ASSESSING THE ENVIRONMENTAL IMPACTS OF OIL AND GAS DEVELOPMENT IN ALASKA

APPENDIX

DEVELOPMENT ALTERNATIVES

Revised March 30, 1975

RESOURCE PLANNING ASSOCIATES

ASSESSING THE ENVIRONMENTAL IMPACTS
OF OIL AND GAS
DEVELOPMENT IN ALASKA

APPENDIX

DEVELOPMENT ALTERNATIVES

Revised March 30, 1975

RESOURCE PLANNING ASSOCIATES, INC.
44 BRATTLE STREET • CAMBRIDGE, MASSACHUSETTS 02138

DEVELOPMENT ALTERNATIVES

Over the next several years, a number of difficult decisions will have to be made about if, when, and how oil and gas development should occur in Alaska. To provide a framework for such decision making, Resource Planning Associates has developed a number of alternative development projections. These alternatives are detailed in this handout, which acts as an appendix to the visual progress report presented today, in terms of:

- The elements of a development alternative
- How the 13 development alternatives were ranked, as well as the ranking itself
- The assumptions to be used for each of the 13 alternatives, together with projected development schedules and maps of likely primary impact sites.

A - ELEMENTS OF A DEVELOPMENT ALTERNATIVE

Projecting the statewide and regional impacts of oil and gas development on Alaska will be difficult at best because of the size and extent of the potential hydrocarbon reserves. Nevertheless, as a first step in determining what those impacts will be, we have developed a range of probable levels of activity - i.e., various development alternatives. Specifically, we

- Developed a base case, which reflects the level of development already completed or in progress on the North Slope or in the Upper Cook Inlet,
- Fashioned 13 separate development alternatives, each assuming the base case plus some other level of activity.

Each development alternative consists of seven major elements: (1) recognition and precise estimation of oil and gas potential; (2) leasing; (3) exploration; (4) discovery; (5) delineation; (6) production; and (7) transport out of the primary impact site. Exhibit 1 is a conceptual diagram of these elements, which are discussed in turn in the remainder of this section.

ESTIMATION OF POTENTIAL

A precise estimate of the oil and gas potential in any given area is extremely important because the level of exploration and development depend on how much oil and gas is expected to be discovered. The accuracy of this estimate depends of course on the level of exploration to date. For instance, the 9.6-billion barrel total estimated for Prudhoe Bay oil production is probably quite accurate since over 100 wells have been drilled and the operating companies have a good idea of the size, thickness, and recovery rate of the producing zone. On the other hand, the 4-billion barrel total estimated for the Chukchi Sea is probably highly inaccurate because no wells have been drilled as yet.

Estimates of reserves are based on published figures* and on our own estimates of potential oil and gas deposits. In turn, these estimates are based on the degree of exploration in the area to date, on the proximity of suspected fields to known producing areas, and on the production characteristics of those already productive areas.

LEASING

Since exploration by drilling cannot begin until acreage has been leased (unless it is a stratigraphic well, drilled not to find reserves but to determine the types of rock in the area), the date of the lease

---

* - Project Independence Blueprint, Oil and Gas Journal, OCS Oil and Gas, industry estimates.

sale will be one important determinant of how quickly an area is explored. Additionally, the "type" of lessor will affect the speed of development. In Alaska, the major lessors are the Federal Government (i.e., the Department of the Interior), the State of Alaska, and the native associations. Each has different objectives and competes with the others for industry funds. Also, each has a different impact on the flow of money into Alaska, with proportionally more money remaining in the state if native- or state-owned lands are leased.

There are several different methods of leasing that also affect cash flow. The standard native agreement with an oil company requires periodic payments over the length of the lease, which means a longer term but lower level cash flow into Alaska. On the other hand, leases sold through competitive bids by the state or the U.S. Department of the Interior require lump-sum payments, thereby providing a sudden but unsustained influx of a substantial amount of money.

EXPLORATION

The level of exploration will depend on:

1. The level of leasing activity. Historically rig activity is greatest prior to and within a short period subsequent to a lease sale. It is assumed that leasing will proceed at a rate sufficient to insure orderly exploration and evaluation of potential in an area.

2. The estimated cost per well. For example, in northern Alaska, an exploratory onshore well of 10,000 feet costs approximately $7 million; in the Gulf of Alaska, the cost is roughly half that. Thus, an oil company can drill two wells in the Gulf for the same price as one in northern Alaska.

3. The rate of discovery. A discovery in an exploratory area tends to increase the level of future exploration in that area.

4. The size of the exploratory area. A geographically large area will require more wells to evaluate the field fully than a geographically small area.

5. The length of the drilling season. Areas with short exploratory drilling seasons such as the North Slope will require more rigs to perform the same level of exploration than areas where weather permits year-round drilling.

