CAPACITY OF CRUDE OIL

GATHERING SYSTEMS AND DEEP-WATER TERMINALS

A Report of the
NATIONAL PETROLEUM COUNCIL
1970

NATIONAL PETROLEUM COUNCIL

E. D. Brockett, *Chairman*
H. A. True, Jr., *Vice Chairman*
Vincent M. Brown, *Executive Director*
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Petroleum Advisory Council
to the
U.S. DEPARTMENT OF THE INTERIOR

Walter J. Hickel, *Secretary*
Hollis M. Dole, *Asst. Secretary-Mineral Resources*
Gene P. Morrel, *Deputy Asst. Secretary-Mineral Resources*

and to the
OFFICE OF OIL AND GAS

Prepared by the
National Petroleum Council
in response to a request from the
Department of the Interior

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July 17, 1970

Prepared by the

NATIONAL PETROLEUM COUNCIL'S COMMITTEE
ON CRUDE OIL DELIVERABILITY

M. A. Wright, *Chairman*

with the assistance of the

TECHNICAL SUBCOMMITTEE ON CRUDE OIL DELIVERABILITY

W. T. Slick, Jr., *Chairman*

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PREFACE

The National Petroleum Council, an industry advisory body representing virtually all sections of the United States oil and gas industries, was established by the Secretary of the Interior on June 18, 1946, pursuant to a directive of the President of the United States. The purpose of the Council is to advise, inform and make recommendations to the Secretary of the Interior with respect to matters relating to petroleum or the petroleum industry submitted to it by the Secretary.

Almost since its inception, the Council has cooperated with the Federal Government in the area of emergency preparedness of the United States petroleum industry. On April 15, 1969, the Hon. Hollis M. Dole, Assistant Secretary of the Interior, requested the National Petroleum Council to:[1]

(a) study and identify the "major" segments which comprise the spectrum of petroleum supply for refineries;

(b) compile capacity data on field gathering systems; and

(c) compile data on the capacity of ports to handle crude oil shipments to refineries.

To carry out this assignment, a 15-member Committee on Crude Oil Deliverability was established, under the chairmanship of M. A. Wright, Chairman of the Board, Humble Oil & Refining Company. The Co-Chairman of the Committee was Dr. Wilson M. Laird, Director, Office of Oil and Gas, United States Department of the Interior.[2]

The Committee subsequently set up a working group to assist it--a Technical Subcommittee, composed of 12 members under the chairmanship of W. T. Slick, Jr., Assistant Manager, Corporate Planning Department, Humble Oil & Refining Company. John Ricca, Deputy Director, Office of Oil and Gas, served as Co-Chairman.[3]

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[1] *See Appendix A, page 35.*

[2] *See Appendix B, page 36, for list of Committee members.*

[3] *See Appendix C, page 37, for list of Subcommittee members.*

NATIONAL PETROLEUM COUNCIL

(Established by the Secretary of the Interior)

July 17, 1970

My dear Mr. Secretary:

Pursuant to a request on April 15, 1969 by the Department of the Interior, the National Petroleum Council has completed its identification of the major segments which comprise the spectrum of petroleum supply for refineries and its compilation of data on the capacity of field gathering systems and of ports in order to make possible reliable determination of deliverability of crude oil in emergencies. I am pleased to transmit to you herewith the Council's report, entitled *Capacity of Crude Oil Gathering Systems and Deep-Water Terminals*.

The report indicates that the total "supply system" through which domestic raw materials are moved to U.S. petroleum refineries can be broken down into component parts, principal of which are (a) wellhead productive capacity of petroleum raw materials, (b) field gathering facilities capacity, (c) main line (trunk line) transportation capacity by pipeline, (d) port (tanker and barge loading) capacity, and (e) marine (tanker and barge) capacity. However, meaningful assessment requires the joint or interrelated evaluation of individual segments of each component part in concert with other physically related facilities. For example, an aggregation of field gathering capacity of and by itself is of little value as it is necessary to relate the capacity of field gathering systems to productive capacity on an individual field basis. For this reason, the Committee preparing the report utilized American Petroleum Institute estimates of emergency productive capacity, which are developed field by field.

On this basis, the Committee found that the emergency spare productive capacity in 1969 of 2,918 MBD would be effectively reduced by approximately 525 MBD due to restrictions which could not be removed from field gathering facilities within 90 days in the event of an emergency, a reduction of 18 percent. Furthermore, the data indicate that emergency spare productive capacity declined to approximately 2.5 million barrels per day in 1970 and gathering capacity limitations further reduced the portion deliverable to trunk lines to approximately 2 million barrels per day. The report stresses that when use is made of these data on emergency spare capacity, full recognition should be given to the applicable American Petroleum Institute definition of that capacity. To underscore this point, the normal spare productive capacity which could be achieved without applying emergency measures by either government or industry is believed by most observers to have been approximately 0.8 to 1.0 million barrels per day in mid-1970.

The statistics on field gathering capacity are emphasized because it was in this area, rather than in the capacity of tanker loading capability of port facilities, that problems were found to exist.

Respectfully submitted,

E. D. Brockett, Chairman

Honorable Walter J. Hickel
Secretary of the Interior
Washington, D. C.

INTRODUCTION

Numerous estimates of United States crude oil productive capacity have been made by the National Petroleum Council, the American Petroleum Institute, the Independent Petroleum Association of America, the Interstate Oil Compact Commission, and individuals for a period of years. These estimates represent the volumes of crude oil which could potentially be produced within the United States at varying times and under specific assumptions. Likewise there have been analyses made on the related subjects of both transportation and storage capacity for petroleum and its products. These reports[1] provide information useful in conjunction with other studies conducted by the government or industry on the capabilities of the United States domestic petroleum industry to make available needed additional volumes of petroleum raw material and products in the event of the failure of foreign sources of supply. The actual responses of available sources of supply, including the United States, during the eight petroleum emergencies[2] that have occurred since 1948 have also provided

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[1] *See Bibliography, p. 59.*

[2] *International Petroleum Interruptions: 1948, Iraqi closure of Kirkuk pipeline; 1951, Iranian nationalization; 1956, Second Arab-Israeli war; 1961, Iraqi seizure of North Rumalia; 1966, Syrian closure of North Iraq pipeline 40 Tripoli and Banias; 1967, Nigerian war; 1967, Third Arab-Israeli war; 1969, Syrian sabotage of Trans-Arabian pipeline.*

useful information. However, these data only indicate that during the emergencies the United States petroleum industry has not been required to produce all its known reservoirs of oil and gas at maximum efficient rates to meet emergency requirements. Thus, experience derived from these past emergencies provides limited insight as to the actual levels of operation at which the entire United States petroleum supply structure would be severely strained.

Total crude oil productive capacity in the United States, according to published studies, grew steadily from 1948 to 1968 (see *Figure 1*, p. 3). Crude producing capacity apparently increased faster than production up to about 1965. In more recent years, however, producibility increases have not kept pace with the growth in United States production, and an actual downturn in total producibility occurred in 1969. As a consequence, the apparent unused or "spare" productive capacity has been declining steadily since the mid-1960's (*Figure 2*, p. 4). These factors, together with the appropriate concern of government agencies for emergency planning, have tended to focus additional attention on the questions of how much unused producing capacity actually exists in the United States.

It should be emphasized that the locale of unused producing capacity is in those fields in the United States having such spare capacity, and not at the major refining and consuming centers. Accordingly, in emergency planning activities, the most relevant question becomes what portion of the spare petroleum productive capacity could actually be delivered through the various components of the supply system to the points where it is needed during an emergency. This question is one aspect of emergency planning that has received limited attention in the past. It is the primary focus of this study.

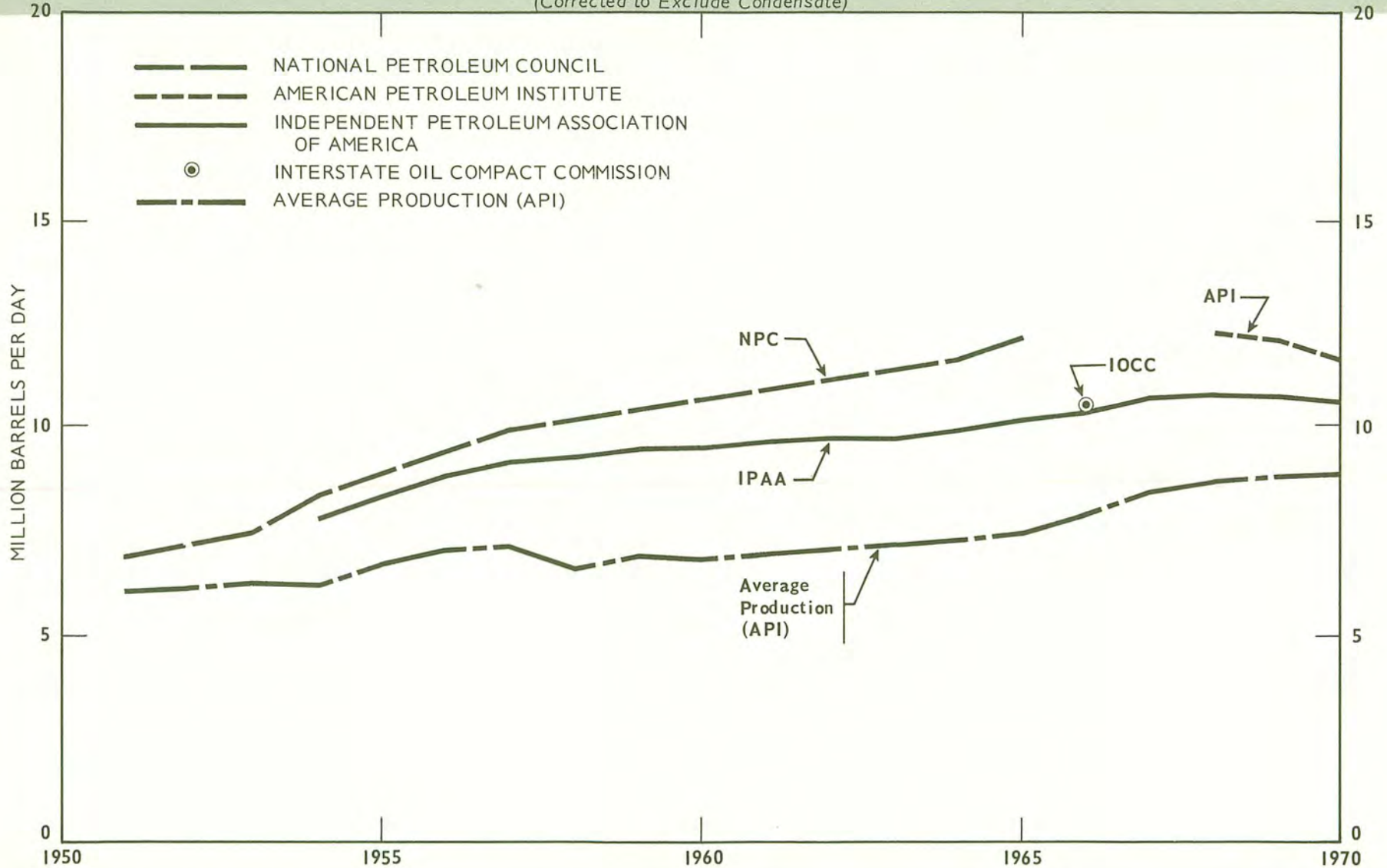
SUMMARY

The total "supply system" through which domestic raw materials are moved to United States petroleum refineries can be broken down into several component parts, principal of which are (a) wellhead productive capacity of petroleum raw materials, (b) field gathering facilities capacity, (c) main line (trunk line) transportation capacity by pipeline, (d) port (tanker and barge loading) capacity, and (e) marine (tanker and barge) capacity. Aggregate measures of each of these component parts is insufficient to establish the total "system" capacity. Meaningful assessment requires the joint or interrelated evaluation of individual segments of each component part in concert with other physically related facilities.

