. Where the Process Subcommittee's modifications to the Bureau's design of the process equipment were of major

proportions or where data was not available, preliminary engineering sketches and layouts were made by the Engineering Subcommittee as necessary to facilitate its investigation. Sketches illustrating most of these modifications have been included in this report. Flow diagrams and equipment lists have also been included when the changes to the designs proposed by the Bureau were of significant proportions.

Summarized tables of the data developed for the Rock Springs, Wyoming location are presented in the following pages. Also included are comparisons of the estimate of cost of the various sections with those prepared by the Bureau for comparable facilities. It is believed that most of the differences between the Committee and the Bureau have been explained in the accompanying text and, except for a few facilities, the Committee and the Bureau are in reasonably close agreement considering the increase in prices since the preparation of the Bureau's estimate in 1947 and 1948.

In summary, estimates of this Subcommittee compare with the Bureau as follows:

	NPC	Bureau
Investment Cost of Plant Proper	$403,300,000	$288,419,000
Housing & Community Facilities	79,800,000	-
Construction Labor-Man-hours (including Community)	52,780,000	25,200,000
"Steel" requirement - including equipment - Tons	217,580	202,800
Coal Requirement - Tons/Yr.	4,730,000	-


BASE LINE
F R E M
E T T E
Lander
PUMP STATION
SWEETWATER Co.
SWEETWATER Co
HYDROGENATION PLANT SITE
TOWN SITE
WATER LINE FROM GREEN RIVER
Rock Springs
Green River
Point of Rocks
Superior
South Superior
Atlantic City
South Pass City
Willow Creek
Sweetwater
Pacific
Morrow
Sand
Rock
Black
Bitter
Blacks
GREEN RIVER
ORIENTATION MAP
COAL HYDROGENATION PLANT

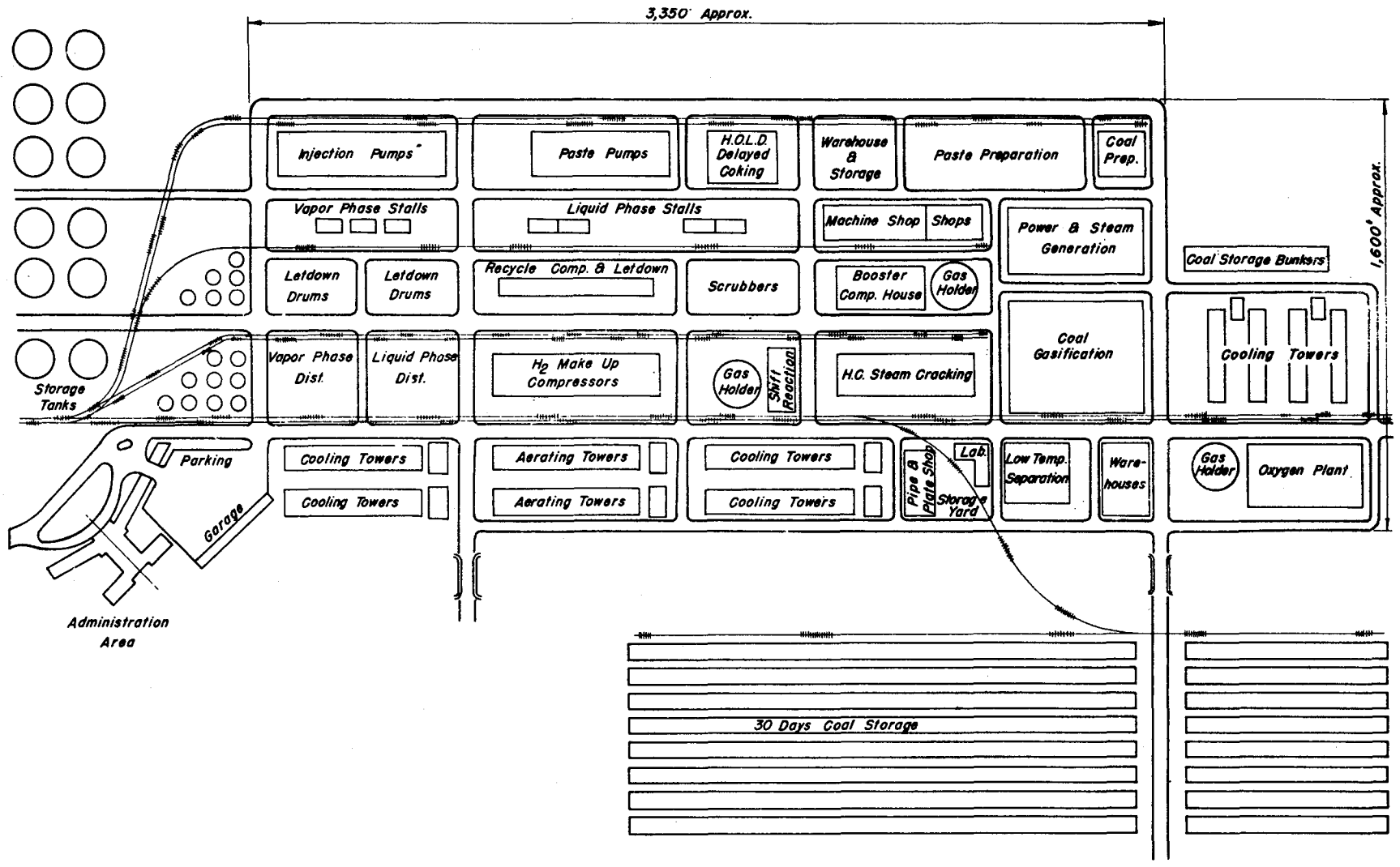
DESIGN DATA

The Hydrogenation Plant site as located by the Bureau of Mines is shown on the opposite section of the U.S.G.S. Wyoming State Map published in 1927. Plant site, town site, railroad, highway and the water line proposed by the Bureau are superimposed on this map.

Plant facilities are located in an area approximately 20 miles north of Rock Springs, Wyoming. The overall dimensions of the area are approximately two miles long (east to west) and about 3/4 of a mile wide (north to south). The plant facilities are located on the north slope of the canyon floor and the coal storage pile is located on the south slope. The plant layout as proposed by the Bureau of Mines is shown on the following page.

The following design conditions were used in developing the cost estimate:

Wet Bulb Temperature	59°F.
Dry Bulb Temperature	
Maximum	98°F.
Minimum	-33°F.
Maximum daily rain fall	2.80 inches
Monthly snowfall	20.6 inches
Maximum recorded wind speed	66 miles/hr.
Design wind force	20 lbs./sq. ft.
Frost line	5'6" below grade
Cooling water temperature	75°F.
Soil bearing	3000 #/SF
Plant site altitude	6925 feet



Plot plan of a 30,000 bbl./day coal-hydrogenation plant.

INVESTMENT COST COMPARISON
30,000 B/SD COAL HYDROGENATION PLANT
ROCK SPRINGS, WYOMING

	USBM				NPC			
	Material	Labor	Other	Total	Material	Labor	Others	Total
Coal Preparation	$4,450,000	$1,302,000	$2,751,000	$8,503,000	$2,828,000	$1,412,000	$2,160,000	$6,400,000
Paste Preparation	1,309,000	603,000	1,038,000	2,950,000	1,325,000	925,000	1,250,000	3,500,000
Liquid Phase Hydrogenation (Note 1)	28,276,000	5,757,000	10,867,000	44,900,000	39,300,000	7,700,000	18,300,000	65,300,000
Delayed Coking (Note 1)	3,245,000	1,178,000	1,944,000	6,367,000	3,270,000	1,430,000	2,300,000	7,000,000
Vapor Phase Hydrogenation (Note 1)	15,578,000	3,415,000	6,207,000	25,200,000	19,900,000	3,900,000	9,300,000	33,100,000
Distillation Units	4,560,000	1,701,000	3,185,000	9,446,000	7,624,000	2,826,000	4,850,000	15,300,000
Tar Acid Recovery	1,016,000	381,000	698,000	2,095,000	1,223,000	547,000	830,000	2,600,000
Low Temp. Gas Separation	2,992,000	1,030,000	2,006,000	6,028,000	6,020,000	1,370,000	3,010,000	10,400,000
Hydrocarbon Steam Cracking	3,936,000	1,138,000	2,420,000	7,494,000	6,900,000	2,550,000	4,450,000	13,900,000
Coal Gasification (Note 2)	5,550,000	2,500,000	4,298,000	12,348,000	3,245,000	1,305,000	2,150,000	6,700,000
Oxygen Plant	4,350,000	1,370,000	2,785,000	8,505,000	6,500,000	1,500,000	2,500,000	10,500,000
Hydrogen Purification & Compression	23,430,000	6,895,000	13,483,000	43,808,000	33,900,000	7,600,000	16,700,000	58,200,000
Tankage, Field Lines & Shipping (Note 3)	4,582,000	1,963,000	1,754,000	8,299,000	4,440,000	2,300,000	3,460,000	10,200,000
Steam & Power Plant	22,870,000	9,730,000	14,075,000	46,675,000	40,800,000	14,500,000	23,700,000	79,000,000
Plant Utilities	14,361,000	5,896,000	10,569,000	30,826,000	14,855,000	6,720,000	10,725,000	32,300,000
General Facilities (Note 3)	8,715,000	5,535,000	10,725,000	24,975,000	15,320,000	7,985,000	11,395,000	34,700,000
Water Supply (Note 4)				(15,000,000)	3,100,000	1,700,000	2,400,000	7,200,000
Temporary Construction Housing (Note 5)					2,600,000	2,600,000	1,800,000	7,000,000
Total for Plant	$149,220,000	$50,394,000	$88,735,000	$288,419,000	$213,150,000	$68,870,000	$121,280,000	$403,300,000
Community & Offsite Housing								
Civic Facilities								9,000,000
Permanent Housing								60,900,000
Commercial Bldgs.								9,900,000
Total Housing					$40,900,000	$29,600,000	$9,300,000	$79,800,000
Grand Total	$149,220,000	$50,394,000	$88,735,000	$288,419,000	$254,050,000	$98,470,000	$130,580,000	$483,100,000

Notes:
(1) Costs are "modernized version" from R.I. 4564
(2) N.P.C. unit not comparable with Bureau unit.
(3) Field lines transferred from General Facilities of Bureau Estimate
(4) Not included in total of Bureau
(5) Additional Temporary Construction Housing required if permanent housing not provided — $2,300,000 | $2,300,000 | $1,600,000 | $6,200,000

SUMMARY

A summary of the investment costs of this Subcommittee is compared with the estimates of the Bureau of Mines in the opposite table. The Bureau estimates are for the conventional case as presented in R I 4564 except for the hydrogenation units and the delayed coking units which were included in the modernized version of the Bureau designs.

Excluding housing facilities the committee estimate is 40% higher than the Bureau. Approximately 35% of this difference is due to the increase in costs since the preparation of the Bureau estimate, 10% is due to offsite facilities such as water supply which were not capitalized by the Bureau, and approximately 20% can be attributed to increased power requirements calculated by this Subcommittee and which now has been substantially agreed to by the Bureau.

The remaining differences are discussed in the following detailed comparisonsof each section. In reviewing these comparisons, it should be noted that comparison of individual items such as Piping, Concrete, etc. is usually difficult because of different accounting or estimating practices in allocating certain material to different captions. Since complete details of the Bureau estimates were not available to the Subcommittee, comparison of each item is made in a general sense only.

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
POWER, STEAM & FUEL BALANCE

	Electric Power KW		1400 psig Steam M#/Hr.		370 psig Steam M#/Hr.		45 psig Steam M#/Hr.		Fuel MMBTU/Hr.(HHV)	
	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum
Demand										
Coal Preparation	5,025	6,200	-	-	-	-	-	-	81	97
Paste Preparation	1,415	1,545	-	-	-	-	2	2	-	-
Hydrogenation	33,300	35,700	-	-	-	-	-	-	-	-
Delayed Coking	5,070	5,830	-	-	10	19	-	-	173	190
Distillation	5,035	5,420	-	-	90	101	86	97	432	475
Phenol Recovery	150	170	-	-	95	107	-	-	94	104
Low Temperature Separation	13,170	13,790	-	-	-	-	3	3	-	-
Steam Cracking	6,650	7,350	-	-	-	-	341	384	800	880
Coal Gasification	2,580	2,750	-	-	-	-	117	132	-	-
Oxygen Manufacture	27,600	33,200	-	-	-	-	-	-	-	-
Hydrogen Purification	95,080	104,350	306	337	126	142	135	152	-	-
Producer Gas Supply	400	525	-	-	-	-	-	-	133	146
Shipping & Blending	515	2,025	-	-	-	-	-	-	-	-
Water Department	6,875	8,320	-	-	261	325	-	-	-	-
Fresh Water Supply	5,500	7,000	-	-	-	-	-	-	-	-
General Plant	4,165	4,910	-	-	18	47	200	400	-	-
Steam Department	1,100	2,650	-	-	983	1,219	740	920	4,071	4,994
Electric Dept. & Misc.	11,970	13,165	2,928	3,649	-	-	-	-	-	-
Total Plant Demand	225,600	254,900	3,234	3,986	1,583	1,960	1,624	2,090	5,784	6,886
Mines	2,400	3,100	-	-	-	-	-	-	-	-
City	5,600	6,000								
Total Demand	233,600	264,000	3,234	3,986	1,583	1,960	1,624	2,090	5,784	6,886
Supply										
Hydrogenation	-	-	-	-	-	-	39	33	-	-
Delayed Coking	-	-	-	-	80	68	9	9	413	372
Steam Cracking	-	-	-	-	-	-	325	276	-	-
Coal Gasification	-	-	-	-	376	320	-	-	-	-
Water Department	-	-	-	-	-	-	248	309	-	-
General Plant	-	-	-	-	-	-	9	19	-	-
Steam Department	-	-	3,234	3,986	-	-	369	457	-	-
Electric Department	233,600	264,000	-	-	1,127	1,572	625	987	-	-
Distillation Unit	-	-	-	-	-	-	-	-	150	135
Coal	-	-	-	-	-	-	-	-	5,221	6,739
Total Supply	233,600	264,000	3,234	3,986	1,583	1,960	1,624	2,090	5,784	6,886

UTILITY CONSUMPTION

Since the base case of the Committee did not correspond to either the base or the speculative case of the Bureau, it was necessary for this Subcommittee to calculate the utility requirements in conjunction with data submitted by the Process Subcommittee.

The steam, power and fuel balance as prepared by the Engineering Subcommittee is shown on the opposite page. Overall comparisons with the original requirements presented by the Bureau for the conventional case are as follows:

		NPC	USBM
Steam Generation - MM#/hr	- Average	3.23	2.53
	- Maximum	3.99	2.53
	- Installed Capacity	5.00	3.28
Power Generation - MKW	- Average	234	175
	- Maximum	264	175
	- Installed Capacity	300	250

The Bureau has reviewed the preliminary balance of the Subcommittee and certain modifications proposed by them have been incorporated in the committee quantities. Excluding utilities for the mines, water supply, and housing which were not capitalized in the cost calculations of the Bureau, the Subcommittee and the Bureau now disagree by only 6.8%, which is well within the range of accuracy of estimating power requirements. It appears that the original disagreement shown in the above comparison was due mainly to failure of the Bureau to compensate for the altitude of the plant at Rock Springs and to allow for motor and transmission losses of electrical energy.

The estimated water requirements are tabulated on the following page. These requirements compare closely with those estimated by the Bureau as follows:

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
WATER REQUIREMENTS

	Cooling Tower Water - GPM		Fresh Water GPM	
	Average	Maximum	Average	Maximum
Coal Preparation			250	250
Paste Preparation			200	250
Hydrogenation	34,900	43,500	140	175
Delayed Coking	3,240	4,330	75	1,500
Distillation	32,250	40,300	85	105
Phenol Recovery	9,650	12,000		
Low Temperature Separation	3,850	4,800		
Steam Cracking	13,000	16,250		
Coal Gasification	3,900	4,900	270	350
Oxygen Manufacture	10,500	12,000	250	250
Hydrogen Purification	70,180	81,500	1,160	1,450
Producer Gas Supply	1,890	1,120		
Shipping & Blending				
Cooling Tower Make-up			8,500	10,475
Drinking Water			200	250
General Plant			350	500
Steam & Power Plant			70	70
Boiler Feed Water (Net)	150,000	170,000	5,320	6,026
Total	332,360	390,700	16,870	21,650

	NPC	USBM
Cooling Tower Circulation MGPM - Average	332	---
- Maximum	391	---
- Installed	399	400
Fresh Water Make-up (ExCity) MGPM - Average	16.9	
- Maximum	21.7	20

Coal requirements based on the balances above are as follows:

	NPC	USBM
Coal - (As rec'd) Tons/hr		
Hydrogenation (Dried)	243	242
Gasification	87	81
Fuel (net)	221	187
Sub-Total	551	510
Cleaning Loss (Ash & H_2O)	23	50
Handling Loss & Misc.	26	-
Total Tons/hr	600	560
Tons/SD	14,400	13,440
Tons/CD @ 90% O.T.	12,960	

Coal Analysis	Hydro.	Gasif. & Fuel	Hydro.	Gasif.	Fuel
% Ash	3.6	4.9	2.5	3.5	2.7
% Moisture	1.5	10.0	1.5	7.0	8.0
BTU/# (as recd.)	13,190	11,830	13,390	12,490	12,460

The essential difference between the two estimates of coal requirements is the calculated quantity for fuel. This is due largely to the higher quantity required for steam generation as mentioned previously. The discrepancy would have been larger if the committee had not credited the fuel requirement with the excess gas from the distillation unit which had been omitted from the Bureau's calculations.

Cleaning loss shown for the committee quantities is actually a drying loss as only crushing and grinding of the low ash Wyoming coal was felt necessary. The Subcommittee has included a handling loss of approximately 4% for loss of fines, spillage and contingencies.

METHOD OF ESTIMATING

Three separate parallel estimates were made for most sections of the plant. Each estimate was made in accordance with the practice of the participating company and no attempt was made to prearrange any factor, cost or method of estimating except construction labor rate which was established at $2.00/hr for this area as of January 1951. This rate was based on a weighted average of several trades used in refinery construction. Current prices were used and in general are those prevailing the first part of 1951.

The three estimates of the direct material and labor costs were then corrected and averaged in conference to arrive at the estimates reported herein.

As might be expected, considerable deviation of the cost of the items within each unit as well as cost of each unit was found between the various estimates. This was due to different accounting practices and allocation of construction costs, to different construction standards, to errors and misinterpretation of design data, and to different bases of estimates. On an overall basis, however, the uncorrected estimates were remarkably close with a maximum difference of only 4.4% between the three estimates.

Indirect construction costs as used by the Bureau for the modernized case were generally accepted by the Subcommittee as representing a compromise within the committee. These other construction costs include field labor indirects, engineering, administration, purchasing, overhead, labor premium, contingencies, and contractor's fee. The Bureau estimate includes 15% contingencies for all units of the "conventional" design and 10% contingency for units of the "modernized" design. The Subcommittee estimate includes 10% contingency for all units.

One exception to the above was the addition of a labor premium charge by the Subcommittee which is based on working the construction forces the sixth day each week at time and one half for the sixth. Considering the industrial activity at the level that existed in 1949 and 1950, the Subcommittee is of the opinion that for the project under consideration the six day work week is a necessary and an unavoidable labor premium:

1) To attract competent construction workers, and
2) To avoid the excessive cost of providing 20 per cent additional housing, tools and supervision if a five day week were adhered to.

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
COAL PREPARATION UNIT

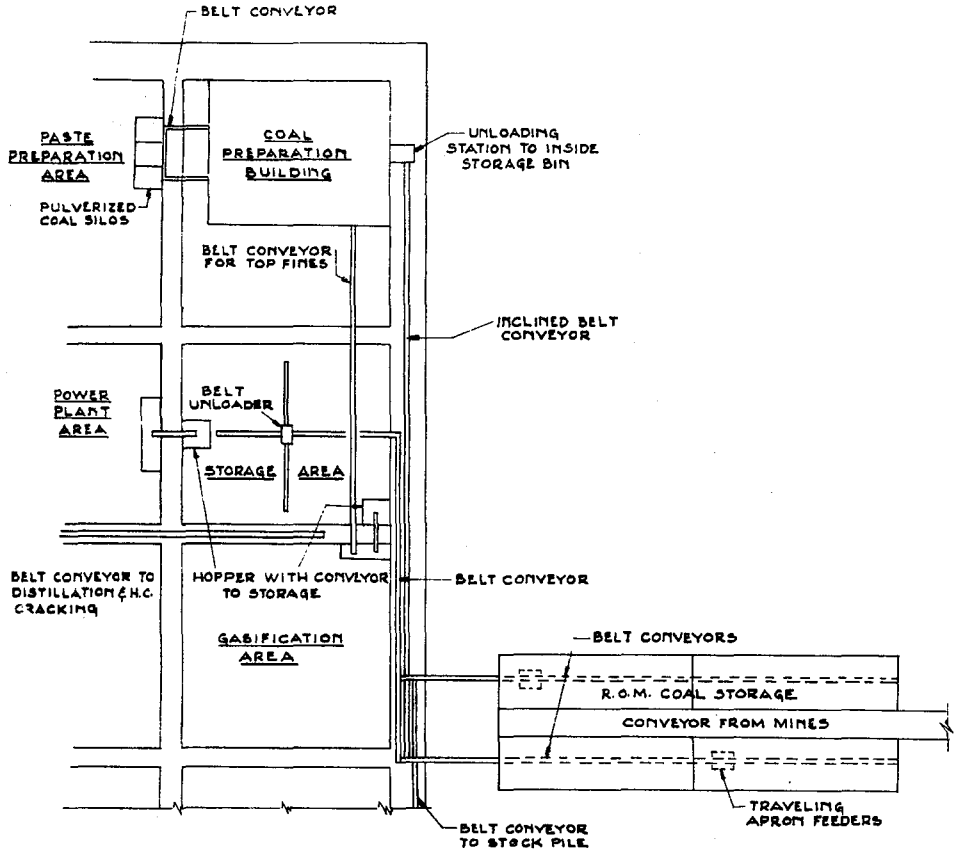
	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Ball Mills	$ 665,000			$ 832,300	$ 168,100	$1,000,400
Bins	348,000			451,000	170,400	621,400
Conveyors	1,123,500			507,000	184,700	691,700
Crushers	57,000			--	--	--
Dryers	560,000			--	--	--
Furnaces	70,000			46,300	13,400	59,700
Special Equipment	430,500			76,400	19,200	95,600
Total Equipment	$3,254,000	$ 551,000	$3,805,000	1,913,000	555,800	2,468,800
Buildings	570,000	285,000	855,000	467,900	313,800	781,700
Concrete	75,000	75,000	150,000	93,400	194,100	287,500
Electrical	260,000	130,000	390,000	152,000	152,000	304,000
Instruments	57,000	23,000	80,000	27,500	7,000	34,500
Insulation	65,000	65,000	130,000	15,900	47,500	63,400
Mech. Handling Equip.	--	--	--	--	--	--
Painting	15,000	45,000	60,000	8,000	14,900	22,900
Piping	80,000	40,000	120,000	60,800	29,800	90,600
Struct. Steel	40,000	20,000	60,000	44,500	18,500	63,000
Miscellaneous	34,000	68,000	102,000	45,000	78,600	123,600
Total Direct	$4,450,000	$1,302,000	$5,752,000	$2,828,000	$1,412,000	$4,240,000
Others			2,751,000			2,160,000
Total			$8,503,000			$6,400,000

COAL PREPARATION UNIT

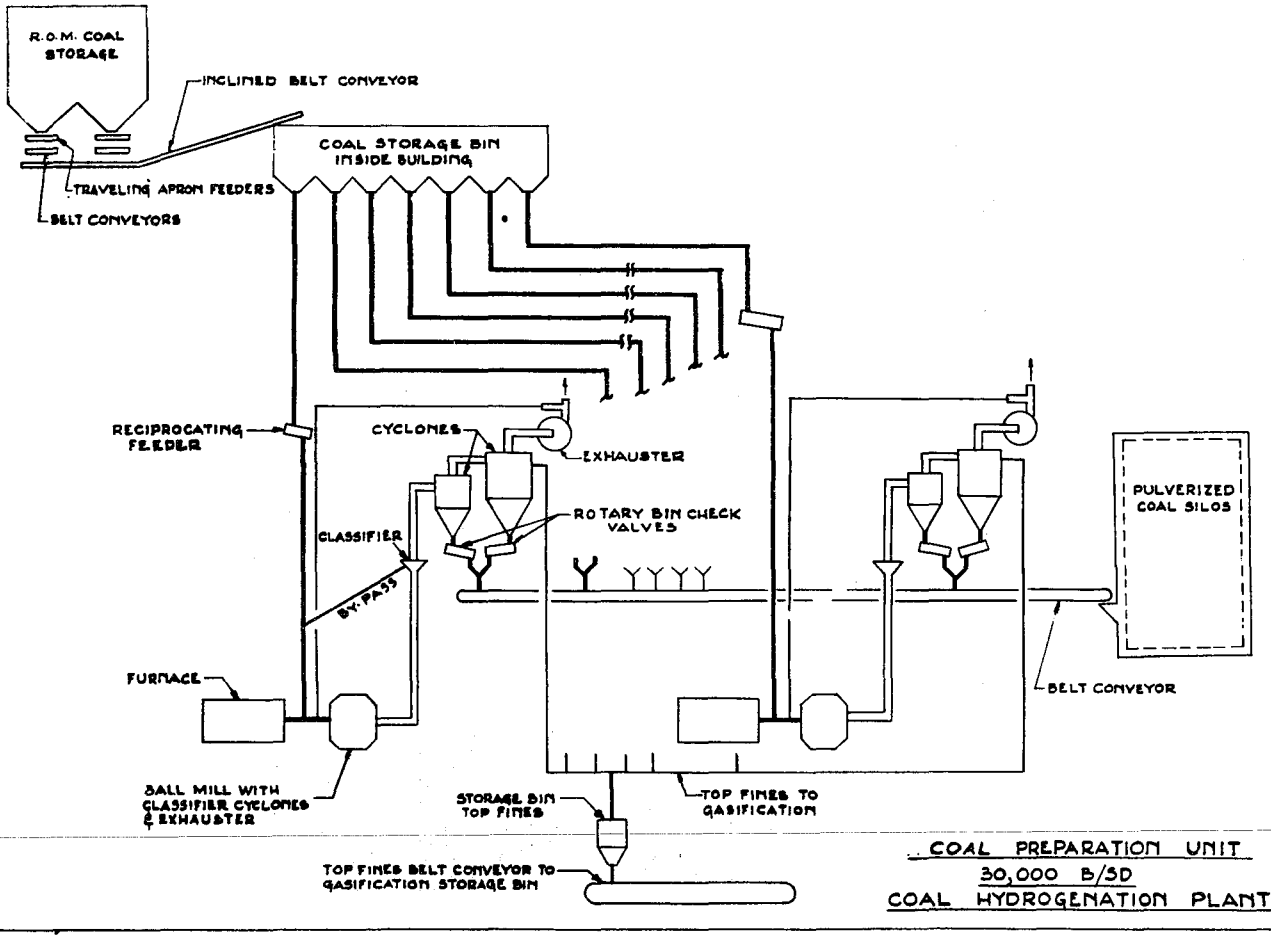
The Coal Preparation Unit was designed by the Bureau of Mines to crush, clean, dry and grind the run-of-mine coal which was assumed to have been mined in highly mechanized mines. In the Bureau's design a conveyor belt transfers coal from the mine to a plant storage bin of three days capacity. From this bin, the coal moves by feeders and conveyor belts to crushers and kilns where it is crushed to size and partially dried. In conjunction with the Raw Materials Subcommittee, this Subcommittee has eliminated the preliminary crushing and drying for the base case at Rock Springs, Wyoming since the coal from the mine is not wetwashed. The coal is fed directly to the gas swept ball mills where it is ground and dried for hydrogenation and gasification. The coal for process furnaces and the power plant is pulverized at the point of use. A complete system of conveyors, feeders, elevators, and pneumatic classifiers is included in the estimate.

The investment cost of the Coal Preparation Unit was based on Bureau of Mines equipment as shown on the following flow sheet.

A comparison of the costs prepared by this Subcommittee as of January 1951 with those prepared by the Bureau as of February 1948 is shown on the opposite page. This Subcommittee's estimate is below that of the Bureau's due to the elimination of certain pieces of equipment as discussed above.



PLOT PLAN



COAL PREPARATION UNIT
30,000 B/SD
COAL HYDROGENATION PLANT

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
PASTE PREPARATION UNIT

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Drums	$ 19,000			$ 34,500	$ 5,200	$ 39,700
Mix Tanks & Mixers	18,400			33,800	10,000	43,800
Pumps & Drivers	46,800			78,000	4,000	82,000
Silos	14,700			39,800	55,700	95,500
Tanks	156,300			91,600	65,400	157,000
Special Equipment	417,800			290,300	105,000	395,300
Total Equipment	$ 673,000	$ 224,000	$ 897,000	$ 568,000	$ 245,300	$ 813,300
Buildings	60,000	30,000	90,000	196,000	137,500	333,500
Concrete	25,000	25,000	50,000	32,500	67,500	100,000
Electrical	60,000	30,000	90,000	61,000	30,600	91,600
Instruments	36,000	15,000	51,000	44,000	20,300	64,300
Insulation	34,000	34,000	68,000	87,000	77,000	164,000
Mech. Handling Equip.	--	--	--	1,100	200	1,300
Painting	7,000	21,000	28,000	10,000	25,000	35,000
Piping	340,000	170,000	510,000	250,000	250,000	500,000
Struct. Steel	40,000	20,000	60,000	24,000	6,000	30,000
Miscellaneous	34,000	34,000	68,000	51,400	65,600	117,000
Total Direct	$1,309,000	$ 603,000	$1.912,000	$1,325,000	$ 925,000	$2,250,000
Others			1,038,000			1,250,000
Total			$2,950,000			$3,500,000

PASTE PREPARATION UNIT

The Paste Preparation Unit was designed by the Bureau of Mines to mix the ground and dried coal from the Coal Preparation Unit with the pasting oil and catalyst to produce a paste that is injected into the Liquid Phase Hydrogenation Unit. The ground coal and catalyst are handled by conveyors and feeders for complete automatic control of quantities. After the paste is prepared, it is stored in blending tanks from whence it is pumped to the Liquid Phase Hydrogenation Unit.

The investment cost of the Paste Preparation Unit was based on the Process Subcommittee's report of January 24, 1951. No important changes were made in the Bureau's design by the Subcommittee.

A comparison of the costs prepared by this Committee as of January 1951, with those prepared by the Bureau as of February 1948, is shown on the opposite page. As will be noted, there is good agreement between the Bureau and the Subcommittee on the investment cost of this unit, particularly when recognition is given to the increase in prices since the Bureau's estimate was completed.

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
LIQUID PHASE HYDROGENATION UNIT

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Compressors	$ 1,500,000			$ 1,050,000	$ 20,000	$ 1,070,000
Exchangers	4,223,600			3,690,000	60,000	3,750,000
Furnaces	1,728,000			2,090,000	530,000	2,620,000
Pumps & Drivers	3,067,000			6,820,000	150,000	6,970,000
Vessels	9,107,400			13,540,000	480,000	14,020,000
Total Equipment	$19,626,000	$1,008,000	$20,634,000	$27,190,000	$1,240,000	$28,430,000
Buildings	$ 324,000	$ 162,000	$ 486,000	$ 510,000	$ 510,000	$ 1,020,000
Concrete	399,000	399,000	798,000	600,000	1,200,000	1,800,000
Electrical	614,000	307,000	921,000	1,240,000	210,000	1,450,000
Instruments	468,000	184,000	652,000	710,000	330,000	1,040,000
Insulation	92,000	92,000	184,000	180,000	170,000	350,000
Mech. Handling Equipment	376,000	---	376,000	400,000	---	400,000
Painting	27,000	73,000	100,000	40,000	160,000	200,000
Piping	4,737,000	2,342,000	7,079,000	6,100,000	2,300,000	8,400,000
Structural Steel	845,000	422,000	1,267,000	860,000	340,000	1,200,000
Miscellaneous	768,000	768,000	1,536,000	1,470,000	1,240,000	2,710,000
Total Direct	$28,276,000	$ 5,757,000	$34,033,000	$39,300,000	$7,700,000	$47,000,000
Others			10,867,000			18,300,000
Total			$44,900,000			$65,300,000

LIQUID PHASE HYDROGENATION UNIT

The Liquid Phase Hydrogenation Unit was designed by the Bureau of Mines to convert the coal paste from the paste preparation unit into a synthetic crude oil by chemically combining coal and hydrogen at high pressure and high temperature in the converters. This crude is sent to the hot catch pot from which a liquid, called H.O.L.D., is returned partly to the paste preparation unit and partly to the delayed coking unit. The vapor stream is cooled and condensed and sent to the cold catch pot where liquid is drawn off. This stream, containing gases, gasoline, middle oils and bottoms, is sent to the liquid phase distillation unit. The vapor leaving the cold catch pot is mostly hydrogen which is recycled through the system.

The Subcommittee has adopted the Bureau's "modernized" version of this unit, firstly, by accepting the contention that higher throughputs with resultant smaller converter volumes could be obtained with increased instrumentation over the conventional German practice, and secondly by using the wrapped or layer construction for the converters rather than the more expensive forged vessels as a basis for estimating.

The Process Subcommittee substantially verified the Bureau of Mines design excepting for an increase in heat exchange surface. The Process Subcommittee also accepted a recent development by the Bureau that internal insulation provided in the original estimate of the Bureau could be reduced. This change provided additonal converter volume and resulted in a reduction of 10% in the converter volume required for a plant capacity of 27,000 barrels per calendar day of liquid fuels.

Equipment data sheets, flow diagram and a layout drawing of the unit follow.

The table on the opposite page compares the estimate of the Subcommittee as of January 1951 with that of the Bureau as of February 1948. The Subcommittee estimate is 46% above the Bureau estimate. Slightly over one fourth of this difference is due to price increases during the interval of time between the two estimates, one fourth is in estimated cost of equipment, 18% is in general items and the remainder (29%) is in the indirect charges. A considerable part of the equipment cost increase is due to the redesign of the pumps found necessary by the Bureau's experience in the Demonstration Plant. In view of the larger pump foundations required, a larger building was required than that proposed by the Bureau resulting in an increase in this and related items. Instrumentation cost does not appear to be unduly large when compared to the conventional estimate of the Bureau and considering the allowance for increased throughput over the conventional case is due to improved instrumentation.

30,000 B/SD COAL HYDROGENATION PLANT

EQUIPMENT SUMMARY

LIQUID PHASE HYDROGENATION UNIT

COMPRESSORS

K-1 Recycle Compressors, 6 required, 350 CFM at 9500 psi, 120°F suction. Discharge at 10,500 psi, 1650 BHP.

EXCHANGERS

E-1 Paste Product Exchangers, 28 shells required, 2560 square feet per shell. Tubes and shell at 10,500 psi, 900°F.
E-8 H.O.L.D. Cooler, 4 required. Double Tube - Oil Side 3" I.D. x 5" O.D. by 860 feet, pressure 10,300 psi at 900°F.
E-9 Product Cooler, 28 shells required, 735 square feet per shell. Tubes at 10,500 psi at 420°F. Shell 100 psi @ 100°F.
E-10 Recycle Gas Coolers, 28 shells required - same as E-9.
E-11 Recycle Compressor Breakin Cooler, 1 required. Double tube - Oil Side 3" I.D. by 5" O.D. by 270 feet, pressure 10,300 psi, 200°F.

FURNACES

F-1 Liquid Phase Preheater, 4 required, each 4.8MM Btu/Hour operating, 20MM Btu/Hour startup. Pressure 10,500 psi at 815°F.

PUMPS AND DRIVERS

P-1 Cool Paste Injection, 24 required, 100 GPM. Suction pressure atmospheric, discharge 10,500 psi at 220°F, 616 BHP. Double Acting-Quintuplex-Synch Motor Drive.
P-7 Flushing Oil Injection, 2 required. Same as P-1, 263 BHP.
P-8 Water Injection, 1 required. Same as P-1. 487 BHP.
P-9 Wash Oil Injection, 2 required. Same as P-1. 666BHP.
P-11 Wash Oil Letdown Engines, 4 required, Duplex - 31-1/2" I.D. by 49-1/2" O.D. x 11-1/2" Stroke (2.78 S/M)

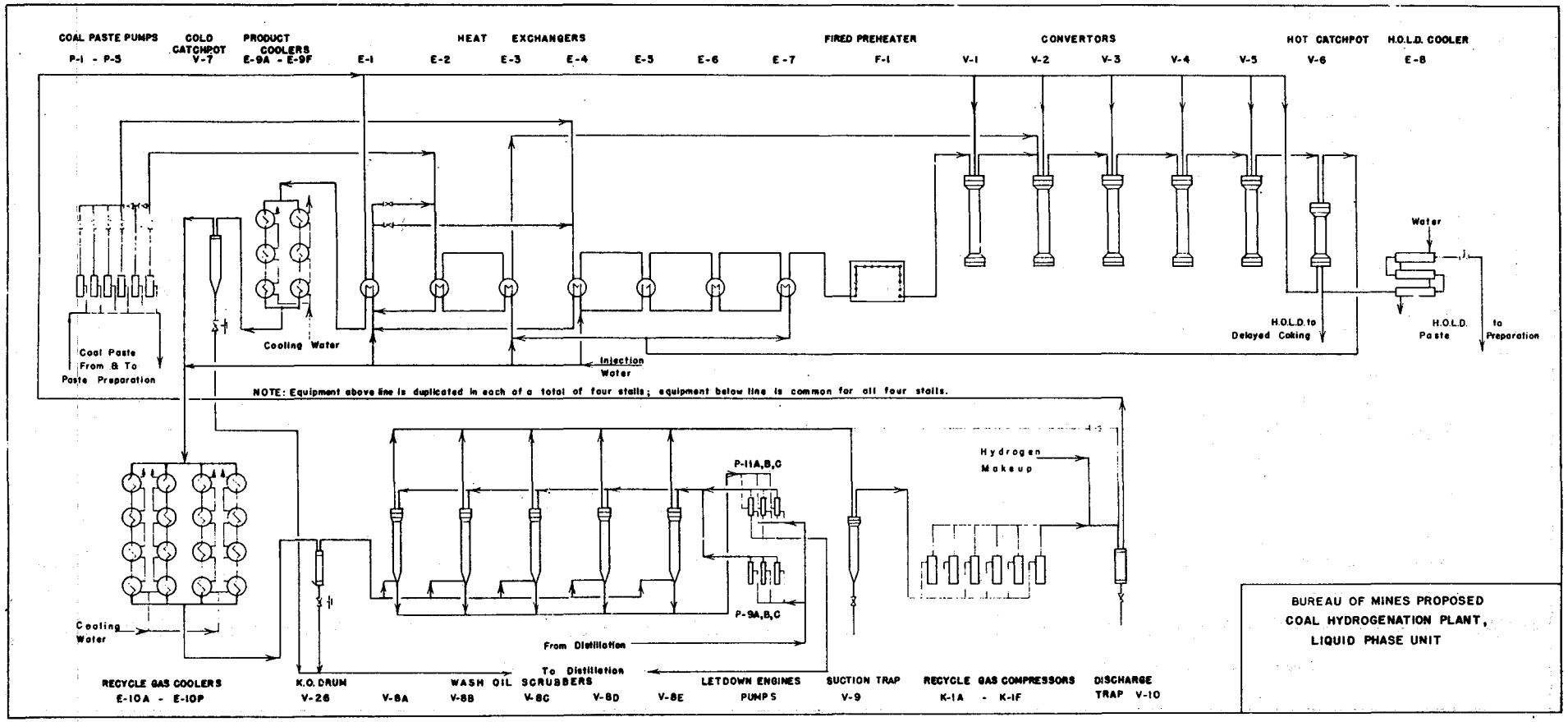
VESSELS

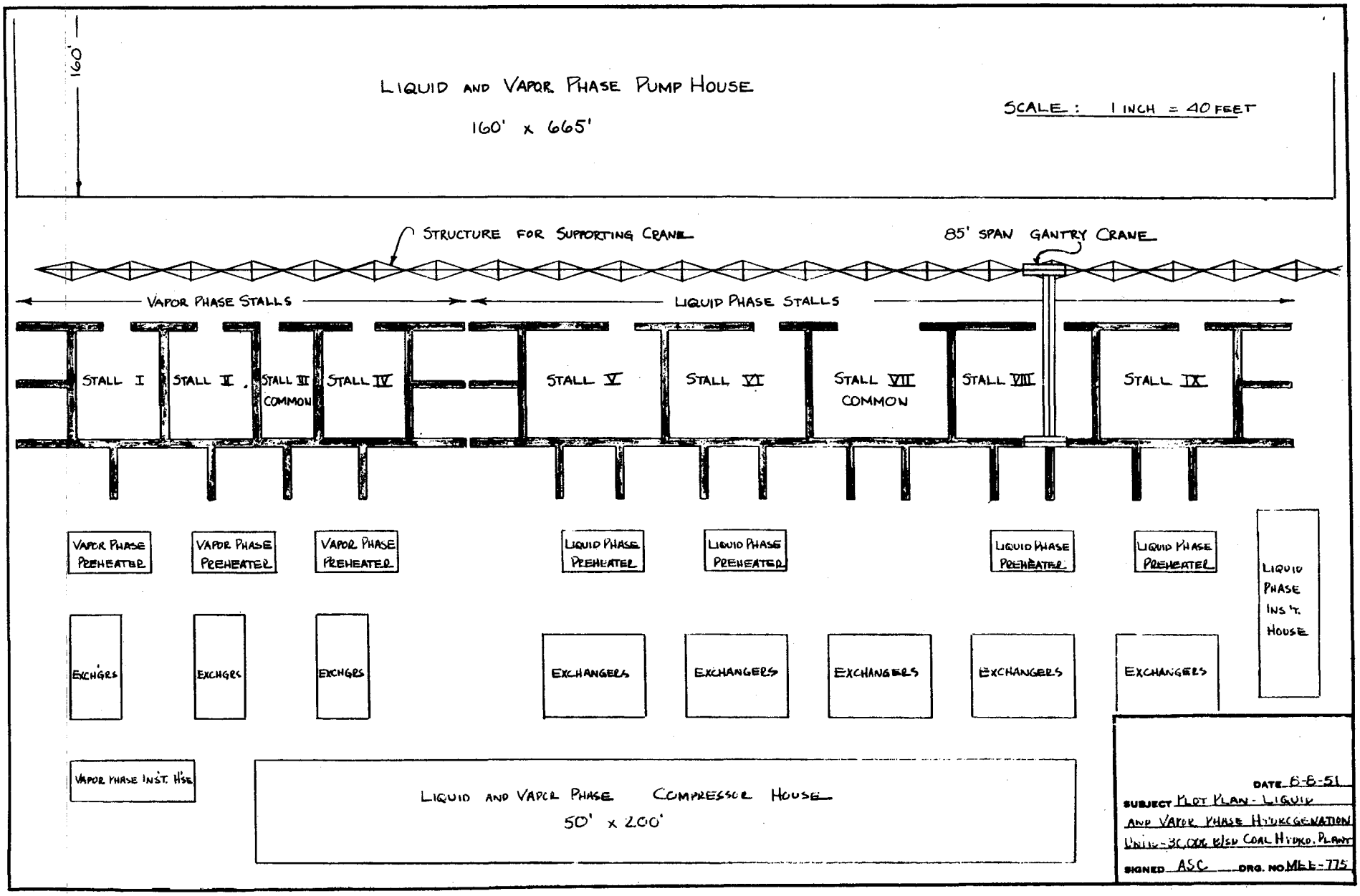
V-1 Liquid Phase Converters, 18 required, 56" I.D., 80" O.D., length 60', pressure 10,300 psi at 900°F (500°F Metal temperature)
V-6 Hot Catch Pot, 4 required, 56" I.D., 80" O.D., length 60'. Same conditions as V-1.
V-7 Cold Catch Pot, 4 required, 56" I.D., 80" O.D., length 27'. Pressure 10,300 psi at 150°F.
V-8 Wash Oil Scrubber, 5 required, 56" I.D., 80" O.D., length 60'. Pressure 10,300 psi at 100°F.
V-9 Comp. Suction Trap, 1 required, same as V-7.
V-10 Comp. Discharge Trap, 1 required, same as V-7.
V-11 Comp. Startup Trap, 1 required, 32" I.D., 49-1/2' O.D., length 6'. Pressure 10,300 psi at 100°F.
V-12 Water Injection Surge, 1 required, 32" I.D., 49-1/2' O.D., length 12-1/2'. Pressure 10, 300 psi at 100°F.
V-13 Flushing Oil Surge, 1 required, 56" I.D., 80" O.D., length 12'. Pressure 10,300 psi at 100°F.
V-25 Nitrogen Surge, 1 required, 56" I.D., 80" O.D., length 12-1/2'. Pressure 10,300 psi at 100°F.
V-26 Knock Out. Same as V-25.
V-27 Emergency Letdown, 2 required, 33' dia. by 20'ss by 20' dia. by 20'ss by 6-1/2' dia. by 20'ss. Pressure, atmospheric at 900°F.

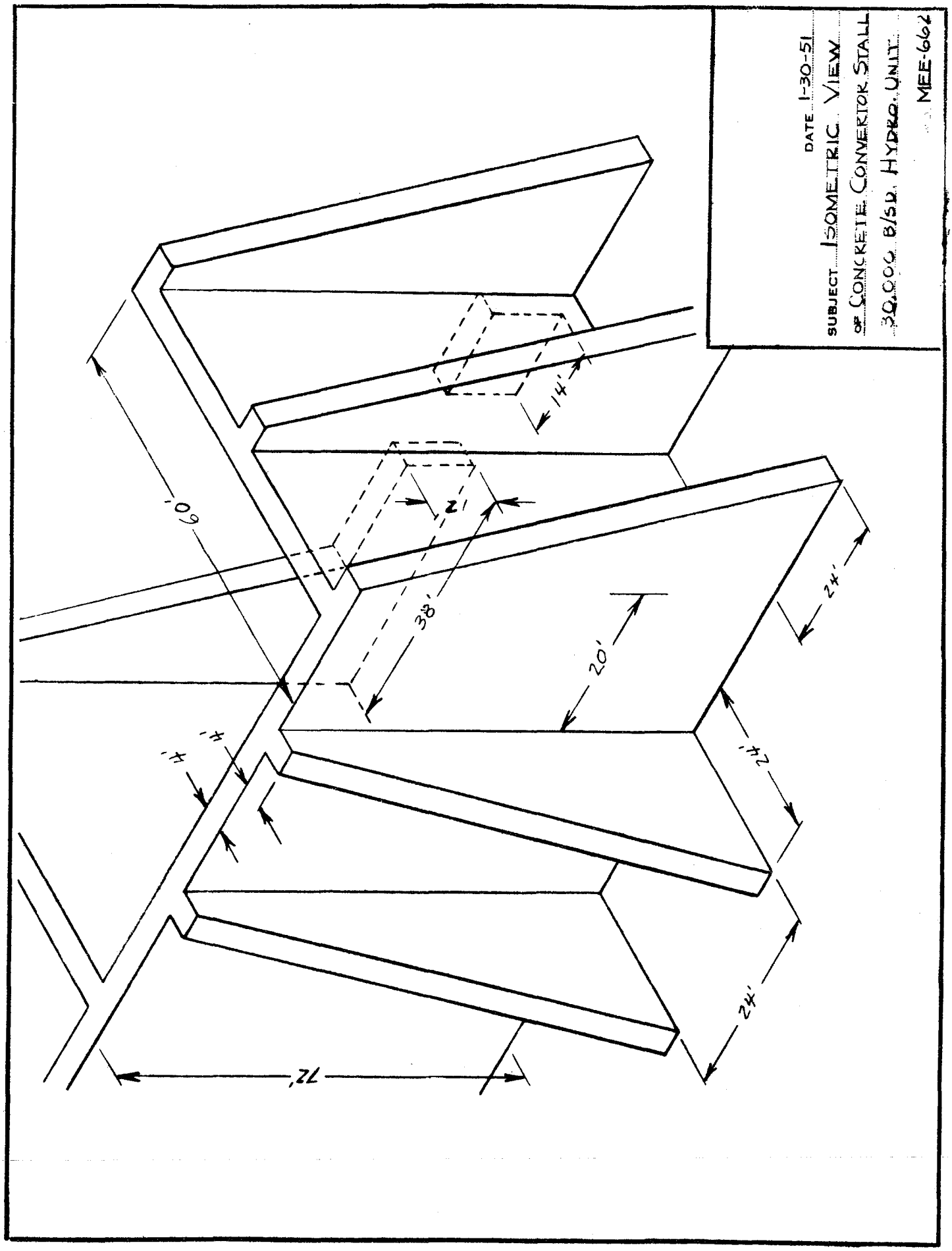
MISCELLANEOUS

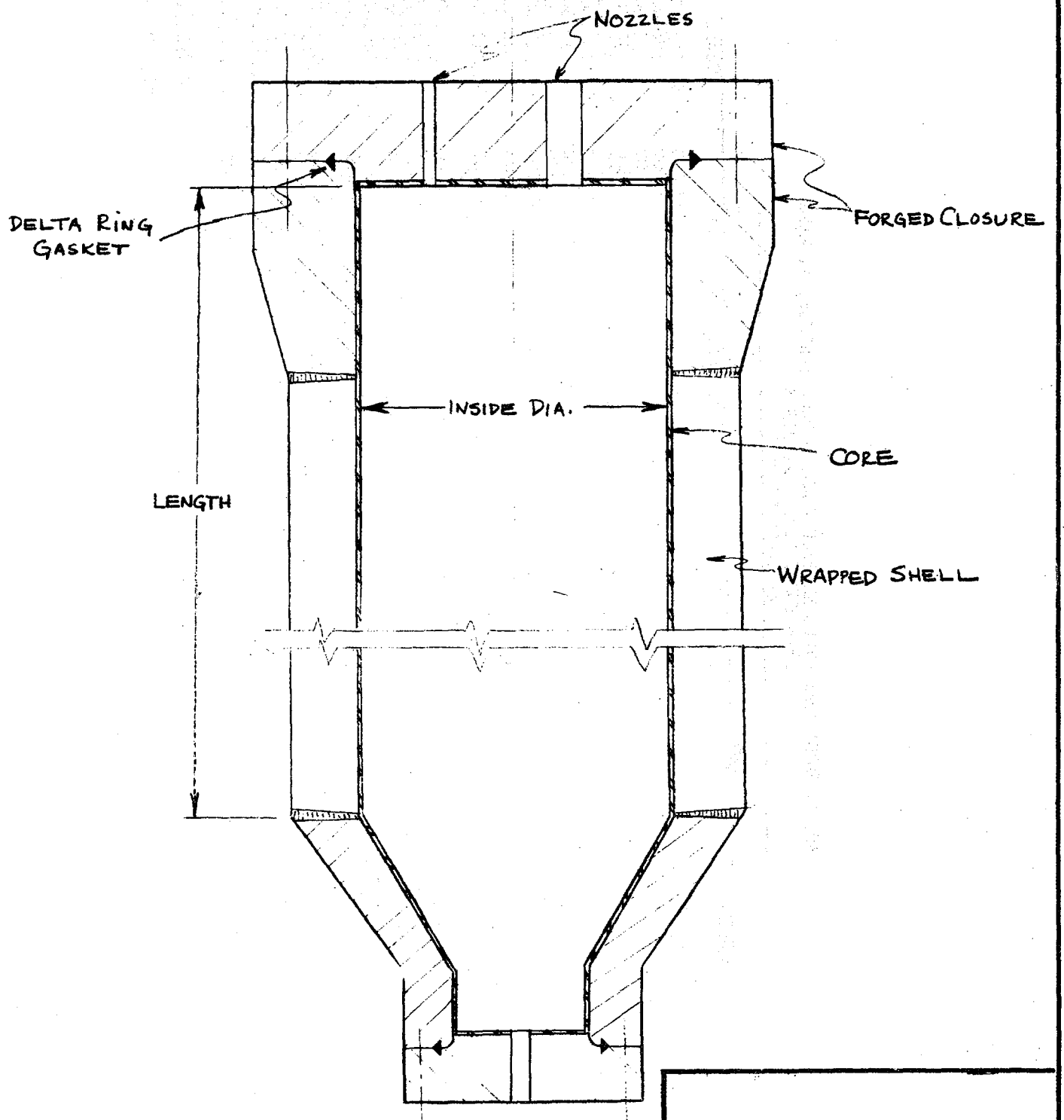
M 1 Gantry Crane, 85 foot span, 85 foot lift, 400 ton Capacity.

NOTE: All conditions shown are operating.


COAL PASTE PUMPS
P-1 - P-5
COLD CATCHPOT
V-7
PRODUCT COOLERS
E-9A - E-9F
HEAT EXCHANGERS
E-1
E-2
E-3
E-4
E-5
E-6
E-7
FIRED PREHEATER
F-1
CONVERTORS
V-1
V-2
V-3
V-4
V-5
HOT CATCHPOT
V-6
H.O.L.D. COOLER
E-8
Water
Coal Paste From & To Paste Preparation
Cooling Water
Injection Water
H.O.L.D. to Delayed Coking
H.O.L.D. Paste to Preparation
NOTE: Equipment above line is duplicated in each of a total of four stalls; equipment below line is common for all four stalls.
P-11A,B,C
P-9A,B,C
Hydrogen Makeup
Cooling Water
From Distillation
To Distillation
RECYCLE GAS COOLERS
E-10A - E-10P
K.O. DRUM
V-26
V-8A
V-8B
V-8C
V-8D
V-8E
WASH OIL SCRUBBERS
LETDOWN ENGINES
PUMPS
SUCTION TRAP
V-9
RECYCLE GAS COMPRESSORS
K-1A - K-1F
DISCHARGE TRAP V-10
BUREAU OF MINES PROPOSED
COAL HYDROGENATION PLANT,
LIQUID PHASE UNIT


160'
LIQUID AND VAPOR PHASE PUMP HOUSE
160' x 665'
SCALE: 1 INCH = 40 FEET
STRUCTURE FOR SUPPORTING CRANE
85' SPAN GANTRY CRANE
VAPOR PHASE STALLS
LIQUID PHASE STALLS
STALL I
STALL II
STALL III COMMON
STALL IV
STALL V
STALL VI
STALL VII COMMON
STALL VIII
STALL IX
VAPOR PHASE PREHEATER
VAPOR PHASE PREHEATER
VAPOR PHASE PREHEATER
LIQUID PHASE PREHEATER
LIQUID PHASE PREHEATER
LIQUID PHASE PREHEATER
LIQUID PHASE PREHEATER
LIQUID PHASE INST. HOUSE
EXCHGRS
EXCHGRS
EXCHGRS
EXCHANGERS
EXCHANGERS
EXCHANGERS
EXCHANGERS
EXCHANGERS
VAPOR PHASE INST. HSE
LIQUID AND VAPOR PHASE COMPRESSOR HOUSE
50' x 200'
DATE 6-6-51
SUBJECT PLOT PLAN - LIQUID AND VAPOR PHASE HYDROGENATION UNITS-30,000 B/SD COAL HYDRO. PLANT
SIGNED ASC ORG. NO. MEE-775


DATE 1-30-51
SUBJECT ISOMETRIC VIEW
OF CONCRETE CONVERTOR STALL
30,000 B/SD. HYDRO. UNIT
MEE-6662
14'
2'
38'
60'
20'
24'
24'
4'
4'
24'
72'



DATE 1-15-51

SUBJECT TYPICAL HIGH PRESSURE VESSEL - 30,000 B/SD COAL HYDROGENATION PLANT

NO. MEE-657

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
DELAYED COKING UNIT

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Coke Drums	$ 300,000			$ 316,000	$ 227,000	$ 543,000
Compressors	650,000			350,000	26,000	376,000
Drums				26,000	4,000	30,000
Exchangers	75,000			68,000	2,500	70,500
Furnace & Stacks	416,000			418,000	145,000	563,000
Pumps & Drivers	101,000			150,000	5,500	155,500
Towers	12,000			26,000	4,500	30,500
Tanks				3,500	1,500	5,000
Decoking Equipment	300,000			290,000	50,000	340,000
Coke Conveyor	75,000					
Total Equipment	$1,929,000	$376,000	$2,305,000	$1,647,500	$ 466,000	$2,113,500
Buildings	32,000	16,000	48,000	70,000	53,000	123,000
Concrete	97,000	97,000	194,000	119,000	184,000	303,000
Electrical	80,000	40,000	120,000	110,000	55,000	165,000
Instruments	177,000	71,000	248,000	120,000	50,000	170,000
Insulation	64,000	64,000	128,000	120,000	66,000	186,000
Mech. Hand. Equip.				6,500	1,000	7,500
Painting	12,000	39,000	51,000	9,000	28,000	37,000
Piping	645,000	322,000	967,000	700,000	350,000	1,050,000
Railroad Cars & Car Puller				24,000	1,000	25,000
Structural Steel	112,000	56,000	168,000	195,000	82,000	277,000
Miscellaneous	97,000	97,000	194,000	149,000	94,000	243,000
Total Direct	$3,245,000	$1,178,000	$4,423,000	$3,270,000	$1,430,000	$4,700,000
Others			1,944,000			2,300,000
Total			$6,367,000			$7,000,000

DELAYED COKING UNIT

In the design of a "modernized" coal hydrogenation plant, the Bureau of Mines contemplated coking a portion of the heavy oil from the liquid phase units to eliminate ash, catalyst, and unconverted solids. Oil produced would be recycled back to the paste preparation unit for further hydrogenation, whereas the spent catalyst bearing coke would be burned in the boiler house.

The Committee accepted this process as commercially feasible and incorporated it into its base or "conventional" scheme. However, the unit, as designed by the Bureau, was modified by the Process Subcommittee as shown on the following flow diagram and equipment lists. These lists also incorporate minor changes by the Engineering Subcommittee and are the basis for the Committee estimate of investment cost.

As will be noted from the opposite table, despite the modifications by the Committee, agreement between the Bureau and the Committee on the investment cost of this unit is good, particularly when recognition is given to the increase in prices since the Bureau's estimate was completed.

COAL HYDROGENATION

Delayed Coking of H.O.L.D.

Equipment Summary

Furnaces

Item	Service	Material	Flow Lbs./Hr.	MW	Wt.% Vapor In	Wt.% Vapor Out	Temperature, °F. In	Temperature, °F. Out	Temperature, °F. Design	Pressure, Psig In	Pressure, Psig Out	Pressure, Psig Design	Duty MM Btu/Hr.	Remarks
F-1	Recycle Gas Superheater													Three Required-Coal fired.
	Radiant Section	Recycle Gas	43,600	21	100	100	340	1100	1150	50	30	75	25.5	
	Connection Section	Water	12,100	18	0	100	100	441		420	370	500	13.8	

Exchangers

Item	Service	Fluid Flowing Tube	Fluid Flowing Shell	Design Temperature, °F. Tube	Design Temperature, °F. Shell	Design Pressure, Psig Tube	Design Pressure, Psig Shell	Total Area Sq. Ft.	Number of Shells	Area per Shell Sq. Ft.	Remarks
E-1	Waste Heat Boiler	Water	5°API Oil	450	750	425	75	3,320	1	3,320	Three Required
E-2	Primary Condenser	Water	Gas & Oil	120	525	150	40	2,500	1	2,500	Three Required
E-3	Secondary Condenser	Water	Gas & Oil	120	240	150	35	60	1	60	Three Required
E-4	Exchange Tower Bottoms Cooler	Water	-10°API Oil	120	800	150	45	120	1	120	Three Required

Towers

Item	Service	Diameter Ft.	Length Ft.	Design Temperature °F.	Design Pressure Psig	Remarks
C-1	Coke Drum	17	60	950	55	Six Required - Two per unit.
C-2	Heat Exchange Tower	9	30	850	45	Three Required.

Vessels

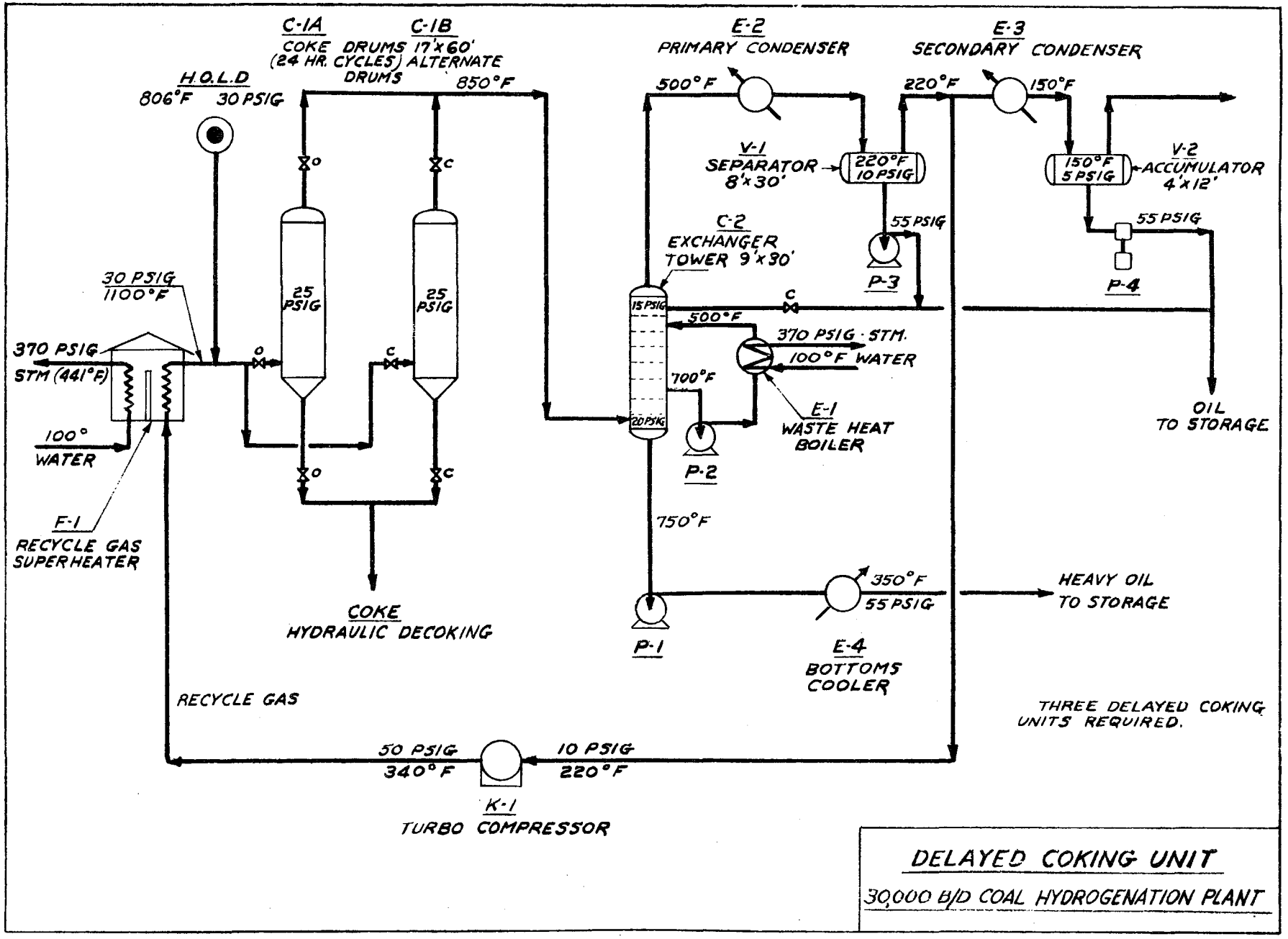
V-1	Separator	8	30	250	35	Three Required. Horizontal
V-2	Accumulator	4	12	180	30	Three Required. Horizontal
V-3	Blow Down	8	20	850	50	One Required - Internally Baffled - Vertical

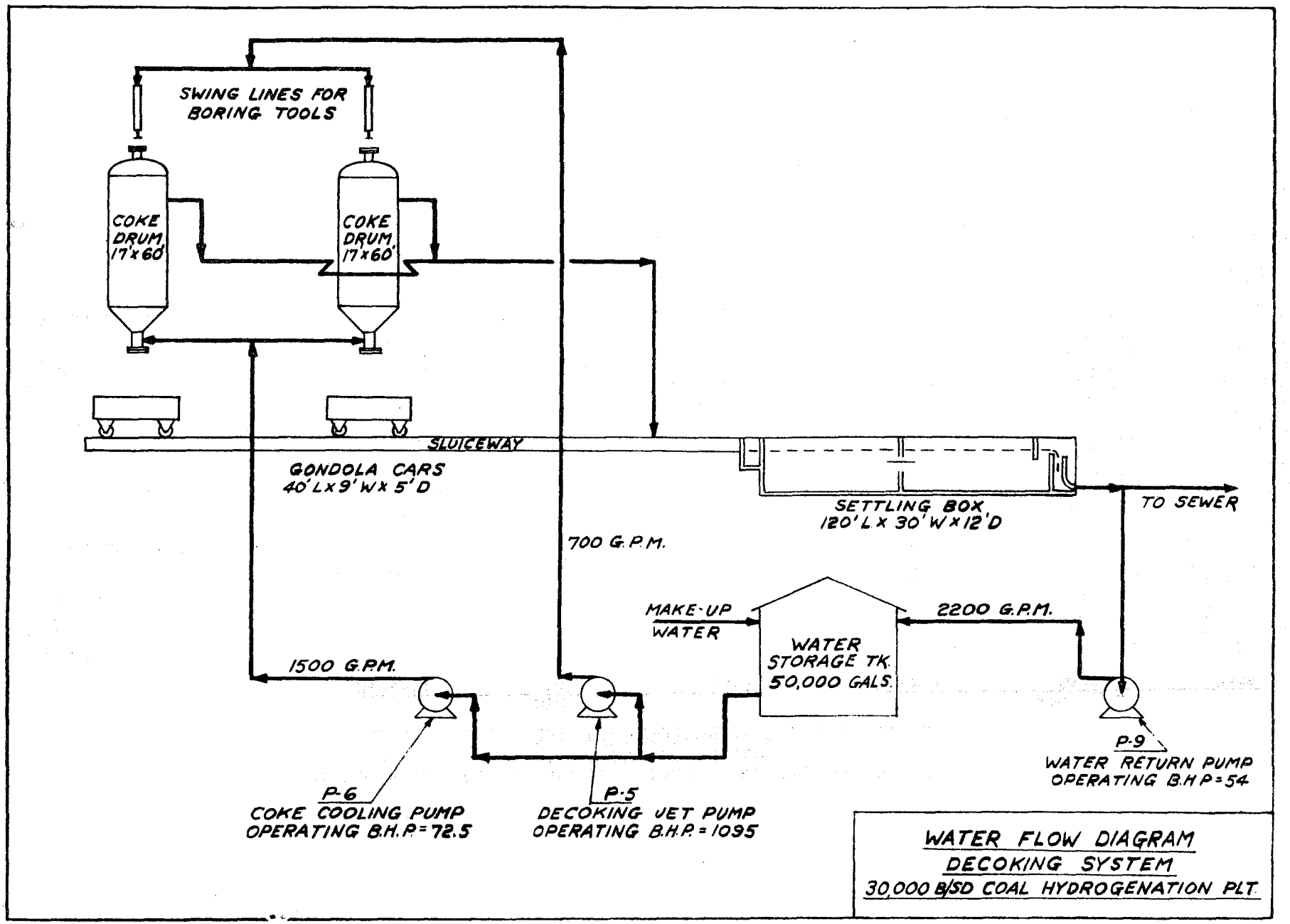
Pumps

Item	Service	Material	Design Rate Hot GPH	Design Temperature °F.	Design Pressures Psig Suction	Design Pressures Psig Discharge	Assumed Efficiency,%	Design Driver BHP	Required	Remarks
P-1	Exchange Tower Bottoms	-10°API Oil	620	800	15	75	15	2.4	6	Reciprocating
P-2	Circulating Oil	5°API Oil	20,000	750	10	55	63	13.8	6	Centrifugal Motor drive
P-3	Distillate Oil from Separator	15°API Oil	2,840	250	5	65	40	4.2	6	Centrifugal Motor drive
P-4	Distillate Oil from Accumulator	15°API Oil	85	180	0	65	15	0.4	6	Reciprocating
P-5	Decoking Jet	Water	42,000	120	0	1900	71	1095	2	Centrifugal Motor drive
P-6	Coke Cooling	Water	90,000	120	10	80	85	72.5	2	Centrifugal Motor drive
P-7	Coke Drum Condensate	-10°API Oil	10,200	850	25	125	-	9.9 THP	2	Reciprocating
P-8	Blow Down Pumpout	-10°API Oil	27,000	750	25	125	-	33 THP	2	Reciprocating
P-9	Water Return	Water	130,000	120	0	30	-	38 THP	1	Centrifugal Motor drive

Compressors

K-1	Recycle Gas	21 MW Gas	11,000 (CFM)	220	10	25	75	1,800	3	Turbo type Motor drive


C-1A
C-1B
COKE DRUMS 17'x60'
(24 HR. CYCLES) ALTERNATE DRUMS
H.O.L.D
806°F 30 PSIG
850°F
E-2
PRIMARY CONDENSER
500°F
E-3
SECONDARY CONDENSER
220°F
150°F
V-1
SEPARATOR
8'x30'
220°F
10 PSIG
V-2
ACCUMULATOR
4'x12'
150°F
5 PSIG
C-2
EXCHANGER
TOWER 9'x30'
55 PSIG
P-3
P-4
55 PSIG
30 PSIG
1100°F
25 PSIG
25 PSIG
15 PSIG
20 PSIG
500°F
370 PSIG · STM.
100°F WATER
700°F
E-1
WASTE HEAT
BOILER
370 PSIG
STM (441°F)
100°
WATER
F-1
RECYCLE GAS
SUPERHEATER
P-2
OIL
TO STORAGE
750°F
COKE
HYDRAULIC DECOKING
P-1
350°F
55 PSIG
E-4
BOTTOMS
COOLER
HEAVY OIL
TO STORAGE
RECYCLE GAS
THREE DELAYED COKING
UNITS REQUIRED.
50 PSIG
340°F
10 PSIG
220°F
K-1
TURBO COMPRESSOR
DELAYED COKING UNIT
30,000 B/D COAL HYDROGENATION PLANT


SWING LINES FOR BORING TOOLS
COKE DRUM 17'x60'
COKE DRUM 17'x60'
SLUICEWAY
GONDOLA CARS 40'Lx9'Wx5'D
SETTLING BOX 120'Lx30'Wx12'D
TO SEWER
700 G.P.M.
MAKE-UP WATER
WATER STORAGE TK. 50,000 GALS.
2200 G.P.M.
1500 G.P.M.
P-9
WATER RETURN PUMP OPERATING B.H.P=54
P-6
COKE COOLING PUMP OPERATING B.H.P.=72.5
P-5
DECOKING JET PUMP OPERATING B.H.P.=1095
WATER FLOW DIAGRAM
DECOKING SYSTEM
30,000 B/SD COAL HYDROGENATION PLT.

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
VAPOR PHASE HYDROGENATION UNIT

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Compressors	$ 1,250,000			$ 880,000	$ 20,000	$ 900,000
Exchangers	3,075,000			2,760,000	40,000	2,800,000
Furnaces	396,000			1,100,000	250,000	1,350,000
Pumps & Drivers	930,000			1,430,000	30,000	1,460,000
Vessels	4,935,000			6,470,000	80,000	6,550,000
Total Equipment	$10,586,000	$ 534,000	$11,120,000	$12,640,000	$ 420,000	$13,060,000
Buildings	$ 249,000	$ 125,000	$ 374,000	$ 170,000	$ 170,000	$ 340,000
Concrete	267,000	267,000	534,000	320,000	580,000	900,000
Electrical	401,000	200,000	601,000	620,000	110,000	730,000
Instruments	365,000	146,000	511,000	410,000	190,000	600,000
Insulation	50,000	50,000	100,000	90,000	90,000	180,000
Mech. Handling Equipment	---	---	---	200,000	---	200,000
Painting	14,000	43,000	57,000	20,000	80,000	100,000
Piping	2,487,000	1,248,000	3,735,000	4,200,000	1,400,000	5,600,000
Structural Steel	713,000	356,000	1,069,000	500,000	200,000	700,000
Miscellaneous	446,000	446,000	892,000	730,000	660,000	1,390,000
Total Direct	$15,578,000	$ 3,415,000	$18,993,000	$19,900,000	$3,900,000	$23,800,000
Others			6,207,000			9,300,000
Total			$25,200,000			$33,100,000

VAPOR PHASE HYDROGENATION UNIT

The Vapor Phase Hydrogenation Unit was designed by the Bureau of Mines as the second stage in the hydrogenation process to produce gasoline from coal. Middle oil from the liquid phase distillation unit is reacted with hydrogen in a converter over a solid catalyst at high pressures and temperatures to form gasoline. From the converter the product is cooled and enters the cold catch pot. Here recycle hydrogen and liquid products are separated. The liquid products are depressurized and go to the vapor distillation unit.

The investment cost of this unit was made on the same basis as was the estimate for the liquid phase hydrogenation unit.

The comparison of estimates on the opposite page shows that the Subcommittee's estimate of January, 1951 is approximately 30% higher than the estimate prepared by the Bureau in February, 1948. The Flow plan and the equipment list for this section is shown on the following pages.

The same comments pertaining to the Liquid Phase Hydrogenation Unit cost estimates are generally applicable here with the exception of the converters. Although the Process Subcommittee allowed the use of a lesser amount of internal insulation and a smaller outage of catalyst than originally proposed, the same number of converters originally proposed by the Bureau were calculated by the Process Subcommittee to be required for a 30,000 barrel per stream day plant.

30,000 B/SD COAL HYDROGENATION PLANT

EQUIPMENT SUMMARY

VAPOR PHASE HYDROGENATION UNIT

COMPRESSORS

K-2 Recycle Compressors, 5 required, 300 CFM at 9500 psi, 120°F suction. Discharge at 10,500 psi, 1410 BHP.

EXCHANGERS

E-12 Feed Product Exchangers, 24 required, 2560 square feet per shell. Tubes and shell at 10,500 psi, 930°F.
E-18 Product Coolers, 30 required, 735 square feet per shell. Tubes at 10,300 psi at 250°F.
E-19 Recycle Comp. Breakin, 1 required, Double tube - Oil Side 3" I.D. by 5" O.D. by 270', pressure 10,300 psi, 200°F.

FURNACES

F-2 Vapor Phase Preheater, 3 required, each 12MM Btu/Hour, startup only. Pressure 10,500 psi at 830°F.

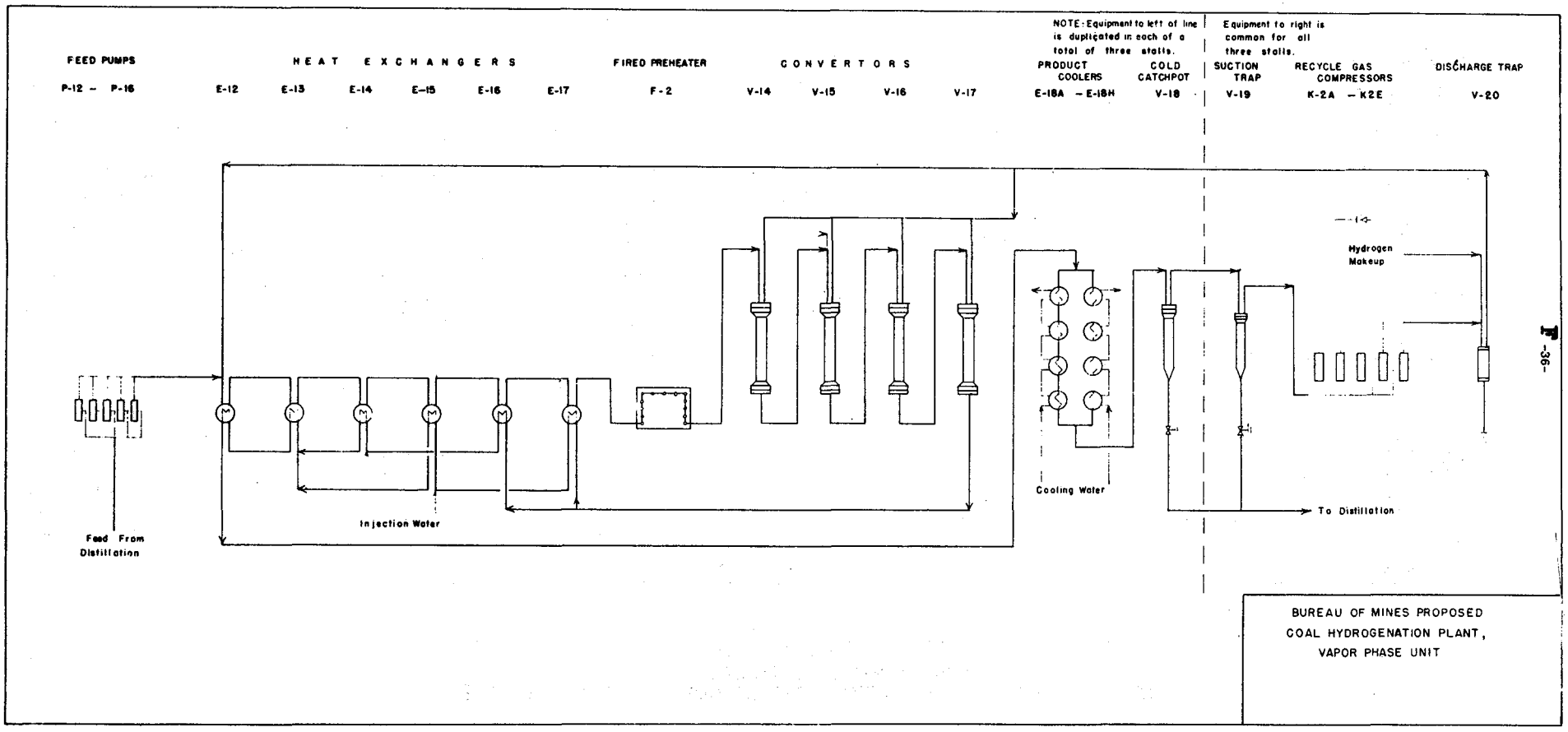
PUMPS & DRIVERS

P-8 Water Injection, 1 required, 100 GPM. Suction pressure atmospheric, discharge 10,500 psi at 220°F, 489 BHP. Double Acting-Quintuplex-Synch. Motor Drive.
P-12 Feed Injection, 6 required. Same as P-8.

VESSELS

V-14 Vapor Phase Converter, 12 required, 56" I.D., 80" O.D., length 60', pressure 10,300 psi at 930°F (500°F Metal Temperature)
V-18 Cold Catchpot, 3 required, 56" I.D., 80" O.D., length 27', pressure 10,300 psi at 100°F.
V-19 Comp. Suction Trap, 1 required. Same as V-18.
V-20 Comp. Discharge Trap, 1 required. Same as V-18.
V-21 Comp. Startup Trap, 1 required, 32" I.D., 49-1/2" O.D., length 6', pressure 10,300 psi at 100°F.

NOTE: All conditions shown are operating.


FEED PUMPS
P-12 – P-16
HEAT EXCHANGERS
E-12
E-13
E-14
E-15
E-16
E-17
FIRED PREHEATER
F-2
CONVERTORS
V-14
V-15
V-16
V-17
NOTE: Equipment to left of line is duplicated in each of a total of three stalls.
PRODUCT COOLERS
E-18A – E-18H
COLD CATCHPOT
V-18
Equipment to right is common for all three stalls.
SUCTION TRAP
V-19
RECYCLE GAS COMPRESSORS
K-2A – K2E
DISCHARGE TRAP
V-20
Hydrogen Makeup
Feed From Distillation
Injection Water
Cooling Water
To Distillation
BUREAU OF MINES PROPOSED
COAL HYDROGENATION PLANT,
VAPOR PHASE UNIT

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
DISTILLATION UNIT

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Compressors	$ 170,000			$ 320,000	$ 8,000	$ 328,000
Drums	262,900			258,000	25,000	283,000
Exchangers	566,170			836,000	25,000	861,000
Furnaces	705,000			1,000,000	285,000	1,285,000
Pumps & Drivers	188,480			400,000	20,000	420,000
Towers & Internals	617,450			960,000	290,000	1,250,000
Total Equipment	$2,510,000	$ 425,000	$2,935,000	$3,774,000	$ 653,000	$4,427,000
Buildings	75,000	38,000	113,000	97,000	65,000	162,000
Concrete	200,000	200,000	400,000	285,000	485,000	770,000
Electrical	250,000	125,000	375,000	290,000	138,000	428,000
Instruments	250,000	100,000	350,000	310,000	137,000	447,000
Insulation	100,000	100,000	200,000	207,000	178,000	385,000
Mech. Handling Equip.	--	--		16,000	1,000	17,000
Painting	25,000	75,000	100,000	25,000	82,000	107,000
Piping	875,000	438,000	1,313,000	1,860,000	740,000	2,600,000
Struct. Steel	150,000	75,000	225,000	390,000	150,000	540,000
Miscellaneous	125,000	125,000	250,000	370,000	197,000	567,000
Total Direct	$4,560,000	$1,701,000	$6,261,000	$7,624,000	$2,826,000	$10,450,000
Others			3,185,000			4,850,000
Total			$9,446,000			$15,300,000

PRODUCT DISTILLATION UNIT

The Product Distillation Unit was designed by the Bureau of Mines to separate the effluent from the Liquid and Vapor Phase Hydrogenation Units. The Liquid Phase section produces heavy middle oil and gasoline cuts for the Vapor Phase Hydrogenation feed as well as a light middle oil for feed to the Tar Acid Recovery Unit and a bottoms cut which is recycled back to the Paste Preparation Unit. The Vapor Phase section produces a recycle oil and a stabilized gasoline product. The light ends are separated into various components of LPG, an off-gas fraction which is charged to the low-temperature unit for recovery and purification of the hydrogen, and a residue gas which is fed to the hydrocarbon steam cracking for hydrogen manufacture.