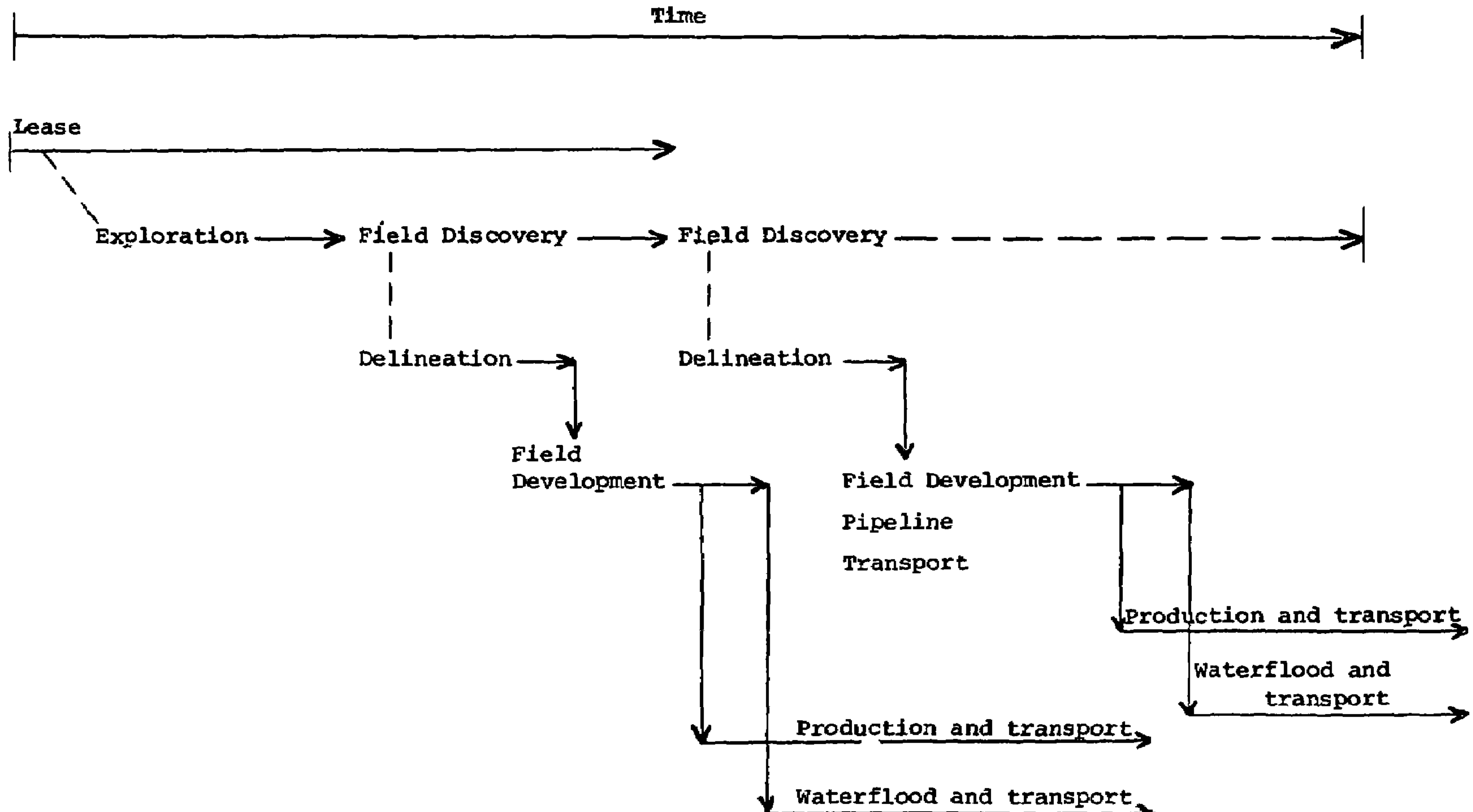
6. Availability of equipment/facilities. Although there is a current worldwide shortage of drilling rigs, tubular goods, and other resources required for oil and gas exploration

and development, we assumed these shortages will not affect exploration and development for individual Alaskan scenarios. Moreover, it was assumed that there will be no competition for resources among the development alternatives, and that the price of oil or the price of gas will not deter exploration and development.

7. The development of drilling technology. Obviously, the availability of sophisticated drilling technology will accelerate exploration. However, the present state of the art does not allow exploration and development of such areas as Chukchi Sea at this time. But it was assumed, nevertheless, that the oil industry's and the government's research and development efforts will proceed at a rate that permits exploration and development in these areas by 1985.

Exhibit 1

ALASKA MODEL DEVELOPMENT



DISCOVERY

Each development alternative assumes that, after a period of exploration, a discovery will result. How quickly discoveries occur depends on whether industry explores the most promising prospects first, thereby leading, presumably, to early discoveries. In any event, it was assumed most of the potential will be discovered within 15 years of commencement of exploration.