FIGURE I

U.S. Crude Oil Productive Capacity [1]

(Corrected to Exclude Condensate)

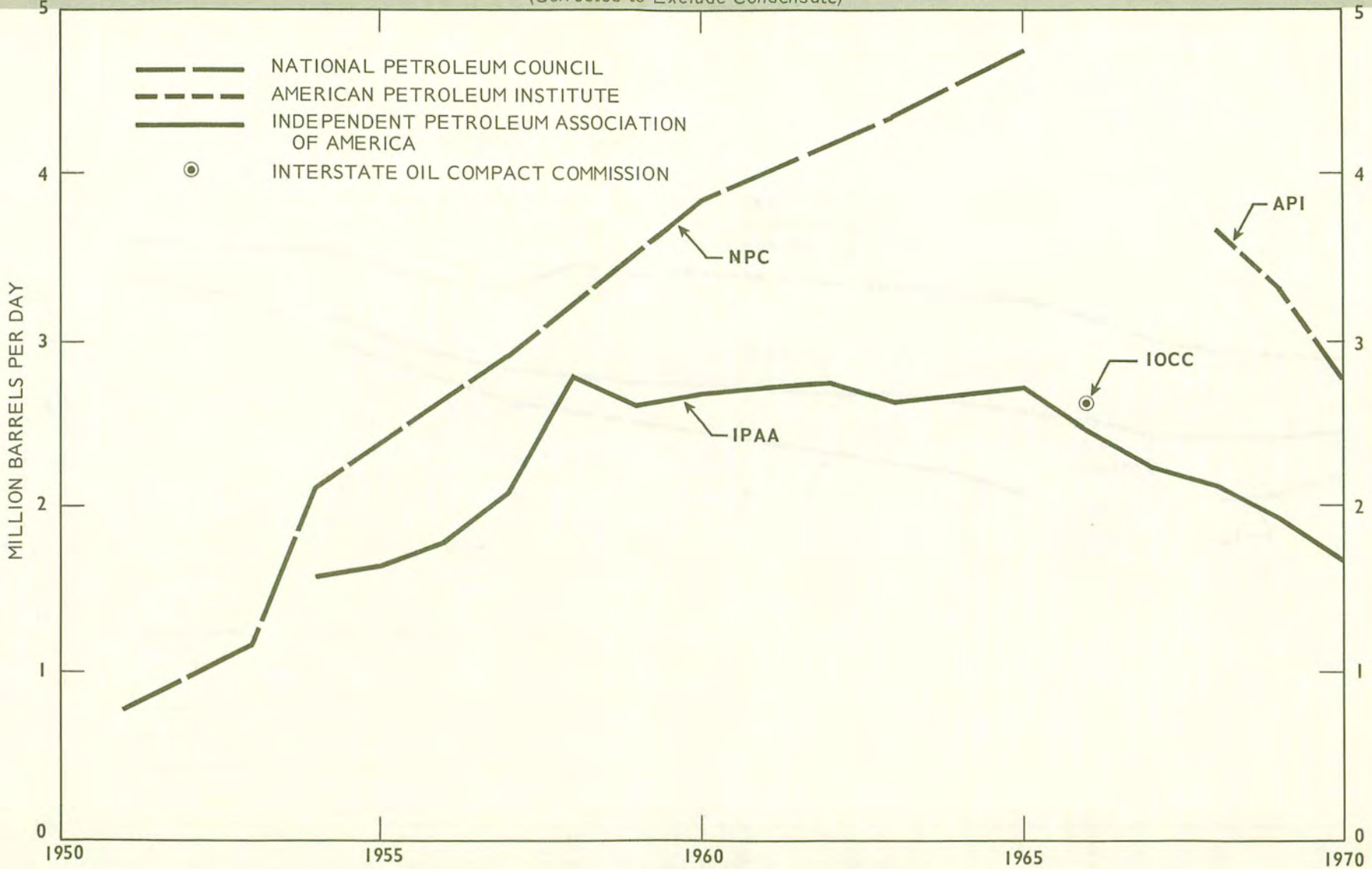


[1] None of these estimates are directly comparable. Each organization has used differing assumptions, which the reader is cautioned to review.

FIGURE 2

U.S. Spare Crude Oil Productive Capacity [1, 2]

(Corrected to Exclude Condensate)



[1] Represents the differences between average annual production of crude oil only and the annually reported productive capacity estimates.

[2] See footnote on Figure 1.

Field gathering capacity consists of facilities between the point of custody transfer and main or trunk line transportation facilities. As such it is an integral part of the overall "supply system" of the United States petroleum industry. While important to the overall system, the field gathering systems inherently possess spare capacity in the majority of their component parts. By nature (many short, small-diameter pipelines with pumps and motors) field gathering systems are also readily expansible in most of their component parts. Nevertheless, the estimated API emergency crude oil productive capacity of 12,055 MBD as of March 31, 1969 (11,627 MBD as of March 31, 1970), would have been effectively reduced by approximately 525 MBD or about 4 percent due to restrictions or "bottlenecks" which could not be removed from field gathering facilities within 90 days in the event of an emergency. Of the total "spare" capacity of 2,918 MBD,[3] the gathering capacity restrictions of 525 MBD represents 18 percent.

An aggregation of capacity in field gathering systems is, of and by itself, of little value. The capacities of gathering systems must be examined individually in relation to the producing capacity of fields served on a field-by-field basis. The Committee is grateful to the American Petroleum Institute and particularly to its Committee on Reserves and Productive Capacity for its assistance in assessing selected individual field productive capacities. Without their cooperation this study could not have been conducted.

Port capacity is another component part of the supply system. In the context of supply emergencies only Texas and Louisiana Gulf Coast ports have relevance since it is only through these ports that spare United States crude oil can be moved to other refining centers. The existing capacity of these ports for crude oil tanker loading is about 4,500 MBD[4] which is well in excess of the additional port capacity requisite for handling the maximum volume of crude which could be made available for tanker movement from Gulf Coast ports (after satisfying local refinery raw materials requirements) of about 2,500 MBD[5] . Port capacity would therefore present no limitations to maximum utilization of domestic petroleum raw materials in an emergency.

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[3] *Based on API productive capacity estimates for March 31, 1969 (see Table II, p. 16, for details).*

[4] *See Table V, p. 23.*

[5] *See page 24 of this report.*

In the process of evaluating gathering system and port capacities, the Committee found indications that productive capacity estimates of the API for some fields warranted additional study; these indications were related to the appropriate API working committee representatives. The API committees made certain changes in their 1970 estimates to account for these as well as other relevant factors. These changes have little effect on the results and conclusions reached by this Committee. In addition, this Committee noted in some instances, based on an examination of the 1967 NPC report on transportation capacities, that there appear to be additional restrictions in the trunk line component of the total supply system, some of which would be additive to the gathering system limitations. While quantifying these trunk line limitations was beyond the purview of this Committee's effort, further information with respect to such trunk line limitations is available to the Department of the Interior from detail obtained in this and previous NPC pipeline (trunk) studies.

STUDY PROCEDURES

Crude oil deliverability has its principal relevance for Federal Government planning activities in the context of petroleum supply emergencies. The international petroleum industry has been affected by eight such emergencies since 1948 (see footnote 2, p.1), each of which has had its own characteristics. These have involved such occurrences as expropriation and shutdown of production in a particular country for an extended period, loss of production from a region for short periods, embargoes, and the continuing closure of the Suez Canal. This Committee concluded that it would be useful to provide an evaluation of the several components of the United States supply system under a common set of emergency assumptions. It therefore decided to adopt the emergency conditions implicit in the API definition and assessment of "Productive Capacity" and relate field gathering capacities for crude oil to that emergency. (See Part Four--"Productive Capacity", p. 29.)

An examination of this API definition indicates that an explicit emergency is not defined. However, such is not necessary since the *degree* of the emergency is clearly indicated as being sufficient to call forth substantially all available productive capacity with local regulatory and equity restrictions being waived. It is worth emphasizing that this definition implies an emergency of the most serious character short of nuclear war. An identical degree of urgency is implicit in the quantification of Field Gathering Capacity and Port Capacity made herein by the NPC Committee on Crude Oil Deliverability.

Field gathering systems have varying meanings in regulatory practice and field operating parlance. For purposes of this study they have been defined as being those facilities necessary to transport crude oil (and natural gas liquids) from the "point of custody transfer" to the "main line transportation facilities" as the latter are defined in the NPC report of 1967, "U.S. Petroleum and Gas Transportation Facilities". The "point of custody transfer" is defined as that point in the supply system where ownership and/or control of the petroleum liquid to be transported passes from the producer to the purchaser or transporter. Physically this "point" will vary with the nature of the producing operations. Historically the point of custody transfer had, in essentially all instances, been at the pipeline company's connection to the producer's lease stock tank in the producing field (or gas processing plant storage yard). With the advent of Lease Automatic Custody Transfer (ACT or LACT) equipment, such became the point of transfer. ACT units may be located on the individual producing leases or at one or more centralized points in an area, but in any event are usually located within the producing field proper or its immediate proximity.

The situation involved in offshore producing operations also deserves special mention. Offshore producing operations can follow one of a number of patterns.

- Produced fluids may be separated through equipment located on offshore platforms. The crude oil (or NGL) may then be (a) delivered to a pipeline connection at the platform (or a nearby offshore location), (b) delivered into a barge at the platform for transfer to a shoreside storage facility of the producer at which custody is subsequently transferred to a purchaser, or (c) delivered to the purchaser in a barge at the platform.

- Alternatively, total fluid production (oil, gas and possibly water) may be transported to a shoreside facility through a multiphase flowline by the producer where the petroleum liquids are separated and subsequently transferred to the purchaser.

In all cases the "field gathering systems" evaluated in this study begin at the point of custody transfer of merchantable oil without regard to how the lease operator is conducting his field activities prior to such delivery.

In some instances in the coastal areas of Louisiana and Texas, field gathering facilities consist of barge facilities;

generally, however, these gathering facilities consist of pipelines and associated pumps and tankage. These facilities and their expansibility were appropriately defined in the earlier NPC study of transportation facilities. That description is subscribed to by this Committee and is incorporated herein for reference.