The investment cost of the Distillation facilities was based on the Process Subcommittee's report of October 19, 1950 entitled "Process Design Review of Distillation Units for a 30,000 B/SD Coal Hydrogenation Plant". The flow diagrams and equipment lists as submitted in this report and upon which the estimate is based are shown on following pages. This report recommended a few relatively minor changes to the design as prepared by the Bureau of Mines all of which increased the cost of the facilities.

A comparison of the costs prepared by this Committee as of January 1951 with those prepared by the Bureau as of February 1948 is shown on the opposite page. This Committee's estimate is considerably above (62%) that of the Bureau's. Approximately 40% of this difference is due to inflation since the date of the Bureau's estimate and approximately 10% is due to changes suggested by the Process Subcommittee. The remaining differences seem to be generally distributed throughout the estimate.

LIQUID PHASE DISTILLATION UNIT FOR 30,000 BSD COAL HYDROGENATION PLANT

Equipment Summary

Towers

Item	Service	Diameter Ft.	Height Ft.	Design Temperature Deg. F	Design Pressure Psig	Remarks
C-5001	Water Wash Tower	8	50	95	80	30 ft. Packing
C-5002	Absorber-Deethanizer		105	280	240	
	Upper Section	4	77			50 SF Trays at 18"
	Lower Section	6	28			14 DF Trays at 18"
C-5003	Debutanizer	8	85	465	190	42 Trays at 20"
C-5004	Depropanizer	5	66	226	290	34 Trays at 18"
C-5005	Still	18.5	102	610	30	32 Trays at 30"
C-5006	Lt. Middle Oil Stripper	6	30	375	30	6 Trays at 24"
C-5009	Lt. Middle Oil Stripper	6	30	375	30	6 Trays at 24"
C-5007	Hvy. Middle Oil Stripper	6	30	515	30	6 Trays at 24"
C-5010	Hvy. Middle Oil Stripper	6	30	515	30	6 Trays at 24"
C-5008	Still	18.5	102	610	90	32 Trays at 30"

Vessels

V-5001-5	Feed Flash Drums	7	20	160	385	Horizontal
V-5006-10	Feed Flash Drums	7	20	160	95	Horizontal
V-5011-12	Feed Flash Drums	12	40	160	30	Horizontal
V-5013-17	Feed Flash Drums	7	20	100	385	Horizontal
V-5018-22	Feed Flash Drums	7	20	100	95	Horizontal
V-5023	Feed Flash Drum	11.5	38	100	30	Horizontal
V-5024	Compressor K.O. Drum	5	14	95	30	Vertical
V-5025	Compressor K.O. Drum	5	14	95	80	Vertical
V-5026	Debutanizer Reflux Drum	8.5	30	105	190	Horizontal
V-5027	Depropanizer Reflux Drum	6	22	118	290	Horizontal
V-5028	Still Reflux Drum	11	36	95	30	Horizontal
V-5029	Still Reflux Drum	11	36	95	90	Horizontal
V-5030	Butane Caustic Wash and Water Wash	3	34	95	225	Vertical

LIQUID PHASE DISTILLATION UNIT FOR 30,000 BSD COAL HYDROGENATION PLANT

Equipment Summary
(Cont'd.)

Heat Exchangers

Item	Service	Fluid Flowing		Design Temperature		Design Pressure		Total Area	Number
		Tube	Shell	Tube °F.	Shell °F.	Tube Psig	Shell Psig	Sq. Ft.	of Shells
E-5001	Compressor Intake Cooler	Water	40 MW Vapor	120	107	-	30	285	1
E-5002	Compressor Interstage Cooler	Water	50 MW V/L	120	200	-	100	1,270	1
E-5003	Compressor Aftercooler	Water	48 MW V/L	120	150	-	275	1,650	1
E-5004	Absorber Intercooler	Water	71°API Oil	120	119	-	280	650	1
E-5005	Absorber Reboiler	5°API Oil	50°API Oil	372	280	175	240	3,750	1
E-5006	Debut, Feed Preheater	Steam	45.6°API Oil	440	415	425	240	1,700	1
E-5007	Debutaniser Condenser	Water	131°API Oil	120	130	-	190	5,950	2
E-5008	Debutaniser Reboiler	5°API Oil	35°API Oil	570	465	175	190	4,750	1
E-5009	Deprop. Feed Preheater	Steam	131°API Oil	293	160	70	290	380	1
E-5010	Deprop. Condenser	Water	143°API Oil	120	126	-	290	1,600	1
E-5011	Deprop. Reboiler	Steam	120°API Oil	293	226	70	290	390	1
E-5012	Deprop. Btms. Cooler	Water	114°API Oil	120	226	-	290	165	1
E-5013	Still Feed - Ovhd. Exch.	12°API Oil	92 MW Vapor	199	240	285	90	7,510	2
E-5022	Still Feed - Ovhd. Exch.	12°API Oil	92 MW Vapor	199	240	285	90	7,510	2
E-5014	Still Condenser	Water	92 MW Vapor	120	225	-	90	23,250	6
E-5023	Still Condenser	Water	92 MW Vapor	120	225	-	90	23,250	6
E-5015	Still Feed - Int. Reflux Exch.	12°API Oil	12°API Oil	315	450	250	65	4,340	2
E-5024	Still Feed - Int. Reflux Exch.	12°API Oil	12°API Oil	315	450	250	65	4,340	2
E-5016	Still Feed - LMO Exch.	15°API Oil	12°API Oil	345	240	350	285	2,340	2
E-5025	Still Feed - LMO Exch.	15°API Oil	12°API Oil	345	240	350	285	2,340	2
E-5017	Still Feed - HMO Exch.	10°API Oil	12°API Oil	485	315	150	285	3,460	2
E-5026	Still Feed - HMO Exch.	10°API Oil	12°API Oil	485	315	150	285	3,460	2
E-5018	Still Feed - LOB Exch.	5°API Oil	12°API Oil	492	385	175	285	15,900	4
E-5027	Still Feed - LOB Exch.	5°API Oil	12°API Oil	492	385	175	285	15,900	4
E-5019	Light Middle Oil Cooler	Water	15°API Oil	120	250	-	350	4,330	2
E-5020	Heavy Middle Oil Cooler	Water	10°API Oil	120	317	-	150	1,375	1
E-5021	Light Oil Bottoms Cooler	Water	5°API Oil	120	305	-	175	580	1

Furnaces

Item	Service	Fluid Flowing	Flow Lbs./Hr.	Molecular Weight	% Vapor		Design Temperature		Design Pressure Psig	Duty MM Btu/Hr.
					In	Out	In °F.	Out °F.		
F-5001	Still Feed Vaporizer	14.4°API Oil	629,165	179	0	42	395	610	285	94
F-5002	Still Feed Vaporizer	14.4°API Oil	629,165	179	0	42	395	610	285	94

LIQUID PHASE DISTILLATION UNIT FOR 30,000 BSD COAL HYDROGENATION PLANT

Equipment Summary
(Cont'd.)

Pumps

Item	Service	Type of Drive	Material Pumped	Design Pumping Rate Hot GPM	Design Temperature °F.	Design Pressure Suction Psig	Design Pressure Discharge Psig	Driver Rating BHP	Number of Operating Units	Spares
P-5001	Compressor Precooler Liq.	Steam Reciprocating	50°API Oil	50	95	0	100		1	1
P-5002	Compressor Interstage Liq.	Motor	69.1°API Oil	139	95	45	275	40	1	1
P-5003	Debutaniser Reflux & Prod.	Motor	131°API Oil	585	105	160	290	60	1	1
P-5004	Depropaniser Reflux & Prod.	Motor	143°API Oil	220	118	260	310	10	1	1
P-5005	Liq. Phase Still Charge	Motor	12°API Oil	1,255	160	0	250	250	2	1
P-5006	Liq. Phase Still Charge	Motor	12°API Oil	1,255	160	0	250	250	2	1
P-5007	Scrubber Oil Return	Motor	25.6°API Oil	2,700	100	0	500	1,000	1	1
P-5008	Still Reflux & Product	Motor	59.1°API Oil	938	95	0	100	100	1	-
P-5009	Light Middle Oil	Motor	15°API Oil	319	345	0	350	100	2	1
P-5014	Light Middle Oil	Motor	15°API Oil	319	345	0	350	100	2	1
P-5010	Heavy Middle Oil	Motor	10°API Oil	308	485	0	150	50	2	1
P-5015	Heavy Middle Oil	Motor	10°API Oil	308	485	0	150	50	2	1
P-5011	Light Oil Bottoms	Motor	5°API Oil	781	570	0	175	125	2	1
P-5016	Light Oil Bottoms	Motor	5°API Oil	781	570	0	175	125	2	1
P-5012	Still Intermed. Reflux	Motor	12°API Oil	412	450	25	65	15	2	1
P-5017	Still Intermed. Reflux	Motor	12°API Oil	412	450	25	65	15	2	1
P-5013	Still Reflux & Product	Motor	59.1°API Oil	938	95	60	250	135	1	1
P-5018	Absorber Intercooler Circl'n.	Motor	71°API Oil	256	119	235	280	10	1	1
PX-1	Caustic Circulation Pump	Motor	20% Caustic Sol'n.	10	95	200	230	1-1/2	1	1

Compressors

Item	Service	Type of Drive	Material Compressed	Design Flow Rate CFM at Suction Conditions	Design Temperature Suction °F.	Design Temperature Discharge °F.	Design Pressure Suction Psig	Design Pressure Discharge Psig	Estimated Compressor Efficiency %	Driver Rating BHP	Remarks
K-5001	Absorber Feed Compressor - 1st Stage	Motor	40.3 M.W.	5050	95	232	0	65	72	850	Provide spare.
K-5002	Absorber Feed Compressor - 2nd Stage	Motor	30.7 M.W.	1430	95	195	55	235	72	840	Provide spare.

VAPOR PHASE DISTILLATION UNIT FOR 30,000 B/SD COAL HYDROGENATION PLANT

Equipment Summary

Towers

Item	Service	Diameter Ft.	Length Ft.	Design Temperature Deg. F.	Design Pressure Psig	Remarks
C-5011	Water Wash	6	50	95	255	30' of Packing
C-5012	Absorber	5	56	140	240	27 Trays at 18" Tray Spacing
C-5013	Stripper	10	32	310	240	8 Trays at 24" Tray Spacing
C-5014	Debutanizer	11.5	130	430	200	45 Trays at 30" Tray Spacing
C-5015	Depropanizer	6.5	66	226	290	34 Trays at 18" Tray Spacing
C-5016	Vapor Phase Still	15.67	75	500	90	20 Trays at 30" Tray Spacing
C-5017	Gasoline-Lean Oil Splitter	21.33	110	415	35	30 Trays at 36" Tray Spacing
C-5018	Deisobutanizer	8	165	165	135	100 Trays at 18" Tray Spacing
C-5019	H_2S Absorber	4.5	50	150	285	24 Trays at 18" Tray Spacing
C-5020	Amine Reactivator	2	34	230	35	12 Trays at 24" Tray Spacing
Vessels						
V-5031	Feed Flash Drum	8	23	102	385	Horizontal
V-5032	Feed Flash Drum	8	23	102	385	Horizontal
V-5033	Feed Flash Drum	8	23	102	385	Horizontal
V-5034	Feed Flash Drum	8	23	102	385	Horizontal
V-5035	Feed Flash Drum	12	42	100	95	Horizontal
V-5036	Compressor Intake Drum	2.5	8	95	80	Vertical
V-5037	Debutanizer Reflux Drum	12	42	115	200	Horizontal
V-5038	Depropanizer Reflux Drum	7.5	16	115	290	Horizontal
V-5039	Vapor Phase Still Reflux Drum	12	42	95	90	Horizontal
V-5040	Gasoline - Lean Oil Splitter Reflux Drum	11.5	34	95	35	Horizontal
V-5041	Deisobutanizer Reflux Drum	8.5	26	105	135	Horizontal
V-5042	Propane Pumping Drum	6.5	16	105	285	Horizontal

VAPOR PHASE DISTILLATION UNIT FOR 30,000 B/SD COAL HYDROGENATION PLANT

Equipment Summary
(Cont'd.)

Heat Exchangers

Item	Service	Fluid Flowing		Design Temperature		Design Pressure		Total Area	Number of
		Tube	Shell	Tube °F.	Shell °F.	Tube Psig	Shell Psig	Sq. Ft.	Shells
E-5028	Vapor Phase Still Overhead Condenser	Water	58°API Oil	120	300	150	90	22,500	6
E-5029	Vapor Phase Still Feed - Bottoms Exchanger	27.7°API Oil	45.7°API Oil	460	310	100	285	6,000	2
E-5030	Vapor Phase Still Bottoms Cooler	Water	27.7°API Oil	120	288	150	100	3,760	2
E-5031	Compressor Aftercooler	Water	57°API Oil	120	105	150	250	920	1
E-5032	Absorber Intercooler	Water	50°API Oil	120	140	150	285	1,150	1
E-5033	Rich Oil StripperReboiler	370# Steam	53.7°API Oil	440	310	410	240	7,060	2
E-5034	Debutanizer Overhead Condenser	Water	134°API Oil	120	140	150	200	13,080	4
E-5035	Splitter Overhead Condenser	Water	48.4°API Oil	120	260	150	35	12,500	4
E-5036	Depropanizer Feed Preheater	45# Steam	134°API Oil	293	200	70	290	2,800	1
E-5037	Depropanizer Overhead Condenser	Water	150°API Oil	120	130	150	290	2,800	1
E-5038	Depropanizer Reboiler	35°API Oil	114°API Oil	415	226	375	290	710	1
E-5039	Splitter Bottoms Cooler	Water	35°API Oil	120	315	150	275	3,000	1
E-5040	Lean Oil Cooler	Water	35°API Oil	120	100	150	275	220	1
E-5041	Deisobutanizer Overhead Condenser	Water	118°API Oil	120	142	150	135	4,600	2
E-5042	Deisobutanizer Reboiler	45# Steam	110°API Oil	293	165	70	135	1,000	1
E-5043	Deisobutanizer Bottoms Cooler	Water	110°API Oil	120	165	150	135	210	1
E-5044	H_2S Absorber Feed Preheater	45# Steam	150°API Oil	293	150	70	310	830	1
E-5045	Lean Amine Solution Cooler	Water	10°API Amine Solution	120	175	150	300	160	1
E-5046	H_2S Absorber Overhead Condenser	Water	150°API Oil	120	150	150	285	1,100	1
E-5047	Lean-Rich AmineSolutions Exchanger	10°API Amine Solution	10°API Amine Solution	230	205	300	285	900	1
E-5048	Reactivator Reboiler	45# Steam	10°API Amine Solution	293	230	70	35	270	1
E-5049	Reactivator Overhead Cooler	Water	Hydrogen Sulfide	120	220	150	35	140	1
E-5050	Feed-Vapor Phase Still Overhead Exchanger	45.7°API Oil	58.0°API Oil	242	350	285	90	7,050	2

VAPOR PHASE DISTILLATION UNIT FOR 30,000 B/SD COAL HYDROGENATION PLANT

Equipment Summary
(Cont'd.)

Furnaces

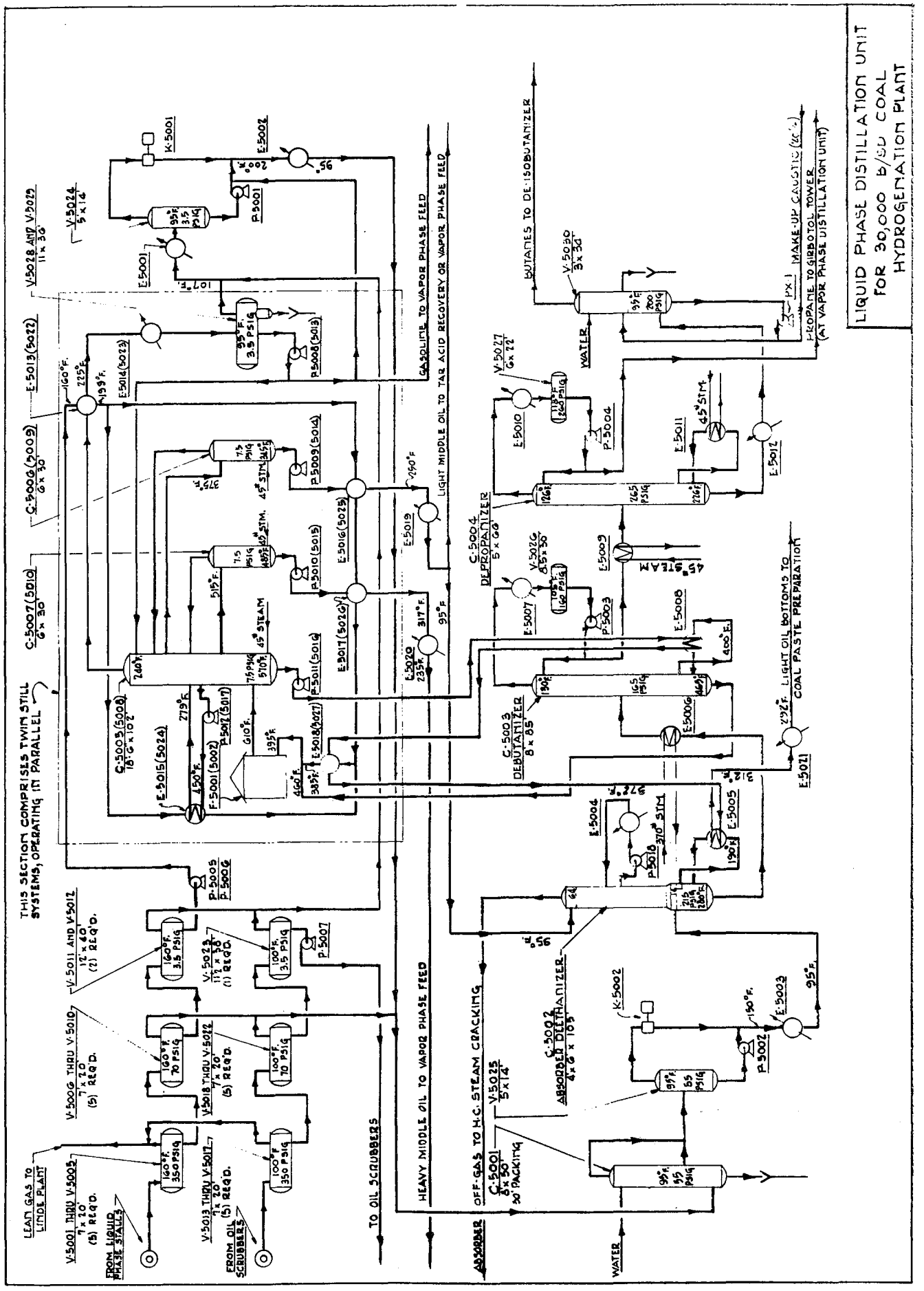
Item	Service	Fluid Flowing	Flow Lbs./Hr.	M.W.	% Vapor In	% Vapor Out	Design Temperature In °F.	Design Temperature Out °F.	Design Pressure In Psig	Duty MM Btu/Hr.
F-5003	Vapor Phase Still Reboiler	45.7°API Oil	542,990	77.5	5	100	310	480	285	84
F-5004	Debutanizer Reboiler	43.8°API Oil	823,000	107	0	100	430	430	290	56.2
F-5005	Splitter Reboiler	35°API Oil	690,000	140	0	100	415	415	275	37

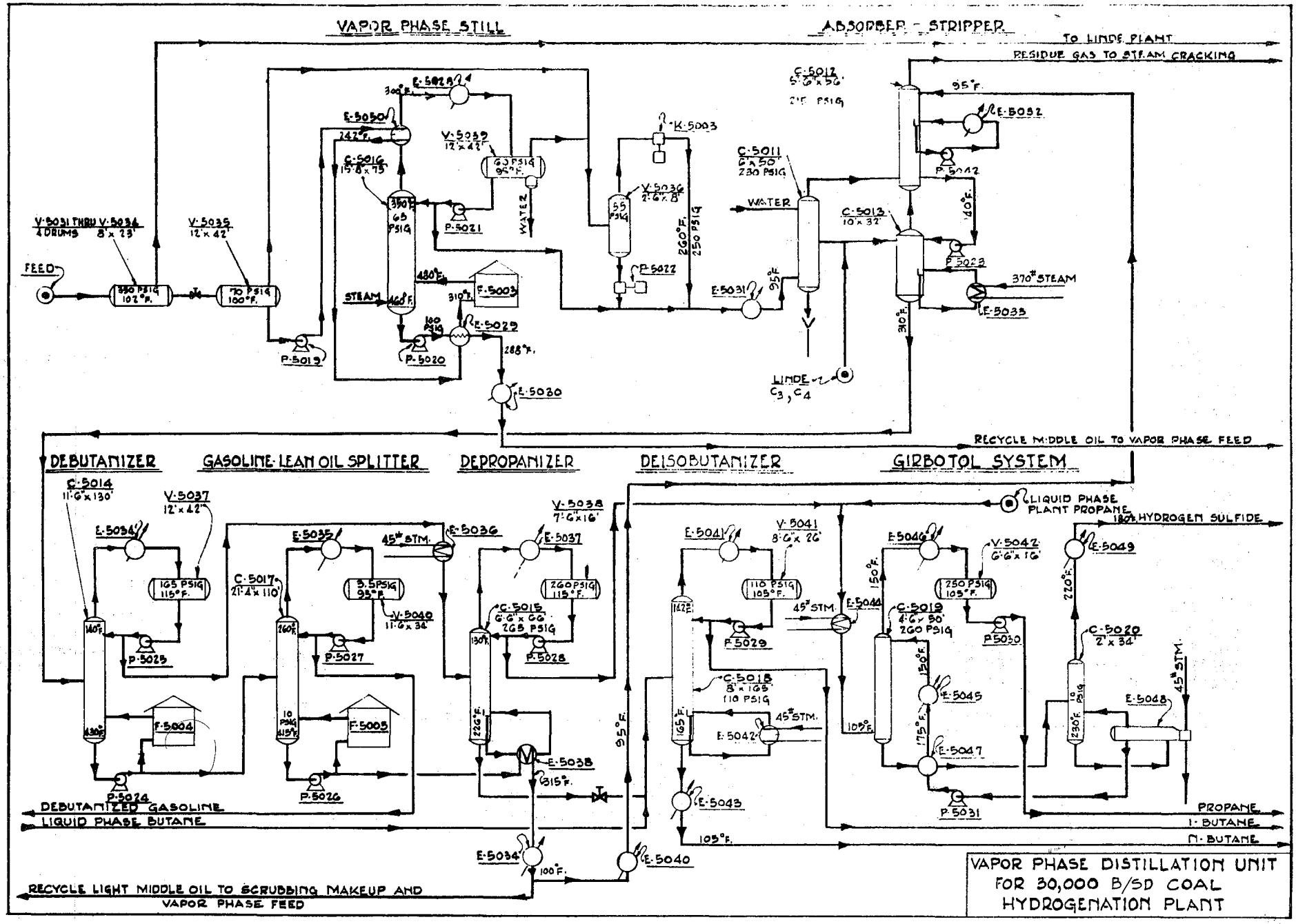
Pumps

Item	Service	Type of Drive	Material Pumped	Design Pumping Rate Hot GPM	Design Temperature °F.	Design Pressure Suction Psig	Design Pressure Discharge Psig	Driver Rating BHP	Number of Operating Units	Number of Spares
P-5019	Feed Pump	Motor	45.7°API Oil	1440	100	70	285	250	1	1
P-5020	Vapor Phase Still Bottoms Pumps	Motor	27.7°API Oil	620	460	65	100	20	1	1
P-5021	Vapor Phase Still Overhead Pump	Motor	58.8°API Oil	1550	95	60	250	250	1	1
P-5022	Compressor Intake Drum Liquid Pump	Steam Reciprocating	80°API Oil	50	100	55	250		1	1
P-5023	Rich Oil from Absorber Pump	Motor	67.8°API Oil	390	140	215	265	20	1	1
P-5024	Debutanizer Furnace Recycle and Bottoms Pump	Motor	43.8°API Oil	1980	430	165	290	200	2	1
P-5025	Debutanizer Overhead Pump	Motor	134°API Oil	1275	115	165	290	150	1	1
P-5026	Splitter Furnace Recycle and Bottoms Pump	Motor	35°API Oil	2500	415	10	275	500	1	1
P-5027	Splitter Overhead Pump	Motor	48.4°API Oil	1280	95	3.5	103.5	100	1	1
P-5028	Depropanizer Overhead Pump	Motor	150°API Oil	430	115	260	310	20	1	1
P-5029	Deisobutanizer Overhead Pump	Motor	118°API Oil	575	105	110	160	25	1	1
P-5030	H_2S Absorber Overhead Pump	Motor	150°API Oil	195	105	250	290	7.5	1	1
P-5031	Lean Amine Circulation Pump	Motor	10°API Oil	150	230	10	300	50	1	1
P-5042	Absorber Side Stream Pump	Motor	50°API Oil	340	140	235	285	15	1	1

Compressors

Item	Service	Type of Drive	Material Compressed	Design Flow Rate CFM at Suction Conditions	Design Temperature Suction °F.	Design Temperature Discharge °F.	Design Pressure Suction Psig	Design Pressure Discharge Psig	Estimated Compressor Efficiency %	Driver Rating BHP	Remarks
K-5003	Vapor Recovery	Motor	MW =23.6	392	95	260	55	250	80	300	Provide a spare.


LIQUID PHASE DISTILLATION UNIT
FOR 30,000 B/SD COAL
HYDROGENATION PLANT
THIS SECTION COMPRISES TWIN STILL SYSTEMS, OPERATING IN PARALLEL
LEAN GAS TO LINDE PLANT
FROM LIQUID PHASE STILLS
FROM OIL SCRUBBERS
TO OIL SCRUBBERS
HEAVY MIDDLE OIL TO VAPOR PHASE FEED
LIGHT MIDDLE OIL TO TAR ACID RECOVERY OR VAPOR PHASE FEED
GASOLINE TO VAPOR PHASE FEED
OFF-GAS TO H.C. STEAM CRACKING
ABSORBER
WATER
BUTANES TO DE-ISOBUTANIZER
PROPANE TO GIBBOTOL TOWER (AT VAPOR PHASE DISTILLATION UNIT)
MAKE-UP CAUSTIC (20%)
LIGHT OIL BOTTOMS TO COAL PASTE PREPARATION
C-5003 DEBUTANIZER 8' x 85'
C-5004 DEPROPANIZER 5' x 66'
C-5002 ABSORBER DEETHANIZER 4'-6" x 105'
C-5001 8' x 50' 30' PACKING
V-5025 5' x 14'
V-5028 AND V-5029 11' x 30'
V-5024 5' x 14'
V-5030 3' x 30'
V-5027 6' x 12'
V-5026 6'5" x 30'
V-5011 AND V-5012 12' x 40' (2) REQ'D.
V-5023 11' x 30' (1) REQ'D.
V-5001 THRU V-5005 7' x 20' (5) REQ'D.
V-5006 THRU V-5010 7' x 20' (5) REQ'D.
V-5013 THRU V-5017 7' x 20' (5) REQ'D.
V-5018 THRU V-5022 7' x 20' (5) REQ'D.
C-5005 (5008) 18'-6" x 102'
C-5006 (5009) 6' x 30'
C-5007 (5010) 6' x 30'
E-5001
E-5002
E-5003
E-5004
E-5005
E-5006
E-5007
E-5008
E-5009
E-5010
E-5011
E-5012
E-5013 (5022)
E-5014 (5023)
E-5015 (5024)
E-5016 (5025)
E-5017 (5026)
E-5018 (5027)
E-5019
E-5020
E-5021
E-5022
E-5023
E-5024
E-5025
E-5026
E-5027
E-5028
E-5029
E-5030
P-5001
P-5002
P-5003
P-5004
P-5005
P-5006
P-5007
P-5008 (5013)
P-5009 (5014)
P-5010 (5015)
P-5011 (5016)
P-5012 (5017)
P-5013 (5018)
P-5014 (5019)
P-5015 (5020)
P-5016 (5021)
P-5017 (5028)
P-5018 (5029)
K-5001
K-5002
45# STEAM
45# STM.
350 PSIG
70 PSIG
3.5 PSIG
7.5 PSIG
55 PSIG
165 PSIG
200 PSIG
260 PSIG


VAPOR PHASE STILL
ABSORBER - STRIPPER
TO LINDE PLANT
RESIDUE GAS TO STEAM CRACKING
FEED
V-5031 THRU V-5034 4 DRUMS 8'x 23'
V-5035 12'x 42'
E-5029A
E-5030
V-5039 12'x 42'
C-5016 15'-8"x 75'
P-5021
WATER
K-5003
V-5036 2'-6"x 8'
P-5022
P-5019
P-5020
E-5029
E-5003
STEAM
E-5030
E-5031
C-5012 5'-6"x 96' 215 PSIG
C-5011 6'x 50' 230 PSIG
WATER
C-5013 10'x 32'
E-5032
P-5042
P-5023
370# STEAM
E-5033
LINDE C3, C4
RECYCLE MIDDLE OIL TO VAPOR PHASE FEED
DEBUTANIZER
GASOLINE-LEAN OIL SPLITTER
DEPROPANIZER
DEISOBUTANIZER
GIRBOTOL SYSTEM
C-5014 11'-6"x 130'
V-5037 12'x 42'
E-5034
P-5025
F-5004
C-5017 21'-4"x 110
E-5035
E-5036
45# STM.
V-5040 11'-6"x 34'
P-5027
F-5005
V-5038 7'-6"x 16'
E-5037
C-5015 6'-6"x 66' 265 PSIG
P-5028
E-5038
E-5041
V-5041 8'-6"x 26'
P-5029
C-5018 8'x 165 110 PSIG
E-5042
E-5043
E-5044
E-5046
V-5042 6'-6"x 16'
C-5019 4'-6"x 50' 260 PSIG
P-5030
E-5045
E-5047
P-5031
LIQUID PHASE PLANT PROPANE
HYDROGEN SULFIDE
E-5049
C-5020 2'x 34'
E-5048
DEBUTANIZED GASOLINE
LIQUID PHASE BUTANE
PROPANE
I-BUTANE
N-BUTANE
E-5034
E-5040
P-5024
P-5026
RECYCLE LIGHT MIDDLE OIL TO SCRUBBING MAKEUP AND VAPOR PHASE FEED
VAPOR PHASE DISTILLATION UNIT FOR 30,000 B/SD COAL HYDROGENATION PLANT

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
TAR ACID RECOVERY UNIT

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Drums	$ 13,000			$ 13,000	$ 1,900	$ 14,900
Exchangers	85,000			87,700	4,000	91,700
Furnaces	210,000			281,000	58,000	339,000
Pumps & Drivers	13,000			48,000	6,000	54,000
Towers & Internals	235,000			200,000	28,000	228,000
Special Equipment	-			10,000	1,600	11,600
Total Equipment	$ 556,000	$ 95,000	$ 651,000	$ 639,700	$ 99,500	$ 739,200
Buildings	20,000	10,000	30,000	42,000	20,000	62,000
Concrete	45,000	45,000	90,000	32,000	64,000	96,000
Electrical	56,000	28,000	84,000	21,000	12,000	33,000
Instruments	55,000	22,000	77,000	46,500	17,000	63,500
Insulation	22,000	22,000	44,000	29,800	25,000	54,800
Mech. Handling Equip.	-	-	-	3,600	500	4,100
Painting	5,600	16,800	22,400	5,000	8,500	13,500
Piping	195,000	97,500	292,500	330,000	220,000	550,000
Struct. Steel	34,000	17,000	51,000	43,000	26,300	69,300
Miscellaneous	27,400	27,700	55,100	30,400	54,200	84,600
Total Direct	$ 1,016,000	$ 381,000	$ 1,397,000	$ 1,223,000	$ 547,000	$ 1,770.000
Others			698,000			830,000
Total			$ 2,095,000			$ 2,600,000

TAR ACID RECOVERY UNIT

The Tar Acid Recovery Unit was designed by the Bureau of Mines to separate various tar acids from a light middle oil fraction produced in the Liquid Phase Product Distillation Unit. This middle oil fraction is scrubbed with a methanol to remove all of the phenols and some neutral oils. The mixed tar acids are separated by vacuum distillation into pure phenol, ortho-cresol, mixed meta-para cresols, xylenols, and higher tar acids. The latter stream is returned to the Vapor Phase Hydrogenation Unit together with the neutral oils. The purified phenols are sent to storage after cooling.

The investment cost of the Tar Acid Recovery facilities was based on the Process Subcommittee's report of November 9, 1950. Equipment lists for these facilities are shown on the following pages. This report recommended a few relatively minor changes to the design as prepared by Bureau of Mines, all of which increased the cost of the facilities.

A comparison of the costs prepared by the Subcommittee as of January 1951, with those prepared by the Bureau as of February 1948 is shown on the opposite page. This Committee's estimate is approximately 24% above that of the Bureau's. Approximately 50% of this is due to increase in prices since the date of the Bureau's estimate and approximately 25% due to changes suggested by the Process Subcommittee. The remaining differences seem to be generally distributed through the estimate.

30,000 BPD COAL HYDROGENATION PLANT

EQUIPMENT SUMMARY

TAR ACID RECOVERY SECTION

Exchangers		Duty MBTU/Hr.	Surface S.F.	Max. Temp. Shell	Max. Temp. Tubes	Max. Press. Shell	Max. Press. Tubes	Material Shell	Material Tubes	Cor. Allow. Inches
E-5051	Middle Oil Preheater	11,955	733	180	450	9	370	C.S.	C.S.	1/4
E-5052	Middle Oil Reboiler	14,735	1,474	375	450	9	370	C.S.	C.S.	1/4
E-5053	Naphtha Condenser	22,530	3,220	250	120	9	50	C.S.	C.S.	1/8
E-5054	Naphtha Cooler	2,850	1,680	160	120	35	50	C.S.	C.S.	1/8
E-5055	Middle Oil Cooler	990	192	375	120	60	50	C.S.	C.S.	1/4
E-5056	Methanol Preheater	21,785	800	192	450	9	370	C.S.	C.S.	1/4
E-5057	Methanol Condenser	84,250	4,530	212	120	9	50	C.S.	C.S.	1/8
E-5058	Methanol Cooler	5,850	1,470	192	120	60	50	C.S.	C.S.	1/8
E-5059	Phenol Condenser	8,900	580	291	120	Vac.	50	C.S.	316	-
E-5060	Phenol Cooler	171	28	281	120	15	50	C.S.	C.S.	1/8
E-5061	o-Cresol Reboiler	8,063	850	342	450	Vac.	370	C.S.	316	-
E-5062	o-Cresol Condenser	3,750	231	293	120	Vac.	50	C.S.	316	-
E-5063	o-Cresol Cooler	162	10	293	120	15	50	C.S.	C.S.	1/8
E-5064	Xylenol Reboiler	3,624	348	333	450	Vac.	370	C.S.	316	-
E-5066	Tar Acids Reboiler	8,659	932	344	450	Vac.	370	C.S.	316	-
E-5067	m-Cresols Condenser	8,600	480	304	120	Vac.	50	C.S.	316	-
E-5068	m-Cresols Cooler	325	50	304	120	15	50	C.S.	C.S.	1/8
E-5069	Tar Acids Reboiler	5,226	475	327	450	Vac.	370	C.S.	316	-
E-5070	Xylenols Condenser	5,460	319	304	120	Vac.	50	C.S.	316	-
E-5071	Xylenols Cooler	493	77	304	120	15	50	C.S.	C.S.	1/8
E-5072	Tar Acids Cooler	251	36	327	120	15	50	C.S.	316	-
Fired Heater										
F-5006	Phenols Reboiler	60,775	8,700	-	421	-	15	-	12% Cr.	-

30,000 BPD COAL HYDROGENATION PLANT

EQUIPMENT SUMMARY

TAR ACID RECOVERY SECTION

Towers		Diam. Ft.	Length Ft.	Trays	Press. psig.	Temp. °F.	Corros. Allow. Inches
C-5021	Naphtha Fractionator	10	40	12	9	375	1/4
C-5022	Methanol Fractionator	12	40	12	9	421	1/4
C-5023	Phenol Fractionator	7	65	30	Vac.	342	1/4
C-5024	o-Cresol Fractionator	5	72	34	Vac.	333	1/4
C-5025	Middle Oil Extractor	9	37	Packg.	55	100	1/8
C-5026	Naphtha Extractor	9	44	Packg.	2	100	1/8
C-5027	m-p-Cresol Fractionator	8	62	28	Vac.	344	1/4
C-5028	Xylenol Fractionator	8	57	25	Vac.	327	1/4
Vessels							
V-5043	Reflux Drum	8	23	-	9	160	1/8
V-5044	Reflux Drum	8	23	-	9	194	1/8
V-5045	Reflux Drum	5.5	15	-	Vac.	281	1/8
V-5046	Reflux Drum	3.5	11	-	Vac.	283	1/8
V-5047	Reflux Drum	5	15	-	Vac.	305	1/8
V-5048	Reflux Drum	5	15	-	Vac.	294	1/8

Pumps		GPH. (60°F.)	Press psig. Suction	Press psig. Discharge	Temp. °F.	BHP	Trim	Drive
P-5032	Neutral Middle Oil	9060	10	100	100	11.5	Iron	Motor
P-5033	Methanol Extract	14620	10	50	100	8.3	Iron	Motor
P-5034	Middle Oil	1175	10	75	375	1.1	Iron	Motor
P-5035	Naphtha	22600	10	50	160	12.8	Iron	Motor
P-5036	Methanol-Water	18300	10	75	192	16.8	Iron	Motor
P-5037	Furnace Recycle	61700	10	110	421	87.5	S.S.	Motor
P-5038	Phenol	4870	-6.4	50	200	4.2	Iron	Motor
P-5039	Phenol Bottoms	2114	-6.4	10	342	.6	S.S.	Motor
P-5040	O-Cresol	2240	-7.4	50	200	1.9	Iron	Motor
P-5041	O-Cresol Bottoms	1968	-7.4	10	333	.6	S.S.	Motor
P-5043	m-p Cresol	5360	-7.4	50	200	4.6	Iron	Motor
P-5044	m-p Bottoms	1350	-7.4	10	344	.4	S.S.	Motor
P-5045	Xylenols	3460	-9.4	50	200	3.1	Iron	Motor
P-5046	Tar Acids	593	-9.4	75	327	.7	S.S.	Motor

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
LOW TEMPERATURE GAS SEPARATION UNIT

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Aeration Towers	$ 84,000			$ 191,000	$ 23,000	$ 214,000
Compressors	502,200			296,300	14,000	310,300
Exchangers	1,000,000			--	--	--
Pumps & Drivers	54,200			480,000	20,000	500,000
Tanks	9,000			5,500	3,200	8,700
Towers & Internals	150,600			239,000	42,000	281,000
Low Temp. Unit Complete	--			3,903,000	667,000	4,570,000
Total Equipment	$1,800,000	$ 300,000	$2,100,000	$5,114,800	$ 769,200	$5,884,000
Buildings	360,000	180,000	540,000	29,000	21,000	50,000
Concrete	130,000	130,000	260,000	48,700	101,300	150,000
Electrical	240,000	120,000	360,000	137,000	56,000	193,000
Instruments	60,000	24,000	84,000	71,000	33,000	104,000
Insulation	50,000	50,000	100,000	--	--	--
Mech. Handling Equip.	--	--	--	1,600	100	1,700
Painting	12,000	36,000	48,000	8,000	25,000	33,000
Piping	200,000	100,000	300,000	501,000	250,000	751,000
Struct. Steel	100,000	50,000	150,000	30,000	20,000	50,000
Miscellaneous	40,000	40,000	80,000	78,900	94,400	173,300
Total Direct	$2,992,000	$1,030,000	$4,022,000	$6,020,000	$1,370,000	$7,390,000
Others			2,006,000			3,010,000
Total			$6,028,000			$10,400,000

LOW TEMPERATURE OFF-GAS SEPARATION

This Unit was designed by the Bureau of Mines to produce about 15 per cent of the required hydrogen by low temperature separation of the off gas from the Liquid and Vapor Phase Distillation and Hydrogenation Units. The gases are first scrubbed with water at high pressure to remove ammonia and most of the carbon dioxide and hydrogen sulfide. The last traces of carbon dioxide and hydrogen sulfide are removed by scrubbing with a caustic solution. The purified gases are then separated by low temperature fractionation into a propane-butane fraction and a ethane-methane fraction, leaving nitrogen, carbon monoxide and hydrogen. By further cooling, the carbon monoxide and nitrogen are liquefied, leaving a substantially pure hydrogen stream which is returned after heat exchange to the hydrogenation section of the plant. The methane and ethane are sent to the Hydrocarbon Steam Cracking Unit for conversion to hydrogen. The propane-butane fraction is fed to the Vapor Phase Distillation Unit for further separation.

The investment cost for the Unit was determined by the Subcommittee on two bases. The purification section was reviewed by the Process Subcommittee in their report of January 23, 1951. This report recommended a few changes and additions of equipment omitted by the Bureau of Mines, all of which increased the cost. The low-temperature fractionation equipment costs were based on quotations from several of the leading companies in this field. This Committee used the lowest cost obtained from these quotations.

A comparison of the costs prepared by the Subcommittee as of January 1951 with those prepared by the Bureau as of February 1948 is shown on the opposite page. The Subcommittee's estimate is considerably higher than that of the Bureau's. This is due to the higher costs of the low temperature fractionation unit and the additional equipment which was specified by the Process Subcommittee. The detailed estimate shown by the Subcommittee is for the purification section only, whereas that of the Bureau is based on the entire Linde Plant. Thus, for example, the compressor costs for the Bureau are for the entire plant, while the cost shown by the Subcommittee is for the compressors added by the Process Subcommittee which the Bureau had omitted.

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
HYDROCARBON STEAM CRACKING AND GIRBOTOL UNIT

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Compressors	$ 30,000			$ 330,000	5,000	$ 335,000
Exchangers	436,856			480,000	10,000	490,000
Furnace	1,233,200			2,200,000	700,000	2,900,000
Girbotol Unit	178,000				Included Below	
Towers & Internals	121,944			180,000	60,000	240,000
Gas Holders	---			55,000	15,000	70,000
Producer Gas Generator	1,000,000			1,100,000	200,000	1,300,000
Stacks	---			60,000	70,000	130,000
Total Equipment	$3,000,000	$510,000	$3,510,000	$4,405,000	$1,060,000	$5,465,000
Buildings	$ 50,000	$ 25,000	$ 75,000	$ 140,000	$ 130,000	$ 270,000
Concrete	113,000	113,000	226,000	120,000	200,000	320,000
Electrical	50,000	25,000	75,000	170,000	120,000	290,000
Instruments	86,000	34,000	120,000	330,000	140,000	470,000
Insulation	75,000	75,000	150,000	100,000	90,000	190,000
Painting	10,000	30,000	40,000	15,000	30,000	45,000
Piping	282,000	141,000	423,000	1,080,000	400,000	1,480,000
Structural Steel	170,000	85,000	255,000	170,000	60,000	230,000
Miscellaneous	100,000	100,000	200,000	270,000	270,000	540,000
Girbotol Unit		Included Above		100,000	50,000	150,000
Total Direct	$3,936,000	$1,138,000	$5,074,000	$6,900,000	$2,550,000	$9,450,000
Others			2,420,000			4,450,000
Total			$7,494,000			$13,900,000

HYDROCARBON STEAM CRACKING AND GIRBOTOL UNIT

The Hydrocarbon Steam Cracking Unit was designed by the Bureau of Mines to produce hydrogen from the lighter fractions of the hydrocarbons synthesized in the hydrogenation process. Gases from the Linde plant and product distillation unit are preheated and sent to the cracking furnace. The cracked gases are partially cooled, introduced with steam into a shift converter where carbon monoxide and additional hydrogen are produced. The Girbotol Unit removes H_2S and CO_2 from the lean and HOLD gas to the Linde plant, from the absorber off gas to cracking, and from the propane product.

The investment cost of this unit was based on the Process Subcommittee report of January 12, 1951 entitled, "NPC Process Review of Hydrocarbon Steam Cracking Section of the Bureau of Mines, 30,000 B/D Coal Hydrogenation Plant". Certain revisions to the Bureau of Mines design were recommended which included the addition of a gas holder and compressor for the Linde gas and thus increased, to some extent, the cost of the unit. An Equipment list and flow plan for this unit appear on the following pages.

A comparison of costs prepared by the Subcommittee as of January 1951 with those prepared by the Bureau as of February 1948 appears on the opposite page. The Committee's estimate is 85% higher than the Bureau's estimate. Approximately 15% of this difference is due to price increases since the date of the Bureau estimate and approximately 5% due to changes suggested by the Process Subcommittee. In general all the items appear to be higher than estimated by the Bureau, although piping and furnace estimates contribute a substantial share of the difference.

HYDROCARBON STEAM CRACKING UNIT

COMPRESSORS

K-3000 Air Blower, 26,400 CFM at 60°F., 8" water discharge, intake at 1 Atm., 4 required.
K-3001 Flue Gas Blower, 75,000 CFM at 400°F., 8" water discharge, intake at 1 Atm., 4 required.
K-3099 Linde Plant Gas Compressor, 4250 CFM at 100°F., 11.3 psia, 50 psi differential pressure.

EXCHANGERS

E-3000 Air Preheater, 3250 sq. ft. per unit, 4 units required.
E-3001 Flue Gas Waste Heat Boiler, 11,300 sq. ft. per unit, 4 units required.
E-3002 and E-3003 Product Steam Superheater, 1320 sq. ft. per unit, 8 units required.
E-3004 and E-3005 Product Feed Exchanger, 725 sq. ft. per unit, 8 units required.
E-3006 Product Waste Heat Boiler, 4400 sq. ft. per unit, 4 units required.

FURNACE

F-3000 and F-3001 Hydrocarbon Steam Cracking Furnace, 8 units required.

TOWERS

C-3000 Product Gas Cooling Tower, 4 required, 12' ID x 20', 450°F., 10 psig.
V-3000 and V-3001 CO Shift Converter, 8 required, 15'ID x 12', 960°F., interior insulation, 2.5 psig.

GAS HOLDERS

T-3099 Gas Holder for Linde Methane and Ethane, 250,000 CF, one required.

PRODUCER GAS GENERATOR

Prg-3000 and Prg-3001, each unit produces 530MSCFPH of gas of 125 Btu/CF net H.V., 8 units required.

GIRBOTOL UNIT

EXCHANGERS

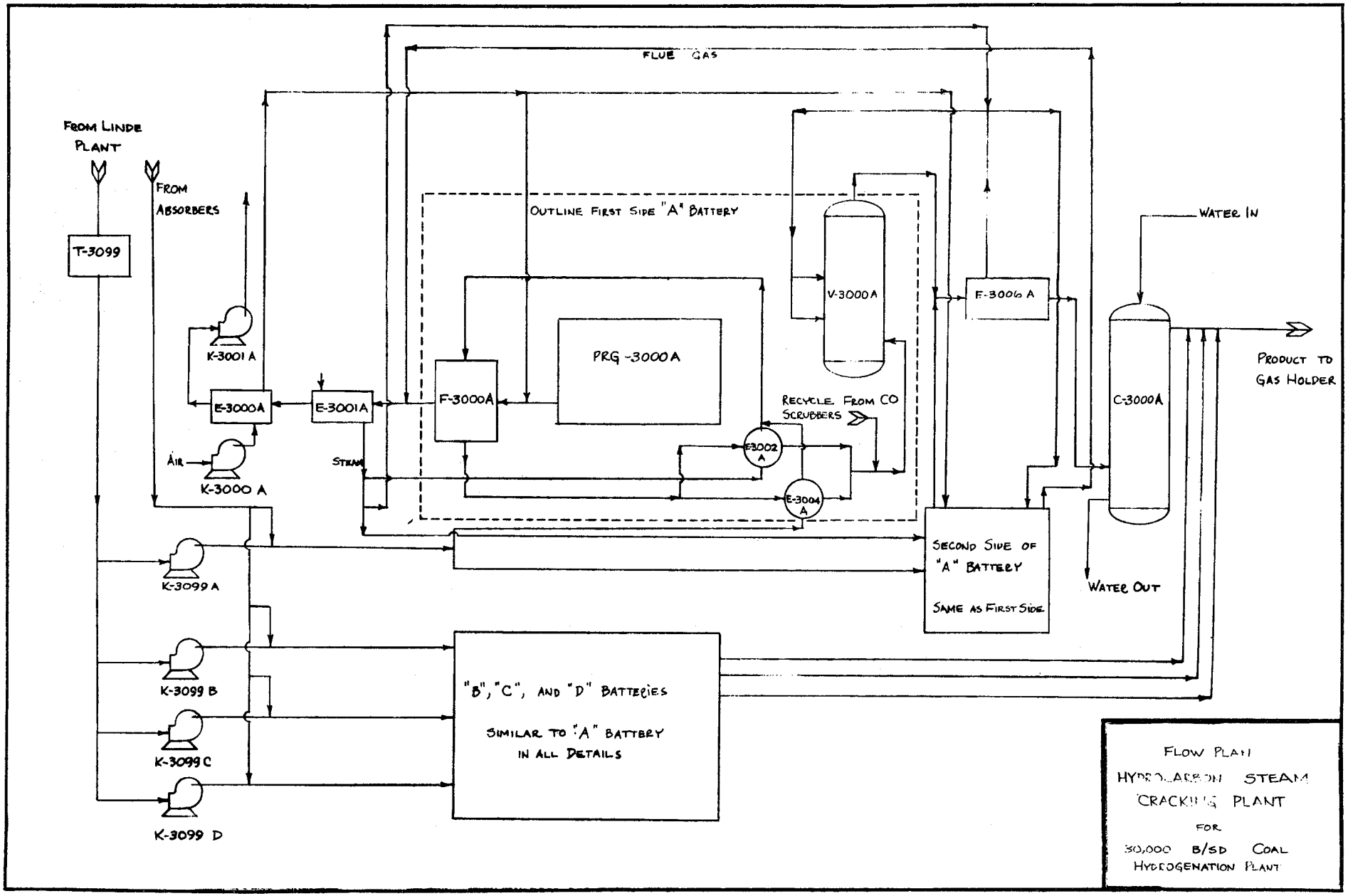
E-3094 Lean Amine Solution Cooler, 430 sq. ft., one unit required.
E-3096 Lean-Rich Amine Solutions Exchanger, 2346 sq. ft., one unit required.
E-3098 Reactivator Overhead Cooler, 370 sq. ft., one unit required.
E-3099 Reactivator Reboiler, 715 sq. ft., one unit required.

TOWERS

C-3097 H_2S and CO_2 Absorber, 1 required, 5' ID x 50', 24 trays, 150°F., 285 psig.
C-3099 Amine Reactivator, 1 required, 3'3" ID x 34', 12 trays, 230°F, 35 psig.

PUMPS

P-3098 Lean Amine Circulation Pump, 400 GPM, Inlet 10 psig, outlet 300 psig, 230°F., 130 BHP, one required.


FLUE GAS
FROM LINDE PLANT
FROM ABSORBERS
T-3099
OUTLINE FIRST SIDE "A" BATTERY
WATER IN
K-3001 A
E-3000A
E-3001A
F-3000A
PRG -3000A
V-3000A
E-3006 A
C-3000A
PRODUCT TO GAS HOLDER
RECYCLE FROM CO SCRUBBERS
E-3002 A
E-3004 A
AIR
STEAM
K-3000 A
SECOND SIDE OF "A" BATTERY
SAME AS FIRST SIDE
WATER OUT
K-3099 A
K-3099 B
K-3099 C
K-3099 D
"B", "C", AND "D" BATTERIES
SIMILAR TO "A" BATTERY IN ALL DETAILS
FLOW PLAN
HYDROCARBON STEAM CRACKING PLANT
FOR
30,000 B/SD COAL HYDROGENATION PLANT

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
COAL GASIFICATION UNIT

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Compressors				$ 12,300	$ 700	$ 13,000
Drums				14,000	2,800	16,800
Furnaces				110,000	31,000	141,000
Gasifiers				340,000	225,000	565,000
Pumps & Drivers				11,500	900	12,400
Shell & Tube Equipment				485,500	15,500	501,000
Towers & Internals				119,500	18,500	138,000
Coal Handling Equipment				789,000	161,000	950,000
Total Equipment				1,881,800	455,400	2,337,200
Buildings				27,600	20,200	47,800
Concrete				75,000	150,000	225,000
Electrical				62,500	48,000	110,500
Instruments				154,000	66,000	220,000
Insulation				55,000	45,600	100,600
Mech. Handling Equipment				18,000	2,000	20,000
Painting				14,000	43,000	57,000
Pipe Work				568,000	284,000	852,000
Structural Steel				236,000	94,000	330,000
Miscellaneous				153,100	96,800	249,900
Total Direct	$5,550,000	$2,500,000	$8,050,000	$3,245,000	$1,305,000	$4,550,000
Others			4,298,000			2,150,000
Total			$12,348,000			$6,700,000

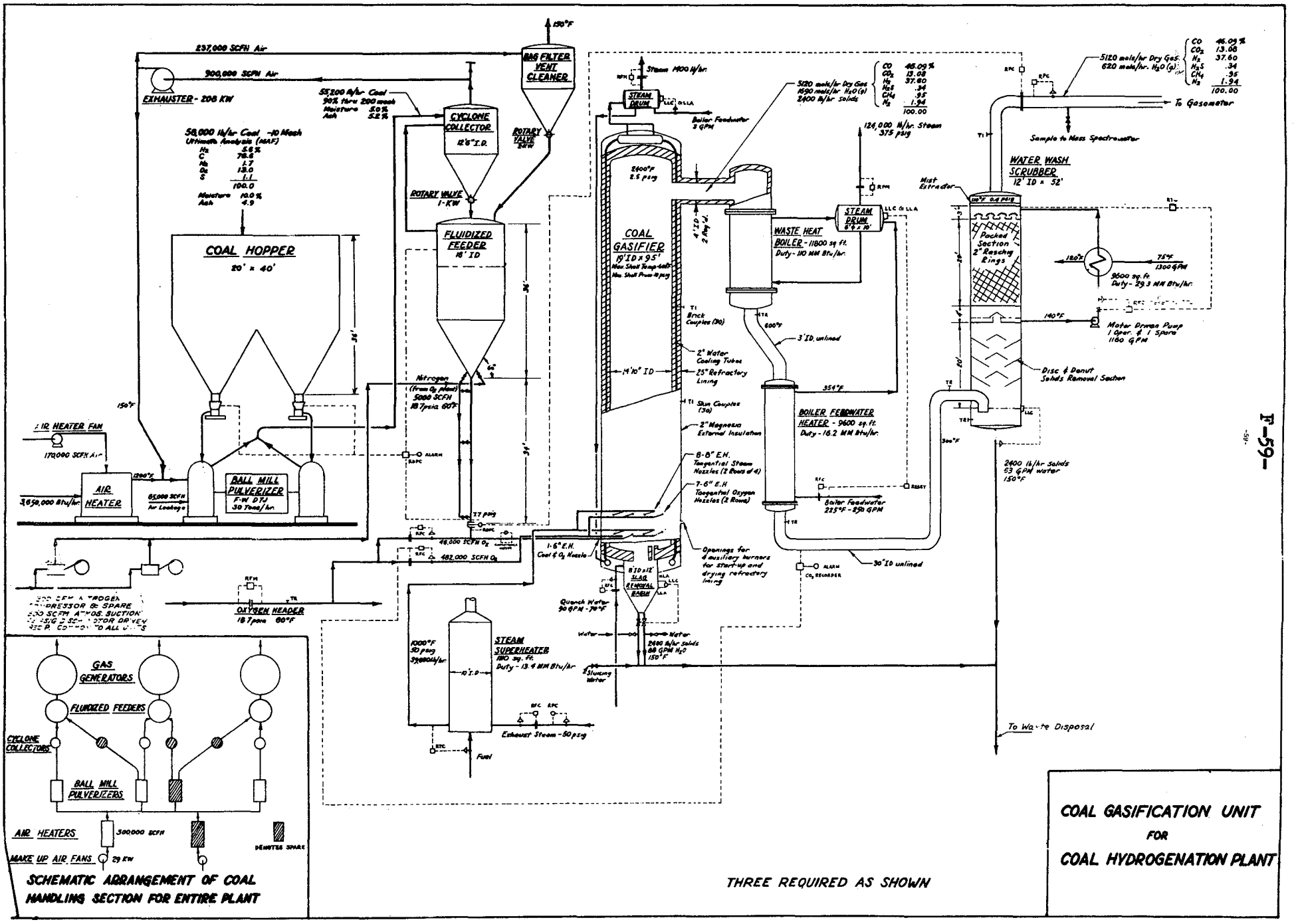
COAL GASIFICATION UNIT

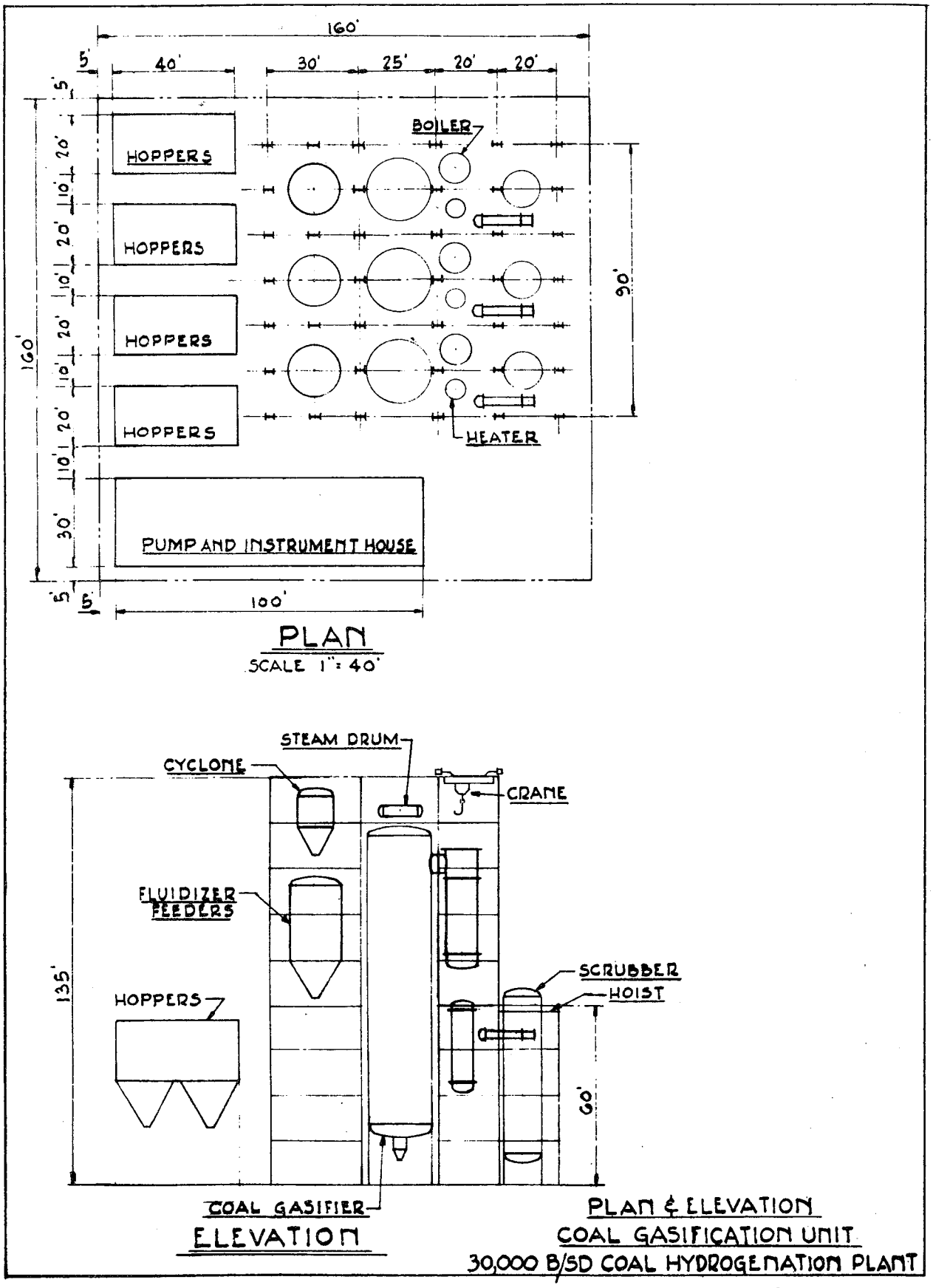
These facilities provide one of the two sources of hydrogen make up for the coal hydrogenation plant. The process involves reaction of dried pulverized coal with oxygen and steam at 2400°F. and substantially atmospheric pressure to produce a mixture predominately of hydrogen, carbon monoxide, and carbon dioxide. Additional conversion of the carbon monoxide gas to hydrogen and purification of the resultant hydrogen is done in other facilities described under the hydrogen purification and compression unit.

The unit was designed by the Process Subcommittee using experimental data obtained by the Bureau. The Bureau agreed to the design as adequately representing required facilites for atmospheric coal gasification.

The estimate of the Engineering Subcommittee is based on the equipment shown on the following flow diagram which incorporates the Engineering Subcommittee's minor modifications to the Process Subcommittee design. A plot and elevation plan of the unit is also shown.

This Subcommittee's estimate of cost is compared with that prepared by the Bureau on the opposite page. No detailed comparison is made because of the differences in type of units. It is evident that considerable reduction in investment cost nas occurred by the use of the committee's design.


237,000 SCFH Air
300,000 SCFH Air
EXHAUSTER - 206 KW
55,200 lb/hr Coal
90% thru 200 mesh
Moisture 20%
Ash 5.2%
58,000 lb/hr Coal -10 Mesh
Ultimate Analysis (MAF)
H2 5.6%
C 78.8
N2 1.7
O2 13.0
S 1.1
100.0
Moisture 10.0%
Ash 4.9
COAL HOPPER
20' x 40'
AIR HEATER FAN
170,000 SCFH Air
AIR HEATER
3,650,000 Btu/hr
BALL MILL PULVERIZER
F-W D12
30 Tons/hr
65,000 SCFH
Air Leakage
CYCLONE COLLECTOR
12'6" I.D.
ROTARY VALVE
1-KW
FLUIDIZED FEEDER
18' ID
Nitrogen
(from O2 plant)
5000 SCFH
187 psia 60°F
48,000 SCFH O2
482,000 SCFH O2
OXYGEN HEADER
187 psia 60°F
BAG FILTER VENT CLEANER
150°F
Steam 1400 lb/hr
STEAM DRUM
Boiler Feedwater
3 GPM
COAL GASIFIER
19'ID x 95'
Max. Shell Temp-460°F
Max. Shell Press-815 psig
2400°F
2.5 psig
4'ID
2 Avg. H.
Brick Couples (10)
2" Water Cooling Tubes
25" Refractory Lining
Skin Couples (30)
2" Magnesia External Insulation
14'10" ID
8-8" E.H. Tangential Steam Nozzles (2 Rows of 4)
7-6" E.H. Tangential Oxygen Nozzles (2 Rows)
1-6" E.H. Coal & O2 Nozzle
Openings for 4 auxiliary burners for start-up and drying refractory lining
8'ID x 12' SLAG REMOVAL RAM
Quench Water 90 GPM - 70°F
Water
Water
2400 lb/hr Solids
68 GPM H2O
150°F
Sluicing Water
STEAM SUPERHEATER
180 sq. ft.
Duty - 13.4 MM Btu/hr
1000°F
50 psig
39,800 lb/hr
10'I.D.
Exhaust Steam - 50 psig
Fuel
5120 mols/hr Dry Gas
1590 mols/hr H2O(g)
2400 lb/hr Solids
CO 46.09%
CO2 13.08
H2 37.60
H2S .34
CH4 .95
N2 1.94
100.00
124,000 lb/hr Steam
375 psig
WASTE HEAT BOILER - 11800 sq ft.
Duty - 110 MM Btu/hr.
STEAM DRUM
6'4" x 10'
600°F
3'ID unlined
354°F
BOILER FEEDWATER HEATER - 9600 sq. ft.
Duty - 16.2 MM Btu/hr.
Boiler Feedwater
225°F - 850 GPM
30"ID unlined
CO2 RECORDER
5120 mols/hr Dry Gas
620 mols/hr H2O(g)
To Gasometer
Sample to Mass Spectrometer
WATER WASH SCRUBBER
12' ID x 52'
Mist Extractor
110°F
0.4 psig
Packed Section 2" Raschig Rings
180°F
75°F
1300 GPM
9500 sq. ft.
Duty - 29.3 MM Btu/hr.
140°F
Motor Driven Pump
1 Oper. & 1 Spare
1180 GPM
Disc & Donut Solids Removal Section
2400 lb/hr Solids
53 GPM water
150°F
To Waste Disposal
GAS GENERATORS
FLUIDIZED FEEDERS
CYCLONE COLLECTORS
BALL MILL PULVERIZERS
AIR HEATERS
500,000 SCFH
MAKE UP AIR FANS
29 KW
DENOTES SPARE
SCHEMATIC ARRANGEMENT OF COAL HANDLING SECTION FOR ENTIRE PLANT
THREE REQUIRED AS SHOWN
COAL GASIFICATION UNIT
FOR
COAL HYDROGENATION PLANT


160'
5'
40'
30'
25'
20'
20'
5'
HOPPERS
HOPPERS
HOPPERS
HOPPERS
BOILER
HEATER
90'
160'
20'
10'
20'
10'
20'
10'
20'
10'
30'
PUMP AND INSTRUMENT HOUSE
5'
5'
100'
PLAN
SCALE 1" = 40'
STEAM DRUM
CYCLONE
CRANE
FLUIDIZER FEEDERS
HOPPERS
135'
SCRUBBER
HOIST
60'
COAL GASIFIER
ELEVATION
PLAN & ELEVATION
COAL GASIFICATION UNIT
30,000 B/SD COAL HYDROGENATION PLANT

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
OXYGEN PLANT

	USBM	NPC
Direct Material	$4,350,000	$6,500,000
Direct Labor	1,370,000	1,500,000
Total Direct	$5,720,000	$8,000,000
Others	2,785,000	2,500,000
Total	$8,505,000	$10,500,000

OXYGEN PLANT

The Process Subcommittee specified an oxygen plant capacity of 1800 tons (95% oxygen) per day to provide the calculated requirement of the Coal Gasification Unit of 1600 tons per day.

A detailed equipment design was not made by the Engineering Subcommittee. However, most of the oxygen plant builders and designers in this country furnished estimated costs of various sized plants and in addition actual construction costs of some of the large tonnage oxygen plants were available to the Subcommittee. With these data the effect of capacity, number of units, and altitude upon investment cost was established.

Some of the oxygen plant designers were of the opinion that oxygen plant sizes should not exceed units of 500-600 ton/day from the standpoint of heat losses, ease of fabrication construction experience, and standardization. Accordingly, the committee assumed the erection of four-450 ton/day plants with a certain amount of common equipment such as blowers, piping, buildings, etc. as a basis for the estimate.

A comparison of the costs of the oxygen plant established by the Subcommittee and that of the Bureau of Mines is shown on the opposite page. The principal discrepancy between the two estimates is due to the increase in prices since the preparation of the estimate by the Bureau. If both estimates were adjusted to comparable price indices, the estimates would differ by only 7%.

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
HYDROGEN PURIFICATION AND COMPRESSION UNIT

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Compressors	$10,596,000			$14,780,000	$ 600,000	$15,380,000
Drums	97,000			150,000	20,000	170,000
Exchangers	1,064,000			940,000	20,000	960,000
Furnaces	50,000			40,000	10,000	50,000
Pumps & Drivers	1,019,500			2,000,000	40,000	2,040,000
Towers & Internals	1,462,000			2,230,000	270,000	2,500,000
Aeration Towers	1,337,500			1,200,000	150,000	1,350,000
Gas Holders & Tanks	459,000			450,000	100,000	550,000
Shift Reactors	315,000			750,000	30,000	780,000
Total Equipment	$16,400,000	$2,800,000	$19,200,000	$22,540,000	$1,240,000	$23,780,000
Buildings	$ 800,000	$ 400,000	$ 1,200,000	$ 1,720,000	$ 800,000	$ 2,520,000
Concrete	500,000	500,000	1,000,000	600,000	1,000,000	1,600,000
Electrical	1,800,000	900,000	2,700,000	1,150,000	450,000	1,600,000
Instruments	430,000	170,000	600,000	370,000	190,000	560,000
Insulation	50,000	50,000	100,000	260,000	180,000	440,000
Painting	40,000	120,000	160,000	60,000	200,000	260,000
Piping	2,500,000	1,250,000	3,750,000	6,030.000	2,730,000	8,760,000
Structural Steel	410,000	205,000	615,000	320,000	140,000	460,000
Miscellaneous	500,000	500,000	1,000,000	850,000	670,000	1,520,000
Total Direct	$23,430,000	$6,895,000	$30,325,000	$33,900,000	$7,600,000	$41,500,000
Others			13,483,000			16,700,000
Total			$43,808,000			$58,200,000

HYDROGEN PURIFICATION AND COMPRESSION UNIT

The Hydrogen Purification and Compression Unit was designed by the Bureau of Mines to purify the hydrogen or hydrogen rich streams produced in the coal gasification and the hydrocarbon steam cracking unit and to compress the purified hydrogen from these units as well as from the low temperature off-gas separation unit for use in the hydrogenation process.

The investment cost of this unit was based on a review of the Bureau of Mines design by the Process Subcommittee. Only minor process modifications were made to the Bureau design.

As shown on the opposite page, the Subcommittee's estimate of January 1951 is 33% higher than the Bureau's estimate of February 1948. About 1/3 of the difference is due to price increases since the date of the Bureau's estimate.

Most of the remaining differences can be explained by failure of the Bureau to account for the altitude correction to compressor horsepower requirement, expansion of building and foundations to accomodate the number of compressors required, and estimated piping costs.

On the following pages the equipment list and the flow and plot plans for this unit are shown.

30,000 B/SD COAL HYDROGENATION PLANT

EQUIPMENT SUMMARY

HYDROGEN PURIFICATION AND COMPRESSION UNIT

Compressors

K-3010 HC Gas Turbo Compressor, 3 Required, 15,500 total installed horsepower.
K-3011 HC Gas Reciprocating Compressor, 4 required, 14,000 total installed horsepower.
K-3012 HC H_2 Hyper Compressor I, reciprocating, 6 required, 21,000 total installed horsepower.
K-3014 HC H_2 Hyper Compressor II, reciprocating, 7 required, 21,000 total installed horsepower.
K-3100 Coal Gas Turbo Compressor I, 8 required, 47,200 total installed horsepower.
K-3101 Coal Gas Turbo Compressor II, 4 required, 15,600 total installed horsepower.
K-3102 Coal H_2 Hyper Compressor I, 7 required, 24,500 total installed horsepower.
K-3104 Coal H_2 Hyper Compressor II, 8 required, 24,000 total installed horsepower.
K-3200 Linde Hyper Compressor I, 3 required, 6,000 total installed horsepower.
K-3201 Linde Hyper Compressor II, 3 required, 7,500 total installed horsepower
K-3300 Nitrogen Test Hyper Compressor, 2 required, 1,400 total installed horsepower.
K-3013 and K-3103 Ammonia Refrigeration Compressor, 5 required, 3,000 total installed horsepower.

Drums

V-3011 and V-3101 CO_2 Scrubber Exit Trap, 24 required, 3' ID x 5', 75°F, 13.6 Atm.
V-3012 and V-3102 Hyper Suction Knockout Vessel, 2 required, 12' ID x 20', 75°F, 13.6 Atm.
V-3013 and V-3103 Copper Liquor Regenerator, 4 required, 12' ID x 40', 185°F, 15 psig, 200 sq.ft. coil.
V-3014 and V-3104 Ammonia Receiver, 4 required, 6' ID x 10', 100°F, 250 psig.
V-3015 and V-3105 Hyper Suction Knockout Vessel, 2 required, 3' ID x 20', 32°F, 92.4 Atm.

Exchangers

E-3010 and E-3105 Copper Liquor Heat Exchanger, 1800 sq.ft.,per unit, 4 units required.
Ex3010 and Ex3105 Copper Liquor Water Cooler, 2150 sq.ft. per unit, 4 units required.
E-3011 and E-3106 Copper Liquor Ammonia Cooler, 2180 sq.ft. per unit, 4 units required.
E-3012 and E-3107 Ammonia Condenser-Copper Liquor Refrigeration, 7150 sq.ft. per unit, 4 units required.
E-3104 Shift Waste Heat Exchanger, 11,800 sq.ft. per unit, 7 units required.

Furnaces

F-3100 Shift Starting Preheater, 20 MM Btu/Hr. Heat Duty, Petro Chem. Type.

Pumps

P-3010 and P-3101 CO_2 Scrubber Water Pump, 9,000 GPM, 475 ft. head, 1180 BHP per unit, 24 units required.
P-3011 and P-3102 CO Scrubber Copper Liquor Let Down, Pump End - 345 GPM 0-1350 psig, Engine End - 575 GPM, 1350-50 psig, 4 units required.
P-3012 and P-3103 Copper Liquor Circulating Pump, 600 GPM, 0-100 psig, 55 BHP per unit, 4 units required.
P-3013 and P-3104 CO Scrubber Copper Liquor Pump, 230 GPM, 0-1350 psig, 330 BHP per unit, 4 units required.
P-3014 Copper Liquor Makeup Pump, 600 GPM, 0-100 psig, 55 BHP per unit, 1 unit required.
P-3015 and P-3106 Aerated Water Return, 108,000 GPM, 0-30 ft. head, 1150 BHP per unit, 3 units required.

Towers

C-3010 and C-3104 Copper Liquor CO Scrubber, 4 required, 4' ID x 60', 100°F, 92.5 Atm.
C-3011 and C-3105 Regenerator Reflux Column, Copper Liquor, 4 required, 8 ID x 24', 11' ID x 37', 300°F, 15 psig.
C-3012 and C-3103 Water CO_2 Scrubber, 24 required, 12' ID x 70', 100°F, 13.6 Atm.

Aeration Towers

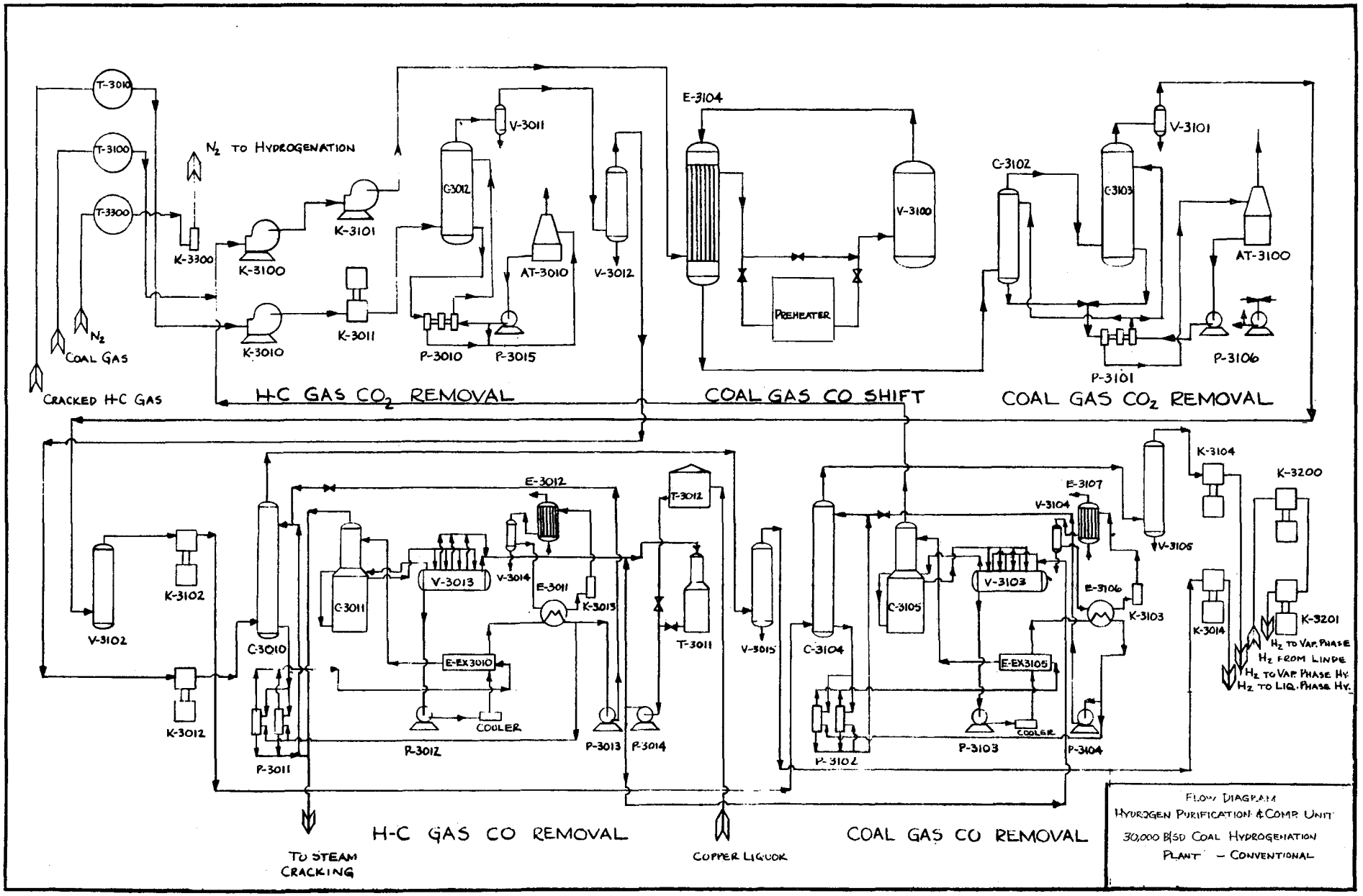
AT-3010 CO_2 Degassing, 64' wide x 24' long x 25' high, 4,300 GPM Liquid Loading, 19 required.
AT-3100 CO_2 Degassing, same as AT-3010 but with monel hardware, 31 required.