The number of discoveries depends on the discovery experience in the area and adjacent areas, and on the size of the total discovery necessary for lucrative commercial production. For example, on the North Slope, discoveries were classed as Prudhoe size (i.e., 6-10 billion barrels), Kuparuk or Lisburne size (i.e., 1-2 billion barrels), or intermediate size (2-6 billion barrels). In the Gulf of Alaska, discoveries were classified as 2 billion barrels, with the proviso that a discovery could be made up of several smaller discoveries in the vicinity if, cumulatively, they justified the expense of production and tanker facilities. This appears to be the minimum economic size for development in the Gulf of Alaska.

DELINEATION

After a discovery has been made, several years are usually required to build platforms, and support facilities and to plan development and production facilities. During this pre-development period, the field area is delineated by drilling 10-15 delineation wells. Each such well is assumed to cost two-thirds the cost of an exploratory well, as knowledge of the stratigraphy, formation pressures, and depth to the pay zone will allow rapid drilling and preclude drilling beyond the pay zone.

DEVELOPMENT

The development element of each development alternative is based on the assumption that there will be no competition among development areas for resources. This assumption was made to allow evaluation of individual alternatives. As alternatives are combined (to form scenarios), this assumption becomes invalid. Development schedules will then be altered to allow for competition according to priorities established by the ranking of the alternatives.

The number of needed oil development wells is calculated by dividing the delineated field size by 320 acres. (Three-hundred-twenty-acre spacing was chosen to permit uniformity among the areas and to allow for secondary recovery efforts such as waterflood.) It is assumed that eight wells will be drilled from a platform or drilling pad during development; this will allow the development of 2,560 acres by each pad.

For gas development, it is assumed 640 acre spacing will be required, and no secondary recovery will occur. While gas stimulation techniques such as fracturing or acidizing may be used, it is impossible to predict their use.

Development time is determined by estimating the time necessary to prepare production facilities and the rate of decline of a field before waterflood was necessary. In most alternatives, it was assumed that one-half of the development wells will be drilled after full production is achieved. The remaining one-half will be drilled prior to secondary recovery. In some cases this schedule was altered to account for pipeline delays or pipeline capacity criteria that might delay bringing later discoveries into production.

PRODUCTION

Production depends on the number of wells producing, the rate at which each well produces, the rate of decline of each well, and the life of the field. The typical production cycle for a field includes initial production, build-up to a maximum production rate as more wells are brought into production, and decline. As decline begins, secondary recovery is assumed to allow for a steady production rate until the field is depleted. It is further assumed in most development alternatives that secondary recovery will begin within 3 years of full production and continue for 7 years, at which time beginning of "breakthrough" of water into the oil producing wells will occur. At this point the field will undergo a rapid decline in production (25 percent per year).

Gas production is different from oil production in that it is assumed to decline at a much slower rate. Moreover, no secondary recovery is assumed for gas.

The lag time between discoveries and development and production tends to stretch out the useful life of pipeline and transport facilities and to require a smaller capacity for these facilities than if all discoveries were brought into production at the same time.

TRANSPORTATION

In developing the various alternatives, only the TAPS pipeline was assumed to predate the development alternatives. Consequently, in each development alternative, additional pipeline and transport requirements had to be calculated. However, where appropriate, total pipeline and transport needs were integrated.

* * *

In addition to the seven major elements of a development alternative conceptualized in Exhibit 1 and discussed above, estimate must be made of the facilities needed to support the projected development. To this end, facilities are divided into two classes - temporary and permanent. Exploration and delineation require temporary facilities, development requires both temporary and permanent facilities, and production requires permanent facilities. In several cases, such as the offshore development, the development phase requires large onshore temporary facilities that will be abandoned when production begins. Similarly, development of the smaller onshore fields requires large temporary facilities, but minimal permanent production facilities.

Facility types considered were:

1. Support facilities - docks, airstrips
2. Development facilities - housing, roads
3. Pipeline facilities - gathering centers, flow stations, roads, temporary airstrips
4. Transport facilities - docks, pipeline terminals, offshore tanker sites, liquefied natural gas plants
5. Refineries.

Facility and transportation requirements are discussed briefly for each alternative. They will be considered in more detail in a separate appendix.

B - RANKING OF DEVELOPMENT ALTERNATIVES

At present some 13 onshore and offshore areas in Alaska may have economically recoverable reserves of oil and gas. Including the baseline development areas, they are:

1. Upper Cook Inlet and Prudhoe Bay Oil
2. Other private development at Prudhoe Bay
3. Southern Cook Inlet
4. Prudhoe Gas - El Paso
5. Gulf of Alaska offshore (includes Kodiak Island subprovince)
6. Beaufort Sea offshore
7. Naval Petroleum Reserve #4 development case - slow
8. Kotzebue Sound (onshore and offshore)
9. Bristol Bay (includes onshore Bristol Basin)
10. Naval Petroleum Reserve #4 development case - fast
11. Bering Sea (includes onshore Bethel Basin)
12. Chukchi Sea
13. Arctic Wildlife Refuge

This listing implies a ranking of the potential producing areas, and indeed they have been ranked from highest to lowest probability of development by the year 2000.*. To arrive at this ranking, we considered a variety of factors. Current plans for lease sales and announced exploratory drilling were assumed to indicate: (1) substantial interest on the part of the oil industry and/or the controlling agency; and (2) a degree of certainty that some level of development would occur in the next two decades. In the absence of any announced intentions to open an area for leasing or drilling, other factors such as proximity to an area under development or the availability of proven, environmentally safe technology were considered. The way in which these and other factors influenced the final rankings is discussed for the base case and each of the 13 potential development alternatives identified.