> "A gathering line system is usually composed of several small-diameter (2"-6") pipes used to collect crude oil from several producing units in a field and transport it to a tank farm, or in specific instances, inject the oil directly into a main trunk line. According to a report by the U.S. Bureau of Mines in 1965, there were about 77,000 miles of crude oil gathering lines, 72,000 miles of crude oil trunk lines, and 61,000 miles of products trunk lines. The crude oil gathering lines may be thought of as the roots which feed the growth of a towering pine tree; whereas trunk pipelines are analogous to the long trunk of the plant.
>
> "Many state governments have established a monthly proration upon the amount of producible oil in their fields. Since the amount of production allowed is usually set in advance, it could be assumed that a uniform rate of production from producers' batteries is obtained. But to the contrary, often there is a period of high-volume flow which may be several times the average daily rate necessary to meet the monthly allowable imposed by the state. This situation is magnified because many field units have a normal operating routine of pumping only during daylight. Thus, peak loading results in the necessity for larger pipe sizes that could permit highly increased pumpings over a sustained period in case of an emergency.
>
> "Flow through gathering systems may be increased by the addition of portable pumping equipment or the installation of additional lines on short notice. Since gathering lines use small-diameter pipe, the cost of pipe and pumping equipment is relatively low in comparison to trunk line equipment. Thus, pipe line companies usually store equipment to facilitate the construction of additional gathering lines if increased capacity is needed in a specific area. Spare pumping equipment also may be used to increase capacity over the near term. The use of plastic pipe in low-pressure gathering systems is another method of increasing gathering ability in a short period of time. Even though this material is more expensive than steel, it is lightweight and readily adaptable on short notice to many applications.

"In general, the pipeline industry has the ability to increase the flow of crude oil through its gathering systems in a short period of time. Use of better scheduling techniques, flexible equipment which is easily transportable, the availability of substitute materials such as plastic and aluminum, and the relatively low cost of reserve pipe mean that gathering system throughputs can be expanded significantly."

While this Committee recognizes the probable validity of the foregoing generalization, it nonetheless deemed it appropriate to examine this portion of the supply system in detail so as to establish both the applicability and the limitations of the premise.

PART ONE

CAPACITY OF CRUDE OIL GATHERING SYSTEMS

It is established that in many areas of the United States most wells are currently producing at capacity. In such areas, field gathering systems are handling current production and while spare gathering capacity doubtless exists, such excess gathering capacity is not relevant to the current study. In such cases, current levels of production are synonymous with productive capacity and the level of production constitutes the limiting factor in the supply system. While there may be isolated exceptions, these conditions apply in all areas of the country except Louisiana, New Mexico, and Texas. API productive capacity, as of March 31, 1969, for areas producing essentially at capacity was 3,651 MBD of which 233 MBD was in the Elk Hills Naval Petroleum Reserve in California. Elk Hills currently produces about 3 MBD. The status of its gathering and transportation facilities is discussed later in this section of the report.

Current production in all areas of the United States exclusive of Louisiana, New Mexico, Texas and Elk Hills was verified to be essentially at capacity as indicated by the following tabulation:

	Bureau of Mines Crude Oil Production (MBD)	Percent of API Capacity
January 1969	3,312	97
June 1969	3,454	101
December 1969	3,390	99

Detailed production and productive capacity data by states are shown in *Table I* (p.13). From these data the Committee concluded that its primary effort should be directed toward the other areas where spare productive capacity does exist.

Between January and June 1969, Texas market demand factors increased 45 percent (from 43.7% to 63.5%); similarly, the factor for those wells subject to allowables in Louisiana increased 15 percent (from 40% to 46%). An examination of individual field performance over this same period was used to help establish whether the apparent spare capacity as reflected by API estimates was reasonable. If a field's production did not increase over the first half of 1969 as allowable factors increased, there would be reason to question whether any effective spare productive capacity did in fact exist.

The Committee turned to the API for assistance in assessing individual field productive capacity data. The NPC Committee utilized data for individual fields furnished by members of the API Reserves and Productive Capacity Committee. Without this data from the API Committee it would not have been possible to conduct this study and the NPC Committee is appreciative of the cooperation and assistance provided by the API Committee members.

Applying the concepts discussed above, the Committee examined data for individual fields in Texas, Louisiana and New Mexico on both production and productive capacity. Since there are over 21,000 producing oil fields in this 3-state area, it was necessary to reduce the available data to a manageable and meaningful volume and several "screening steps" were taken. All fields producing in excess of 1,000 barrels per day were first identified. Production data for these fields were then compared to their productive capacity data in order to isolate fields with spare productive capacity. Actual performance for the January-June (1969) period was also examined as a part of this identification process. This analysis indicated that there were slightly over 500 fields producing 1,000 barrels per day or more. Closer examination indicated, as is discussed below, that an in-depth analysis of all of these fields would not be necessary to identify and analyze field gathering capacity for significant restrictions or bottlenecks.

TABLE I

CRUDE OIL PRODUCTIVE CAPACITY AND ACTUAL PRODUCTION
IN THOSE STATES PRODUCING ESSENTIALLY AT CAPACITY

	CRUDE OIL MBD[1]					
	API Productive Capacity Estimates (3/31/70)	API Productive Capacity Estimates (3/31/69)	Bureau of Mines Production			API Estimated Production (3/31/70)
STATE			1/69	6/69	12/69	
Alabama	21	22	22	21	21	21
Alaska	235	218	177	202	216	216
Arkansas	47	53	50	49	50	46
California	1,278[2]	1,266[2]	997	1,036	1,034	1,033
Colorado	70	76	79	80	74	71
Illinois	124	145	145	141	134	127
Indiana	23	23	22	20	22	22
Kansas	232	249	240	245	242	238
Kentucky	33	36	36	35	34	34
Michigan	36	36	33	33	33	33
Mississippi	203	173	161	179	182	178
Montana	110	136	126	124	113	113
Nebraska	31	33	34	33	32	31
New York	4	5	3	3	3	3
North Dakota	62	66	61	65	63	63
Ohio	31	32	31	30	26	30
Oklahoma	571	588	621	621	600	581
Pennsylvania	12	12	10	12	10	12
Utah	67	67	65	64	62	60
West Virginia	10	10	7	9	9	9
Wyoming	393	393	379	439	417	403
Other[3]	12	12	13	13	13	11
TOTAL	3,605	3,651	3,312	3,454	3,390	3,335

[1]Excludes lease condensate.

[2]Includes Elk Hills productive capacity.

[3]Arizona, Florida, Missouri, Nevada, South Dakota, Tennessee, and Virginia.

In the judgment of this Committee, the characteristics of field gathering facilities are such that some nominal spare gathering capacity always exists in essentially all fields, and furthermore, some limited additions to gathering facilities can be made on relatively short notice (see page 8 for discussion from earlier NPC study). It was further concluded that investigation of those fields with indicated "spare" productive capacity in excess of 1,000 barrels per day would be sufficient to assess overall field gathering system capabilities. "Screening studies" conducted by the Committee established that there were just over 200 fields which met these criteria, and the Committee proceeded to study the fields so identified. The 204 fields subsequently studied were found to represent 82 percent of the indicated spare productive capacity of the United States (see *Table III* on p. 17); the remaining 18 percent of spare productive capacity consists of a small amount in several thousand fields, none of which contains as much as 1,000 barrels per day of spare capacity. The Committee believes that it is reasonable to assume that field gathering capacity is already available or could be installed in an emergency in the multiplicity of fields represented in this 18 percent of spare capacity. The results of actual surveys of the larger fields with spare capacity support this conclusion.

A questionnaire was developed to ascertain from crude oil gatherers the crude handling capacity of their gathering facilities within the fields in question, as well as their ability to expand such facilities in a 90-day time frame in the event of an emergency. A copy of the questionnaire utilized is shown in *Appendix D*, p. 39.

Cooperation in conducting the survey was excellent with responses being received from 35 of 39 companies contacted; the results covered 204 fields; additionally, a separate investigation was made of the Elk Hills field in California.

The fields surveyed, other than Elk Hills, were all in Louisiana, New Mexico and Texas and were found to account for 5,126 MBD of productive capacity by API estimates. In June 1969, these fields accounted for 30 percent of total United States production and 48 percent of the combined Louisiana, New Mexico and Texas production. However, what is more important, they accounted for 43 percent of the total United States productive capacity and 82 percent of total "spare productive capacity." In this context, "spare productive capacity" is defined by this Committee for purposes of its study as the API estimate of productive capacity achievable March 31, 1969 minus June 1969 actual production. The remaining 18 percent of spare capacity is scattered in a very large number of fields, none of which represents a significant volume.

From the survey results the Committee determined that only 17 of the 205 fields (including Elk Hills) would have restrictions in field gathering facilities. These fields are grouped in the major producing areas as follows:

	Number of Fields	Amount of Field Gathering Restriction (MBD)
Texas Gulf Coast	1	75
East Texas	3	301
West Texas	5	66
So. Louisiana	8	81
	17	523

The amount of restriction, 523 MBD, represents that portion of API estimated capacity that could not be moved from the point of custody transfer to a location on main or trunk line transportation facilities. This volume limitation represents only 4 percent of the 12,055 MBD productive capacity of the United States as of March 31, 1969[1]. It should be pointed out, however, that estimated total United States "spare productive capacity" in June 1969 was only 2,918 MBD,[2] and thus this restriction represents 18 percent of such spare productive capacity.

These gathering capacity estimates are based on facilities existing as of December 31, 1969, as they might be supplemented by emergency measures in 90 days. This date was selected so as to permit the results of the present study to be more readily related to the API estimates of productive capacity as of March 31, 1970, publication of which was anticipated to be contemporaneous with the completion of this study. Comments on the actual relationship between the results of these two studies are incorporated later herein. This Committee's estimates are further qualified by the condition that the nature of the emergency requiring increases in production is such that normal commercial justification for needed facilities would be set aside and only the availability of equipment and the physical ability to install it would be limiting. Detailed tabulation of the production, API productive capacity estimates, indicated spare productive capacity and field gathering facilities limitations are shown in *Tables II* and *III* on pages 16 and 17.

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[1] *The "API 90-day productive capacity" estimate is for crude oil production capacity at a single point in time with no implication of the sustainability of such capacity.*

[2] *This is based upon the difference between API productive capacity estimates for March 31, 1969 and the June 1969 actual production, thus not directly comparable to data shown in Figure 2, on page 4.*

TABLE II

CRUDE OIL PRODUCTIVE CAPACITY AND ACTUAL PRODUCTION
IN STATES HAVING "SPARE" PRODUCTIVE CAPACITY

STATE	CRUDE OIL MBD[1] Bureau of Mines Production 1/69 (1)	6/69 (2)	12/69 (3)	API Capacity Estimates (3/31/69) (4)	INDICATED SPARE CAPACITY[2] (5)
LOUISIANA					
North	124	121	119	141	20
South	1,745	1,957	1,965	2,832	875
Total	1,869	2,078	2,084	2,973	895
NEW MEXICO					
Northwest	17	17	16	15	(-2)[3]
Southeast	319	324	326	409	85
Total	336	341	342	424	83
TEXAS					
RRC Dist. 1	47	47	46	52	5
" " 2	173	219	212	288	69
" " 3	368	447	425	901	454
" " 4	218	234	222	306	72
" " 5	32	43	42	93	50
" " 6	291	376	385	947	571
" " 7-B	101	109	102	116	7
" " 7-C	127	123	119	129	6
" " 8 & 8-A	1,276	1,425	1,438	1,919	494
" " 9	161	161	149	171	10
" " 10	80	80	76	85	5
Total	2,874	3,264	3,216	5,007	1,743
TOTAL	5,079	5,683	5,642	8,404	2,721
ELK HILLS	3	3	3	233	230
ALL OTHER	3,309	3,451	3,387	3,418	(-33)[3]
TOTAL U.S.	8,391	9,137	9,032	12,055	2,918

[1]Excludes lease condensate.