Gas Holders & Tanks

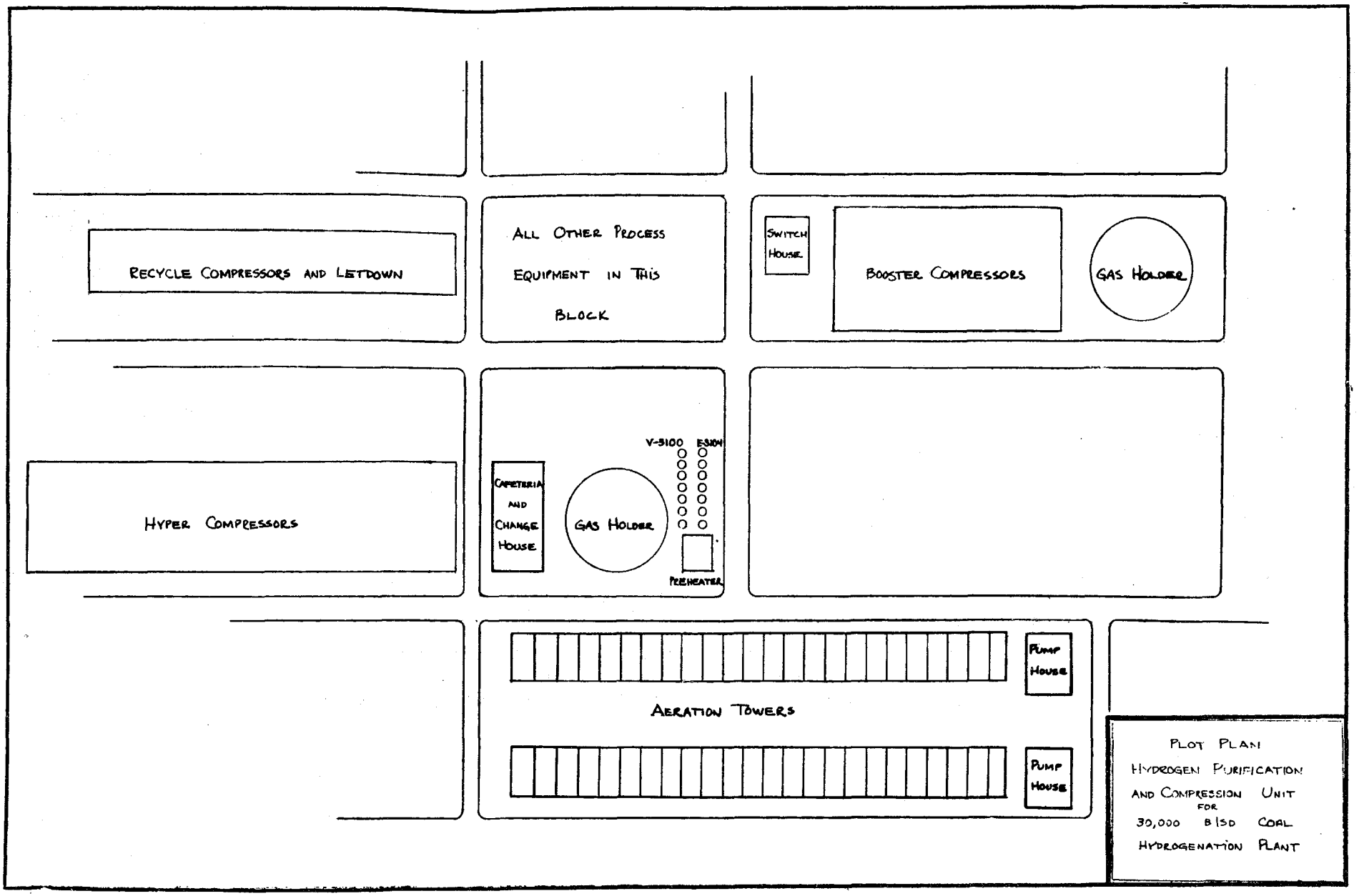
T-3010 Cracked Gas Holder, 1,500,000 CF, 1 Atm., 100°F, 143' ID x 96', 1 required.
T-3011 Copper Liquor Makeup, 8' ID x 12', 1 Atm., 100°F, 1 required.
T-3012 Copper Liquor Storage, 18' ID x 12', 1 Atm., 100°F, 1 required.
T-3100 Coal Gas Holder, 1,500,000 CF, 1 Atm., 100°F, 143' ID x 96', 1 required.
T-3300 Nitrogen Holder, 150,000 CF, 1 Atm., 100°F, 67' ID x 45', 1 required.

Shift Reactors

V-3100 12' ID x 16', 850°F, 13.6 Atm., 7 required.



FLOW DIAGRAM
HYDROGEN PURIFICATION & COMP. UNIT
30,000 B/SD COAL HYDROGENATION
PLANT - CONVENTIONAL


RECYCLE COMPRESSORS AND LETDOWN
ALL OTHER PROCESS EQUIPMENT IN THIS BLOCK
SWITCH HOUSE
BOOSTER COMPRESSORS
GAS HOLDER
HYPER COMPRESSORS
CAFETERIA AND CHANGE HOUSE
GAS HOLDER
V-3100
ESION
PREHEATER
AERATION TOWERS
PUMP HOUSE
PUMP HOUSE
PLOT PLAN
HYDROGEN PURIFICATION AND COMPRESSION UNIT FOR 30,000 BISD COAL HYDROGENATION PLANT

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
TANKAGE UNIT

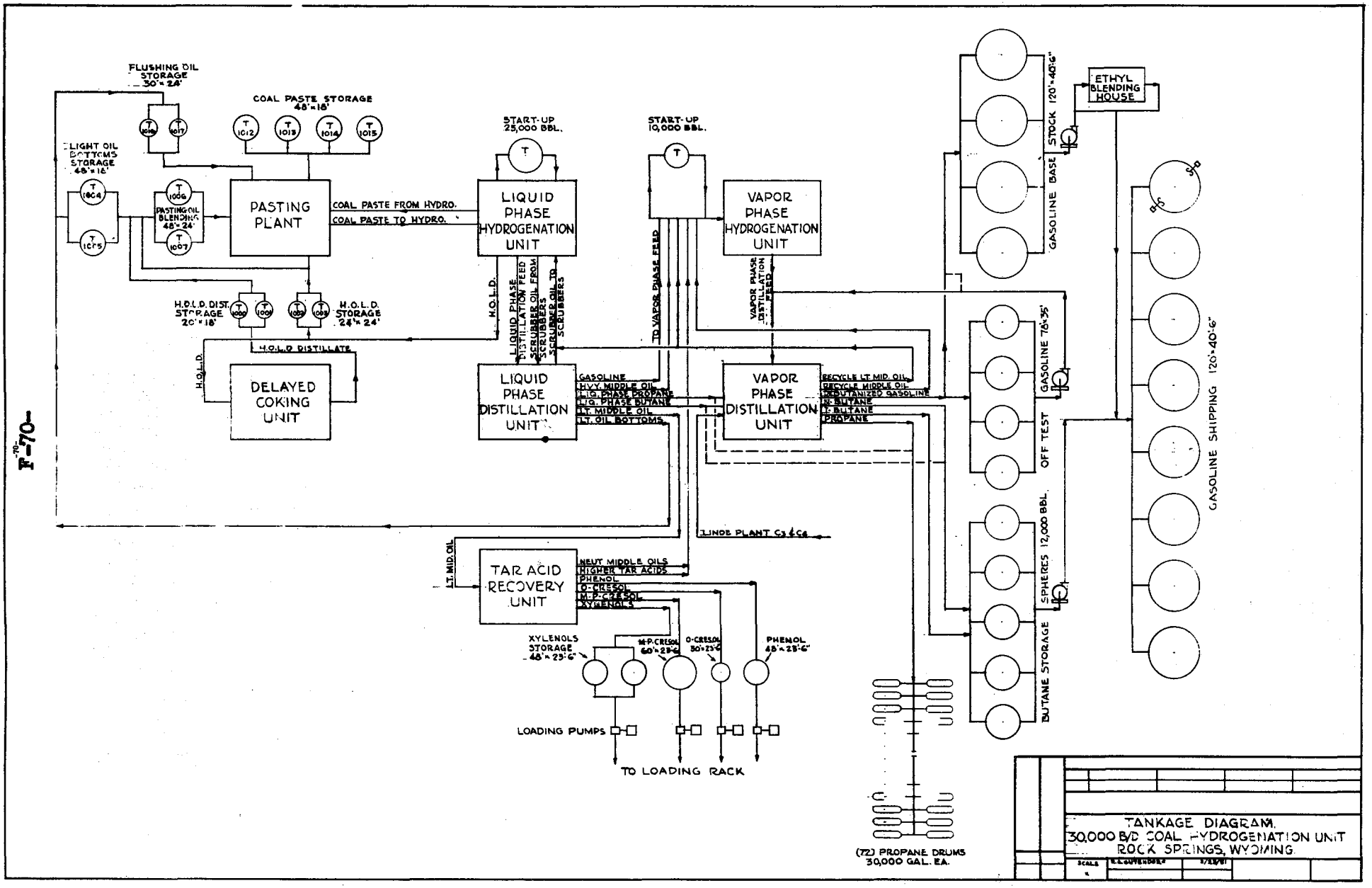
	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Drums	$ 605,000			$1,052,000	$ 72,000	$1,124,000
Ethyl Blending	--			30,000	21,600	51,600
Loading Racks	--			188,500	100,000	288,500
Mixers	--			27,500	5,700	33,200
Pumps & Drivers	25,600			51,500	5,000	56,500
Tanks	1,085,400			1,373,000	632,000	2,005,000
Total Equipment	$1,716,000	$ 400,000	$2,116,000	$2,722,500	$ 836,300	$3,558,800
Buildings	40,000	20,000	60,000	41,000	29,000	70,000
Concrete	86,000	86,000	172,000	71,000	92,000	163,000
Electrical	50,000	25,000	75,000	42,300	23,000	65,300
Instruments	80,000	32,000	112,000	22,000	8,000	30,000
Insulation	40,000	40,000	80,000	16,600	16,000	32,600
Mech. Handling Equip.	--	--	--	--	--	--
Painting	20,000	60,000	80,000	25,000	95,000	120,000
Piping	2,450,000	1,225,000	3,675,000	1,300,000	1,026,000	2,326,000
Struct. Steel	50,000	25,000	75,000	63,000	42,000	105,000
Miscellaneous	50,000	50,000	100,000	136,600	132,700	269,300
Total Direct	$4,582,000	$1,963,000	$6,545,000	$4,440,000	$2,300,000	$6,740,000
Others			1,754,000			3,460,000
Total			$8,299,000			$10,200,000

TANKAGE, FIELD LINES, & SHIPPING

These were designed by the Bureau of Mines to include storage capacity for 30 days' production of gasoline and phenols and 10 days' production of liquefied petroleum gas. The Engineering Subcommittee has modified the tankage layout and added additional tanks in accordance with general refinery practices, although keeping the same product storage capacity as specified by the Bureau. A tankage flow diagram is shown on the next page. This also shows the tanks for the Paste Preparation Unit, the cost of which was not included in this section. The Subcommittee has included in the Tankage Unit a number of utility tanks for storage of boiler feedwater, circulating water, and drinking water which the Bureau did not include.

A comparison of the costs prepared by this Committee as of January 1951 with those prepared by the Bureau as of February 1948 is shown on the opposite page.

For purpose of comparison, the estimate of direct costs of Field Lines by the Bureau has been transferred from the General Plant Facilities to this section. No correction has been made to the indirect costs which accounts for the different percentages shown for the Bureau estimates on these two sections. The estimate of this Committee is 23% higher than the Bureau. Approximately 1/3 of this difference is due to increase in price since preparation of the Bureau estimate. A large measure of the remaining difference is due to the additional tanks specified by the Committee. The Committee also included an ethyl blending plant, loading racks for both tank car and tank truck shipment and mixers for the gasoline tanks, all of which appeared to have been omitted by the Bureau.


FLUSHING OIL STORAGE 30'×24'
COAL PASTE STORAGE 48'×18'
LIGHT OIL BOTTOMS STORAGE 48'×18'
PASTING OIL BLENDING 48'×24'
PASTING PLANT
COAL PASTE FROM HYDRO.
COAL PASTE TO HYDRO.
START-UP 25,000 BBL.
LIQUID PHASE HYDROGENATION UNIT
START-UP 10,000 BBL.
VAPOR PHASE HYDROGENATION UNIT
ETHYL BLENDING HOUSE
STOCK 120'×40'×6"
GASOLINE BASE
H.O.L.D. DIST. STORAGE 20'×18'
H.O.L.D. STORAGE 24'×24'
H.O.L.D.
LIQUID PHASE DISTILLATION FEED
SCRUBBER OIL FROM SCRUBBERS
SCRUBBER OIL TO SCRUBBERS
TO VAPOR PHASE FEED
VAPOR PHASE DISTILLATION FEED
H.O.L.D. DISTILLATE
DELAYED COKING UNIT
LIQUID PHASE DISTILLATION UNIT
GASOLINE
H.VY. MIDDLE OIL
L.IQ. PHASE PROPANE
L.IQ. PHASE BUTANE
L.T. MIDDLE OIL
L.T. OIL BOTTOMS
VAPOR PHASE DISTILLATION UNIT
RECYCLE LT. MID. OIL
RECYCLE MIDDLE OIL
DEBUTANIZED GASOLINE
N. BUTANE
I. BUTANE
PROPANE
GASOLINE 78'×35'
OFF TEST
GASOLINE SHIPPING 120'×40'×6"
SPHERES 12,000 BBL.
BUTANE STORAGE
LINDE PLANT C3 & C4
L.T. MID. OIL
TAR ACID RECOVERY UNIT
NEUT MIDDLE OILS
HIGHER TAR ACIDS
PHENOL
O-CRESOL
M-P-CRESOL
XYLENOLS
XYLENOLS STORAGE 48'×23'-6"
M-P-CRESOL 60'×23'-6"
O-CRESOL 30'×23'-6"
PHENOL 48'×23'-6"
LOADING PUMPS
TO LOADING RACK
(72) PROPANE DRUMS 30,000 GAL. EA.
TANKAGE DIAGRAM.
30,000 B/D COAL HYDROGENATION UNIT
ROCK SPRINGS, WYOMING.
SCALE
K.K. GUVENDER
6/23/61

F-70

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
STEAM & POWER PLANT

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Boilers				$12,000,000	$2,700,000	$14,700,000
Pumps				272,000	10,000	282,000
Feed Water Heaters				110,000	10,000	120,000
Water Treating Equipment				1,046,000	315,000	1,361,000
Other Auxiliaries				728,000	380,000	1,108,000
Turbo-Generators & Condensers				9,654,000	375,000	10,029,000
Compressors				10,000	5,000	15,000
Total Equipment	$16,000,000	$5,800,000	$21,800,000	$23,820,000	$3,795,000	$27,615,000
Buildings	2,400,000	1,200,000	3,600,000	4,608,000	3,511,000	8,119,000
Concrete	250,000	250,000	500,000	381,000	514,000	895,000
Electrical	660,000	330,000	990,000	3,044,000	1,057,000	4,101,000
Instruments	300,000	120,000	420,000	1,037,000	880,000	1,917,000
Insulation	300,000	300,000	600,000	400,000	235,000	635,000
Piping	2,500,000	1,250,000	3,750,000	5,754,000	3,483,000	9,237,000
Structural Steel	160,000	80,000	240,000	200,000	150,000	350,000
Other Miscellaneous	300,000	400,000	700,000	1,556,000	875,000	2,431,000
Total Direct	$22,870,000	$9,730,000	$32,600,000	$40,800,000	$14,500,000	$55,300,000
Others			14,075,000			23,700,000
Total			$46,675,000			$79,000,000

STEAM AND POWER PLANT

Steam generation facilities consist of five 1,000,000 pounds per hour steam generators designed for 1400 psig and 950° F. at the superheater outlet. Power generation is accomplished by five 60/66,000 KW per hour, 13,800 volt turbo-generators.

The basis for selection of this equipment has been described previously in the discussion of the utility balance of the plant. The equipment list and miscellaneous explanatory drawings for this section as well as the plant utilities follows.

The estimate of cost of these facilities by the Bureau and the Subcommittee is compared on the opposite page. It will be noted that the Subcommittee estimate is 67% higher than that prepared by the Bureau. Approximately 15% is due to the rise in costs since preparation of the Bureau's estimate, the remainder is accounted for by the differences in over-all utility requirements as discussed in the section on the utility balance of the plant. It will be recalled that the Bureau's original estimate was based on an installed capacity of only 3,275,000 pounds per hour steam generation and 250,000 kilowatts per hour of power generation. As explained previously the Bureau has since revised their utility estimate so that the Subcommittee and the Bureau differ now by something less than 7% in the over-all power requirements of the plant proper. The estimate of cost shown in the opposite table has not been revised by the Bureau to incorporate these changes. It should also be mentioned that the Subcommittee estimates include power consumption for the mines and the plant water supply which were handled separately by the Bureau. In addition, power for the community is also included in the Subcommittee power demand and it will be necessary for the Economics Subcommittee to make the proper adjustment depending upon how the cost of housing is handled.

It will be noted from the opposite table that rather large and irregular discrepancies exist between the various items of the two estimates. Since no details were available on the Bureau's estimate, the Subcommittee was unable to isolate any reasons for these differences. It is probable that most of the difference is due to segregation of accounts since it appears that on an over-all basis the two estimates are comparable at equivalent size and cost index.

NPC SUBCOMMITTEE
30,000 B/D HYDROGENATION PLANT
STEAM & POWER PLANT AND PLANT UTILITIES
EQUIPMENT REQUIRED

Following is a list and brief description of the major equipment required for the supply of steam, electric power, cooling water, service water, drinking water, plant air, instrument air, and other miscellaneous plant utilities required for operation of the 30,000 B/D Hydrogenation Plant.

Steam Plant

Steam Generators

5 - (1 Spare) 1,000,000 Lb/Hr. steam generators, designed for 1400 psig and 950°F. T.T. at superheater outlet. The boilers to be complete with all auxiliary equipment, including air preheaters, forced and induced draft fans, self-supporting steel stack, boiler non-return valves, boiler feed stop valves, feedwater regulators, etc. Also complete with necessary automatic combustion control equipment, instrumentation, individual boiler panel boards, and main instrument panel board. The boilers shall be suitable for burning pulverized coal fuel and shall be complete with suitable pulverized coal fuel burners, coal pulverizers, storage hoppers, and other necessary coal handling equipment.

Boiler Feed Water Pumps

5 - (1 Spare) 2500 GPM 1800 psi disc. pressure centrifugal pumps driven by 4075 BHP steam turbines suitable for 370 pound steam and 45 pound exhaust pressure.

Feedwater Heaters

2 - 320,000 GPH (Each about 60% of Max. Demand) Deaerating Feedwater Heaters complete and including additional storage capacity of about 150,000 gallons each, (Approx. 30 min. capacity basis max. demand) designed for operation on 45 psi steam, and to heat feedwater from 50°F to 290°F.

High Pressure Feedwater Heater

2 - High Pressure shell and tube type feedwater heaters suitable for operation with 370 psi 640°F steam and 1800 psi feedwater pressure. Each heater shall be designed to heat about 2,670,000 lbs./hr. of feedwater from 290°F to about 425°F, with drain cooler to provide 20°F sub-cooling below saturated steam temperature of 441°F.

STEAM & POWER PLANT & PLANT UTILITIES EQUIPMENT REQUIRED (Continued)

Continuous Blowdown System

1 - Continuous blow-down system complete with 1st stage flash drum designed for 370 psi operating pressure, 2nd stage flash drum designed for 45 psi operating pressure, and feedwater heat exchanger suitable for handling about 800,000 lbs./hr. of 1400 psi blowdown basis continuous rate of about 2% of max. steam demand, and feedwater temperature of 50°F and 100 psi pressure.

Water Treating Facilities

1 - Complete water treating plant having a rated capacity of about 4,500,000 Lbs./Hr., including necessary coagulators, hot process softeners, zeolite filters, chemical storage, and chemical feeding equipment. Also complete with instrumentation, control panel board, raw water pumps, heater charge pumps, chemical feed pumps, and other miscellaneous small pumps. The following tankage shall be provided for emergency feedwater supply and normal storage facilities basis about 60 hours at maximum steam demand.

Service	No.	Tank Capacity
Condensate	4	93,000 Bbls.
Treated Water	4	93,000 "

Pressure Reducing & Desuperheating Stations

1400 psig 900°F to 370 psig 640°F

Total capacity required - 2,600,000 Lbs./Hr.
5 - Stations each rated 520,000 Lbs./Hr.

370 psig 640°F to 45 psig Sat.

Total capacity required - 1,000,000 Lbs./Hr.
2 - Stations each rated 500,000 Lbs./Hr.

45 psig to Atmospheric Relief

2 - Stations each rated at about 125,000 Lbs./Hr. for start-up and excess pressure relief.

Buildings

Steam Generators - 125' x 400'
Firing Aisle & Control Room - 50' x 400'
Water Treating & Chemical Bldg. - 150' x 300'
Misc. Pumps & Compressor Bldg. - 75' x 300'

STEAM & POWER PLANT & PLANT UTILITIES
EQUIPMENT REQUIRED
(Continued)

Power Plant

Turbo-Generators

5 - (1 Spare) 60/66,000 KW/Hr. 13,800 Volt Turbo-Generators
1 - 1400 Lb. 950°F. Steam inlet, 370 Lb. bleed steam, and condensing at 2" Hg.

1 - 1400 Lb. 950°F. Steam inlet, 45 Lb. bleed steam, and condensing at 2" Hg.

3 - 1400 Lb. 950°F. Steam inlet, condensing at 2" Hg.

Electrical Distribution System

Provide main switchgear and main sub-station for about 300,00 KW/Hr. maximum power demand, complete with circuit breakers, disconnects, and transformers for primary distribution at 34,000 Volts.

The plant distribution facilities will be underground with the cables enclosed in suitable waterproof conduits for the various plant electrical energy demand and operating unit lighting loads, and distribution to the various process units, cooling towers, etc., will require about 30 odd secondary sub-stations for the breakdown at 4160 Volts, 440 Volts, and 110-200 Volts as indicated on Sheet No. 11 of Section 2 - Calculations.

Provide plant street lighting system, independently of power system, for 5000-6000 Volt series lighting circuit with central automatic photoelectric cell control point, complete with poles and lighting fixtures with built-in transformers as required.

Buildings

Turbine Room - 75' x 650'
Switch House - 30' x 400'

Water Systems

Cooling Towers, Pumps, Pumphouses, Supply & Return Water Lines, and Concrete Cooling Tower Basins with about 15 min. storage, basis total circulation rate as follows:

Liquid & Vapor Phase Hydro.

1 - 45,000 GPM Cooling Tower.
4 - 15,000 GPM 565 HP Centrifugal Pumps.
Steam Turbine Drive - 370 psi Steam - 45 psi exh.

STEAM & POWER PLANT & PLANT UTILITIES EQUIPMENT REQUIRED (Continued)

Delayed Coking

1 - 9000 GPM Cooling Tower
2 - 9000 GPM 340 HP Centrifugal Pumps
Steam turbine drive. 370 psi Steam - 45 psi Exh.

Liquid & Vapor Phase Dist.

1 - 42,000 GPM Cooling Tower
4 - 10,000 GPM 375 HP Centrifugal Pumps
2 - 12,000 GPM 450 HP Centrifugal Pumps
Steam turbine drive. 370 psi Steam - 45 psi Exh.

Phenol Recovery

1 - 12,000 GPM Cooling Tower
2 - 12,000 GPM 450 HP Centrifugal Pumps
Steam turbine drive. 370 psi Steam - 45 psi Exh.

Low Temp. Off-Gas Separation & Hydroc. Steam Cracking

1 - 12,000 GPM Cooling Tower
2 - 12,000 GPM 450 HP centrifugal pumps
Steam turbine drive. 370 psi Steam - 45 psi Exh.

Hydroc. Steam Cracking "C-3000" (Separate Cooling Tower)

1 - 10,000 GPM Cooling Tower
2 - 10,000 GPM 380 HP Centrifugal Pumps
Steam turbine drive. 370 psi Steam - 45 psi Exh.

Coal Gasification & Oxygen Plant

1 - 17,000 GPM Cooling Tower
2 - 5,000 GPM 190 HP Centrifugal pumps.
2 - 12,000 GPM 450 HP Centrifugal pumps.
Steam turbine drive - 370 psi Steam - 45 psi Exh.

H_2 Purification Unit

1 - 82,000 GPM Cooling Tower
6 - 16,400 GPM 620 HP Centrifugal Pumps
Steam turbine drive - 370 psi steam - 45 psi Exh.

Power Plant

1 - 170,000 GPM Cooling Tower
6 34,000 GPM 940 HP Centrifugal Pumps
Steam turbine drive - 370 psi steam - 45 psi Exh.

Tankage for Cooling Tower Make-up Storage

Basis 2 Days Storage at rate of 10,475 GPM

Service	No.	Tank Capacity
Raw Water	4	182,500 Bbls.

STEAM & POWER PLANT & PLANT UTILITIES
EQUIPMENT REQUIRED
(Continued)

Water Systems (Cont.)

Plant Drinking Water

Tankage - (basis 2 day supply plant drinking water only)

2 - 8400 Bbl. Tanks.

Pumps & Distribution

2 - 250 GPM 20 HP motor driven Centrifugal Pumps.
6" Main Supply Line underground to all buildings and operating units.

Treating Facilities

Filtration Plant and Chlorination Facilities for 250 GPM Rate.

(Locate drinking water pumps and other equipment at Power Plant in Water Treating Plant Building.)

Service Water System

2 - 3500 GPM 200 HP Motor driven centrifugal pumps. (Locate at Power Plant Water Treating Plant Building.)

16" plant main supply line underground to all operating units.

Boiler Feed Water Pumps for Waste Heat Boilers

2 - 2500 GPM 1560 H.P. Steam Turbine driven centrifugal pumps, 370 psi steam and 45 psi exhaust pressure.
12" Overhead plant supply line suitable for 750 pound operating pressure, to Liquid & Vapor Phase Hydrogenation Unit, Delayed Coking Unit, Hydrocarbon Steam Cracking Unit, and Coal Gasification Plant. (Locate pumps at Water Treating Plant Building.)

Distribution Lines

30" main plant supply line from incoming river water supply to the various cooling towers.
1 - 11,000 GPM, 375 HP Motor driven emergency cooling tower make-up pump, to take suction from raw water tanks. (Locate pump in water treating plant building.)

Field Lines - Overhead Supports (From Power Pl.)

1400 psi Steam

14" Line to H_2 Purification Plant.

STEAM & POWER PLANT & PLANT UTILITIES
EQUIPMENT REQUIRED
(Continued)

Field Lines - Overhead Supports (From Power Pl.) (Cont.)

370 psi Steam

24" Main Line for Supply to Operating Units.

45 psi Steam

36" Main Line for Supply to Operating Units and Buildings for Heating.

Condensate Return to Power Plant

10" Main Line to H_2 Purif. Plant and
6" Extension from Distillation Units.

Plant Air Supply

6" Main Line to Operating Units.

Instrument Air Supply

4" Main Line to Operating Units.

Fuel Gas System

Provision shall be made for the production of HC Fuel Gas (1180 btu./cu.ft.) on the vapor phase distillation unit and for supply line from this unit to the phenol recovery unit for normal consumption of about 93,700,000 btu./hr. and maximum consumption of about 104,000,000 btu./hr.

Provision shall be made for the distribution of Producer Fuel Gas (130 btu./Hr.) from the plant producer gas unit, for a total normal production of 88,700,000 btu./hr. and maximum production of 118,000,000 btu./hr., to the following units for the normal and maximum rates of consumption as follows:

Producer Gas Reqm'n'ts-MM btu./Hr.	Normal	Max.
a. Coal Gasification	62.0	68.8
b. Liquid & Vapor Phase Dist.	26.7	46.5(Start-up)
c. H_2 Purification Unit	-	20.0(Start-up)
Total	88.7	118.0

Max. total = Max. (a) + 1.10 Normal (b) + Max. (c)

STEAM & POWER PLANT & PLANT UTILITIES
EQUIPMENT REQUIRED
(Continued)

Plant Air Supply

4 - 1200 cfm 300 BHP 125 psig compressors.
1 Motor Drive & 1 Steam Drive.

Instrument Air Supply

4 - 500 cfm 72 BHP Steam Driven 65 psig Air Compressors.
1 - Instrument Air Dryer System
(Locate air compressors at Power Plant in extension to Water Treating Building.)

Plant Fire Water System

Storage Reservoir

Provide reservoir for collection of clean plant waste water for capacity of about 350,000 Bbls. (Basis 24 Hrs. at Rate of 10,000 GPM.)

Fire Pumps, and Building

4 - 2500 GPM 125 psi 260 BHP Pumps.
2 - 300 HP Motor drive.
2 - 260 HP Steam Turbine drive.

Fire Water Supply Line

16" Main Loop Line surrounding entire Unit Area with 2 - 12" Cross Tie Lines, and complete with Hydrants, and stationary Fire Nozzles for protection of all operating units and buildings.

Fire Station & Hose Houses

Provide centrally located main fire station for housing plant fire truck, chemical, and fire fighting equipment storage, and repair shop for portable fire equipment, building to be approximately 40' x 60'.

Provide about 10 hose houses approximately 9' x 15', for storage of hose reels, foam carts, and other miscellaneous portable fire equipment, at strategic points throughout the plant area.

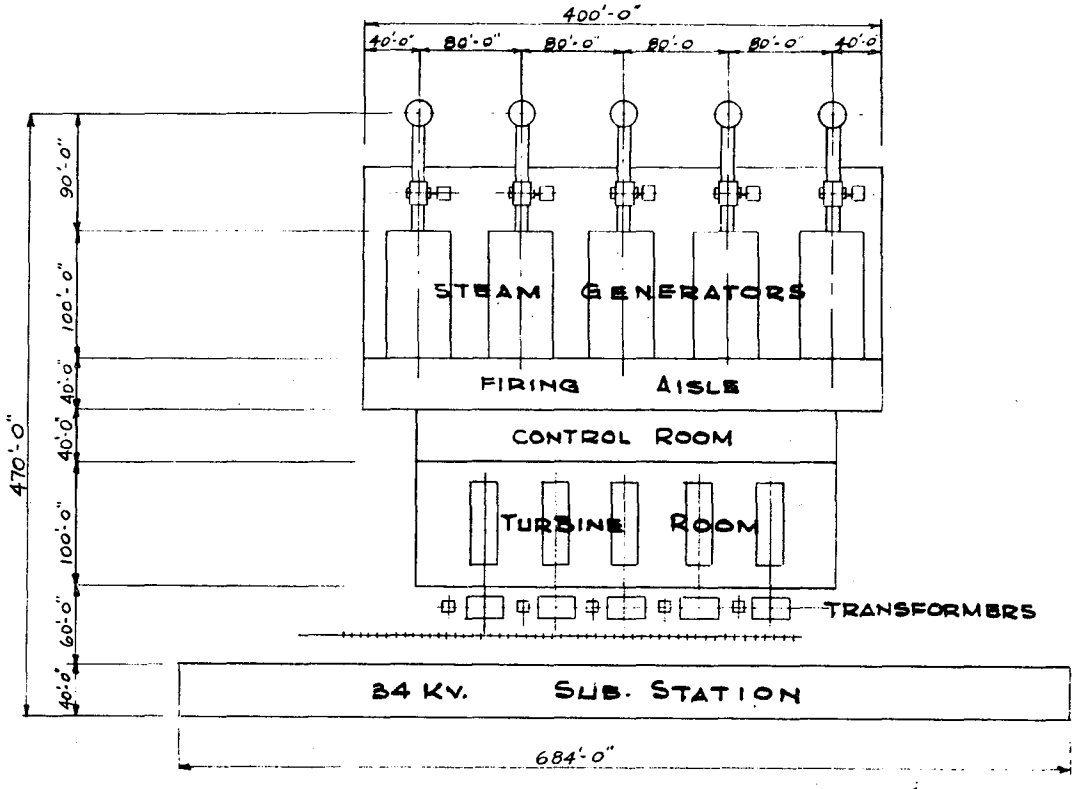
STEAM & POWER PLANT & PLANT UTILITIES
EQUIPMENT REQUIRED
(Continued)

Plant Drainage Facilities

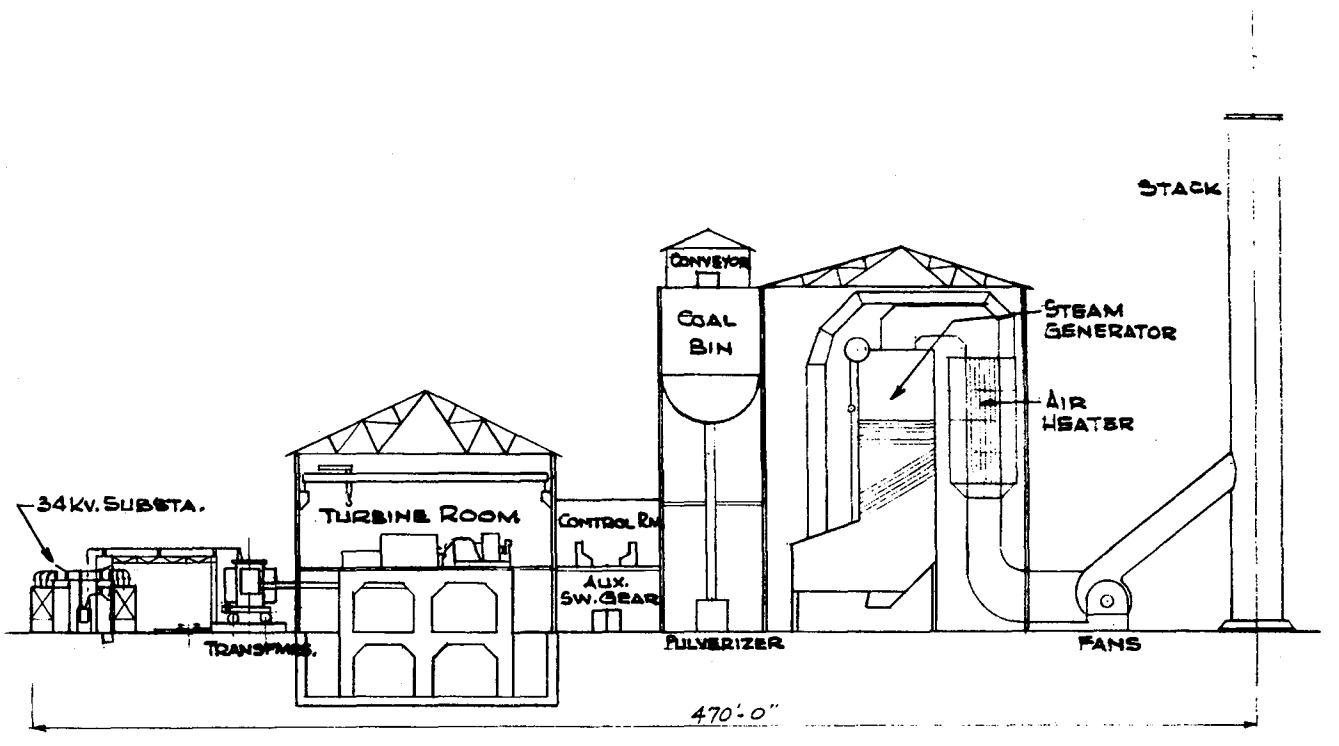
Provide underground sewer system for handling oil contaminated drainage and run-off for final routing through a main plant oil trap of the latest approved API design. (Included in waste disposal section of estimate.) Provide suitable ditches, catch basins, etc., for surface drainage as required.

Telephone Facilities

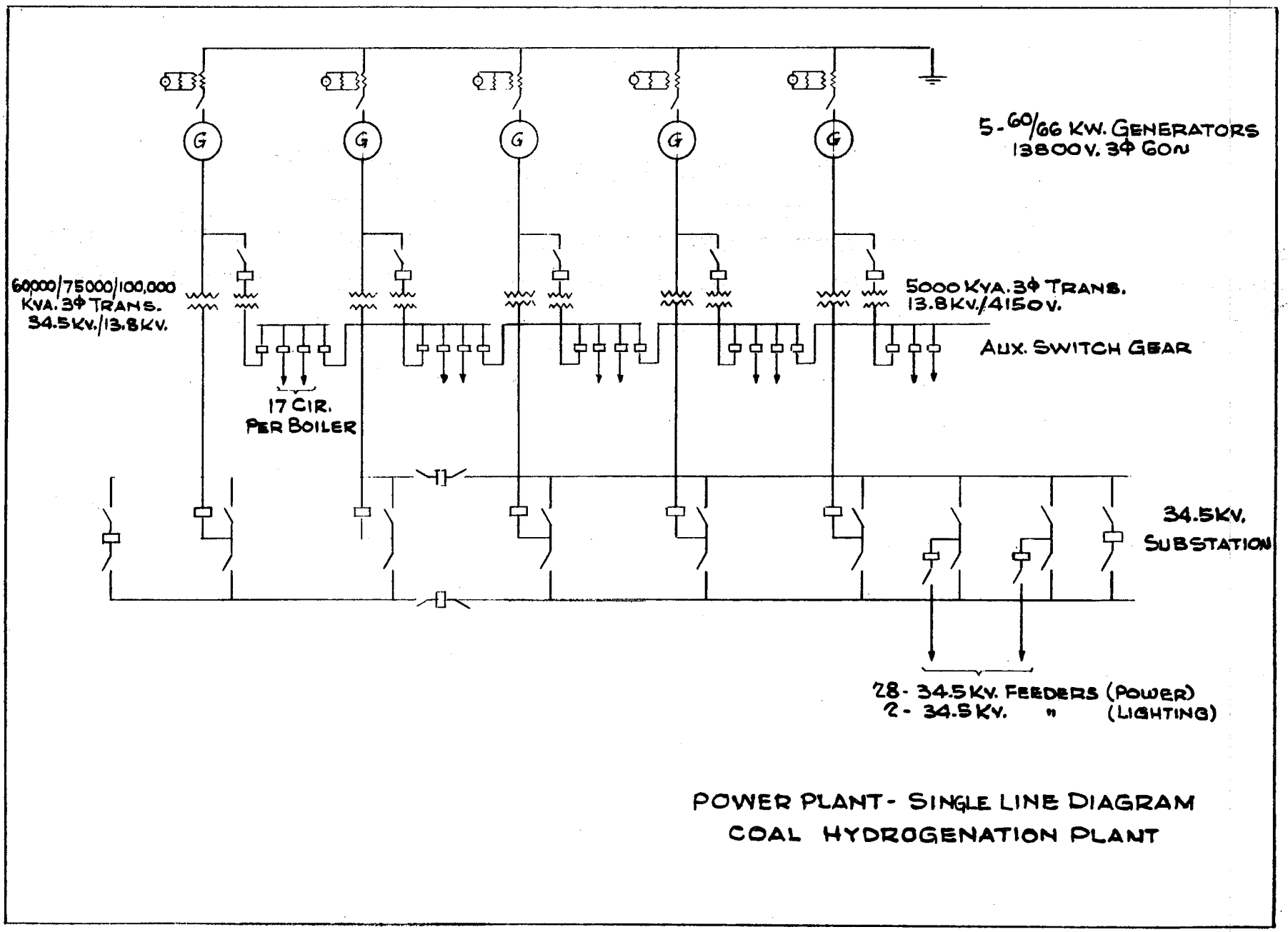
Provide suitable PBX or other type of central automatic telephone switch board system, with telephone wire circuits and complete system of telephone communication system from main office to all buildings, offices, and operating units throughout the entire plant.



POWER PLANT - PLAN
COAL HYDROGENATION PLANT
SCALE 1" = 100'



POWER PLANT-SECTION
COAL HYDROGENATION PLANT
SCALE 1"=50'



POWER PLANT - SINGLE LINE DIAGRAM
COAL HYDROGENATION PLANT

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
PLANT UTILITIES

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Cooling Water	$4,000,000	$2,000,000	$6,000,000	$5,400,000	$2,100,000	$7,500,000
Drinking Water				60,000	40,000	100,000
Service Water	167,000	83.000	250,000	160,000	90,000	250,000
Electric Distribution	7,500,000	2,500,000	10,000,000	6,200,000	2,200,000	8,400,000
Yard Lighting				50,000	50,000	100,000
Telephones				130,000	70,000	200,000
Steam Distribution	585,000	438,000	1,023,000	1,100,000	1,400,000	2,500,000
Condens. Distribution				70,000	55,000	125,000
Air Supply	335,000	165,000	500,000	285,000	115,000	400,000
Fire Lines				650,000	350,000	1,000,000
Fuel Gas	1,774,000	710,000	2,484,000	750,000	250,000	1,000,000
Total Direct	$14,361,000	$5,896,000	$20,257,000	$14,855,000	$6,720,000	$21,575,000
Others			10,569,000			10,725,000
Total			$30,826,000			$32,300,000

PLANT UTILITIES

The estimate of cost of the various utility services have been based upon the equipment list shown on preceeding pages. A comparison with the estimate prepared by the Bureau of Mines is shown on the opposite page. It will be noted that the Subcommittee estimate is surprisingly close to that of the Bureau's, particularly when cognizance is taken of the increase in proces during the interval of time between the two estimates and the increased power and steam requirements as calculated by the Committee. The Bureau has included fire lines amounting to $3,000,000 in another section of the estimate (General Plant), whereas the main transformer substation is included in the Power Plant section by the Committee. It is apparent that the Subcommittee estimate for plant utilities would be considerably under that of the Bureau if calculated on a comparable basis.

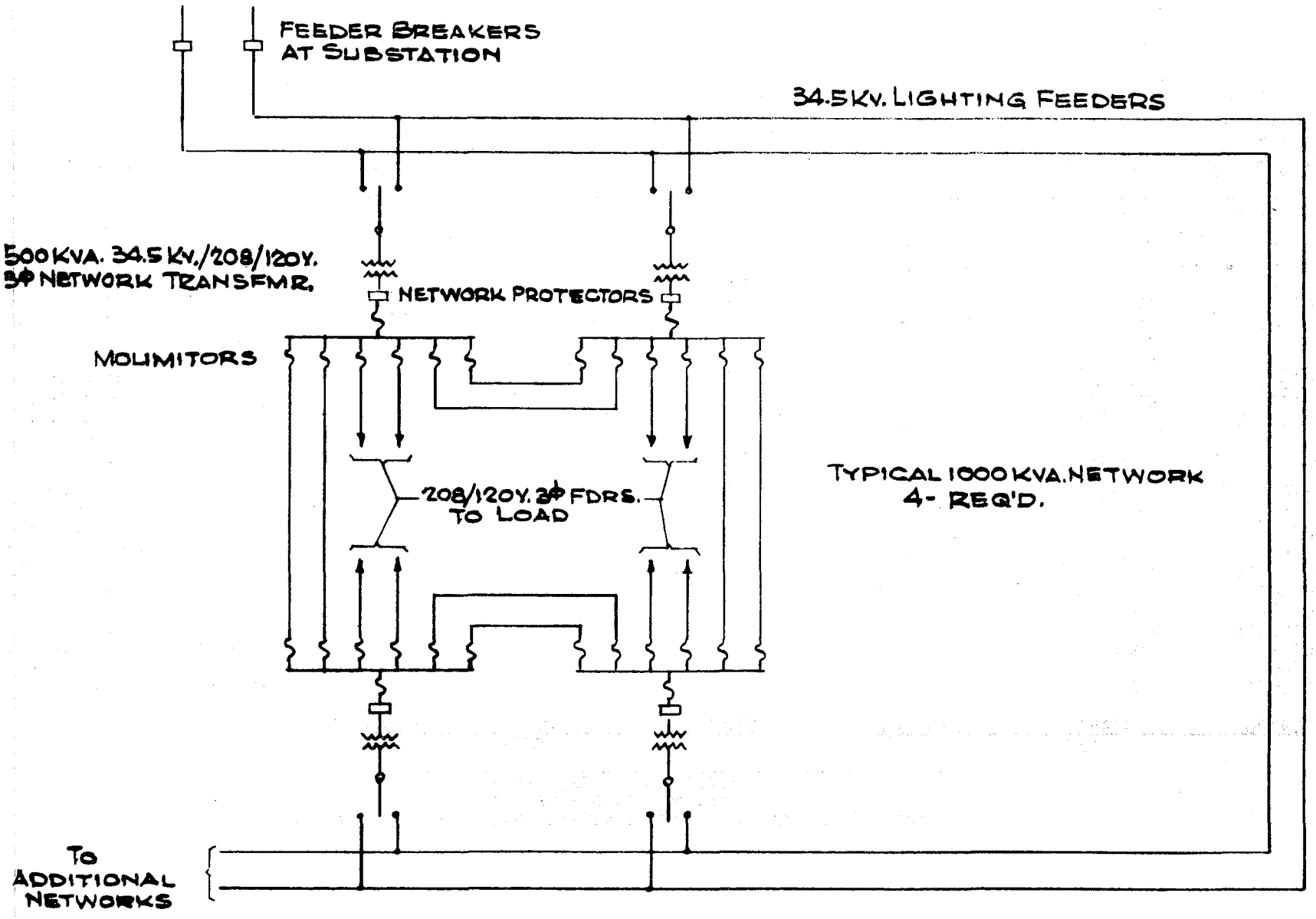


DIAGRAM
LIGHTING DISTRIBUTION NETWORK
COAL HYDROGENATION PLANT

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
INVESTMENT COST COMPARISON
GENERAL PLANT FACILITIES

	USBM			NPC		
	Material	Labor	Total	Material	Labor	Total
Main Administration Building				$1,200,000	$ 700,000	$ 1,900,000
Plant Cafeteria				250,000	150,000	400,000
Medical Building & Equipment				110,000	65,000	175,000
Employee Building				950,000	550,000	1,500,000
Field Laboratory				850,000	500,000	1,350,000
Warehouse & Equipment				1,090,000	630,000	1,720,000
Shops & Equipment				1,900,000	1,100,000	3,000,000
Gate & Guard Houses				85,000	50,000	135,000
Area Toilets				20,000	10,000	30,000
Repair Garage				105,000	60,000	165,000
Parking Shelter				110,000	60,000	170,000
Total Buildings	$5,465,000	$2,235,000	$7,700,000	$6,670,000	$3,875,000	$10,545,000
Site Preparation	$ ---	$1,700,000	$1,700,000	$1,720,000	$ 735,000	$ 2,455,000
Railroad-Spur to Plant	---	---	---	630,000	280,000	910,000
Railroad-in Plant	250,000	100,000	350,000	280,000	120,000	400,000
Roads	530,000	250,000	780,000	545,000	230,000	775,000
Fencing				45,000	15,000	60,000
Catalyst Preparation	350,000	150,000	500,000	350,000	150,000	500,000
Coal Stock Pile	---	---	---	450,000	150,000	600,000
Rolling Stock	470,000	---	470,000	540,000	---	540,000
Refinery Motorized Equipment	---	---	---	250,000	---	250,000
Waste Disposal	650,000	600,000	1,250,000	1,585,000	1,165,000	2,750,000
Fire Protection	1,000,000	500,000	1,500,000		Included With Utilities	
Miscellaneous	---	---	---	2,255,000	1,265,000	3,520,000
Total Direct	$8,715,000	$5,535,000	$14,250,000	$15,320,000	$7,985,000	$23,305,000
Others			10,725,000			11,395,000
Total			$24,975,000			$34,700,000

GENERAL PLANT FACILITIES

The General Plant Facilities include items essential to plant construction and operation but not directly serving any individual area or process. The facilities that have been included are shown on the investment comparison on the opposite page.

The Subcommittee's estimate of January, 1951 is 40% higher than the Bureau's estimate of February, 1948. About 25% of this difference is due to cost increases since the date of the original estimate. The remaining differences appear mostly in the facilities that were not included in the Bureau estimate such as railroad spur to plant, coal stock pile, and refinery motorized equipment. Also the Subcommittee's estimate provided more for buildings. It may be noted that the fire protection system and transfer pumps and yard piping, originally included in general plant facilities in the Bureau's estimate, have been included in plant utilities and tankage respectively in the Subcommittee's estimate.

WATER SUPPLY

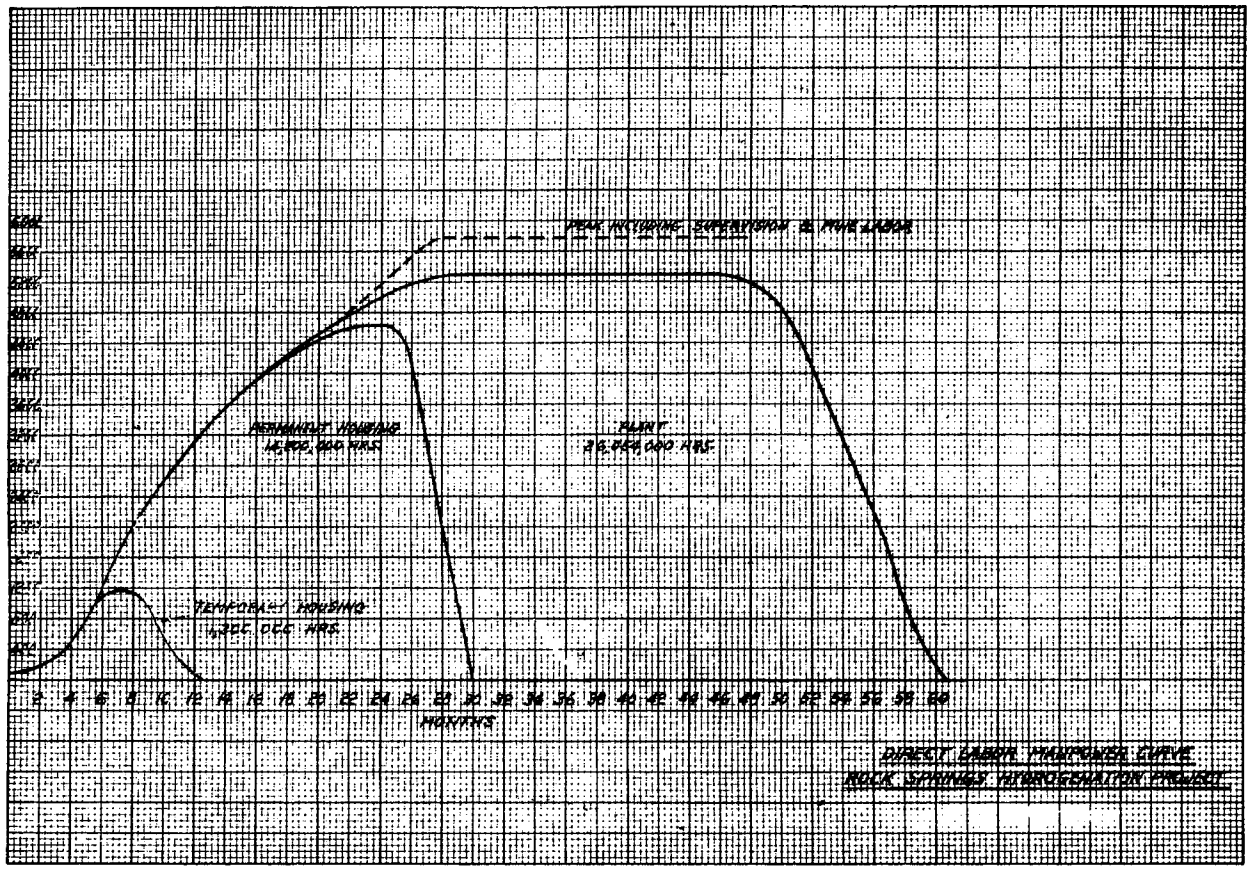
The Bureau of Mines selected Lake Fremont, located approximately 100 miles north of the Plant Site as the source of water for the Project, - the required quantity being 20,000 GPM. A study indicated this project was entirely feasible but not the most economical solution, so this estimate is based on pumping water up from Green River.

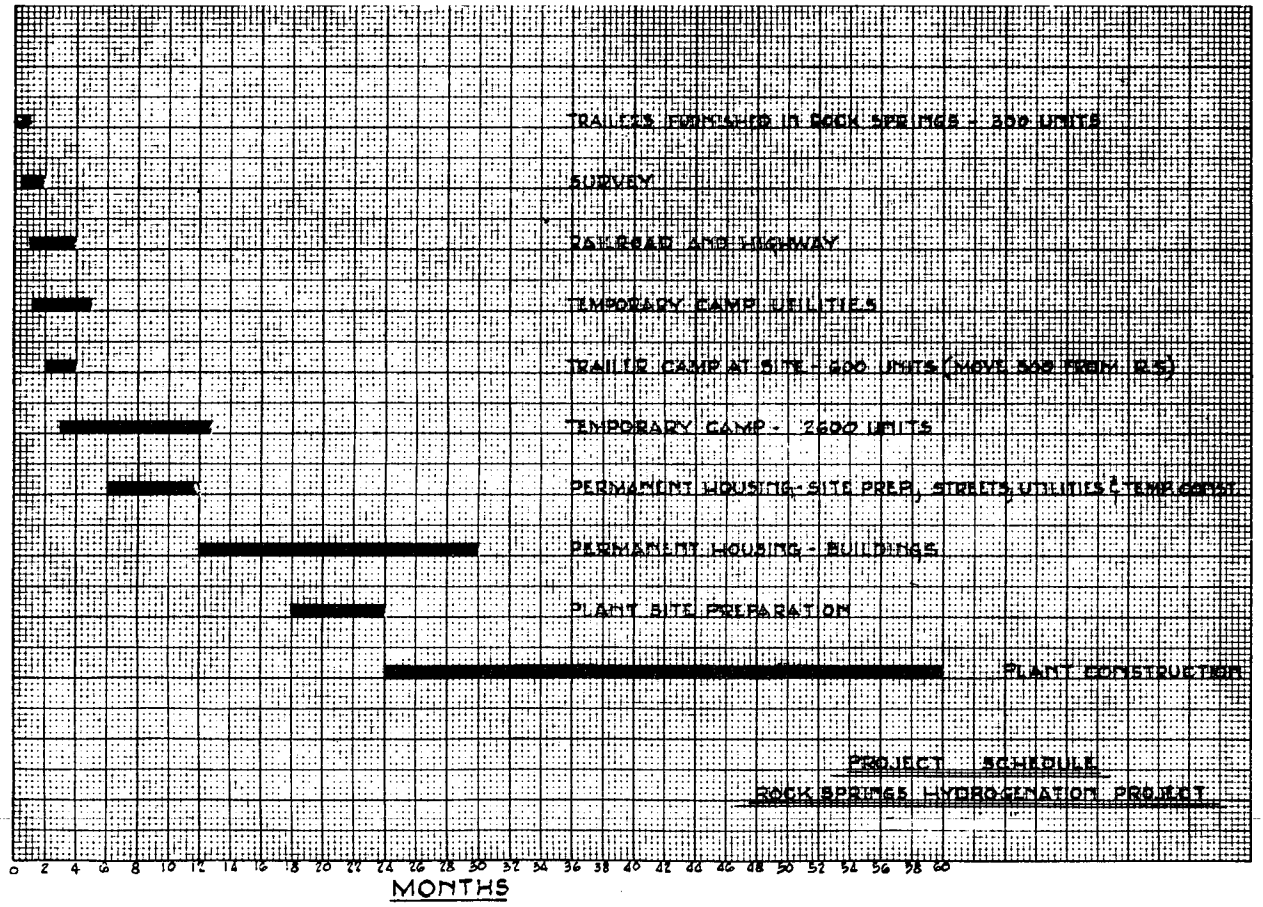
The Bureau justified the longer line using an electric power cost of 1¢ per KWH, and a 20-year amortization period. While power cost information is not now available, it should be less than 1/2¢ per KWH. Substituting a power cost of 1/2¢ per KWH in the Bureau's calculations makes the Green River pumping station $240. per day cheaper than the gravity system.

Calculations check the Bureau's conclusion that for the 32-mile line pumping water from the Green River to the Plant Site, the power saving from a 48" line does not justify the extra investment cost over a 42" line. The total head to be overcome is 1000 ft. plus a line loss of 250 ft. (using an internally coated steel or concrete pipe) or a total of 1250 ft. This head would require four pumping stations (with one operator per station) when designed for economy in investment in class of piping and pumping stations with power requirement of 7000 KW. A power transmission line from the Plant Site to the river would also be needed. Final design might make utilization of this power transmission line to Rock Springs, in increased capacity, attractive on a standby exchange basis to both the local power company and the plant.

The summary estimate is as follows:

	Material	Labor	Other	Total
32 Miles 42" Pipe 6' Cover				$5,460,000
32 Miles Electric Transmission Line				490,000
4 Pumping Stations				800,000
Pump Suction Basin				100,000
Filtration Plant				350,000
Total	$3,100,000	$1,700,000	$2,400,000	$7,200,000


PEAK WORKING, SUPERVISION & PWE LABOR
PERMANENT HOUSING
14,800,000 MAN
PLANT
28,000,000 MAN
TEMPORARY HOUSING
4,200,000 MAN
MONTHS
DIRECT LABOR REQUIRED CURVE
ROCK SPRINGS HYDROGENATION PROJECT


TRAILERS FURNISHED IN ROCK SPRINGS - 300 UNITS
SURVEY
RAILROAD AND HIGHWAY
TEMPORARY CAMP UTILITIES
TRAILER CAMP AT SITE - 600 UNITS (MOVE 300 FROM R.S.)
TEMPORARY CAMP - 2600 UNITS
PERMANENT HOUSING - SITE PREP., STREETS, UTILITIES & TEMP. CAMPS
PERMANENT HOUSING - BUILDINGS
PLANT SITE PREPARATION
PLANT CONSTRUCTION
PROJECT SCHEDULE
ROCK SPRINGS HYDROGENATION PROJECT
MONTHS

TEMPORARY CONSTRUCTION HOUSING

The Hydrogenation Project being located 20 miles north of Rock Springs, Wyoming is a "Grass Roots" project at which no facilities exist to accomodate even the first site development crews. Housing is in short supply in Rock Springs and surrounding communities.

The Bureau of Mines has based its estimate on a five year program, starting with completion of process design and authorization to start work. This period provides two years for site development, housing construction, plant engineering, and equipment purchasing functions, and three years for main plant construction.

Temporary facilities are required to accommodate site development and permanent housing construction crews and absorb peak manpower requirement during main plant construction. It is planned to utilize permanent housing facilities as they are made available to their fullest capacity to house construction workers.

A brief construction schedule and manpower requirement curve is shown on the opposite page. The schedule shows a manpower requirement of 3200 men before any permanent housing is available. It is necessary to supply accommodations of temporary nature for these people.

Considering the temporary nature of the facilities, it is proposed that barracks-type accommodations be provided. The facilities shall be similar to temporary training camps built during the war, consisting of barracks, mess and galley, recreation hall, food storage and refrigeration, and necessary utilities. It is necessary to construct a power line from Rock Springs, the cost of which is included in water development, to supply electricity for the temporary camp. A temporary pipe line is required to bring water from Rock Springs, the need for which arises before the permanent line can be installed. Gas can be made available by early completion of the line from Rock Springs, the cost of which is included under "Permanent Housing".

The location of the temporary camp is adjacent to the Plant Site.

The Bureau of Mines estimate of the manhours to construct the plant is 26,054,000 hours. This number corresponds to the estimated direct labor cost of $52,104,000. at $2.00 per hour labor rate. In addition, 15,500,000 hours are required to

construct the housing facilities. Total labor required is 41,554,000 hours, not including supervision, mine labor, or labor to construct railroad, highway, and water line. Although Bureau estimate of labor is low, it was used by the subcommittee as the basis for estimating temporary housing facilities to avoid undue delay in completion of this report.

Schedule studies show that five years is a rather optimistic construction period for a project of this type. For two years practically all labor effort is directed toward completion of housing facilities for more workers. Failure to complete housing facilities as planned would result in higher manpower peaks during plant construction.

Manpower requirements peak at 5300 men. In addition 200 supervisors and 300 mine workers are required raising the total to 5800 men. The supervision is based on 1.55% of the Bureau of Mines direct labor plus material cost, and the mine labor required to open the mines, is 50% of the full complement of mine labor. Assuming a capacity of 4200 workers for the permanent community during the peak manpower requirement period, 1600 men require temporary facilities during this period.

As mentioned above, 3200 men are required on the site at the end of the first year. During the first year 4,000,000 hours are expended developing the site prior to construction of any permanent housing. During the second year the bulk of the permanent housing is completed and 9,200,000 hours are expended. It is proposed to provide for 3200 workers on a temporary basis and build permanent housing at a rate sufficient to accommodate additional workers.

Usually some construction workers own trailors which they bring to the job. It is assumed that 300 men will be so equipped that the operator will furnish 300 additional trailers. A trailer park is required to accomodate these units.

In accordance with the above the cost of temporary construction housing is estimated as follows:-

	Units	
Barrack facilities	2600	$5,910,000
Trailer Park	600	130,000
Trailers	300	600,000
Temporary Water Supply		360,000
		$7,000,000

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
COMMUNITY COSTS

Housing

	Type I	Type II	Type III	Total
Number of Units	1350	2600	1300	5250
Dwellings	$14,370,350	$22,268,600	$10,256,300	$46,895,250
Land	10,800	20,800	2,600	34,200
Landscape	135,000	260,000	81,900	476,900
Streets, Drives & Walks	1,215,000	2,340,000	780,000	4,335,000
Incinerators, Clothes Lines etc.	67,500	130,000	61,600	259,100
Electrical	425,250	819,000	143,000	1,387,250
Site Preparation	48,600	93,600	15,600	157,800
Sub-total	$16,272,500	$25,932,000	$11,341,000	$53,545,500
Temporary Construction	----------Included above ----------			
Profit	----------Included above ----------			
Field Superintendance	162,000	260,000	113,100	535,100
Insurance & Taxes	162,000	260,000	113,100	535,100
Engineering & Purchasing	121,500	195,000	85,800	402,300
Contingency	1,620,000	2,593,000	1,134,000	5,347,000
Sub-total	$ 2,065,500	$ 3,308,000	$ 1,446,000	$ 6,819,500
Fee ex Profit - 1%	162,000	260,000	113,000	535,000
Sub-total indirects	$ 2,227,500	$ 3,568,000	$ 1,559,000	$ 7,354,500
Total	$18,500,000	$29,500,000	$12,900,000	$60,900,000

Civic Facilities

Water System		
600,000 Gal. Tank	$120,000	
Pumps & Chlorination Plant	12,600	
Piping	226,000	
House Connections	209,000	
Indirects & Others	79,400	
Total		$ 647,000
Schools		
2 Grade Schools - 1800 Students	2,160,000	
2 High Schools - 1600 Students	2,250,000	
Total		$4,410,000
Hospital		
128 Bed Hospital		$1,750,000
Community Center		
Building 24,400 SF	288,000	
Furniture	56,000	
Total		$ 344,000
Fire Fighting Equipment		
Fire House	60,000	
Pumper, Ladder & Salvage Truck	39,000	
Fire Hydrants	30,000	
Hose, Chemicals, Misc.	15,000	
Total		$ 144,000
Sewer System		
Outfall Collection System 54,000,000 SF net area	1,350,000	
Treating Plant	175,000	
Total		$1,525,000
Gas Line from Rock Springs		180,000
Total Civic Facilities		$9,000,000

PERMANENT HOUSING

The Engineering Subcommittee has prepared estimates of costs of the housing facilities required for the Hydrogenation Plant at Rock Springs, Wyoming, presented in such a manner so that the Economics Subcommittee can allocate costs of various sections of the community against the cost of liquid fuel production as is necessary.

For purposes of this portion of the estimate, the Bureau's estimate of 4,109 employees was used. In a sparsely settled area such as Rock Springs, Wyoming, the majority of employees for a large plant and mine would probably live in a new city adjacent to the plant. This city would also house and provide working quarters for a large group of service personnel incidental to the needs of the production employees. The service personnel have been estimated at 70% of the production workers so that the total number of employed persons in the community would be 4,100 x 1.7 or 7,000 persons. On the basis of census records, total number of facilities would then be 5,830 and the total population of the city would be slightly over 20,000 people.

It is assumed that housing would not have to be provided for 10% of the families so that 5,250 housing units would be required.

The three types of housing and quantity of units proposed are as follows:

1. 1,350 single family houses of frame construction.
2. 2,600 single family houses of simplified frame construction.
3. 350 apartment buildings, four units per building, of frame construction.

In preparing the estimates of costs of the housing units, the housing units have been estimated including the housing proper, land, sidewalks, streets, sewers, electric service and all indirect charges. The estimated costs of these housing facilities are shown in a table on the opposite page.

Community facilities include the following:

Schools
Hospital
Community center
Streets, sewers
Utility distribution
Fire fighting equipment
Gas line from Rock Springs

School facilities through senior high school are provided to accommodate a total of 3,400 students. A hospital with 128 beds is provided for the community.

A general community building is provided to house a post office, police, civic offices, auditorium, etc. The building will be two stories, except the auditorium section, 150 feet long by 100 feet wide with a total floor area of 24,400 square feet. Black top surfaced streets of 1 1/2 miles per 100 separate houses of 3/4 mile per 100 apartment units are provided. A sewage disposal system consisting of a primary digestion tank, a secondary tile field, and a gathering system is provided. Average water consumption is estimated at 1.2 million gallons per day and a stand pipe of 12 hours supply is included as well as a dual unit chlorination plant.

Community power demand has been estimated at 6,000 kilowatts and allowance for this demand has been made in the estimates of the power generation facilities of the Coal Hydrogenation Plant.

Commercial buildings, such as hotels, theaters, banks, etc. have been estimated on the basis of the average community of this size at approximately $1,700 per household unit. For a community of 20,000 people this requires facilities amounting to $9,900,000 which would provide ten blocks (800,000 square feet) of net space at $12.50 per square foot.

30,000 B/SD COAL HYDROGENATION PLANT - ROCK SPRINGS, WYOMING
METAL REQUIREMENTS

	USBM				NPC					
	Steel Tons	Equipment Tons	Non-Ferrous Tons	Total Tons	Carbon Steel Tons	Alloy Steel Tons	Equipment Tons	Equipment Cost	Non-Ferrous Tons	Total Tons
Coal Preparation	4,568	2,325	53	6,946	3,000	-	2,800	$2,000,000	25	5,825
Paste Preparation	1,751	367	13	2,131	1,800	-	350	500,000	4	2,154
Liquid Phase Hydrogenation	10,632	17,439	128	28,199	21,800	3,300	5,600	9,600,000	175	30,875
Delayed Coking Unit	2,788	715	18	3,521	3,100	50	560	1,100,000	7	3,717
Vapor Phase Hydrogenation	6,716	9,396	85	16,197	13,000	2,000	1,900	3,300,000	90	16,990
Product Distillation	6,018	1,373	53	7,444	7,000	50	1,500	2,100,000	20	8,570
Tar Acid Recovery	1,060	191	12	1,263	1,000	180	110	180,000	1	1,291
Low Temperature Off-Gas Separation	3,811	349	349	4,509	3,800	120	640	2,250,000	25	4,585
Hydrocarbon Steam Cracking	7,132	1,362	11	8,505	5,000	400	1,975	1,600,000	25	7,400
Coal Gasification	11,518	2,521	54	14,093	2,950	-	1,925	1,270,000	5	4,880
Oxygen Plant	3,703	1,041	587	5,331	3,950	-	1,110	1,790,000	625	5,685
Hydrogen Purification & Compression	19,850	9,124	369	29,343	18,300	700	7,800	20,500,000	200	27,000
Tankage, Field Lines & Shipping	13,173	46	11	13,230	16,000	-	110	300,000	2	16,112
Steam & Power Generation	17,441	5,547	400	23,388	9,400	-	17,200	26,600,000	60	26,660
Plant Utilities	8,718	4,981	1,275	14,974	8,800	200	3,940	5,550,000	425	13,365
General Plant	4,887	432	-	5,319	9,400	-	1,500	2,500,000	-	10,900
Water Supply	-	-	-	-	5,500	30	190	300,000	120	5,840
Temporary Construction Housing	-	-	-	-	500	-	-	-	20	520
Contingency @ 10%	12,376	5,721	342	18,439	13,400	700	4,920	8,140,000	180	19,231
Plant Total	136,142	62,930	3,760	202,832	147,700	7,730	54,130	$89,580,000	2,009	211,600
Community & Offsite Housing					5,500				480	5,980
Total	136,142	62,930	3,760	202,832	153,200	7,730	54,130	$89,580,000	2,489	217,580

METALS REQUIREMENT
30,000 B/SD COAL HYDROGENATION
ROCK SPRINGS, WYOMING

The estimate of metals required for construction is compared with the estimate prepared by the Bureau in the table on the opposite page.

The Subcommittee has included under the caption "carbon steel", all structural shapes, plates, piping material, castings, forgings, vessels, tanks, trays. Ferrous alloy includes similar items where alloy steel was employed. Non-ferrous metals are mainly copper and aluminum. The caption, equipment, includes items such as pumps, motors, exchangers and no attempt has been made to divide these materials into alloy or non-ferrous metals.

Although there is some discrepancy in division of the metals to the various classifications, the two estimates of the total metals are almost identical excluding the materials for housing and water supply which were estimated by the Bureau.

Maintenance steel has not been included. It is recommended that this steel be estimated at 75% of the total maintenance material at $1,000/ton when final maintenance material costs have been completed.

30,000 B/SD COAL HYDROGENATION PLANT
CHEMICAL CONSUMPTION
ROCK SPRINGS, WYOMING

		Annual Consumption	Unit Cost	Annual Cost
Ferric Oxide	Tons	36,400	$ 50	$1,820,000
Fullers Earth	"	220	30	6,600
Zinc Oxide	"	8	340	2,720
Chromic Acid	"	6.5	560	3,640
Sulfur	"	16	22	350
Ammonium Thiomolybdate	"	3.5	2,000	7,000
Clay (Attapulgas)	"	64	30	1,920
Hydrofluoric Acid	"	10	500	5,000
Ammonia	"	88	80	7,040
Sodium Hydroxide	"	660	75	49,500
Formic Acid	"	30	300	9,000
Acetic Acid	"	7	480	3,660
Copper Shavings	"	14	480	6,720
Steam Cracking Catalyst	$/Day	29	-	19,700
Shift Catalyst	Tons	146	1,200	175,200
Methanol	M Gals	230	350	80,500
MEA	Tons	16	600	9,600
Lime	"	1,800	13	23,400
Rock Salt	"	650	19	11,800
Sulfuric Acid	"	1,100	20	22,000
Chlorine		21	205	4,300
				$2,269,650
Additional Freight (Estimated)	Tons	5,400	$20 (ca)	105,350
Total				$2,375,000

CHEMICAL CONSUMPTION
30,000 B/SD COAL HYDROGENATION PLANT
ROCK SPRINGS, WYOMING

Daily chemical consumption of the plant was developed jointly by the Process Subcommittee and the Engineering Subcommittee. Prices were assigned by the Engineering Subcommittee as shown in the opposite table. Most of the prices are approximate and were taken from trade publications as prices prevailing during January 1951. Where freight was not included in actual prices, a rate of approximately $1/cwt was assumed.

The initial fill of catalyst and chemicals is estimated as follows:

	Tons	Cost
Steam Cracking Catalyst	145	$250,000
Shift Catalyst	730	750,000
Vapor Phase Hydrogenation Catalyst	330	31,000
Methanol	(220 M gals.)	77,000
CO Removal Liquor		151,000
Others		141,000
Total		$1,400,000

The above does not include a normal inventory of chemicals and catalyst which would amount to $600,000 if an inventory equivalent to three months consumption is maintained.

30,000 B/SD COAL HYDROGENATION PLANTS

INVESTMENTS FOR INDUSTRY CASES

In addition to the base plant located at Rock Springs, Wyoming, the Engineering Subcommittee has estimated investment costs as well as construction labor and steel requirements for 30,000 barrel per stream day Coal Hydrogenation plants located at seven other sites which were selected by the Raw Materials Subcommittee as representative of a synthetic fuels industry of significant proportions.

The Process Subcommittee has provided information showing the changes in quantities of process streams that resulted from using the different coals found at these locations. In addition, the base case at Rock Springs was recalculated on the basis of eliminating the Tar Acid Recovery Unit as well as correcting for minor process inconsistencies that existed in the base case. This has been labeled Wyoming Sweetwater to distinguish it from the base case.

The investment costs for each site were projected from the estimates for the base case at Rock Springs, Wyoming. In addition to the changes in process conditions, consideration was also given to changes in labor rates, freight rates and altitude when calculating the investment costs for other locations.

Variables used to adjust the base case for the process conditions at other locations are tabulated below.

Unit	Variable
Coal Preparation	Quantity of hydrogenation coal as received
Paste Preparation	Quantity of paste
Liquid Phase Hydrogenation	Number of converters, quantity of paste
Delayed Coking	Quantity of feed to coking, quantity of dried coke
Vapor Phase	Number of converters
Distillation Units	No process change
Low Temperature Hydrogen Recovery	Hydrogen produced in Linde Plant

Unit	Variable
Hydrocarbon Steam Cracking	Hydrogen available from Hydrocarbon Cracking Unit
Coal Gasification	Hydrogen from coal gas
Oxygen Plant	Quantity of 95% oxygen required
Hydrogen Purification and Compression	Total hydrogen required
Tankage, Field Lines, and Shipping	Same as base case but excluding phenol tanks and accessories
Steam and Power Plant	Maximum quantity of steam required
Plant Utilities	All items, except Cooling Water, Electrical Distribution, Steam and Condensate Distribution, the same as base case. Variables prorated on the maximum quantities involved.

Labor rates for each location were based on published information for the nearest large cities from which a labor force would be procured. A weighted average was taken of the January 1951 wage rate for several trades and was used as an overall figure in calculating labor costs at each site.

An overall freight factor for each plant location was assumed in an effort to have the estimates reflect in some degree the generally different freight rates for the various locations.

Labor rates and freight factors are shown in the table below.

Location	Freight Factor	Overall Labor Rate $/Hour	Nearest City
Base Case (Rock Spring, Wyoming)	1.00	2.00	Salt Lake City, Utah
Dunn County, North Dakota	0.99	2.16	Minneapolis, Minn.
Rosebud County, Montana	1.00	2.00	Billings, Montana

Location	Freight Factor	Overall Labor Rate $/Hour	Nearest City
Knox County, Indiana	0.98	2.21	Indianapolis, Ind.
Muhlenberg County, Kentucky	0.98	2.15	Charleston, W. Va.
Union County, Kentucky	0.98	2.37	St. Louis, Mo.
Franklin County, Illinois	0.98	2.37	St. Louis, Mo.
Wetzel County, West Virginia	0.97	2.55	Pittsburgh, Pa.

The high altitude of the base case location (7,000 feet above sea level) requires that certain items of equipment such as blowers and compressors that take suction at atmospheric pressure be designed for greater loads than encountered at sea level. When appropriate, certain equipment costs were reduced when it was felt that a less expensive unit would be satisfactory at a lower elevation.

A lower design cooling water temperature was used for the base case than normally encountered on most of the other locations. This would require some increase in costs for this cooler and condenser surface. Since the corrections were not detailed by the Process Subcommittee and the effect on the total investment would be very small, the additional investments at the other sites was neglected.

Costs of the water supply and the railroad spur were based on the following distances:

Plant	Distance (Miles) Water	Railroad
Wyoming-Sweetwater	33	14
Montana-Rosebud	35	50
North Dakota-Dunn	30	0
Kentucky-Muhlenberg	15	0
Kentucky-Union	5	0
Illinois-Franklin	40	0
Indiana-Knox	10	0
West Virginia-Wetzel	30	0

Housing costs for the Western Sites are the same as described in the base case. At the Eastern locations, it has been assumed that no temporary housing will have to be furnished. Construction workers will in many cases drive considerable distances or some bus transportation may have to be furnished.

Permanent housing has been estimated for the Eastern sites on the basis that:

1. No housing need be provided for miners.
2. Only 20% of plant employees and service workers will require housing.
3. A service worker ratio of 70% of plant employees will exist.
4. The Bureau estimate of 3525 plant employees was used for this calculation resulting in 990 households.

30,000 B/SD COAL HYDROGENATION PLANTS
SUMMARY OF INDUSTRY CASES

	Investment Costs Dollars						Labor	Metals
	Material	Labor	Others	Total Plant	Community Offsite Housing	Grand Total	Manhours	Short Tons
Rock Springs, Wyo. (Base Case)	213,150,000	68,870,000	121,280,000	403,300,000	79,800,000	483,100,000	52,780,000	217,580
Sweetwater Co.,Wyo.	208,000,000	67,400,000	120,000,000	395,400,000	79,800,000	475,200,000	52,000,000	211,300
Dunn Co., No. Dakota	211,600,000	75,400,000	128,000,000	415,000,000	79,800,000	494,800,000	53,500,000	218,600
Rosebud Co., Montana	213,400,000	69,700,000	123,800,000	406,900,000	79,800,000	486,700,000	54,800,000	216,900
Knox Co., Indiana	198,800,000	70,300,000	121,300,000	390,400,000	15,100,000	405,500,000	37,800,000	201,400
Muhlenberg Co., Ky.	198,100,000	68,000,000	119,100,000	385,200,000	15,100,000	400,300,000	37,600,000	200,700
Union Co., Ky.	197,600,000	74,500,000	125,300,000	397,400,000	15,100,000	412,500,000	37,400,000	198,800
Franklin Co., Ill.	200,100,000	76,300,000	128,000,000	404,400,000	15,100,000	419,500,000	38,700,000	205,500
Wetzel Co., West Va.	202,300,000	83,000,000	134,200,000	419,500,000	15,100,000	434,600,000	38,800,000	210,000

INDUSTRY SUMMARY

A summary of the investment costs, construction labor, and metal requirements for the various sites is shown on the opposite page and more detailed tabulations for each site follow.