1. Upper Cook Inlet and Prudhoe Bay. These two areas form the base case because development of oil and gas wells is either already completed or in progress. That these areas will be important producing areas in the near future is a virtual certainty, given the approval of the appropriate environmental impact statements and the nation's urgent need for additional oil supplies.

* This ranking does not necessarily imply the sequence in which these areas will be developed. For example, although certain interior areas of Alaska have good hydrocarbon-bearing potential, are adjacent to the route proposed for the TAPS pipeline, and are onshore and relatively close to the crude pipeline, the quantity of oil in those fields may be insufficient for economic recovery. On the other hand, some of the more remote areas have far higher potential for oil production; consequently, they are more likely to be developed if oil were discovered in the rather large geologic structures that have been located to date.

2. Prudhoe Bay - Private. When the TAPS pipeline is installed, current projections indicate that only 1.6 million barrels of oil per day of the pipeline's capacity will be utilized by the presently planned Prudhoe Bay developments. Unless development is accelerated at Prudhoe Bay, this available capacity could be used by some reasonably large discoveries that have been made adjacent to the existing and planned Prudhoe facilities. If Prudhoe Bay development is accelerated, these discoveries could be used to fill the pipeline as production at Prudhoe Bay declines. Although these fields have not yet been delineated, their proximity to the pipeline alone makes their commercialization highly probable (i.e., 90 percent).

3. Cook Inlet, Southern portion. This region is adjacent to the upper, or northern, Cook Inlet which is already producing both oil and gas. In addition, state and federal government lease sales are scheduled for 1975. These two factors and the fact that Cook Inlet waters are relatively ice-free and convenient for tankers indicate this region will probably--a 90-percent probability, in fact--be developed rather quickly.

4. Prudhoe Bay natural gas development (El Paso). Natural gas reserves on the North Slope have been delineated, and the pipelining and conversion to liquefied natural gas appear economically feasible. However, although the proposal for the pipeline has been submitted, it has not yet been approved, nor has the environmental impact statement been prepared. This leaves some minor doubts about construction of a natural gas pipeline parallel to the TAPS pipeline, which has been approved. But since environmental concerns about gas transport are generally less severe than for oil, the major uncertainty appears to be the economic viability of building a pipeline and liquefaction plant to transport the gas to the West Coast. The probability for this development is about 75 percent.

5. Gulf of Alaska. Offshore development seems likely because: (a) the possibility of finding large fields is high; (b) the technology for producing oil from 500- to 600-foot depths is available; and (c) the waters of the Gulf are ice-free and (d) the area is the closest by tanker to the West Coast, where most of the oil will be used. And although offshore drilling, especially in an area of seismic activity, is costly and difficult, the region has the advantage of not needing a major pipeline to transport the oil to a tanker terminal; single-point moorings would be feasible. Consequently, the Gulf of Alaska is very likely (75 percent) to be developed.

6. Beaufort Sea. The Beaufort Sea by itself would probably not have been attractive without the prior discoveries and accumulated operating experience at Prudhoe Bay. However, there is a 60-percent probability of production because there are

large, potential oil structures in areas adjacent to known production, technology exists for performing the exploratory drilling and delineation from natural and/or man-made islands in the shallow waters (this is already being done in the Mackenzie River delta in Canada), and federal and state lease sales are scheduled in the next few years.

7. Naval Petroleum Reserve #4 (NPR-4) (slow development case). Exploratory drilling commissioned by the Navy is already under way, and initial seismic analyses indicate the possibility of structures of Prudhoe magnitude. Moreover, since the major reserves are onshore, no new technology is required to tap the fields. The major uncertainty associated with NPR-4 development, however, is the status of the state-claimed offshore acreage out to the 3-mile limit and the outcome of U.S. Department of the Interior's efforts to open the reserve to leasing. Because of this uncertainty, there is only a 50-percent probability of slow development of the NPR-4.

8. Kotzebue Sound. These native- and state-controlled lands and waters are already being explored under special exploration agreements. Although there is promising potential, the location presents problems. Winter ice formation will interfere with offshore exploratory drilling as well as prevent or at least hamper the use of tankers in the area. Consequently, a pipeline may have to be constructed to connect the region to an ice-free port in the south or to one in which the ice will not interfere with shipping operations. In spite of the good potential of Kotzebue, then, there is only a 50-percent probability of development there by 1990.