[2]The difference between Columns 4 and 2.

[3]Statistical difference between Bureau of Mines production and API capacity figures for 6/69.

MEMO: Proration Factor (%)			
Texas	43.7	63.5	62.7
Louisiana	40.0	46.0	46.0

TABLE III

RESULTS OF NPC 205-FIELD SURVEY OF CRUDE OIL GATHERING SYSTEMS

STATE	FIELD GATHERING FACILITIES SURVEYED							LIMITATIONS IN FIELD GATHERING FACILITIES			
					As Percentages of Totals on Table 2					As Percentage of Totals on Table 2	
	Fields Number	Actual Production 6/69 MBD	API Capacity (3/31/69) MBD	Indicated "Spare" Productive Capacity MBD	Production 6/69 %	Productive Capacity %	"Spare" Productive Capacity %	Fields Number	Capacity Restrictions MBD	Capacity %	Spare %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LOUISIANA											
North	-	-	-	-	-	-	-	-	-	-	-
South	89	1,287	1,982	695	66	70	80	8	81	3	9
Total	89	1,287	1,982	695	62	67	78	8	81	3	9
NEW MEXICO											
Northwest	-	-	-	-	-	-	-	-	-	-	-
Southeast	5	47	130	83	15	32	98	-	-	-	-
Total	5	47	130	83	14	31	100	-	-	-	-
TEXAS											
RRC Dist. 1	-	-	-	-	-	-	-	-	-	-	-
" " 2	8	138	193	56	63	67	81	-	-	-	-
" " 3	41	268	585	317	60	65	70	1	75	8	17
" " 4	11	61	84	23	26	27	32	-	-	-	-
" " 5	1	30	77	47	70	83	94	1	42	45	84
" " 6	9	308	867	559	82	92	98	2	259	27	45
" " 7-B	2	11	18	7	10	15	100	-	-	-	-
" " 7-C	-	-	-	-	-	-	-	-	-	-	-
" " 8 & 8-A	38	590	957	367	41	50	74	5	66	3	13
" " 9	-	-	-	-	-	-	-	-	-	-	-
" " 10	-	-	-	-	-	-	-	-	-	-	-
Total	110	1,406	2,781	1,376	43	56	79	9	442	9	25
TOTAL	204	2,740	4,893	2,154	48	58	79	17	523	6	19
ELK HILLS	1	3	233	230	100	100	100	-	-	-	-
ALL OTHER	-	-	-	-	-	-	-	-	-	-	-
TOTAL U.S.	205	2,743	5,126	2,384	30	43	82	17	523	4	18

The Committee wishes to emphasize that when use is made of these data on productive capacity and spare productive capacity, full recognition should be given to the applicable API definition of productive capacity discussed in Part Four of this study (p.31).

In examining the individual survey responses, the Committee found it necessary to make detailed evaluation of the multiple responses in several major producing areas. Complex interrelationships exist between the various pipeline gatherers' facilities in fields where several companies are gathering crude oil and where facilities of several fields are interconnected. This was particularly applicable in the East Texas, West Texas and South Louisiana areas.

Typical of this complexity are the Scurry County and the East Texas field areas of Texas, and parts of South Louisiana. *Appendix E* (p. 47) represents a condensation of the separate analysis of the Scurry County area. While detail of this type would not normally be incorporated in a report such as this, it is being included both to better describe the nature of gathering facilities to the reader not familiar with the physical aspects of the petroleum industry, and to offer guidance to other investigators who may wish to make similar analyses in the future.

In the process of its evaluation, the Committee noted that the API crude oil productive capacity estimates for some fields were questionable based on their performances in 1969 during the period that allowable production was increased in Louisiana, southeast New Mexico and Texas. Data on the fields and capacities in question were made available to API working committees on reserves and productive capacity for consideration in conjunction with their 1969 survey. The API 90-day crude oil productive capacity achievable March 31, 1970, subsequently has been reported as 11,627 MBD--a reduction of 428 MBD from the estimated March 31, 1969 rate.

A reexamination has been made of the 17 fields from which there were gathering systems restrictions versus the 1970 90-day crude oil productive capacity. Crude oil productive capacity estimates were reduced in 8 of the fields in the 1970 evaluation. This had the effect of eliminating the indicated restrictions. However, the total restrictions in gathering capacity have remained at about 525 MBD due to offsetting increases in API productive capacity estimates in other fields. A comparison by areas is shown in the following table:

FIELDS WITH GATHERING CAPACITY RESTRICTIONS

AREA	Number of Fields		Indicated Restrictions	
	1969	1970	1969 (MBD)	1970 (MBD)
South Louisiana	8	2	81	7
South Texas (RRC 3)	1	1	75	50
East Texas (RRC 5-6)	3	3	301	302
West Texas (RRC 8-8a)	5	3	66	193
TOTAL	17	9	523	552

Elk Hills Naval Petroleum Reserve

Because of its unique position in total United States petroleum productive capacity estimates, the Elk Hills Naval Petroleum Reserve in California warrants special comment. The discussion which follows is based upon information supplied to the NPC Committee by Captain R. E. Sparks, Officer in Charge, Naval Petroleum Reserve in California.

Most California spare productive capacity is attributed to the Elk Hills Naval Petroleum Reserve. This represents a unique situation since production from Elk Hills is controlled by the United States Government and not industry.

Study has determined that all Elk Hills spare productive capacity can be delivered through existing field gathering systems to the several pump stations at Elk Hills from which crude oil production is moved to main pipeline receiving points. Deliverability of total Elk Hills spare productive capacity to West Coast refining centers is currently limited, however, because of physical limitations in the connecting stub-line and main pipeline segments.

The Elk Hills Naval Petroleum Reserve in California accounts for 230 MBD of the total spare productive capacity included in the API estimate. The Stevens Oil Zone accounts for 160 MBD of Elk Hills spare productive capacity and the Shallow Oil Zone 70 MBD.

The current gathering system capacity at Elk Hills is capable of delivering 115 MBD of Stevens Oil Zone production to the Buena Vista Tank Farm and 60 MBD to the Section 24 Z Pump Station, or a total of 175 MBD of Stevens Oil Zone production. In addition, there exists capability to deliver 30 MBD of Shallow Oil Zone production to the Section 25 S Pump Station and 60 MBD to the Buena Vista Tank Farm, or a total of 90 MBD of Shallow Oil Zone production. All Shallow Oil Zone production could alternatively be delivered to the Buena Vista Tank Farm with some

additional pumping equipment which could be installed within a period of 90 days.

The main pipeline systems of the individual companies to the northern and southern California refining centers are complex and interrelated. Because of this interrelationship, it is difficult to estimate the overall main line capability of the combined efforts of all the companies. We estimate, however, that the current combined capability is about 100 MBD, plus or minus 10 MBD. Further, we estimate it would take from one and one-half to two years to install the connecting stub lines and to construct or expand main line systems needed to move total Elk Hills productive capacity. Accordingly, while field gathering systems are adequate to handle all of the Elk Hills productive capacity, less than half of the potential production could be moved to refining centers due to limitations in main line transportation facilities.

Other Observations

The Committee offers the following additional observations from its work on aspects of the supply system related to but not within the purview of its own study.

Productive capacity of natural gas liquids according to the estimates of the AGA was 3,259 MBD on March 31, 1969. This compares to 1,900 MBD of actual production in 1968. The Committee has commented on the position of natural gas and natural gas liquid facilities in the total supply system in Part Four of this report. The Committee has made no assessment of field or maritime transportation facilities for natural gas liquids. It is noted, however, that only those additional natural gas liquids extracted from associated and dissolved gas have relevance to this study. Capacity for such liquids by AGA measurement was 1,000 MBD as of March 31, 1969; actual production in 1968 was 660 MBD. This Committee would not anticipate serious limitations on moving to main line transportation the additional 340 MBD of natural gas liquids that might be produced in an emergency if maximum crude oil producibility were utilized.

Field gathering capacity evaluations were made up to the point of delivery to main line transportation. In the process of its work, the Committee, cognizant of the data contained in the NPC 1967 report on petroleum transportation capacities, noted that limitations in the overall system are indicated in some main line segments. Areas where this appears to be the case include South Texas to Houston, East Texas to the South, South Louisiana, West Texas to Gulf Coast, and West Texas to the Midwest and South Louisiana. The Committee did not attempt to quantify these limitations.

PART TWO

CAPACITY OF DEEP-WATER TERMINALS

This portion of the study evaluates United States Gulf Coast tanker loading facilities and the available Gulf Coast port capacities for loading domestic crude oil on tankers for delivery to United States and/or foreign ports in the case of an emergency. A survey was conducted to obtain the above information, the results of which are shown in *Tables IV* and *V*, on pages 22 and 23. Response to the survey was excellent, with 19 of 22 companies contacted replying. A copy of the questionnaire used is shown in *Appendix D*, on p. 39.

Table IV, on p. 22, lists specific information concerning the facilities available by Gulf Coast port area and company, while *Table V*, on p. 23, lists capacity information for Gulf Coast ports. As shown by *Table V*, the total Gulf Coast current usable capacity for tanker loading of crude oil is 4,498 MBD. Within 90 days, this capacity for tanker loading can be increased only about 10 percent to 4,979 MBD. The Committee recognizes that there are inconsistencies between capacities into the terminals and capacities out of the terminals and that the usable capacity for tanker loading is the minimum of these two parameters for each deep-water terminal.

While expansion capability of Gulf Coast ports appears to be relatively small, 481 MBD, it should be noted that 1969 marine movements of crude oil from the Gulf Coast to District 1

TABLE IV

AVAILABLE FACILITIES FOR CRUDE OIL TANKER LOADING -
U.S. GULF COAST PORTS

PORT AREA AND COMPANY	TANKER BERTHS	LARGEST VESSEL CURRENTLY BEING LOADED (MAX. DWT)	MAXIMUM DRAFT VESSEL (FEET)	MAXIMUM LENGTH VESSEL (FEET)	TANKAGE NET M BBL	BALLAST FACILITIES		AVAILABILITY OF BUNKERS	
						Storage Capacity M BBL	Disposal Rate MBD	Via Shore-side Facilities	Via Lightering
U.S. Gulf Coast									
Brownsville									
Permian	2	30	34	800	468	--	--	No	No
Corpus Christi									
Atlantic Pipe Line	1	50	40	941	850	65	24	Yes	No
Humble (Harbor Isl.)	1	76	39	810	1,400	110	55	Yes	Yes
Mobil	1	50	40	750	251	17	12	No	Yes
Permian	1	52	35	800	734	--	--	No	No
Southern Minerals	2	67	40	900	600	--	--	No	No
Sun (C. C. Refinery)	3*	40	38	800	350	30	30	Yes	No
Sun (Ingleside)	1	35	36	818	855	43	173	No	No
Galveston									
Amoco (Texas City)	2	35	36	700	321	--[1]	2	Yes	No
Houston									
Atlantic Richfield	3	60	38	740	280	150	144	Yes	No
Crown Central	1	30	36	625	180	--	--	Yes	No
Humble	2	75	40	810	724	78	--[2]	Yes	No
Texaco	1	20	30	630	844	40	40	No	No
Mississippi River, Baton Rouge, New Orleans									
Cal-Ky (Empire)	1	73	39	810	935	80	36	No	Yes
Gulf (Ostrica)	1	65	40	1,000	835	100	100	Yes	No
Humble (Baton Rouge)	4	76	39	850	300	80	1	Yes	--
Texaco (Houma)	Barges	3	8	50	744	--	--	No	No
Texaco (Loup)	1	50	40	--[3]	576	5	5	Yes	Yes
Texaco (Pilottown)	1	50	40	--[3]	352	--	--	No	No
Port Arthur, Beaumont, Lake Charles									
British Pet. (Port Arthur)	2	50	37	750	485	95	50	Yes	No
Cities Service (Clifton Ridge)	1	30	36	640	630	12	36	No	No
Mobil (Clifton Ridge)	2*	32	32	650	500	--	--	No	Yes
Mobil (Beaumont)	4*	50	37	800	322	10	100	Yes	No
Pan American (Beaumont)	3*	36	35	650	300	100	--[4]	No	No
Shell (Haymark)	1	16	20	--[3]	216	--	--	No	No
Sun (Sun Sta.)	1	--[5]	36	818	3,142	95	163	Yes	No
Texaco (Port Neches)	2	35	38	660	196	20	20	No	No
Union (Beaumont)	1	32	36	660	230	Unlimited	33	Yes	No
Union Texas (Port Neches)	1	30	28	550	130	--	--	No	No

*Includes Barge Dock.