30,000 B/SD COAL HYDROGENATION PLANTS
SUMMARY OF ESTIMATE
FOR INDUSTRY CASES
SWEETWATER COUNTY, WYOMING

	Investment Costs				Labor	Metal
	Material	Labor	Others	Total	Manhours	Short Tons
Coal Preparation	$ 2,700,000	$ 1,400,000	$ 2,100,000	$ 6,200,000	700,000	5,550
Paste Preparation	1,300,000	900,000	1,200,000	3,400,000	450,000	2,110
Liquid Phase Hydrogenation	38,700,000	7,600,000	18,200,000	64,500,000	3,800,000	30,400
Delayed Coking	3,300,000	1,500,000	2,400,000	7,200,000	750,000	3,760
Vapor Phase Hydrogenation	19,900,000	3,900,000	9,300,000	33,100,000	1,950,000	16,990
Distillation Units	7,600,000	2,800,000	4,900,000	15,300,000	1,400,000	8,550
Low Temp. Hydrogen Recovery	6,200,000	1,400,000	3,200,000	10,800,000	700,000	4,710
Hydrocarbon Steam Cracking	7,300,000	2,700,000	4,700,000	14,700,000	1,350,000	7,840
Coal Gasification	3,000,000	1,200,000	2,000,000	6,200,000	600,000	4,520
Oxygen Plant	5,200,000	1,300,000	2,600,000	9,100,000	650,000	4,550
Hydrogen Purification & Compression	33,600,000	7,600,000	16,700,000	57,900,000	3,800,000	26,900
Tankage, Field Lines & Shipping	4,300,000	2,300,000	3,500,000	10,100,000	1,150,000	15,550
Steam & Power Plant	39,500,000	14,000,000	23,000,000	76,500,000	7,000,000	25,900
Plant Utilities	14,400,000	6,500,000	10,600,000	31,500,000	3,250,000	12,100
General Plant Facilities	15,300,000	8,000,000	11,400,000	34,700,000	4,000,000	10,880
Water Supply	3,100,000	1,700,000	2,400,000	7,200,000	850,000	5,840
Temporary Construction Housing	2,600,000	2,600,000	1,800,000	7,000,000	1,300,000	520
					33,700,000	186,670
				Contingency	3,400,000	18,630
Total Plant	$208,000,000	$67,400,000	$120,000,000	$395,400,000	37,100,000	205,300
Community & Offsite Housing						
Civic Facilities				9,000,000		
Permanent Housing (Employees)				36,000,000		
Permanent Housing (Others)				24,900,000		
Commercial				9,900,000		
Total Housing				$ 79,800,000	14,900,000	6,000
Grand Total				$475,200,000	52,000,000	211,300

30,000 B/SD COAL HYDROGENATION PLANTS
SUMMARY OF ESTIMATE
FOR INDUSTRY CASES
DUNN COUNTY, NORTH DAKOTA

	Investment Costs				Labor	Metal
	Material	Labor	Others	Total	Manhours	Short Tons
Coal Preparation	$4,600,000	$2,500,000	$3,800,000	$10,900,000	1,160,000	9,560
Paste Preparation	1,400,000	1,000,000	1,400,000	3,800,000	470,000	2,290
Liquid Phase Hydrogenation	35,600,000	7,600,000	17,300,000	60,500,000	3,520,000	28,300
Delayed Coking	3,700,000	1,800,000	2,700,000	8,200,000	840,000	4,270
Vapor Phase Hydrogenation	19,000,000	4,100,000	9,100,000	32,200,000	1,900,000	16,400
Distillation Units	7,600,000	3,100,000	5,000,000	15,700,000	1,440,000	8,600
Low Temp. Hydrogen Recovery	6,800,000	1,700,000	3,600,000	12,100,000	800,000	5,200
Hydrocarbon Steam Cracking	6,900,000	2,700,000	4,600,000	14,200,000	1,250,000	7,450
Coal Gasification	3,200,000	1,400,000	2,200,000	6,800,000	650,000	4,850
Oxygen Plant	6,300,000	1,700,000	3,400,000	11,400,000	800,000	5,550
Hydrogen Purification & Compression	34,600,000	8,500,000	17,700,000	60,800,000	3,940,000	27,800
Tankage, Field Lines & Shipping	4,300,000	2,500,000	3,600,000	10,400,000	1,160,000	15,550
Steam & Power Plant	42,600,000	16,600,000	26,200,000	85,400,000	7,700,000	28,100
Plant Utilities	15,300,000	7,600,000	11,800,000	34,700,000	3,520,000	13,000
General Plant Facilities	14,500,000	8,300,000	11,400,000	34,200,000	3,840,000	10,400
Water Supply	2,600,000	1,700,000	2,400,000	6,700,000	800,000	5,500
Temporary Construction Housing	2,600,000	2,600,000	1,800,000	7,000,000	1,300,000	500
					35,090,000	193,320
				Contingency	3,510,000	19,280
Total Plant	$211,600,000	$75,400,000	$128,000,000	$415,000,000	38,600,000	212,600
Community & Offsite Housing						
Civic Facilities				9,000,000		
Permanent Housing (Employees)				36,000,000		
Permanent Housing (Others)				24,900,000		
Commercial				9,900,000		
Total Housing				$79,800,000	14,900,000	6,000
Grand Total				$494,800,000	53,500,000	218,600

30,000 B/SD COAL HYDROGENATION PLANTS
SUMMARY OF ESTIMATE
FOR INDUSTRY CASES
ROSEBUD COUNTY, MONTANA

	Investment Costs				Labor	Metal
	Material	Labor	Others	Total	Manhours	Short Tons
Coal Preparation	$3,600,000	$1,800,000	$2,800,000	$8,200,000	900,000	7,430
Paste Preparation	1,300,000	900,000	1,300,000	3,500,000	450,000	2,110
Liquid Phase Hydrogenation	38,000,000	7,500,000	17,800,000	63,300,000	3,750,000	29,800
Delayed Coking	4,600,000	2,000,000	3,400,000	10,000,000	1,000,000	5,250
Vapor Phase Hydrogenation	19,900,000	3,900,000	9,300,000	33,100,000	1,950,000	16,990
Distillation Units	7,600,000	2,800,000	4,900,000	15,300,000	1,400,000	8,550
Low Temp. Hydrogen Recovery	6,600,000	1,500,000	3,300,000	11,400,000	1,750,000	4,180
Hydrocarbon Steam Cracking	7,100,000	2,600,000	4,600,000	14,300,000	1,300,000	7,620
Coal Gasification	3,000,000	1,200,000	2,000,000	6,200,000	600,000	4,500
Oxygen Plant	5,500,000	1,400,000	2,700,000	9,600,000	700,000	4,800
Hydrogen Purification & Compression	33,400,000	7,600,000	16,700,000	57,700,000	3,800,000	26,600
Tankage, Field Lines & Shipping	4,300,000	2,300,000	3,500,000	10,100,000	1,650,000	15,550
Steam & Power Plant	40,100,000	14,200,000	23,300,000	77,600,000	7,100,000	26,200
Plant Utilities	14,600,000	6,600,000	10,600,000	31,800,000	3,300,000	12,280
General Plant Facilities	18,200,000	8,800,000	13,000,000	40,000,000	4,400,000	12,920
Water Supply	3,000,000	2,000,000	2,800,000	7,800,000	930,000	6,400
Temporary Construction Housing	2,600,000	2,600,000	1,800,000	7,000,000	1,300,000	500
					36,280,000	191,680
				Contingency	3,620,000	19,220
Total Plant	$213,400,000	$69,700,000	$123,800,000	$406,900,000	39,900,000	210,900
Community & Offsite Housing						
Civic Facilities				$ 9,000,000		
Permanent Housing (Employees)				36,000,000		
Permanent Housing (Others)				24,900,000		
Commercial				9,900,000		
Total Housing				$79,800,000	14,900,000	6,000
Grand Total				$486,700,000	54,800,000	216,900

30,000 B/SD COAL HYDROGENATION PLANTS
SUMMARY OF ESTIMATE
FOR INDUSTRY CASES
KNOX COUNTY, INDIANA

	Investment Costs				Labor	Metal
	Material	Labor	Others	Total	Manhours	Short Tons
Coal Preparation	$ 2,800,000	$ 1,600,000	$ 2,400,000	$ 6,800,000	730,000	5,850
Paste Preparation	1,300,000	1,000,000	1,400,000	3,700,000	450,000	2,160
Liquid Phase Hydrogenation	38,600,000	8,500,000	18,900,000	66,000,000	3,840,000	30,900
Delayed Coking	4,000,000	2,000,000	3,100,000	9,100,000	910,000	4,650
Vapor Phase Hydrogenation	19,500,000	4,300,000	9,600,000	33,400,000	1,950,000	17,000
Distillation Units	7,500,000	3,100,000	5,100,000	15,700,000	1,400,000	8,600
Low Temp. Hydrogen Recovery	6,500,000	1,700,000	3,300,000	11,500,000	770,000	5,050
Hydrocarbon Steam Cracking	7,300,000	3,100,000	5,000,000	15,400,000	1,400,000	7,970
Coal Gasification	2,800,000	1,300,000	1,900,000	6,000,000	590,000	4,280
Oxygen Plant	4,500,000	1,300,000	2,300,000	8,100,000	590,000	4,020
Hydrogen Purification & Compression	32,200,000	8,200,000	17,000,000	57,400,000	3,710,000	26,100
Tankage, Field Lines & Shipping	4,200,000	2,500,000	3,700,000	10,400,000	1,130,000	15,550
Steam & Power Plant	38,400,000	15,500,000	24,100,000	78,000,000	7,020,000	25,600
Plant Utilities	14,000,000	7,200,000	11,000,000	32,200,000	3,260,000	12,020
General Plant Facilities	14,400,000	8,500,000	11,700,000	34,600,000	3,840,000	10,450
Water Supply	800,000	500,000	800,000	2,100,000	270,000	1,830
					31,860,000	182,030
			Contingency		3,140,000	18,170
Total Plant	$198,800,000	$70,300,000	$121,300,000	$390,400,000	35,000,000	200,200
Community & Offsite Housing						
Civic Facilities				$1,700,000		
Permanent Housing (Employees)				6,800,000		
Permanent Housing (Others)				4,700,000		
Commercial				1,900,000		
Total Housing				$15,100,000	2,800,000	1,200
Grand Total				$405,500,000	37,800,000	201,400

30,000 B/SD COAL HYDROGENATION PLANTS
SUMMARY OF ESTIMATE
FOR INDUSTRY CASES
MUHLENBERG COUNTY, KENTUCKY

	Investment Costs				Labor	Metal
	Material	Labor	Others	Total	Manhours	Short Tons
Coal Preparation	$ 2,700,000	$ 1,500,000	$ 2,300,000	$ 6,500,000	700,000	5,660
Paste Preparation	1,300,000	1,000,000	1,300,000	3,600,000	470,000	2,160
Liquid Phase Hydrogenation	39,200,000	8,400,000	19,100,000	66,700,000	3,900,000	31,300
Delayed Coking	3,800,000	1,800,000	3,000,000	8,600,000	840,000	4,400
Vapor Phase Hydrogenation	19,500,000	4,200,000	9,500,000	33,200,000	1,950,000	17,000
Distillation Units	7,500,000	3,000,000	5,000,000	15,500,000	1,400,000	8,600
Low Temp. Hydrogen Recovery	6,500,000	1,600,000	3,300,000	11,400,000	750,000	5,050
Hydrocarbon Steam Cracking	7,400,000	3,000,000	5,000,000	15,400,000	1,400,000	8,050
Coal Gasification	2,700,000	1,200,000	1,800,000	5,700,000	560,000	4,140
Oxygen Plant	4,300,000	1,200,000	2,200,000	7,700,000	560,000	3,820
Hydrogen Purification & Compression	32,000,000	8,000,000	16,700,000	56,700,000	3,720,000	25,900
Tankage Field Lines & Shipping	4,200,000	2,500,000	3,600,000	10,300,000	1,160,000	15,550
Steam & Power Plant	37,600,000	14,700,000	23,200,000	75,500,000	6,850,000	25,000
Plant Utilities	13,800,000	6,900,000	10,600,000	31,300,000	3,210,000	11,800
General Plant Facilities	14,400,000	8,200,000	11,400,000	34,000,000	3,820,000	10,450
Water Supply	1,200,000	800,000	1,100,000	3,100,000	330,000	2,520
					31,620,000	181,400
				Contingency	3,180,000	18,100
Total Plant	$198,100,000	$68,000,000	$119,100,000	$385,200,000	34,800,000	199,500
Community & Offsite Housing						
Civic Facilities				$1,700,000		
Permanent Housing (Employees)				6,800,000		
Permanent Housing (Others)				4,700,000		
Commercial				1,900,000		
Total Housing				$15,100,000	2,800,000	1,200
Grand Total				$400,300,000	37,600,000	200,700

30,000 B/SD COAL HYDROGENATION PLANTS
SUMMARY OF ESTIMATE
FOR INDUSTRY CASES
UNION COUNTY, KENTUCKY

	Investment Costs				Labor	Metal
	Material	Labor	Others	Total	Manhours	Short Tons
Coal Preparation	$ 2,600,000	$ 1,600,000	$ 2,300,000	$ 6,500,000	680,000	5,450
Paste Preparation	1,300,000	1,100,000	1,400,000	3,800,000	470,000	2,160
Liquid Phase Hydrogenation	39,200,000	9,300,000	19,800,000	68,300,000	3,920,000	31,300
Delayed Coking	3,700,000	1,900,000	3,100,000	8,700,000	800,000	4,260
Vapor Phase Hydrogenation	19,500,000	4,600,000	9,900,000	34,000,000	1,940,000	17,000
Distillation Units	7,500,000	3,400,000	5,200,000	16,100,000	1,440,000	8,600
Low Temp. Hydrogen Recovery	6,600,000	1,800,000	3,500,000	11,900,000	760,000	5,070
Hydrocarbon Steam Cracking	7,400,000	3,300,000	5,300,000	16,000,000	1,390,000	8,050
Coal Gasification	2,700,000	1,300,000	2,100,000	6,100,000	550,000	4,140
Oxygen Plant	4,400,000	1,300,000	2,400,000	8,100,000	550,000	3,900
Hydrogen Purification & Compression	32,300,000	8,900,000	17,800,000	59,000,000	3,760,000	26,000
Tankage, Field Lines & Shipping	4,200,000	2,700,000	3,900,000	10,800,000	1,140,000	15,550
Steam & Power Plant	37,600,000	16,300,000	24,700,000	78,600,000	6,900,000	25,000
Plant Utilities	13,800,000	7,600,000	11,300,000	32,700,000	3,200,000	11,800
General Plant Facilities	14,400,000	9,100,000	12,200,000	35,700,000	3,840,000	10,450
Water Supply	400,000	300,000	400,000	1,100	140,000	920
					31,480,000	179,650
				Contingency	3,120,000	17,950
Total Plant	$197,600,000	$74,500,000	$125,300,000	$397,400,000	34,600,000	197,600
Community & Offsite Housing						
Civic Facilities				$1,700,000		
Permanent Housing (Employees)				6,800,000		
Permanent Housing (Others)				4,700,000		
Commercial				1,800,000		
Total Housing				$15,100,000	2,800,000	1,200
Grand Total				$412,500,000	37,400,000	198,800

30,000 B/SD COAL HYDROGENATION PLANTS
SUMMARY OF ESTIMATE
FOR INDUSTRY CASES
FRANKLIN COUNTY, ILLINOIS

	Investment Costs				Labor	Metal
	Material	Labor	Others	Total	Manhours	Short Tons
Coal Preparation	$ 2,600,000	$ 1,600,000	$ 2,300,000	$ 6,500,000	720,000	5,450
Paste Preparation	1,300,000	1,100,000	1,400,000	3,800,000	470,000	2,160
Liquid Phase Hydrogenation	39,000,000	9,200,000	20,000,000	68,200,000	3,880,000	31,200
Delayed Coking	3,600,000	1,900,000	3,000,000	8,500,000	800,000	4,160
Vapor Phase Hydrogenation	19,500,000	4,600,000	9,900,000	34,000,000	1,940,000	17,000
Distillation Units	7,500,000	3,400,000	5,200,000	16,100,000	1,430,000	8,600
Low Temp. Hydrogen Recovery	6,600,000	1,800,000	3,500,000	11,900,000	760,000	5,070
Hydrocarbon Steam Cracking	7,500,000	3,300,000	5,500,000	16,300,000	1,390,000	7,960
Coal Gasification	2,600,000	1,300,000	2,000,000	5,900,000	550,000	4,100
Oxygen Plant	4,200,000	1,300,000	2,300,000	7,800,000	550,000	3,740
Hydrogen Purification & Compression	32,200,000	8,900,000	17,600,000	58,700,000	3,750,000	26,100
Tankage, Field Lines & Shipping	4,200,000	2,700,000	3,900,000	10,800,000	1,140,000	15,550
Steam & Power Plant	37,600,000	16,300,000	24,700,000	78,600,000	6,900,000	25,000
Plant Utilities	13,900,000	7,600,000	11,400,000	32,900,000	3,460,000	11,900
General Plant Facilities	14,400,000	9,100,000	12,200,000	35,700,000	3,840,000	10,450
Water Supply	3,400,000	2,200,000	3,100,000	8,700,000	1,070,000	7,300
					32,650,000	185,740
			Contingency		3,250,000	18,560
Total Plant	$200,100,000	$76,300,000	$128,000,000	$404,400,000	35,900,000	204,300
Community & Offsite Housing						
Civic Facilities				$1,700,000		
Permanent Housing (Employees)				6,800,000		
Permanent Housing (Others)				4,700,000		
Commercial				1,900,000		
Total Housing				$15,100,000	2,800,000	1,200
Grand Total				$419,500,000	38,700,000	205,500

30,000 B/SD COAL HYDROGENATION PLANTS
SUMMARY OF ESTIMATE
FOR INDUSTRY CASES
WETZEL COUNTY, WEST VIRGINIA

	Investment Costs				Labor	Metal
	Material	Labor	Others	Total	Manhours	Short Tons
Coal Preparation	$ 2,600,000	$ 1,700,000	$ 2,400,000	$ 6,700,000	670,000	5,450
Paste Preparation	1,300,000	1,200,000	1,600,000	4,100,000	470,000	2,160
Liquid Phase Hydrogenation	42,500,000	10,900,000	22,400,000	75,800,000	4,290,000	34,400
Delayed Coking	4,700,000	2,700,000	3,800,000	11,200,000	1,060,000	5,520
Vapor Phase Hydrogenation	20,000,000	5,200,000	10,700,000	35,900,000	2,040,000	17,540
Distillation Units	7,400,000	3,600,000	5,500,000	16,500,000	1,420,000	8,600
Low Temp. Hydrogen Recovery	6,400,000	1,900,000	3,700,000	12,000,000	750,000	5,010
Hydrocarbon Steam Cracking	8,000,000	3,900,000	6,000,000	17,900,000	1,530,000	8,840
Coal Gasification	2,200,000	1,200,000	1,800,000	5,200,000	470,000	3,480
Oxygen Plant	3,200,000	1,100,000	1,900,000	6,200,000	430,000	2,890
Hydrogen Purification & Compression	31,300,000	9,400,000	17,700,000	58,400,000	3,690,000	26,600
Tankage, Field Lines & Shipping	4,200,000	2,900,000	4,000,000	11,100,000	1,140,000	15,550
Steam & Power Plant	37,700,000	17,600,000	25,900,000	81,200,000	6,930,000	25,300
Plant Utilities	13,900,000	8,200,000	11,900,000	34,000,000	3,220,000	11,900
General Plant Facilities	14,400,000	9,800,000	12,700,000	36,900,000	3,850,000	10,450
Water Supply	2,500,000	1,700,000	2,200,000	6,400,000	760,000	6,200
					32,720,000	189,890
				Contingency	3,280,000	18,910
Total Plant	$202,300,000	$83,000,000	$134,200,000	$419,500,000	36,000,000	208,800
Community & Offsite Housing						
Civic Facilities				1,700,000		
Permanent Housing (Employees)				6,800,000		
Permanent Housing (Others)				4,700,000		
Commercial				1,900,000		
Total Housing				$15,100,000	2,800,000	1,200
Grand Total				$434,600,000	38,800,000	210,000

ENGINEERING ESTIMATES
OF CAPITAL REQUIREMENTS
AND OPERATING COSTS
FOR RETORTING AND REFINING SHALE OIL

Prepared by

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

August 1, 1951

August 1, 1951

Mr. L. C. Kemp, Jr., Chairman
The Texas Company
135 East 42nd Street
New York 17, N. Y.

NPC Subcommittee on Synthetic Fuels
Production Costs
Shale Oil Engineering Group

Dear Mr. Kemp:

The Shale Oil Engineering Group of your Engineering Subcommittee has prepared the following estimates on retorting, refining, and pipeline transportation for use by the NPC Subcommittee in determining the costs of producing refined fuels from Colorado oil shale on 50,000 B/CD and 250,000 B/CD operation levels:

1. Costs of Facilities
2. Operating Costs
3. On-Site Operating and Maintenance Personnel Requirements
4. Maintenance and Operating Materials Requirements
5. Fuel and Utilities Requirements
6. Catalyts and Chemicals Requirements
7. Equipment Life
8. Metals Requirements
9. Operating Inventories.

The estimates herein are based upon the processing presented in the report of the Shale Oil Processing Group titled National Petroleum Council on Synthetic Fuels Production Costs - Shale Oil Retorting and Refining Facilities, dated April 15, 1951.

All cost estimates are on a January 1, 1951 basis.

All estimates of the costs of facilities except the continuous coker and the retorts are factor estimates based upon costs of erected commercial facilities adjusted to the January 1, 1951 basis. The cost of the continuous cokers has been assumed to be the same as the cost of commercial delayed cokers. The cost of the retorts was arrived at from quotations on the detailed designs supplied by the Process Group.

Estimates have not been prepared on the following:

1. Capital and operating costs of Oil Shale Mining and crushing. These estimates have been prepared by a separate NPC committee.

2. Permanent community facilities for operating personnel. These also are being prepared by a separate NPC committee.

3. Executive, comptroller, legal, research and development and other staff services or facilities; Marketing and distribution and other sales services and facilities. The Group felt that these costs can be readily ascertained by the economics committee from present industry experience.

4. Value or Royalties due owner of oil shale properties. The Group assumed that this determination would be made by the mining and economics committees.

5. Operating capital.

The Group wishes to acknowledge the assistance received from many people representing our various companies and other organizations. This report has required the work of many specialists in various phases of Engineering, Estimating, and Economics, and their aid has contributed greatly to the preparation of this report.

Submitted by:

Shale Oil Engineering Group

Homer Reed	Union Oil Company of California
A. K. Brumbaugh, Jr.	General Petroleum Corporation
F. W. Curtis	Shell Oil Company
L. P. Elliott	California Research Corporation
Frank Fontana	Richfield Oil Corporation
C. K. Viland	~~Pide~~ Water Associated Oil Company

By Homer Reed

Homer Reed, Chairman

HR:lal

Revised
September 17, 1951

SUMMARY OF ESTIMATES

1. MATERIALS BALANCE	50,000 B/CD Case	250,000 B/CD Case
Feed: Crushed Shale to Retorts, Tons/CD	76,800	384,000
Shale Oil to Coking Units, B/CD	50,000	250,000
Yield of Finished Products:		
Liquid Fuels, B/CD		
LPG	1,780	8,920
Premium Motor Gasoline (Research Knock Rating + 3 ml TEL 96)	12,690	63,450
Regular Motor Gasoline (Research Knock Rating + 3 ml TEL 85)	12,690	63,450
Diesel	13,020	65,100
Fuel Oil	1,010	5,040
Total Liquid Fuels, B/CD	41,190	205,960
Less Diesel Burned for Fuel	820	2,740
Less Fuel Oil Burned for Fuel	670	1,990
Total Liquid Fuels for Sales, B/CD	39,700	201,230
Fuel Gas to Sales, MSCF/CD		
Colorado Refinery Fuel Gas	24,830	124,150
By-Products to Sales, Tons/CD		
Ammonia	92	460
Sulfur	43	215
Coke	1,180	5,900
2. COST OF FACILITIES	$245,000,000	$1,100,000,000
3. OPERATING COSTS	$89,800/CD	$403,330/CD

SHALE OIL ENGINEERING GROUP REPORT

INDEX

		Page No.
I.	GENERAL	
	Summary	1
	Description of Project	2
	Location of Facilities	10
II.	SUMMARIES OF ESTIMATES	
	Cost of Facilities	13
	Operating Costs	15
	Personnel	16
	Maintenance Costs	25
	Fuels & Utilities	26
	Operating Materials	31
	Chemicals	33
	Catalysts	34
	Capital Charges	35
	Metals Requirements	36
	Estimated Life	37
	Normal Working Inventories	39
III.	ESTIMATES	

(Summaries in Section II were prepared from these estimates. Page numbers in this section apply only to the individual estimates.)

Section 100 - Operating Units

Item	103	Retorting
	104	Coking Unit
	105	Catalytic Hydrogenation
	106	Catalytic Reforming
	107	Hydrogen Production
	108	Catalytic Cracking
	109	Catalytic Polymerization
	110	Redistillation
	111	Ammonia Recovery
	112	Sulfur Unit

INDEX (Continued)

Section 200 - Utilities

Item 201 Steam Power Plants
202 Power Transmission
Includes: Item 212 Telephone System
204,205,209 Water Treating & Distribution
Includes: Item 203 Water Reservoirs
Item 802 Sewerage System
207 Steam Distribution
208 Condensate System
210 Air Compressor Plant

Section 300 - Maintenance Facilities

Item 301 Maintenance Operating Buildings
302 Central Shops
303 Warehouse

Section 400 - Tankage

Item 401 Crude Shale Oil
402 Unfinished Oils - Colorado and Los Angeles
403 Products Pipe Line - Head and Terminal Storage
404 Finished Oils
405 Ammonia Storage

Section 500 - Pipelines and Pumping Units

Item 501 Crude Shale Oil Lines
502 Retort Gas Lines
503 Intermediate Product Gathering System
504 Colorado to California Product Line
505 Pumping Stations

Section 600 - Quarters

Item 602 Laboratories
603 Operating Unit Buildings
605 Other Refinery Buildings

Section 700 - Real Estate Improvements

Item 701 Refinery Sites
702 Roads
703 Fences

INDEX (Continued)

Section 800 - Waste Disposal

Item 802 Sewerage System (Included with Item 204)
803 Refuse

Section 900 - Transportation & Shipping

Item 901 Rail Spurs
902 Loading Rocks
903 Coke Handling & Shipping Facilities
904 Sulfur Handling Facilities

DESCRIPTION OF PROJECT

This report covers facilities for the retorting, refining, and pipeline transportation to a marketing center for two cases:

A. 50,000 B/CD of crude shale oil charge to the Coking Units
B. 250,000 B/CD of crude shale oil charge to the Coking Units.

Included are retorting and refining facilities together with the necessary auxiliary facilities in Colorado, a pipeline for the transfer of the unfinished gasoline and diesel to California, and refining facilities in California. The facilities for which estimates have been prepared are similar in scope to those described in the Shale Oil Processing Report dated April 15, 1951, with some minor variations.

A. 50,000 B/CD Case

The retorts used are of the underfeed, continuous upflow type as developed by the Union Oil Company of California. One unit mine and crushing plant of 19,200 tons/CD capacity of oil shale production supplies one unit retort with crushed oil shale. The costs of mining and crushing of the shale have been covered in the report of the Oil Shale Mining Sub-Group dated March 5, 1951, and are not included in this estimate.

Each unit retort produces 12,500 B/CD of crude shale oil which is then fed to a unit refinery of 50,000 B/CD capacity. Thus four unit mines and four unit retorts provide the feed for one unit refinery. The retort is entirely self-sufficient in the use of fuel, and a large quantity of excess retort gas is piped to the refinery, where it is used for process heat and for steam and power generation. Under average operating conditions, there will be sufficient retort gas to supply all the energy requirements for process heating and power generation for the Colorado facilities. Power required for Mining and Crushing has been provided in these estimates. For peak loads or emergency operation the power generation facilities have been designed to operate on retort gas, crude shale oil, and refinery fuel gas. The economics of the design of the retort gas pipeline preclude construction of retort pipelines longer than from about three to five miles; this is one of the principal reasons for locating the refining facilities in Colorado, the other being that crude shale oil has a pour point of about 90°F, making transportation by pipeline for long distances uneconomical.

The Colorado refinery produces partially refined gasoline and diesel, which can be readily transported by pipeline. The Colorado Refinery also produces the following by-products: sweet refinery gas, ammonia, sulfur, and coke. These are available for Sales. No production of excess retort gas is shown.

The Colorado Refinery will consist of the following:

1. Coking Unit
2. Catalytic Hydrogenation Plant
3. Catalytic Reforming Plant
4. Hydrogen Production Plant
5. Ammonia Recovery Plant
6. Sulfur Plant.

Included with the Colorado Retorting and refining facilities are necessary auxiliary facilities such as tankage, water supply, power generation and distribution facilities, loading and unloading facilities, roads, etc. No estimate has been prepared for a new community for the permanent personnel, although estimates for water distribution and liquid sewage disposal facilities for communities of 15,000 and 75,000 population have been included as supplementary information with Item 204, Water Distribution.

Available data indicate that the supply of Colorado River water will be adequate for a number of shale oil projects such as those envisioned in this estimate. A detailed discussion of the availability of Colorado River water is included with Item 204. Provisions have been made to treat and process all liquid sewerage and industrial water that must be disposed of in the Colorado River. Spent shale will be disposed of in canyons below the retorts.

From Colorado, the catalytically reformed gasoline and the hydrogenated diesel will be blocked through a single pipeline to California, except 2,100 B/CD of gasoline and 2,900 B/CD of diesel for local Sales in Colorado. In addition, 820 B/CD of Diesel will be removed from the pipeline for pumping station fuel. Included with the pipeline are necessary pumping stations and tankage at the Colorado and California terminals. The estimated length of the Pipeline from DeBeque to Los Angeles is 690 miles, with an additional twenty miles of feeder lines in the Los Angeles area. Housing facilities for all permanent Pipeline personnel have been provided at each pumping station.

The California refining facilities will consist of an addition to one existing California Refinery in the Los Angeles Basin. The chief functions of this plant will be to rerun the catalytically reformed gasoline and to catalytically crack hydrogenated diesel to increase the yield of gasoline. The California Refinery will consist of the following:

1. Redistillation facilities
2. Catalytic Cracking Unit
3. Catalytic Polymerization Unit.

Included in the estimates for these additions are provisions for all necessary auxiliary facilities (e.g. utilities, tankage, etc.) for the new refining units. The California refinery will produce the following finished products: LPG, premium motor gasoline, regular motor gasoline, diesel fuel, and fuel oil. Some fuel oil and all the refinery fuel gas will be utilized as refinery fuel.

A complete material balance showing the production of all finished products at all locations and their disposition is presented on Page 5.

B. 250,000 B/CD Case

The same type facilities that were required for the 50,000 B/CD case will be utilized in the 250,000 B/CD case. The retorting and refining facilities in Colorado will be multiplied by a factor of five. Auxiliary facilities will be enlarged as necessary. A single product pipeline to California will be utilized, and the catalytically reformed gasoline and hydrogenated diesel blocked through the line, except 2,100 B/CD of gasoline

and 2,900 B/CD of diesel for local sales in Colorado, and 2,740 B/CD of diesel for pumping station fuel. The California refining facilities will be in the form of additions to three existing refineries in the Los Angeles Basin.

A discussion of the processes used and the reasons therefor may be found in the Shale Oil Processing Group Report dated April 15, 1951.

SHALE OIL PROCESSING

Estimated Materials Balance
Showing Disposition of Products

Revised
September 17, 1951

NPC Subcommittee on Synthetic Fuels

Shale Oil Engineering Group

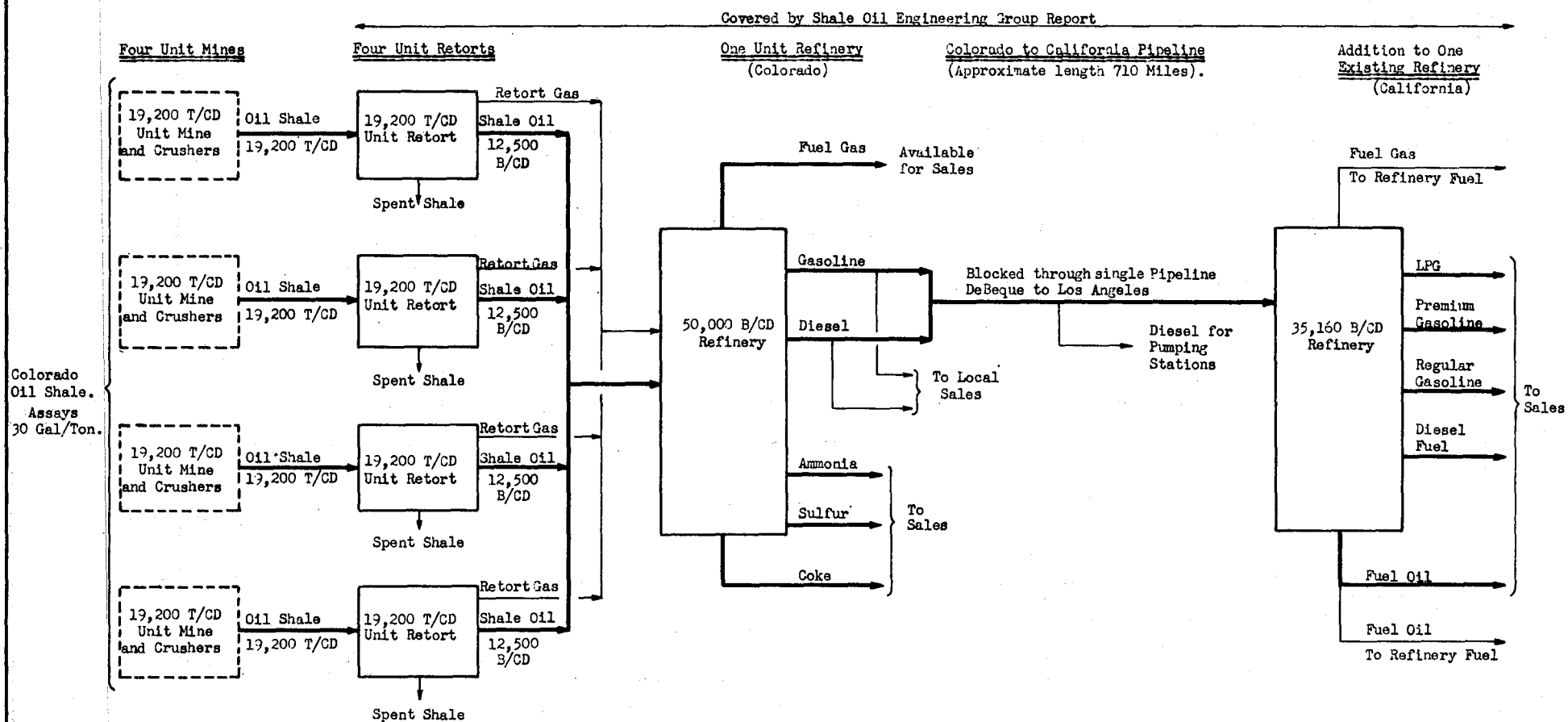
	FEED: 50,000 B/CD of Crude Shale Oil						FEED: 250,000 B/CD of Crude Shale Oil					
	Products Available for Sales			Used for Refinery or Pipeline Fuel		Total Liquid Fuels Production	Products Available for Sales			Used for Refinery or Pipeline Fuel		Total Liquid Fuels Production
	MSCF/CD	B/CD	Tons/CD	MSCF/CD	B/CD	B/CD	MSCF/CD	B/CD	Tons/CD	MSCF/CD	B/CD	B/CD
PRODUCTS:												
Colorado												
Refinery Gas	24,830						124,150					
Regular Motor Gasoline[a]		2,100				2,100		2,100				2,100
Diesel		2,900			820[b]	3,720		2,900			2,740[b]	5,640
Ammonia			92						460			
Sulfur			43						215			
Coke			1,180						5,900			
California												
Refinery Gas				4,750[c]						22,870[c]		
LPG		1,780				1,780		8,920				8,920
Premium Motor Gasoline[a]		12,690				12,690		63,450				63,450
Regular Motor Gasoline[a]		10,590				10,590		61,350				61,350
Diesel		9,300				9,300		59,460				59,460
Fuel Oil		340			670[c]	1,010		3,050			1,990[c]	5,040
Total		39,700			1,490	41,190		201,230			4,730	205,960

a. Research Knock Ratings (F-1) + 3ml TEL
   Colorado Regular 83
   California Premium 96
   California Regular 85

b. Pipeline Fuel

c. California Refinery Fuel

SHALE OIL PROCESSING
50,000 B/CD Case
NPC Subcommittee on Synthetic Fuels - Shale Oil Engineering Group

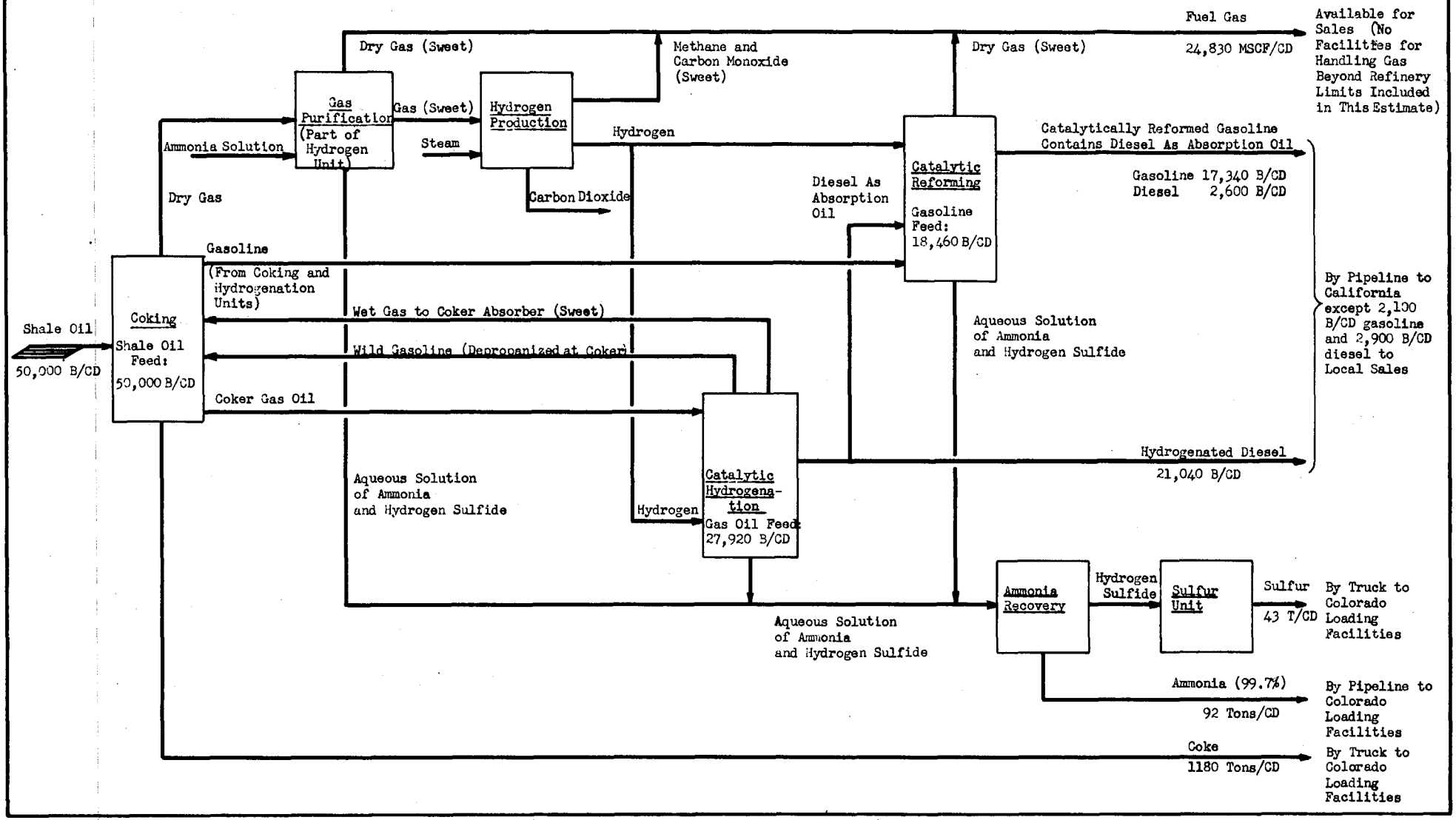


Facilities Required For 250,000 B/CD Case: Twenty Unit Mines, Twenty Unit Retorts, Five Unit Colorado Refineries, One Colorado to California Pipeline, and Additions to Three Existing California Refineries.

SHALE OIL PROCESSING

Schematic Flow of 50,000 B/CD Colorado Refining Facilities

NPC Subcommittee On Synthetic Fuels - Shale Oil Engineering Group



Note: Figures Not in parenthesis are for 50,000 B/CD Case, and are for additions to one existing refinery.

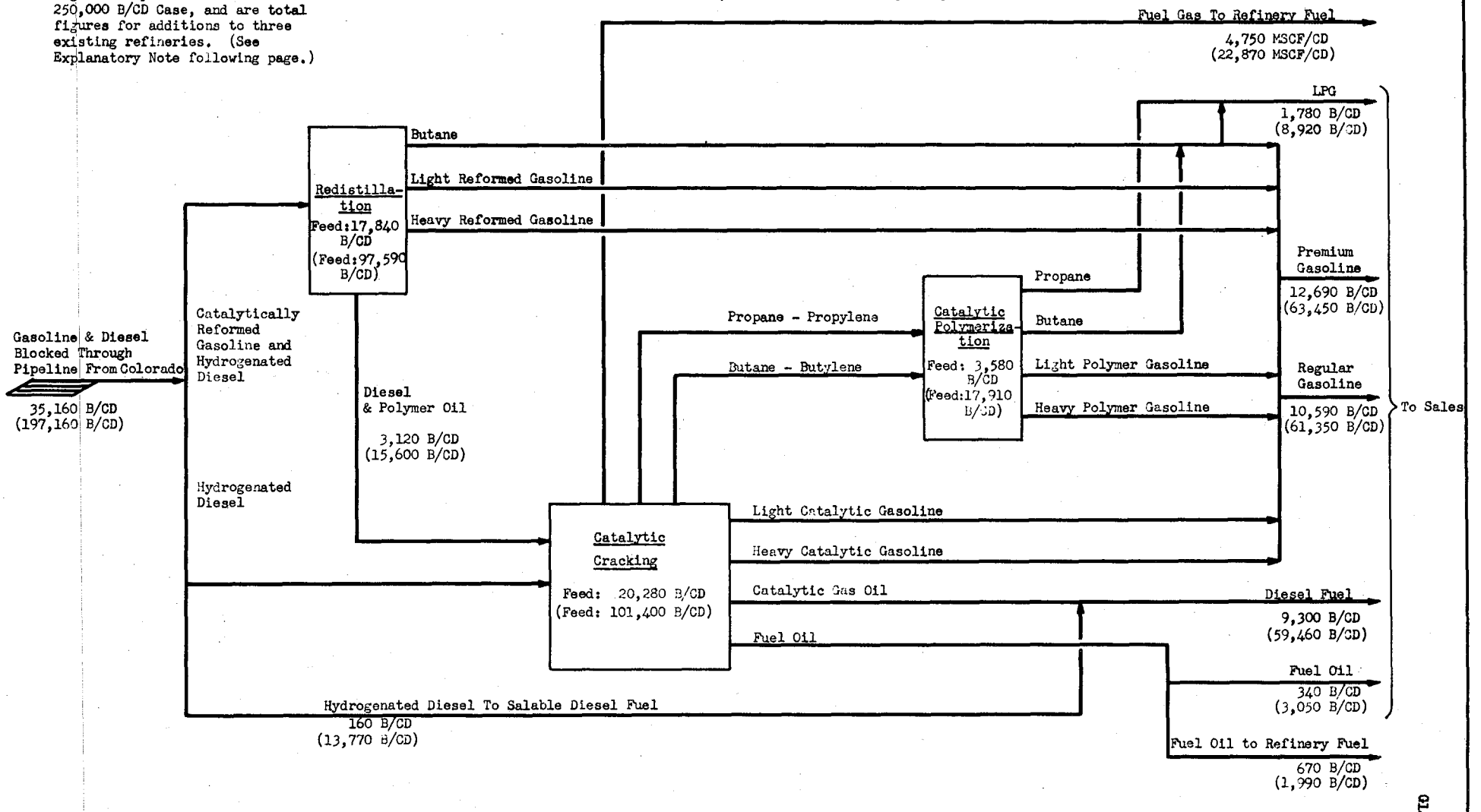
Figures in parenthesis are for 250,000 B/CD Case, and are total figures for additions to three existing refineries. (See Explanatory Note following page.)

SHALE OIL PROCESSING

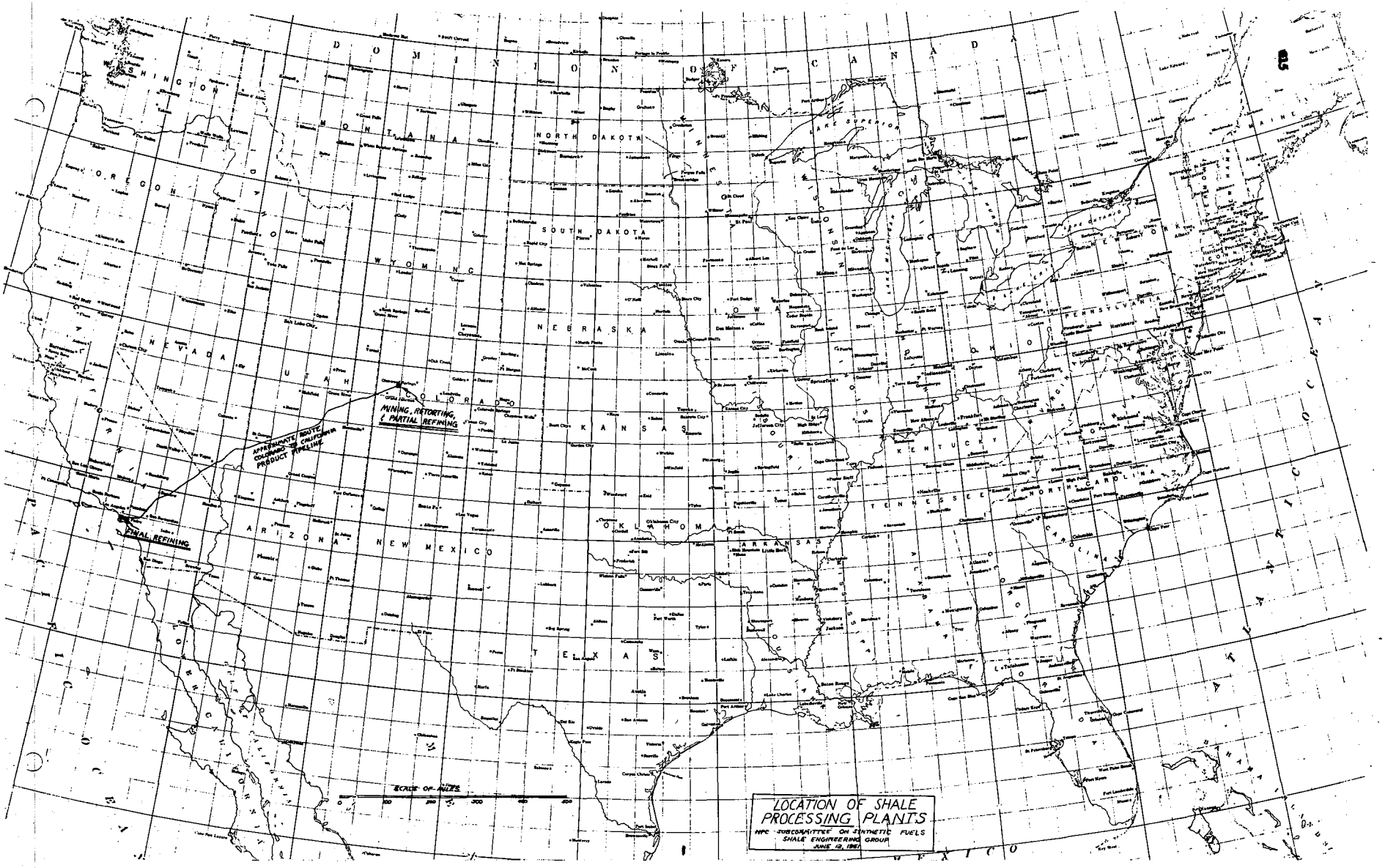
Schematic Flow of California Refining Facilities

NPC Subcommittee On Synthetic Fuels, Shale Oil Engineering Group

Revised September 17, 1951



014


MINING, RETORTING, & PARTIAL REFINING
APPROXIMATE ROUTE COLORADO TO CALIFORNIA PRODUCT PIPELINE
FINAL REFINING
SCALE OF MILES
0 100 200 300 400
LOCATION OF SHALE PROCESSING PLANTS
NPC SUBCOMMITTEE ON SYNTHETIC FUELS
SHALE ENGINEERING GROUP
JUNE 12, 1981

LOCATION OF FACILITIES

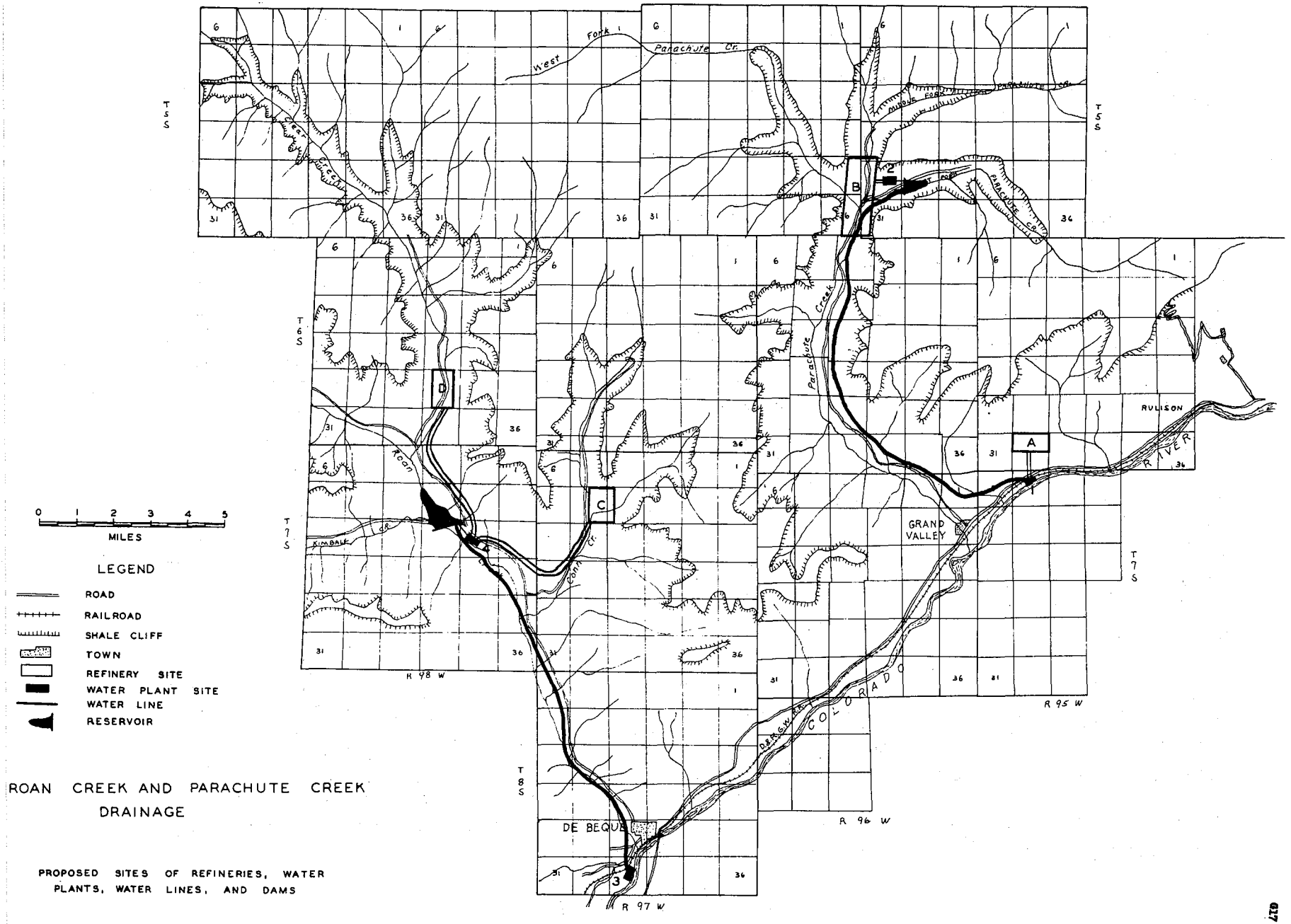
The retorting and partial refining facilities are located near the Green River shale deposits in west central Colorado, while the final refining section is located in the Los Angeles area of California. These areas are connected by a 710-mile pipeline which traverses the states of Colorado, Utah, Arizona, Nevada and California. The general location of all the facilities is shown on a map of the United States which follows.

Specifically, the Colorado facilities are located near the Colorado River, northeast of Grand Junction between Rifle and DeBeque. Rifle is 55 miles from Grand Junction, with DeBeque between. This area is served by the Denver and Rio Grande Western Railroad and U. S. Highway No. 6. Details of this area are shown on a map of the area which follows.

In general the refineries are located in valleys beneath the shale-bearing cliffs, at elevations varying from 5,100 to 5,800 feet above sea level. The mines and the retorts which supply these refineries are located on the slopes of the cliffs approximately 1,500 to 2,000 feet above the refineries. In several cases the refineries will be a considerable distance from existing railroad and highway facilities. Information concerning the location of these refineries follows:

Designation On Colorado Area Map.	Name of Refinery	Location with Respect to Rail and Highway Facilities.
"A"	Cottonwood Gulch	50,000 B/CD Capacity - Located close to existing rail and highway facilities.
"B"	Parachute Creek	Two refineries, each of 50,000 B/CD capacity - Located about 11 miles from existing rail and highway facilities.
"C"	Conn Creek	50,000 B/CD Capacity - Located about 10 miles from existing rail and highway facilities.
"D"	Clear Creek	50,000 B/CD Capacity - Located about 15 miles from existing rail and highway facilities.

Roads will be built to refineries B, C, and D, and to the mines and retorts above all the refineries. Railroads will not be extended to the refineries, but sidings for loading and unloading facilities will be built at selected sites.



ROAN CREEK AND PARACHUTE CREEK DRAINAGE

PROPOSED SITES OF REFINERIES, WATER PLANTS, WATER LINES, AND DAMS

617

F.C.D. 318 5-9-51

ESTIMATED COST OF FACILITIES

NPC Subcommittee On Synthetic Fuels
Shale Oil Engineering Group

Item No.	Description	50,000 B/CD Case			250,000 B/CD Case		
		Labor & Materials	Other	Total	Labor & Materials	Other	Total
		$	$	$	$	$	$
103	Retorts, Retort Site Development, Roads to Sites	37,200,000	12,800,000	50,000,000	186,200,000	51,800,000	238,000,000
104	Coking Unit	16,200,000	3,890,000	20,090,000	81,000,000	19,450,000	100,450,000
105	Catalytic Hydrogenation	9,930,000	3,627,000	13,557,000	49,650,000	18,135,000	67,785,000
106	Catalytic Reforming	9,685,000	3,590,000	13,275,000	48,425,000	17,948,000	66,373,000
107	Hydrogen Production	9,500,000	2,460,000	11,960,000	47,500,000	11,550,000	59,050,000
108	Catalytic Cracking	6,895,000	2,420,000	9,315,000	30,251,000	10,800,000	41,051,000
109	Catalytic Polymerization	1,815,000	625,000	2,440,000	8,498,000	3,020,000	11,518,000
110	Redistillation	2,060,000	716,000	2,776,000	9,337,000	3,344,000	12,681,000
111	Ammonia Recovery	570,000	165,000	735,000	2,850,000	825,000	3,675,000
112	Sulfur Unit	552,000	198,000	750,000	2,760,000	990,000	3,750,000
201	Steam Power Plants	18,825,000	6,275,000	25,100,000	93,975,000	31,325,000	125,300,000
202	Power Transmission	4,250,000	1,546,400	5,796,400	21,700,000	7,910,000	29,610,000
203	Water Reservoirs				804,000	224,000	1,028,000
204, 205, 209	Water Treating & Distribution	1,620,000	547,000	2,167,000	15,940,000	4,437,000	20,377,000
207	Steam Distribution	450,000	163,800	613,800	2,250,000	819,000	3,069,000
208	Condensate System	120,000	43,600	163,600	600,000	218,400	818,400
210	Air Compressor Plant	266,000	89,000	355,000	1,331,000	444,000	1,775,000
212	Telephone System	103,000	37,470	140,470	1,050,000	382,000	1,432,000
301	Maintenance Operating Buildings	78,000	27,000	105,000	390,000	134,000	524,000
302	Central Shops	973,000	477,000	1,450,000	2,910,000	1,390,000	4,300,000
303	Warehouse	128,000	61,000	189,000	412,000	195,000	607,000
400	Tankage	4,722,000	1,324,000	6,046,000	21,767,000	5,428,000	27,195,000
501	Crude Lines	289,000	158,000	447,000	1,310,000	537,000	1,847,000
502	Retort Gas Lines	4,637,000	1,394,000	6,031,000	23,135,000	6,140,000	29,325,000
503	Intermediate Product Gathering System	735,000	245,000	980,000	3,075,000	1,025,000	4,100,000
504	Colorado to California Product Pipeline	20,540,000	6,350,000	27,390,000	38,775,000	12,925,000	51,700,000
505	Pumping Stations	4,040,000	1,864,000	5,904,000	10,300,000	4,330,000	14,630,000
602	Laboratories	337,500	112,500	450,000	1,687,500	562,500	2,250,000
603	Operating Unit Buildings	862,500	287,500	1,150,000	4,312,500	1,437,500	5,750,000
605	Other Refinery Buildings	187,500	62,500	250,000	937,500	312,500	1,250,000
701	Refinery Sites	750,000	250,000	1,000,000	3,750,000	1,250,000	5,000,000
702	Roads	450,000	150,000	600,000	2,250,000	750,000	3,000,000
703	Fences	37,500	12,500	50,000	187,500	62,500	250,000
802	Sewerage System	1,710,000	587,000	2,297,000	8,790,000	2,444,000	11,234,000
803	Refuse	30,000	10,000	40,000	150,000	50,000	200,000
901	Rail Spurs	84,000	36,000	120,000	265,000	97,000	362,000
902	Loading Racks	258,000	100,000	358,000	435,000	146,000	581,000
903	Coke Storage & Shipping	378,000	131,000	509,000	1,298,000	374,000	1,672,000
904	Sulfur Handling Facilities	50,000	5,000	55,000	230,000	23,000	253,000
	Sub Total for Facilities	161,318,000	53,337,270	214,655,270	730,538,000	223,234,400	953,772,400

ESTIMATED COST OF FACILITIES

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	50,000 B/CD Case			250,000 B/CD Case		
		Labor & Materials $	Other $	Total $	Labor & Materials $	Other $	Total $
Capital Investment for Catalysts:							
105	Catalytic Hydrogenation			830,000			4,150,000
106	Catalytic Reforming			1,020,000			5,100,000
107	Hydrogen Production						
	Catalyst			640,000			3,200,000
	Carbon			340,000			1,700,000
108	Catalytic Cracking			192,000			960,000
109	Catalytic Polymerization			16,500			82,500
112	Sulfur Unit			10,000			50,000
	Sub Total for Catalysts			3,048,500			15,242,500
	Sub Total for Facilities & Catalysts			217,703,770			969,014,900
Capital Investment for Estimated Process Royalties				11,730,000			58,650,000
	Sub Total for Facilities, Catalysts, & Royalties			229,433,770			1,027,664,900
	Additional Costs of Colorado Facilities due to Low Availability of Construction Labor in Area			15,566,230			72,335,100
GRAND TOTAL, ESTIMATED CAPITAL INVESTMENT				245,000,000			1,100,000,000
Capital Investment per Daily Barrel of Crude Shale Oil Processed				4,900			4,400
Capital Investment per Daily Barrel of Refined Liquid Fuels Produced for Sales				6,200			5,500

Explanatory Notes:

1. Costs included under Other are for the following: Tools, Engineering, Contractor Overhead, Contractor Fees, Owners' Supervision and Inspection, and Contingency.
2. Contingency for all items calculated as 10% of Labor & Materials.
3. Capital Investment per Daily Barrel of Crude Shale Oil Processed and per Daily Barrel of Refined Liquid Fuels Produced for Sales does not include provision for mining, crushing, and other items detailed in the letter of transmittal as not being included in this estimate.

Revised
September 17, 1951

SUMMARY OF OPERATING COSTS

NPC Subcommittee on Synthetic Fuels

Shale Oil Engineering Group

	50,000 B/CD Case $/CD	250,000 B/CD Case $/CD
Operating Personnel	8,890	36,490
Maintenance Personnel	12,740	58,560
Service Personnel	1,340	6,160
Administrative Personnel	1,660	4,700
Total Personnel Costs	24,630	105,910
Operating Materials	9,710	46,070
Maintenance Materials	8,190	38,740
Chemicals	220	1,080
Catalysts	3,670	18,350
Purchased Utilities	790	2,570
Property Taxes	4,810	20,970
Insurance	1,510	6,740
Total Operating Costs, Exclusive of Depreciation	53,530	240,430
Depreciation	36,270	162,900
GRAND TOTAL OPERATING COSTS FOR RETORTING, REFINING AND PIPELINE TRANSPORTATION	89,800	403,330

Explanatory Notes:

1. Operating costs do not include costs of mining, crushing, and other items detailed in the letter of transmittal as not being included in this estimate.

2. Depreciation includes amortization of paid-up process royalties, initial charge of catalyst, and added construction labor costs in Colorado.

Revised
September 17, 1951

SUMMARY OF PERSONNEL REQUIREMENTS

NPC Subcommittee on Synthetic Fuels

Shale Oil Engineering Group

	50,000 B/CD Case		250,000 B/CD Case	
	Total Personnel Required	Cost, $/CD Including 20% Social Welfare	Total Personnel Required	Cost, $/CD Including 20% Social Welfare
Operating	670	8,890	2,762	36,490
Maintenance	896	12,740	4,115	58,560
Service	110	1,340	502	6,160
Administrative	77	1,660	224	4,700
Total	1,753	24,630	7,603	105,910

Distribution of Personnel by Location:

	50,000 B/CD Case				250,000 B/CD Case			
	Colorado	Product Pipeline	California	Total	Colorado	Product Pipeline	California	Total
Operating	501	96	73	670	2,431	115	216	2,762
Maintenance	759	66	71	896	3,675	79	361	4,115
Service	102		8	110	478		24	502
Administrative	64	9	4	77	202	9	13	224
Total	1,426	171	156	1,753	6,786	203	614	7,603

Explanatory Notes:

1. Personnel shown represents total number that would be required for seven-day operations, based on a 40-hour work week.

2. Service Personnel for Pipeline included with Operating Personnel.

OPERATING PERSONNEL

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	50,000 B/CD Case					250,000 B/CD Case				
		Operating Foremen		Non-Supervisory Personnel		Total	Operating Foremen		Non-Supervisory Personnel		Total
		Number	$/CD	Number	$/CD	$/CD	Number	$/CD	Number	$/CD	$/CD
103	Retorting	18	300	126	1,320	1,620	90	1,500	630	6,600	8,100
104	Coking Unit	5	80	108	1,100	1,180	23	400	540	5,500	5,900
105	Catalytic Hydrogenation	5	80	36	390	470	23	400	180	1,950	2,350
106	Catalytic Reforming			36	390	390			180	1,950	1,950
107	Hydrogen Generation			50	530	530			248	2,650	2,650
108-110	California Refining Facilities	5	80	68	720	800	14	230	202	2,160	2,390
111	Ammonia Recovery			9	90	90			45	440	440
112	Sulfur Unit			5	50	50			23	250	250
201	Steam Power Plants	9	130	27	290	420	45	660	135	1,430	2,090
204, 205, 209	Water Treating and Distribution	5	60	9	90	150	9	120	45	450	570
400	Tankage	2	30	12	130	160	8	120	46	510	630
500	Pipelines	8	140	88	990	1,130	9	160	106	1,180	1,340
802	Sewerage System			5	50	50			23	230	230
803	Refuse			6	60	60			30	300	300
901-903	Transportation and Shipping Facilities	1	20	18	200	220	2	40	71	780	820
904	Sulfur Handling Facilities			9	90	90			35	400	400
	Total	58	920	612	6,490	7,410	223	3,630	2,539	26,780	30,410
	Add 20% Social Welfare					1,480					6,080
	GRAND TOTAL COST, OPERATING PERSONNEL					8,890					36,490

Explanatory Notes:

1. Number of Employees represents the <u>total</u> number that would be required for seven-day operations, based on a 40-hour work week. This data is included for the information of those making estimates for community facilities.

2. Costs based on wage and salary rates presented hereafter.

Revised
September 17, 1951

MAINTENANCE PERSONNEL

NPC Subcommittee on Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	50,000 B/CD Case					250,000 B/CD Case				
		Maintenance Foremen		Non-Supervisory Personnel		Total	Maintenance Foremen		Non-Supervisory Personnel		Total
		Number	$/CD	Number	$/CD	$/CD	Number	$/CD	Number	$/CD	$/CD
All Except 108-110, 503-505, & Calif. Section of 400	All Colorado Retorting, Refining, & Auxiliary Facilities	53	830	706	8,160	8,990	258	4,030	3,417	39,540	43,570
108-110 & Calif. Section of 400	California Refining Facilities	5	80	66	760	840	25	390	336	3,890	4,280
503-505	Colorado to California Pipeline	6	90	60	700	790	7	110	72	840	950
	Total	64	1,000	832	9,620	10,620	290	4,530	3,825	44,270	48,800
	Add 20% Social Welfare					2,120					9,760
	GRAND TOTAL COST, MAINTENANCE PERSONNEL					12,740					58,560

Explanatory Notes:

1. For Distribution of Maintenance Personnel Costs Among Colorado Facilities, See Table on Maintenance Costs, Page 25.
2. Number of Employees represents the total number that would be required for seven-day operations, based on a 40-hour work week. This data is included for the information of those making estimates of community facilities.
3. Costs based on wage and salary rates presented on Pages 23 and 24.

SERVICE PERSONNEL

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Description of Function	50,000 B/CD Case					250,000 B/CD Case				
	Foremen		Non-Supervisory Employees		Total	Foremen		Non-Supervisory Employees		Total
	Number	$/CD	Number	$/CD	$/CD	Number	$/CD	Number	$/CD	$/CD
Colorado: Accounting			17	170	170			60	590	590
Inspection Laboratories	5	60	22	230	290	22	290	112	1,150	1,440
Warehouse			8	80	80			34	360	360
Miscellaneous (Includes Fire & Safety, Cafeteria, Guards, Janitors).	2	30	48	470	500	10	150	240	2,350	2,500
California: Accounting, Inspection Laboratory, Personnel			8	80	80			24	240	240
Total	7	90	103	1,030	1,120	32	440	470	4,690	5,130
Add 20% Social Welfare					220					1,030
GRAND TOTAL COST, SERVICE PERSONNEL					1,340					6,160

Explanatory Notes:

1. Number of Employees represents the <u>total</u> number that would be required for seven day operations, based on a 40-hour work week. This data included for those making estimates of community facilities.

2. Costs based on wage and salary rates presented hereafter.

ADMINISTRATIVE PERSONNEL

(Supervisory, Technical, Stenographic)

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

	50,000 B/CD Case	250,000 B/CD Case
Vice Presidents	1	1
General Manager Colorado Retorting & Refining	1	1
General Superintendent Colorado Operations	-	1
Superintendents of Operations	1	5
Chief Engineers	1	1
Superintendents of Personnel	1	1
Superintendents of Utilities	-	1
Superintendents of Pipelines	1	1
Superintendents of California Refining	-	1
Assistant Chief Engineers	2	2
Assistant Superintendents	5	21
Supervisors (Includes Chief Clerks)	4	13
Personnel Supervisors & Representatives	6	16
Engineers	27	87
Dispatchers	6	6
Chemists	6	30
Secretaries	3	3
Stenographers	9	21
Doctors	1 (Part Time)	2
Industrial Nurses	2	10
Total	77	224
Cost of Salaries, $/CD	1,380	3,920
Add 20% Social Welfare	280	780
GRAND TOTAL COST, ADMINISTRATIVE PERSONNEL	1,660	4,700

Explanatory Notes:

1. Requirements for foremen presented under Operating, Maintenance, and Service Personnel.

2. Costs based on salary rates presented hereafter.

WAGE & SALARY RATES

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Salary Rates	$/Month
Administrative Personnel	
Vice President	2,000
General Manager, Colorado Retorting & Refining	1,500
General Superintendent, Colorado Operations	1,350
Superintendents, Chief Engineers	950
Assistant Superintendents, Assistant Chief Engineers, Supervisors	725
Personnel Supervisors, Representatives	575
Engineers, Dispatchers	500
Chemists	375
Secretaries	300
Stenographers	280
Doctors	1,000
Industrial Nurses	300
Foremen	425, 475, 550
Service Personnel:	
Fire & Safety Inspectors	300, 320, 340, 380
Guards	300
Janitors	280
Cafeteria Personnel	240, 350, 390
Accounting Clerks	280, 300, 330, 360
Warehouse Personnel	275, 305, 335
Telephone Operators	280

Wage Rates

Six basic wage rates have been set up for all classifications. The rates used and examples of job classifications for each wage rate follows:

$/Day	Examples of Job Classifications For Each Wage Rate.
17.45	Special Stillmen, Lead Craftsmen
16.80	Head Stillmen, Power Plant Engineers
16.10	Stillmen On Specialized Units, Heavy Equipment Operators
15.55	Stillmen, Guagers, Truck Drivers
15.05	Pumpers, Craftsmen Helpers, Power Plant Firemen
14.00	Helpers, Laborers, Light Truck Drivers

Laboratory Inspectors Are Included Under All Rates.

WAGE & SALARY RATES

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

For Maintenance Personnel at Colorado (exclusive of Foremen) the average wage was taken to be $16.20/Day based on the following breakdown of the maintenance force:

Job Classification	%
Lead Craftsmen	53.5
Craftemen Helpers	22.0
Gangleaders	2.0
Labor Gang	17.0
Truck Drivers	4.0
Tool Keepers	1.5
Total	100.0

This does not include Warehouse personnel.

Explanatory Footnotes:

1. All rates are exclusive of social welfare.

2. Where more than one rate shown for salaried personnel, salary used dependent upon job classification.

Revised
September 17, 1951

MAINTENANCE COSTS

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item	Description	50,000 B/CD Case: Maintenance Costs $/CD Labor	Materials	Total	Total $/Year	Cost of Facilities $	Maintenance Costs, Per Cent Per Year of Costs of Facilities	250,000 B/CD Case: Maintenance Costs $/CD Labor	Materials	Total	Total $/Year	Cost of Facilities $	Maintenance Costs, Per Cent Per Year of Costs of Facilities
103	Retort Site Development		(Breakdown of	)		6,800,000	0.5		(Breakdown of	)		32,400,000	0.5
	Roads to Retorts and Mines		(Maintenance for	)		1,200,000	4.0		(Maintenance for	)		5,650,000	4.0
	Retort Buildings & Structures		(Various Sections	)		5,800,000	1.5		(Various Sections	)		27,450,000	1.5
	Retorts and Equipment		(of Item 103	)		36,200,000	5.0		(of Item 103	)		172,500,000	5.0
	Total Item 103	2,800	2,740	5,540	2,022,100	50,000,000	4.0	13,400	13,000	26,400	9,636,000	238,000,000	4.0
104	Coking Unit	1,560	840	2,400	876,000	20,090,000	4.4	7,740	4,200	11,940	4,358,100	100,450,000	4.3
105	Catalytic Hydrogenation	1,120	370	1,490	543,850	13,557,000	4.0	5,580	1,860	7,440	2,715,600	67,785,000	4.0
106	Catalytic Reforming	1,090	360	1,450	529,250	13,275,000	4.0	5,450	1,820	7,270	2,653,550	66,373,000	4.0
107	Hydrogen Production	860	450	1,310	478,150	11,960,000	4.0	4,220	2,250	6,470	2,361,550	59,050,000	4.0
108-110	California Refining Facilities	940	700	1,640	598,600	14,531,000	4.1	4,860	3,130	7,990	2,916,350	65,250,000	4.5
111	Ammonia Recovery	170	80	250	91,250	735,000	12.4	850	390	1,240	452,600	3,675,000	12.3
112	Sulfur Unit	50	30	80	29,200	750,000	3.9	270	150	420	153,300	3,750,000	4.1
201	Steam Power Plants	1,550	1,200	2,750	1,003,750	25,100,000	4.0	7,730	6,000	13,730	5,011,450	125,300,000	4.0
202-212	Power Transmission & Telephone System	1,000	150	1,150	419,750	5,936,870	7.1	3,860	870	4,730	1,726,450	31,042,000	5.6
204,205,209	Water Treating and Distribution	130	70	200	73,000	2,167,000	3.4	1,260	650	1,910	697,150	20,377,000	3.4
207	Steam Distribution	30	50	80	29,200	613,800	4.8	160	280	440	160,600	3,069,000	5.2
208	Condensate System	10	20	30	10,950	163,600	6.7	90	80	170	62,050	818,400	7.6
210	Air Compressor Plant	30	30	60	21,900	355,000	6.2	150	170	320	116,800	1,775,000	6.6
300	Maintenance Facilities	70	20	90	32,850	1,744,000	1.9	210	80	290	105,850	5,431,000	1.9
400	Tankage	130	130	260	94,900	6,046,000	1.6	540	540	1,080	394,200	27,195,000	1.4
500	Pipeline	980	630	1,610	587,650	40,752,000	1.4	1,280	1,920	3,200	1,168,000	101,602,000	1.1
600	Quarters	60	70	130	47,450	1,850,000	2.6	300	350	650	237,250	9,250,000	2.6
702	Roads	50	30	80	29,200	600,000	4.9	250	170	420	153,300	3,000,000	5.1
802	Sewerage System	40	10	50	18,250	2,297,000	0.8	160	50	210	76,650	11,234,000	0.7
803	Refuse		10	10	3,650	40,000	9.1	20	30	50	18,250	200,000	9.1
901-903	Transportation and Shipping	60	170	230	83,950	987,000	8.5	140	610	750	273,750	2,615,000	10.5
904	Sulfur Handling Facilities (Mobile Equipment Only)	10	30	40	14,600	55,000	26.5	40	140	180	65,700	253,000	26.0
	TOTAL MAINTENANCE COSTS	12,740	8,190	20,930	7,639,450	213,605,270		58,560	38,740	97,300	35,514,500	947,494,400	

Explanatory Notes:

1. Maintenance Labor Costs include 20% Social Welfare.
2. For Details of Maintenance Manpower, see Table on Maintenance Personnel, Page 18.
3. 4.6 Maintenance Per Year on Cost of Facilities for Item 103 is Weighted Average.

SUMMARY OF FUELS & UTILITIES REQUIREMENTS

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	50,000 B/CD Case						250,000 B/CD Case					
		Electricity KWH/CD	Steam M Lb/CD	Fuel MM Btu/CD	Water M Gal/CD	Air MSCF/CD	Diesel Power BHP/CD	Electricity KWH/CD	Steam M Lb/CD	Fuel MM Btu/CD	Water M Gal/CD	Air MSCF/CD	Diesel Power BHP/CD
All Except 108-110 & 503-505	All Colorado Retorting, Refining and Auxiliary Facilities.	1,741,600	11,860	74,750	3,560	750		8,903,400	60,960	373,500	17,780	3,750	
108-110,400	California Refining Facilities California Tankage	12,900	3,230	3,380	780			50,900	12,330	12,900	3,000		
503-505	Colorado to California Pipeline	62,400					51,600	158,400					192,000
	TOTAL REQUIREMENTS	1,816,900	15,090	78,130	4,340	750	51,600	9,112,700	73,290	386,400	20,780	3,750	192,000

Explanatory Notes:

1. The major portion of these fuels and utilities requirements can be fulfilled by utilizing retort gas, California refinery fuel gas, diesel fuel, and fuel oil. These requirements have been netted out of salable products. Only the following utilities requirements must be charged for in $/CD:

	$/CD	$/CD
California Facilities (for Purchased Electricity, California Steam exclusive of fuel component, and California Water).	430	1,670
Colorado to California Pipeline (for Purchased Electricity)	360	900
	790	2,570

2. For Details of Calculations and notes on utilities for mining and crushing, see following pages.

FUELS & UTILITIES REQUIREMENTS - COLORADO

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	50,000 B/CD Case				250,000 B/CD Case			
		Electricity KWH/CD	Steam M Lb/CD	Fuel MM Btu/CD	Air MSCF/CD	Electricity KWH/CD	Steam M Lb/CD	Fuel MM Btu/CD	Air MSCF/CD
103	Retorting	450,000		650		2,250,000		3,250	
104	Coking Unit	190,600		7,200		952,800		36,000	
105	Catalytic Hydrogenation	96,000	40	700	300	480,000	220	3,500	1,500
106	Catalytic Reforming	154,000		1,400	300	770,000		7,000	1,500
107	Hydrogen Production	480,000	9,400	15,600		2,400,000	47,000	78,000	
111	Ammonia Recovery	16,400	1,920			82,000	9,600		
112	Sulfur Unit	2,400	(240)	10		12,000	(1,200)	30	
201	Steam Power Plant		100	49,100			2,000	245,300	
204,205,209	Water Treating & Distribution					240,000			
210	Air Compressor Plant	7,300				36,500			
300	Maintenance Shops & Warehouse	2,000	70	20	150	9,800	360	100	750
400	Tankage (Colorado)	800				2,400			
501,502	Crude Lines, Retort Gas Lines	1,300				13,200			
503	Intermediate Product Gathering System					100			
504,505	Product Pipeline (DeBeque)	26,400				79,200			
600	Quarters	5,000		70		25,000		320	
900	Transportation & Shipping Facilities	4,200				14,400			
Street and Area Lighting		18,000				102,000			
	Total, Exclusive of Losses	1,454,400	11,290	74,750	750	7,469,400	57,980	373,500	3,750
Condensate Losses			570				2,980		
Line & Transformer Losses		89,200				445,000			
Internal Power Plant Losses		198,000				989,000			
	TOTAL REQUIREMENTS, COLORADO	1,741,600	11,860	74,750	750	8,903,400	60,960	373,500	3,750

Explanatory Footnotes On Following Page.

FUELS & UTILITIES REQUIREMENTS - COLORADO

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Explanatory Notes:

1. For average conditions, retort gas will fulfill Colorado fuels requirements, leaving refinery fuel gas production available for Sales. Average production of retort gas and demand for fuels in Colorado follows:

	50,000 B/CD Case		250,000 B/CD Case	
	MMSCF/CD	MM Btu/CD	MMSCF/CD	MM Btu/CD
Average Retort Gas Production, (from Item 103): (83.3 Btu/SCF)	1,036	86,300	5,180	431,500
Average Fuels Demand, Colorado		74,750		373,500

The Group feels that credit should not be taken for any indicated average excess retort gas, since during periods of peak demands there may be no excess and it may be necessary to burn other fuels. The probable order of fuels preference is: (1.) retort gas, (2.) crude shale oil, and (3.) refinery fuel gas. The steam power plants are designed to burn all these fuels.

2. Power plants designed to generate power for mining and crushing as well as for facilities covered by this report. Power requirements for mining and crushing (from Oil Shale Mining Group Report dated March 5, 1951): 240,000 KWH/CD for the 50,000 B/CD case and 1,200,000 KWH/CD for the 250,000 B/CD case. In the Mining Report, this electrical power is charged for at a rate of 0.925¢/KWH. Since this power is produced from retort gas, and all costs for this generation are included in this report, in any combination of the reports the costs for the power for the mines should be backed out. This amounts to $2,220/CD for the 50,000 B/CD case and $11,100/CD for the 250,000 B/CD case.

3. Industrial water requirements for Colorado facilities estimated to be (from Item 204): 3,560 M Gal/CD for the 50,000 B/CD case and 17,780 M Gal/CD for the 250,000 B/CD case. This estimate is considerably higher than that of the Process Group, but the Engineering Group has provided for increased water cooling should it be required. By product water from retorting will be used for mine wetting water.

FUELS & UTILITIES REQUIREMENTS - CALIFORNIA

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	50,000 B/CD Case Electricity KWH/CD	Steam M Lb/CD	Fuel MM Btu/CD	Water M Gal/CD	250,000 B/CD Case Electricity KWH/CD	Steam M Lb/CD	Fuel MM Btu/CD	Water M Gal/CD
108-110	California Refining Facilities	11,300	3,230	3,380	780	43,000	12,330	12,900	3,000
400	Tankage (California)	1,600				7,900			
	TOTAL REQUIREMENTS, CALIFORNIA	12,900	3,230	3,380	780	50,900	12,330	12,900	3,000

Utilities Cost For California Refining Facilities:

	50,000 B/CD Case $/Unit	Units/CD	$/CD	250,000 B/CD Case $/Unit	Units/CD	$/CD
Electricity (Purchased)	0.0057/KWH	12,900	70	0.0057/KWH	50,900	290
Steam (Exclusive of Fuel, Which is Netted Out of Salable Products)	0.10/M Lb	3,230	320	0.10/ M Lb	12,330	1,230
Water	0.05/M Gal	780	40	0.05/M Gal	3,000	150
TOTAL COST OF CALIFORNIA UTILITIES			430			1,670

Explanatory Note:

1. Fuels used for process heat and steam production as follows:

	50,000 B/CD Case MSCF/CD	B/CD	250,000 B/CD Case MSCF/CD	B/CD
Fuel Gas	4,750		22,870	
Fuel Oil		670		1,990

FUELS & UTILITIES REQUIREMENTS - COLORADO TO CALIFORNIA PIPELINE

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	50,000 B/CD Case Electricity KWH/CD	50,000 B/CD Case Diesel Power BHP/CD	250,000 B/CD Case Electricity KWH/CD	250,000 B/CD Case Diesel Power BHP/CD
503-505	Pipeline Stations:				
	Green River - Diesel		27,600		96,000
	Hanksville - Diesel				96,000
	Escalante - Diesel		24,000		
	Las Vegas - Electric	36,000		79,200	
	Yermo - Electric	26,400		79,200	
	TOTAL REQUIREMENTS, PIPELINE	62,400	51,600	158,400	192,000

Utilities Cost For Pipeline Colorado to California:

	$/Unit	Units/CD	$/CD	$/Unit	Units/CD	$/CD
Electricity (Purchased)	0.0057/KWH	62,400	360	0.0057/KWH	158,400	900

Explanatory Notes:

1. Diesel fuel withdrawn from Pipeline for pumping station fuel:

B/CD	B/CD
820	2,740

2. Requirements for DeBeque Pumping Station included with Colorado facilities.

OPERATING MATERIALS

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	Operating Supplies	Cost $/Unit	50,000 B/CD Case Units/CD	50,000 B/CD Case $/CD	250,000 B/CD Case Units/CD	250,000 B/CD Case $/CD
103	Retorting	Hydraulic Oil	0.30/gal.	960 gal.	290	4,800 gal.	1,440
		Sodium			30		140
		Miscellaneous			70		340
104	Coking Unit	Miscellaneous			40		210
105	Catalytic Hydrogenation	Compressor Lubricating Oil			30		160
		Miscellaneous			20		80
106	Catalytic Reforming	Compressor Lubricating Oil			50		250
		Miscellaneous			20		80
107	Hydrogen Production	Miscellaneous			20		80
108-110	California Refining Facilities	Miscellaneous			220		1,100
112	Sulfur Unit	Miscellaneous					10
201	Steam Power Plant	Lubricating Oil, Hydrogen, & Miscellaneous			60		280
204,205,209	Water Treating & Distribution	Sand, Zeolite, Lubricants, & Misc.			10		70
210	Air Compressor Plant	Compressor Lubricating Oil			10		50
302	Central Shops	Rags, Cutting Oils, Oxygen, Acetylene, Tools, Packing, Etc.			100		500
303	Warehouse	Stationery			10		20
400	Tankage	Tetraethyl Lead (Total for Colorado and California)			7,710		37,030
500	Pipeline	Diesel Fuel for Pumping Stations		820 Bbl.		2,740 Bbl.	
		Lubricating Oil, Grease, and Miscellaneous at $15/BHP/Yr.			270		820
600	Quarters	Laboratory and Building Supplies			420		2,110
803	Refuse	Gasoline and Lubricants			20		100
901-903	Transportation & Shipping	Miscellaneous			240		930
904	Sulfur Handling Facilities	Fuels and Lubricants			70		270
	GRAND TOTAL COST OF OPERATING MATERIALS				9,710		46,070

Explanatory Notes:

1. Tetraethyl lead usage indicated is a maximum. All motor gasolines leaded to 3ml/gal.
2. Diesel fuel for pumping stations netted out of salable products; therefore it is not charged for in $/CD.
3. For chemicals and catalysts requirements, see separate tables.