9. Bristol Bay. Some onshore exploratory drilling has already taken place, and although the results have been negative, initial seismic analyses indicate a reasonably good potential for the area. In addition, lease sales have been scheduled. However, major factors impeding production, should oil be discovered, are midwinter ice that creates transportation problems and competition with Gulf of Alaska development for drilling equipment. Moreover, no environmental impact statement has been filed as yet. These factors, *in toto*, imply development by 1990 has only a 40-percent probability.

10. Naval Petroleum Reserve #4 (fast development case). As noted for the slow development alternative, exploration is under way in NPR-4. Whether the area is developed quickly or slowly will probably depend on the size of the initial discovery, i.e., an extensive discovery would encourage more rapid development to alleviate the nation's energy shortage. Counteracting these

pressures for rapid development will be the Navy's reluctance to relinquish control of the reserve to the U.S. Department of the Interior. Political entanglements over who will benefit from NPR-4 also promise to inhibit rapid development. Weighing these factors subjectively, the probability of this alternative is only 35 percent.

11. Bering Sea. The lack of exploration in the Bering Sea understandably creates some doubt about the region's potential, although seismic data indicate moderately promising structures. Lease sales have been scheduled for 1976, but no environmental impact statement has been submitted. Considering the problems created by the winter ice formation and competition with the Gulf of Alaska and Bristol Bay development efforts for equipment, the Bering Sea has only a 30-percent chance of being developed by 1990.

12. Chukchi Sea. The Chukchi Sea, like the Bering Sea, is still a questionable development area since no exploration has been conducted. The area is remote from existing or planned pipeline and tanker transport; consequently, its development in this century will depend to a great extent on the discovery of large reserves in adjacent onshore and Beaufort Sea areas. Moreover, ice movements in the deeper waters present drilling and production problems. Therefore, the probability of the Chukchi Sea's being developed by 1990 is quite low - i.e., 20 percent.

13. Arctic Wildlife Refuge. This area has a very large, onshore oil potential which should make it attractive for exploration. However, the area has been withdrawn from exploration by the Department of the Interior, and there is strong environmental opposition to allowing exploration.

There are several onshore provinces that have not been considered in this ranking. These include the Koyokuk Basin (State of Alaska Division of Oil and Gas potential estimate 3.4 billion barrels oil, 9.3 trillion cubic feet gas), the Yukon-Kandik Basin (potential estimate 1.7 billion barrels oil, 11.4 trillion cubic feet gas) and the Copper River Basin (potential estimate .2 billion barrels oil, 1.2 trillion cubic feet gas). Although they may be explored at some time in the future, the uncertain status of native and Federal withdrawals in the potential areas precludes reasonable appraisal of development and production. Furthermore, the relatively small size of the potential, when compared to the potential of other areas, would seem to imply smaller socio-economic impacts on the Alaskan community.

C - ASSUMPTIONS FOR EACH ALTERNATIVE

COOK INLET BASE CASE

General Assumptions

Oil and gas development is currently in progress in the Upper Cook Inlet Basin of southeastern Alaska. The current level of production of oil is 195,000 barrels per day from 6 fields. Marketed production of natural gas from Cook Inlet totaled 136 billion cubic feet in 1973, with total production of casinghead and dry gas of 225 BCF.

According to Future Petroleum Provinces of the United States, the discovered oil-in-place is estimated at 2.6 billion barrels and the gas at 5 trillion cubic feet.

All development to date has occurred on private or state lands. Although leasing is scheduled for the future, it will not be considered in this case but rather as a part of the Southern Cook Inlet development alternative.

Exploration

Oil in commercial quantities was discovered at Swanson River on the Kenai Peninsula in 1957. Since then, exploration has continued, with 10 wildcats drilled in 1974 alone. No further exploration is assumed in the Upper Cook Inlet area.

Development

Since 1957, six oil fields and 21 gas fields have been discovered. Development is nearly complete on all the oil fields. Of the gas fields, 8 are producing, 2 are depleted and 11 are shut-in. Most of the shut-in fields have only 1 or 2 completions and cannot be considered developed.

Production

Oil. Statistics for the six onshore and offshore oil-producing areas are:

	1973 Production (Thousand Bbls.)	Estimated Number Of Wells	Depth (feet)
Offshore			
Granite Point	4,233	25	8,772
McArthur River	39,191	52	9,572
Middle Ground Shoal	9,033	33	9,000
Trading Bay	8,000	42	5,650
Beaver Creek	416	1	
Onshore			
Swanson River	9,741	37	

The McArthur River Field was the major producing field in the state, producing 53.2 percent of all oil produced. The average production rate for the field was 2,090 barrels of oil per well per day. Secondary recovery (waterflood) is utilized in the field, as it is in all the Cook Inlet oil fields. Both water and gas injection are used at Swanson River Field.