[1]Ballast discharges to API separator box.
[2]Varies with quality of ballast.
[3]Limited by maximum DWT and draft specifications.
[4]Disposal by vacuum truck.
[5]Limited by maximum draft and length specifications.

TABLE V

CAPACITIES FOR CRUDE OIL TANKER LOADING -
U.S. GULF COAST PORTS

		CURRENT CAPACITIES MBD			EMERGENCY CAPACITIES MBD[3]		
	Number of Terminals	Into Terminals[1]	Out of Terminals	For Loading[2]	Into Terminals[1]	Out of Terminals	For Loading[2]
U.S. Gulf Coast							
Corpus Christi/Brownsville Area	8	1,538	2,986	1,472	1,789	3,636	1,745
Houston/Galveston/Baytown Area	5	1,548	1,520	1,160	1,644	1,616	1,256
Beaumont/Port Arthur/Lake Charles Area	10	1,670	2,208	1,088	1,670	2,508	1,200
Mississippi River Area	6	1,532	1,108	778	1,532	1,108	778
TOTAL GULF COAST	29	6,288	7,822	4,498	6,635	8,868	4,979

[1]Capacity into terminals via pipeline and tanker/barge without affecting local refining operations.
[2]Capacity for tanker loading is the minimum of Capacity In/Capacity Out for each terminal.
[3]Capacities that can be achieved in 90 days.

were 181 million barrels,[1] approximately 500 MBD. In addition, intradistrict movements from Gulf ports within District 3 were some 241 million barrels, about 650 MBD. Current loading capability is approximately nine times greater than the 1969 actual operating experience and can be increased to approximately ten times the 1969 rate. Furthermore, the limiting factor on port capacity, in many instances, is not tanker loading capability, but rather the limitations of the trunk line component of the total supply system to deliver crude oil into the port facilities. As shown on Table V, p. 23, the present Gulf Coast capacity for loading crude oil by tanker is 4,498 MBD. This figure greatly exceeds the volume of crude oil which can be made available for tanker movement (approximately 2,500 MBD).

Crude Oil Productive Capacity	MBD
Texas Gulf Coast (RRC Districts 1, 2, 3, 4)	1,500[2]
South Louisiana (Including Offshore)	2,800[2]
Subtotal	4,300
Trunk Line Capacity into United States Gulf Coast Area from Non-Coastal Producing Areas	2,200[3]
Subtotal	6,500
Less: United States Gulf Coast Refining Capacity	4,000[4]
Total Crude Oil Available for Tanker Movement	2,500

No attempt has been made to analyze West Coast tanker loading capabilities. The West Coast is a crude deficient area and loss of overseas crude oil supplies in an emergency could

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[1] *Mineral Industry Surveys, United States Department of the Interior, Petroleum Statement, January, 1970.*

[2] *Page 16 of this Report.*

[3] *U.S. Petroleum and Gas Transportation Capacities, NPC, 1967.*

[4] *Oil and Gas Journal, Vol. 68, No. 14, April 6, 1970.*

present problems of obtaining alternate supplies for this area. Accordingly, ability to load domestic crude for shipment elsewhere, other than between West Coast ports, is of little or no relevance for emergency planning purposes.

It is apparent that present Gulf Coast tanker loading facilities are more than adequate to handle anticipated emergency tanker movements and any need for emergency expansion of such port facilities is unlikely.

PART THREE

PROCEDURES FOR FUTURE STUDIES

Field gathering system capacity, particularly where the gathering capacity limits the productive capacity, is of continuing interest to government and industry planners alike. The need for future studies and the procedures to be followed in their completion should recognize the unique manner in which these two elements of the supply systems are related, and how they are likely to change with time, as well as the experience gained in this study.

It is not necessary to study field gathering capacity in areas where there is no significant surplus productive capacity. Such a study does not yield meaningful statistics. The study of this Committee checked the validity of first ascertaining the areas or specific fields where surplus productive capacity is indicated to exist, and then measuring the connected field gathering capacity, or that capacity which can be connected within a 90-day period. A comparison of productive and connected field gathering capacities can provide a measure of the constraint, if any, that field gathering capacity imposes on productive capacity.

As demand for domestic petroleum increases over time, the available spare productive capacity will increase or decrease depending on exploratory and development drilling success. Increases in production levels will bring about expansions in

capacities of field gathering facilities where needed, dependent on individual company appraisal of their economic worth. Once installed, such facilities (and their capacity) are not likely to decline should demand changes or exploratory effort result in lower allowable production factors. The evaluation of the need for future studies, as well as the procedures which might be followed in any future studies, should take into account changes in United States productive capacity and connected field gathering capacity from a base point of time such as that recognized in this study.

Future studies need not start over again and repeat the work of this Committee, but rather could build upon the work done in this study, examining only those areas where new productive capacity has been developed subsequent to this investigation. Timing of future studies is difficult to predict as need, if any, will be dictated by future events. The rate of additions to productive capacity which has been experienced in immediate past years would suggest, however, that a lapse of several years might occur without significantly changing the general relevance of the current study. The experience gained in this study suggests also the merit of including detailed instructions along with a general description of the purpose of the study on the questionnaires. Thereby, individuals actually completing the questionnaires can include useful qualifications to the information furnished that will be of assistance to those who are analyzing and interpreting the data.

PART FOUR

SPECTRUM OF PETROLEUM SUPPLIES FOR REFINERIES

The Committee examined the "Spectrum of Petroleum Supplies for Refineries" (see next page) developed by the Office of Oil and Gas of the Department of the Interior and concluded that the general concept of a "supply system" which this spectrum reflects is indeed sound. The "Spectrum" has two major divisions -- (I.) Up to Point of Custody Transfer, (II.) Beyond Point of Custody Transfer--with the capacity elements distributed to each segment as follows:

I. Up to Point of Custody Transfer
(Crude Oil Productive Capacity)

1. Reservoir Capacity
2. Drilling Capacity
3. Well Capacity
4. Field Production Facilities Capacity

II. Beyond Point of Custody Transfer

5. Field Gathering System Capacity
6. NGL Facilities Capacity
7. Bulk Transfer Capacity
8. Storage Capacity
9. Port Capacity
10. Maritime Transport Capacity

THE SPECTRUM OF PETROLEUM SUPPLY FOR REFINERIES

API 90-DAY PRODUCTIVE CAPACITY

I. Reservoir Capacity
- A. Primary Recovery
  - 1. Primary reserves
  - 2. Reservoir pressure
  - 3. Reservoir drive mechanism
  - 4. Reservoir rock characteristics
  - 5. Number of wells
  - 6. Maximum efficient rate
- B. Additional Recovery
  - 1. Secondary and tertiary reserves
  - 2. Number of production and injection wells
  - 3. Additional recovery facilities
  - 4. Volume of injection fluid (liquid or gas)
  - 5. Conformance and sweep efficiency

II. Drilling Capacity
- A. Rotary Rigs
  - 1. Land
  - 2. Inland barge
  - 3. Offshore
- B. Cable Tool Rigs
- C. Oil Country Tubular Goods
- D. Muds, chemicals and other materials
- E. Vehicles
- F. Supporting Services (Logging, Cementing, etc.)

III. Well Capacity
- A. Casing - Tubing Size
- B. Multiple Completion
- C. Wellhead, Valves, Chokes & Fittings
- D. Artificial Lift Equipment
- E. Production Rigs (Workover & Servicing)
- F. Utilities
- G. Regulatory Limitations

IV. Field Production Facilities Capacity (Crude and Condensate)
- A. Flow Lines
- B. Gas-Oil Separators
- C. Heater-Treaters and Demulsifying Chemicals
- D. Stock Tanks - Automatic Custody Transfer Equipment
- E. Salt Water Disposal Facilities
- F. Other Lease Facilities and Utilities

→ POINT OF CUSTODY TRANSFER

V. Field Gathering System Capacity
- A. Oil Pipelines, barges, trucks
- B. Pump
- C. Meters and Samplers
- D. Utilities
- E. Field Storage
- F. Gas Gathering System

VI. NGL Facilities Capacity (Casinghead and Gas Wells)
- A. Gas Processing Facilities
- B. Pumps
- C. Compressors
- D. Utilities
- E. NGL Storage

VII. Bulk Transfer Capacity
- A. Trunk Pipelines (size, pumps, meters, crossings, and interties)
- B. Trucks, railcars, barges
- C. Storage en route

VIII. Storage Capacity
- A. Trunk Pipeline Terminals
- B. Refineries
- C. Port Terminals

IX. Port Capacity
- A. Pier facilities and tugs
- B. Offshore facilities
- C. Loading rates and limitations
- D. Channel depth and width
- E. Pumping
- F. Seasonal limitations

X. Maritime Transport Capacity
- A. Tankers
- B. Barges

CAPACITY BENCHMARKS

1. Present Physical Capacity - (applicable to all)
2. Design Capacity - (applicable to all)
3. Crash Capacity - (applicable to all)

The "Spectrum" and the segments suffer from the weakness, however, that those not familiar with the industry might infer that the ten capacity elements embodied in the spectrum are indeed elements connected in series and that the capacity of the system is limited by the capacity of the smallest of these elements. The actual physical relationships and the relative significance of the ten capacity elements is much more complex and warrants further comment.

At the outset of its work the Committee adopted the API Technical Report No. 1, "Standard Definitions of Petroleum Statistics," as a Committee guideline and such is incorporated herein by reference.

"Productive Capacity"--The first measurable segment of the supply system is the ability of the industry to produce crude, condensate and natural gas liquids. A simple reference to "deliverability" or "capacity" is in itself too vague to be useful. A clear statement of the conditions under which "capacity" is to be determined is essential to meaningful use of the results.

After consideration of the four elements of Crude Oil Productive Capacity, i.e., Reservoir Capacity, Drilling Capacity, Well Capacity and Field Production Facilities Capacity, it was concluded that the definition of "API 90-day productive capacity" explicitly recognizes these four elements.