CHEMICALS

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	Chemical	Cost, fob Use Point, $/Unit	50,000 B/CD Case Usage Lbs/CD	50,000 B/CD Case Total Cost $/CD	250,000 B/CD Case Usage Lbs/CD	250,000 B/CD Case Total Cost $/CD
112	Sulfur Unit	Sulfuric Acid	30/Ton	3,200	50	16,000	240
204,205,209	Water Treating and Distribution	Lime	28/Ton	1,475.	20	7,373	100
		Ferrisul	57/Ton	440	10	2,200	60
		Sulfuric Acid	30/Ton	567	10	2,834	40
		Salt	22/Ton	2,926	30	14,630	160
		Chlorine & Other			100		480
	GRAND TOTAL COST, CHEMICALS				220		1,080

CATALYSTS

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	Catalyst	Cost, fob Use Point $/Unit	50,000 B/CD Case Usage Units/CD	50,000 B/CD Case Total Cost $/CD	250,000 B/CD Case Usage Units/CD	250,000 B/CD Case Total Cost $/CD
105	Catalytic Hydrogenation	Catalyst (Renew Every 2 Yr.)	1.00/Lb.	970 Lb.	970	4,840 Lb.	4,840
106	Catalytic Reforming	Catalyst (Renew Every 2 Yr.)	1.00/Lb.	1,130 Lb.	1,130	5,640 Lb.	5,640
107	Hydrogen Production	Catalyst	1.00/Lb.	470 Lb.	470	2,350 Lb.	2,350
		Carbon	.85/Lb.	335 Lb.	280	1,675 Lb.	1,420
108	Catalytic Cracking	Catalyst	320/Ton	2 Tons	640	10 Tons	3,200
109	Catalytic Polymerization	Catalyst	550/Ton	0.3 Tons	160	1.5 Tons	820
112	Sulfur Unit	Catalyst (2 Yr. Catalyst Life)	.10 Lb.	150 Lb.	20	750 Lb.	80
	GRAND TOTAL COST, CATALYSTS				3,670		18,350

ESTIMATED CAPITAL CHARGES

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

	50,000 B/CD Case $/CD	250,000 B/CD Case $/CD
Property Taxes	4,810	20,970
Insurance	1,510	6,740
Depreciation	36,270	162,900
Total Capital Charges	42,590	190,610

Explanatory Notes:

1. Property Taxes calculated as 0.6% of capital investment per year for facilities outside California; 1.7%, for facilities in California.

2. Insurance calculated on basis that 90% of facilities insurable, 10% non-insurable. Premiums paid on 90% of cost of insurable facilities at 2.31¢/$100/month.

3. Depreciation based on 18.5 years.

SHALE OIL PROCESSING

Estimated Metals Requirements

NPC Subcommittee On Synthetic Fuels
Shale Oil Engineering Group

Item No.	Description	50,000 B/CD Case: Metals Requirements - Ex Machinery: Carbon Steel Tons	Ferrous Alloys Tons	Non-Ferrous Alloys Tons	50,000 B/CD Case: Metals Requirements Machinery: Total Tons	Dollar Value	250,000 B/CD Case: Metals Requirements - Ex Machinery: Carbon Steel Tons	Ferrous Alloys Tons	Non-Ferrous Alloys Tons	250,000 B/CD Case: Metals Requirements Machinery: Total Tons	Dollar Value
103	Retorts, Retort Site Development, & Roads to Sites	22,600	400	60	2,140	$ 2,740,000	113,000	2,000	300	12,700	$ 13,700,000
104	Coking Unit	8,570	6,265	958	147	2,400,000	42,850	31,325	4,790	735	12,000,000
105	Catalytic Hydrogenation	2,100	1,030	1	980	866,000	10,500	5,150	5	4,300	4,330,000
106	Catalytic Reforming	1,800	755	1	1,315	1,571,000	9,000	3,775	5	6,575	7,855,000
107	Hydrogen Generation	1,500	100	30	150	125,000	7,500	500	150	750	725,000
108-110	California Refining Facilities	10,175	610	10	1,375	1,850,000	40,950	2,400	38	5,150	6,960,000
111	Ammonia Recovery	220	10	2	68	68,100	1,100	50	10	340	340,500
112	Sulfur Unit	147	19		12	60,000	735	95		60	300,000
201	Steam Power Plants	640	3	26	2,900	7,500,000	3,200	15	130	24,500	37,500,000
202	Power Transmission	96		122	290	1,100,000	480		610	1,450	5,500,000
203	Water Reservoirs						190				
204	Water Distribution System	583			27	74,000	4,858			222	610,000
205	Colorado River Pumping Plants	96			4	19,000	595			25	120,000
207	Steam Distribution	400	2				2,000	10			
208	Condensate System	50	1				250	5			
209	Water Treating Systems	109			6	29,000	425			25	120,000
210	Air Compressor Plant	155			20	80,000	775			100	400,000
212	Telephone System	9		14	2	18,000	87		135	14	116,000
301	Maintenance Operating Buildings	4			4	3,500	20			20	17,500
302	Central Shops	550		1	300	450,000	1,600		5	900	1,350,000
303	Warehouse	130			20	18,000	430			70	63,000
400	Tankage	17,000		9	48	72,000	78,000		40	105	314,000
501	Crude Lines	600		1	4	16,000	2,300		3	20	80,000
502	Gas Line	4,500		14	12	36,000	22,500		70	60	180,000
503-504	Gathering System & Product Line	68,300		20	530	1,890,000	153,500		60	1,845	6,500,000
600	Quarters	840	25	8			4,200	100	40		
703	Fences	67					335				
802	Sewerage	160			15	45,000	550			50	150,000
803	Refuse	5			24	36,000	25			120	180,000
901	Rail Spurs	205					655				
902	Loading Racks	5			2	8,000	20			5	20,000
903	Coke Handling Facilities	220		1	130	228,000	500		2	480	842,000
904	Sulfur Handling Facilities				37	50,000				175	230,000
	Total Metals Requirements	141,830	9,220	1,278	10,562	$21,352,600	503,130	45,425	6,393	61,396	$100,503,000

ESTIMATED LIFE OF FACILITIES

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	50,000 B/CD And 250,000 B/CD Cases Estimated Life, Years
103	Retorting	15
104	Coking Unit	15
105	Catalytic Hydrogenation	15
106	Catalytic Reforming	15
107	Hydrogen Production	15
108	Catalytic Cracking	20
109	Catalytic Polymerization	20
110	Redistillation	20
111	Ammonia Recovery	15
112	Sulfur Unit	15
201	Steam Power Plants	40
202	Power Transmission	25
204, 205, 209	Water Treating and Distribution	20
207	Steam Distribution	30
208	Condensate System	30
210	Air Compressor Plant	20
212	Telephone System	25
301	Maintenance Operating Buildings	30
302	Central Shops	25
303	Warehouse	30
400	Tankage	30
501	Crude Lines	25
502	Retort Gas Lines	25
503	Intermediate Product Gathering System	25
504	Colorado to California Product Pipeline	40
505	Pumping Stations	
	Pumps	20
	Buildings and Tanks	30
600	Quarters	30
702	Roads	20
703	Fences	20
802	Sewerage System	20
803	Refuse	
	Mobile Equipment	5
	Incinerator	20

ESTIMATED LIFE OF FACILITIES

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	50,000 B/CD And 250,000 B/CD Cases Estimated Life, Years
901	Rail Spurs	40
902	Loading Racks	20
903	Coke Storage & Shipping	
	Trucks	5
	Machinery	20
904	Sulfur Handling Facilities	7
	Weighted Average For All Facilities	18.5

Explanatory Note:

Weighted Average Years Life For All Facilities Calculated by Converting Years Life To Per-Cent Depreciation per Year, and Averaging Same on Basis of Estimated Cost of Facilities.

Capital Investment for Royalties and Catalysts Depreciated at Same Rate as for Units Concerned.

NORMAL WORKING INVENTORIES

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Item No.	Description	Material	50,000 B/CD Case	250,000 B/CD Case
			$	$
103	Retorting	Hydraulic Oil	6,000	30,000
		Operating Materials	5,000	25,000
		Maintenance Materials	450,000	2,250,000
		Sodium	10,000	50,000
104	Coking Unit	Operating Supplies	4,000	19,000
		Maintenance Supplies	197,000	986,000
105	Catalytic Hydrogenation	Catalyst	176,000	440,000
		Maintenance Supplies	200,000	1,000,000
		Operating Supplies	5,000	25,000
		Compressor Oil	6,000	30,000
106	Catalytic Reforming	Catalyst	206,000	515,000
		Maintenance Supplies	200,000	1,000,000
		Operating Supplies	5,000	25,000
		Compressor Oil	9,000	45,000
107	Hydrogen Production	Catalyst	160,000	800,000
		Carbon	85,000	425,000
		Operating Supplies	1,000	5,000
		Maintenance Supplies	78,000	390,000
108-110	California Refining Facilities	Cracking Catalyst	96,000	480,000
		Polymerization Catalyst	11,000	55,000
		Spare Parts & Warehouse Stocks	145,300	456,800
111	Ammonia Recovery	Warehouse Supplies	7,000	38,000
112	Sulfur Unit	Catalyst	5,000	25,000
		Maintenance Supplies	10,000	50,000
		Operating Supplies	500	2,500
201	Steam Power Plant	Operating Supplies	4,000	19,000
		Maintenance Supplies	219,000	1,094,000
202	Power Transmission	Maintenance Supplies	26,000	145,000
204,205,209	Water Treating & Distribution	Chemicals	5,000	25,000
		Maintenance Supplies	300	3,000
207	Steam Distribution	Maintenance Supplies	9,000	51,000
208	Condensate System	Maintenance Supplies	3,000	15,000
210	Air Compressor Plant	Maintenance Supplies	300	1,300
212	Telephones	Maintenance Supplies	1,000	14,000
301	Maintenance Operating Buildings	Warehouse Supplies	200	1,000
302	Central Shops	Steel Plate, bars, rolled shapes, oxygen, acetylene, tool room stocks, miscellaneous.	100,000	500,000
303	Warehouse	Warehouse Stocks	300,000	900,000
		Spare Parts	1,000,000	2,900,000

NORMAL WORKING INVENTORIES

NPC Subcommittee On Synthetic Fuels

Shale Oil Engineering Group

Revised
September 17, 1951

Item No.	Description	Material	50,000 B/CD Case $	250,000 B/CD Case $
400	Tankage	Tetra ethyl lead (30 Days' Supply)	235,000	1,100,000
		Maintenance Supplies	24,000	100,000
		Product Inventory in Tanks	4,425,000	22,010,000
500	Pipelines & Pumping	Operating	20,000	60,000
		Maintenance	145,000	500,000
		Reformed Gasoline & Intermediate Diesel To Fill Pipeline	1,370,000	5,400,000
600	Quarters	Operating Supplies	21,000	105,000
702	Roads	Maintenance Materials	3,000	15,000
802	Sewerage System	Maintenance Supplies	300	1,600
803	Refuse	Maintenance Parts	200	1,000
901-903	Transportation & Shipping	Operating Supplies	9,000	34,000
		Maintenance Supplies	15,000	55,000
904	Sulfur Handling Facilities	Operating Supplies	2,500	10,000
		Maintenance Supplies	1,300	5,000
	GRAND TOTAL VALUE, NORMAL WORKING INVENTORIES		10,016,900	44,232,200

Explanatory Footnotes:

1. Evaluation of Tankage Product Inventory

	Estimated Inventory Value $/Unit	50,000 B/CD Units	50,000 B/CD $	250,000 B/CD Units	250,000 B/CD $
Crude Shale Oil	1.60/Bbl	250,000		1,250,000	
Coker Naphtha	3.13	100,000		500,000	
Coker Distillate	2.26	140,000		700,000	
Reformed Gasoline	3.13	200,000		980,000	
Intermediate Diesel	2.26	253,000		1,265,000	
Finished Gasoline	3.13	515,000		2,565,000	
Finished Diesel	2.26	225,000		1,125,000	
Fuel Oil	.99	5,000		22,000	
Butane	1.95	4,000		18,000	
Ammonia	60.00/Ton	650		3,200	
Coke	4.73/Ton	5,000		25,000	
TOTAL			4,423,030		22,011,380
Round off to			4,425,000		22,010,000

2. Evaluation of Pipeline Product Inventory

	Estimated Inventory Value $/Unit	50,000 B/CD Units	50,000 B/CD $	250,000 B/CD Units	250,000 B/CD $
Reformed Gasoline	3.13/Bbl	210,000		830,000	
Intermediate Diesel	2.26	315,000		1,240,000	
TOTAL			1,369,200		5,400,300
Round off to			1,370,000		5,400,000

BASIS OF ESTIMATE

SHALE RETORTING PLANT - ITEM 103

Section 1

Description

The entire 250,000 B/D shale oil operation is composed of five integrated "unit" refineries with a throughput of 50,000 B/D. Each of these integrated "unit" refineries utilizes four Shale Retorting Plants to provide the feed stock. In turn, these plants receive shale from two "unit" mines, each with a daily output of 38,400 tons of shale rock.

Each unit refinery is located in the valley at an elevation of approximately 5,500 feet above sea level. The retorting plants are each located within a 3-mile radius of the refinery at a 7,000 ft elevation. The unit mines themselves are at an elevation of 8,000 ft above sea level and within one-half mile of their retorting plants.

The shale rock is progressively conveyed from the mine site to a storage area and from the storage area to the retorting plant where it is processed. The shale ash is conveyed to the edge of the retorting site where it is discharged into the valley.

In this portion of the economic study, the development of the shale storage area was included along with adequate underground facilities to take shale from the storage pile, load a transport conveyor, and move it to a storage hopper located on each retorting site. The solids flow system is clearly shown in Figure 5, Section 1 of the Shale Oil Processing Committee Report.(1)

The retorting plant itself is clearly depicted in Figures 1 and 2, Section 1 of the Shale Oil Processing Committee Report. Twenty-one kilns comprise each retorting plant and they are arranged in rows of seven kilns each. The shale is conveyed from the shale hopper described above on two conveyor belt systems. One 48" wide conveyor belt system supplies shale to two rows of kilns, utilizing seven three-way stationary trippers to discharge shale into the hoppers on each side of the belt as required. The other 36" wide system supplies shale to the remaining outside row of kilns, utilizing seven two-way stationary trippers for this purpose.

The shale ash is picked up from the kilns on two special heat-resistant belt conveyors. These conveyors are located between the rows of kilns just below the shale feed conveyors. In order to balance the load requirement, each ash conveyor takes the entire ash from its outside row of kilns. In addition, one conveyor takes ash from four of the retorts in the inside row and the other handles the ash from the remaining three retorts.

These ash conveyors discharge onto a single heat resistant disposal conveyor that carries the ash to the edge of the site where a traveling stacker distributes the ash into the valley.

(1) Report by Shale Oil Processing Committee titled National Petroleum Council Committee on Synthetic Fuels Production Costs - Shale Oil Retorting and Refining Facilities, dated April 15, 1951.

SHALE RETORTING PLANT - ITEM 103

Section 1

Description

The operation of the retorts is well explained in Section 1, Part III, and clearly shown in Figures 3 and 4 of this section of the Shale Oil Processing Committee Report. In review, the shale is removed from the shale belt conveyor with a stationary tripper that discharges into a hopper. The shale passes down through the hopper into the four underfeed mechanisms on each retort. The shale is fed upward through the kiln where it is contacted with the hot flue gas from the combustion of the coke in the spent shale. The shale leaves with the flue gas through the disengaging section located below the retorting section.

The outlets from the disengaging sections for each row of seven kilns are manifolded together. This can best be seen in Figures 1 and 2, Section 1 of the Oil Shale Processing Committee Report. Each manifold is 4 ft in diameter at the first kiln and is progressively increased in diameter up to a 6 ft diameter at the seventh kiln. Each manifold then discharges into the precleaner where the shale oil is removed.

The precleaner is equipped with a double 24" wide drag chain conveyor to remove the sludge and convey it back onto the 48" wide shale feed conveyor. The sludge is composed of shale fines which have passed through the disengaging section and by the underfeed mechanism into shale oil production.

The majority of entrained shale oil mist in the gas effluent from the precleaner is recovered and returned to the precleaner by means of four American air filter rotoclones operating in parallel.

The discharge gas from these rotoclones is then in turn passed through four parallel impact separators manufactured by the Ultrasonic Corporation to complete the oil recovery.

The oil-free lean gas goes to a booster blower that discharges into a 13 ft diameter gas line which goes to the refinery.

The design of this gas line and the unique manner in which the saturated gas is maintained above the freezing point of water is described in Section 2 of the Shale Oil Processing Committee Report. The cost estimate for this gas line is to be developed by others.

The shale oil production from the precleaner is pumped into a 5,000 barrel storage tank where the temperature is maintained at 125°F with an immersion burner using retort gas. The oil production leaves this tank and flows by gravity through a 6" buried line to the refinery. This line is traced to prevent the shale oil which has a pour point of 90°F from solidifying in the line.

SHALE RETORTING PLANT - ITEM 103

Section 2

Specifications

	50,000 B/D Refinery	250,000 B/D Operation
Site Development	26.2 acres cleared with 6,100,000 cu yd total excatation	131 acres cleared with 30,100,000 cu yd total excavation
Roads to Retorts	11.4 miles road with 24' roadbed surfaced with 6" crushed rock and 3" asphaltic concrete	56 miles road with 24' roadbed surfaced with 6" crushed rock and 3" asphaltic concrete
Concrete Foundations	22,000 cu yd	120,000 cu yd
Structural Steel	1,400 tons	7,000 tons
Painting	3,000,000 sq ft	15,000,000 sq ft
Equipment Specifications		
The items listed below have been specified in the Shale Oil Processing Committee Report for a single retorting plant.		
Process Housing Vessel Summary Hopper Summary Kiln Specifications Conveyors Mist Separator Hydraulic Equipment Blowers Piping Instrumentation Pumps Kiln Plow Specification	4 equipment units required	20 equipment units required

N.P.C. SHALE OIL ENGINEERING ESTIMATE

COKING UNIT - ITEM #104

Description of Facilities

This estimate is based on the well-established "Delayed Coking Process" rather than the more speculative "Continuous Coker." It is felt that the capital costs for the two types will be very similar, and that operating costs, based on the Delayed Coker, will be conservative; i.e., above those for a possible Continuous Coker of the same size.

The design charge rate for the Unit is 25,000 B/CD which, with a demonstrated operating efficiency of 95%, works out to 27,270 B/CD. To accommodate this rate there will be installed 3 Heaters operating in parallel, each Heater discharging alternately into a pair of Coke Drums. One Drum will hold approximately 300 tons of coke which will be formed during approximately 36 hours of operating. The decoking schedule will be staggered so that one Drum is cleaned every 12 hours. Leaving the Coke Drums, the collected hydrocarbons go to a single Fractionating Tower where gasoline, gas oil and recycle material are produced. The gasoline will be depropanized and the off-gas from the main Fractionator and Depropanizer Accumulators will be put through an Absorber to recover all C_4 and heavier components. This Absorber is also sized to handle wet gas from the Hydrogenation Unit.

Decoking will be by the standard hydraulic system in which high pressure water is used to remove the coke from the drums. The material after reduction to 5" maximum size will be transferred in water suspension to the recovery area where by the use of vibrating screens and a Dorr Clariflocculator, the coke and water are separated. The coke will be transferred by belt conveyors to the storage yard. Facilities for loading coke for shipment are not included. Two Units are included in the 50,000 Bbl. Refinery estimates.

SPECIFICATIONS

COKING UNIT - ITEM #104

	50,000 Bbl. Refinery	250,000 Bbl. Operation
Site Development		
Process Area	400' x 800'	2000' x 800'
Decoking & Storage Area	600' x 1200'	3000' x 1200'
Process Equipment		
Oil Heaters	6 Heaters at 50 MM BTU's each	30 Heaters at 50 MM BTU's each
Main Fractionators	2 - 12'-6"ø x 33 plates	10 - 12'-6"ø x 33 plates
Stabilizer Tower	2 - 4'ø x 30 plates	10 - 4'ø x 30 plates
Strippers	2 - 5'ø x 5 plates	10 - 5'ø x 5 plates
Absorber	2 - 6'ø x 20 plates	10 - 6'ø x 20 plates
Decoking Equipment		
Coke Drums	12 - 17'ø x 70'	60 - 17'ø x 70'
Decoking Pumps	4 - 1250 HP	20 - 1250 HP
Screens	6 - 4' x 12' Robbins Eliptex	30 - 4' x 12' Robbins Eliptex
Clariflocculator	2 - 75'ø	10 - 75'ø

HYDROGEN PRODUCTION UNIT - ITEM 107

Section 1

Description

1.1 General

The plant can be considered as divided into the following sections:

a. Preparation of the process refinery gas
b. Production of crude hydrogen
c. Initial purification of crude hydrogen
d. Purification of the crude hydrogen by Hypersorption
e. Auxiliary facilities and equipment required for the successful operation of the plant

1.2 Preparation of Feed Gas

The refinery gas used as process material in this plant design is produced from the coking operation on the crude shale oil. To avoid subsequent poisoning of the catalyst in the hydrogen furnace, any hydrogen sulfide in the gas is removed with an ammonia wash.

1.3 Production of Crude Hydrogen

The desulfurized gas is then reacted with an excess of steam at 1400-1500°F in the presence of a nickel catalyst to produce a crude hydrogen. The hydrogen furnace designed for this operation consists of a combustion chamber in which a number of vertical alloy steel tubes are suspended. The nickel catalyst is supported within these tubes.

To afford flexibility, the combustion chamber is divided into cells. Fuel gas is burned in these cells to furnish the heat for the highly endothermic steam - hydrocarbon reaction. These furnaces are operated under pressures approaching 50 psig to circumvent final compression of the gas. The effluent from the furnace will have the following average composition:

	Mol % (Dry)
H_2	72
CO	16
CO_2	7
CH_4	5
	100

HYDROGEN PRODUCTION UNIT - ITEM 107

Section 1

Description

1.4 Initial Purification of Crude Hydrogen

The effluent gas from the hydrogen furnace undergoes an initial purification step wherein the carbon monoxide is converted to hydrogen and carbon dioxide in the presence of steam.

This is accomplished by cooling the furnace effluent from 1450°F to 800°F with the addition of low pressure steam. The amount of steam required is approximately 5-6 volumes per volume of carbon monoxide and carbon dioxide. The steam-gas mixture is passed through an iron oxide catalyst which converts most of the carbon monoxide to carbon dioxide and hydrogen. The exothermic reaction is controlled by the addition of steam to the reaction chamber.

The effluent gas from the converter has the approximate composition:

	Mol % (Dry)
H_2	75
CO	2
CO_2	18.5
CH_4	4.5
	100.0

This gas is cooled from 850°F to 100°F by interchange with the feed gas and subsequent water cooling.

1.5 Hypersorption Purification

The hydrogen gas from the converter is compressed to 600 psig and delivered to Hypersorption unit. In the Hypersorber, the impurities from the hydrogen stream are split into a side cut and bottoms stream with the purified hydrogen production going overhead. The bottoms stream is vented and the side cut is used as a source of fuel in the hydrogen furnace.

1.6 Auxiliary Facilities

The following auxiliary equipment is required for the operation of the plant:

a. Condensate recovery system which consists of storage tank, vent, condenser and pumps.

b. An inert gas generator with a capacity of 25,000 SCFH. This system includes the generator, gas holder and blower with a discharge pressure of 5 psig.

c. Cooling water system which includes a forced draft cooling tower, circulating pumps and water treating facilities.

d. Buildings, structures, roadways, utility sewers within plant boundary, safety devices, instruments, etc.

HYDROGEN PRODUCTION UNIT - ITEM 107

Section 2

Specifications

Item	Number Required	Description
Vessels		
CO Converter	3	15' Dia x 17' High; 2 Beds Catalyst each 4'-4" Deep
Cooling and Condensing Towers	2	15-1/2' Dia x 25' High; Gunite Lined; 12' Bed of 3" Raschig Rings
Degasifying Column	1	7-1/2' Dia x 12-1/2' High; Gunite Lined; 6' Bed 3" Raschig Rings
Condensate Storage Tank	1	13' Dia x 21' Long
Hypersorber and Auxiliary Facilities	4	7-1/2' Dia x 210' High. Each unit has productive capacity of 12,600,000 SCF/CD of high purity hydrogen.
Heaters and Steam Generators		
Hydrogen Furnace	6	Twin unit furnace with tubes of 25-20 chrome-nickel steel alloy, designed in accordance with Girdler specifications.
Waste Heat Boilers	3	Capacity of 80,000 Lb/Hr of 95 psig saturated steam
Compressors		
Hypersorber Feed Gas Compressor	4 Active 1 Spare	2 Stage Compressors having 1500 HP Steam Turbine Drive
Pumps		
Condensate Pump	1 Active 1 Spare	30 gpm at 30 psig Steam Turbine Drive Spare: Electric Motor Drive
Boiler Feed Water Pumps	3 Active 3 Spare	175 gpm at 30 psig Steam Turbine Drive Spare: Electric Motor Drive
Condensate Recirculation Pump	1 Active 1 Spare	3500 gpm at 30 psig Steam Turbine Drive Spare: Electric Motor Drive
Condensate Pump	1 Active 1 Spare	260 gpm at 30 psig Steam Turbine Drive Spare: Electric Motor Drive

HYDROGEN PRODUCTION UNIT - ITEM 107

Section 2

Specifications

Item	Number Required	Description
Pumps (Cont'd)		
Condensate Pump	1 Active 1 Spare	330 gpm at 30 psig Steam Turbine Drive Spare: Electric Motor Drive
Condensate Pump	1 Active 1 Spare	310 gpm at 30 psig Steam Turbine Drive Spare: Electric Motor Drive
Cooling Water Circulating Pump	1 Active 1 Spare	30,000 gpm at 50 psig Steam Turbine Drive Spare: Electric Motor Drive
Blowers		
Induced Draft Fans	3 Active 3 Spare	Designed for Waste Heat Boilers Steam Turbine Drive Spare: Electric Motor Drive
Air Blowers	1 Active 1 Spare	2400 SCFM of Air at 6" WG Steam Turbine Drive Spare: Electric Motor Drive
Inert Gas Blower	1 Active	25,000 SCFH of Inert Gas at 5 psig Electric Motor Drive
Miscellaneous		
Ejectors with inter- and after coolers		Capacity: 260 gpm of Condensate Steam: 700 Lb/Hr at 475 psig
"		Capacity: 30 gpm of Condensate Steam: 100 Lb/Hr at 475 psig
Gas Holder		Capacity: 50,000 SCF
Inert Gas Generator		Capacity: 25,000 SCFH of Inert Gas
Induced Draft Cooling Tower		Duty: 475,000,000 Btu/Hr Inlet water temperature 111°F Outlet water temperature 80°F Air Wet Bulb temperature 70°F

HYDROGEN PRODUCTION UNIT - ITEM 107

Section 2

Specifications

Exchanges

Name	No Units	Total Fluid		Temperatures				Total Duty Btu/Hr
				Shell		Tubes		
		Shell	Tubes	In	Out	In	Out	
Condensate Cooler	12	Condensate 3,440 gpm	Cooling Water 11,980 gpm	234°	95°	80°	120°	239,600,000
Converter Heat Exchanger	12	Crude Hydrogen and Steam 168,200 Lb/Hr	Refinery Gas and Steam 104,800 Lb/Hr	850	655	324	750	28,240,000
Surface Condenser	2	Steam 137,000 Lb/Hr	Cooling Water 10,320 gpm	126	116	80	105	141,800,000
Surface Condenser	2	Steam 13,800 Lb/Hr	Cooling Water 1,046 gpm	126	116	80	105	14,340,000
Vent Condenser	2	Steam 27,400 Lb/Hr	Cooling Water 1,390 gpm	220	150	80	120	27,800,000
First Stage Inter-Cooler	10	Crude Hydrogen 55,640 SCFM	Cooling Water 1,576 gpm	282	100	80	79	14,976,000
After Cooler	10	Crude Hydrogen 54,800 SCFM	Cooling Water 1,380 gpm	293	100	80	100	13,824,000

Pipeline Terminal Facilities

Catalytic Cracking - Item 108
Catalytic Polymerization - Item 109
Redistillation Unit - Item 110

Description of Facilities

The products received at the Terminal end of the pipeline are to be further processed in existing West Coast refineries, each to consist of a Catalytic Cracking Plant, a Catalytic Polymerization Plant, and a Redistillation Unit.

For processing the products yield of the total 250,000 B/CD refinery operation, each of the three plants will charge:

Catalytic Cracker	33,800 B/CD Diesel
Catalytic Polymerization	5,970 B/CD C_3 and C_4
Redistillation Unit	33,230 B/CD Diesel and Gasoline

For processing the products yield of only one 50,000 B/CD refinery, it is planned to install only one finished products refining unit. This small refinery unit is rated at 60% capacity of one of the larger units, and its facilities will be sized to charge:

Catalytic Cracker	20,280 B/CD Diesel
Catalytic Polymerization	3,580 B/CD C_3 and C_4
Redistillation Unit	19,940 B/CD Diesel and Gasoline

Each refinery, regardless of size, is to be a complete installation with all its utilities, piping and R.D. tankage. Storage tankage is covered in a report by others.

A simplified flow diagram describing the individual units and their tie-in to the overall refinery operation is included in this part of the report.

Pipeline Terminal Facilities

Catalytic Cracking - Item 108
Catalytic Polymerization - Item 109
Redistillation Unit - Item 110

Specifications

	50,000 B/CD	250,000 B/CD
Plot Area for:		
1 Catalytic Cracker)		
1 Catalytic Polymerization Unit)		
1 Redistillation Unit)-	4 Acres	5 Acres
Tankage	3 "	6 "
		11
		x 3
Total Land Required	7 Acres	33 Acres

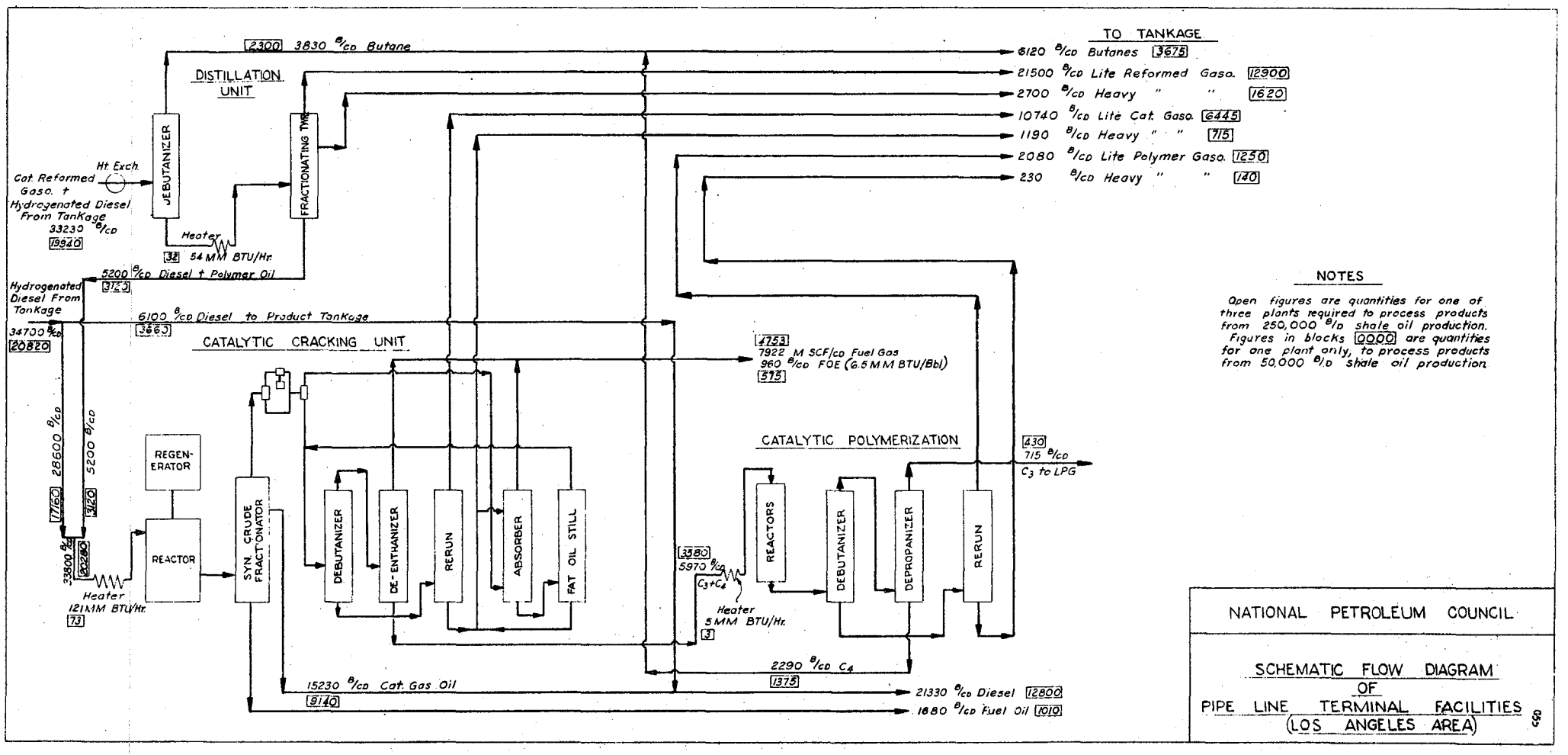
Rundown Tankage Requirements - 250,000 B/CD

	B/CD	Bbls Each	Total Bbls
Butanes	6,120	2 - 7500 spheres	15,000
Lt. Reformed Gasoline	21,500	2 - 30000	60,000
Hvy. Reformed Gasoline	2,700	2 - 3750	7,500
Lt. Cracked Gasoline	10,740	2 - 15000	30,000
Hvy. Cracked Gasoline	1,190	2 - 2000	4,000
Lt. Polymer Gasoline	2,080	2 - 3750	7,500
Hvy. Polymer Gasoline	230	2 - 1000	2,000
Diesel	21,330	2 - 30000	60,000
Fuel Oil	1,680	2 - 2000	4,000
C_3 to LPG	715	2 - 1000 press.tks.	2,000
Slop Tanks		15000	15,000
Total barrels for R.D. Tanks at Each of 3 Plants			207,000

At storage capacity of 35,000 B/acre of land, total land area required is 6 acres per facility.

Rundown Tankage Requirements - 50,000 B/CD

	B/CD	Bbls Each	Total Bbls
Butanes	3,675	2 - 4500 spheres	9,000
Lt. Reformed Gasoline	12,900	2 - 15000	30,000
Hvy. Reformed Gasoline	1,620	2 - 2000	4,000
Lt. Cracked Gasoline	6,445	2 - 7500	15,000
Hvy. Cracked Gasoline	715	2 - 1000	2,000
Lt. Polymer Gasoline	1,250	2 - 2000	4,000
Hvy. Polymer Gasoline	140	2 - 1000	2,000
Diesel	12,800	2 - 15000	30,000
Fuel Oil	1,010	2 - 2000	4,000
C_3 to LPG	430	2 - 600 press.tks.	1,200
Slop Tanks		5000	5,000
Total barrels R.D. Storage Required			106,200
Storage Acreage Required			3 Acres



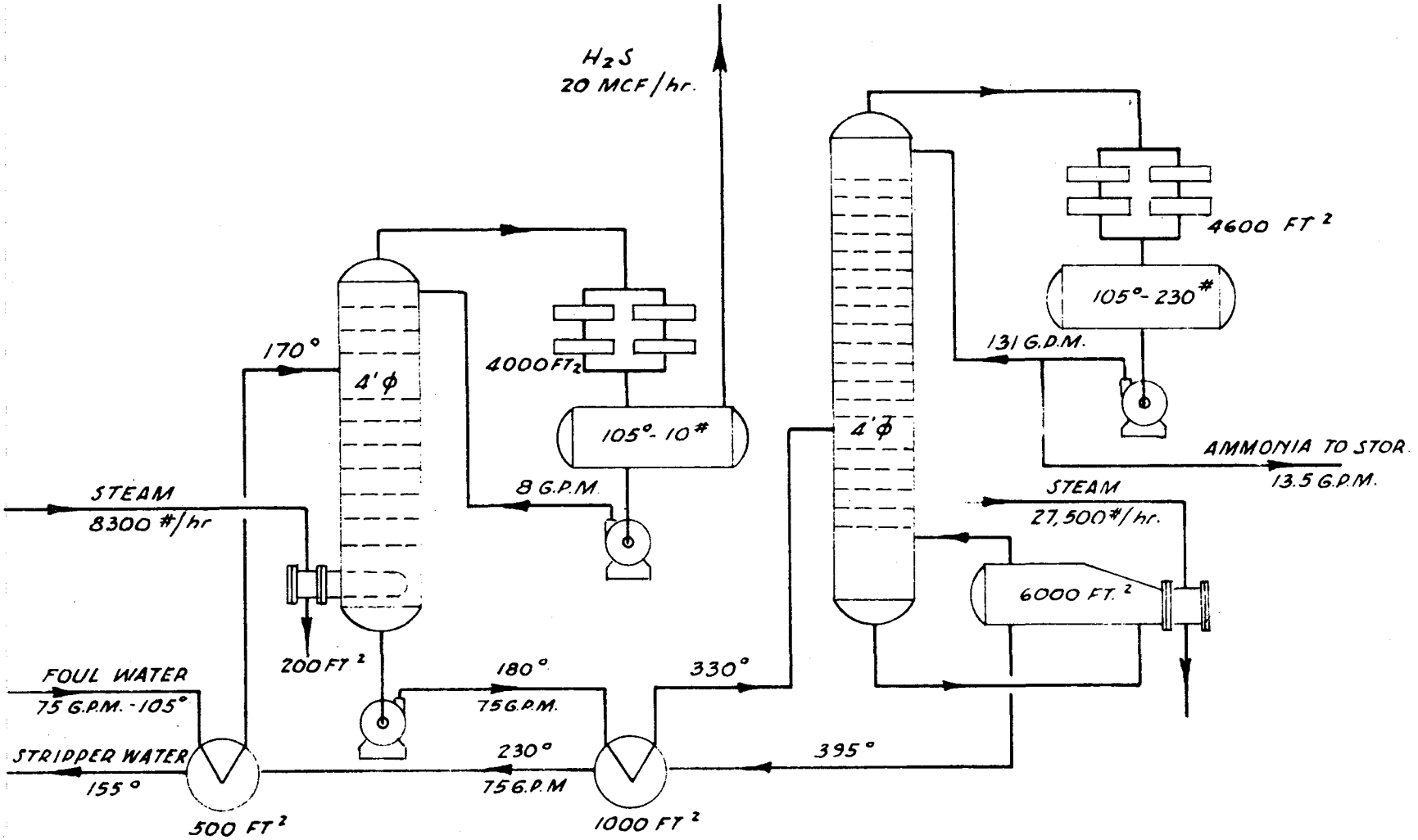
NOTES

Open figures are quantities for one of three plants required to process products from 250,000 B/D shale oil production. Figures in blocks [0000] are quantities for one plant only, to process products from 50,000 B/D shale oil production.

NATIONAL PETROLEUM COUNCIL

SCHEMATIC FLOW DIAGRAM
OF
PIPE LINE TERMINAL FACILITIES
(LOS ANGELES AREA)

GPC



SHALE OIL ESTIMATE · AMMONIA RECOVERY
FOR 25000 B/C.D. OPERATION.

N.P.C. SHALE OIL ENGINEERING ESTIMATE

AMMONIA RECOVERY - ITEM #111

Description of Facilities

The feed to this Unit is the aqueous solution of ammonia and hydrogen sulfide from the hydrogenation and reforming units.

Contrary to the recommendation of the Process Report, no equipment is furnished for removal of the last trace of water from the ammonia product as we are informed that such processing is not economical. There should be no difficulty in disposing of the slightly wet liquid ammonia for uses other than refrigeration.

The flow sheet of the Unit, page 2, shows the major items of equipment and is self-explanatory.

SULFUR UNIT - Item 112

Description of Facility

GENERAL

The feed to the sulfur unit is the raw H_2S stream produced at the ammonia recovery unit. Attention is called to the main overall refinery process flow diagram which (1) does not include this sulfur unit, and (2) shows that coker gas which is not required for hydrogen production goes directly to fuel. Subsequent committee discussions pointed up the desirability of (1) including a sulfur unit (hence this added facility), and (2) treating all fuel gas for removal of H_2S.

It has been assumed here that the total coker fuel gas will be desulfurized by scrubbing it with dilute ammonia solution in the same manner as that portion already shown going to hydrogen production, the split between fuel gas to sales and fuel gas to hydrogen production taking place after scrubbing. A review of the hydrogen plant estimate, which included partial H_2S scrubbing facilities, shows that doubling the scrubbing load will not alter that estimate, being of a magnitude sufficiently small to be absorbed in the contingencies allowed for that unit. Therefore, the balance of this report will deal only with the unit for converting the recovered H_2S to elemental sulfur.

PROCESS DESCRIPTION

From the ammonia recovery unit the H_2S flows under its own static pressure (10 psig at the boundary limit is desired) to the sulfur unit. Here it is first bubbled through an ammonia scrubber, where in contact with dilute sulfuric acid, residual ammonia is removed as ammonium sulfate. This pretreatment of the gas is required to assure success in the following steps. After removal of the NH_3 contaminant, one-third of the feed is burned with air in the H_2S burner:

$$H_2S + 1\text{-}1/2\ O_2 \longrightarrow SO_2 + H_2O$$

The heat of combustion is used to generate 150 psig steam.

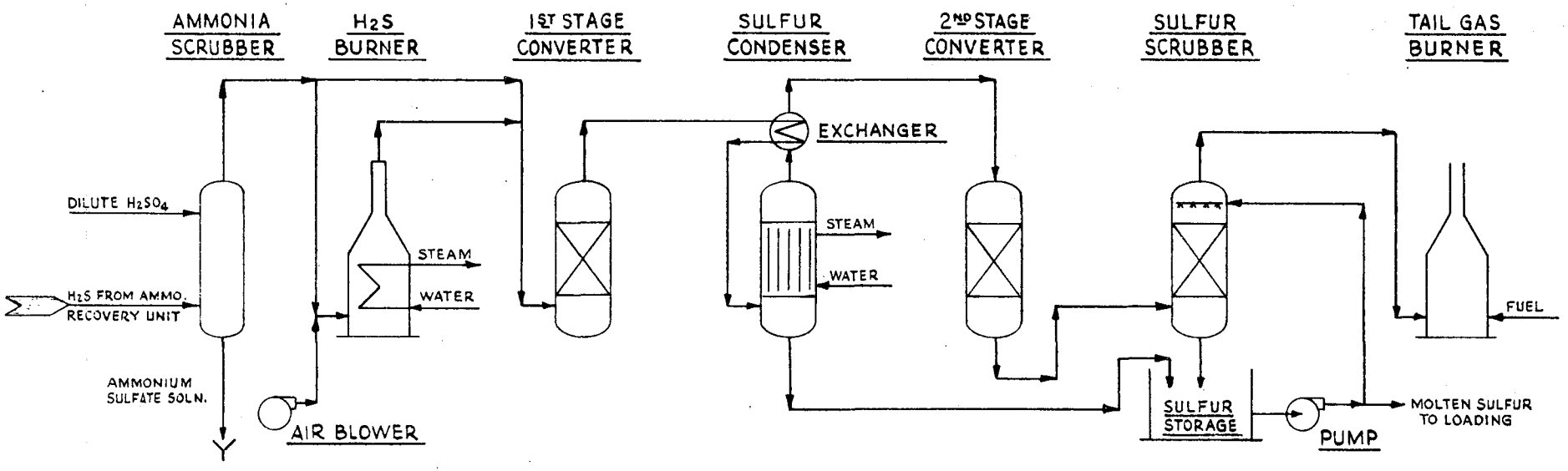
The combustion products are then mixed with the remaining two-thirds of the H_2S and passed through the first stage converter where the following reaction occurs:

$$2\ H_2S + SO_2 \longrightarrow 3\ S + 2\ H_2O$$

The effluent from the first converter is cooled in an exchanger and sulfur condenser where the sulfur vapor is condensed and removed from the gas stream together with the generation of more steam. The gas stream is then passed to a second stage converter to carry the reaction to greater completion and finally to a sulfur scrubber where sulfur vapor is scrubbed from the gas by contacting with molten sulfur. The tail gas from the scrubber contains some unreacted H_2S which is burned in a tail gas burner before being discharged into the atmosphere.

The product sulfur is pumped to storage. A simplified flow diagram is attached to illustrate this commercially proven process.

SIMPLIFIED PROCESS FLOW DIAGRAM



SULFUR UNIT

SULFUR UNIT - Item 112

SPECIFICATIONS

	50,000 Bbl Refinery
Site Development	
Process Area	75' x 100'
Storage Area	100' x 100'
Process Equipment	
H_2S Burner (boiler)	One at 9 MM Btu/hr (8,000 lb/hr 150 psig steam)
Converters	Two 12' Dia. x 10' and 9' Dia. x 10'
Heat Exchangers and Condensers	Two Total Duty = 3 MM Btu/hr (includes generation of 2,000 lb/hr steam)
Sulfur Scrubber	One 6' Dia. x 25'
Ammonia Scrubber	One 3' Dia. x 20'
Sulfur Pumps	Two each at 300 GPM and 65' Head
Boiler Feedwater Pumps	Two each at 40 GPM and 300 psig
Air Blowers	Three each at 1,500 CFM at 6 psi ΔP
Tail Gas Burner	One at 5 MM Btu/hr

SULFUR UNIT - Item 112

Material Balance

	50,000 Bbl/D Refinery lb/hr
Charge	
H_2S	4,152 (50 T/CD)
NH_3	45
H_2O	119
	4,316
Products	
Recovered Sulfur	3,550 (43 T/CD)
Tail Gas Sulfur (as SO_2)	370

50,000 BBL. SHALE OIL REFINERY

GENERAL

We have been instructed to base this report on steam turbine generation, although gas turbines have been seriously considered as prime movers.

Accordingly, this report contemplates a Power Plant furnishing electricity and delivering 150# steam through extraction type turbines. It allows for distribution of power to load centers, feeding each of the Mines, Retorting Plants, Refining Units and areas such as Pipe Line Pump Station, Colorado River Water Plant, Tank Farms, Shops, etc. The following facilities would be supplied at each of these load centers:

1. Power at 4160Y volts - 3 phase - 60 cycles.
2. Power at 460 volts - 3 phase - 60 cycles.
3. Lighting at 120-240 volts - 1 phase - three wire - 60 cycles.
4. Telephone.
5. Fire Alarm.

It is contemplated that motors up to and including 100 HP be served at 460 volts and that motors above 100 HP be operated at 4160 volts.

At the Refining Units and Retorting Plants these facilities would be extended to the Battery Limits. At the Mines and at the Colorado River, no allowance has been made for any work beyond the Load Centers. However, Refinery utilities have been allowed for complete. This includes electric work for all facilities in buildings, shops and offices, as shown in the report of April 15th, as well as tank farm, water reservoir and loading areas. Street lighting is included.

From the viewpoint of steam lines and Refinery load center feeders, a central location of the Power Plant would be desirable. However, the problem of the large retort gas lines, together with the multiplicity of outgoing power feeders, has led to locations, along the upper edge of the Refinery sites, being used for these estimates. The Power Plant, together with transformer and switch gear yards, will cover approximately 5 acres.

This report also covers telephone and fire alarm systems. The fire alarm is included under Power Transmission.

50,000 BBL. SHALE OIL REFINERY

STEAM POWER PLANT - ITEM #201

Description of Facilities

It is proposed to install a Power Plant generating electricity at 13,800 volts, three phase, 60 cycles and delivering 150# steam to the Refinery. The generators would be unitized, each independent unit consisting of a boiler, turbo-generator and their auxiliaries. The boilers would be arranged to burn retort gas, refinery gas or oil. They would automatically shift from one to the other as necessary. It is contemplated that turbines operating on 900# 900° steam be used to drive hydrogen cooled generators. Fin-fan cooling would be employed for condensing, resulting in approximately 22" of vacuum during hot weather.

It is proposed to install 5 - 25,000 K.W. 0.8 power factor generators. By increasing hydrogen pressure from 15# to 30#, at least 12% constant overload capacity would be available, increasing their rating to 28,000 K.W. 3 of these generators would be driven by extraction type turbines. Although 4 generators could carry the peak loads, it is contemplated that all 5 would normally be in operation. In this case, if one unit faulted it would automatically disconnect itself, leaving the other 4 to carry the load without interruption.

Due to the relatively poor vacuum, the full condensing turbines will use approximately 17,000 BTU per K.W. generated. Partly due to the use of retort gas and fin-fan cooling, unit auxiliaries are estimated to use 10% of the power generated. This, together with transformer and line losses, would given an estimated power availability factor of 85%. On a gas basis, this would equal 20,000 BTU for each K.W. utilized.

The extraction type turbines would deliver 20# of 150# steam and use 43,000 BTU for each K.W. generated. If 17,000 BTU were allowed for electricity, a pound of steam would require 1,300 BTU.

Boiler treated water will be used to replace unreturned condensate and for make-up in the 5 forced draft cooling towers. Each tower must cool to 80° maximum the 600 GPM necessary for generator and oil cooling purposes.

The estimate allows for the Power Plant complete in place, including the generator switch gear. The switch gear for outgoing feeders and a building extension to house it is covered under Power Transmission.

STEAM POWER PLANTS - ITEM #201

GAS CONSUMPTION AND ELECTRICAL GENERATION

The electrical requirements shown in the individual reports are based on yearly averages contemplating 90% utilization of the various Units. The sum of the indicated requirements totals 70,500 K.W. Due to Power Plant Auxiliaries and line and transformer losses an average of 82,500 K.W. must be generated.

An analysis of the operation of the units, including regeneration, clean-outs, etc. indicates a one hour demand of 82,000 K.W., which requires generation of 96,000 K.W. or approximately 16% more than the yearly average. The Power Plant was designed to carry this load on the 100,000 K.W. rating of four generators, leaving the fifth as a spare.

Refinery loads have the habit of growing. As load increased, generator hydrogen pressure could be increased, raising the rating to an estimated 112,000 K.W. If the load still increased, capacitors could be installed on the 4.16 K.V. side of loaded transformers or feeders. In this manner the average power factor could be raised to 90%, when 125,000 K.W. could be generated. Thus increased capacity would be paid for only as needed and capacitor installations would be of maximum benefit.

The yearly averages show approximately 90% utilization of retort gas. It is reasonable to anticipate that refinery steam and fuel demands would increase somewhat proportionally and at the same time as the power demands. If this were true, a 16% overall increase would necessitate intermittant use of refinery rich gas.

The refinery rich gas would supply somewhat less than the refining unit heating. In case of the loss of the proposed single gas line, from the Retorting Units, a major refinery shutdown could be avoided by burning shale oil in the Power Plant.

50,000 BBL. REFINERY AND 250,000 BBL. OPERATION

STEAM POWER PLANTS - ITEM #201

ENERGY BALANCE

	50,000 Bbl. Refinery		250,000 Bbl. Operation	
	A	B	A	B
Fuel Consumption MMBtu./C.D.	49,095	82,000	245,270	410,000
Steam Generated MLB/C.D.	11,860	30,000	59,300	150,000
Steam to Refinery MLB/C.D.	11,760	29,000	59,300	145,000
Electricity Generated KW.hr./C.D.	1,981,000	3,000,000	9,893,000	15,000,000
Electricity to Refinery KW.hr./C.D.	1,783,000	2,730,000	8,903,500	13,650,000

NOTE: Column "A" shows present proposed yearly averaged load.
Column "B" shows possible 100% loading with electricity based on use of four generators and steam on two.

50,000 BBL. SHALE OIL REFINERY

POWER TRANSMISSION - ITEM 202.

GENERAL

The designation of this Item, "Power Transmission," is not truly descriptive of the installations proposed in this report. There are a number of electrical systems required for normal refinery operation and an attempt has been made to include all of them, with the exception of the telephone system, in this estimate. Some of these extra items include plant call system, fire alarm system, fire pump control system, etc.

In the case of major refining units, the common practice is to supply all incoming facilities at the battery limits. This estimate covers all installations necessary to meet this requirement.

DESIGN CONSIDERATIONS

The generating station is isolated and must be entirely self-supporting. From the nature of its load and the cost and hazard of service interruptions, every consideration must be given to providing continuity of service. Experience has shown that only at relatively long intervals is it practicable to de-energize feeders and transformers serving the average refining unit. Generation and distribution to major refining units would be at 13.8 K.V., a voltage at which all maintenance and repair work should be done, whenever possible, on de-energized equipment.

Based on the above, this estimate allows for a spare turbo-generator and a transfer buss in the power station switch gear. Transformer banks serving multiple loads have spares operating in parallel. Switch gear is arranged to be isolated to allow of de-energized maintenance. Radial feeders are run from the power plant to single transformers serving the various load centers. There are no breakers on either the primary or secondary side of these transformers other than the breaker located at the power plant buss. This breaker is arranged to be tripped by primary current and, by means of pilot-wire or carrier control, may be tripped by relays located on the secondary side of the transformers. The feeder, transformer, and load center are treated as a single unit, the breaker is under constant supervision and may be by-passed by a similar breaker and worked on in a de-energized condition, inside of a building rather than in the open. The load centers serve single refining units or areas and the loss of a single feeder or transformer will affect only its own loading. This also offers opportunities to de-energize these feeder-transformer-load center units for maintenance at times of complete unit shutdowns. Refinery loads tend to grow as time goes on and an allowance of 15% to 20% has been made throughout to allow for this.

50,000 BBL. SHALE OIL REFINERY

POWER TRANSMISSION - ITEM #202

OUTLINE OF PROPOSED FACILITIES

Part I - Power Generation

The generating station must be sized to carry its demand of 94,200 K.W. and allow a reasonable amount of growth. It is proposed to install 5 - 25,000 K.W., 0.8 power factor, turbo-generators, generating at 13.8 K.V., three phase, 60 cycles, and operating on 900#, 900° steam. By raising the hydrogen pressure from 15# to 30# these units would be good for 28,000 K.W. at 0.8 P.F. continuously. These would be on the line at all times with a present rated peak loading of about 94% for 4 of them; thus the fifth generator could be regarded as a spare as far as the 50,000 Bbl. Refinery is concerned. In the case of the 250,000 Bbl. Operation with its interconnecting transmission lines, this generator could be isolated and used to feed directly into the outgoing lines if desired. The 94%, one hour peak, loading shown for 4 generators is at normal rating and 80% power factor. The average power factor will very likely be a little higher than this, probably around 83%. Under these circumstances, the loading would be 90½% which would allow approximately 10% load growth before increasing hydrogen pressure. There was no allowance made in this estimate for capacitors as it was thought that the most economical means of allowing for load growth would be by means of adding capacitor installations as needed. As generator, feeder or load center transformer capacity was approached, capacitors could be installed on the 4160 volt side. This would assure that these installations would be of maximum benefit. It is entirely practicable to raise the power factor, at maximum demand, to about 90%, thus providing for an approximate 30% increase in peak loading. In this manner the cost of extra capacity would be paid for only as it was needed.

Part II - Power Station Switch Gear

It is proposed to use 15 K.V. air circuit breakers of the draw-out type, mounted in steel cubicles, for the station switch gear. After derating for altitude these are operated rather close to their rating but it is felt that they still have a sufficient factor of safety. The station bus would be paralleled by a transfer bus and by means of disconnecting switches, all breakers could be connected to either bus. Disconnects would be provided so that any outgoing feeder breaker could be shifted to the transfer bus which would be connected to the main bus

Part II - Power Station Switch Gear - (Continued)

through a bus-tie breaker. This breaker would protect the feeder at such times as the feeder breaker was isolated for maintenance. The generator section of the switch gear is included in the overall cost of the power plant. 19 breakers would be used for outgoing feeders and one to tie the main and transfer buses together. See page 19 for diagram of switch gear used for estimating purposes.

Part III - Distribution - General

The most economical distribution would be at the generated voltage of 13.8 K.V., but in the case of feeders to the Mines, Retorting and Hydrogen Plants, the currents involved are such as to make transmission at this voltage undesirable. Probably 44 K.V. would be most suitable. A survey of the Refinery interconnection transmission lines indicates 110 K.V. as the most desirable voltage. This would necessitate transformer banks and switching stations at these two separate voltages. This is an undesirable duplication of facilities and it was decided to base this estimate on a common 69 K.V. transmission voltage. The present Utility Company power line along the Colorado River is at this voltage. If the interconnecting lines were built soon enough, they could serve to carry construction power to the various Refinery sites.

Part IV - 69 K.V. Distribution

The installed 69 K.V. transformers at the load centers serving the Mines, California Pipe Line Pump Station, Colorado River Water Facilities, Retorting and Hydrogen Plants for the 50,000 Bbl. Refinery total 76,000 K.V.A. To feed this load it is proposed to install at the Power Station, 4 - 25,000 K.V.A. transformers at 13.8/69 K.V. These would normally be operated in parallel but one could be taken out of service at any time. They would be so relayed that a transformer which faulted would be disconnected, leaving the others to carry the load. The secondaries of these transformers would be tied in through breakers to main and transfer buses to which the individual feeder breakers were connected. All breakers could be bypassed and taken out of service for maintenance. These breakers and buses would be installed on an open fabricated steel structure. The estimate allows for the feeder lines to be carried on wooden poles. Page 20 shows the wiring diagram of the transformer and switching station from which the estimate was made.

Part V - 13.8 K.V. Distribution

All load centers inside the Refinery area proper, with the exception of the Hydrogen Plants, would be served at 13.8 K.V. There would be 17 outgoing feeders and 15 load centers. It is proposed to take these feeders underground from the station, some direct to the load centers which they serve, and others, such as tank farm, etc. only as far as the nearest practicable pole line location. The switch gear in connection with these outgoing feeders is shown on page 19 , which was used for estimating purposes.

Part VI - Load Centers

Each of the outgoing feeders would terminate directly in a transformer feeding its load center. It is proposed that the load center switch gear and equipment be in steel cubicles, housed in a windowless brick or monolithic concrete building. The building would be equipped with proper heating and ventilated with filtered air. The transformers would be located just outside the building and their secondaries would enter the building through extended throats. The cubicles would set over troughs or tunnels in the floor and outgoing circuits would leave the building underground. Metering, for accounting purposes, was allowed for. Page 21 shows a typical load center for a major unit, with outgoing feeders carried to the Battery Limits. It is typical of the diagrams which were used for estimating purposes.

Part VII - Plant Lighting

Plant motor loads can stand a reasonable variation in voltage. Lighting voltage, however, should be held very closely to the rating of the lamps. Some power loads, such as those at the Laboratory, are also quite sensitive to voltage changes. It is proposed to feed all lighting, also power loads sensitive to voltage changes in the Refinery area proper, from a single regulated bus, at 4.16 K.V. This bus, located adjacent to the power plant, would be fed by 2 - 1500 K.V.A. transformers, operated in parallel, but either one capable of carrying the total load. If either faulted, it would clear itself automatically. These transformers would be equipped with load ratio control. 3 outgoing feeders would leave the bus and be looped throughout the plant area. They would be arranged with disconnects, at proper locations, so that in emergency, 2 feeders could carry the total load. At the Mines and Retorting Plants, allowance has been made for one regulated 4.16 K.V. feeder to carry all lighting.

Part VIII - Plant Utilities Power

There are certain plant utilities and services, such as shops, garages, plant air and instrument air, water treating, ice machines, office building, etc., which are common to the Refinery as a whole. Their constant operation is quite necessary and it is inadvisable to supply them from circuits and transformers feeding major units. It is proposed in the refining area proper that these be fed from a parallel bank of 4000 K.V.A. transformers, at 4.16 K.V., in the same manner as the plant lighting. It is proposed that the Ammonia Recovery Plants be supplied by this system. In this case, the feeders would not be regulated. Other plant utilities such as the tank farm, water basins, etc., would be fed from separate load centers similarly to the major refining units.

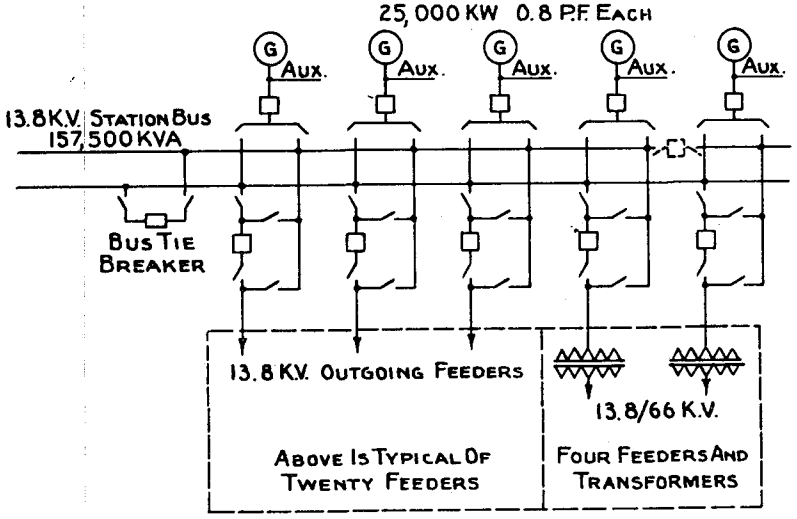
Part IX - 460 and 120-240 Volt Distribution

This estimate contemplates that all motors up to and including 100 HP be operated at 460 volts and those above 100 HP at 4160 volts. Transformers were sized, as nearly as practicable, to allow for the loadings at these two voltages. Distribution lines at 460 and 120-240 volts were held to a minimum by liberal use of relatively small sized transformers. This applies particularly to large area and street lighting. These locations include tank farm, coke storage areas, etc.

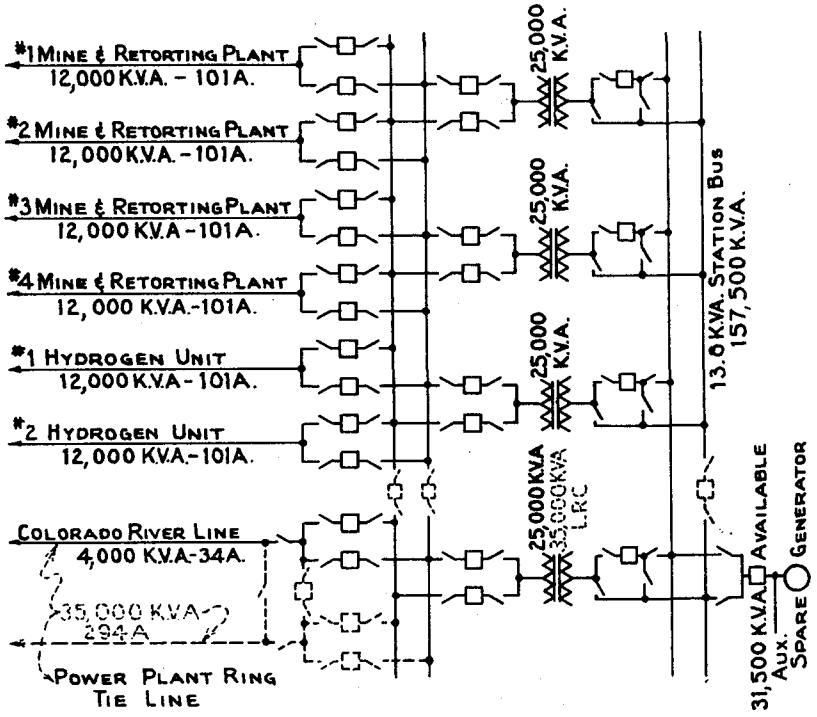
Part X - Fire Alarm System

It is proposed that a standard Gamewell fire alarm system be installed covering the Refinery proper and its Mines and Retorting Plants. Non-interfering master stations would be installed to code calls for the major areas and auxiliary stations would be placed in these areas as necessary. A diaphone horn was allowed for Refinery coding and air whistles at the Mines and Retorting Plants. The fire alarm to Mines and Retorting Plants along with fire water pump start would be relayed through the telephone cables. The Fire Alarm control center would be in a room in the power plant, adjacent to the telephone exchange room.

50,000 Barrel Operation
Power Station Switchgear

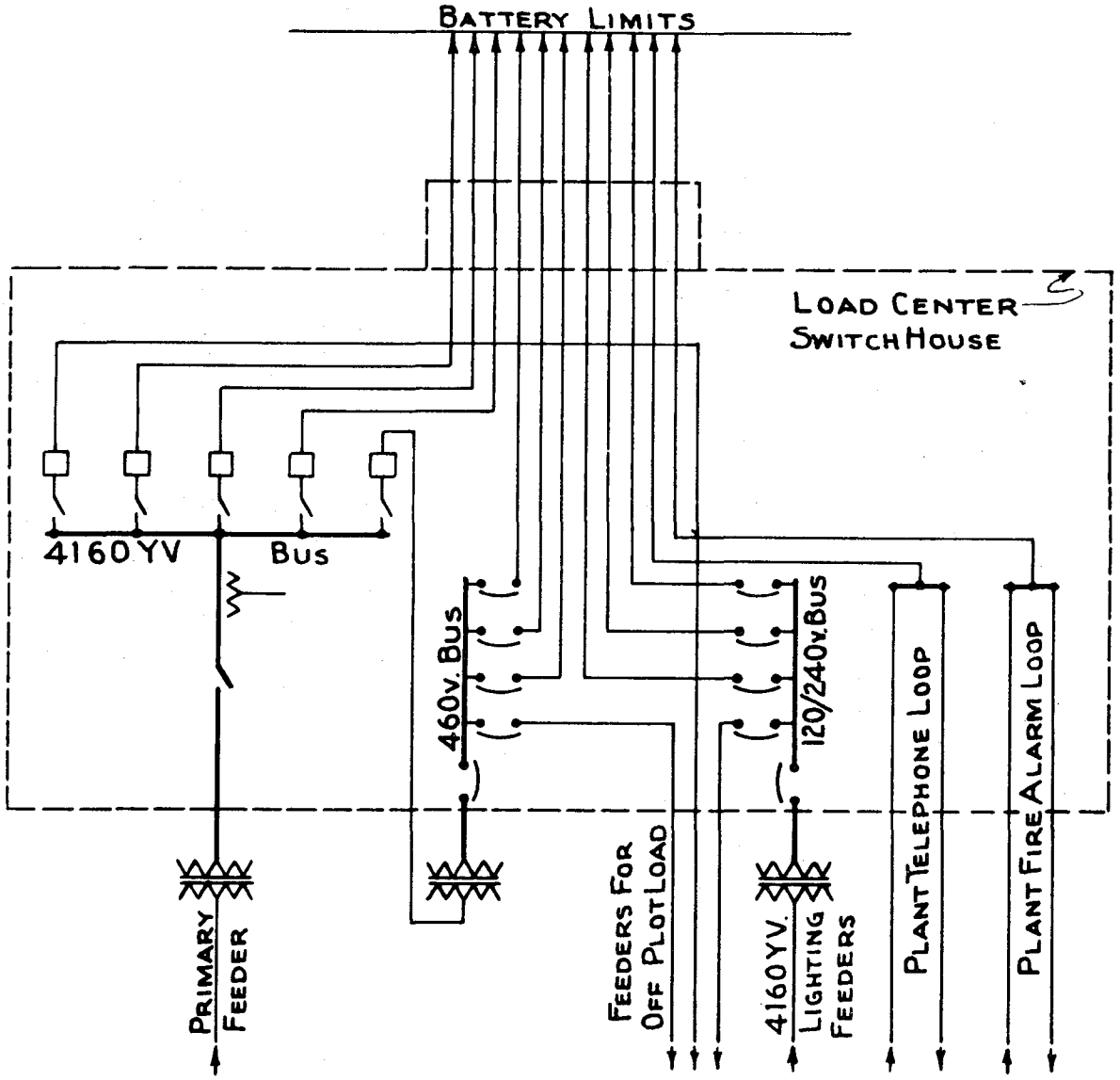


50,000 Barrel Operation
13.8 K.V./69 K.V. Transformer & Switching Station



Dotted = Used Only For 250,000 Barrel Operation.
Three Transformers Always Needed For 50,000
Barrel Refinery. The Fourth Is An Operating Spare

50,000 Barrel Operation
Typical Load Center For Major Refining Unit
All Facilities Extended To Battery Limits



Estimate Allows For Windowless Brick Or Concrete Building With Heating And Filtered Ventilation. Transformer Secondaries Enter Building Through Throats Extending Into Steel Cubicle Type Switchgear. Switchgear Sets Over Troughs, Which Lead To Vaults And Cables Are Extended To Battery Limits In A Tile Duct Run

50,000 BBL. SHALE OIL REFINERY

TELEPHONES - ITEM #212

DESCRIPTION OF FACILITIES

It is proposed to install a system allowing intercommunication between dial type telephones in the Refinery Proper and its Mines and Retorting Plants. The initial installation would consist of a 100 line automatic telephone switchboard. It is contemplated that it would be installed in a room in the Power Plant. From this exchange would extend lead-covered paper insulated cables throughout the refinery and to the Mines and Retorting Plants. These cables would appear in the load centers feeding major refinery units and areas. It is contemplated that this installation cover all telephones complete in place.

It is proposed that the telephone cables and battery be also used for other purposes. A plant call system, employing air whistles for signals, relayed through the telephone cable, is allowed for in this estimate. It is proposed to relay the fire alarm system at the Mines and Retorting Plants to the Refinery thru this cable. Also allowed for is remote starting of fire water pumps. Telemetering, facsimile and supervisory control, using these cables, is allowed for in another section of this report.

250,000 BBL. SHALE OIL OPERATION

STEAM POWER PLANTS - ITEM 201

Description of Facilities

General

The integration of the five 50,000 bbl. refineries makes advisable certain changes in individual power plants as listed below:

Parachute Creek - 100,000 B/CD

Spare turbo generators were allowed for in each of the 50,000 bbl. refinery power plant estimates. It is thought that with the ability to transfer power from other locations a single spare generator at this location should be sufficient. Following the same reasoning only one 35,000 K.V.A. transformer has been shown in the 69 K.V. set up. See Page 35 for the diagram used for estimating purposes.

Cottonwood Gulch

This location will be called on to serve off-site load in the Administration Center and at the Colorado River Water Plant. It is also the most desirable easterly location to serve Pipe Line and Colorado River Water Plant facilities at De Beque. It is proposed to move the extra 25,000 K.V.A. full-condensing turbo-generator from Parachute Creek to this location.

250,000 BBL. SHALE OIL OPERATION

STEAM POWER PLANTS - ITEM 201

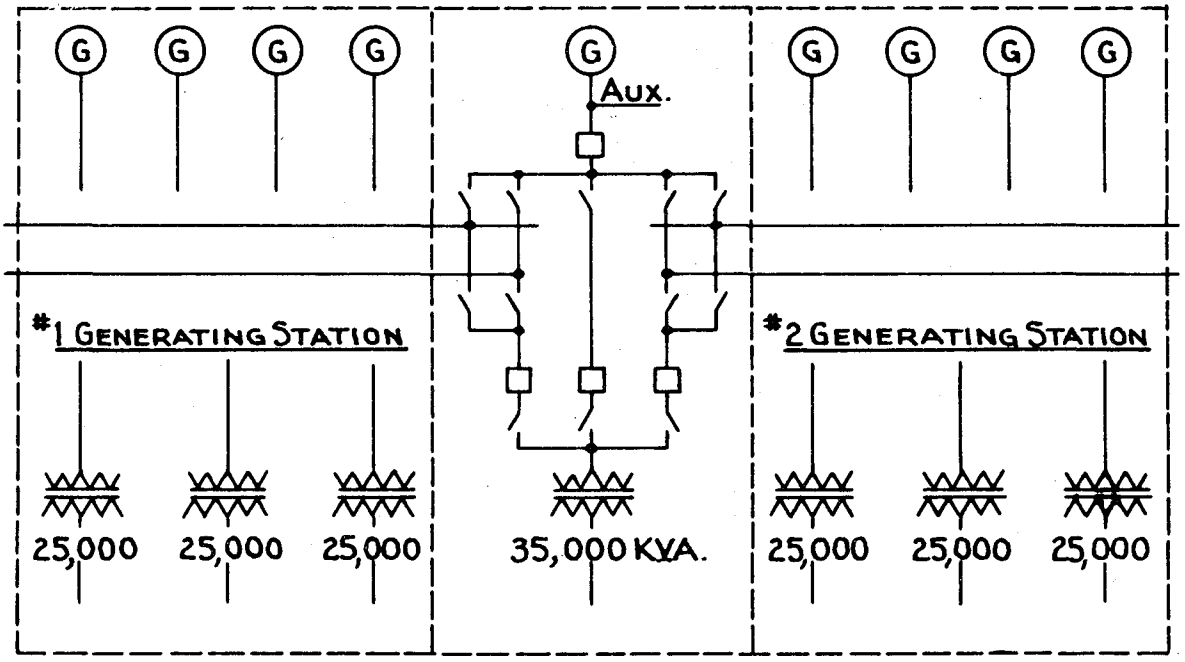
Gas Consumption and Electrical Generation

The integrated operation of the five refineries results in some shifting about of power loads. Economies are made in California Pipe Line, Colorado River Water Pumping and Transportation and Shipping. New load appears at the Administration Center and the overall generation remains five times that of a single refinery.

There would be 23,000 K.W. of power load outside of the Refinery areas proper. Of this, 12,000 K.W. would be served from the 69 K.V. system and 11,000 K.W. at 13.8 K.V. direct from the Refineries. A large portion of this 13.8 K.V. load would of necessity come from Cottonwood Gulch and would require use of refinery rich gas during the hours when the mines were in operation.

The 12,000 K.W. of load on the 69 K.V. system could be distributed between the other four refineries in a manner requiring minimum use of rich gas. When the 69 K.V. system was called on to deliver its rated 35,000 K.V.A. in plant interconnection, it probably would draw on two plants, leaving two to carry the normal load. In this case, the plants furnishing interconnection would have to burn rich gas or shale oil.

250,000 Barrel Operation
Generating Facilities At Parachute Creek



Showing Connections For One Generator And One 35,000 K.V.A. 13.8/66 K.V. Transformer Serving As Spares For Both Generating Stations

250,000 BBL. SHALE OIL OPERATION

POWER TRANSMISSION AND DISTRIBUTION - ITEM #202

Description of Facilities

General

With the combining of the five 50,000 bbl. refineries it becomes advisable to interconnect them in the interest of continuity. Also the volume of off-site load at the Colorado River becomes important enough that it is no longer advisable to carry it from a single power plant, as was contemplated in the 50,000 bbl. estimate.

The individual refinery estimate allowed for transmission at 69 K.V. This estimate allows for interconnecting the refinery sites with lines at the same voltage and furnishing service points at several intermediate locations. The lines would have 35,000 K.V.A. capacity.

There are many problems in connection with the operation of this proposed system and it is felt that they could be best met by setting up a general Utility or Power Organization. This should operate similarly to any outside Electric Utility Co. The assumption has been made that such a department would be set up. It would operate the power plants and the transmission and distribution systems. This would include all of the 13,800 volt system and its transformers.

Under this system the refineries would become customers for electricity and steam. The refinery maintenance electricians would not be concerned with any voltages higher than 4160. Maintenance on the higher voltage lines and equipment is quite specialized, both as to personnel, tools and equipment, and can be handled to best advantage by a central organization.

It has been assumed that this Power Department would operate from the Administration Center. Allowance has been made for setting up a central control station under the direction of a load-dispatcher. Allowed for are carrier-wave supervisory control, as well as radio and telephone communication for the system as a whole. The load dispatcher would be able to operate the breakers at the service points by remote control. Thus he could sectionalize the lines and control loading of the separate power plants as necessary. Automatic frequency control has been included.

Part 1 - Changes at Individual Refinery Sites

At Parachute Creek it is proposed to abandon one 25,000 K.V.A. 13.8/69 K.V. transformer altogether and change the second similar spare transformer to 35,000 K.V.A. See Page 35 for wiring diagram used for estimations. At the other four plants the spare 25,000 K.V.A. transformer would also be changed to 35,000 K.V.A. See Page 19 for diagram. In this manner, the interconnecting lines could be supplied through the use of otherwise spare transformers and by a net increase of 15,000 K.V.A. in transformer capacity.

Part 2 - Interconnecting Transmission Lines

It is proposed to encircle the refinery sites with a ring transmission circuit. The ring would be fed from four locations and serve off-site loads at four locations. Each feeder point, load center and section of interconnecting line would automatically disconnect itself, in case of trouble, without affecting the balance of the system.

Although the ring would be fed by spare generators and transformers at each of four locations, one location could supply all demands. It was felt that this would allow a sufficient factor of safety and flexibility enough to afford normal emergency use of the spare turbo-generators and transformers at each location. See Page 39 for sketch showing proposed interconnecting lines.

Part 3 - Installations at Ring Feeder Points

At each of the four feeder points one 25,000 K.V.A. transformer would be increased to 35,000 K.V.A. and provided with load ratio control. The 69 K.V. switch gear yard and structure would be enlarged and four additional breakers with associated equipment installed. One additional 13.8 K.V. circuit breaker would be necessary at each location. See Page 20, which was used for estimation. Synchronous condensers were included for line voltage control.

Part 4 - Installations at Service Points

Allowance has been made for the following at each of the four service points. A 69 K.V. installation consisting of a steel structure carrying three breakers and their auxiliary equipment and a polyphase transformer with 4160Y volt secondary. The necessary transformers from 4160 to 460 volts for small motors and to 120/240 volts for lighting are also included in place. No allowance has been made for any wiring beyond the service point. See Page 40 for diagram used for estimating purposes.

Part 5 - Off-site Loads

The off-site loading of the 69 K.V. system is listed as follows:

De Beque:	K.W.
Pipe Line Pump Station, Colorado River Water Plant #3, Ammonia Loading, Coke Storage, handling and loading, plus an allowance for miscellaneous buildings	5180
Roan Creek Water Booster Plant:	1872
Roan Creek Water Plant #4	1190
Parachute Creek Water Booster Plant	1334

9600 K.W. were allowed.

The off-site loading at 13.8 K.V. from the refinery sites is listed below:

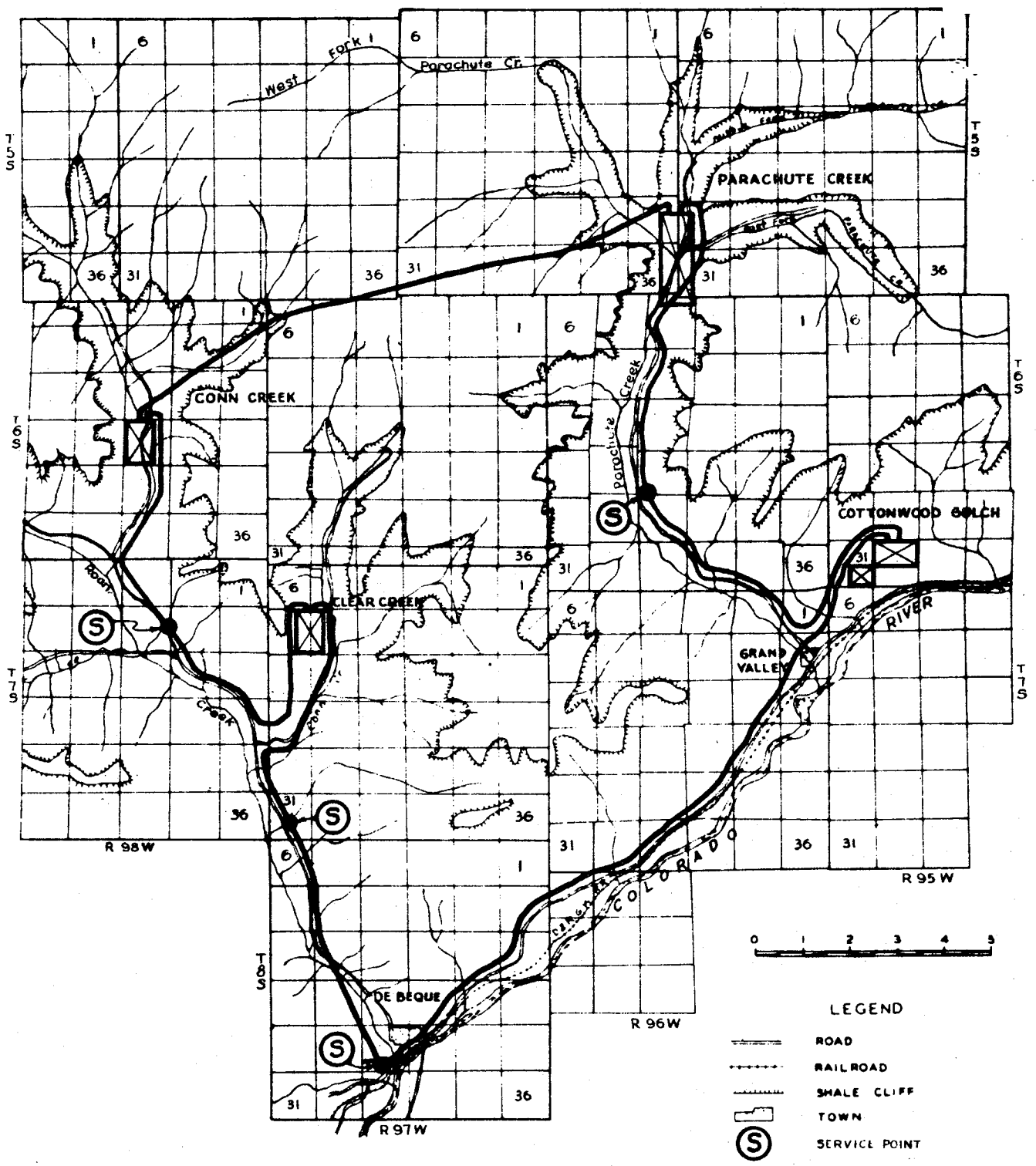
Parachute Creek	
Water Plant #2	372
Cottonwood Gulch	
Administration Center, Colorado River Water Plant #1, Ammonia Loading, Coke Storage, handling and loading, Ethyl Plant and loading racks for gasoline and Diesel, plus an allowance for street lighting and light and heat, etc., for miscellaneous buildings	7600

8,000 K. W. were allowed.