Gas. There are both onshore and offshore gas-producing areas. The offshore producing areas are North Cook Inlet, Redoubt Shoal, West Foreland, North Middle Ground Shoal, and Ivan River. Onshore areas are West Fork, Beaver Creek, Sterling, Falls Creek, Beluga River, Moquawkie, Nicolai Creek, Birch Falls and Kenai. Gas is also produced at the oil fields, but is generally reinjected. Kenai is listed by The Division of Oil and Gas, State of Alaska as the major gas-producing field in the state, having produced 72 billion cubic feet of gas from 18 wells in 1973. As of December 1973, there were 53 active producing gas wells in eight fields.

Facilities

Two refineries are currently operating at Kenai. The Standard Oil of California refinery has a daily capacity of 22,000 barrels, while the refinery run by Tesoro-Alaskan Petroleum Corporation has a capacity of 38,000 barrels per day.

Oil pipelines transport crude oil produced from the Granite Point, Middel Ground Shoal (both offshore), and Swanson River (onshore) to the coastal site of Nikiski. Another oil pipeline connects the Trading Bay and McArthur River producing areas with Drift River.

Several gas pipelines are also in existence. One runs from Kenai through Sterling and West Fork to Anchorage. Another runs from the North Cook Inlet producing area underwater and then onshore along the coast to Nikiski. There is a third pipeline from Kenai to Nikiski.

Of the 135 BCF of gas sold in Alaska in 1973, 26 BCF was shipped through pipelines to Anchorage; 61 BCF was processed at the Phillips Marathon gas liquefaction plant for shipment to Japan; 21 BCF was used at the Collier Carbon and Chemical ammonia-urea plant; and 11 BCF was used to generate electricity for Chugach Electric, the City of Kenai, Nikiski, the Standard Refinery, Consolidated Utilities and the ARCO Spark platform. The remainder of the gas sold was used for gas injection as part of the Swanson River pressure maintenance program.

PRUDHOE BASE CASE (SADLEROCHIT RESERVOIR ONLY)

General Assumptions

Exploratory oil drilling has been in progress onshore at Prudhoe Bay, following discovery in 1968, for several years. Current development drilling is not expected to lead to oil production until mid-1977, when it is assumed that the Alyeska pipeline will be ready for operation. No commercial gas production is expected. Gas escaping from wells will be fed into a gas-injection plant, to be subsequently injected back into the producing zone.

The published American Petroleum Institute estimate of potential recoverable reserves in the Sadlerochit Reservoir alone is 9.6 billion barrels. It is assumed that initial production will be only from this reservoir, gas drive as the recovery mechanism. Subsequent decisions whether to waterflood will be made after several years of production. Accelerated production requiring additional development wells to fill the pipeline to its capacity of 2 million BOPD is not considered.

Exploration

Exploration of the Sadlerochit Reservoir has been completed. No further exploration or delineation of the field is assumed, although the size of the field may be extended during development.

Development

Atlantic Richfield is the only company currently involved in development drilling. It is assumed that 30-45 days are required to drill a development well, the average depth of which will be 10,000 feet. Development drilling will probably be completed by 1980-1981. Six-hundred-forty-acre spacing is assumed for initial development drilling, with 320 then 160 spacing assumed for accelerated production or waterflood. Initial development is confined to an oil column 200 feet in thickness with later wells moving both upstructure and downstructure of this interval.

Production

The rate of production is assumed to be 8,000 barrels of oil per day (BOPD) per well. Production will be initiated in 1977 at 1.2 million BOPD, peaking to 1.6 million BOPD by 1980. If the participating companies decide to accelerate development, however, production may reach a peak of 2.0 million BOPD by 1980. One-hundred-fifty wells are assumed for initial production, while 500 wells may ultimately be drilled.

Facilities

Oil production from Prudhoe Bay cannot be realized until a satisfactory oil transportation network is in operation. It is assumed that Alyeska will complete its trans-Alaska pipeline by mid-1977. Right-of-way permits have been granted by both federal and state authorities for the pipeline route from Prudhoe Bay to Valdez. Parallel haul-road construction along the pipeline right-of-way is expected to be completed by mid-1975, when construction of the pipeline structure is scheduled to begin. However, possible shortages of necessary supplies - i.e., all forms of steel equipment and particularly tubular goods - may deter realizing completion of the pipeline during 1977. Construction of a temporary dock has been finished at the Valdez terminal site. The schedule for construction of all transport-related facilities is as follows:

Phase I:

1974
- Existing camps upgraded and new camp construction begun (33 total)
- Road from the Yukon River to Prudhoe Bay completed
- Clearing of right-of-way for pipeline south of the Yukon River
- Preparation of pump station sites
- Beginning of construction of Valdez tanker terminal

1975
- Laying of pipeline south of the Yukon
- Beginning of pump station installation
- Clearing of right-of-way for pipeline north of the Yukon

1976
- Laying of pipeline north of the Yukon

1977
- Installation of pump stations 1, 3, 4, 8, and 10
- The pipeline capacity would be 1.2 million BOPD at completion of this phase.