API DEFINITION OF 90-DAY PRODUCTIVE CAPACITY[1]

> "Productive Capacity. Estimates of Productive capacities of crude oil developed by the American Petroleum Institute Committee on Reserves and Productive Capacity represent the maximum daily rates of production which can be attained under specified conditions on March 31 of any given year.
>
> "The working definition of productive capacity used by the Committee is as follows:
>
> > 'The ninety-day crude oil productive capacity is the maximum daily crude production rate, at the point of custody transfer, that could be achieved in ninety days (following December 31 of any given year) with existing wells, well equipment, and surface facilities--plus

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[1] *See Appendix F, p.53 for 1967 comments of API Committee on Crude Oil Reserves which developed this definition.*

work and changes that can be reasonably accomplished within the time period using present service capabilities and personnel and with productivity declining as it would under capacity operation.'

"Estimates of the productive capacity for particular fields or reservoirs are based on proved acreage, wells, well equipment, and surface production facilities as of the previous December 31, with adjustments for (1) increases in productive capacity which would result from alterations and improvements in existing facilities and programs for development drilling and improved recovery techniques, which could be completed within the ninety-day period with existing capabilities and personnel; and (2) the natural decreases in productive capacity resulting from capacity operations during the ninety-day period. It should be noted, however, that there is no adjustment for additions to reserves and increased productive capacity that might result from exploratory drilling during the ninety-day period. Furthermore, estimates do not include quantities of crude oil in lease storage on March 31 which could be drawn upon at the time of capacity operation.

"Estimates prepared by the Committee are based on the following assumptions:

1. There will be no restrictions on production resulting from a lack of markets for crude oil.

2. There will be no change in crude oil prices or the unit cost of materials, equipment, and labor within the ninety-day period allowed for the buildup of capacity.

3. There will be no statutory restrictions on production, but limitations on gas and water production will be retained where the objective is to prevent the reduction of ultimate recovery, the pollution of air or water, or the creation of fire hazards.

4. There will be no restrictions on production resulting from the inadequacy of storage or transportation facilities beyond the point of custody transfer.

5. Intrafield equity considerations will be satisfactorily resolved so that production for given fields can be maximized."

Beyond the API definition and the discussion appearing in *Appendix F,* p. 53, this Committee would simply emphasize that, in relation to crude oil producing capacity, the reservoir capacity is perhaps the most critical since beyond a point this capacity is determined by naturally occurring physical factors over which man has little control. The study, understanding and control of reservoir performance, is in itself the subject of an entire engineering discipline and no more effort than to recognize the fact is attempted here.

The Committee would also urge the reader to note that the "API 90-day capacity" is simply the crude oil production capacity at a single point in time with no implication of the sustainability of such capacity.

DRILLING CAPACITY

The contribution of drilling capacity to the total system is to sustain the exploration and development activity necessary to offset decline in capacity of existing reservoirs and to add new reserves (reservoirs) to support anticipated demand and production growth. Drilling has essentially no contribution to make to the expansion of current production on short notice in the event of emergencies.

Drilling is by and large a service industry. Most drilling is done by contractors for the lessee possessed of (a) the right to drill, (b) the capital and the incentive to spend it, as well as (c) the opportunity to do so at risks commensurate with anticipated returns. Since drilling is a service or contracting industry, its physical capability at any time is generally responsive to the demands of its customers. Like any other business, it is subject to cycles in which rigs are idle or "stacked" as well as times when rigs are in short supply. When rigs are in short supply, it has generally been true that qualified drilling crews are also in short supply. Modern drilling rigs are generally complex and expensive heavy capital equipment so that there is substantial lead time required to increase drilling capacity. Such is particularly true for offshore drilling rigs.

The quality of drilling capacity is also an aspect which deserves comment. Drilling equipment varies widely in its character and is tailored to meet the needs of the operation. Rigs are specifically designed for cable tool or rotary drilling; depths of a few hundred to 20,000 feet or more; land or offshore drilling; fixed platform or floating vessel. Rigs designed for

one purpose are obviously unsuitable for use in widely different circumstances. This point is very fundamental and is commented on only because studies prepared as a basis for government policy formulation have not recognized it.[2]

REMAINDER OF SPECTRUM

Four of the six remaining elements of the supply system beyond "the point of custody transfer" have been the explicit subject of earlier portions of this study (Field Gathering System and Port Capacity) or were the object of earlier studies (U.S. Petroleum and Gas Transportation Capacities, NPC, 1967, and Petroleum Storage Capacity, NPC, 1963). Storage capacity is also the subject of a concurrent NPC updating revision of its earlier work. Maritime Transport Capacity information is available from H. Clarkson"s "Tanker Register" and "Weekly Shipping Review."

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[2] *Charles River Associates report prepared for Office of Science and Technology.*

APPENDICES

UNITED STATES
DEPARTMENT OF THE INTERIOR
OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

COPY

APR 15 1969

Dear Mr. Abernathy:

In fulfilling the responsibilities assigned to the Secretary of the Interior with respect to emergency preparedness for the petroleum industry, there is a recognized need to know the crude oil and refinery supply capability of the domestic industry during periods of emergency. In times of emergency, the Office of Oil and Gas or, if activated, the Emergency Petroleum and Gas Administration, has the responsibility to make, as promptly as possible, reliable estimates of petroleum supply, and, as required, to prepare and coordinate programs to meet national emergency requirements.

The Office of Oil and Gas tentatively has identified ten major oil supply system segments which comprise the complete spectrum of petroleum supply for refineries and the principal limiting elements for each segment. The purpose of this delineation is to establish a basis on which to develop factual statistical measurements of capabilities in order to arrive at an acceptable appraisal and estimate of refinery supply deliverability in an emergency. The ten major segments are measurable, and each segment is dependent sequentially on the preceding segment. Capacities of each are interdependent in terms of total deliverability. Estimates of capacity of some of these segments have been made but insufficient data are available on at least two of the segments.

Insufficient data is available on field gathering systems and port capacity. This additional data would provide a minimum acceptable level of data to determine the present physical capacity of the entire petroleum supply system.

We request, therefore, that the National Petroleum Council, first, study and identify the 'major' segments which comprise the spectrum of petroleum supply for refineries, and, second, compile capacity data on field gathering systems and port capacity in order to make possible reliable deliverability determination. In addition, it will be helpful if the study can establish the basis for a routine method of determining total deliverability for emergencies.

Sincerely yours,

Secretary of the Interior

Mr. Jack H. Abernathy
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D. C. 20006

NATIONAL PETROLEUM COUNCIL
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Economics Department
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MEMORANDUM OF INSTRUCTIONS
QUESTIONNAIRE ON CRUDE OIL GATHERING SYSTEM CAPACITY
NPC TECHNICAL SUBCOMMITTEE ON CRUDE OIL DELIVERABILITY

Please complete a separate questionnaire for each gathering system and subtrunkline which you operate and which provides an outlet for one or more of the fields listed on Table I. If two subtrunklines serve any one of the fields listed, please prepare a separate questionnaire for each. Responses to the questions asked should be framed in the context of the maximum production which is considered possible from the respective fields in the event of a national emergency. The possible increased production which your facilities might be required to handle is indicated on Table I as a percent of your reported June 1969 actual offtake. Following are some additional comments on the information requested in the questionnaire:

1. The point of delivery to the main trunkline, refining center, barge terminal or loading port--If delivery is to a trunkline, the information should be consistent with the pipeline data provided for the NPC 1967 Transportation Study. If delivery is to a barge terminal, please complete the answers to Question No. 5 of the questionnaire.

2. Data on available capacity of the field gathering system as of December 31, 1969--For this study, "field gathering systems" are defined as those facilities which transport crude (and NGL) from the point of custody transfer to the nearest major cross-country pipeline artery, refining center, barge terminal, or loading port. In most instances, the capacity of the field gathering system will be determined by the capacity(ies) of the subtrunk (main gathering) line(s) which connect(s) the field gathering system to the main trunk artery, refining center, barge terminal or loading port. However, if your system should have a bottleneck in the field gathering lines, please comment in the appropriate space--either on the form or as an attachment.

   We are interested in obtaining all pertinent information regarding the capacities and restraints of each of your pipelines which serve these fields. If your company should have more than one pipeline serving one of these fields, please prepare a separate questionnaire for each individual system. Furthermore, if any one of your systems involves several segments having different pipeline diameters or other physical parameters, please tabulate all pertinent details of each segment.

Further, if any gathering lines (subtrunklines) should be routed so that they can deliver to an origin point of one of the main crude oil trunk arteries listed in the 1967 report, or to a refining center or loading port which is intermediate to their final destinations, please furnish the pertinent details of capacity, pipe diameter, and emergency reserve capacity.

3. Data on maximum emergency capacity available within 90 days--In developing this information, assume that the nature of the emergency is of such urgency that normal economic factors do not act as constraints and that only physical capabilities are limiting. Bottleneck removal which can be accomplished with stocks of pipe or machinery, which are normally available either within your system or in suppliers' warehouses, should be assumed. Where opportunities exist to substantially increase capacity from one field at the expense of another field, such should be noted, including the volumes involved.

4. Comments--Provide any additional pertinent information which you think would be of value to the governmental and industry individuals assigned responsibility for coordinating and developing crude oil transportation plans under conditions of national emergency.

NPC QUESTIONNAIRE ON THE CAPACITIES
OF CRUDE OIL GATHERING SYSTEMS

OIL FIELD _____

COMPANY _____

1. Connection to main trunkline, refining center, barge terminal, or loading port

   a. Name _____

   b. Point of delivery _____
   (Attach plat and indicate location thereon)

2. Capacity data for subtrunkline as of December 31, 1969. (See attached memorandum for description of data required.)

   a. Total capacity during normal operations, MB/D _____

   b. Total capacity--continuous operations _____

   c. Existing spare capacity, MB/D _____

   d. Diameter(s) _____ Length (miles) _____

   e. Normal operating period--hours/day _____

      Normal operating pressure _____ psi.

   f. Connected horsepower _____

3. Emergency capacity

   a. Maximum total capacity attainable within 90 days, MB/D _____

   b. Brief description of bottleneck removal and amount of the capacity increase achieved through:

      (1) Increased operating pressure _____

      (2) Longer operating periods _____

      (3) Addition of pipe _____

      (4) Addition of machinery _____

(5) Other (please describe) _____

_____

_____

4. Comments

a. If bottleneck is not in subtrunkline, identify other bottlenecks _____

_____

_____

b. If more than one field is connected to subtrunkline described above, how does this affect the fields covered hereby _____

_____

_____

_____

c. If your company has more than one subtrunkline out of the field, list the destinations of other lines and describe the interactions, if any, between these lines. Include total capacity limitations for the combined system _____

_____

_____

_____

5. Barge Operations (if applicable)

a. Barge loading terminal location _____

_____

b. Loading terminal capacity, MB/D

(1) Normal operations _____

(2) Maximum 90-day capacity _____

c. Barge operator(s) _____

_____

d. Normal barge destination _____

_____

6. Individual in your company who should be contacted should questions arise concerning your reply covering this particular field:

Name _____

Address _____

_____

Telephone _____

NPC QUESTIONNAIRE ON CRUDE OIL TANKER
LOADING FACILITIES AND CAPACITIES
AT DEEP-WATER TERMINALS AND REFINERIES FOR
THE UNITED STATES (EXCLUDING HAWAII)

COMPANY _____

NAME OF TERMINAL OR REFINERY _____

NEAREST CITY _____ COUNTY _____ STATE _____

1. Facilities

   a. Information on each berth (if buoy, please indicate)

      (1) Maximum DWT vessel* _____

         (a) Berth No. 1 _____

         (b) Berth No. 2 (and any additional berths) _____

      (2) Maximum Draft vessel (feet)* _____

         (a) Berth No. 1 _____

         (b) Berth No. 2 (and any additional berths) _____

* Show maximum DWT and Draft occasioned by limitations (shallow channels, bridges, etc.) between terminal and open sea if such limitations exist and do further restrict size and Draft of vessels. Where tide or other forces afford limitation ranges, please indicate.