A total off-site loading allowance of 17,600 K.W. was made. The larger portion of this would be served by the extra generator at Cottonwood Gulch

Part 6 - Fire Alarm System

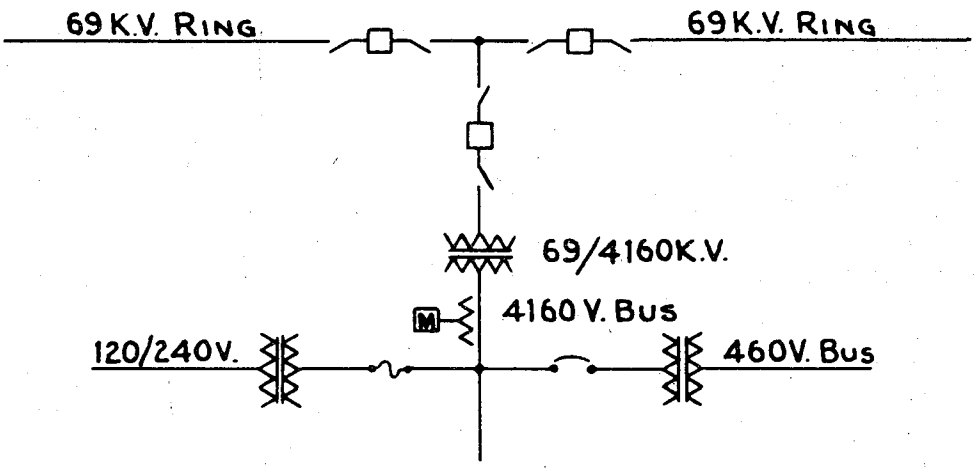
It is proposed to relay all fire alarm signals through the telephone cable to the Administration Center. There, would be located, an audible signal, an annunciator, and a tape recorder. It is thought that this would give immediate notice of a fire location and allow of making arrangements for assistance.



250,000 Bbl. Shale Oil Operation
69 K.V. Ring Interconnecting
Transmission System

50,000 And 250,000 Barrel Operations

Typical Service Point On 69 K.V. Ring Transmission Line



Note:

Estimate Does Not Allow For Any Electrical Work Beyond The Service Point Buses

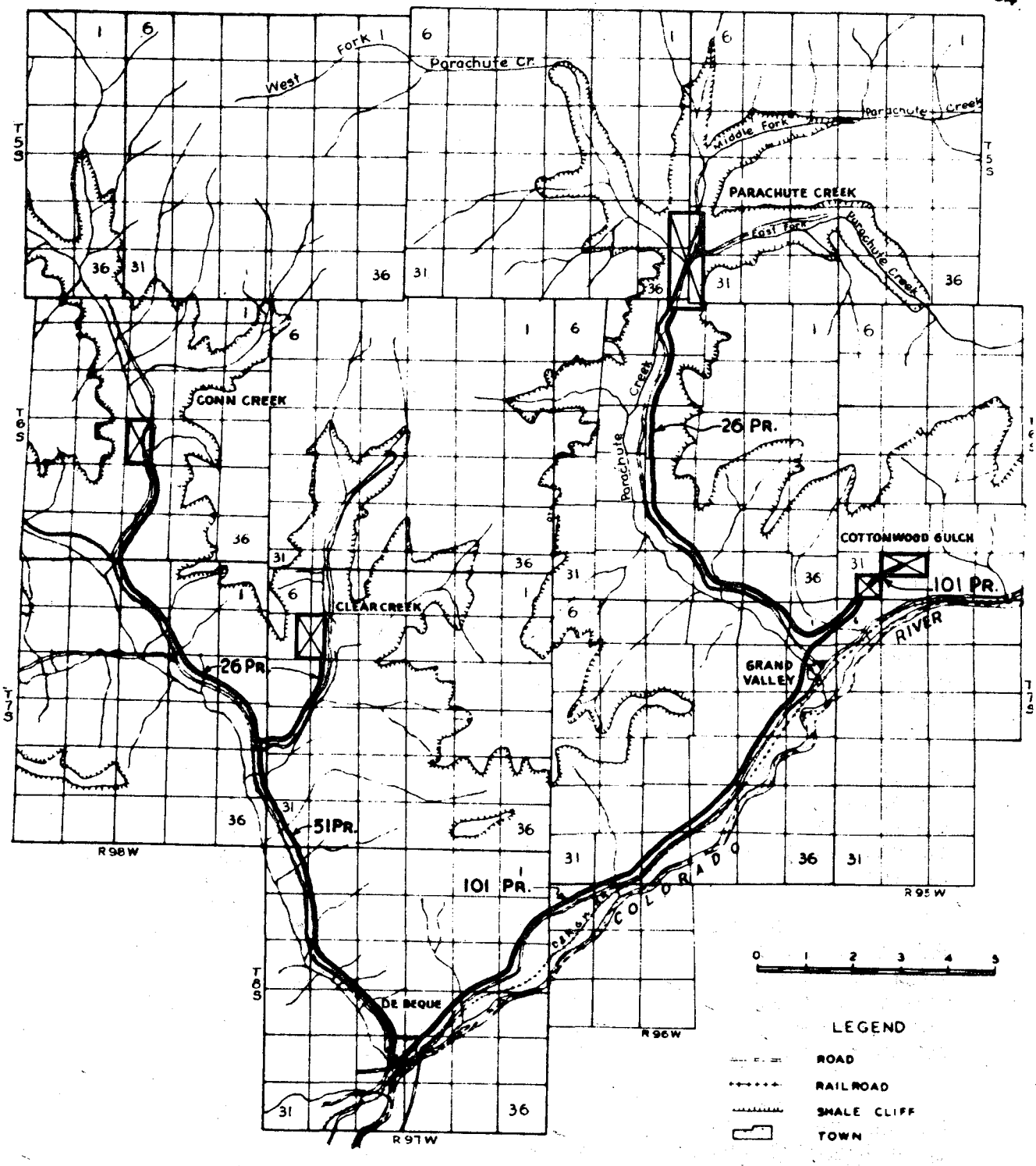
250,000 BARREL OPERATION

TELEPHONE SYSTEM - ITEM #212

Description of Facilities

It is proposed to install a system which would allow of direct dialing between all of its telephones. The Refineries, Administration Center and De Beque installations would be connected by aerial lead cables carried on wooden poles. See Page 42 for routing. The allowed-for automatic exchange at Cottonwood Gulch would be shifted to the Administration Center and enlarged into a central exchange.. Cottonwood Gulch, the Administration Center, De Beque and the Colorado River Water Plants would become subscribers of this exchange. Ten trunk lines would run to each of the other three refineries whose exchanges would be rearranged to accommodate them.

Allowance has been made for installation of tele-types or facsimile between the Refinery Warehouses and the Central Warehouse. This will not only provide necessary records but will reduce the load on the telephone exchange very materially. It has been assumed that the Power Department would maintain the exchanges and connecting cable lines and that Refinery Maintenance would be responsible for local telephones and the wiring in the refinery areas.



250,000 Bbl. Shale Oil Operation
Interconnecting Aerial Cable System
For Communication and Control Purposes

File: R-13.11A

Associated, California
June 1, 1951

N.P.C. ENGINEERING SUBCOMMITTEE REPORT ON SYNTHETIC FUEL PRODUCTION COSTS - WATER SUPPLY AND SEWERAGE

I-A DESCRIPTION
250,000 BARREL PER DAY SHALE OIL PROJECT

Water requirements for the 250,000 barrel per day shale oil project are to be supplied from the Colorado River and tributaries. While the subject of availability of water from the Colorado River is quite complex, it presently appears there is sufficient water available to support a shale oil industry many times the size established for this study.

It is assumed that water will have been firmed up by planned storage dams permitting release to the Colorado River at a constant rate. By so doing all committments in the upper basin can be satisfied, and the requirements between the upper and lower basin states can be met.

Availability of adequate water from the Colorado River is indicated in letter of February 9, 1951 to Mr. Tell Ertl, Chairman of the Oil Shale Raw Material Sub-Group as written by Judge Clifford H. Stone, Director of the Colorado water Conservation Board. This letter contains the following statements:

"The compact allocation of Colorado River water to Colorado will average 3,855,375 acre-feet a year. It is estimated that the present uses of water including those under authorized projects in Colorado will amount to approximately 1,600,000 acre-feet a year. This leaves a balance of 2,255,375 acre-feet for future development.

In order that you may better appraise the above outflow figures, may I state that it is estimated that the present uses and those contemplated under authorized

projects from the main stream of the Colorado River and the Gunnison River are approximately 800,000 acre-feet and those for the White River are estimated to approximate 34,000 acre-feet a year."

For purposes of this study, it has been assumed that the Green Mountain reservoir or similar facilities referred to in Senate Document No. 80, Colorado-Big Thompson Project dated June 15, 1937, on Page 3, paragraphs a, b and c will be constructed. Use of Colorado River water for the development of a shale oil industry is specifically mentioned in this document.

Industrial water requirements for a 250,000 barrel per day project are based on data supplied by the Mining and Processing Groups, but including an allowance for contingencies including a larger use of conventional water cooling than proposed by the Processing Subcommittee. The processing report dated April 15, 1951 calls for water usage of 6,870 g.p.m., whereas this study assumes a requirement of 12,350 g.p.m. This latter figure is in line with normal refinery requirements, taking into account differences in processing for the shale oil project. The figures for the 250,000 barrel project may be summarized as follows:

Withdrawal from Streams:	G.P.M.
Retorting and Mining	None
Refining (including boilers and power plant)	11,900
Drinking and Sanitary Uses, Total	450
Total Industrial Water	12,350
Effluents Returned to Streams	
Retort Water By-Product to Sewer after Use in Mining (2.5 Gal. per Ton)	667
Sanitary and Processing Effluent	2,265
Total Effluents	2,932
Net Water Required	9,418

In addition, the municipal water requirements of a new city to support the working personnel of the project have been estimated as follows:

Total Population	75,000
Water Requirement:	
Consumption	5,200
Pumping Capacity	15,600 G.P.M.
Storage Capacity for Treated Potable Water	2 Days
Treated Sewage Returned to River	3,460 G.P.M.

Total water removed from the Colorado for the entire project is therefore 17,500 g.p.m. Treated sewage and other effluent to the extent of 6,392 g.p.m. will be returned to the river, making the net consumption of surface water 11,160 g.p.m.

Location of Facilities

The locations of the pumping stations, water treating facilities, lines and storage reservoirs for the mining, retorting and refining facilities are shown on the attached map.

Water Treatment

All water required for the processing units is to be pumped from the Colorado River near Grand Valley and near De Beque into initial settling and clarifying basins at the river intake pumping stations, water plants 1 and 3.

Quality of Raw Water

The quality of surface water from the Colorado River near Cameo and Glenwood Springs is reported as

N.P.C. Engineering
Subcommittee Report June 1, 1951

follows in the U. S. Department of Interior Water Supply Paper 970, Page 159:

	Cameo, Colo.		Glenwood Springs Colorado		Assumed Average to Shale Projec
Parts per Million	1934	1935	1942	1943	
TDS	513	343	232	251	335
Hardness ($CaCO_3$)	218	165	131	137	163
Ca	61	48	39	40	47
Mg	16	11	8.1	9.0	11
NA	98	55	28	33	53
K	3.6	3.0	2.0	2.2	2.7
HCO_3	138	122	98	99	114
SO_4	120	78	56	63	79
Cl	134	74	38	43	72
SiO_3	12	12	11	11	11
Fe	.11	.11	.09	.06	.09
Fl	-	.2	.3	.2	.2
NO_3	1.1	.8	.6	.6	.8
BO_3	-	.01	.1	.2	.1
Mean Discharge-CFS	2568	3952	2688	2455	2916

High pressure pumping stations will transfer the clarified water into two earth fill dam storage reservoirs. One is located on the east fork of Parachute Creek near its junction with Parachute Creek, and will serve the 100,000 barrel refinery; and the other is at the junction of Roan and Kimball Creeks. This will serve the 50,000 barrel units located on Conn and Clear Creeks. No untreated water storage is provided for the Grand Valley Refinery because of its proximity to the river. Storage capacity of Parachute reservoir is 800 acre-feet, while that of Roan reservoir is 1,300 acre-feet, or a total of about 60 days requirement. Parachute dam is smaller because of

narrowness and steepness of the canyon.

Pumping

There were two systems - Grand Valley intake plant to Grand Valley Refinery (Site A), and to Parachute Creek dam. Pumping to Site A consists of plant plus sanitary water, 4,130 g.p.m. capacity through 4,900 feet of 18" transite pipe, total static plus flowing head of 133 p.s.i.; and of boiler water 750 g.p.m. capacity through 4,900 feet of 8" transite pipe, total static plus flowing head of 100 p.s.i.

Plant and sanitary water is delivered at 60 p.s.i. calculated at the top edge of the plot to supply hydrants and process equipment. Boiler water is delivered at 10 p.s.i. to flow into the boiler water supply tank at each refinery site.

Clarified water from Grand Valley intake plant is pumped through 28" cement lined steel pipe, capacity 8,000 g.p.m., at 330 p.s.i. discharge pressure, to an automatic booster station along Parachute Creek. Here pressure is boosted to 190 p.s.i., the water flowing through 26" transite pipe up to the West Parachute Dam, total length of line equals 78,000 feet.

Water Plant 2 takes suction from the West Parachute Dam through about 500 feet of 26" transite pipe with a capacity of 8,000 g.p.m.

Water Plant 2 pumps plant and sanitary water to Site B through 500 feet of 24" transite pipe with a capacity of 6,500 g.p.m. and a final pressure of 60 p.s.i., boiler water through 500 feet of 12" transite pipe with a capacity of 1,500 g.p.m. and a pressure of 10 p.s.i.

The second system starts with the De Beque intake plant (Water Plant 3) where clarified water is pumped through cement lined 28" pipe with a capacity of 8,000 g.p.m. at a pressure of 200 p.s.i. up to a booster

station. This automatic booster raises pressure to 190 p.s.i., pumping the water through a 26" transite pipe to the Roan Dam. Total length is 67,000 feet.

Water Plant 4 takes suction from Roan Dam through about 500 feet of 26" transite pipe with a capacity of 8,000 g.p.m.

Water Plant 4 pumps plant and sanitary water to Site C through 29,000 feet of pipe which is cement lined steel at the start at least, as the pumping pressure is 268 p.s.i. and the rate 4,130 g.p.m. Boiler feed water from Water Plant 4 to Site C is 750 g.p.m. capacity, 172 p.s.i. pump pressure through 12" transite pipe.

Water Plant 4 pumps plant and sanitary water to Site D through 22,000 feet of 24" transite pipe with a capacity of 4,130 g.p.m. and a discharge pressure at the refinery site of 60 pounds per square inch. Boiler water is pumped through 22,000 feet of 10" transite pipe with a capacity of 750 g.p.m., and a discharge pressure of 10 p.s.i.

Flocculation type clarification units are to be provided at Water Plants 1 and 3 to remove turbidity and partially soften the entire volume used. Such processing is to consist of treatment in a Graver or similar reactivator type clarifier by the addition of lime and Ferrisul or similar coagulant, and for the recirculation and removal of sludge.

The treating units at the damsites will each serve 100,000 barrels refining capacity and the smaller one at the main Colorado River pumping station will serve the 50,000 barrel refinery near Grand Valley. They will pass the water through rapid sand filters and then treat process and boiler water separately.

Cooling tower water treatment involves acidification of filtered water in the smaller section of one of two clearwells provided in each treating plant.

Acid is added on automatic control to hold pH to just under the calcium carbonate scaling point as indicated by Langlier's Index. This pH control is variable. Cooling water is further treated by chlorine injection to control algae. Sodium dichromate or other corrosion inhibitor is added at the refinery site to insure satisfactory heat exchanger life.

Boiler plant water is acidified in the second clearwell to pH of 6.8. This water is then zeolite softened. Sufficient zeolite softeners are provided at each plant to permit regeneration.

Separate lines from the treating plants to the refinery sites are provided for treated process water and softened boiler feed water.

A power transmission line to serve the pumping stations will be needed. Power requirements for pumping and treating, as well as transfer of by-product waters to the mine sites total 10,000 KW. The pumping facilities are sized to pump at double the average rate of consumption.

Treated Water Storage

In addition to raw water storage outlined above, for the three 50,000 barrel units located near Cottonwood Gulch, Conn Creek and Clear Creek respectively, concrete storage reservoirs of 6,000,000 gallons capacity are provided for treated cooling water. These represent approximately two days usage each of treated water. For the 100,000 barrel unit near the forks of Parachute Creek, a similar concrete tankage of 10,000,000 gallons capacity is provided. These reservoirs are to be located up hill to give a static pressure at the plant of about 60 p.s.i.

Storage of treated boiler feed water is provided at each processing site in steel tankage to the extent of two days average usage. This requires a 28,000 barrel tank.

N.P.C. Engineering
Subcommittee Report June 1, 1951

A distribution system for sanitary drinking water is provided at each processing site as well as to all mines and retorting units.

High pressure fire water pumping equipment with a capacity of 4,000 g.p.m. is provided in each processing unit.

The attachments detail the cost estimate of the 250,000 B/CD water system which may be summarized as follows:

Item No.	Item	Cost	Tons of Steel
203	Water Reservoirs	$1,028,000	190
204	Water Distribution System (including all pumps)	17,720,000	5,080
205	Colorado River Pumping Plants (and clarification, less pumps)	1,532,000	620
209	Water Treating Systems	1,125,000	450
211	High Pressure Fire Water (included in Items 204 and 205)	-	-

The item numbers are those set forth in the agenda of the January 9, 1951 meeting of the N.P.C. Shale Oil Engineering Subcommittee.

Operating costs for the water facilities of the project are estimated as follows:

Treating costs are estimated at about $0.14/ 1,000 gallons, exclusive of electricity. Since consumption is estimated at about 12,500 gallons per minute, cost per day is $2,520.

It is planned that by-product water from the retorts can be used for mine wetting water. Such by-product water will be processed through separators and

steam stripped to remove ammonia and other contaminants prior to being stored or used. Excess will be discharged with treated plant effluent water.

Refinery Sewerage

Nationwide sentiment against stream pollution applying particularly to the Colorado River, which supplies drinking water to important metropolitan centers such as Los Angeles, dictates against discharging objectionable waste from the shale oil project into the stream. Thus each plant designed should provide for API separators to remove oily waste, and steam stripping or other adequate purification of water containing obnoxious materials.

In the plants proper separate drainage systems should be provided leading to near-by streams to handle storm runoff waters and other uncontaminated waste waters. This avoids overloading the separator and other facilities with water not needing treatment.

Sanitary sewerage is to be processed in separate small septic tanks, from which the effluent can drain to the storm water system.

Waste waters from the retorts and coking units will contain such objectionable materials as tar acids, tar bases, hydrogen sulfide, mercaptans and ammonia. These streams, therefore, prior to entering the API skimming ponds should be steam stripped and the recovered gases fed into furnaces.

It should be recognized that effluent waters from a shale oil project represent a difficult disposal problem.

Estimated cost of the liquid waste disposal facilities may be summarized as follows:

Item No.	Item	Cost	Tons of Steel
802	Sewerage and Industrial Water Disposal	$11,234,000	600

Operating cost for the above industrial facilities is estimated at $1,750 per day, including labor, materials and maintenance. A total of 70 employees are estimated to be required to operate the facilities.

N.P.C. Engineering
Subcommittee Report June 1, 1951

Municipal Water Supply

Water for the city of 75,000 inhabitants supplying the workers and located presumably in the De Beque area is also to be supplied from the Colorado River. The total requirements of 5,200 g.p.m. represent a per capita consumption of 100 gallons per day per person. Besides pumps, mains, treating facilities, etc., a standpipe system comprising two concrete reservoirs holding 48 hours supply of potable water and located on higher ground above the city is planned.

A suction basin in the Colorado River is to be provided to supply the pumping station. Water treatment in an adjacent plant is to include sedimentation, filtration, softening by lime-soda to not over 200 ppm, aeration and chlorination. Pumping facilities for the treated water are provided and also distribution mains for the city, buried to a minimum depth of three feet.

City Sewerage

Sewer mains and gathering system are to be provided with connections up to each house. A treating plant will process this sewage, discharging the effluent into the Colorado River. Capacity is to be 5,000 g.p.m. of city sewerage. Sewerage processing is to include grit removal, sludge settling, sludge digestion and trickling filtration of effluent water prior to discharge into the Colorado River.

Cost of Municipal Water and Sewerage Systems

The investment for the suction basin, water treating plant, two standpipe storage tanks and water distribution system for the new municipality of 75,000 people is estimated at $10,030,000. The steel requirements are 1,250 tons.

The sewerage system, including mains, pumping stations and treatment plant is estimated to cost $7,500,000, and to require use of 400 tons of steel.

It is assumed that operating costs for these facilities will be borne by the municipality. Return on this investment should be realized from water charges to the city's inhabitants.

Summary

Summarizing, investment of $32,639,000 has been estimated to be required for the 250,000 barrel per calendar day N.P.C. Shale Oil Project for industrial water supply and liquid waste disposal. These facilities require 6,940 tons of steel. Size of these facilities permit, to a major extent, conventional water cooling. Pumps and line sizes are chosen to permit transferring of water at double the average rate of consumption.

The municipal water and sewerage systems for the new municipality of 75,000 inhabitants are estimated to represent an investment of $17,800,000 and 1,250 tons of steel are required.

CKV-FCD:jm

File: R-13.11A

Associated, California
June 1, 1951

N.P.C. ENGINEERING SUBCOMMITTEE REPORT ON SYNTHETIC FUEL COSTS - WATER SUPPLY AND SEWERAGE

I-B DESCRIPTION
50,000 BARREL PER DAY SHALE OIL PROJECT

General bases for the 50,000 barrel per day project may be assumed to be the same as for the 250,000 barrel per day project. Since the plant site "A" near Grand Valley appears to present the fewest problems this has been selected. In this case no dam is required, and the lines from the treating plant on the river to the plant are of minimum length.

Water requirements may be summarized as:

Withdrawal from Streams

Retorting and mining	none
Refining	2,380 g.p.m.
Sanitary	90
Total industrial water	2,470 g.p.m.

Effluents Returned to Streams

Retort water by-product to sewer after use in mining	133 g.p.m.
Sanitary and processing effluent	453 g.p.m.
Net required	1,884 g.p.m.

In addition, municipal water requirements are estimated to be as follows:

N.P.C. Engineering
Subcommittee Report I-B June 1, 1951

Total population	15,000
Water requirement:	
Consumption	1,040 g.p.m.
Pumping capacity	3,200 g.p.m.
Storage capacity for treated potable water	2 days
Treated sewage returned to River	692 g.p.m.

Total water removed from the Colorado for the entire project would therefore be 3,510 g.p.m. Treated sewage and other effluent to the extent of 1,278 g.p.m. will be returned to the river, making a net consumption of 2,232 g.p.m.

Treatment would be at the site given as Water Plant 1, on the river, and would be the same as for Refinery Site A in the 250,000 barrel project. Treated water storage consisting of a concrete reservoir of 6,000,000 gallons capacity would provide for storage of treated water. Treated boiler water is stored in a 28,000 barrel steel tank.

Sanitary water distribution is supplied at refinery, retort and mine sites.

Fire fighting water is supplied by a booster pump at the refinery site, using the process water distribution mains.

It is planned that retort water will be steam stripped for odor removal and used for mine operations.

In accordance with numbered items in the agenda of the January 9, 1951 meeting of the N.P.C. Shale Oil Engineering Subcommittee break-down of the industrial items are as follows:

N.P.C. Engineering
Subcommittee Report I-B June 1, 1951

Item No.	Item	Estimated Cost	Steel Tons
203	Water Reservoirs	None	
204	Water Distribution System (including all pumps)	$1,635,000	610
205	Colorado River Pumping Plants (and clarification, less pumps)	250,000	100
209	Water Treating Systems	282,000	115
211	High Pressure Fire Water (included in Items 204 and 205)	-	-
	Sub Total - Water System	$2,167,000	825
802	Sewerage and Industrial Water Disposal	2,297,000	175

Summarizing, a total investment of $4,464,000 has been estimated to be required for the 50,000 barrel per day project. It should be recognized that this project utilizes the simplest refinery site as far as water supply is concerned, and provides for a minimum of treated water storage. These facilities require 1,000 tons of steel.

Operating costs are estimated at about $0.14 per 1,000 gallons, exclusive of electricity. Since consumption is estimated at about 2,500 gallons per minute, cost per day equals $504.00.

Municipal water and sewerage are similar to those planned for the larger project, but scaled down in size.

Municipal water supply for a new city of 15,000 to support the 50,000 barrel per calendar day shale project is estimated to represent an investment of $2,500,000, and to require 210 tons of steel.

The municipal sewage system will cost approximately $2,000,000, and require 110 tons of steel.

CKV-FCD: jm

II-A SPECIFICATIONS - WATER SYSTEM FOR 250,000 BARREL PER DAY SHALE PROJECT

	Estimated Cost	Tons of Steel Required
2 Colorado River Pumping Suction Basins and Intake Pumps for Water Plants 2 and 3 (including high pressure and low pressure pumps, manifolding and fire booster pumps) Total withdrawal capacity 21,000 g.p.m.	$1,907,000	380
Water Plant #1 (clarification and pumping capacity for 13,000 g.p.m., filtration, pH control, partial softening of 4,800 g.p.m.)	1,032,000	420
Water Plant #2 (filtration, pH control, partial softening and pumping capacity for 8,000 g.p.m.)	562,500	225
Water Plant #3 (clarification and pumping capacity for 8,000 g.p.m.)	500,000	200
Water Plant #4 (filtration, pH control, partial softening and pumping capacity for 8,000 g.p.m.)	562,500	225
Transfer lines for raw and treated water including:		
20,000 feet 28" O.D. cement lined steel 350# pipe		
10,000 feet 22" O.D. cement lined steel 300# pipe		
125,000 feet 26" 200# transite pipe		
22,000 " 24" " " "		
20,000 " 20" " " "		
4,900 " 18" " " "		
29,000 " 12" " " "		
22,000 " 10" " " "		
1,000 " 26" 100# transite pipe		
500 " 24" " " "		
500 " 12" " " "		
4,900 " 8" " " "		
Plus necessary fittings and valves	8,125,000	2,000

Specifications - Water System - Cont'd.

	Estimated Cost	Tons of Steel Required
Parachute Dam - 800 acre-feet capacity	$338,000	100
Roan Dam - 1300 acre-feet capacity	690,000	90
Water distribution at 5 refinery sites including process, sanitary and boiler water lines, fittings and tankage	4,648,000	1,500
Piping between refineries and retort areas and mines, pumps, valves, fittings, storage tanks. Also distribution lines in retort and mine areas	3,040,000	1,200

II-B SPECIFICATIONS - LIQUID WASTE DISPOSAL SYSTEM FOR 250,000 BARREL PER DAY SHALE PROJECT

	Estimated Cost	Tons of Steel Required
Sanitary sewage facilities for five 50,000 bbl. refineries consisting of sewers, septic tanks, drains to storm sewer lines for refineries, retorts, mines (capacity 3,000 g.p.m. of effluent)	$970,000	55
Storm drains, refinery area for all non-oily water, includes manholes and clean-out points Approx. 55,000 linear ft. 54" transite pipe 35,000 " " 42" " " 150,000 " " 18" " " 2-1/2 miles of open ditch 20'x6' concrete lined	7,500,000	175
Plant drains for all oil-bearing water, includes manholes and clean-out points	1,781,500	135
Water disposal facilities - includes API type separators on oily plant water and strippers at refinery and retort sites to strip retort water being returned to mines, and effluent to sewers	682,500	225

Operating costs for project sewerage are estimated at about $100.00 per day.

II-C SPECIFICATIONS - MUNICIPAL WATER SYSTEM FOR CITY OF 75,000 INHABITANTS SUPPORTING 250,000 BARREL PER DAY SHALE PROJECT

		Estimated Cost	Tons of Steel Required
Suction Basin - Colorado River including pumps (capacity 15,600 g.p.m.)		$200,000	75
Water Treating Plant 6,000 g.p.m., including pumps		1,500,000	350
Two 8,000,000 gallon standpipe tanks (concrete)		600,000	110
Distribution System			
18 Miles 16" and larger pipe, transite 120#		4,000,000	
8" Pipe and smaller		2,000,000	315
House connections, Fire plugs, Valves and fittings	Estimated at 33% of large piping cost	2,000,000	
		$10,300,000	850

II-D SPECIFICATIONS - MUNICIPAL SEWER SYSTEM FOR CITY OF 75,000 INHABITANTS SUPPORTING 250,000 BARREL PER DAY SHALE PROJECT

	Estimated Cost	Tons of Steel Required
Sewer mains and gathering system, sewerage pumping stations and one sewerage treatment plant, including grit removal, sludge settling, sludge digestion and trickling filtration. Capacity 5,000 g.p.m.	$7,500,000	400

II-E SPECIFICATIONS - WATER SYSTEM FOR 50,000 BARREL PER DAY SHALE OIL PROJECT

	Estimated Cost	Tons of Steel Required
Colorado River Suction Basin pumping facilities, manifolding	$224,000	60
Water Plant #1 (clarification, filtration, pH control, softening)	532,000	215
Transfer lines for raw and treated water	90,000	20
Water distribution at refinery sites	713,000	300
Piping between refineries and retort areas and mines, pumps, valves, fittings, storage tanks. Distribution lines in retort and mine areas	608,000	230
	$2,167,000	825

II-F SPECIFICATIONS - SEWERAGE AND LIQUID WASTE DISPOSAL FOR 50,000 BARREL PER DAY SHALE OIL PROJECT

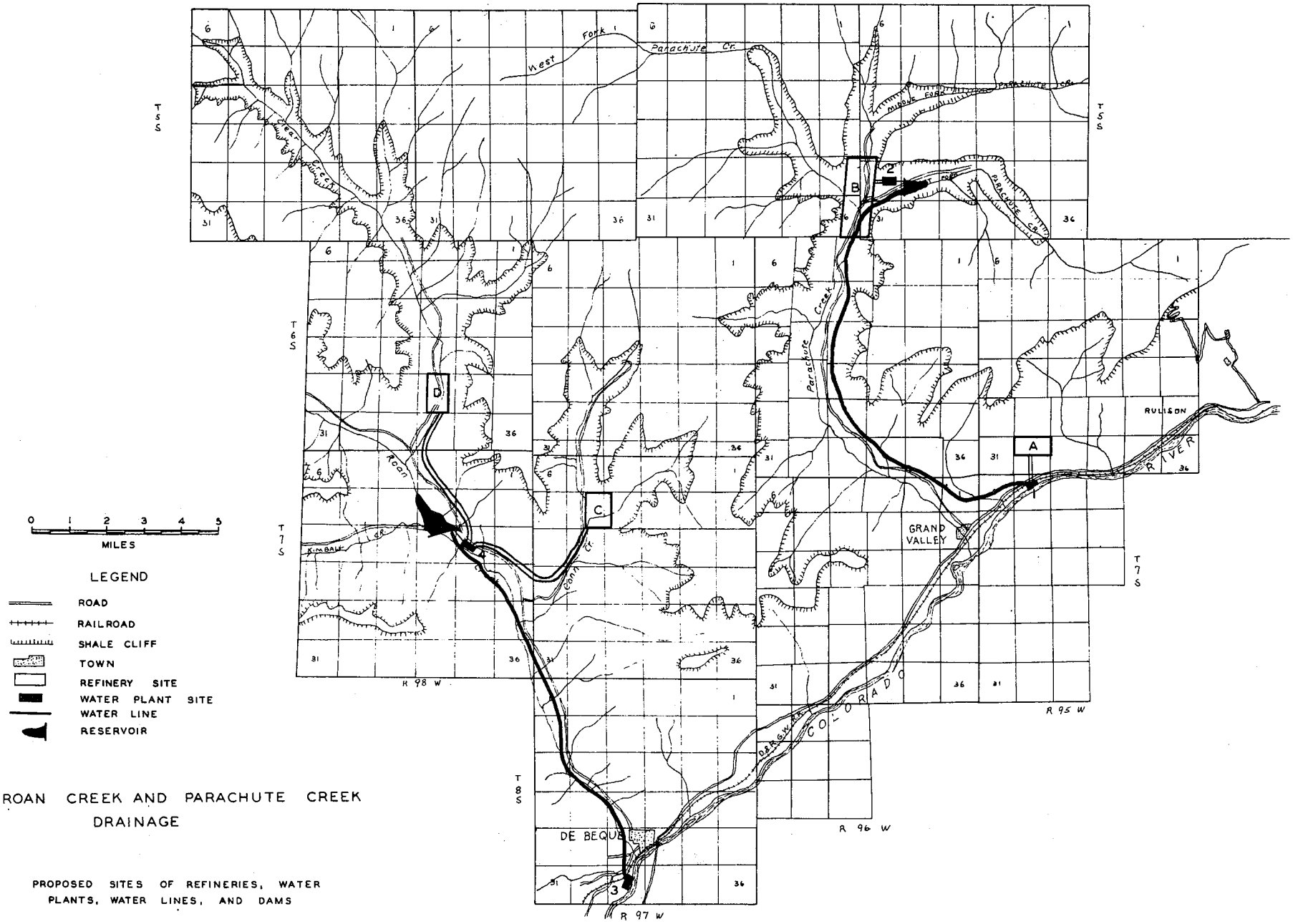
	Estimated Cost	Tons of Steel Required
Sanitary sewage facilities	$194,000	11
Storm drains, refinery area, for all non-oily water	1,500,000	35
Plant drains, refinery area, for all oily water	356,000	27
Water Disposal facilities	187,000	100
Storm drains - retort area	60,000	2
	$2,297,000	175

II-G SPECIFICATIONS - MUNICIPAL WATER SYSTEM FOR CITY OF 15,000 SUPPORTING 50,000 BCD SHALE PROJECT

	Estimated Cost	Tons of Steel Required
Suction basin, Colorado River, pumping capacity 3200 gpm; Water treating plant, capacity 1200 gpm; standpipe tankage with capacity of 3,000,000 gallons; distribution system	$2,500,000	210

II-H SPECIFICATIONS - MUNICIPAL SEWAGE SYSTEM FOR CITY OF 15,000 SUPPORTING 50,000 BCD SHALE PROJECT

	Estimated Cost	Tons of Steel Required
Sewer mains and gathering system; pumping stations; treatment plant including grit removal, sludge settling, sludge digestion and trickling filtration. Capacity 1000 gpm	$2,000,000	110



ROAN CREEK AND PARACHUTE CREEK DRAINAGE

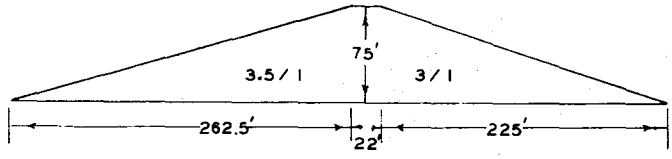
PROPOSED SITES OF REFINERIES, WATER PLANTS, WATER LINES, AND DAMS

EXHIBIT XI

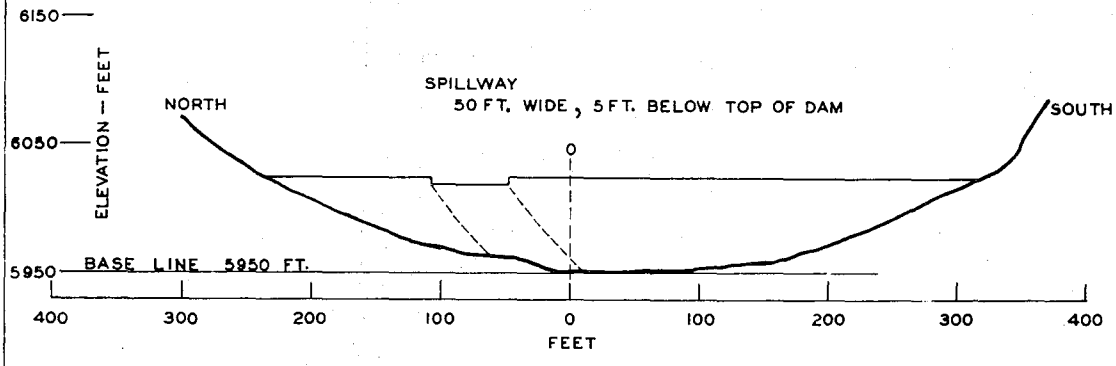
C104

F.C.D 318 5-9-51

G105



MAXIMUM CROSS-SECTION 0-0



PARACHUTE DAM

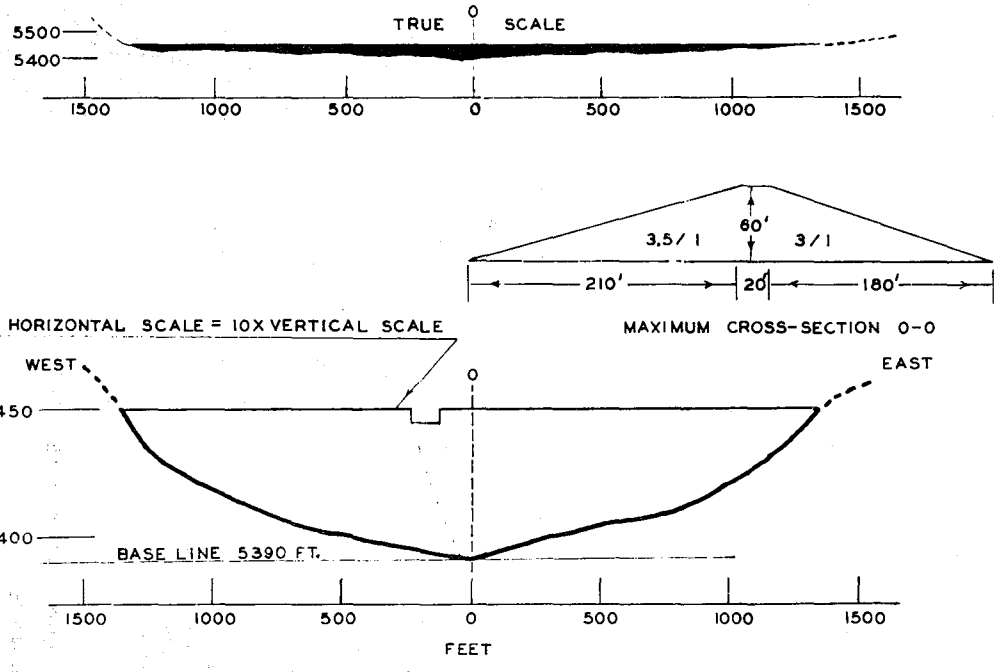
ESTIMATED STORAGE — 800 ACRE FEET

236,000 CUBIC YARDS OF EARTH

555 FT. LONG AT TOP

75 FT. MAXIMUM HEIGHT

22 FT. WIDE AT TOP



ROAN DAM

ESTIMATED STORAGE — 1300 ACRE FEET

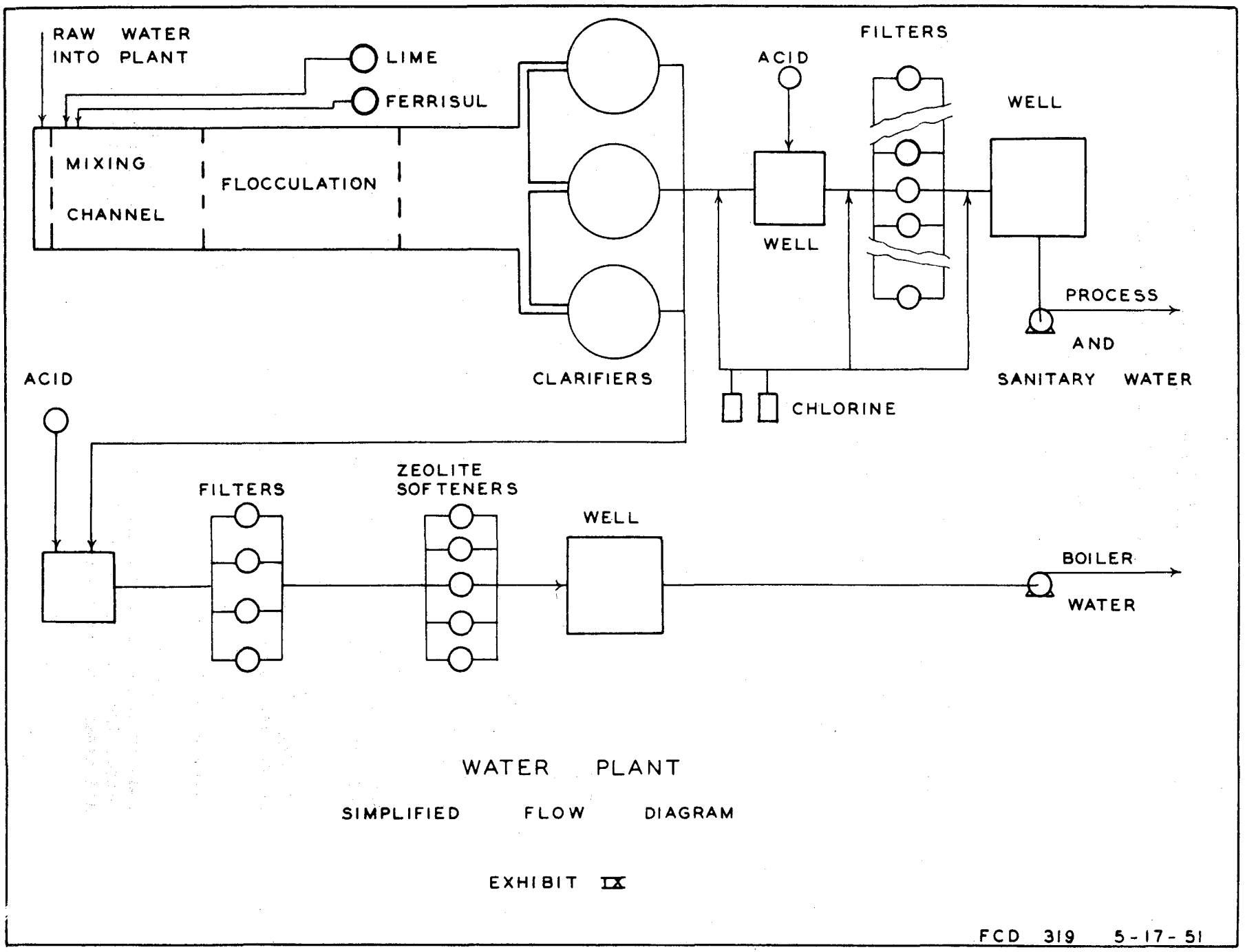
317000 CUBIC YARDS OF EARTH

2700 FT. LONG AT TOP

60 FT. MAXIMUM HEIGHT

20 FT. WIDE AT TOP

EXHIBIT VII



WATER PLANT

SIMPLIFIED FLOW DIAGRAM

EXHIBIT IX

FCD 319 5-17-51

G106

N.P.C. SHALE OIL ENGINEERING COMMITTEE

STEAM DISTRIBUTION - ITEM 207

Description of Facilities

50,000 Bbl. Refinery

The design of the Steam Distribution System covered in this report is based on the following assumptions:

(1) That the Steam Power Plant be centrally located along the upper end of the Refinery Site.

(2) That the Refining Units be contained in an area 1000' x 3000' directly below the Power Plant.

(3) That the operating and maintenance buildings be grouped together and located still farther down the canyon.

(4) That the Refining Unit Estimates carry their steam lines to the Battery Limits.

The steam consumptions shown in the report are yearly averages based on 90% utilization. These figures were increased by 15% to represent maximum operating demand and the steam lines designed to allow of 25% (approx.) additional growth.

It is proposed to feed the refinery area proper from a looped 12" line carried on pipe supports. The loop would be sectionalized at each point of major take-off to allow of partial isolation as necessary.

The system was supplied with the necessary expansion joints, drop-out pots and traps. In the case of the refining units, lines were extended to the Battery Limits.

An allowance of 2000' of 6" underground line was allowed for supplying the Administrative and Maintenance Buildings and the steam lines were carried to the buildings.

Main steam meters and individual meters for the refining units were included.

In the case of the 250,000 bbl. operation it was assumed that it would be uneconomical to supply steam to the Administration Center from the Cottonwood Gulch Refinery. Distances were too great and steam demands seasonal.

AIR COMPRESSOR PLANT - ITEM 210

Section 1

Description

The air compressor plant serves two functions: (1) instrument air supply, and (2) high pressure air supply. The capacity of the system is 2,000 cu ft per minute and the component parts of the plant are:

Engine building, reinforced concrete 50' x 100' floor space
2 - 300 HP synchronous motor-driven, 2 stage air compressors
Heat exchanger and after coolers
Air cleaners
Dewatering drums
Pipe, fittings, unions, gaskets and bolts
Valves

Specifications

Commodity:	Compressed Air
Pressure-Temperature Rating:	175 psig calculated (API 5-G-1)
Elevation:	5,500 feet above sea level
Compressors:	2 - Type OCE 20-1/2 - 12 x 12, 300 RPM 2 Stage Chicago Pneumatic Tool Company, or equivalent
Motor:	2 - 300 HP Synchronous Motors, unity power factor, 2300 volt, 3 phase, 60 cycle, with separate belt-driven exciter
Motor Starters and Switchgear:	Standard heavy duty metal clad equipment, synchronous motor, full voltage, unloaded start
Air Receivers:	ASME Code - Master surge vessels, 150 psig at 600 cu ft and 20 psig at 1,800 cu ft
Heat Exchangers and After Coolers:	ASME Code
Dewatering Drums:	ASME Code
Valves:	Nordstrom, or equal
Pipe:	Seamless carbon steel

TANKAGE

1. Description of Facility

Tankage to support on "integrated" shale oil development includes crude shale oil refinery-feed storage; intermediate storage of unfinished oils at each Colorado refinery;a tank farm at the head end of the products pipe line; drainage tanks at the terminal end of the line; and feed, blend and finished product tankage at California refining facilities. Tankage also is provided to store and ship by-product ammonia from the Colorado refineries.

All tank storage facilities included in this estimate are shown on the enclosed Flow Diagram, Drawing GT-4676. Crude shale oil from small heated retort run-down tanks, considered on-plot, flows by gravity through an insulated line to heated refinery feed tanks. Intermediate storage is provided at each refinery for coker naphtha, coker gas oil, reformed gasoline, hydrogenated Diesel, and ammonia. Reformed gasoline and Diesel oil are transported via a gathering system to storage tanks located near the town of DeBeque at the head end of the Colorado-California products pipe line. The pipe line feeds directly to Los Angeles area refineries where feed tankage for Diesel oil, reformed gasoline isprovided. The necessary tankage for naphtha rerunning, catalytic cracking and polymerization, and storage of finished products are shown.

Ethyl blending plants for leading market gasolines also are included as they would be located near the tankage areas in Colorado and Los Angeles and are outside process boundaries. 5,000 B/D local product distribution is assumed for both the 50,000 B/D and the 250,000 B/D cases, and a 2100 B/D ethylizing plant has been provided in Colorado for this purpose. In Los Angeles, ethylizing plants to handle 42,300 B/D regular and premium grade gasolines are provided at each refinery. The operating and maintenance personnel for the plants are included in the appropriate tankage summary sheets.

Specific tankage requirements are summarized under the following item numbers:

Item 401--Crude Shale Oil - Refinery Feed Storage

Crude feed tankage is 500,000 bbl. per refinery. This provides a maximum storage for refinery feed stock of approximately ten days.

Fintube type steam heaters are provided for heating the crude oil feed tanks. Also included in this item are steam lines from refinery boilers for tank heating and crude feed lines with necessary valves from the tanks to the process boundary. Crude feed pumps are considered to be items of process equipment.

Item 402--Unfinished Oils - Colorado and Los Angeles Refineries

Colorado tankage facilities include ten days' storage capacity for coker gas oil and coker naphtha. Product storage of approximately three and one-half days is provided at each refinery for the intermediate hydrogenated Diesel oil and reformed gasoline. Lines and valves to process boundaries, but no pumps, are included in this item.

Los Angeles tankage includes new feed storage at refineries for approximately ten days' supply of intermediate Diesel oil and reformed gasoline. These two stocks will be received batchwise directly from the products pipe line and slop tanks are provided at each refinery to collect the major part of the interface mixtures. Process plant product storage is provided for blending the various grades of gasoline produced in the catalytic cracking and polymerization operations. No pumps are included.

Item 403 --Products Pipe Line Terminal Storage

Storage capacity for eight and one-half days supply of Diesel oil and reformed gasoline is provided at a central tank farm located near the town of DeBeque, Colorado adjoining the initial pump station at the head end of the products pipe line. Together with intermediate storage at the refineries, this gives a total of twelve days product storage in Colorado.

Since the intermediate products go directly to the Los Angeles refineries, little storage is provided at the terminal end of the products pipe line. Tankage to relieve possible surges and for line drainage is provided at the Los Angeles distribution terminal. The refinery feed tanks provide approximately ten days terminal storage space.

Item 404--Finished Oils

Approximately 35 days storage is provided for finished products; premium and regular grade gasolines and Diesel oil. It is common practice when making additions to an existing refinery to provide 30 or more days storage for finished products. This allows capacity to absorb variations in seasonal demand and shipping rates.

In addition, 10,000 bbl. storage capacity is included in Colorado for local gasoline distribution and is equipped with tank mixers for ethyl blending. Colorado Diesel sales are to be drawn directly from the pump station storage.

Item 405--Chemical Storage

Storage capacities for liquid anhydrous ammonia of three and one half days refinery production are included both at the refineries and the product loading racks at the rail heads. This provides a total of seven days ammonia storage.

No pumps or loading facilities are provided under this item.

2. Specifications

Cone roofs are specified for all crude, Diesel and fuel oil storage tanks, while floating roof tanks are provided for gasoline storage. All tanks are designed for maximum height of forty-eight feet. Tank foundations both in Colorado and California are on rock and oil grades without piling or concrete spreads. Site preparation includes fine grading and firewalls.

Fire protection consists of firewalls around two sides of each tank in Colorado, with firewall between tankage and refinery where applicable. In addition, a dam of the largest tank capacity is provided between tank site and river to prevent possible contamination of the Colorado River. At the Los Angeles refineries firewalls completely surround each tank. High pressure water lines through tank areas also are included.

All tankage cost estimates are based on erection and installation at specified sites in Colorado and California, and include foundations, painting, pipe fittings and necessary appurtenances as well as remote reading gages. Overhead flood lighting throughout the tank areas is provided. Tank mixers for ethylizing are provided in the market gasoline storage tanks.

Liquid anhydrous ammonia is stored in horizontal pressure drums. Reinforced concrete foundations, lines to process boundaries and appurtenances are included.

PIPE LINES AND PUMPING UNITS

1. Description of Facility

Item 501--Crude Shale Oil Lines

The typical 50,000 B/D refinery processes the production from four 19,200 T/D "unit" mines and four 19,400 T/D retorting plants located on benches, some 1500-2000 feet above the refinery site, which is situated on nearby canyon floor. Heated crude shale oil will flow by gravity from retort rundown tanks downhill through an insulated line to refinery feed storage tanks.

The crude oil lines have been sized to handle 25,000 BPD of crude shale oil from each of two general retorting process areas. The lines are placed above ground and are assumed to be parallel to and supported from the retort gas lines. The general layout for a 250,000 B/D project is shown on Drawing GT-4652.

Crude shale oil has a pour point of 90°F, a specific gravity of about 0.93 and a viscosity of 223 SSU at 100°F. Shale oil is assumed to enter the lines at 120°F, and under normal flow conditions, will enter refinery storage at approximately 105°F, when the atmospheric temperature is -20°F. The lines could be designed so that they would drain completely and provisions for heating probably could be eliminated. However, for the purpose of this estimate, a 4 inch heating line has been installed parallel to and insulated with the crude line. Hot Diesel oil could thus be circulated to maintain crude oil temperatures above 110°F. This design permits bringing all crude lines into service within 24 hours. This same auxiliary line might also be used to pump Diesel oil up to the retort and mine yards for use in operating mining equipment (trucks, compressors, etc.)

Item 502--Retort Gas Lines

Process and utility requirements for the entire mining, retorting and Colorado refining program are to be met by using 80 BTU retort gas, as a source of fuel. This gas is piped downhill through large diameter conduits to each refinery site. Utility plants are assumed located directly adjacent to each refinery.

Total project demand (mines, retorts and refinery) for a typical 50,000 B/D development amounts to 840 million SCF/CD, and assuming 90% operating factors on both retorts and refineries, the demand would be 930 million SCF/SD. Total gas production at the retorts amounts to 1,040 million SCF/CD, or 1,160 million SCF/retort SD. Design for the retorts-to-refinery gas lines for a typical 50,000 B/D operation has been based on a combined gas flow rate of 950 million SCF/Day from two retorting

process areas. The lines are sized for a pressure drop from 10 inches of water gage pressure at the retort boundary to a delivery pressure of 5 inches of water at the refinery consuming areas. The Process Committee's report indicates that Bloom type burners will be used to fire this low head gas. A flare and a pressure control valve are provided near each retort area to dispose of excess gas.

The length of gas lines required for a single 50,000 B/D project was taken as the average required for the five refineries as shown on Drawing GT-4680 (see Item 503). A nominal allowance also has been included in the estimate for piping within the refinery area to the various process plant boundaries. A detailed study was made of the gas line layout for the 50,000 B/D Clear Creek refinery, see Drawing GT-4671.

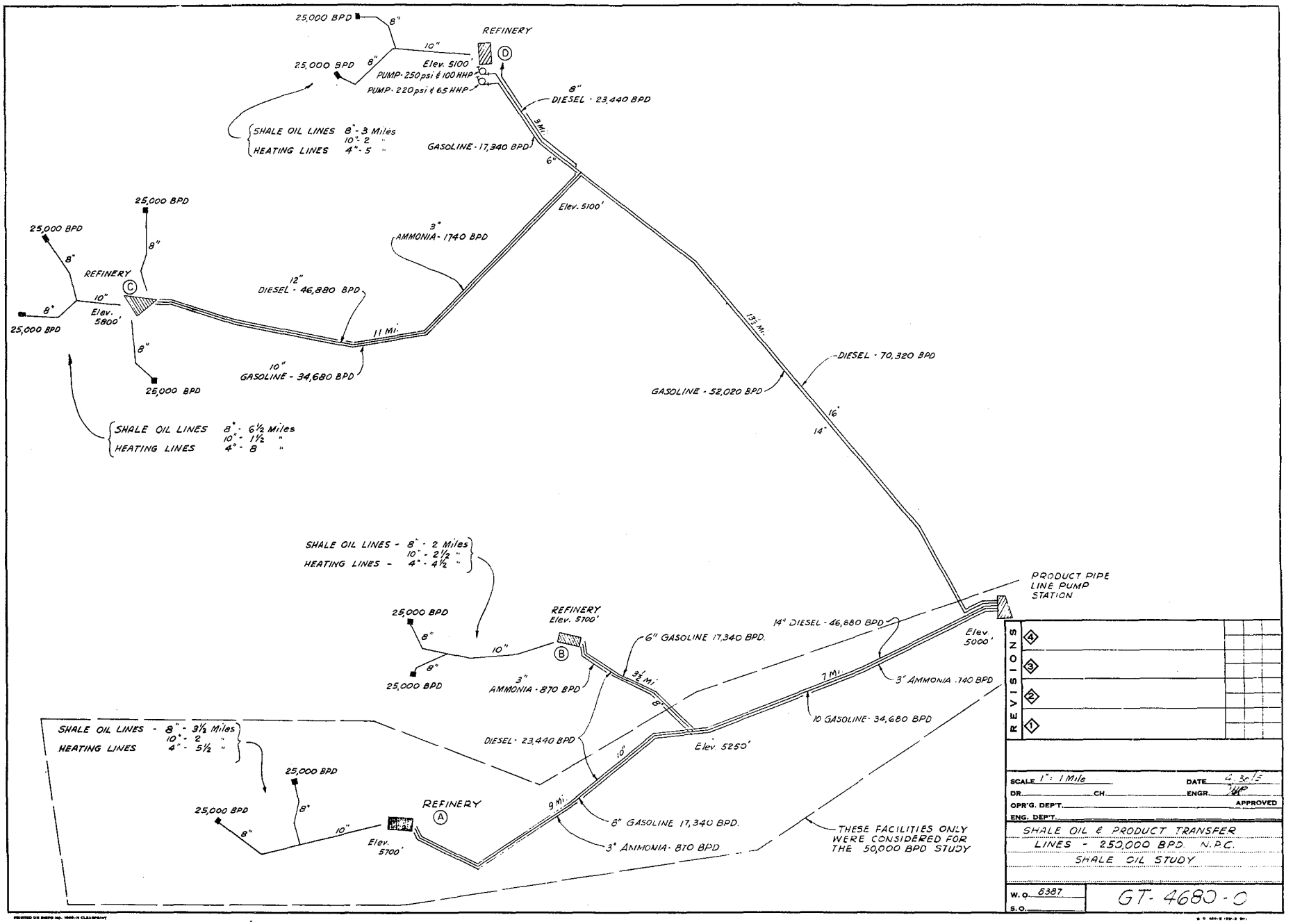
It was assumed for the design of the gas lines that retort gas enters at 124°F and is saturated with water vapor. Taking into account the sensible heat and heat of condensation of water available in the cooling gas stream, it is doubtful that freezing conditions ever will occur in the line even under winter conditions and at lower flow rates. Drawing GT-4678 shows the approximate temperature drop to be expected in these lines when coated on the interior with a 1-inch thick layer of perlite cement. This chart is for severe winter conditions with atmospheric temperatures of -20°F and a wind velocity of 35 mph. If the line temperatures should fall below freezing, some icing would occur, but it would take many weeks of uncommonly severe weather to deposit much of a build-up of ice. Approximately 90% of the water in the gas will be removed by traps as liquid before gas temperatures drop into the freezing range. On the basis of these studies, it is concluded that line heaters are unnecessary.

The tentative design for the retort gas pipe line presented in Part II of Process Committee's report of April 15 has been considerably modified in the final design upon which the estimate is based. Structural details for the estimated line are shown on Drawing GT-4670-1.

Much of the terrain traversed by the gas lines is rough and precipitous, and it probably will be necessary to carry the lines on stanchion supports rather than to cradle them in troughs along the ground. As discussed heretofore it is proposed that the crude lines be carried on these same supports.

Item 503--Intermediate Product Gathering System

The reformed gasoline and hydrogenated Diesel oil products produced at each of the Colorado refineries are first conveyed by pipe line to a terminal tank farm located near the town of DeBeque at the head end of the Colorado-California pipe line. Separate lines are provided for each product.



REVISIONS
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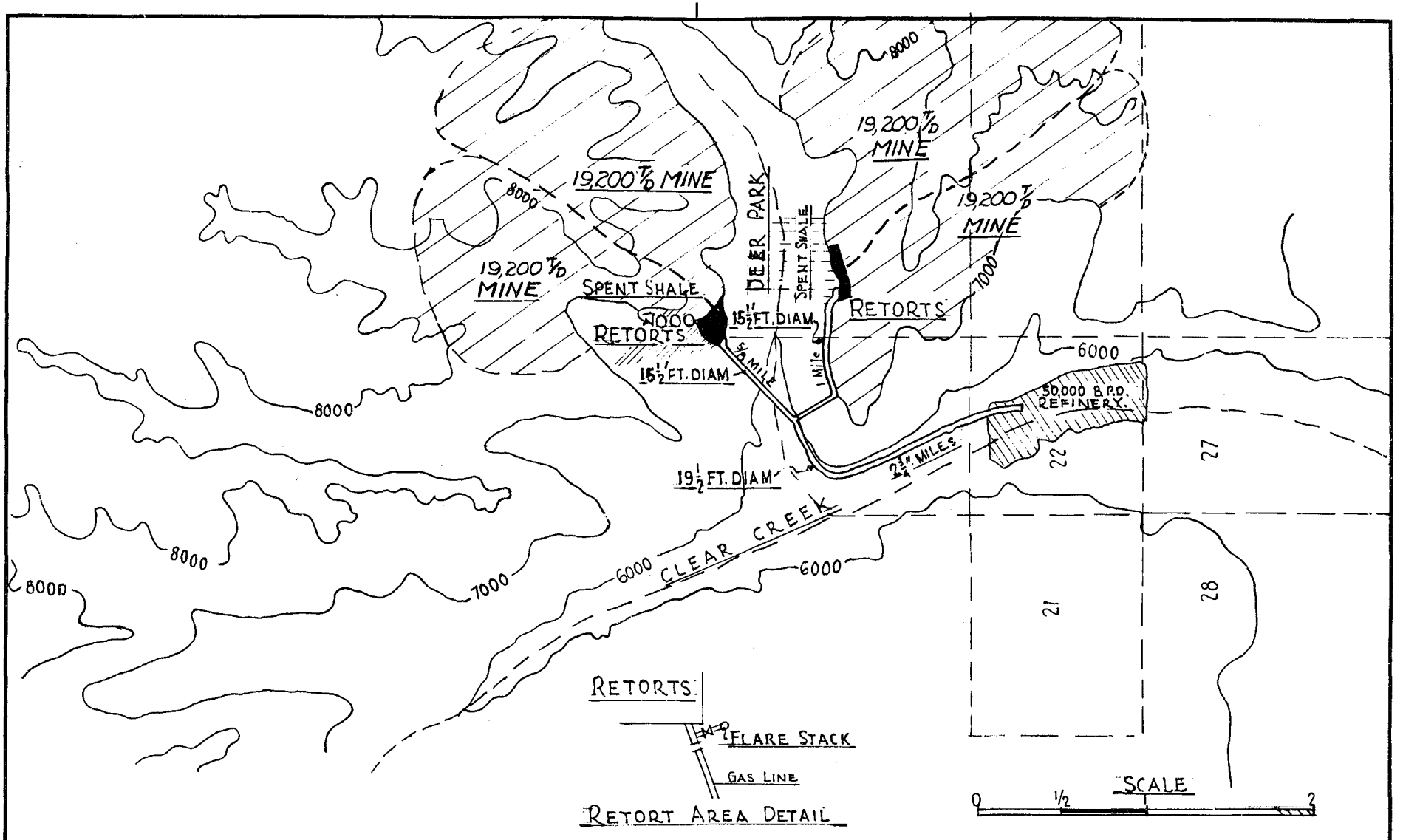
SCALE 1" = 1 Mile DATE 4-30-15
DR. CH. ENGR. WP
OPR'G. DEP'T. APPROVED
ENG. DEP'T.

SHALE OIL & PRODUCT TRANSFER LINES - 250,000 BPD. N.P.C.
SHALE OIL STUDY

W. O. 8387
S. O.

GT-4680-0

PRINTED ON SEPIA NO. 1000-H CLEARPRINT


19,200 T/D MINE
19,200 T/D MINE
19,200 T/D MINE
19,200 T/D MINE
8000
8000
8000
8000
7000
7000
6000
6000
6000
SPENT SHALE
SPENT SHALE
DEER PARK
RETORTS
RETORTS
15½ FT. DIAM.
15½ FT. DIAM.
19½ FT. DIAM.
½ MILE
1 Mile
2¾ MILES
50,000 B.P.D. REFINERY
CLEAR CREEK
22
27
21
28
RETORTS
FLARE STACK
GAS LINE
RETORT AREA DETAIL
SCALE
0
½
1

| REVISIONS | | |

Drawing GT-4680 shows the gathering facilities for the 250,000 B/D project. The lines are designed for gravity flow from all refineries except the one located at Cottonwood Gulch. Pumps are provided to move products from the latter.

Ammonia pipe lines are covered under Item 902.

Item 504--Colorado-to-California Product Line

Products from Colorado refining operations are transported batchwise via pipe line to California for finishing. The initial station for the line was established at DeBeque and the terminal is at Los Angeles. The pipe line route between these two points is approximately 690 miles. An additional 20 miles of line has been included for direct distribution to various refineries in the Los Angeles basin area. Drawing GT-4682 shows the location and profile of the route selected.

For design purposes, it was assumed that the line would be pressured to a maximum of 65% of the pipe yield strength. The heaviest product carried in the line is a Diesel oil having a viscosity of 150 SSU at 35°F. The design assumes the line is buried with a minimum of 24 inch of coverage. Housing facilities for all pipe line personnel have been provided at each station.

The pipe line for the 250,000 B/D program has been designed for a throughput of 200,000 B/D. Five pumping stations are required. Each station is provided with 130,000 bbls. of tankage and requires approximately 3,000 hydraulic HP. The pump stations at DeBeque, Las Vegas and Yermo are assumed to be electric driven. The stations at Green River and Hanksville are assumed to be Diesel drive.

The pipe line for the 50,000 B/D program has been designed for a throughput of 40,000 B/D. As in the previous case five stations are required and an alternative route is shown. The DeBeque, Las Vegas and Yermo stations are electric, while Green River and Escalante would be Diesel drives. Each station is provided with 40,000 bbls. of surge tankage.

2. Specifications

Item 501--Crude Lines

(a) 50,000 BPD Case

Insulated above-ground combination pipe lines including: 3 1/2 miles of 8 inch crude line plus 4 inch heating line; 2 miles of 10 inch crude line plus 4 inch heating line; heating oil tankage (2-5000 bbl. tanks), a heating oil pump (400 BPH at 1100 psi) and an oil heater.

(b) 250,000 BPD Case

Insulated above-ground combination pipe lines including: 15 miles of 8 inch crude line plus 4 inch heating line; 8 miles of 10 inch crude line plus 4 inch heating line; heating oil tankage (10-5000 bbl. tanks); 5 heating oil pumps and heaters.

Item 502--Gas Lines

(a) 50,000 BPD Case

3 miles of 14 1/2 Ft. diameter pipe
2 miles of 18 1/2 Ft. diameter pipe

Pipe carried on stanchion and ring girder supports, expansion joints are provided every 80-100 feet, and electrically heated water draw-off traps are installed every alternate 80 Ft. or as required. The line is covered with external protective coating and aluminum paint. An internal 1-inch thick insulating coat of perlite cement is to be installed.

(b) 250,000 BPD Case

Five 50,000 BPD units.

Item 503--Gathering System

(a) 50,000 BPD Case

17 miles of 10 inch, 250 psi line for Diesel oil
17 miles of 8 inch, 250 psi line for gasoline

(b) 250,000 BPD Case

49 miles of 6-14 inch, 250 psi lines for Diesel oil
65 miles of 8-16 inch, 250 psi lines for gasoline
2 Diesel oil pumps (1000 BPH at 250 psi)
2 gasoline pumps (720 BPH at 200 psi)

Item 504--Product Line

	50,000 BPD Case	250,000 BPD Case
Average length of system	710 miles	710 miles
Line Size	10" and 12"	20" and 24"
Average Throughput		
Diesel	23,400 BPD	117,200 BPD
Gasoline	17,350 BPD	86,700 BPD
Maximum Station Discharge Pressure	1,470 psi	875 psi

FACILITIES: QUARTERS - ITEM 600

Section 1

Description

The entire 250,000 B/D shale oil operation was visualized as being administered from a central staff building located most probably in the business district of a city such as Los Angeles. The building would house the departments and services (i.e., Comptroller's, Marketing, Tax Division, etc.) not directly concerned with any field operations.

The refining and retorting operations would be directed in the case of each 50,000 B/D refinery from a refining administration building located within each refinery. These five separate refinery administrations in turn would report to the staff located in the central administration building previously discussed.

It is not within the scope of this study to include any staffing or services which lie outside of those directly required to operate each 50,000 B/D refinery. Based on this, the following quarters were estimated under the general item 600.

1. Laboratories - Item 602
2. Operating Unit Buildings - Item 603
3. Hospital - Item 604
   (This item is included under Item 603 as Dispensary Facilities.)
4. Other Refinery Buildings - Item 605

FACILITIES: QUARTERS - ITEM 600

Section 2

Specifications

General Administration Building - Item 601

Outside the scope of this study.

Laboratories - Item 602

The laboratory building for each 50,000 B/D refinery to be two stories in height. External walls of building to be constructed of concrete and brick, interior walls to be plastered except certain enclosures, such as offices and other rooms where sectional removable partitions are practical. Reinforced concrete tunnels of adequate size to provide a complete overhead piping and drainage system with full head clearance beneath same. Floor covering to be asphalt tile, plastic tile, terrazzo and concrete, depending upon requirements at particular locations. Adequate heating and ventilating equipment to be installed. Buildings to be approximately 70' x 170', or approximately 11,000 square feet ground area. Laboratory equipment as required to be provided.

Operating Unit Buildings - Item 603

Refinery Administration Building

The refinery administration building for each 50,000 B/D refinery to be two stories in height. Included in this building would be the facilities for a cafeteria and dispensary in addition to the required office space.

Building to be reinforced concrete with metal lath and plaster permanent partitions, and sectional removable metal partitions separating offices. Composition roofing on concrete slab, asphalt tile floor covering and fluorescent lighting. Building to be approximately 45' x 300' or approximately 13,500 square feet ground area.

Building to be furnished complete with steel type desks, chairs, bookcases, reference tables, and other accessories as required. In addition, cafeteria and dispensary equipment to be provided as required.

Office mechanical equipment such as typewriters, calculators, reproduction equipment, file cabinets and accessories to be provided.

Operators' Change House

Operators' change house to be single story building. Construction to be reinforced concrete walls with steel beam roof and steel membrane roof deck with insulated composition roofing. Cement floor slab on grade, quarry tile flooring, terra cotta wainscote, plaster walls, ceramic tile floors in washrooms and toilets. Mechanical heating and ventilating system provided. Building to be equipped with metal lockers on concrete islands. Building to be approximately 45' x 100' or approximately 4,500 square feet ground area.

FACILITIES: QUARTERS - ITEM 600

Section 2

Specifications

Hospital - Item 604

This item is included in Item 603 as Dispensary Facilities.

Other Refinery Buildings - Item 605

Gaugers' Offices

Several isolated buildings are provided with complete facilities for one or two men. Buildings to have concrete floor on grade, concrete block walls, insulated metal roof with composition roofing, asphalt tile floors, electric light and heat, and equipped with enclosed toilet, wash basin, metal lockers and supply and sample storage. Each building to have a floor area in the neighborhood of 300 square feet.

Area Foreman's Office

Several isolated buildings are provided. Buildings to have concrete floor on grade, concrete block walls, insulated metal roof with composition roofing, asphalt tile floors, electric light and heat, and equipped with enclosed toilet, wash basin, metal lockers, and necessary shelving. Each building to have floor area of approximately 600 square feet.

Fire and Safety Service Building

One building required in each 50,000 B/D refinery. Single story building to have concrete floor on grade, concrete block walls, insulated metal roof with composition roofing, asphalt tile floors, electric light and heat, and equipped with enclosed toilet, wash basin, metal lockers and necessary shelving. Each building to have floor area of approximately 1,500 square feet.

Mobile Equipment Shelter

Building to be steel frame, transite covered, concrete floor, heating equipment adequate to prevent freezing. To have adequate facilities to house about fifty cars and trucks. Floor to be approximately 10,000 square feet.

ROADS - ITEM 702

Section 1

Description and Specifications

This item includes the main entrance road from Highway 6 to each 50,000 B/D refinery and all the refinery roads including the refinery tank farm. It does not include the road system connecting the refinery with the retorting and mining sites, or the road system within the battery limits of each refinery unit. The road system extending from the refinery to the retorting and mining sites was included in Item 103 - Retorting Sites.

All roads in this section are designed for heavy traffic and are 24 feet wide. The roads within the refinery and tank farm are to be 3" asphaltic concrete over an approved sub-base. The main entrance roads are to be 3" asphaltic concrete over 6" of crushed rock sub-base. Roads shall conform with Colorado State Highway specifications.

REFUSE - ITEM 803

Section 1

Description and Specifications

This item includes the necessary facilities and equipment to maintain the appearance of the area and dispose of the refuse. In the refinery area, the combustible material will be disposed of in an incinerator and the non-combustible material trucked to an adjacent area requiring fill.

The following equipment and facilities are provided under this item:

1. One Dumpster Truck, complete with an adequate number of pick-up containers for both combustible and non-combustible refuse.

2. Two Trucks, four-wheel drive, equipped with snow plow attachments. These trucks are required in the refinery and retorting areas for snow removal from the 25-mile road system for each 50,000 B/D refinery-retorting operation.

3. One Street Sweeper is provided in each refinery to maintain the streets.

4. One Skip Loader is provided for each group of four retorting plants to maintain the sites free of shale debris.

5. One Incinerator for each refinery to handle combustible material.

TRANSPORTATION AND SHIPPING FACILITIES

1. Description of Facilities

Item 901 - Rail Spurs

The central maintenance shops and material warehouses are assumed to be located near the town of Grand Valley for the 250,000 BPD case. Trackage has been provided to service approximately 400 feet of warehouse frontage on each of four spur tracks. These tracks are assumed to extend beyond the warehouses to open storage areas for pipe, steel, etc.

Spur trackage for shops and warehouses for the 50,000 BPD case is provided on the basis of 1/4 of the above facilities.

In addition, spur trackage has been provided for product shipping from two loading yards, one located east of Grand Valley servicing the Parachute Creek and Cottonwood Gulch refineries, and the other located near DeBeque servicing the Clear Creek and Conn Creek refineries. The general layout of the loading facilities provided at these two sidings is shown on Drawing GT-4679.

Item 902 - Loading Racks

Loading racks for tank car shipment of gasoline and Diesel fuel are provided on the product loading railspur at DeBeque. Facilities for transporting and shipping by-product ammonia also are included under this item.

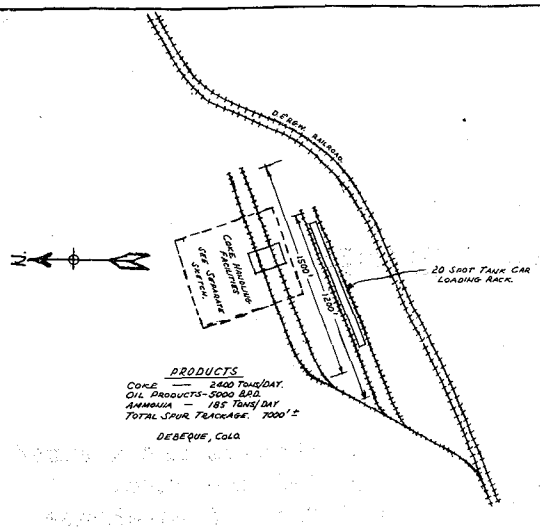
For the 250,000 B/D case, an 8-car loading rack for ammonia shipment is provided at Grand Valley. A 20-car loading rack for 5,000 B/D of oil products as well as ammonia shipment is provided at DeBeque. Ammonia product lines from each refinery to the appropriate rail spurs convey 275 T/D anhydrous ammonia to the Grand Valley loading facilities, and 185 T/D to those at DeBeque.

Item 903 - Coke Handling and Shipping Facilities

A. Trucking Facilities for Coke

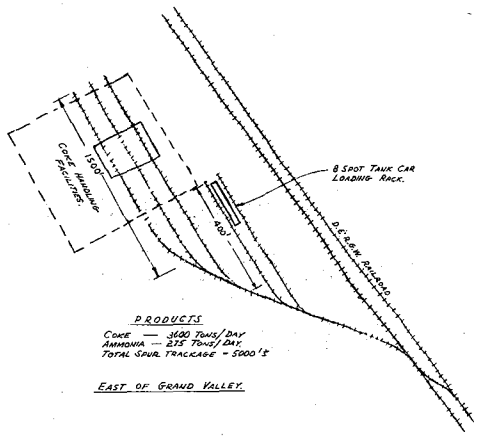
Trucks have been provided to haul the coke from the refinery site to railroad terminal facilities. The equipment required to load the trucks has not been included in this estimate. Diesel truck and trailer units having a capacity of 23 tons have been selected for this service. These trucks conform to the legal requirements of the State of Colorado. For the purpose of this estimate we have assumed an operating factor of 18 hours per day. The estimate is based on handling 6,000 tons of coke per day for the 250,000 bbl. per day case and 1,200 tons per day for the 50,000 bbl. per day case.

G123



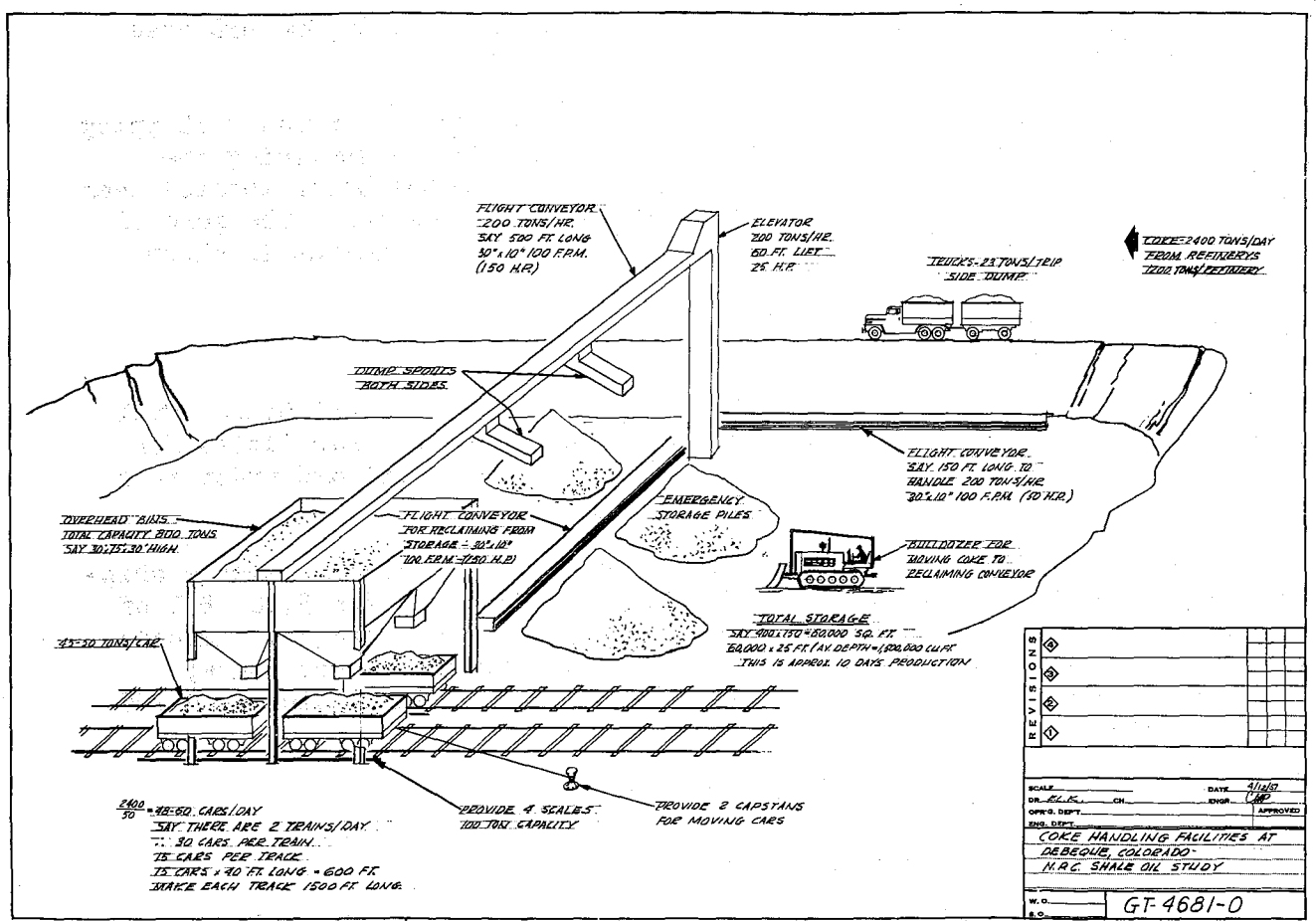
PRODUCTS
COKE — 2400 TONS/DAY.
OIL PRODUCTS - 5000 B.P.D.
AMMONIA — 185 TONS/DAY
TOTAL SPUR TRACKAGE. 7000'±

DEBEQUE, COLO.



PRODUCTS
COKE — 3600 TONS/DAY
AMMONIA — 275 TONS/DAY.
TOTAL SPUR TRACKAGE - 5000'±

EAST OF GRAND VALLEY.



REVISIONS

SCALE	DATE 4/1/60
DR. EL.K. CH.	ENGR.
OPR'G. DEPT.	APPROVED
ENG. DEPT.	

COKE HANDLING FACILITIES AT
DEBEQUE, COLORADO
N.R.C. SHALE OIL STUDY

W.O. GT-4681-0
S.O.