Phase II:

1977-78
- Completion of installation of pump stations 6, 9, and 12

Completion of two of five planned supertanker berths at Valdez

Pipeline capacity would be 1.6 million BOPD at completion of this phase.

Phase III:

1978-80

- Completion of installation of pump stations 2, 5, 7, and 11

- Pipeline capacity would be 2.0 million BOPD at completion of this phase.

In summary, facilities will include, in addition to the pipeline and its related structures, several airstrips, an operations center for each company (150-225 men each), gathering centers (flow stations) with 300,000 BOPD capacity each, a small refinery of 6,300 BOPD capacity (presently in operation) to provide fuel for use at the Prudhoe Bay location, and service and drilling company facilities.

Impact Area

Two hundred square miles (128,000 acres) will be affected by currently planned oil development in Prudhoe Bay. Of this, approximately 80,000 acres will be affected by initial development (area of 200-foot oil column), with additional acreage being developed over time. The pipeline will be 789 miles in length with a 150-foot right-of-way. According to the TAPS-EIS, 940 square miles of the state's 572,000 would be occupied by the oil field and pipeline system. The terminal at Valdez would cover approximately 900 acres.

Exhibit 2

MAP KEY FOR EXHIBITS 3 to 33

Potential Development Areas

Trans Alaskan Pipeline System

Onshore Impact Site

Potential Exploratory Area

- -Onshore
  - -Primary Development Impact Area
- -Offshore (no primary impact area assigned)

Central Gathering and Flow Center

Gathering Center

Gas Field - Discovered

Oil Field - Discovered

Small Diameter Pipeline

Large Diameter Pipeline

Possible Pipeline

Currently Developed Areas (base case)