(3) Maximum length vessel (feet) _____

(a) Berth No. 1 _____

(b) Berth No. 2 (and any additional berths) _____

_____

_____

b. Tankage (crude oil only)

(1) Total number of tanks** _____

(2) Gross barrels _____

(3) Net barrels _____

c. Please provide schematic of terminal facilities if available.

Capacity into Terminal

a. Maximum rate via pipeline(s): (Show by company if more than one pipeline connected.) _____

(1) Receipt when simultaneously outloading crude to tankers or barges (B/D) _____

(2) Receipt when not simultaneously outloading crude to tankers or barges (B/D) _____

b. Maximum rate via tanker/barge: _____

(1) Receipt when simultaneously outloading crude to tankers or barges (B/D) _____

(2) Receipt when not simultaneously outloading crude to tankers or barges (B/D) _____

(3) Receipt when simultaneously receiving via pipeline and outloading crude to tankers or barges (B/D) _____

** If tanker loading facility is in conjunction with operating a refinery, show only those tanks that can be used for accumulating oil for outloading to ships without interfering with refinery operations.

3. Capacity Out of Terminal into Tankers or Ocean-Going Barges

   a. Maximum rate when loading crude oil only (B/D) _____

   b. Maximum rate when loading crude oil simultaneously with maximum rate for loading products (B/D) _____

4. Emergency Increases in Capacity

   a. Into terminal _____

      (1) Additional amount (B/D) _____

      (2) Limitation to be removed _____

      (3) Time required*** _____

   b. Out of terminal _____

      (1) Amount (B/D) _____

      (2) Limitation to be removed _____

      (3) Time required*** _____

5. Ballast Facilities

   a. Total barrel storage capacity _____

   b. Disposal rate from ballast facilities (B/D) _____

6. Bunkering

   a. Are bunkers available at terminal (indicate if via shoreside facilities or via lightering) _____

      _____

*** Assume equipment is available for immediate installation. Indicate if work can be performed within 90 days.

Discussion of Kelly-Snyder Area

INTRODUCTION

The Kelly-Snyder area, Scurry County, Texas, serves as an example of the complexity of certain pipeline gathering systems and the depth of analysis which was necessary to identify gathering system limitations for this NPC study.

Before analyzing the pipeline capacities, the availability of spare productive capacity was determined using productive capacity data furnished by the API. These data indicated that, while not all of the fields in the general Kelly-Snyder area have spare productive capacity, there are 5 significant fields connected to the area gathering system with spare capacity. Other fields in the area are currently producing at capacity and their production is being handled satisfactorily. Thus, it was not necessary to report on their pipeline capacity. It was, however, necessary to analyze the interrelationship of the pipeline systems from these fields with the pipeline systems from the fields with spare productive capacity.

The major interaction of the SACROC, Salt Creek and other pipeline systems in the area involves production from Cogdell, Sharon Ridge fields, and miscellaneous producing horizons within the Kelly-Snyder area (see *Figure 3*, p. 50, for schematic diagram of fields and their gathering systems and *Figure 4*, p. 51, for map of Kelly-Snyder area).

DISCUSSION

It is generally recognized that almost all of the spare production in the Kelly-Snyder area is in the SACROC unit. Thus, the question becomes how much of the increased SACROC production can existing gathering systems handle. In answering this question, the assumption was made that (a) all other fields would be increased to their maximum level even if this would reduce SACROC production and (b) the production from the Cogdell field would be rerouted to the extent possible, to maximize SACROC production.

The Salt Creek field is located about 30 miles north of the Kelly-Snyder field. Production is moved to Colorado City by a pipeline system which also handles SACROC production. The results of the NPC survey indicated that the capacity of the pipeline system in Salt Creek can be increased to accommodate the maximum increase in production. However, the capacity of the system into Colorado City can only be increased by 1.0 MBD, more than the increased Salt Creek production; this will only allow a movement of an additional 1.0 MBCD of SACROC production.

A part of the Cogdell field facility is located about 10 miles north of the Kelly-Snyder field. Production is gathered by two pipeline companies. Replies indicate the current available space in the two pipelines out of the Cogdell field exceeds the maximum production of the field. Under normal conditions, the two systems move the Cogdell production to Colorado City through subtrunk lines which also handle SACROC production. Thus, any Cogdell volume which can be rerouted would free up space to move increased SACROC production to Colorado City.

As shown on *Figure 3*, p. 50, a line between Cogdell and SACROC has some flexibility regarding the direction Cogdell production moves. Under normal conditions, flow in the Post-Cogdell section of this line is south and there is space available to move crude east to Bowie from where it can go either to Drumright or Texas City as well as an additional volume south to Colorado City. During a national emergency the line could reverse the flow in the Cogdell-Post area to move some Cogdell production north to Monroe and hence to Drumright on the main trunk line. The available capacity to Bowie would remain unchanged. Hence, all of the Cogdell production in the flexible system could be diverted away from Colorado City during a national emergency. This would increase the available space in one of the gathering systems for SACROC production.

The survey indicated that the capacity of the crude pipeline systems serving SACROC could be increased by 94.0 MBCD over the current capacity within 90 days. This would still result, however, in a pipeline deficiency of 35.4 MBCD versus maximum SACROC production. A brief discussion of the various crude oil pipeline systems serving SACROC follows.

One pipeline system serves the SACROC unit and other fields (primarily Cogdell). That pipeline system's movements could be diverted to free the full capacity of the pipeline system into Colorado City for SACROC production. As a result, this system could accommodate an increase in SACROC production.

A second pipeline system serving SACROC is connected to a line to Colorado City and a subtrunk line to Wink which feeds the trunk line to El Paso. In addition to the SACROC production, this second pipeline system receives production at North Snyder from miscellaneous other sources in the Kelly-Snyder field and from the Sharon Ridge field which it feeds into the line to Wink about 19 miles west of the North Snyder Pump Station. Thus, part of the available space in the line to Wink is reserved for movement from other fields; however, the full capacity to Colorado City is available for SACROC production. Of the total SACROC production that this second pipeline system could handle, part would go to Wink and part to Colorado City. During a

national emergency this pipeline system could handle an increase in SACROC production.

A third pipeline system in the SACROC unit could also be increased within 90 days during a national emergency. Of its capacity, only part is needed for production from other fields--Sharon Ridge field and other wells in the North Snyder area. Therefore, space available for SACROC production could be increased. Capacity out of Scurry Station can go either to Iatan and then to Beaumont via the Mobil Pipeline or to Colorado City for shipment to the West Texas Gulf Pipeline.

The operator of the third system also has a products pipeline from Snyder LPG Gathering System to Iatan Station. The capacity of this line could be increased if required. The line is currently operating only 18 hours per day, which means that this system could handle additional crude.

The total capacity of still a fourth pipeline system which serves both Cogdell and SACROC is limited by the capacity from Kelly Station into Colorado City. Part of this space is required for Cogdell production and another portion is required for production which is trucked into Kelly Station from several sources in the area.

CONCLUSION

In summary, the existing crude pipeline systems serving the Kelly-Snyder area could accommodate all but 35.4 MBCD of the potential increase in crude production. Essentially all of the increased production would be delivered to the major trunk lines at Colorado City. These lines are: Shell Pipeline to Cushing; Basin Pipeline to Cushing; West Texas Gulf to Longview and the Houston area, and Amoco Pipeline to the Rancho system.

This discussion has been incorporated to demonstrate the need for the "system analysis" approach taken by the Committee. Detailed data are not necessary to illustrate this point and have been deleted as some constitutes proprietary information.