B. Handling Facilities at DeBeque and Grand Valley

The general layout of the loading facilities at the railroad siding is shown on Drawing GT-4681. The trucks hauling coke from the refinery areas dump the coke onto flight conveyors and a bucket elevator which fills an overhead storage bin. The rail cars are filled from this overhead bin. A storage area is provided to dump coke when the rail loading car facilities are inoperative. The conveyor is provided to handle coke from this storage area and to the overhead loading bin. The storage bin has been sized for 8 hours supply. Loaded railcars will be weighed by means of railroad track scales. Loading facilities are required at both DeBeque and Grand Valley for the 250,000 bbl. per day case. The loading facilities will be required only at DeBeque for the 50,000 bbl. per day case.

2. Specifications

	50,000 BPD Project	250,000 BPD Project
Item 901 - Rail Spurs		
Trackage for shops and warehouses	2,500 ft.	10,000 ft.
Trackage at Loading Yards		
Grand Valley	-	5,500 ft.
DeBeque	4,300 ft.	5,500 ft.
Item 902 - Loading Racks		
Ammonia Pipe Line - 3"	17 miles	35 miles
Loading Racks		
Grand Valley	-	8 car
DeBeque	20 car	20 car
Item 903 - Coke Handling Facilities		
23 Ton Diesel Trucks	5	20
Coke Handling and Loading Equipment		
Grand Valley	-	300 T/hr
DeBeque	100 T/hr	200 T/hr

SULFUR HANDLING FACILITIES - Item 904

Description

The molten sulfur produced by the Sulfur Plant, Item 112, will be collected in a pile and cooled at each refinery. From the refineries the sulfur will be transported by truck to the rail sidings, Item 901, and dumped into gondola cars. Bulldozers and power shovels will be provided at each refinery to move and transfer the sulfur into trucks.

This estimate includes the trucks, bulldozers, and shovels required for the handling of the sulfur. Equipment requirements are based upon operations two shifts/day, seven days/week.

Specifications

	50,000 B/CD	250,000 B/CD
Dump Trucks Required (10 tons capacity)	2	8
Bulldozers Required	1	5
Power Shovels Required (0.5 cubic yard capacity)	1	5
Sulfur to be Handled, tons/CD	43	215

September 13, 1951

ECONOMICS OF COAL HYDROGENATION, ROCK SPRINGS, WYOMING

INTRODUCTION

The economics of coal hydrogenation at Rock Springs, Wyoming, are presented based on the process set forth by the Bureau of Mines. These economics are consistent with the raw material, process, and engineering studies carried on by the NPC Subcommittee on Synthetic Liquid Fuels Production Costs. The Rock Springs, Wyoming, location has been studied in detail by the Subcommittee and is the site originally picked by the Bureau of Mines for the evaluation of the coal hydrogenation process.

A separate report will cover coal hydrogenation on a multi-plant basis in which 216,000 B/D of liquid fuels are produced. Under these conditions, plants were evaluated in various sections of the country operating on various types of coal.

This study develops economics in the same manner as employed by U.S. industries in general for the evaluation of new processes or projects. Throughout the study, all costs or prices have been adjusted to the level of January 1, 1951, in order that this study may be adjusted as economic conditions may change.

DISCUSSION

The attached table and appendices present the evaluation of coal hydrogenation at Rock Springs and the basis for each of the cost items used. Where possible, the determination of these figures was based upon analogous situations, operations, or equipment as found in the petroleum, coal, or chemical industries. Thus, even though no definite operational experience or costs on coal hydrogenation plants were available, it is believed that all major factors have been included and that their magnitude is correct, except where noted in the report.

The cost of producing gasoline via the coal hydrogenation process is materially above the present price of gasoline. A summary of the results presented in the attached table is as follows:

	CASE			
	A	B	C	D
Investment Cost				
Per B/CD of Total Liquid Fuels	$18,500	$22,400	$20,600	$19,000
Per B/CD of Gasoline	$24,600	$29,800	$27,400	$25,200
Cost of Gasoline Including 6% Return, ¢/Gal.	39.1	43.0	41.4	39.8

In the foregoing table, it will be noted that the cost of gasoline has been developed for four different situations. The variations are due to housing expenditures, which are discussed later in this report.

The cost of gasoline was determined by assigning reasonable prices to the by-products and deducting this by-product income from the total plant costs. The by-product credits, and their effect in reducing the cost of gasoline, are shown in the following table:

By-Product	Quantity per CD	Price	Value $/CD	Reduction in Cost of Gasoline, ¢/Gal.
LPG	6,390 Bbls	3.0¢/Gal	$ 8,051	0.98
Chemicals				
Phenol	85,000 Lbs	15.8¢/Lb	13,430	1.64
o-Cresol	27,000 Lbs	7.5¢/Lb	2,025	0.25
m,p-Cresol	111,000 Lbs	10.5¢/Lb	11,655	1.42
Xylenols	182,000 Lbs	5.5¢/Lb	10,010	1.22
Total			$45,171	5.51

The prices assigned to the chemicals in the above table are discussed in an appendix attached hereto.

If the approach to chemical by-product credits were based on the eventual construction of, for instance, eight coal hydrogenation plants, it is probable that competition would force the price of these chemicals down to a level only slightly greater than their value as gasoline charge stock. The economics of the Rock Springs coal hydrogenation plant were also determined for the case in which the chemicals are completely converted to liquid fuels (see the companion report on a coal hydrogenation multi-plant basis) and under this condition the cost of gasoline was 0.9 cents per gallon higher.

The credit of 3¢ per gallon which has been assigned to the LPG is based upon a marketing study included in the appendices. It is quite likely that a coal hydrogenation plant will, during the first few years, be unable to dispose of its entire LPG production. This has been historically true in most of the gasoline plants constructed in the United States. After an assured supply is available, it is generally true that markets are developed and reasonable success can be assured for sale of production.

The gasoline obtained from the coal hydrogenation process contains a large quantity of aromatics such as benzene, toluene, and xylene. These aromatics could be separated and sold as by-products or retained in the gasoline stream where they are valuable octane components. Although these aromatics, particularly benzene, have been recently sold at prices of about 50 cents per gallon, a long term price on these products, based on cost indices at January 1, 1951, levels probably would not equal the cost of gasoline (39 to 43 cents per gallon) from this process. Thus there is no justification for setting up another series of cases in which aromatics would be sold separately as by-products.

The four variations in investment cost represent relative levels of responsibility on the part of the project sponsor toward providing housing and

community facilities. Briefly, these cases are:

A - No housing or community development other than that required to house temporary construction workers.

B - Complete housing and community development including (1) housing for employees, (2) housing for tradespeople, teachers, etc., (3) general community facilities, comprised of streets, utilities, schools, etc., and (4) commercial buildings.

C - Housing for employees and general community facilities.

D - General community facilities and housing for temporary construction workers.

Of these four cases, A and B represent, respectively, the minimum and maximum expenditures. Neither of these cases, however, is believed to represent the probable situation. In order to obtain an adequate and stable labor supply at minimum investment, it is the opinion of the Subcommittee that the housing program would approach that of case C. These expenditures are presented in the following table:

	CASE			
	A	B	C	D
	(In Thousands of Dollars)			
Construction Housing (Part of Operating Investment)	$13,200	$ 7,000	$ 7,000	$13,200
Housing for Employees	-	48,000	48,000	-
Housing for Tradespeople and Others	-	33,600	-	-
General Community Facilities	-	12,100	12,100	12,100
Commercial Buildings	-	13,300	-	-
Total	$13,200	$114,000	$67,100	$25,300

For the different categories included under housing and community development, factors representing the excess of rental income over maintenance cost were estimated. They are as follows:

(1) Construction Housing: No return since this housing is utilized only during construction and then salvaged or abandoned and is properly part of the plant investment.

(2) Housing for Employees and Tradespeople: A net income over 20 years of 90% of initial cost was assumed.

(3) General Community Facilities: It was assumed that a new community would not be able to assess taxes during the 20-Year period which would be sufficient to retire an appreciable portion of the investment and so no recovery was included.

(4) Commercial Buildings: The assurance of a stable market for 20 years should permit tradespeople to pay sufficient rents to yield a net income equal to 200% of the investment.

The process royalties, included among the items of investment, have been assigned a cost of $1,000,000. The actual amount could not be definitely determined at this time, due to the absence of established royalties on various portions of the process. Thus, the $1,000,000 cost is a token figure and is probably below the actual cost.

One item, which has been omitted but should be recognized, is the interest on capital expenditures during the construction period. This interest expense cannot be fixed without knowledge of the type of financing involved and the return that the creditors, institutional or private, would require.

A depreciation, or amortization, rate of 5% per year has been used on all items of investment which are deductible for income tax purposes. This rate is believed to be consistent with the composite physical life of the facilities.

The addition of the return on the investment at 6% per year, plus allowance for federal income taxes at a rate of 50%, results in a cost of gasoline of 41.4 cents per gallon under case C. This figure compares with a refinery realization of about 11 cents per gallon for the marketing area considered. As pointed out in the appendices, it is believed that a return of 6% on investment is the minimum applicable to ventures of this nature. Thus, although the allowance for return and income taxes has a considerable effect on the final cost of gasoline, it is our belief that a reduction in the return on investment is not a valid means of attempting to make the cost of gasoline more competitive with current refinery realization. Even without considering obsolescence a more realistic rate of return would be not less than 15 % per year in recognition of the risk involved in such a project.

The other items of expense and income used in this study are believed to be amply explained in the attached table and appendices. These sources of information, however, make no attempt to duplicate items presented in the reports of the Process, Engineering, and Raw Materials Subcommittees.

By: P. R. Schultz

Economics Subcommittee
P. R. Schultz, Chairman
R. G. Atkinson
F. T. Barr
J. H. Hirsch
T. R. Moore
C. F. Parker
J. D. Snakenberg

SUMMARIZED ECONOMIC CALCULATIONS FOR 27,000 B/CD
COAL HYDROGENATION PLANT AT ROCK SPRINGS, WYOMING

		Units/CD	Price	$/CD
1.	PRODUCT YIELDS AND BY-PRODUCT INCOME			
2.	Liquid Fuels			
3.	Motor Gasoline, Bbls.	19,490	...	--
4.	LP Gas, Bbls.	6,390	3.0¢/Gal.	$ 8,051
5.	Total Liquid Fuels, Bbls.	25,880		
6.	Chemicals			
7.	Phenol, Lbs.	85,000	15.8¢/Lb.	13,430
8.	o-Cresol, Lbs.	27,000	7.5¢/Lb.	2,025
9.	m,p-Cresols, Lbs.	111,000	10.5¢/Lb.	11,655
10.	Xylenols	182,000	5.5¢/Lb.	10,010
11.	By-Product Income, $/CD	--	--	$45,171

		Basis	$/CD
12.	OPERATING EXPENSE		
13.	HYDROGENATION PLANT		
14.	Labor		
15.	Operating Labor	238 Men/Shift @ $2.00/Hr.	$ 11,424
16.	Maintenance Labor	2.5% Per Yr. of $396,300,000 Investment	27,651
17.	Unit Supervision and Clerical	15% of Operating Labor	1,714
18.	Payroll Extras	20% of Items 15, 16, & 17	8,158
19.	Material		
20.	Operating	20% of Maintenance Material	2,964
21.	Maintenance	1.4% Per Yr. of $396,300,000 Investment	14,819
22.	Utilities	Credit from Sale of Power to Coal Mine	- 1,218
23.	Catalysts and Chemicals	Detailed in Engineering Report	6,507
24.	Tetraethyl Lead	0.11 cc Per Gal. @ 0.224¢/cc	209
25.	Total Direct Expense		$ 72,228
26.	General Overhead (Plant Burden) & Administrative Overhead	50% of Items 15, 16, 17, 20, & 21	29,271
27.	Research and Development	$1,000,000 Per Year	2,740
28.	State, County, & Local Taxes and Insurance	1.5% per Yr. of $396,300,000 Investment	16,290
29.	Total Hydrogenation Plant Expense Excluding Depreciation		$120,529
30.	COAL MINE (12,960 Tons/CD)		
31.	Labor		
32.	Total Mine Labor	670 Total Mine Employees	7,957
33.	Payroll Extras	Vacations, Etc., Plus 30¢/Ton for U.M.W. Welfare Fund	4,704
34.	Purchased Power	Purchased from Hydrogenation Plant	1,218
35.	Total Supplies		5,884
36.	Administrative Overhead		1,659
37.	State, County, & Local Taxes and Insurance		4,108
38.	Depletion and Royalty		1,063
39.	Total Mine Expense Excluding Depreciation		$ 26,593
40.	Total Operating Expense Excluding Depreciation		$147,122

		Case (See Explanation in Text)			
		A	B	C	D
41.	INVESTMENT				
42.	Total Plant	$396,300,000	$396,300,000	$396,300,000	$396,300,000
43.	Construction Housing	13,200,000	7,000,000	7,000,000	13,200,000
44.	Coal Mine	12,700,000	12,700,000	12,700,000	12,700,000
45.	Process Royalties	1,000,000	1,000,000	1,000,000	1,000,000
46.	Start-Up Expense	18,500,000	18,500,000	18,500,000	18,500,000
47.	Working Capital	37,400,000	37,400,000	37,400,000	37,400,000
48.	Total Investment Excluding Housing	$479,100,000	$472,900,000	$472,900,000	$479,100,000
49.	Housing for Employees	--	48,000,000	48,000,000	--
50.	Housing for Tradespeople & Others	--	33,600,000	--	--
51.	General Community Facilities	--	12,000,000	12,000,000	12,000,000
52.	Commercial Buildings	--	13,300,000	--	--
53.	Total Investment	$479,100,000	$579,800,000	$532,900,000	$491,100,000
54.	ECONOMICS $/CD				
55.	Total Operating Expense	$147,122	$147,122	$147,122	$147,122
56.	Depreciation of Operating Facilities (Items 42, 43, & 44)	57,836	56,986	56,986	57,836
57.	Amortization of Process Royalties and Start-Up Expense	2,671	2,671	2,671	2,671
58.	Depreciation of Housing Facilities	...	14,644	8,219	1,644
59.	Sub-Total	$207,629	$221,423	$214,998	$209,273
60.	Credit for By-Products	- 45,171	- 45,171	- 45,171	- 45,171
61.	Income from Electricity Sold to Community	--	- 962	- 566	--
62.	Rental Income from Housing Facilities	--	- 13,704	- 5,918	--
63.	Cost of Gasoline Before Profit	$162,458	$161,586	$163,343	$164,102
64.	Return on Investment @ 6% per Yr. of Item 54	78,755	95,309	87,600	80,729
65.	Federal Income Taxes @ 50% Rate	78,755	95,309	87,600	80,729
66.	Cost of Gasoline Including Return:				
67.	$/CD	$319,970	$352,204	$338,543	$325,560
68.	¢/Gal.	39.1	43.0	41.4	39.8

M E M O R A N D U M

July 6, 1951

Re: Economics Subcommittee of
NPC Subcommittee on Synthetic
Fuels Production Costs

Product Value and Quality - Rock Springs Coal Hydrogenation Plant

The construction of a coal hydrogenation plant at Rock Springs, Wyoming, poses a difficult problem in the marketing of products. The northern Rocky Mountain States are, in general, sparsely populated and have excess refinery capacity and crude oil production. Recognizing these factors, the following information was developed on this matter.

We requested three companies to furnish their thoughts as to the refinery realizations for regular grade gasoline and LPG in the Rock Springs area. The results of this survey are:

	¢/gallon	
	Regular Gasoline	LPG
Company 1	11.0	3.0
Company 2	11.3	3.0
Company 3	9.75	2.8

In this area premium gasoline amounts to approximately 17% of the total gas sales and can be assumed to be 1¢ per gallon higher in price than the regular grade.

In the studies made by Companies 1 and 2, it was assumed that Rock Springs, Wyoming, would take over the entire market within its shipping radius (approximately 160 miles), and that other suppliers would no longer distribute products in this area. This would assume that the refiners at Casper, Wyoming, would no longer distribute products in Wyoming west of Casper, but would move additional products out of the area to the east and to the south via pipeline. Company 3 based its study upon moving the products from Rock Springs to the nearest region where present product distribution would not be so greatly disturbed. On this basis it was determined that the area which would bring the best netback was Washington and Oregon, and it was assumed that a pipeline costing approximately $16,400,000 would be built. The price established for gasoline recognized the pipeline tariff which included a return of 7% on the pipeline investment. Similarly, the gasoline could be moved east from Wyoming to be marketed in the Kansas City or Omaha area and a netback of about 9.75 cents per gallon obtained.

It will be noted that all three companies were very close together on their LPG value.

It is recommended that for the Rock Springs case a regular grade price of 11¢ per gallon and an LPG price of 3¢ per gallon be used.

The total gasoline stream produced from the Rock Springs bituminous coal is indicated to have a clear CFR-R octane number of 85 which increases to 91.5 with the addition of 1.0 cc of TEL per gallon. As of January, 1951, the gasoline marketed in the Rock Springs area was comprised of 83% regular grade with a CFR-R rating of 82 and 17% premium grade with a CFR-R rating of 90. Thus, the coal hydrogenation plant unleaded gasoline quality exceeds the regular grade sold in the area, and to obtain the premium grade quality of 90 CFR-R octane, 0.66 TEL per gallon are required. Therefore, on the total gasoline sales, an average TEL requirement of 0.11 cc per gallon is indicated.

P. R. Schultz

SOD ESS 05 807 1A OP 644N

TEL. ELIZABETH 5-2000

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ESSO LABORATORIES

STANDARD OIL DEVELOPMENT COMPANY

#10920

DEVELOPMENT DIVISION

A. D. GREEN
DIRECTOR
C. W. TYSON
ASSOCIATE DIRECTOR

H. Z. MARTIN
H. W. SCHEELINE
ASSISTANT DIRECTORS

P. O. BOX 51, LINDEN, N. J.

September 28, 1951

Coal Hydrogenation by
Phenols Credit
DD 25.122

Mr. P. R. Schultz
Stanolind Oil & Gas Company
Stanolind Building
Tulsa 2, Oklahoma

Dear Sir:

We are writing to give you our latest recommendations on the realizations on tar acids for use in the NPC review of coal hydrogenation costs.

In establishing these figures we have talked with Mr. John M. Weiss, a well-known authority in this field. Various industry sources have also been used. In all this we have had the assistance of our chemicals development group and our chemicals market analysis people. As a result of this review it appears that disposal of all the phenol, cresols and xylenols from one 30,000 B/D plant should be assumed. These comprise:

Phenol	-	31.0 MM Lbs./yr.
m,p-Cresol	-	40.5 MM Lbs./yr.
o-Cresol	-	9.9 MM Lbs./yr.
Xylenols	-	66.4 MM Lbs./yr.

Recommended realizations for these amounts at the point of consumption are as follows:

Phenol	-	17.3¢/Lb.
m,p-Cresol	-	13¢/Lb.
o-Cresol	-	10¢/Lb.
Xylenols	-	8¢/Lb.

The phenol realization is present market quotation for USP phenol. A brief review of the phenol separation section of the tar acids recovery plant indicated that it should be possible to produce this grade. The m,p-cresol realization is an average of a number of fairly uniform suggestions as to the discount from present price, and the margin required under phenol to stimulate its use. The o-cresol realization is discounted more severely from present price owing to the relatively poorer outlook for expansion of its market.

Mr. P. R. Schultz Sept. 28, 1951

The figure for xylenols was arrived at assuming that the 3,5-dimethyl phenol could be disposed of at a price in the m,p-cresol/phenol range, and that market for the remaining xylenols could be developed if they were available at 5 or 6¢/Lb. Rough adjustment for separation cost was included.

The 17.3¢/lb. for phenol probably establishes a ceiling both for the phenol itself, and for other tar acids insofar as their price is tied to that of phenol. From some preliminary estimates, it appears that relatively large quantities of synthetic phenol can be made available at this price. In any case it should be realized that it would take a number of years to build up the necessary market for all but the phenol from one hydrogenation plant.

In figuring net realization at the point of production transportation costs should be deducted from the above figures. The phenol production from one 30,000 B/D plant comprises only 10-15% of the current U.S. consumption. It may, therefore, be assumed that it could be disposed of at the nearest suitable consuming center. The use of East St. Louis as an alternative to Pittsburgh for this purpose is probably satisfactory. For the cresols and xylenols, however, the quantities to be disposed of are so large that the use of Pittsburgh as the average point of consumption seems necessary. On this basis, for the Rock Springs case the following rail transportation costs are recommended:

Phenol	Rock Springs to East St. Louis	2.0¢/Lb.
Cresols and Xylenols	Rock Springs to Pittsburgh	2.5¢/Lb.

A tabulation giving freight rates from the other hydro plant locations to the points of consumption is appended. This includes also information on use of river barging for some cases. Since it would be necessary to move product from Rock Springs to the Mississippi River by rail, the use of river transportation in this case does not show a saving in overall cost.

In the above figures no provision is made for costs of loading or unloading, switching, demurrage, etc. Some of these are included in the hydrogenation plant operating costs. They should not be large and their omission is probably not unduly optimistic.

The tar acids yields shown above, and recommended by the Process Subcommittee, are not those now being suggested by the Bureau of Mines. However, the Bureau has not been able to say whether the newer figures are consistent with the gasoline yields and qualities used in the NPC review. For this reason it appears necessary to continue using the older yields. No information has been received from the Bureau as to what effect variation in coal quality will have on tar acids yields.

Yours very truly,

C. L. TYSON

FTB/esc
Att.

Per: Frank T. Barr
Frank T. Barr

cc: Messrs. R. G. Atkinson
L. E. Carlsmith
J. H. Hirsch
T. R. Moore
J. C. Meyland, Jr. C. F. Parker J. D. Snakenberg

TAR ACIDS TRANSPORTATION COSTS*

Cents Per Pound

	Via Rail		Via River Barge Tanker
	Phenol	Cresols and Xylenols	All
Sweetwater County, Wyoming to:			
Pittsburgh	2.7841	2.5657	-
East St. Louis	1.9652	-	-
St. Paul	1.8997	1.8997	-
St. Paul to Pittsburgh	-	-	0.2815
Pittsburgh Local Switching	0.0555	0.0555	-
To Pittsburgh from:			
Sweetwater County, Wyoming	2.7841	2.5657	-
Rosebud County, Montana	2.5657	2.5657	-
Dunn County, No. Dakota	2.2163	2.2163	-
Union County, Kentucky	0.9935	0.9717	0.1305
Muhlenberg County, Kentucky	1.0700	1.0003	-
Franklin County, Illinois	1.1015	1.1015	-
Knox County, Indiana	0.9767	0.9767	-
Monongalia County, West Virginia	0.5164	0.5164	-
To East St. Louis from:			
Sweetwater County, Wyoming	1.9652	-	-
Rosebud County, Montana	2.0963	-	-
Dunn County, No. Dakota	1.6159	-	-
Union County, Kentucky	0.6769	-	-
Muhlenberg County, Kentucky	0.7214	-	-
Franklin County, Illinois	0.4940	-	-
Knox County, Indiana	0.5389	-	-
Monongalia County, West Virginia	1.1339	-	-
To St. Paul from:			
Sweetwater County, Wyoming	1.8997	1.8997	-
Rosebud County, Montana	1.6814	1.6814	-
Dunn County, No. Dakota	1.1791	1.1791	-

*Rail rates established August 15, 1951. Include surcharges and taxes, but exclude tank car rental and demurrage. These not significant for all rail movement. Barge rates on contract basis. Transfer, rail to barge, say 0.2¢/#; barge to rail for local movement to customer say 0.1¢/#. Thus, cost by rail plus barge from Rock Springs (Sweetwater County), Wyoming, including Pittsburgh local delivery by rail would be 1.8997 + 0.2 + 0.2815 + 0.1 + 0.0555 = 2.5367. This would be compared with 2.5657 for cresols and xylenols all rail.

S.O.D. - Dev. Div.
FTB/esc 9/28/51
TB-1780-1

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THE TEXAS COMPANY

Texaco Petroleum Products

Refining Department

135 East 42nd Street
New York 17, N.Y.

July 26, 1951

Mr. P. R. Schultz,
Stanolind Oil and Gas Company,
Stanolind Building,
Tulsa, Oklahoma.

N.P.C. ECONOMICS SUBCOMMITTEE

Dear Sir:

On the basis of final figures as submitted by the engineering and process groups, I am attaching hereto a table which develops the operating and maintenance labor. It will be noted that with respect to operating labor it is expressed in terms of men per shift for the major operating units of the hydrogenation plant. With respect to the maintenance labor it has been developed on the basis of percentage of investment varying from one to six per cent, depending upon the type of unit to be maintained.

The numbers of men per shift were basically those furnished by the process groups with corrections in a few instances on the basis of experience of outside companies, particularly with respect to the steam and power generation by use of coal. The maintenance labor as per cent of investment was developed through consultation with Messrs. J. D. Snakenberg, F. T. Barr, and J. H. Hirsch, and represents a consensus of opinion based on company experience.

The Bureau of Mines' calculation of cost in R. I. 4564 estimated general overhead (plant burden or indirect plant expense) at 40% of direct labor and material and estimated general administrative expense at 10% of direct labor and material. Based on the experience of the companies represented by Messrs. J. D. Snakenberg, F. T. Barr, J. H. Hirsch, and the writer, the total of 50% for general overhead and administrative expense appears to be reasonable though the split between the two items will vary according to different company policies and practices. In general, general overhead (plant burden or indirect plant expense) includes expense of operating all plant service groups exclusive of the utilities group. For example, operation of service groups includes:

Testing Laboratory
Engineering and Drafting
Process Engineering
Storehouse Operations
Industrial Relations
Employees Service Records
Medical Service

Mr. P. R. Schultz July 26, 1951

Safety Program
Employees Training Programs
Operation of Employees Recreation Facilities
Operation of Employees Service Building
Shop Operation which cannot be allocated to Direct Expenses
Operation of Automobiles and Trucks not allocated to Direct Expenses
Fire Protection Expense
Plant Protection Expense (Watchmen, Guards, and Gatemen)
Operation of Rolling Stock such as Switch Engines, Cranes and Hoists, to extent they cannot be allocated to Direct Expenses.

General overhead also includes the cost of the general supervisory forces and accounting to the extent company policy would determine economic to locate at the plant. General administrative expense includes all direct supervision of plant operations not specifically located at the plant site together with advisory staffs. It would also include the cost of maintaining staffs for the following company administrative groups:

Legal
Controller
Treasurer
Purchasing
Insurance
Bulk Sales
Executive Offices

In addition to the operating costs for both plant burden and administrative overhead there are incurred a large number of service type expenses both at the plant and the general office which add to the cost of operation. Such items are:

Contributions and Donations
Travelling and Personal Expenses
Telephone and Telegraph
Memberships and Subscriptions
Printing and Stationery
General Office Rentals and Maintenance

Inasmuch as the total of 50% for general overhead and administrative expense appears to be in line with oil company experience even though the pattern of division of the two varies widely, it is recommended that for the purpose of estimating costs for coal hydrogenation that we use the same split as used by the Bureau of Mines, that is, 40% for general overhead and 10% for general administrative expense.

Yours very truly,

/s/ T. R. Moore

TRM-FM T. R. Moore.

30,000 BPD COAL HYDROGENATION PLANT ROCK SPRINGS, WYOMING

Department	Maintenance Labor			Operating Labor
	Plant Investment	% of Investment	Annual Cost	Men Per Shift
Coal Preparation	$ 6,400,000	6.0	$ 384,000	7
Coal Gasification	6,700,000	5.0	335,000	7
Oxygen Plant	10,500,000	2.5	262,500	7
H. C. Steam Cracking	12,000,000	2.5	300,000)	16
Producer Gas for H.C. Steam Cracking	1,900,000	4.0	76,000)	
Hydrogen Recovery	10,400,000	2.5	260,000	8
Paste Preparation	3,500,000	5.0	175,000	5
Catalyst Preparation	500,000	4.0	20,000	5
Hydrogen Purification	58,200,000	3.0	1,746,000	21
Coal Hydrogenation	98,400,000	2.5	2,460,000	64
Product Distillation	15,300,000	2.0	306,000	10
Delayed Coking	7,000,000	4.0	280,000	13
Phenol Recovery	2,600,000	2.5	65,000	6
Waste Disposal	3,500,000	1.0	35,000	5
Tankage & Loading	10,200,000	1.0	102,000	13
Steam & Power Generation	90,000,000	2.0	1,800,000	29
Water System	15,000,000	1.0	150,000	10
Producer Gas	1,000,000	4.0	40,000	3
Buildings, Shops, & General Facilities	43,200,000	3.0	1,296,000	-
Coal Handling & Storage	-			9
Total	$396,300,000	2.55	$ 10,092,500 ($27,651/CD)	238

COPY

Petroleum and Its Products

CULF RESEARCH & DEVELOPMENT COMPANY
P. O. Drawer 2038 - Pittsburgh 30, Pa.

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Vice President
Blaine B. Wescott
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Eugene Ayres
Tech. Asst. to Exec. Vic Pres.
H. W. Daugherty
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Division Directors
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M. Muskat - Physics
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R. J. S. Pigott - Engineering
L. W. Vollmer - Materials & Prod. Chem.
R. D. Wyckoff - Geophysical Res. & Dev.

July 27, 1951

File: ND 07

Air Mail

Mr. P. R. Schultz
Stanolind Oil and Gas Company
Stanolind Building
Tulsa, Oklahoma

Dear Mr. Schultz:

Attached is a memorandum by our Mr. V. N. Hurd, dated May 31, 1951, summarizing his study of refinery wage rates and presenting recommended rates for use in the calculation of synthetic fuels costs. Using these recommended rates and a labor force breakdown from the Bureau of Mines, dated February 3, 1950, we have calculated an average labor rate of $2.00/hr.

In addition to the direct labor cost, an allowance for payroll extras should be included in the economic calculations to cover such items as overtime, holiday premiums, shift differentials, accident and sickness benefits, unemployment insurance, pensions, social security, etc. Based on data obtained from several companies participating in the N.P.C. study, it is recommended that the allowance for payroll extras be taken at 20% of the labor cost. Similarily, based on the experience of these companies, an allowance of 15% of operating labor is recommended for unit supervision and clerical labor.

Very truly yours,

/s/ Joel H. Hirsch

Joel H. Hirsch

JMcA
JHH;kh
Att.
cc: Messrs. R. G. Atkinson
F. T. Barr
T. R. Moore
C. F. Parker
J. D. Snakenberg

H15

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Y

File: ND 07
NA 00

FROM V. N. Hurd AT Harmarville

TO Mr. Joel H. Hirsch AT Harmarville May 31, 1951

SUBJECT Refinery Wage Rates

As part of the study being made by the National Petroleum Council on the economics of producing synthetic liquid fuels from coal, a schedule of representative refinery wage rates was required. To aid in developing such a schedule, several oil companies submitted to the N.P.C. lists of wage rates paid by them in various parts of the country. A list of these companies along with the locations of the refineries for which rates were given is shown in Table No. 1. In addition, average wage rates for September, 1948, as compiled by the Bureau of Labor Statistics were available for various sections of the country.

In order to condense the data into the most useable form, an attempt was first made to reduce the number of labor classifications and wage rates to a minimum. The Gulf Port Arthur refinery, for example, listed 158 labor classifications having 40 different wage rates, and it was desired to reduce these classifications to the lowest practical number. This was done by plotting the number of labor classifications at a given wage rate against wage rate for several refineries. It was found that the total range of wage rates could be divided into eight or nine sections resembling frequency distributions, each section containing a wage rate common to a relatively large number of labor classifications. Using the labor classifications indicated by these plots as being those representing the most common wage rates, the available data were then tabulated for five sections of the country (Gulf Coast, Eastern U.S., Middle West, Rocky Mountain, and Pacific Coast). After correcting all wage rates to January 1, 1951, representative rates were selected for each classification, usually by averaging. Bureau of Labor Statistics data were used for comparison purposes, but did not enter into the averaged figures.

Study of the information thus obtained indicated that a single wage rate for each classification could be employed for the entire country. The rates finally chosen are shown in Table No. 2, along with the maximum and minimum rates which had been selected for the various sections of the country, and the corresponding National average rates compiled by the Bureau of Labor Statistics.

Most of the minimum wage rates shown are from the Pacific Coast region. Comparison of the National average and Pacific Coast data of the Bureau of Labor Statistics indicates, however, that the Pacific Coast rates lie very close to those for the National average. Similarly, most of the maximum rates are from the Eastern section of the country, but again the Bureau of Labor Statistics data indicate that the deviation of the Eastern section from the National

average is small. It is believed that most of the difference between the maximum and minimum values shown is due to the limited number of rates which went into the averages for each section of the country. For this reason, use of National average rather than sectional figures probably gives the most representative rates possible from the available data.

/s/ V. N. Hurd

V. N. Hurd

VNH:kh

Table No. 1.

COMPANIES SUBMITTING WAGE RATES

Company	Location of Refinery
Esso Standard Oil Company	Gulf Coast Eastern Seaboard (2 refineries)
Gulf Oil Corporation	Port Arthur, Texas Fort Worth, Texas Sweetwater, Texas New York, New York Philadelphia, Pennsylvania Pittsburgh, Pennsylvania Toledo, Ohio Cincinnati, Ohio
Texas Company	Los Angeles, California Lawrenceville, Illinois Casper, Wyoming Westville, New Jersey
Union Oil Company	Los Angeles, California Oleum, California Cut Bank, Montana

Table No. 2

REFINERY WAGE RATES, JANUARY 1, 1951

Classification	Wage Rate, $/Hour			
	Recommended Value	Maximum	Minimum	Bureau of Labor Statistics
Operator or Stillman No. 1	2.36	2.45	2.18	2.31
Ass't. Operator or Ass't. Stillman	2.15	2.23	2.02	2.10
Helper	2.00	2.06	1.89	1.98
Laboratory Technician	2.16	2.23	2.07	---
Routine Tester	1.90	1.93	1.83	1.91
Power Plant Engineer No. 1	2.42	2.47	2.37	---
Boiler House Operator	2.17	2.25	2.01	---
Helper	1.96	2.10	1.82	---
Pumper	2.18	2.35	2.00	2.07
Pumper Helper	1.88	2.01	1.75	1.97
Gauger	2.05	2.13	1.93	2.01
Rackman	1.90	1.92	1.88	1.83
Laborer	1.60	1.67	1.48	1.53
Craftsman No. 1	2.20	2.29	2.06	2.14
Craftsman No. 2	2.03	2.10	1.93	---
Helper	1.83	1.92	1.75	1.80

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CITIES SERVICE PETROLEUM ADVISERS, INC.,
Sixty Wall Tower, New York 5, N.Y.

July 27, 1951

Mr. P. R. Schultz
Stanolind Oil and Gas Company
Stanolind Building
Tulsa 2, Oklahoma

NPC SUBCOMMITTEE ON SYNTHETIC LIQUID FUELS PRODUCTION COSTS

Dear Mr. Schultz:

The attached table is an estimate of maintenance material requirements for a 27,000 barrel per calendar day coal hydrogenation plant at Rock Springs, Wyoming. It is based on the investment figures from Mr. Neyland's wire of July 19, 1951. The figures by departments, expressed in percentage of investment, reflect experience of four companies with extensive oil refining operations for their most comparable operations.

Operating supplies shown in turn represents experience of various companies for these items, expressed in terms of percentage of maintenance materials.

Very truly yours,

/s/ J. D. Snakenberg

J. D. Snakenberg

JDS:db
cc:
Messrs. J. C. Neyland, Jr.
T. R. Moore
F. T. Barr
J. E. Hirsch

Att.

27,000 B/CD COAL HYDROGENATION PLANT AT ROCK SPRINGS, WYOMING

Department	Maintenance Material				Operating Supplies	
	Plant Investment	% of Investment	Annual Cost	Daily Cost	Annual Cost	Daily Cost
	$		$	$	$	$
Coal Preparation	6,400,000	2.0	128,000		26,000	
Coal Gasification	6,700,000	2.0	134,000		27,000	
Oxygen Plant	10,500,000	1.5	157,000		31,000	
H. C. Steam Cracking	12,000,000	1.5	180,000		36,000	
Producer Gas for Steam Cracking	1,900,000	2.0	38,000		7,000	
Hydrogen Recovery	10,400,000	1.5	156,000		31,000	
Paste Preparation	3,500,000	2.0	70,000		14,000	
Catalyst Preparation	500,000	2.0	10,000		2,000	
Hydrogen Purification	58,200,000	2.0	1,164,000		233,000	
Coal Hydrogenation	98,400,000	1.5	1,476,000		295,000	
Product Distillation	15,300,000	1.0	153,000		31,000	
Delayed Coking	7,000,000	2.0	140,000		28,000	
Phenol Recovery	2,600,000	1.5	39,000		8,000	
Waste Disposal	3,500,000	1.0	35,000		7,000	
Tankage and Loading	10,200,000	1.0	102,000		20,000	
Steam and Power Generation	90,000,000	1.0	900,000		180,000	
Water System	15,000,000	0.5	75,000		15,000	
Producer Gas	1,000,000	2.0	20,000		4,000	
Buildings, Shops, General Facilities	43,200,000	1.0	432,000		86,000	
TOTAL	396,300,000	1.4	5,409,000	14,819	1,081,000	2,962

Operating supplies include items of the nature of lubricating oil, gaskets and packing, small hose, protective equipment and clothing, flashlights and batteries, and rags. They do not include chemicals, catalysts, or tetraethyl lead.

AIR MAIL

PRICE WATERHOUSE & CO.

56 PINE STREET

NEW YORK 5

September 27, 1951

Mr. P. R. Schultz,
Economics Subcommittee,
National Petroleum Council Committee on
Synthetic Liquid Fuels Production Costs,
Stanolind Oil and Gas Company,
Stanolind Building,
Tulsa 2, Oklahoma.

Dear Sir:

In connection with the estimates of costs of the production of gasoline from coal and from oil shale you have asked us to state what in our opinion would be a reasonable rate of return on the capital invested in the proposed enterprises.

It is our viewpoint that "capital invested" means total capital, whether equity or borrowed, invested or retained in the business.

The preliminary figures which you submitted to us include for the purpose of discussion a nominal rate of return of 6%. Even with such an obviously low rate the resultant price of gasoline in both cases is so high as to make both projects unsuitable for development on a commercial unsubsidized basis. It, therefore, might appear that any discussion in support of a higher rate of return is purely academic. However, we understand that the Committee may be called upon in the future to prepare estimates of costs of improved processes which, it is contended, may more nearly approach a competitive market price for gasoline. It is, therefore, important in presenting the two cases now under consideration, to establish a reasonable rate of return on capital invested in the synthetic fuels industry, irrespective of whether the ultimate objective is the production of gasoline with relatively minor chemical by-products or the production of chemicals with gasoline as the by-product.

It should be understood that a rate of return means net earnings, computed on generally accepted principles of accounting, which include as expense provisions for income taxes and allowances for normal depreciation and obsolescence but that such net earnings do not contemplate the possible obsolescence of the enterprise as a whole. It should also be understood that in dealing with a net earnings percentage on total capital invested no consideration is given to any possible guarantee of minimum earnings.

Based upon our experience in examinations, reviews and investigations of financial affairs of varying fields of industry and commerce and giving due consideration to the factors of risks involved in this proposed enterprise, it is our opinion that an annual rate of earnings of not less than 15% on the total capital invested in or retained in a business subject to the risks of a highly competitive and speculative enterprise would be necessary and reasonable in order to attract investment of private capital.

Yours very truly,

PRICE WATERHOUSE & CO.

E S S O L A B O R A T O R I E S
Standard Oil Development Company

Ref. #10,743

Development Division
A. D. Green
Director
C. W. Tyson
Associate Director

H. Z. Martin
H. W. Scheeline
Assistant Directors

P. O. Box 51, Linden, N.J.

REVISION

September 25, 1951

NPC Economics Subcommittee:
Development of General Fixed and Overhead Cost Items
DD 25.12

Mr. P. R. Schultz
Stanolind Oil & Gas Co.
Tulsa, Oklahoma

Dear Mr. Schultz:

We are forwarding herewith our memorandum outlining in some detail the results of our study of estimating methods for general fixed and overhead items in manufacturing cost determination. These include administrative costs, insurance and taxes, research and development costs, depreciation, and re uired return on investment. They should be applicable to processing operations similar to conventional oil refining. They may not apply very satisfactorily to mining operations and the like, except that depreciation and required return on investment should be constant throughout the project.

The figures recommended are those which have been developed in connection with earlier activities of the Economics "working group". A few revisions in the text have been made to conform with suggestions agreed to at the meeting of July 24 and 25.

In summary the following are recommended:

1) For administrative costs 10% of the direct labor and material costs for the operation should be used.

2) For insurance and taxes 1.5%/yr. of total plant investment should be employed. This would not cover income taxes.

3) For research and development $1 MM/yr. per plant should be used, assuming hydrogenation plants of nominal 30,000 B/D capacity and shale oil plants of nominal 50,000 B/D capacity. This figure might be low for a first plant, but should be satisfactory for industry-wide cases comprising plants aggregating about 250,000 B/D capacity.

4) Five per cent depreciation allowance should be used, based on the estimated operating life of 20 years; actually, based on depreciation allowed for income tax purposes the books would probably show about 2% more depreciation.

Mr. P. R. Schultz 9-25-51

5) The return required on total investment in the project to interest prospective investors should be taken at a minimum of 6% after income taxes assessed at a minimum of 50% on profit before income taxes. This would apply to a synthetic fuels manufacturing operation which has a fair chance of becoming competitive with petroleum refining. Less attractive proposals would require that the return estimated be sharply higher. For the purpose of this study, however, it is recommended that the 6% be used in all cases, with the understanding that it is as low as is likely to be justified.

It should be noted that all the estimating techniques used by the Economics Subcommittee are based on the assumption that the synthetic fuels plants will be operated at full capacity, limited only by technical and operability considerations. On a truly competitive basis risk may have been inadequately allowed for.

As indicated in the memorandum, considerable uncertainty with regard to prediction of the cost of capital for synthetic fuels projects exists. The figure recommended was arrived at through consideration of returns actually obtained in a number of existing industries, with the thought that these would compete for capital with the synthetic fuels projects. It had been our intention to estimate cost of capital only upon the basis of a completely unsubsidized operation. The uncertainties involved, however, made necessary the consideration of some bases involving subsidy in one form or another.

The return figure recommended is to apply without reference to the proportion of borrowed to invested capital. It is based upon figures developed for a wide range of this ratio. These points are further explained and amplified in the memorandum.

Yours very truly,

C. W. TYSON

Per: /s/ Frank T. Barr

FTB:mh
Att.
cc: Messrs. R. G. Atkinson
J. Hirsch
T. R. Moore
C. F. Parker
J. D. Snakenberg

C
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E S S O L A B O R A T O R I E S
Standard Oil Development Company
Development Division

Revised

Ref. #10,744

September 25, 1951

MEMORANDUM

NPC REVIEW OF SYNTHETIC FUELS COSTS

DD 25.122

DEVELOPMENT OF ESTIMATING METHODS FOR GENERAL FIXED AND OVERHEAD GROUPS IN MANUFACTURING COSTS

Cost items included in the general fixed and overhead groups are 1) administrative (ex direct plant administration) but including a) legal, b)purchasing, c) general accounting, d) marketing and distribution, and e) executive offices; 2) insurance and taxes (ex income taxes); 3) research and development; 4) depreciation; and 5) required return on investment, including consideration of the effect of income taxes and of the type of financing.

These items are discussed individually below. The discussion is directed essentially toward processing operations, and more particularly toward coal hydrogenation. Costs in mining industries follow a pattern sufficiently different from those in processing operations that common techniques are difficult to establish. It is useful to make the techniques for both mining and processing as consistent as possible, however.

1. Administrative

It is recommended that a figure of 10% of the direct labor and materials cost for the processing operation be used.

For the 30,000 B/SD coal hydrogenation plant this is likely to run about $2 MM/yr. This amounts to about 3% of the total products cost, including 5% depreciation, a not unreasonable ratio for such cost items. Departments to carry out the five functions included in this group would be of fairly large size. It must be remembered that the 30,000 B/SD coal hydrogenation plant is roughly comparable in investment and size to, say, a 200,000 or 300,000 B/D refinery. While the hydrogenation plant is not as complicated, from a business point of view, as the complete refinery would be, many administrative requirements are common to both. Purchasing would be limited owing to the use of a single large-scale raw material, but many of the normal duties of a purchasing department would remain. Similarly, although marketing is considered to be on the wholesale basis only, and would presumably involve arrangements for transfer of the entire plant output for relatively long periods of time, the need for a complete marketing and product distribution department exists. Insofar as general accounting, legal, and executive requirements are concerned, these are in most respects closely related to the number of people involved in the plant operation, and would be similar to that for the large refinery.

Actually, in refining experience charges against the administrative function can often be much greater than the 10% of labor and materials costs.

2. Insurance and Taxes

It is recommended that an allowance of 1.5%/yr. of plant investment be made to cover insurance and taxes other than income taxes.

Commercial insurance will probably run about one-half of 1%. About two-tenths per cent should be allowed on the average for state income and franchise taxes. Ad valorem taxes will run about 0.7%. Owing to the uncertainties as to precisely what insurance rate might be obtained for the hydro plant, it appears reasonable to round off the total to 1.5%.

The use of 1.5% on investment for insurance and taxes compares with a total of 2% suggested for quick estimate in the Bureau of Mines' Report of Investigations 4534, Guide for Making Cost Estimates for Chemical Type Operations (November, 1949). The figure of 1.5% is not out of line with at least some refinery experience.

3. Research and Development

It is recommended that a figure of $1 MM/yr. for the 30,000 B/SD coal hydrogenation plant be used.

This amounts to about 1-1/2% on the total products cost. If this rate were used for each of the proposed 8 plants for the industry-wide estimate, the resulting $8MM/yr. would be of the order of magnitude of the expenses on synthetic fuels development now being incurred by the Bureau of Mines. Actually, the first plant should probably carry more research and development load, perhaps as high as 2-3% on products cost, since a certain amount of distribution of research effort can be achieved where a number of plants carry out similar operations.

While it may be suggested that the research and development for the synthetic fuels plants will have been completed by the time they are built, it has been the general experience in the petroleum and processing industries that work of this nature is necessary just to keep the business going and to maintain its position. If this is not allowed for, then it is only reasonable to charge past costs of research, development, and demonstration to the operation.

4. Depreciation

It is recommended that 5% of the plant investment be charged for depreciation.

This is based on the requirement that raw materials supply at each location be sufficient to allow 20-years' operation of the plant. It does not take into account any probability of obsolescence, or of premature retirement of plant facilities. In this respect, requirement for research and development discussed above might be justifiably raised, so as to make certain that the process is kept in technically favorable enough position to insure its continued operation.

The 5% depreciation allowance may be compared with an allowable depreciation based on Bureau of Internal Revenue rates of the order of 7%. To the extent that cost of competitive products is based on maximum allowable depreciation, this means that the 5% is low. It would, no doubt, be well to keep in mind that the books of the operating company would show costs equivalent to about 2% higher depreciation than recommended herein.

5. Return on Investment

A review of financing problems, coupled especially with the extremely large size of a project comprising even only one 30,000 B/D hydrogenation plant or one 25,000 B/D shale oil plant suggests that the overall cost of capital for the plant would vary widely depending upon the indicated economics of the process. For an operation which seemed likely to become fairly profitable a reasonably low interest rate would satisfy prospective bond holders.

If, however, the project were not so attractive, increased interest rate would be required to offset the greater risk involved. This, in turn, would make the project even less favorable. Similar considerations, balancing high return against high risk, would apply to equity investors. As a result, it would not be expected that money would be available directly from the general public for a project with uncertain prospects, especially considering the hundreds of millions or billions of dollars' scale of investment involved.

With these reservations, therefore, it is recommended that, as an example of the lowest capital costs which might be met for a reasonably favorable project, an overall return on total new investment of 6% after income taxes be used.

a) Income Tax

Although the present Federal income tax rate is somewhat below 50%, it is expected that it will be raised to the 50-55% range in the near future. This will, no doubt, have some effect on the market prices of gasoline from natural petroleum, but not a large one. The 50% basis, therefore, appears not unduly high, especially since some State income taxes may be involved in addition to the Federal income tax.

b) Comparison with Returns for Public Utility Operation

A number of considerations can be taken into account in connection with establishing the example for the return necessary. First, a profit on total capital of at least 6% after income taxes is generally considered reasonable for public utilities, e.g., for natural gas pipe lines. Since a public utility by definition has an assured market, its net return should certainly not be any higher than that for a manufacturing operation which has no assured market. On this basis the 6% for return on synthetic fuels plant investment is on the low side.

c) Comparison with Returns Obtained by Existing Oil Companies

The oil industry has generally obtained at least a 6% return on its borrowed plus invested capital. Without consideration of the change in the purchasing power of the dollar the returns for thirty oil companies as given by Pogue and Coqueron, "Financial Analysis of Thirty Oil Companies," published yearly by Chase National Bank, show an average of about 5.9% for the years 1934-38; 6.5% for the years 1939-43; and 11.3% for the years 1944-48. Adjusting both invested capital and profits to common dollar value revises these figures to 5.9, 5.9, and 7.4%, respectively. For 1949, the unadjusted and adjusted figures are 11.1 and 7.0%, respectively, while in 1950 the unadjusted figure was 12.7%. Since the synthetic fuel industry would be in direct competition with the natural petroleum industry, it is unlikely that investors would be willing to accept lower returns from the synthetic fuel operation than could be obtained from natural petroleum processing. This would be reflected in competition for investors' money in the stock market as well as elsewhere.

The effect of the decrease in invested capital in an existing industry by virtue of write off compared with the total investment for a new plant in the synthetic fuel case should be kept in mind.

Another consideration with respect to return required to interest investors is that for new projects in the petroleum and chemical industries a much higher return than 6% must be estimated to make the project attractive. Reasoning on this basis could easily develop justification for returns of 10,20, 30% and higher.

d) Capital Structure with High Funded Debt

With a high proportion of funded debt paying interest at considerably lower than the 6% suggested as example on total investment, an apparently lower overall required return can be developed by setting up the proper type of financial plan. Obtaining a high proportion of funded debt to equity investment, however, would require more assurance as to the position of the project than could be expected without some sort of subsidy. While subsidy, for example, in the form of guaranteed purchase contracts by a government agency, has been suggested, figures determined in this way would not be true costs. Although, after establishing true costs, it may reasonably be determined that a project should be subsidized, it seems certain that the basic cost estimate should be for a manufacturing project "standing on its own feet."

e) Financial Costs on Subsidized Basis

In connection with the way a synthetic fuels project might be financed, a number of suggested financing plans were set up by the Jersey Treasurer's office. These are all very preliminary and tentative. They are based on the assumption that some sort of a products purchase contract would be arranged so as to insure recovery of costs, and to this extent must be considered subsidized. On this basis it is considered possible that 80 or 90% borrowed capital might be obtained, providing sufficiently rapid amortization were allowed. These plans are compared in the following tabulation:

Plan No.	Description	Capital Chgs. per Gal.Gaso.	Equiv. Ret. before Inc. Taxes on Tot. Invest., After 5% Depr.	Ret. on Equity Invest., Discounted to Start of Proj.
I	90% Funded Debt, 10% Common Stock; debt fully amortized in 10 years	7.6¢	8.9%	14.7%
II	80% Debt., 10 Yr. Pay-off	6.7¢	7.4%	9.6%
III	Same as I, plus 5% return on equity investment during debt pay-off period	8.3¢	10.1%	17.3%
IV	Same as II, plus 5% return	8.1¢	9.9%	13.1%
V	90% Funded Debt; 10 year red'n. to 20% of total investment	6.3¢	6.7%	11.6%
VI	80% Debt, 10 Yr. red'n. to 20%	5.5¢	5.1%	6.8%
VII	90% Funded Debt, 7 Yr. Pay-off of debt	11.6¢	16.2%	23.3%
VIII	80% Debt, 7 Yr. Pay-off	10.3¢	13.8%	16.1%

Notes:

1) The plant investment is assumed to be $200 MM for 25,000 B/D gasoline production, plus $10 MM working capital, or $8,000 + $400 per B/D gasoline.

2) Capital charges include write off (and return, in Plans III and IV) as indicated, plus interest on remaining debt at 3-1/4%. A two-year construction period is assumed, and interest is paid during this period, but amortization starts the 3rd year in all cases.

3) After amortization of the debt as indicated, and (where necessary) write off of any remaining investment above an assumed $11 MM scrap value plus $10 MM working capital remaining, the capital charges are assumed available as return on the equity investment.

4) Return on equity investment shown is actual return discounted (at the same rate) to the start of the project*. Returns on equity investment are shown after 50% income tax. It is assumed that no income tax would be assessed on amortization payments in excess of normal depreciation. This would require accelerated depreciation allowance.

5) In all cases equity investment is common stock equal to the difference between total investment and funded debt.

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* The discounted return on equity is such as to give the following results:

1) The equity investment is increased during the period of debt amortization at the discounted return rate compounded annually.

2) Actual returns following this period are applied the year they are earned toward extinguishing the equity. The discounted return rate is charged on the net equity investment.

3) The equity is thus reduced to the $21 MM assumed scrap value plus working capital by the time the plant is retired.

4) The discounted return is therefore theoretically available on the original equity throughout the life of the plant. In the cases where the original equity is greater than the $21 MM final equity (Plans II, IV, VI, and VIII), the necessary capital repayment is included.

The previous figures are based on an assumed 25,000 B/D gasoline production from shale. Coal hydrogenation and synthesis from coal were not considered because of their anticipated higher costs. Costs from shale are expected to be more nearly in line with costs by conventional petroleum refining.

In reality the level of financial costs would depend upon the level of the costs of raw materials, manufacturing, and transportation. As final estimates of the latter costs are not yet available, it is not possible to give a reliable or final estimate of financial costs. In making tentative estimates, it has been assumed that the production of gasoline from shale would be in a range that might be considered competitive, or nearly so, with the manufacture of gasoline from crude petroleum.

On this basis, however, it does not appear that a company organized to manufacture gasoline from shale could be set up with its equity securities owned by the general public. The newness of the operation, the fact that the process does not promise savings in cost over conventional methods, and the tremendous outlays necessary all argue against general public ownership of the equity securities. Heavy backing from existing oil companies and/or the government would be necessary. Hence, it has been assumed that the oil companies would provide the equity capital for the shale company and that a large purchaser, perhaps a government agency, would contract on a long-term basis to purchase or pay for a given amount of product at a specified price.

Although the table covers a number of possible situations, under present conditions the first plan seems the most defensible. This assumes (as do all plans) plant cost of $200 MM and an additional $10 MM as working capital. Capitalization consists of 10% equity capital, furnished by five or six oil companies, and 90% borrowed capital, provided by institutional investors. The debt is assumed as 10-year debt, largely because investors would probably be unwilling to tie up their funds for greater lengths of time on a new project of this type. Uncertainties both in the economic and legislative fields argue against risking funds for longer periods. The 3-1/4% interest rate reflects current levels. Building is assumed to require two years. The entire debt is repaid in equal annual installments during the third through tenth years. The oil companies are assumed to receive no return on their investment until after the tenth year. Estimated financial cost, before depreciation credit, is 7.6¢ per gallon of gasoline, or an average of 13.6% per year on the $210 MM over eight years' production. If 5% per producing year on the $200 MM plant investment is taken as depreciation, this cost includes the equivalent of 8.9% return before income tax on total original investment.

It will be observed that, from consideration of these plans, some decrease below the 6% return after income taxes (or 12% before) can be justified for the conditions of subsidy involved. Furthermore, the plans themselves represent varying degrees of risk, and varying effective subsidy. All are based on the assumption that pay-out of the borrowed capital can reasonably be hastened by providing no return on equity capital during the amortization period. However, this has the effect of seriously reducing the equivalent return represented by the profits available when the bonded indebtedness is finally paid off. Again this means simply that a low overall return on the total investment is not sufficient to interest investors.

It is not intended to leave the impression that a company organized to manufacture synthetic gasoline could not attract equity capital from the investing public. Conventional methods of financing could be used if the synthetic process could promise a cost advantage and if smaller plant size could be projected. A favorable cost differential of only 1/2¢ to 1¢ per gallon of gasoline would be sufficient if promoters could convince investors of the validity of the estimates. Furthermore, a plant costing something like $50 MM to $70 MM could be financed much more easily than one costing $200 MM.

Other sources of capital can be considered. Presumably, an R.F.C. loan might be obtained. The fact that it would be necessary to go to the R.F.C. instead of obtaining money from private sources, however, would be a measure of the amount of subsidy provided by R.F.C. Similarly, while supply of a portion of the capital by an existing oil company or a group of oil companies would have the effect of reducing the cost of outside capital obtained, it would not be a net reduction, since the credit standing of the backers of the project would be affected. Although these effects cannot be readily measured in money, the risk exists and must be allowed for. Any proposal for financing which does not take into account full evaluation and cost of the risk involved cannot be considered a true evaluation of the cost of operation.

f) Conclusion

It seems reasonable, in view of the foregoing, to conclude that for a synthetic fuels manufacturing operation that has a fair chance of being competitive with petroleum refining, an overall capital cost of 12% on total investment in addition to depreciation allowance would be met. This would be equivalent to 6% on 100% equity investment after income tax. The shale alternative may possibly meet this condition; coal hydrogenation does not seem likely to.

/s/ F.T.B.

FRANK T. BARR

FTB:mh/w

M E M O R A N D U M

September 13, 1951

Re: Economics Subcommittee of
NPC Subcommittee on Synthetic
Fuels Production Costs

Determination of Start-Up Expense and Working Capital
for Coal Hydrogenation Plant at Rock Springs, Wyoming

The amount of capital provided for start-up expense and working capital is an important factor in the financing of a venture such as a synthetic fuel plant. Certain of the items included in these two capital requirements are common to most industries and all of them are at times encountered in the petroleum industry. Thus, there is ample justification for including all of the separate items considered.

One item, however, which cannot be accurately predicted is the length of time required until the plant is operating continuously at design capacity and the average rate of production during this period. For projects of this nature, it was decided that an average production of 65% of design capacity for a period of one year should be used. The petroleum industry's experience in the initial operation of new plants and processes would undoubtedly reveal many cases where greater or lesser difficulties were encountered. Thus, although this item could be greater or lesser, it has at least been recognized and estimated on a reasonable basis.

The start-up expense and the working capital are handled separately for the following reasons:

1. Start-up expense represents a true expense which, ordinarily, is written off on a current basis against other income. This presumes, however, that the plant operator has other profitable ventures. In this case, it is believed preferable to capitalize this expense and amortize it over the composite life of the facilities. In this manner, a constant production cost is obtained, thereby simplifying the treatment of this matter in the economics.

2. Working capital includes, in this study, various prepaid expenses and a sum required to meet fluctuations between income and expenses. Since the average daily cost of these prepaid expenses has been included in the operating costs, no depreciation can be taken.

The amount required for start-up expense is determined as follows:

Basis	Amount
Employee Training and Recruiting: A training period, up to three months for certain personnel, will be required for operating and maintenance labor and the direct supervisory force. Additional costs will be incurred in recruiting and moving personnel to the site. Use total cost equal to 90 days times these labor items ($48,947/CD).	$ 4,400,000
Initial Operation at Less Than Design Capacity: Operating difficulties will reduce initial year's production to 65% of design capacity. Thus, during 35% of the first year, certain cash costs such as total plant payroll, overhead, a portion of supplies, property taxes, and other items on the plant, plus the payroll for a skeleton labor force and other costs on the mine, must be met without any product income to offset these costs. Total amount is 35% x 365 days x $110,400	$14,100,000
Total Start-Up Expense	$18,500,000

The working capital items are calculated as follows:

Basis	Amount
Product Inventory and Accounts Receivable: Volume of storage tanks will require about 30 days operation at design capacity before products can be shipped on current basis. Billing and receipt of income will require an additional 60 days. Thus, receipt of income will lag about 90 days behind production. During this period, only cash costs, i.e., operating expenses less depreciation and other capital charges, will have to be met. Amount required is 90 days x $147,122/CD	$13,200,000
Catalysts, Chemicals, and Materials Inventories: In addition to the initial catalyst charge ($1,400,000), a normal inventory of catalysts and chemicals of 6 months supply ($1,187,500), and a normal inventory of operating and maintenance materials for plant and mine of one year's supply ($8,638,500) are provided.	$11,200,000
Additional Sum: The preceding items, and other expenses such as maintenance costs, are subject to rather large fluctuations. For this reason, it is necessary to provide a fund to meet these variable expenses, and an amount equal to 90 days times cash costs ($147,122/CD) is provided.	$13,200,000
Total Working Capital	$37,400,000

M E M O R A N D U M

September 13, 1951

Re: Economics Subcommittee of NPC
Subcommittee on Synthetic Liquid
Fuels Production Costs

Revisions to Housing Investment Estimate for Coal Hydrogenation Plant at Rock Springs, Wyoming

At the time the housing estimate for the Rock Springs coal hydrogenation plant was originally prepared, the personnel requirements were based on the report prepared by the U.S. Bureau of Mines for this project. Inasmuch as the total plant and mine personnel, as estimated by the NPC groups, exceeds the U.S.B.M. estimate by 34%, it was necessary to make adjustments as follows:

Housing Item	Investment as Presented in NPC Engineering Report Based on U.S.B.M. Estimate of Personnel	Investment as Used by NPC Economics Subcommittee Based on NPC Estimate of Personnel
Housing for Employees	$ 35,800,000	$ 48,000,000
Housing for Tradespeople and Others	25,100,000	33,600,000
General Community Facilities	9,000,000	12,100,000
Commercial Buildings	9,900,000	13,300,000
Total (Case B)	$ 79,800,000	$107,000,000

The above adjustment does not affect the unit cost for a dwelling unit or the allocation of the community development expenditures. These unit costs are presented in the report on offsite facilities for the Rock Springs plant.

P. R. Schultz

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Review of Basis for Housing Estimates of Off-Site Committee

The builders of a Shale Oil Plant near Rifle, Colorado or a Hydrogenation Plant near Rock Springs, Wyoming, are confronted with the need of adequate and appropriate housing for their employees in order to attract suitable employees to start up and operate the new plants. This group of employees requires civic and commercial services on a scale in keeping with the remoteness from other population centers. The civic and commercial service people need housing. Utility and civic services must be scaled to accommodate the whole.

The timing conditions are unique. The plans for the whole must be made and construction carried out so that the entire town is ready to function at the time the plant starts. The various plant departments will start approximately simultaneously. But practically none of the ultimate inhabitants of the town will be there until the town is completed, as there has been no need or function for them until then.

These circumstances of timing have a controlling effect on the initial financing through the planning and construction period, since they preclude:

1. The conventional financing of civic facilities, schools, hospitals, roads, sewers and utilities through bonding and assessments on individual property owners and the planning and construction of these facilities by usual civic processes.

2. The individual construction of houses by the great majority of permanent plant and mine employees.

3. The individual construction of houses by the majority of service workers.

4. The construction of a substantial portion of the commercial buildings by the ultimate proprietors.

The Off-Site Subcommittee estimated permanent housing to meet these needs, based on the belief that the costs are too immense and the future too uncertain to attract outside builders to assume the risks.

This committee's temporary housing studies showed it imperative to avoid the permanent housing man power requirement (14,200,000 man hours) being concurrent with the plant man power requirement (26,054,000 man hours). It was found possible to accomplish this by building the permanent housing in the first two years and the plant proper in the last three years of the estimated five-year construction period. This permitted holding the peak man power requirement down to 5,800 men. It permitted holding the temporary housing requirement down to 2,900 units furnished; used first in the permanent housing

program and again in the plant proper construction program. The temporary housing requirement is minimized by using 2,600 units of permanent housing for plant construction workers, and early arrivals of plant and mine forces, resulting in an important saving on temporary housing costs. Should the permanent housing program be reduced, temporary housing would have to be increased.

G. B. Burleson
E. H. Roy
J. D. Snakenberg

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April 20, 1951

Mr. L. C. Kemp, Jr.
The Texas Company
135 East 42nd. St.
New York 17, New York

Dear Sir:

Yesterday I had a thorough discussion of the economic aspect of permanent housing projects, in connection with synthetic fuel plants, with Mr. G. Dewey Hynes, Vice President of The Equitable Life Assurance Society, who deals with such matters for his company. His conclusions are summarized in his letter of April 19th, attached.

Mr. Hynes states that since the value of the housing would be completely dependent on the continued operation of the plant, the housing would not represent a good risk, either from the point of view of ownership by his company, or for a loan. At the present time, the possibility of the community becoming a "ghost town" is the controlling matter to him, (1) because the plant represents a new industry of unproven earning power when marketing its product in the competitive market served by the petroleum industry, and (2) because the region does not have, and is not likely to have, other industries with attendent housing demands. Further, (3) the plant is not of a type, or in a location near markets and supplies, which offers any likelihood of its being converted to other industrial use if its designed operation should be discontinued.

Mr. Hynes said that, of course, his company would give consideration to housing ownership or loans if some one of recognized financial standing assumed the full risk of the continued operation of the plant, thus insuring occupancy of the houses. For example, he said if several large oil companies were to build the plant, and would assume this risk with regard to the housing, his company would be satisfied, as the financial standing of these companies would be the basis on which the project would be judged. The raising of funds by these companies for housing would thus be on a basis no different than for the plant proper.

Mr. Hynes was fully in accord with the premise that an orderly planned housing project must be considered nothing less than essential to the successful inauguration of a project of this nature and scope in a sparsely settled region.

It is Mr. Hynes opinion that a large scale housing project, including commercial buildings, should "carry itself" from its rentals. This, of course, was based on amoritization rates common to insurance companies. I did not have time to discuss with Mr. Hynes, Industry's experience with building employee housing, where the company involved is associated with the housing in the minds of employees. This experience is that rentals are depressed by the employees associating them with wages and working conditions.

Mr. Hynes volunteered the suggestion that it would be unnecessary to check with other insurance companies, if I had thought of doing so, as the answer was too obvious to allow any possibility that another similar institution might reach a different conclusion than his.

Yours very truly,

JDS:vm

/s/ J. D. Snakenberg

COPY

THE EQUITABLE LIFE ASSURANCE SOCIETY
OF THE UNITED STATES

393 Seventh Avenue, New York
Thomas I. Parkinson, President

G. Dewey Hynes
Vice President

April 19, 1951

Mr. J. D. Snakenberg
National Petroleum Council Subcommittee
on Synthetic Fuel Costs
54 Wall Street
New York, N.Y.

Dear Mr. Snakenberg:

The housing which is required for the two projects, which we discussed at length today, Rock Springs Hydrogenation or a Shale Oil Project in Colorado, would not qualify as an investment for a life insurance company unless they carried the endorsement of an acceptable guarantor.

If we can be of further assistance to you and your Subcommittee, we shall be very pleased to have you call upon us.

Yours very truly,

/s/ G. Dewey Hynes

Vice President

GDH:DMD

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CITIES SERVICE

PETROLEUM ADVISERS, INC., Sixty Wall Tower, New York 5, N.Y.

June 13, 1951

Mr. Joel H. Hirsch
Gulf Research and Development Company
P. O. Drawer 2038
Pittsburgh 30, Pennsylvania

Dear Sir:

On May 29 I had a conference on the Synthetic Fuel Plant housing problem with Mr. M. Carter McFarland, Office of the Administrator, Housing and Home Finance Agency, Room 603, Normandie Building, K Street, Washington, D.C. Mr. Raymond M. Foley is Administrator and I am advised that Mr. McFarland is one of his top assistants in this Agency. The particular information sought was what aid can be obtained from government agencies for housing projects, with incidental analysis of the housing problem in cases similar to those of the proposed synthetic fuel plants.

Briefly I learned that there is no government agency to provide help, that the providing of housing is necessary in isolated communities such as are under consideration, and that it presents peculiar and difficult financing problems under these conditions.

Mr. McFarland stated that no agency such as the RFC is authorized to loan money for such projects (they did during the last war but not under the present laws). Neither could any FHA approval of housing loans be extended to a project of this kind at the time of construction. Sometime later, after operations were established, and if the project then seemed to justify, there is a possibility that housing might then qualify for FHA approval. The agency would naturally be slow to qualify housing dependent on a single industry.

The agency has no basis for qualifying loans other than that it be a good risk as gauged by ordinary business standards. The agency insures loans for a fee which goes to a reserve to pay off bad loans. Thus, the mistakes that it can make are limited. Their function is to assist in making housing available where needed but where financing would not otherwise be available, although the project presented a good risk. The agency has no function of helping new industries to get established, - however meritorious, which would allow the agency to alter its usual standards of judging what constitutes a good risk.

There is a bill pending which has passed one branch of Congress, which would authorize them to make exceptions for certain cases that need housing in connection with defense projects. Even though passed, however, it would not alter this Committee's study, since the synthetic fuel plants are not defense projects.

Mr. Joel H. Hirsch June 13, 1951

Even before he had heard the complete story, Mr. McFarland's wide experience with such matters prompted him to state that the plant builder could not afford to leave housing to chance in cases like Rock Springs and Rifle. Mr. McFarland went on to state that the outstanding feature of such a situation, not appreciated by many, is the necessity of financing civic facilities (such as roads, water and sewer systems, schools and hospitals and the like) at a time when no taxing base exists from which these facilities are ordinarily developed, step by step, as a community grows. Not only would the civic facilities have to be initially designed, financed, and constructed by the plant builder, but he stands little chance of ever getting a substantial return on this investment after normal taxing units are established.

Not only do the providing of civic facilities present a problem, but the ownership of homes by the plant builder is undesirable. Congress has told the agency for the Atomic Energy Plants to avoid getting involved in building housing again as they did at Oak Ridge and other plants; with the Government owning housing, this surely represents a form of subsidy. When an attempt is made to raise rents, the employees demand a raise in wages. Also the government housing standards had been higher than those common in the communities involved with the result that the housing costs were too high to permit selling the housing for what it cost.

Mr. McFarland felt that in the case of housing, every effort should be made to sell the housing to the individual using the housing within a year or two after the plant started. He recognized the difficulty of selling until confidence in continuity of operations be adequately established. He thought one plan to bridge this gap might be the plan of an option to buy, extended for a suitable period, with all rental to date applying against the agreed price.

Mr. McFarland believes the costs and risks above-referred to must inevitably be incurred by the plant builder in an isolated area such as those under consideration, but he did not attempt any suggestions how this might most equitably be reflected in the price of the product. If the plants were nearer large centers practically all these costs and risks could be avoided by the plant builder.

Very truly yours,

/s/ J. D. Snakenberg

JDS:db

cc: Messrs. L. C. Kemp, Jr.
R. G. Atkinson
F. T. Barr
T. R. Moore
P. R. Schultz

September 27, 1951

ECONOMICS OF COAL HYDROGENATION - MULTI-PLANT CASE

INTRODUCTION

The economics of coal hydrogenation on a multi-plant basis are presented using the process as set forth by the U.S. Bureau of Mines. This so called multi-plant case is comprised of an evaluation of eight separate plants, producing a total of 216,000 B/CD of liquid fuels, which are scattered geographically and use a variety of types of coal. None of the individual plants should be considered as being representative of the optimum locations for plants of this nature. If it is necessary for this study to be an exemplar of some kind, it is proposed that the average costs for all eight plants be construed as those resulting from the development of a capacity in excess of 216,000 B/CD - perhaps a million barrels per day - from this process. The primary value of this study will be derived from the insight it provides into variations in costs resulting from the geographic distribution and the types of coals used.

These economics are consistent with the raw material, process and engineering studies performed by the NPC Subcommittee on Synthetic Liquid Fuels Production Costs. The derivation of individual items of income and expense was performed in the same manner as explained in the separate report on the Rock Springs, Wyoming, coal hydrogenation plant. Throughout this study, all costs or prices have been adjusted to the level of January 1, 1951, in order that this study may be adjusted as economic conditions may change.

DISCUSSION

The attached table presents the evaluation of eight separate coal hydrogenation plants at sites selected by the Raw Materials Subcommittee of the NPC Subcommittee on Synthetic Liquid Fuels Production Costs.

The results of this study are briefly summarized in the following table:

Location	Investment Cost: Per B/CD of Total Liquid Fuels	Investment Cost: Per B/CD of Gasoline	Cost of Gasoline, ¢/Gal.
Sweetwater Co., Wyoming (Rock Springs)	$19,100	$25,300	42.5
Rosebud Co., Montana	19,300	24,800	42.1
Dunn Co., N. Dakota	19,900	25,300	43.1
Franklin Co., Illinois	18,700	25,000	44.7
Knox Co., Indiana	18,200	23,800	43.1
Union Co., Kentucky	18,400	24,300	43.5
Muhlenberg Co., Kentucky	17,400	23,000	41.0
Wetzel Co., W. Va.	19,900	27,400	48.5
Average, 8 Plants	18,900	24,900	43.5

In the above table, the cost of gasoline includes a return, after income taxes at an assumed rate of 50%, of 6% per year on investment.

The investment used for these plants is comparable to that shown as Case C in the separate report on the Rock Springs plant. Under the Case C basis, housing for the plant employees and general community facilities are included, but the housing for tradespeople and others, and commercial buildings, are excluded. There is, however, an appreciable difference between housing costs for western locations compared to eastern locations. This distinction is due solely to the remoteness and sparsity of population of the western locations. A discussion of this matter can be found in the report of the offsites group of the Engineering Subcommittee.

One of these sites, viz., Rock Springs, Wyoming, is the particular site chosen by the U.S. Bureau of Mines for the detailed evaluation of the coal hydrogenation process. As mentioned previously, a separate report has been prepared by the NPC on this particular site, but it should be noted that the evaluation of the Rock Springs plant as presented herein is on a different basis. In the report dealing solely with the Rock Springs plant, the maximum credit for by-product chemicals was allowed on the premise that it was the first and only plant of this type. In this report, the economics for all of the plants have been developed on the premise that they are in competition with each other. This premise has a decided effect on by-product credits, but relatively no effect on the cost of gasoline. For instance, if all eight plants were to attempt to market phenols, the total quantity available would be roughly twice the present U.S. consumption of these chemicals, as a class. Under these conditions, present market prices would not be obtained, but rather the value of these chemicals would decrease to a level approximating their value as gasoline charge stock. Thus, the eight plants presented herein do not have facilities for recovering phenols, and the phenols are therefore converted to liquid fuels. In summary, a comparison of the two Rock Springs plant evaluations indicates that the additional cost of recovering phenols nearly offsets the additional value of these chemicals, as follows:

	Rock Springs Coal Hydrogenation Plant	
Unit Costs (Case C)	Chemicals Recovered	Chemicals Converted to Liquid Fuels
Total Investment, $/B/CD*	$27,400	$25,300
Cost of Gasoline, ¢/Gal.		
Before By-Product Credit	46.9	43.5
Credit for Phenols	- 4.5	-
Credit for LPG	- 1.0	- 1.0
Net Cost	41.4	42.5

* Based on Gasoline Yield.

In addition to phenols, large volumes of aromatics such as benzene could be recovered from the coal hydrogenation process. It is very doubtful, however, that a long-term price for aromatics, even based on commodity price levels of January 1, 1951, would exceed the cost of gasoline shown herein. Thus, no justification exists for setting up additional cases on even one plant for the recovery of aromatics.

Among the items of investment, there are several which require further explanation. First, the amount of $1,000,000 shown for process royalties is probably less than the actual expense; to date, no royalties have been

established for certain phases of the processing scheme. Second, a portion of the start-up expense, covering operation at less than design capacity during the initial year of operation, is proportionately less than that shown in the separate report on the Rock Springs plant. This results from the premise that the initial plant, at Rock Springs or elsewhere, would be instrumental in improving the initial operation of succeeding plants. It was therefore assumed that these eight plants would achieve 80% of design capacity during the first year vs. 65% for the initial plant.

One item of investment, the interest on capital expenditures during the construction period, has been omitted. Without knowledge of the type of financing involved and the return that the investors, institutional or private, would require, this sum cannot be determined.

The average cost of gasoline determined for these eight plants (43.5¢ per gallon), greatly exceeds the average refinery realization on gasoline which is estimated to be 12 to 13¢ per gallon throughout the same marketing areas. A considerable portion of the cost of gasoline from these coal hydrogenation plants is due to the addition of the 6% per year return on investment plus the allowance for federal income taxes at a 50% rate. It would be extremely unrealistic, however, to develop economics of this nature without indicating a return on the investment. Also, it is our opinion that a 6% return is the minimum applicable to a venture of this nature. Even without considering obsolescence a more realistic rate of return would be not less than 15% per year in recognition of the risk involved in such a project.

This report makes no attempt to explain any items of income or expense that can be found in the report on the Rock Springs plant or in the reports of the Process, Engineering, or Raw Materials Subcommittees.

By: P. R. Schultz

Economics Subcommittee
P. R. Schultz, Chairman
R. G. Atkinson
F. T. Barr
J. H. Hirsch
T. R. Moore
C. F. Parker
J. D. Snakenberg

ECONOMICS OF COAL HYDROGENATION PLANTS -
MULTI-PLANT CASE
Note: Chemicals are converted to liquid fuels

Location State County	Wyoming Sweetwater	Montana Rosebud	N. Dakota Dunn	Illinois Franklin	Indiana Knox	Kentucky Union	Kentucky Muhlenburg	W. Virginia Wetzel	Total 8 Plants
PRODUCT YIELDS & BY-PRODUCT CREDITS									
Product Yields, B/CD									
Gasoline	20,340	20,940	21,320	20,220	20,590	20,380	20,420	19,620	163,830
LPG	6,660	6,060	5,680	6,780	6,410	6,620	6,580	7,380	52,170
Total Liquid Fuels	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	216,000
By-Product Value									
LPG, $/Gal.	3.0	3.0	3.0	4.0	4.0	4.0	4.0	4.5	--
By-Product Credit, $/CD									
LPG	$ 8,392	$ 7,636	$ 7,157	$ 11,390	$ 10,769	$ 11,122	$ 11,054	$ 13,948	$ 81,468
COAL REQUIRED, TONS/CD	12,150	16,650	24,500	12,000	12,400	11,820	12,250	10,820	112,590
OPERATING EXPENSES, $/CD									
Coal Hydrogenation Plant									
Labor									
Operating	$ 11,088	$ 11,520	$ 11,712	$ 11,376	$ 11,184	$ 11,328	$ 11,232	$ 12,000	$ 91,440
Maintenance	27,085	28,118	28,910	28,198	27,370	27,811	26,961	29,299	223,752
Unit Supervision & Clerical	1,663	1,728	1,757	1,706	1,678	1,700	1,685	1,800	13,717
Payroll Extras	7,987	8,273	8,476	8,256	8,046	8,168	7,976	8,620	65,782
Materials									
Operating	2,911	2,996	3,063	3,028	2,940	2,995	2,902	3,149	23,984
Maintenance	14,553	14,982	15,317	15,139	14,700	14,975	14,508	15,745	119,919
Utilities	- 1,132	- 666	- 980	- 900	- 930	- 887	- 1,161	- 1,298	- 7,964
Catalysts & Chemicals	6,135	5,875	5,545	3,980	4,250	4,020	4,010	5,730	39,565
Tetraethyl Lead	218	611	984	380	406	672	673	370	4,314
Total Direct Expense	$ 70,498	$ 73,437	$ 74,784	$ 71,163	$ 69,644	$ 70,782	$ 68,786	$ 75,415	$ 574,509
General Overhead (Plant Burden) & Administrative Overhead	28,650	29,672	30,380	29,724	28,936	29,405	28,644	30,996	236,407
Research and Development	2,740	2,740	2,740	2,740	2,740	2,740	2,740	2,740	21,920
State, County, & Local Taxes and Insurance	15,962	16,434	16,767	16,619	16,044	16,332	15,830	17,240	131,228
Total Plant Expense Excluding Depreciation	$117,850	$122,283	$124,671	$120,246	$117,364	$119,259	$116,000	$126,391	$ 964,064
Coal Mine									
Labor									
Total Mine Labor	$ 7,460	$ 3,829	$ 6,689	$ 24,000	$ 24,800	$ 21,631	$ 8,820	$ 24,101	$ 122,330
Payroll Extras	4,410	5,161	7,595	4,200	4,340	4,137	4,042	3,787	37,672
Purchased Power	1,142	666	980	900	930	887	1,161	1,298	7,964
Total Supplies	5,516	9,657	4,459	)	)	)	)	)	)
Administrative Overhead	1,555	1,165	2,450	) 14,100	) 14,569	) 13,888	) 14,151	) 13,849	) 103,400
State, County, & Local Taxes and Insurance	3,852	1,249	2,940	)	)	)	)	)	)
Royalty	996	1,832	2,303	--	--	--	6,125	--	11,256
Total Mine Expense Excluding Depreciation	$ 24,931	$ 23,559	$ 27,416	$ 43,200	$ 44,639	$ 40,543	$ 34,299	$ 44,035	$ 282,522
Total Operating Expense Excluding Depreciation	$142,781	$145,842	$152,087	$163,446	$162,003	$159,802	$150,299	$170,426	$1,246,686

Location State County	Wyoming Sweetwater	Montana Rosebud	N. Dakota Dunn	Illinois Franklin	Indiana Knox	Kentucky Union	Kentucky Muhlenburg	W. Virginia Wetzel	Total 8 Plants
INVESTMENT									
Total Plant	$388,400,000	$399,900,000	$408,000,000	$404,400,000	$390,400,000	$397,400,000	$385,200,000	$419,500,000	$3,193,200,000
Construction Housing	7,000,000	7,000,000	7,000,000	--	--	--	--	--	21,000,000
Coal Mine	11,900,000	7,300,000	11,000,000	29,600,000	30,600,000	29,100,000	21,200,000	44,500,000	185,200,000
Process Royalties	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	8,000,000
Start Up Expense	12,200,000	12,300,000	12,900,000	12,800,000	12,500,000	12,600,000	12,300,000	13,300,000	100,900,000
Working Capital	36,600,000	38,800,000	38,100,000	41,300,000	41,000,000	40,500,000	38,600,000	43,000,000	317,900,000
Total Investment Excluding Housing	$457,100,000	$466,300,000	$478,000,000	$489,100,000	$475,500,000	$480,600,000	$458,300,000	$521,300,000	$3,826,200,000
Housing for Employees	46,700,000	42,900,000	48,500,000	12,400,000	12,300,000	12,200,000	9,700,000	13,400,000	198,100,000
General Community Facilities	11,700,000	10,800,000	12,200,000	3,100,000	3,100,000	3,100,000	2,400,000	3,400,000	49,800,000
Total Investment	$515,500,000	$520,000,000	$538,700,000	$504,600,000	$490,900,000	$495,900,000	$470,400,000	$538,100,000	$4,074,100,000
ECONOMICS, $/CD									
Total Operating Expense	$142,781	$145,842	$152,087	$163,446	$162,003	$159,802	$150,299	$170,426	$1,246,686
Depreciation of Operating Investment	55,794	58,147	60,009	59,452	57,671	58,493	55,671	63,562	468,799
Amortization of Process Royalties & Start-Up Expense	1,808	1,822	1,904	1,890	1,849	1,863	1,822	1,959	14,917
Depreciation of Housing Facilities	8,000	7,356	8,315	2,123	2,110	2,096	1,658	2,301	33,959
Sub-Total	$208,383	$213,167	$222,315	$226,911	$223,633	$222,254	$209,450	$238,248	$1,764,361
Credit for By-Products	- 8,392	- 7,636	- 7,157	-11,390	-10,769	-11,122	-11,054	-13,948	-81,468
Income from Electricity Sold to Community	- 570	- 523	- 591	- 151	- 150	- 149	- 118	- 163	- 2,415
Rental Income from Housing Facilities	- 5,758	- 5,289	- 5,979	- 1,529	- 1,516	- 1,504	- 1,196	- 1,652	-24,423
Cost of Gasoline before Profit	$193,663	$199,719	$208,588	$213,841	$211,198	$209,479	$197,082	$222,485	$1,656,055
Return on Investment @ 6% per Year	84,740	85,479	88,553	82,946	80,696	81,518	77,326	88,455	669,713
Federal Income Taxes @ 50% Rate	84,740	85,479	88,553	82,946	80,696	81,518	77,326	88,455	669,713
Cost of Gasoline Including Return:									
$/CD	$363,143	$370,677	$385,694	$379,733	$372,590	$372,515	$351,734	$399,395	$2,995,481
¢/Gal.	42.5	42.1	43.1	44.7	43.1	43.5	41.0	48.5	43.5

September 26, 1951

ECONOMICS OF PRODUCING LIQUID FUELS FROM OIL SHALE - INITIAL PLANT

INTRODUCTION

The economics of an initial plant to produce 39,700 B/CD of refined products from oil shale have been determined using the process established by the shale oil process group of the NPC Subcommittee on Synthetic Liquid Fuels Production Costs. This processing scheme has been agreed to by the U.S. Bureau of Mines. These economics are based on the data provided by other groups, functioning within this NPC Subcommittee, which studied the process, engineering, and raw materials phases of this subject.