Figure 3

GATHERING AND SUB - TRUNK PIPELINE CAPACITIES AND MOVEMENTS : KELLY - SNYDER AREA

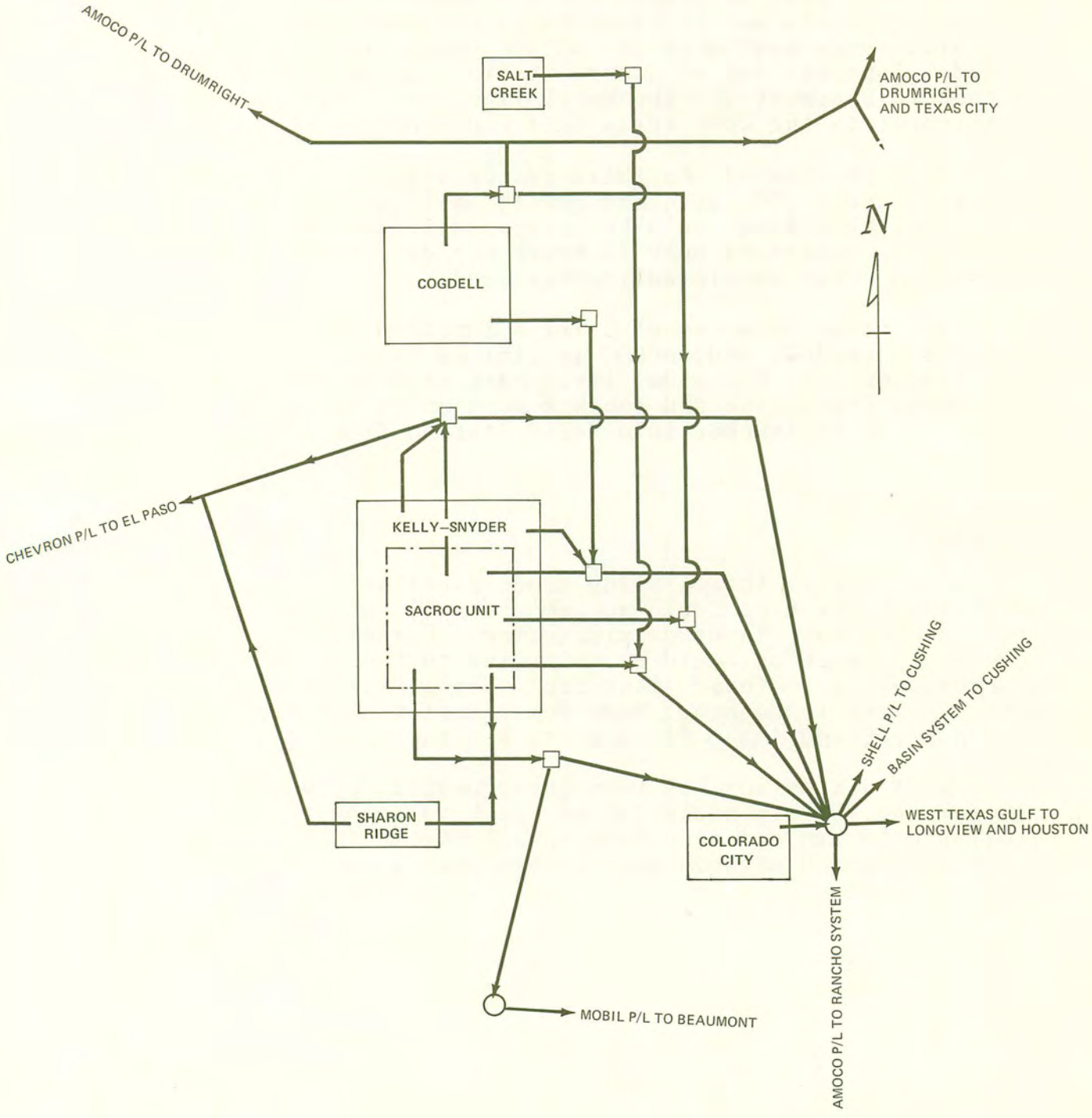
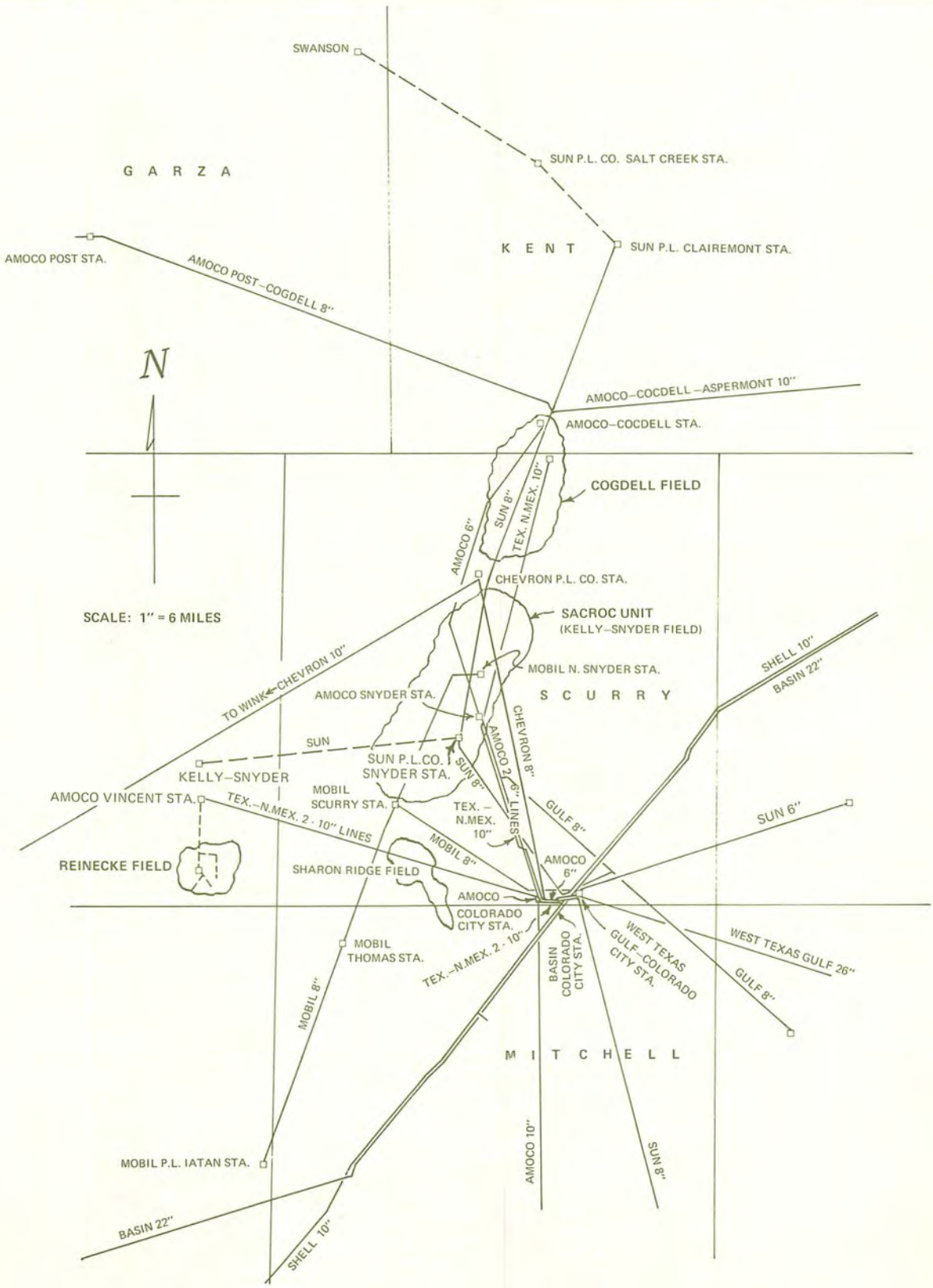


Figure 4
MAP OF KELLY - SNYDER AREA



API "90-DAY" DEFINITION OF CRUDE OIL PRODUCTIVE CAPACITY

In developing the definition of Productive Capacity, the API Committee on Crude Oil Reserves in their 1967 Report commented as follows:

"PRODUCTIVE CAPACITY - CONCEPTS AND DEFINITIONS

"INTRODUCTION. A special Study Group was appointed to review all previous studies of productive capacity and develop such new definitions and procedures for the determinations as would give estimates serving most effectively the needs of the public, government and industry. After numerous meetings and exhaustive deliberations over a period of eighteen months the Study Group developed the following four concepts which may each be useful in understanding productive capacity:

1. An initial capacity figure which would reflect what existing wells and equipment could do as a result of opening valves, changing chokes or otherwise using present facilities more intensively without alteration;

2. Productive capacity after ninety days with allowance for whatever improvements in well productivities and facilities could be achieved within that time period;

3. Productive capacity after one year with allowance for whatever improvements in well productivities and facilities could be achieved within that time period;

4. Productive capacity that would exist under long-run optimal economic conditions.

"In all cases, statutory restrictions on production rates are assumed to be removed; economics are based on such a condition plus the maintenance of current constant price levels.

"Although a complete description of productive capacity would involve the determination of all four values, the second concept - the 90-day productive capacity -

has been selected. This value fulfills certain short-term governmental needs and does not present as many conceptual or data-gathering problems as do the subsequent points on the curve. The determination of productive capacities at points one or more years in the future would involve forecasting, which is outside the scope of the Committee's work. Only the 90-day productive capacity will be defined in detail and reported.

"DEFINITION - 90-DAY CRUDE OIL PRODUCTIVE CAPACITY. The 90-day crude oil productive capacity is the maximum daily crude production rate, at the point of custody transfer, that could be achieved in 90 days with existing wells, well equipment and surface facilities - plus work and changes that can be reasonably accomplished within the time period using present service capabilities and personnel and with productivity declining as it would under capacity operation. It is assumed that there would be no change in crude oil prices or costs of materials, equipment and/or labor, no statutory restrictions on production rates (but no relief from surface regulations on gas and/or water production), no restrictions on storage or transportation beyond the point of custody transfer and no lack of markets.

(1) Maximum daily crude production rate - The figures reported in most cases reflect production that could be obtained from the proved and, in some instances, the indicated additional reserves as defined and reported by the API Committee on Reserves and Productive Capacity. The definition excludes reserves and producing capacity that might be developed by exploratory drilling during the 90-day period. The concept implies nothing about the determined rate being sustainable over any specified period of time - it is simply a point on a continous curve. The production decline rates applicable in each specific field are considered in determining the capacity at the end of the 90-day period. Data are reported as of December 31 and reflect the capacity that would be developed by March 31, based on field conditions and information as of December 31.

(2) Point of custody transfer - The point in the production system at which capacity is estimated is that point at which the oil is transferred from the producing function to the transportation function. In most cases the point of transfer would be where the oil is put into another system (pipeline, truck, barge, etc.) for movement to refineries or terminals. The selection of this point of measure capacity implies that not only may reservoir characteristics and down-hole equipment place limitations on capacity, but well-head equipment separators, flow lines, lease tanks, intrafield barges and other oil handling facilities may create limitations also.

(3) That could be achieved in ninety days with existing wells, well equipment and surface facilities - plus work and changes that can be reasonably accomplished within the time period using present service capabilities and personnel - The wells considered include those already producing, those shut in that could and would be put on stream, and development wells on proved acreage which would be completed and put on stream within ninety days. Various changes in, or additions to, down-hole and well-head equipment and lease facilities could be made; e.g., pumps, tubing, flow lines, separators, etc. Also, certain steps could conceivably be taken to stimulate or improve production from the reservoir; this includes various types of formation treatments and workovers. The limitation imposed by the definition of such changes or additions is that they must be capable of being completed in ninety days with present services, personnel, material, and equipment capabilities. For example, although it may be desirable to work over most of the wells in a given field, workover equipment and personnel, reasonably expected to be available, may only be capable of handling a few wells; or, it may be desirable to install larger pumping units or flow lines in a field, but the equipment cannot be obtained and installed in this short a time. It should be assumed that all fields would be undergoing such servicing and improvement and that no one field could

expect a larger share of services, equipment or personnel than it would receive in normal times.

(4) With productivity declining as it would under capacity operation - It was mentioned under item (1) that consideration should be given to the declining production capability of a reservoir over time - in this case, 90 days. The specific rate of decline selected will vary from field to field and will be determined by the particular set of circumstances in each field. Both reservoir characteristics and ability of well and surface equipment to handle maximum production will influence the choice of a decline rate; however, in all instances, it is assumed that production over the time period will be limited only by facilities and equipment or the reservoir itself. For example, two fields with similar reservoir characteristics may have drastically different producing rates if one has a restriction imposed by separator capacity and the other does not; as a result the two fields may have drastically different decline rates.

(5) It is assumed that there would be no change in crude-oil prices or costs of material, equipment and/or labor - This is a simplifying assumption to avoid predicting movements of crude oil prices and operating costs. The intent is to emphasize the capacity that would be developed because of incentives accruing from additional production...and not from incentives resulting from increased crude oil prices. It is conveivable that total operating expenses might be increased, but the increase would result from the use of more labor, services, equipment, etc., and not from a rise in the prices of these items.

(6) No statutory restrictions on production rates (but no relief from surface regulations and gas and/or water production) - All market demand restrictions are removed as well as established MER restrictions. It would be assumed that intrafield equity considerations can be satisfactorily resolved so that a

field's production can be maximized. Gas-oil and water-oil ratio limitations cannot be ignored, since it is assumed that these restrictions would preclude rates which would result in a significant reduction in ultimately recoverable oil. Gas flaring to the legal limit is permitted under this assumption - in 'no-flare-order' fields, it is assumed that this limitation would be waived in favor of the legal limit. The only other production restrictions applicable would be those which prohibit the pollution of potable water sources and those which prohibit air pollution with gas or the creation of fire hazards from gas.

(7) No restrictions on storage or transportation beyond the point of custody transfer and no marketing constraints - It is assumed that transportation facilities, storage, refineries, terminals, and markets are adequate, and so situated, to accommodate all the oil made available at the point of custody transfer if the current market prices for crude oil persist.

"Estimates of productive capacity are, for the most part, handled on a field-by-field basis giving consideration whenever possible to basic production units within a field. Priority attention is given to those fields believed to have significantly large excess productive capacities."

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