A separate report will cover shale oil production on a larger scale in which approximately 200,000 B/CD of refined products are produced.

This study develops the economics in the same manner as employed by U.S. industries in general for the evaluation of new processes or projects. Throughout the study, all costs or prices have been adjusted to the level of January 1, 1951, in order that this study may be adjusted as economic conditions may change.

DISCUSSION

The attached table and appendices present the evaluation of an initial shale oil project and the basis for each of the cost items used. Where possible, the determination of these figures was based upon analogous situations, operations, or equipment as found in the petroleum or chemical industries. The retorting of oil shale is the one operation on which no commercial experience was available from which this group could derive costs. The operating and maintenance costs were based on the pilot plant operations of the Union Oil Company of California who developed this particular type of retort. Thus, it is believed that all major cost factors have been included and that their order of magnitude is correct.

The shale oil project consists of five major units; these are:

(1) Oil shale mines located in the Green River shale formation of Western Colorado.

(2) Oil shale retorts, located near the mine portals, to produce a crude shale oil.

(3) Oil shale refinery, located within a few miles of several retort sites, to produce raw gasoline and gas oil fractions.

(4) Pipeline to transport the semifinished products to refineries in the Los Angeles area.

(5) Incremental refining facilities at existing refineries near Los Angeles to process raw gasoline and gas oil into finished motor fuel, diesel fuel, fuel oil, and LPG.

Of these items, the first four represent new facilities that are in no way integrated into our present supply of liquid fuels. The fifth item, incremental facilities at an existing refinery in California, represents a concession to predicted future trends in petroleum product supply and demand. The pipeline could have been designed to carry the semifinished products to Kansas City or St. Louis at about the same cost, or to Chicago at a slightly greater cost. It appears, however, that the demand for liquid fuels in California is growing at a faster pace than other sections of the country. From this viewpoint, it is apparent that established refineries in California will be greatly concerned in obtaining additional supplies of liquid fuels and also in utilizing their present refineries to make finished products.

The crude shale oil could be vis-broken and transported to a refinery site in California, but it is the consensus of those studying this project that the semifinishing of products at the Colorado site is more economical in that it permits the use of the retort off-gas, having a heating value of 83 Btu/SCF, for plant fuel. This gas, otherwise, would have no fuel value.

The products obtained from this project are as follows:

Product	Volume/CD
At Colorado	
Ammonia, Tons	92
Sulfur, Tons	43
Coke, Tons	1,180
Fuel Gas (1,060 Btu/SCF), MSCF	24,830
At California	
Motor Gasoline, Bbls	25,380
Diesel Fuel, Bbls	12,200
Fuel Oil, Bbls	340
LPG, Bbls	1,780
Total Liquid Fuels, Bbls	39,700

A small additional quantity of liquid fuels are produced but are consumed in the Colorado operations. A small portion of the semifinished gasoline and gas oil could be marketed in the Colorado region, but since it is doubtful that such a premise would improve the economics, it was assumed that all liquid fuels would be finished and marketed in California. Of these eight separate products, six were given by-product status and only motor gasoline and diesel fuel were considered as major products. In

order to simplify the economics, the cost of these major products was expressed in terms of "equivalent gasoline". This phrase has several definitions, and to clarify its use in this study, the calculation of "equivalent gasoline" volume is presented below:

Product	Relative Refinery Market Value	Production, B/CD	Volume as Equivalent Gasoline, B/CD
Motor Gasoline	100%	25,380	25,380
Diesel Fuel	70%	12,200	8,540
Total		37,580	33,920

As indicated above, the factor used to convert diesel fuel is merely the refinery realization relative to motor gasoline.

For the four cases considered, the investment cost and the cost of gasoline including a 6% per year return can be summarized as follows:

	CASE			
	A	B	C	D
Investment Cost				
Per B/CD of Total Liquid Fuels	$7,700	$ 8,900	$8,400	$7,800
Per B/CD of Equivalent Gasoline	$9,000	$10,400	$9,800	$9,200
Cost of Equivalent Gasoline Including 6% Return, ¢/Gal.	15.5	16.6	16.2	15.7

The four variations in investment cost represent relative levels of responsibility on the part of the project sponsor toward providing housing and community facilities. Briefly, these cases are:

A - No housing or community development.

B - Complete housing and community development including (1) housing for employees, (2) housing for tradespeople, teachers, etc., (3) general community facilities comprised of streets, utilities, schools, etc., and (4) commercial buildings.

C - Housing for employees and general community facilities.

D - General community facilities.

Of these four cases, A and B represent respectively, the minimum and maximum expenditures. Neither of these cases, however, is believed to represent the probable situation. In order to obtain an adequate and stable labor supply at minimum investment, it is the opinion of the Subcommittee that the housing program would approach that of case C. These expenditures are presented in the following table:

	CASE			
	A	B	C	D
	(In Thousands of Dollars)			
Housing for Employees	-	$22,000	$22,000	-
Housing for Tradespeople and Others	-	15,400	-	-
General Community Facilities	-	5,500	5,500	$5,500
Commercial Buildings	-	6,100	-	-
Total	-	$49,000	$27,500	$5,500

For the different categories included under housing and community development, factors representing the excess of rental income over maintenance costs were estimated. They are as follows:

(1) Housing for Employees and Tradespeople: A net income over 20 years of 90% of initial cost was assumed.

(2) General Community Facilities: It was assumed that a new community would not be able to assess taxes during the 20-Year period which would be sufficient to retire an appreciable portion of the investment and so no recovery was included.

(3) Commercial Buildings: The assurance of a stable market for 20 years should permit tradespeople to pay sufficient rents to yield a net income equal to 200% of the investment.

The by-product credits, and their effect in reducing the cost of "equivalent gasoline", are shown in the following table:

By-Product	Quantity per CD	Price	Value $/CD	Reduction in Cost of Equivalent Gasoline, ¢/Gal.
Fuel Oil	340 Bbls	$1.60/Bbl	$ 544	0.04
LPG	1,780 Bbls	5.3¢/Gal.	3,962	0.28
Ammonia	92 Tons	$80.00/Ton	7,360	0.52
Sulfur	43 Tons	$20.50/Ton	882	0.06
Coke	1,180 Tons	$4.00/Ton	4,720	0.33
Fuel Gas	24,830 MSCF	7.0¢/MSCF	1,738	0.12
Total			$19,206	1.35

The development of the prices used for these by-products is presented in the appendices attached hereto. The LPG price of 5.3¢/gal. is based on a mixture comprised of 80% butane and 20% propane.

The depreciation of the facilities has been set at a rate consistent with the composite life of the equipment. Thus, the mine investment has been depreciated at a rate of 10% per year corresponding to a composite life of 10 years for all depreciable items. The plant, excluding such items as process royalties, has an indicated composite life of 19.6 years, corresponding to a 5.11% depreciation rate. This, however, was rounded off to an even 5% and applied to all investment items excluding the mine.

Although every effort was made to include all items of expense and income pertaining to a project of this nature, there are two items which have purposely been excluded. The first is interest on capital expended during the construction period. The interest expense would depend on the type of financing and on the return that the creditors,

institutional or private, would expect. Neither of these factors has been determined, and it was decided to omit this item. The second item is the cost of acquiring oil shale lands or mineral rights. This matter is discussed in the oil shale mining report, wherein it is pointed out that, to date, the cost of acquiring these properties would not appreciably alter the cost of mining shale.

The producing cost of 16.2¢ per gallon (case C) compares with a refinery realization of 11.7¢/gallon on gasoline in the Los Angelse area. Thus, while shale oil products are not competitive, it is apparent that they are potentially the next important source of liquid fuels.

The financial incentive for this source of liquid fuels, however, will not be created until the price of crude oil has increased considerably above its present price. This, however, would not guarantee that investors, or petroleum companies, would care to invest in a new and somewhat speculative venture if it could earn only 6% per year, after income taxes at a 50% rate. This return, plus depreciation at slightly over 5%, would pay out the investment in about 9 years. This is not a sufficiently rapid payout on a new project, particularly in the petroleum industry where a high rate of obsolescence has always been encountered. The return of 6% per year should therefore be considered as a minimum applicable to the evaluation of this process. If anything, the rate of return should be increased to a level of not less than 15% per year in recognition of the risks involved in such a project.

The other items of expense and income used in this study are believed to be amply explained in the attached table and appendices. These sources of information, however, make no attempt to duplicate items presented in the reports of the Process, Engineering, and Raw Materials Subcommittees.

By: P. R. Schultz

<u>Economics Subcommittee</u>
P. R. Schultz, Chairman
R. G. Atkinson
F. T. Barr
J. H. Hirsch
T. R. Moore
C. F. Parker
J. D. Snakenberg

SUMMARIZED ECONOMIC CALCULATIONS FOR 39,700 B/CD OF REFINED PRODUCTS FROM SHALE OIL PROJECT

		Units/CD	Price	$/CD
1.	PRODUCT YIELDS AND BY-PRODUCT INCOME			
2.	Liquid Fuels			
3.	Motor Gasoline, Bbls.	25,380	--	--
4.	Diesel Fuel, Bbls.	12,200	--	--
5.	Residual Fuel Oil, Bbls.	340	$1.60/Bbl.	$ 544
6.	LPG, Bbls.	1,780	5.30¢/Gal.	3,962
7.	Total Liquid Fuels, Bbls.	39,700	--	--
8.	Other Products			
9.	Ammonia, Tons	92	$80.00/Ton	7,360
10.	Sulfur, Tons	43	$20.50/Ton	882
11.	Coke, Tons	1,180	$ 4.00/Ton	4,720
12.	Fuel Gas (1,060 Btu/SCF), MSCF	24,830	7.0¢/MSCF	1,738
13.	By-Product Income, $/CD	--	--	$19,206

		Basis	$/CD
14.	OPERATING EXPENSE		
15.	RETORTING, REFINING, & PIPELINE FACILITIES		
16.	Labor		
17.	Operating	612 Employees @ $1.98/Hr.	$ 6,921
18.	Maintenance	1.81% per Yr. of $214,655,000 Investment	10,620
19.	Unit Supervision & Clerical	Detailed in Engineering Report	1,100
20.	Payroll Extras	20% of Items 17, 18, & 19	3,728
21.	Material		
22.	Operating	Detailed in Engineering Report	1,470
23.	Maintenance	1.39% per Yr. of $214,655,000 Investment	8,190
24.	Utilities	See Footnote *	-2,260
25.	Catalysts and Chemicals	Detailed in Engineering Report	3,890
26.	Tetraethyl Lead	1.5 cc per Gallon @ 0.224¢/cc	3,582
27.	Total Direct Expense		$37,241
28.	General Overhead (Plant Burden) & Administrative Overhead	50% of Items 17, 18, 19, 22, & 23	14,150
29.	Research & Development	$1,000,000 per Year	2,740
30.	State, County, & Local Taxes and Insurance	1.5% per Year of $230,220,000 Investment	9,461
31.	Total Plant and Pipeline Expense Excluding Depreciation		$63,592
32.	OIL SHALE MINE (76,800 T/CD)		
33.	Labor		
34.	Total Mine Labor	1,156 Total Employees	$15,116
35.	Payroll Extras	Basis Given in Oil Shale Mining Report	2,700
36.	Utilities	Purchased from Shale Oil Plant	3,050
37.	Total Supplies	Detailed in Oil Shale Mining Report	10,949
38.	Administrative Overhead	10% of Total Labor Cost	1,780
39.	State, County, & Local Taxes and Insurance	1.08% per Year of Mine Investment	792
40.	Depletion and Royalty	(None Estimated)	--
41.	Total Mine Expense Excluding Depreciation		$34,387
42.	Total Operating Expense Excluding Depreciation		$97,979

		Case (See Explanation in Text)			
		A	B	C	D
43.	INVESTMENT				
44.	Total Plants and Pipeline	$214,660,000	$214,660,000	$214,660,000	$214,660,000
45.	Construction Labor Premium	15,570,000	15,570,000	15,570,000	15,570,000
46.	Oil Shale Mines	26,020,000	26,020,000	26,020,000	26,020,000
47.	Process Royalties	11,730,000	11,730,000	11,730,000	11,730,000
48.	Start-Up Expense	9,400,000	9,400,000	9,400,000	9,400,000
49.	Working Capital	27,700,000	27,700,000	27,700,000	27,700,000
50.	Total Investment Excluding Housing	$305,080,000	$305,080,000	$305,080,000	$305,080,000
51.	Housing for Employees	--	22,000,000	22,000,000	--
52.	Housing for Tradespeople & Others	--	15,400,000	--	--
53.	General Community Facilities	--	5,500,000	5,500,000	5,500,000
54.	Commercial Buildings	--	6,100,000	--	--
55.	Total Investment	$305,080,000	$354,080,000	$332,580,000	$310,580,000
56.	ECONOMICS, $/CD				
57.	Total Operating Expense	$ 97,979	$ 97,979	$ 97,979	$ 97,979
58.	Depreciation of Operating Facilities (Items 44,45, & 46)	38,614	38,614	38,614	38,614
59.	Amortization of Process Royalties & Start-Up Expense	2,895	2,895	2,895	2,895
60.	Depreciation of Housing Facilities	--	6,712	3,767	753
61.	Sub-Total	$139,488	$146,200	$143,255	$140,241
62.	Credit for By-Products	- 19,206	- 19,206	- 19,206	- 19,206
63.	Income from Electricity Sold to Community	--	- 440	- 259	0
64.	Rental Income from Housing Facilities	--	- 6,282	- 2,712	0
65.	Cost of Major Products Before Profit	$120,282	$120,272	$121,078	$121,035
66.	Return on Investment @ 6% per Yr. of Item 55	50,150	58,205	54,670	51,054
67.	Federal Income Taxes @ 50% Rate	50,150	58,205	54,670	51,054
68.	Cost of Major Products Including Return	$220,582	$236,682	$230,418	$223,143
69.	Cost of Equivalent Gasoline**, ¢/Gal.	15.5	16.6	16.2	15.7

* Utilities purchased from outside sources for pipeline and California refining facilities equal $790/CD; credit for utilities sold to mine is $3,050/CD.

** Equivalent gasoline volume is comprised of 100% of gasoline plus 70% of diesel fuel, which basis represents relative value of these two products.

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UNION OIL COMPANY OF CALIFORNIA
Union Oil Building
Los Angeles 17, California

ECON-183

September 10, 1951

AIRMAIL

Mr. P. R. Schultz
Stanolind Oil and Gas Company
Stanolind Building
Tulsa, Oklahoma

NPC SUBCOMMITTEE ON SYNTHETIC LIQUID FUELS PRODUCTION COSTS

Dear Mr. Schultz:

The attached memorandum presents the data relative to product prices and TEL requirements requested in your letter of August 10, 1951.

Very truly yours,

/s/ Charles F. Parker

Charles F. Parker

CFP:as
Attachment

cc: Messrs. R. G. Atkinson
Frank T. Barr
Joel H. Hirsch
T. R. Moore
J. D. Snakenberg
D. F. Houlihan (2)

NPC SUBCOMMITTEE ON SYNTHETIC LIQUID FUELS PRODUCTION COSTS

LOS ANGELES PRODUCT PRICES AND ESTIMATED TETRAETHYL LEAD REQUIREMENTS

Product Prices

The following are present representative refinery prices, ex taxes, in the Los Angeles area for the principal petroleum products, delivery by cargo or pipeline:

	¢/Gal	$/Bbl
Gasoline, premium	12.5	5.25
Gasoline, regular	11.5	4.83
Diesel oil		3.44
Residual fuel oil		1.70

For evaluation work, the above prices should be adjusted to allow for applicable selling expense. An allowance of 10¢ per barrel is suggested.

Following are estimates of year-around average refinery values for LPG fractions in the Los Angeles area:

	¢/Gal
Propane	2.5
Butane	6.0
Commercial butane (annual average, approximately 50% butane and 50% propane)	4.25

The above values are consistent from a time standpoint with the engineering estimates of capital requirements and operating expenses, which are based on January 1, 1951, data.

Gasoline Quality and TEL Requirements

The following tabulation presents a comparison of the characteristics of the gasolines produced from shale oil and typical pre-Korea California gasolines:

	Typical California Gasoline		Shale Oil Gasoline	
	Regular	Premium	Regular	Premium
TEL, ml/gal	1.4	2.4	1.5	1.5
KR, research	82.5	91.0	82.5	91.0
KR, motor	77.5	84.0	77.0	82.0
Engler, e.p.	393	367	400	380
Engler, 90%	350	324	350	340
Nitrogen, wt %	.006	.006	.001	.003
Sulfur, wt %	.19	.10	.01	.05
Induction, min.	500/	500/	500/	500/
ASTM gum, mg/100 ml	1.6	1.8	1.0	1.0
Cu dish gum, mg/100 ml	6.8	6.4	3.0	8.0
Accel. gum, mg/100 ml	2.7	3.3	4.0	4.0

As shown above, it is estimated that the addition of 1.5 cc/gal TEL will be needed to produce finished gasolines from shale having the research knock-rating characteristics of typical California gasoline. The delivered price of TEL, as of January 1, 1951, was 0.224¢/cc and is the same at the present time. The data on California gasolines represent an average of the summer and winter tests. Shale oil gasoline figures are based on a 50% ratio of premium to total motor gasoline as reflected in the Process and Engineering studies. Since World War II, this ratio in the Five Western States has ranged between 40% and 55%.

WHBuell:as
9/10/51

MEMORANDUM

September 26, 1951

Re: Economics Subcommittee of
NPC Subcommittee on Synthetic
Liquid Fuels Production Costs

By-Product Prices, Other Than Liquid Fuels, for Initial Shale Oil Plant

The partial refining of crude shale oil at the Colorado site produces the following by-products in addition to liquid fuels:

By-Product	Quantity/CD
Ammonia	92 tons
Sulfur	43 tons
Coke	1,180 tons
Fuel Gas (1,060 Btu/SCF)	24,830 MSCF

The prices assigned to these by-products were developed as follows:

Ammonia: At the present, anhydrous ammonia is moving into this region in tank car quantities from midwestern plants. There is no freight equalization on this movement and the suppliers obtain $80 per ton f.o.b. their plants. For the quantity of ammonia produced by this plant (92 tons/CD) it is believed that a price, f.o.b. the plant, of $80 per ton could be realized. For larger quantities, freight equalization would have to be considered.

Sulfur: There are several plants in the Rocky Mountain area producing sulfur from hydrogen sulfide. The price of sulfur f.o.b. these plants is based on the Gulf Coast price plus allowance for difference in freight to nearby consumers such as refineries at Casper, Wyoming. On a similar basis, it is estimated that the sulfur, f.o.b. a refinery site near Rifle, Colorado, should obtain a price of $20.50 per ton.

Coke: The coke currently being produced from Rocky Mountain refineries obtains a variety of prices. A certain portion is used in beet sugar refining as an adsorbent and commands a premium price. Some is used by the aluminum industry for electrodes, and the balance is used as refinery and industrial fuel. It is doubtful that any of the shale oil coke could be marketed to the beet sugar refiners, and thus the price obtainable for this coke would range between $3.50 to less than $5.00 per ton, with a reasonable average price of $4.00/ton.

Fuel Gas: The gas produced from the Colorado refining operation is comparable in heating value (1,060 Btu/SCF) to natural gas, but includes small percentages of hydrogen sulfide and carbon monoxide. Further, the volume of gas produced will undoubtedly fluctuate from day to day, and, during short periods, none may be produced. In view of these disadvantages, it is obvious that natural gas distributors would not offer to purchase this gas at the same price as natural gas. It is estimated that a reasonable price for this gas is 7.0¢/MSCF.

P. R. Schultz

M E M O R A N D U M

September 10, 1951

Re: Economics Subcommittee of
NPC Subcommittee on Synthetic
Fuels Production Costs

Average Hourly Wages for Operating Labor for Initial Shale Oil Plant

The attached letter from Mr. J. H. Hirsch, with its supporting memorandum, recommends an average wage of $2.00 per hour for operating labor below the position of shift foreman. This wage is representative of the U.S. average for refinery operating personnel, and wages in certain sections of the country deviate by 10 to 15 cents per hour from this average. This is particularly true of the Pacific Coast refineries and is evident in the average hourly wage of $1.86 per hour employed by the Shale Oil Engineering Group (comprised of Pacific Coast refiners) in their estimate of the operating labor cost.

This matter was discussed at a joint meeting of the Oil Shale Engineering Group and the Economics Subcommittee, and an agreement reached. Inasmuch as a portion of the facilities would be located at an existing refinery site in California, it is obvious that these employees would be paid on a scale consistent with Pacific Coast wages. The majority of the operating personnel, however, are employed at the Colorado site, and the Oil Shale Engineering Group concurred that Pacific Coast wages would not apply to this region. The Economics Subcommittee therefore recommended that the average hourly wage as developed in Mr. Hirsch's letter be applied to the Colorado operating personnel. The following table summarizes the calculation of the average hourly wage for the operating personnel:

Location	No. of Employees	Hourly Wage	$/CD
Colorado Site and Pipeline	544	$2.00	$6,200
California Site	68	$1.86	721
Total	612	$1.98	$6,921

Therefore, an average hourly wage of $1.98 is recommended for operating personnel in this study.

P. R. Schultz

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Petroleum and Its Products

GULF RESEARCH & DEVELOPMENT COMPANY
P.O. Drawer 2038 - Pittsburgh 30, Pa.

Paul D. Foote
Executive Vice President
E. A. Eckhardt
Vice President
Blaine B. Wescott
Asst. to Exec. Vice President
Eugene Ayres
Tech. Asst. to Exec. Vice Pres.
H. W. Daugherty
Business Manager

Division Directors
B. B. Cox - Geology
J. McAfee - Chemistry
M. Muskat - Physics
L. J. Peters - Geophysical Operations
R. J. S. Pigott - Engineering
L. W. Vollmer - Materials & Prod. Chem.
R. D. Wyckoff - Geophysical Res. & Dev.

July 27, 1951

File: ND 07

Air Mail

Mr. P. R. Schultz
Stanolind Oil and Gas Company
Stanolind Building
Tulsa, Oklahoma

Dear Mr. Schultz:

Attached is a memorandum by our Mr. V. N. Hurd, dated May 31, 1951, summarizing his study of refinery wage rates and presenting recommended rates for use in the calculation of synthetic fuels costs. Using these recommended rates and a labor force breakdown from the Bureau of Mines, dated February 3, 1950, we have calculated an average labor rate of $2.00/hr.

In addition to the direct labor cost, an allowance for payroll extras should be included in the economic calculations to cover such items as overtime, holiday premiums, shift differentials, accident and sickness benefits, unemployment insurance, pensions, social security, etc. Based on data obtained from several companies participating in the N.P.C. study, it is recommended that the allowance for payroll extras be taken at 20% of the labor cost.

Very truly yours,

/s/ Joel H. Hirsch

Joel H. Hirsch

JMcA
JHH;kh
Att.
cc: Messrs. R. G. Atkinson
F. T. Barr
T. R. Moore
C. F. Parker
J. D. Snakenberg

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Y

File: ND 07
NA 00

FROM V. N. Hurd AT Harmarville

TO Mr. Joel H. Hirsch AT Harmarville May 31, 1951

SUBJECT Refinery Wage Rates

As part of the study being made by the National Petroleum Council on the economics of producing synthetic liquid fuels, a schedule of representative refinery wage rates was required. To aid in developing such a schedule, several oil companies submitted to the N.P.C. lists of wage rates paid by them in various parts of the country. A list of these companies along with the locations of the refineries for which rates were given is shown in Table No. 1. In addition, average wage rates for September, 1948, as compiled by the Bureau of Labor Statistics were available for various sections of the country.

In order to condense the data into the most useable form, an attempt was first made to reduce the number of labor classifications and wage rates to a minimum. The Gulf Port Arthur refinery, for example, listed 158 labor classifications having 40 different wage rates, and it was desired to reduce these classifications to the lowest practical number. This was done by plotting the number of labor classifications at a given wage rate against wage rates for several refineries. It was found that the total range of wage rates could be divided into eight or nine sections resembling frequency distributions, each section containing a wage rate common to a relatively large number of labor classifications. Using the labor classifications indicated by these plots as being those representing the most common wage rates, the available data were then tabulated for five sections of the country (Gulf Coast, Eastern U.S., Middle West, Rocky Mountain, and Pacific Coast). After correcting all wage rates to January 1, 1951, representative rates were selected for each classification, usually by averaging. Bureau of Labor Statistics data were used for comparison purposes, but did not enter into the averaged figures.

Study of the information thus obtained indicated that a single wage rate for each classification could be employed for the entire country. The rates finally chosen are shown in Table No. 2, along with the maximum and minimum rates which had been selected for the various sections of the country, and the corresponding National average rates compiled by the Bureau of Labor Statistics.

Most of the minimum wage rates shown are from the Pacific Coast region. Comparison of the National average and Pacific Coast data of the Bureau of Labor Statistics indicates, however, that the Pacific Coast rates lie very close to those for the National average. Similarly, most of the maximum rates are from the Eastern section of the country, but again the Bureau of Labor Statistics data indicate that the deviation of the Eastern section from the National

average is small. It is believed that most of the difference between the maximum and minimum values shown is due to the limited number of rates which went into the averages for each section of the country. For this reason, use of National average rather than sectional figures probably gives the most representative rates possible from the available data.

/s/ V. N. Hurd

V. N. Hurd

VNH:kh

Table No. 1.

COMPANIES SUBMITTING WAGE RATES

Company	Location of Refinery
Esso Standard Oil Company	Gulf Coast Eastern Seaboard (2 refineries)
Gulf Oil Corporation	Port Arthur, Texas Fort Worth, Texas Sweetwater, Texas New York, New York Philadelphia, Pennsylvania Pittsburgh, Pennsylvania Toledo, Ohio Cincinnati, Ohio
Texas Company	Los Angeles, California Lawrenceville, Illinois Casper, Wyoming Westville, New Jersey
Union Oil Company	Los Angeles, California Oleum, California Cut Bank, Montana

Table No. 2

REFINERY WAGE RATES, JANUARY 1, 1951

Classification	Wage Rate, $/Hour			
	Recommended Value	Maximum	Minimum	Bureau of Labor Statistics
Operator or Stillman No. 1	2.36	2.45	2.18	2.31
Ass't. Operator or Ass't. Stillman	2.15	2.23	2.02	2.10
Helper	2.00	2.06	1.89	1.98
Laboratory Technician	2.16	2.23	2.07	---
Routine Tester	1.90	1.93	1.83	1.91
Power Plant Engineer No. 1	2.42	2.47	2.37	---
Boiler House Operator	2.17	2.25	2.01	---
Helper	1.96	2.10	1.82	---
Pumper	2.18	2.35	2.00	2.07
Pumper Helper	1.88	2.01	1.75	1.97
Gauger	2.05	2.13	1.93	2.01
Rackman	1.90	1.92	1.88	1.83
Laborer	1.60	1.67	1.48	1.53
Craftsman No. 1	2.20	2.29	2.06	2.14
Craftsman No. 2	2.03	2.10	1.93	---
Helper	1.83	1.92	1.75	1.80

COPY

The Texas Company

Texaco Petroleum Products

Refining Department

135 East 42nd Street
New York 17, N.Y.

September 26, 1951

Mr. P. R. Schultz
Stanolind Oil and Gas Company,
Stanolind Building,
Tulsa, Oklahoma.

N.P.C. ECONOMICS SUBCOMMITTEE

Dear Sir:

Engineering estimates as submitted for retorting and refining of shale oil left incomplete the question of overhead which was to be supplied by the economics committee. It is felt that overhead for this industry would follow the general pattern of the oil industry and therefore we recommend establishment of these factors in accordance with the outline detailed in the succeeding paragraph.

The Bureau of Mines' calculation of cost in R. I. 4564 estimated general overhead (plant burden or indirect plant expense) at 40% of direct labor and material and estimated general administrative expense at 10% of direct labor and material. Based on the experience of the companies represented by Messrs. J. D. Snakenberg, F. T. Barr, J. H. Hirsch, and the writer, the total of 50% for general overhead and administrative expense appears to be reasonable though the split between the two items will vary according to different company policies and practices. In general, general overhead (plant burden or indirect plant expense) includes expense of operating all plant service groups exclusive of the utilities group. For example, operation of service groups includes:

Testing Laboratory
Engineering and Drafting
Process Engineering
Storehouse Operations
Industrial Relations
Employees Service Records
Medical Service
Safety Program
Employees Training Programs
Operation of Employees Recreation Facilities
Operation of Employees Service Building
Shop Operation which cannot be allocated to Direct Expenses
Operation of Automobiles and Trucks not allocated to Direct Expenses
Fire Protection Expense

Mr. P. R. Schultz September 26, 1951

Plant Protection Expense (Watchmen, Guards, and Gatemen)
Operation of Rolling Stock such as Switch Engines, Cranes and Hoists, to extent they cannot be allocated to Direct Expenses.

General overhead also includes the cost of the general supervisory forces and accounting to the extent company policy would determine economic to locate at the plant. General administrative expense includes all direct supervision of plant operations not specifically located at the plant site together with advisory staffs. It would also include the cost of maintaining staffs for the following company administrative groups:

Legal
Controller
Treasurer
Purchasing
Insurance
Bulk Sales
Executive Offices

In addition to the operating costs for both plant burden and administrative overhead there are incurred a large number of service type expenses both at the plant and the general office which add to the cost of operation. Such items are:

Contributions and Donations
Travelling and Personal Expenses
Telephone and Telegraph
Memberships and Subscriptions
Printing and Stationery
General Office Rentals and Maintenance

Inasmuch as the total of 50% for general overhead and administrative expense appears to be in line with oil company experience even though the pattern of division of the two varies widely, it is recommended that for the purpose of estimating costs for retorting and refining shale oil that we use the same split as used by the Bureau of Mines, that is, 40% for general overhead and 10% for general administrative expense.

Yours very truly,

/s/ T. R. Moore

TRM-FM

T. R. Moore.

AIR MAIL

PRICE WATERHOUSE & CO.

56 PINE STREET

NEW YORK 5

September 27, 1951

Mr. P. R. Schultz,
Economics Subcommittee,
National Petroleum Council Committee on
Synthetic Liquid Fuels Production Costs,
Stanolind Oil and Gas Company,
Stanolind Building,
Tulsa 2, Oklahoma.

Dear Sir:

In connection with the estimates of costs of the production of gasoline from coal and from oil shale you have asked us to state what in our opinion would be a reasonable rate of return on the capital invested in the proposed enterprises.

It is our viewpoint that "capital invested" means total capital, whether equity or borrowed, invested or retained in the business.

The preliminary figures which you submitted to us include for the purpose of discussion a nominal rate of return of 6%. Even with such an obviously low rate the resultant price of gasoline in both cases is so high as to make both projects unsuitable for development on a commercial unsubsidized basis. It, therefore, might appear that any discussion in support of a higher rate of return is purely academic. However, we understand that the Committee may be called upon in the future to prepare estimates of costs of improved processes which, it is contended, may more nearly approach a competitive market price for gasoline. It is, therefore, important in presenting the two cases now under consideration, to establish a reasonable rate of return on capital invested in the synthetic fuels industry, irrespective of whether the ultimate objective is the production of gasoline with relatively minor chemical by-products or the production of chemicals with gasoline as the by-product.

It should be understood that a rate of return means net earnings, computed on generally accepted principles of accounting, which include as expense provisions for income taxes and allowances for normal depreciation and obsolescence but that such net earnings do not contemplate the possible obsolescence of the enterprise as a whole. It should also be understood that in dealing with a net earnings percentage on total capital invested no consideration is given to any possible guarantee of minimum earnings.

Based upon our experience in examinations, reviews and investigations of financial affairs of varying fields of industry and commerce and giving due consideration to the factors of risks involved in this proposed enterprise, it is our opinion that an annual rate of earnings of not less than 15% on the total capital invested in or retained in a business subject to the risks of a highly competitive and speculative enterprise would be necessary and reasonable in order to attract investment of private capital.

Yours very truly,

PRICE WATERHOUSE & CO.

E S S O L A B O R A T O R I E S
Standard Oil Development Company

Ref. #10,743

Development Division
A. D. Green
Director
C. W. Tyson
Associate Director

H. Z. Martin
H. W. Scheeline
Assistant Directors

P. O. Box 51, Linden, N.J.

REVISION

September 25, 1951

NPC Economics Subcommittee:
Development of General Fixed and Overhead Cost Items
DD 25.12

Mr. P. R. Schultz
Stanolind Oil & Gas Co.
Tulsa, Oklahoma

Dear Mr. Schultz:

We are forwarding herewith our memorandum outlining in some detail the results of our study of estimating methods for general fixed and overhead items in manufacturing cost determination. These include administrative costs, insurance and taxes, research and development costs, depreciation, and re uired return on investment. They should be applicable to processing operations similar to conventional oil refining. They may not apply very satisfactorily to mining operations and the like, except that depreciation and required return on investment should be constant throughout the project.

The figures recommended are those which have been developed in connection with earlier activities of the Economics "working group". A few revisions in the text have been made to conform with suggestions agreed to at the meeting of July 24 and 25.

In summary the following are recommended:

1) For administrative costs 10% of the direct labor and material costs for the operation should be used.

2) For insurance and taxes 1.5%/yr. of total plant investment should be employed. This would not cover income taxes.

3) For research and development $1 MM/yr. per plant should be used, assuming hydrogenation plants of nominal 30,000 B/D capacity and shale oil plants of nominal 50,000 B/D capacity. This figure might be low for a first plant, but should be satisfactory for industry-wide cases comprising plants aggregating about 250,000 B/D capacity.

4) Five per cent depreciation allowance should be used, based on the estimated operating life of 20 years; actually, based on depreciation allowed for income tax purposes the books would probably show about 2% more depreciation.

Mr. P. R. Schultz 9-25-51

5) The return required on total investment in the project to interest prospective investors should be taken at a minimum of 6% after income taxes assessed at a minimum of 50% on profit before income taxes. This would apply to a synthetic fuels manufacturing operation which has a fair chance of becoming competitive with petroleum refining. Less attractive proposals would require that the return estimated be sharply higher. For the purpose of this study, however, it is recommended that the 6% be used in all cases, with the understanding that it is as low as is likely to be justified.

It should be noted that all the estimating techniques used by the Economics Subcommittee are based on the assumption that the synthetic fuels plants will be operated at full capacity, limited only by technical and operability considerations. On a truly competitive basis risk may have been inadequately allowed for.

As indicated in the memorandum, considerable uncertainty with regard to prediction of the cost of capital for synthetic fuels projects exists. The figure recommended was arrived at through consideration of returns actually obtained in a number of existing industries, with the thought that these would compete for capital with the synthetic fuels projects. It had been our intention to estimate cost of capital only upon the basis of a completely unsubsidized operation. The uncertainties involved, however, made necessary the consideration of some bases involving subsidy in one form or another.

The return figure recommended is to apply without reference to the proportion of borrowed to invested capital. It is based upon figures developed for a wide range of this ratio. These points are further explained and amplified in the memorandum.

Yours very truly,

C. W. TYSON

Per: /s/ Frank T. Barr

FTB:mh
Att.
cc: Messrs. R. G. Atkinson
J. Hirsch
T. R. Moore
C. F. Parker
J. D. Snakenberg

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E S S O L A B O R A T O R I E S
Standard Oil Development Company
Development Division

Revised

Ref. #10,744

September 25, 1951

MEMORANDUM

NPC REVIEW OF SYNTHETIC FUELS COSTS

DD 25.122

DEVELOPMENT OF ESTIMATING METHODS FOR GENERAL FIXED AND OVERHEAD GROUPS IN MANUFACTURING COSTS

Cost items included in the general fixed and overhead groups are 1) administrative (ex direct plant administration) but including a) legal, b)purchasing, c) general accounting, d) marketing and distribution, and e) executive offices; 2) insurance and taxes (ex income taxes); 3) research and development; 4) depreciation; and 5) required return on investment, including consideration of the effect of income taxes and of the type of financing.

These items are discussed individually below. The discussion is directed essentially toward processing operations, and more particularly toward coal hydrogenation. Costs in mining industries follow a pattern sufficiently different from those in processing operations that common techniques are difficult to establish. It is useful to make the techniques for both mining and processing as consistent as possible, however.

1. Administrative

It is recommended that a figure of 10% of the direct labor and materials cost for the processing operation be used.

For the 30,000 B/SD coal hydrogenation plant this is likely to run about $2 MM/yr. This amounts to about 3% of the total products cost, including 5% depreciation, a not unreasonable ratio for such cost items. Departments to carry out the five functions included in this group would be of fairly large size. It must be remembered that the 30,000 B/SD coal hydrogenation plant is roughly comparable in investment and size to, say, a 200,000 or 300,000 B/D refinery. While the hydrogenation plant is not as complicated, from a business point of view, as the complete refinery would be, many administrative requirements are common to both. Purchasing would be limited owing to the use of a single large-scale raw material, but many of the normal duties of a purchasing department would remain. Similarly, although marketing is considered to be on the wholesale basis only, and would presumably involve arrangements for transfer of the entire plant output for relatively long periods of time, the need for a complete marketing and product distribution department exists. Insofar as general accounting, legal, and executive requirements are concerned, these are in most respects closely related to the number of people involved in the plant operation, and would be similar to that for the large refinery.

Actually, in refining experience charges against the administrative function can often be much greater than the 10% of labor and materials costs.

2. Insurance and Taxes

It is recommended that an allowance of 1.5%/yr. of plant investment be made to cover insurance and taxes other than income taxes.

Commercial insurance will probably run about one-half of 1%. About two-tenths per cent should be allowed on the average for state income and franchise taxes. Ad valorem taxes will run about 0.7%. Owing to the uncertainties as to precisely what insurance rate might be obtained for the hydro plant, it appears reasonable to round off the total to 1.5%.

The use of 1.5% on investment for insurance and taxes compares with a total of 2% suggested for quick estimate in the Bureau of Mines' Report of Investigations 4534, Guide for Making Cost Estimates for Chemical Type Operations (November, 1949). The figure of 1.5% is not out of line with at least some refinery experience.

3. Research and Development

It is recommended that a figure of $1 MM/yr. for the 30,000 B/SD coal hydrogenation plant be used.

This amounts to about 1-1/2% on the total products cost. If this rate were used for each of the proposed 8 plants for the industry-wide estimate, the resulting $8MM/yr. would be of the order of magnitude of the expenses on synthetic fuels development now being incurred by the Bureau of Mines. Actually, the first plant should probably carry more research and development load, perhaps as high as 2-3% on products cost, since a certain amount of distribution of research effort can be achieved where a number of plants carry out similar operations.

While it may be suggested that the research and development for the synthetic fuels plants will have been completed by the time they are built, it has been the general experience in the petroleum and processing industries that work of this nature is necessary just to keep the business going and to maintain its position. If this is not allowed for, then it is only reasonable to charge past costs of research, development, and demonstration to the operation.

4. Depreciation

It is recommended that 5% of the plant investment be charged for depreciation.

This is based on the requirement that raw materials supply at each location be sufficient to allow 20-years' operation of the plant. It does not take into account any probability of obsolescence, or of premature retirement of plant facilities. In this respect, requirement for research and development discussed above might be justifiably raised, so as to make certain that the process is kept in technically favorable enough position to insure its continued operation.

The 5% depreciation allowance may be compared with an allowable depreciation based on Bureau of Internal Revenue rates of the order of 7%. To the extent that cost of competitive products is based on maximum allowable depreciation, this means that the 5% is low. It would, no doubt, be well to keep in mind that the books of the operating company would show costs equivalent to about 2% higher depreciation than recommended herein.

5. Return on Investment

A review of financing problems, coupled especially with the extremely large size of a project comprising even only one 30,000 B/D hydrogenation plant or one 25,000 B/D shale oil plant suggests that the overall cost of capital for the plant would vary widely depending upon the indicated economics of the process. For an operation which seemed likely to become fairly profitable a reasonably low interest rate would satisfy prospective bond holders.

If, however, the project were not so attractive, increased interest rate would be required to offset the greater risk involved. This, in turn, would make the project even less favorable. Similar considerations, balancing high return against high risk, would apply to equity investors. As a result, it would not be expected that money would be available directly from the general public for a project with uncertain prospects, especially considering the hundreds of millions or billions of dollars' scale of investment involved.

With these reservations, therefore, it is recommended that, as an example of the lowest capital costs which might be met for a reasonably favorable project, an overall return on total new investment of 6% after income taxes be used.

a) Income Tax

Although the present Federal income tax rate is somewhat below 50%, it is expected that it will be raised to the 50-55% range in the near future. This will, no doubt, have some effect on the market prices of gasoline from natural petroleum, but not a large one. The 50% basis, therefore, appears not unduly high, especially since some State income taxes may be involved in addition to the Federal income tax.

b) Comparison with Returns for Public Utility Operation

A number of considerations can be taken into account in connection with establishing the example for the return necessary. First, a profit on total capital of at least 6% after income taxes is generally considered reasonable for public utilities, e.g., for natural gas pipe lines. Since a public utility by definition has an assured market, its net return should certainly not be any higher than that for a manufacturing operation which has no assured market. On this basis the 6% for return on synthetic fuels plant investment is on the low side.

c) Comparison with Returns Obtained by Existing Oil Companies

The oil industry has generally obtained at least a 6% return on its borrowed plus invested capital. Without consideration of the change in the purchasing power of the dollar the returns for thirty oil companies as given by Pogue and Coqueron, "Financial Analysis of Thirty Oil Companies," published yearly by Chase National Bank, show an average of about 5.9% for the years 1934-38; 6.5% for the years 1939-43; and 11.3% for the years 1944-48. Adjusting both invested capital and profits to common dollar value revises these figures to 5.9, 5.9, and 7.4%, respectively. For 1949, the unadjusted and adjusted figures are 11.1 and 7.0%, respectively, while in 1950 the unadjusted figure was 12.7%. Since the synthetic fuel industry would be in direct competition with the natural petroleum industry, it is unlikely that investors would be willing to accept lower returns from the synthetic fuel operation than could be obtained from natural petroleum processing. This would be reflected in competition for investors' money in the stock market as well as elsewhere.

The effect of the decrease in invested capital in an existing industry by virtue of write off compared with the total investment for a new plant in the synthetic fuel case should be kept in mind.

Another consideration with respect to return required to interest investors is that for new projects in the petroleum and chemical industries a much higher return than 6% must be estimated to make the project attractive. Reasoning on this basis could easily develop justification for returns of 10,20, 30% and higher.

d) Capital Structure with High Funded Debt

With a high proportion of funded debt paying interest at considerably lower than the 6% suggested as example on total investment, an apparently lower overall required return can be developed by setting up the proper type of financial plan. Obtaining a high proportion of funded debt to equity investment, however, would require more assurance as to the position of the project than could be expected without some sort of subsidy. While subsidy, for example, in the form of guaranteed purchase contracts by a government agency, has been suggested, figures determined in this way would not be true costs. Although, after establishing true costs, it may reasonably be determined that a project should be subsidized, it seems certain that the basic cost estimate should be for a manufacturing project "standing on its own feet."

e) Financial Costs on Subsidized Basis

In connection with the way a synthetic fuels project might be financed, a number of suggested financing plans were set up by the Jersey Treasurer's office. These are all very preliminary and tentative. They are based on the assumption that some sort of a products purchase contract would be arranged so as to insure recovery of costs, and to this extent must be considered subsidized. On this basis it is considered possible that 80 or 90% borrowed capital might be obtained, providing sufficiently rapid amortization were allowed. These plans are compared in the following tabulation:

Plan No.	Description	Capital Chgs. per Gal.Gaso.	Equiv. Ret. before Inc. Taxes on Tot. Invest., After 5% Depr.	Ret. on Equity Invest., Discounted to Start of Proj.
I	90% Funded Debt, 10% Common Stock; debt fully amortized in 10 years	7.6¢	8.9%	14.7%
II	80% Debt., 10 Yr. Pay-off	6.7¢	7.4%	9.6%
III	Same as I, plus 5% return on equity investment during debt pay-off period	8.3¢	10.1%	17.3%
IV	Same as II, plus 5% return	8.1¢	9.9%	13.1%
V	90% Funded Debt; 10 year red'n. to 20% of total investment	6.3¢	6.7%	11.6%
VI	80% Debt, 10 Yr. red'n. to 20%	5.5¢	5.1%	6.8%
VII	90% Funded Debt, 7 Yr. Pay-off of debt	11.6¢	16.2%	23.3%
VIII	80% Debt, 7 Yr. Pay-off	10.3¢	13.8%	16.1%

Notes:

1) The plant investment is assumed to be $200 MM for 25,000 B/D gasoline production, plus $10 MM working capital, or $8,000 / $400 per B/D gasoline.

2) Capital charges include write off (and return, in Plans III and IV) as indicated, plus interest on remaining debt at 3-1/4%. A two-year construction period is assumed, and interest is paid during this period, but amortization starts the 3rd year in all cases.

3) After amortization of the debt as indicated, and (where necessary) write off of any remaining investment above an assumed $11 MM scrap value plus $10 MM working capital remaining, the capital charges are assumed available as return on the equity investment.

4) Return on equity investment shown is actual return discounted (at the same rate) to the start of the project*. Returns on equity investment are shown after 50% income tax. It is assumed that no income tax would be assessed on amortization payments in excess of normal depreciation. This would require accelerated depreciation allowance.

5) In all cases equity investment is common stock equal to the difference between total investment and funded debt.

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* The discounted return on equity is such as to give the following results:

1) The equity investment is increased during the period of debt amortization at the discounted return rate compounded annually.

2) Actual returns following this period are applied the year they are earned toward extinguishing the equity. The discounted return rate is charged on the net equity investment.

3) The equity is thus reduced to the $21 MM assumed scrap value plus working capital by the time the plant is retired.

4) The discounted return is therefore theoretically available on the original equity throughout the life of the plant. In the cases where the original equity is greater than the $21 MM final equity (Plans II, IV, VI, and VIII), the necessary capital repayment is included.

The previous figures are based on an assumed 25,000 B/D gasoline production from shale. Coal hydrogenation and synthesis from coal were not considered because of their anticipated higher costs. Costs from shale are expected to be more nearly in line with costs by conventional petroleum refining.

In reality the level of financial costs would depend upon the level of the costs of raw materials, manufacturing, and transportation. As final estimates of the latter costs are not yet available, it is not possible to give a reliable or final estimate of financial costs. In making tentative estimates, it has been assumed that the production of gasoline from shale would be in a range that might be considered competitive, or nearly so, with the manufacture of gasoline from crude petroleum.

On this basis, however, it does not appear that a company organized to manufacture gasoline from shale could be set up with its equity securities owned by the general public. The newness of the operation, the fact that the process does not promise savings in cost over conventional methods, and the tremendous outlays necessary all argue against general public ownership of the equity securities. Heavy backing from existing oil companies and/or the government would be necessary. Hence, it has been assumed that the oil companies would provide the equity capital for the shale company and that a large purchaser, perhaps a government agency, would contract on a long-term basis to purchase or pay for a given amount of product at a specified price.

Although the table covers a number of possible situations, under present conditions the first plan seems the most defensible. This assumes (as do all plans) plant cost of $200 MM and an additional $10 MM as working capital. Capitalization consists of 10% equity capital, furnished by five or six oil companies, and 90% borrowed capital, provided by institutional investors. The debt is assumed as 10-year debt, largely because investors would probably be unwilling to tie up their funds for greater lengths of time on a new project of this type. Uncertainties both in the economic and legislative fields argue against risking funds for longer periods. The 3-1/4% interest rate reflects current levels. Building is assumed to require two years. The entire debt is repaid in equal annual installments during the third through tenth years. The oil companies are assumed to receive no return on their investment until after the tenth year. Estimated financial cost, before depreciation credit, is 7.6¢ per gallon of gasoline, or an average of 13.6% per year on the $210 MM over eight years' production. If 5% per producing year on the $200 MM plant investment is taken as depreciation, this cost includes the equivalent of 8.9% return before income tax on total original investment.

It will be observed that, from consideration of these plans, some decrease below the 6% return after income taxes (or 12% before) can be justified for the conditions of subsidy involved. Furthermore, the plans themselves represent varying degrees of risk, and varying effective subsidy. All are based on the assumption that pay-out of the borrowed capital can reasonably be hastened by providing no return on equity capital during the amortization period. However, this has the effect of seriously reducing the equivalent return represented by the profits available when the bonded indebtedness is finally paid off. Again this means simply that a low overall return on the total investment is not sufficient to interest investors.

It is not intended to leave the impression that a company organized to manufacture synthetic gasoline could not attract equity capital from the investing public. Conventional methods of financing could be used if the synthetic process could promise a cost advantage and if smaller plant size could be projected. A favorable cost differential of only 1/2¢ to 1¢ per gallon of gasoline would be sufficient if promoters could convince investors of the validity of the estimates. Furthermore, a plant costing something like $50 MM to $70 MM could be financed much more easily than one costing $200 MM.

Other sources of capital can be considered. Presumably, an R.F.C. loan might be obtained. The fact that it would be necessary to go to the R.F.C. instead of obtaining money from private sources, however, would be a measure of the amount of subsidy provided by R.F.C. Similarly, while supply of a portion of the capital by an existing oil company or a group of oil companies would have the effect of reducing the cost of outside capital obtained, it would not be a net reduction, since the credit standing of the backers of the project would be affected. Although these effects cannot be readily measured in money, the risk exists and must be allowed for. Any proposal for financing which does not take into account full evaluation and cost of the risk involved cannot be considered a true evaluation of the cost of operation.

f) Conclusion

It seems reasonable, in view of the foregoing, to conclude that for a synthetic fuels manufacturing operation that has a fair chance of being competitive with petroleum refining, an overall capital cost of 12% on total investment in addition to depreciation allowance would be met. This would be equivalent to 6% on 100% equity investment after income tax. The shale alternative may possibly meet this condition; coal hydrogenation does not seem likely to.

/s/ F.T.B.

FRANK T. BARR

FTB:mh/w

M E M O R A N D U M

September 12, 1951

Re: Economics Subcommittee of
NPC Subcommittee on Synthetic
Fuels Production Costs

Determination of Start-Up Expense and Working Capital for Initial Oil Shale Plant

The amount of capital provided for start-up expense and working capital is an important factor in the financing of a venture such as a synthetic fuel plant. Certain of the items included in these two capital requirements are common to most industries and all of them are at times encountered in the petroleum industry. Thus, there is ample justification for including all of the separate items considered.

One item, however, which cannot be accurately predicted is the length of time required until the plant is operating continuously at design capacity and the average rate of production during this period. This matter was discussed with the Shale Oil Engineering Group, and it was decided that an average production of 65% of design capacity for a period of one year should be used. The petroleum industry's experience in the initial operation of new plants and processes would undoubtedly reveal many cases where greater or lesser difficulties were encountered. Thus, although this item could be greater or lesser, it has at least been recognized and estimated on a reasonable basis.

The start-up expense and the working capital arehandled separately for the following reasons:

1. Start-up expense represents a true expense which, ordinarily, is written off on a current basis against other income. This presumes, however, that the plant operator has other profitable ventures. In this case, it is believed preferable to capitalize this expense and amortize it over the composite life of the facilities. In this manner, a constant production cost is obtained, thereby simplifying the treatment of this matter in the economics.

2. Working capital includes, in this study, various prepaid expenses and a sum required to meet fluctuations between income and expenses. Since the average daily cost of these prepaid expenses has been included in the operating costs, no depreciation can be taken.

The amount required for start-up expense is determined as follows:

Basis	Amount
Employee Training and Recruiting: A training period, up to three months for certain personnel, will be required for operating and maintenance labor and the direct supervisory force. Additional costs will be incurred in recruiting and moving personnel to the site. Use total cost equal to 90 days times these labor items ($22,369/CD)	$ 2,000,000
Initial Operation at Less Than Design Capacity: Operating difficulties will reduce initial year's production to 65% of design capacity. Thus, during 35% of first year, certain cash costs such as total plant payroll, overhead, a portion of supplies, property taxes, and other items on the plant, plus the payroll for a skeleton labor force and other costs on the mine, must be met without any product income to offset these costs. Total amount is 35% x 365 x $57,500/CD	7,400,000
Total Start-Up Expense	$ 9,400,000

The working capital items are calculated as follows:

Basis	Amount
Product Inventory and Accounts Receivable: Volume of storage tanks and pipeline will require about 50 days operation at design capacity before products can be shipped on current basis. Billing and receipt of income will require an additional 60 days. Thus, receipt of income will lag about 110 days behind production. During this period, only cash costs, i.e., operating expenses less depreciation and other capital charges, will have to be met. Amount required is 110 x $97,979/CD	$10,800,000
Catalysts, Chemicals and Materials Inventories: In addition to the initial catalyst charge ($3,048,500), a normal inventory of catalysts and chemicals of about 6 months supply ($744,500), and a normal inventory of maintenance and operating materials of about one year's supply ($4,297,000) are provided. These items are detailed in the reports of the Shale Oil Engineering Group and Oil Shale Mining Group.	8,100,000
Additional Sum: The preceding items, and other expenses such as maintenance costs, are subject to rather large fluctuations. For this reason, it is necessary to provide a fund to meet these variable expenses and an amount equal to 90 days times cash costs ($97,979/CD) is provided.	3,800,000
Total Working Capital	$27,700,000

PETROLEUM ADVISERS, INC.

SIXTY WALL TOWER

NEW YORK 5, N.Y.

September 26, 1951

Mr. P. R. Schultz
Stanolind Oil and Gas Company
Stanolind Building
Tulsa 2, Oklahoma

Economics Subcommittee of
NPC Subcommittee on Synthetic
Liquid Fuels Production Costs

Dear Sir:

The permanent housing estimates of the Engineering Subcommittee Off-Site Facilities Group purposely were developed on a unit basis for application to various sizes of employee groups, and are to be used in the Oil Shale case. These unit costs are:

Housing	$9667 per employee (Plant or Tradespeople)
Civic Facilities	$1425 per employee (Plant and Tradespeople)
Commercial Buildings	$1572 per employee (Plant and Tradespeople)

These unit costs can be applied to the total Colorado mining, retorting and refining employees, using a factor of 80% to be housed in the 50,000 B/CD case and 90% to be housed in the 250,000 B/CD case. These percentages are based on the number of employees relative to the size of adjacent towns. With their relatively small group of 300 employees at Rifle, the Bureau of Mines housed 70 or 23.4%.

In each case, housing for tradespeople and others is taken at 70% of employees, as in the Rock Springs case.

No housing would be needed for the California employees shown in the Shale Oil Engineering Report. Housing for the pipeline employees has been provided in the pipeline estimate.

Yours very truly,

J. D. Snakenberg

JDS:db

cc: Messrs. R. G. Atkinson
F. T. Barr
J. H. Hirsch
T. R. Moore
C. F. Parker
J. C. Neyland
L. C. Kemp
H. L. Malakoff
D. F. Houlihan

COPY

Review of Basis for Housing Estimates of Off-Site Committee

The builders of a Shale Oil Plant near Rifle, Colorado or a Hydrogenation Plant near Rock Springs, Wyoming, are confronted with the need of adequate and appropriate housing for their employees in order to attract suitable employees to start up and operate the new plants. This group of employees requires civic and commercial services on a scale in keeping with the remoteness from other population centers. The civic and commercial service people need housing. Utility and civic services must be scaled to accommodate the whole.

The timing conditions are unique. The plans for the whole must be made and construction carried out so that the entire town is ready to function at the time the plant starts. The various plant departments will start approximately simultaneously. But practically none of the ultimate inhabitants of the town will be there until the town is completed, as there has been no need or function for them until then.

These circumstances of timing have a controlling effect on the initial financing through the planning and construction period, since they preclude:

1. The conventional financing of civic facilities, schools, hospitals, roads, sewers and utilities through bonding and assessments on individual property owners and the planning and construction of these facilities by usual civic processes.

2. The individual construction of houses by the great majority of permanent plant and mine employees.

3. The individual construction of houses by the majority of service workers.

4. The construction of substantial portion of the commercial buildings by the ultimate proprietors.

The Off-Site Subcommittee estimated permanent housing to meet these needs, based on the belief that the costs are too immense and the future too uncertain to attract outside builders to assume the risks.

E. H. Roy
J. D. Snakenberg

April 20, 1951

Mr. L. C. Kemp, Jr.
The Texas Company
135 East 42nd. St.
New York 17, New York

Dear Sir:

Yesterday I had a thorough discussion of the economic aspect of permanent housing projects, in connection with synthetic fuel plants, with Mr. G. Dewey Hynes, Vice President of The Equitable Life Assurance Society, who deals with such matters for his company. His conclusions are summarized in his letter of April 19th, attached.

Mr. Hynes states that since the value of the housing would be completely dependent on the continued operation of the plant, the housing would not represent a good risk, either from the point of view of ownership by his company, or for a loan. At the present time, the possibility of the community becoming a "ghost town" is the controlling matter to him, (1) because the plant represents a new industry of unproven earning power when marketing its product in the competitive market served by the petroleum industry, and (2) because the region does not have, and is not likely to have, other industries with attendent housing demands. Further, (3) the plant is not of a type, or in a location near markets and supplies, which offers any likelihood of its being converted to other industrial use if its designed operation should be discontinued.

Mr. Hynes said that, of course, his company would give consideration to housing ownership or loans if some one of recognized financial standing assumed the full risk of the continued operation of the plant, thus insuring occupancy of the houses. For example, he said if several large oil companies were to build the plant, and would assume this risk with regard to the housing, his company would be satisfied, as the financial standing of these companies would be the basis on which the project would be judged. The raising of funds by these companies for housing would thus be on a basis no different than for the plant proper.

Mr. Hynes was fully in accord with the premise that an orderly planned housing project must be considered nothing less than essential to the successful inauguration of a project of this nature and scope in a sparsely settled region.

It is Mr. Hynes opinion that a large scale housing project, including commercial buildings, should "carry itself" from its rentals. This, of course, was based on amoritization rates common to insurance companies. I did not have time to discuss with Mr. Hynes, Industry's experience with building employee housing, where the company involved is associated with the housing in the minds of employees. This experience is that rentals are depressed by the employees associating them with wages and working conditions.

Mr. Hynes volunteered the suggestion that it would be unnecessary to check with other insurance companies, if I had thought of doing so, as the answer was too obvious to allow any possibility that another similar institution might reach a different conclusion than his.

Yours very truly,

JDS:vm

/s/ J. D. Snakenberg

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THE EQUITABLE LIFE ASSURANCE SOCIETY
OF THE UNITED STATES

393 Seventh Avenue, New York
Thomas I. Parkinson, President

G. Dewey Hynes
Vice President

April 19, 1951

Mr. J. D. Snakenberg
National Petroleum Council Subcommittee
on Synthetic Fuel Costs
54 Wall Street
New York, N.Y.

Dear Mr. Snakenberg:

The housing which is required for the two projects, which we discussed at length today, Rock Springs Hydrogenation or a Shale Oil Project in Colorado, would not qualify as an investment for a life insurance company unless they carried the endorsement of an acceptable guarantor.

If we can be of further assistance to you and your Subcommittee, we shall be very pleased to have you call upon us.

Yours very truly,

/s/ G. Dewey Hynes

Vice President

GDH:DMD

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CITIES SERVICE PETROLEUM ADVISERS, INC., Sixty Wall Tower, New York 5, N.Y.

June 13, 1951

Mr. Joel H. Hirsch
Gulf Research and Development Company
P. O. Drawer 2038
Pittsburgh 30, Pennsylvania

Dear Sir:

On May 29 I had a conference on the Synthetic Fuel Plant housing problem with Mr. M. Carter McFarland, Office of the Administrator, Housing and Home Finance Agency, Room 603, Normandie Building, K Street, Washington, D.C. Mr. Raymond M. Foley is Administrator and I am advised that Mr. McFarland is one of his top assistants in this Agency. The particular information sought was what aid can be obtained from government agencies for housing projects, with incidental analysis of the housing problem in cases similar to those of the proposed synthetic fuel plants.

Briefly I learned that there is no government agency to provide help, that the providing of housing is necessary in isolated communities such as are under consideration, and that it presents peculiar and difficult financing problems under these conditions.

Mr. McFarland stated that no agency such as the RFC is authorized to loan money for such projects (they did during the last war but not under the present laws). Neither could any FHA approval of housing loans be extended to a project of this kind at the time of construction. Sometime later, after operations were established, and if the project then seemed to justify, there is a possibility that housing might then qualify for FHA approval. The agency would naturally be slow to qualify housing dependent on a single industry.

The agency has no basis for qualifying loans other than that it be a good risk as gauged by ordinary business standards. The agency insures loans for a fee which goes to a reserve to pay off bad loans. Thus, the mistakes that it can make are limited. Their function is to assist in making housing available where needed but where financing would not otherwise be available, although the project presented a good risk. The agency has no function of helping new industries to get established, - however meritorious, which would allow the agency to alter its usual standards of judging what constitutes a good risk.

There is a bill pending which has passed one branch of Congress, which would authorize them to make exceptions for certain cases that need housing in connection with defense projects. Even though passed, however, it would not alter this Committee's study, since the synthetic fuel plants are not defense projects.

Mr. Joel H. Hirsch June 13, 1951

Even before he had heard the complete story, Mr. McFarland's wide experience with such matters prompted him to state that the plant builder could not afford to leave housing to chance in cases like Rock Springs and Rifle. Mr. McFarland went on to state that the outstanding feature of such a situation, not appreciated by many, is the necessity of financing civic facilities (such as roads, water and sewer systems, schools and hospitals and the like) at a time when no taxing base exists from which these facilities are ordinarily developed, step by step, as a community grows. Not only would the civic facilities have to be initially designed, financed, and constructed by the plant builder, but he stands little chance of ever getting a substantial return on this investment after normal taxing units are established.

Not only do the providing of civic facilities present a problem, but the ownership of homes by the plant builder is undesirable. Congress has told the agency for the Atomic Energy Plants to avoid getting involved in building housing again as they did at Oak Ridge and other plants; with the Government owning housing, this surely represents a form of subsidy. When an attempt is made to raise rents, the employees demand a raise in wages. Also the government housing standards had been higher than those common in the communities involved with the result that the housing costs were too high to permit selling the housing for what it cost.

Mr. McFarland felt that in the case of housing, every effort should be made to sell the housing to the individual using the housing within a year or two after the plant started. He recognized the difficulty of selling until confidence in continuity of operations be adequately established. He thought one plan to bridge this gap might be the plan of an option to buy, extended for a suitable period, with all rental to date applying against the agreed price.

Mr. McFarland believes the costs and risks above-referred to must inevitably be incurred by the plant builder in an isolated area such as those under consideration, but he did not attempt any suggestions how this might most equitably be reflected in the price of the product. If the plants were nearer large centers practically all these costs and risks could be avoided by the plant builder.

Very truly yours,

/s/ J. D. Snakenberg

JDS:db

cc: Messrs. L. C. Kemp, Jr.
R. G. Atkinson
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ECONOMICS OF PRODUCING LIQUID FUELS FROM OIL SHALE - MULTI-PLANT CASE

INTRODUCTION

The economics of shale oil production facilities to produce approximately 200,000 B/CD of refined products from oil shale have been determined using the process established by the shale oil process group of the NPC Subcommittee on Synthetic Liquid Fuels Production Costs. This processing scheme has been agreed to by the U.S. Bureau of Mines. These economics are based on the data provided by other groups functioning within this NPC Subcommittee which studied the Process, Engineering, and Raw Materials phases of this project.

A separate report covers shale oil production from an initial plant with a capacity of 39,700 B/CD. In the report on the initial plant, the basis for estimating the various items of income and expense is presented and, due to the similarity between the two estimates, no discussion has been provided herein for items determined on an identical basis.

This study develops the economics in the same manner as employed by U.S. industries in general for the evaluation of new processes and projects. Throughout the study, all costs or prices have been adjusted to the level of January 1, 1951, in order that this study may be adjusted as economic conditions may change.

DISCUSSION

The attached table presents the summarized economic calculations for producing approximately 200,000 B/CD of refined products from oil shale. Where possible, the determination of these figures is based upon analogous situations, operations, or equipment as found in the petroleum or chemical industries. The retorting of oil shale is the one operation on which no commercial experience was available from which this group could derive costs. The operating and maintenance costs were based on the pilot plant operations of the Union Oil Company of California who developed this particular type of retort. Thus, it is believed that all major cost factors have been included and that their order of magnitude is correct.

The shale oil project consists of five major units; these are:

(1) Oil shale mines located in the Green River shale formation of western Colorado.

(2) Oil shale retorts, located near the mine portals, to produce crude shale oil.

(3) Oil shale refineries, located within a few miles of the various retorting sites, to produce raw gasoline and gas oil fractions.

(4) A pipe line, serving all of the Colorado refinery sites, to transport the semifinished products to refineries in the Los Angeles area.

(5) Incremental refining facilities at existing refineries near Los Angeles to process raw gasoline and gas oil into finished motor fuel, diesel fuel, fuel oil, and LPG.

Of these five major units, the first four represent new facilities that are not in any way integrated into our present supply of liquid fuels. The fifth item, incremental facilities at existing California refineries, represents a concession to predicted future trends in petroleum product supply and demand. The pipe line could have been designed to carry the semifinished products to Kansas City or St. Louis at about the same cost, or to Chicago at a slightly greater cost. It appears, however, that the demand for liquid fuels in California is growing at a faster pace than other sections of the country. From this viewpoint, it is apparent that established refineries in California will be greatly concerned in obtaining additional supplies of liquid fuels and also in utilizing their present refineries to make finished products.

The crude shale oil could be vis-broken and transported to a refinery site in California, but it is the consensus of those studying this project that the semifinishing of products at the Colorado site is more economical in that it permits the use of the retort off-gas, having a heating value of 83 Btu/SCF, for plant fuel. This gas, otherwise, would have no fuel value.

The products obtained from this project are as follows:

Product	Quantity/CD
At Colorado	
Ammonia, Tons	460
Sulfur, Tons	215
Coke, Tons	5,900
Fuel Gas (1,060 Btu/SCF), MSCF	124,150
At California	
Motor Gasoline, Bbls	126,900
Diesel Fuel, Bbls	62,360
Fuel Oil, Bbls	3,050
LPG, Bbls	8,920
Total Liquid Fuels, Bbls	201,230

A small additional quantity of liquid fuels are produced but are consumed in the Colorado operations. A small portion of the semifinished gasoline and gas oil could be marketed in the Colorado region, but since it is doubtful that such a premise would improve the economics, it was assumed that all liquid fuels would be finished and marketed in California. Of these eight separate products, six were given by-product status and only motor gasoline and diesel fuel were considered as major products. In order to simplify the economics, the cost of these major products was expressed in terms of "equivalent gasoline".

This phrase has several definitions, and to clarify its use in this study, the calculation of "equivalent gasoline" volume is presented below:

Product	Relative Refinery Market Value	Production, B/CD	Volume as Equivalent Gasoline, B/CD
Motor Gasoline	100%	126,900	126,900
Diesel Fuel	70%	62,360	43,652
Total		189,260	170,552

As indicated above the factor used to convert the volume of diesel fuel to "equivalent gasoline" is merely the refinery realization on diesel fuel relative to motor gasoline.

The products classified as by-products were given prices corresponding to their estimated value at the site at which they are produced. In total, these by-product credits reduce the cost of "equivalent gasoline" by 1.4 cents per gallon.

For the four cases considered, the investment cost and the cost of gasoline, including a 6% per year return, can be summarized as follows:

	CASE			
	A	B	C	D
Investment Cost				
Per B/CD of Total Liquid Fuels	$6,800	$8,100	$7,500	$6,900
Per B/CD of Equivalent Gasoline	$8,000	$9,600	$8,900	$8,200
Cost of Equivalent Gasoline Including 6% Return, ¢/Gal.	13.9	15.2	14.7	14.1

The four variations in investment cost represent relative levels of responsibility on the part of the project sponsor toward providing housing and community facilities. Briefly, these cases are:

A - No housing or community development

B - Complete housing and community development including (1) housing for employees, (2) housing for tradespeople, teachers, etc., (3) general community facilities comprised of streets, utilities, schools, etc., and (4) commercial buildings.

C - Housing for employees and general community facilities.

D - General community facilities.

Of these four cases, A and B represent, respectively, the minimum and maximum expenditures. Neither of these cases, however, is believed to represent the probable situation. In order to obtain an adequate and stable labor

supply at minimum investment, it is the opinion of the Subcommittee that the housing program would approach that of case C. These expenditures are presented in the following table:

	CASE			
	A	B	C	D
	(In Thousands of Dollars)			
Housing for Employees	-	$121,600	$121,600	-
Housing for Tradespeople and Others	-	85,100	-	-
General Community Facilities	-	30,500	30,500	$ 30,500
Commercial Buildings	-	33,600	-	-
Total	-	$270,800	$152,100	$ 30,500

For the different categories included under housing and community development, factors representing the excess of rental income over maintenance costs were estimated. They are as follows:

(1) Housing for Employees and Tradespeople: A net income over 20 years of 90% of initial cost was assumed.

(2) General Community Facilities: It was assumed that a new community would not be able to asses taxes during the 20-year period which would be sufficient to retire an appreciable portion of the investment and so no recovery was included.

(3) Commercial Buildings: The assurance of a stable market for 20 years should permit tradespeople to pay sufficient rents to yield a net income equal to 200% of the investment.

Two differences between this study and the study on the initial plant (39,700 B/CD) are in the price allowed on the by-product ammonia and in the start-up expense. The ammonia price was reduced from $80, in the initial plant study, to $77.50 per ton for this study, in recognition of freight equalization on the larger production. The start-up expense for this study is proportionately less than that given in the initial plant study due to the assumption that the plants in this study would benefit from the experience obtained on the initial plant and would increase their production during the first year to 80% (vs. 65%) of design capacity.

The depreciation of the facilities has been set at a rate consistent with the composite life of the equipment. Thus, the mine investment has been depreciated at a rate of 10% per year corresponding to a composite life of 10 years for all depreciable items. The plant, excluding such items as process royalties, has an indicated composite life of 18.7 years corresponding to a 5.34% depreciation rate. This, however, was rounded off to an even 5% and applied to all investment items excluding the mine, which was depreciated at 10%, and the working capital, which is not depreciable.

Although every effort was made to include all items of expense and income pertaining to a project of this nature, there are two items which have

purposely been excluded. The first is interest on capital expended during the construction period. The interest expense would depend on the type of financing and on the return that the creditors, institutional or private, would expect. Neither of these factors has been determined, and it was decided to omit this item. The second item is the cost of acquiring oil shale lands or mineral rights. This matter is discussed in the oil shale mining report, wherein it is pointed out that, to date, the cost of acquiring these properties would not appreciably alter the cost of mining shale.

The producing cost of 14.7¢ per gallon of equivalent gasoline (case C) compares with a refinery realization of 11.7¢ per gallon of gasoline in the Los Angeles area. The cost of 14.7¢ per gallon developed in this study is 1.5¢ per gallon less than that determined for the initial plant of 39,700 B/CD capacity. This reduction is essentially due to the savings in the pipeline investment and operating costs. Otherwise, the two studies are very similar.

The cost developed in this study indicates that while shale oil products are not competitive, they are potentially the next important source of liquid fuels. The financial incentive for this source of liquid fuels, however, will not be created until the price of crude oil has increased considerably above its present price. This, however, would not guarantee that investors or petroleum companies would care to invest in a new and somewhat speculative venture if it could earn only 6% per year after income taxes at a 50% rate. This return, plus depreciation at slightly over 5%, would pay out the investment in about nine years. This is not a sufficiently rapid payout on a new project, particularly in the petroleum industry where a high rate of obsolescence has always been encountered. The rate of 6% per year should, therefore, be considered as a minimum applicable to the evaluation of this process. If anything, the rate of return should be increased to a level of not less than 15% per year in recognition of the risks involved in such a project.

The other items of expense and income used in this study are believed to be amply explained in the separate report of the initial plant case for producing liquid fuels from oil shale and in the reports of the Process, Engineering, and Raw Materials Subcommittees.

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SUMMARIZED ECONOMIC CALCULATIONS FOR 200,000 B/CD OF REFINED PRODUCTS FROM SHALE OIL PLANTS

		Units/CD	Price	$/CD
1.	PRODUCT YIELDS AND BY-PRODUCT INCOME			
2.	Liquid Fuels			
3.	Motor Gasoline, Bbls.	126,900	--	--
4.	Diesel Fuel, Bbls.	62,360	--	--
5.	Residual Fuel Oil, Bbls.	3,050	$1.60/Bbl.	$ 4,880
6.	LPG, Bbls.	8,920	5.30¢/Gal.	19,856
7.	Total Liquid Fuels, Bbls.	201,230	--	--
8.	Other Products			
9.	Ammonia, Tons	460	$77.50/Ton	35,650
10.	Sulfur, Tons	215	$20.50/Ton	4,408
11.	Coke, Tons	5,900	$ 4.00/Ton	23,600
12.	Fuel Gas (1,060 Btu/SCF), MSCF	124,150	7.0¢/MSCF	8,690
13.	By-Product Income, $/CD	--	--	$97,084

		Basis	$/CD
14.	OPERATING EXPENSE		
15.	RETORTING, REFINING, & PIPELINE FACILITIES		
16.	Labor		
17.	Operating	2,539 Employees @ $1.98/Hr.	$ 28,750
18.	Maintenance	1.87% per Yr. of $953,772,000 Investment	48,800
19.	Unit Supervision & Clerical	Detailed in Engineering Report	4,250
20.	Payroll Extras	20% of Items 17, 18, & 19	16,360
21.	Material		
22.	Operating	Detailed in Engineering Report	6,410
23.	Maintenance	1.48% per Yr. of $953,772,000 Investment	38,740
24.	Utilities	See Footnote *	- 12,690
25.	Catalysts and Chemicals	Detailed in Engineering Report	19,430
26.	Tetraethyl Lead	1.5 cc per Gallon @ 0.224¢/cc	17,908
27.	Total Direct Expense		$167,958
28.	General Overhead (Plant Burden) & Administrative Overhead	50% of Items 17, 18, 19, 22, & 23	63,475
29.	Research & Development	$5,000,000 per Year	13,700
30.	State, County, & Local Taxes and Insurance	1.5% per Yr. of $1,026,108,000 Investment	41,565
31.	Total Plant and Pipeline Expense Excluding Depreciation		$286,698
32.	OIL SHALE MINE (384,000 T/CD)		
33.	Labor		
34.	Total Mine Labor	5,780 Total Employees	$ 75,580
35.	Payroll Extras	Basis Given in Oil Shale Mining Report	13,500
36.	Utilities	Purchased from Shale Oil Plant	15,260
37.	Total Supplies	Detailed in Oil Shale Mining Report	54,740
38.	Administrative Overhead	10% of Total Labor Cost	8,910
39.	State, County, & Local Taxes and Insurance	1.08% per Year of Mine Investment	3,960
40.	Depletion and Royalty	(None Estimated)	--
41.	Total Mine Expense Excluding Depreciation		$171,950
42.	Total Operating Expense Excluding Depreciation		$458,648

		Case (See Explanation in Text)			
		A	B	C	D
43.	INVESTMENT				
44.	Total Plants and Pipeline	$ 953,770,000	$ 953,770,000	$ 953,770,000	$ 953,770,000
45.	Construction Labor Premium	72,340,000	72,340,000	72,340,000	72,340,000
46.	Oil Shale Mines	130,100,000	130,100,000	130,100,000	130,100,000
47.	Process Royalties	58,650,000	58,650,000	58,650,000	58,650,000
48.	Start-Up Expense	27,800,000	27,800,000	27,800,000	27,800,000
49.	Working Capital	122,700,000	122,700,000	122,700,000	122,700,000
50.	Total Investment Excluding Housing	$1,365,360,000	$1,365,360,000	$1,365,360,000	$1,365,360,000
51.	Housing for Employees	--	121,600,000	121,600,000	--
52.	Housing for Tradespeople & Others	--	85,100,000	--	--
53.	General Community Facilities	--	30,500,000	30,500,000	30,500,000
54.	Commercial Buildings	--	33,600,000	--	--
55.	Total Investment	$1,365,360,000	$1,636,160,000	$1,517,460,000	$1,395,860,000
56.	ECONOMICS, $/CD				
57.	Total Operating Expense	$458,648	$ 458,648	$ 458,648	$ 458,648
58.	Depreciation of Operating Facilities (Items 44, 45, & 46)	175,943	175,943	175,943	175,943
59.	Amortization of Process Royalties & Start-Up Expense	11,842	11,842	11,842	11,842
60.	Depreciation of Housing Facilities	--	37,096	20,836	4,178
61.	Sub-Total	$646,433	$ 683,529	$ 667,269	$ 650,611
62.	Credit for By-Products	- 97,084	- 97,084	- 97,084	- 97,084
63.	Income from Electricity Sold to Community	--	- 2,440	- 1,435	0
64.	Rental Income from Housing Facilities	--	- 35,853	- 14,992	0
65.	Cost of Major Products Before Profit	$549,349	$ 548,152	$ 553,758	$ 553,527
66.	Return on Investment @ 6% per Yr. of Item 55	224,443	268,958	249,446	229,457
67.	Federal Income Taxes @ 50% Rate	224,443	268,958	249,446	229,457
68.	Cost of Major Products Including Return	$998,235	$1,086,068	$1,052,650	$1,012,441
69.	Cost of Equivalent Gasoline**, ¢/Gal.	13.9	15.2	14.7	14.1

* Utilities purchased from outside sources for pipeline and California refining facilities equal $2,570/CD; credit for utilities sold to mine is $15,260/CD.

** Equivalent gasoline volume is comprised of 100% of gasoline plus 70% of diesel fuel, which basis represents relative value of these two products.