Exhibit 3

PRUDHOE BAY AND COOK INLET

BASE CASE

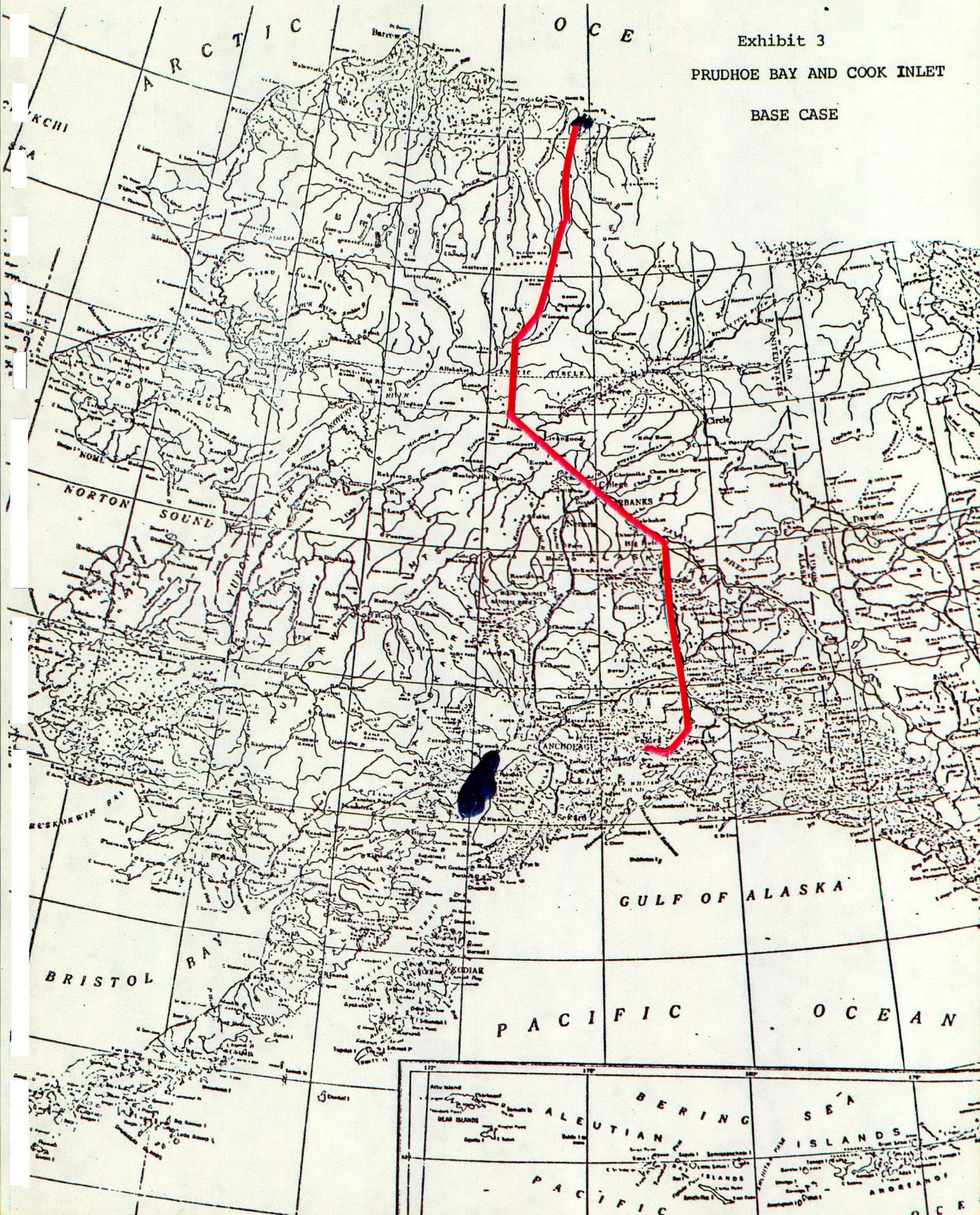
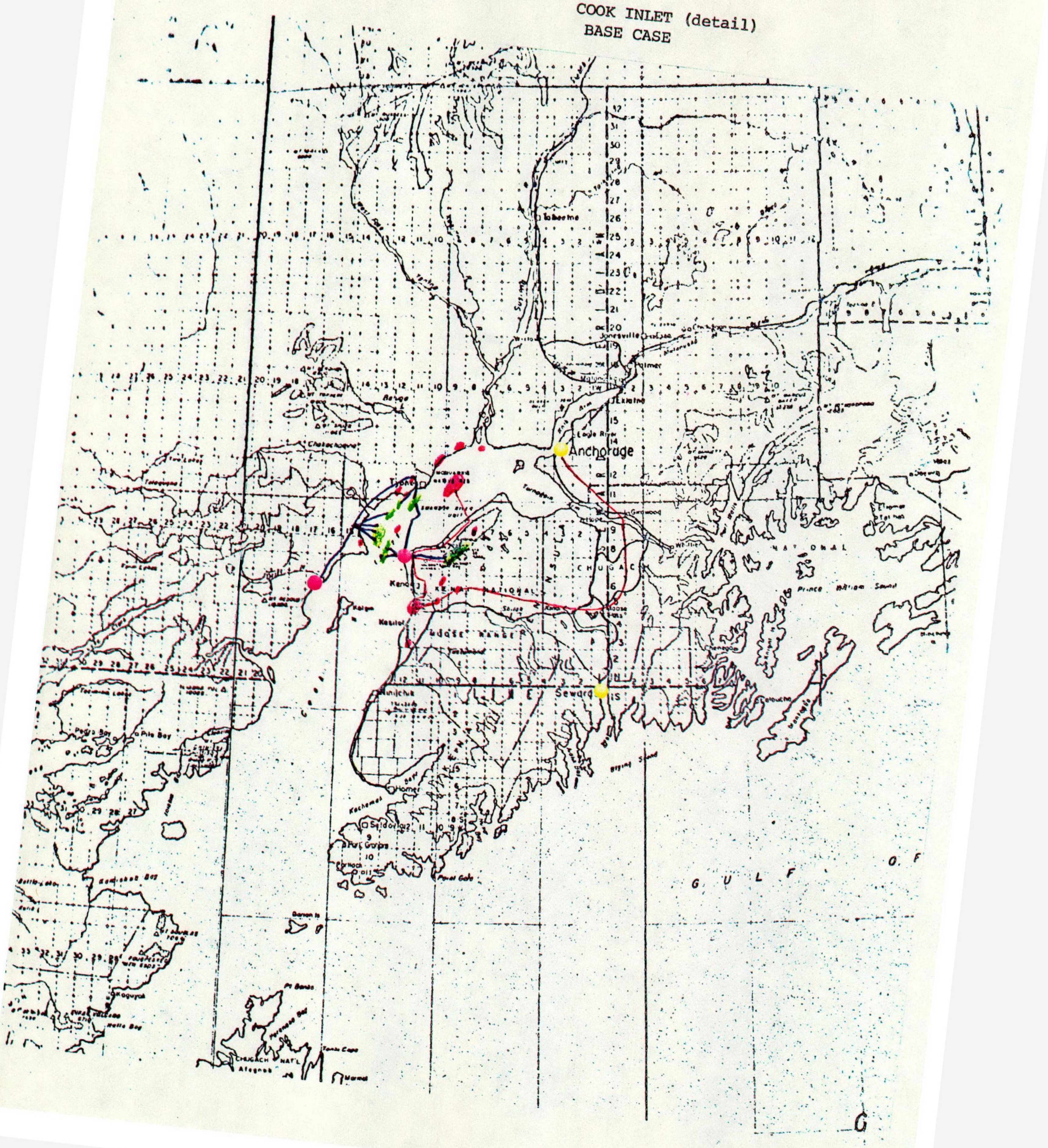


Exhibit 4

COOK INLET (detail)
BASE CASE



PRUDHOE - PRIVATE

General Assumptions

The Prudhoe Bay Field Sadlerochit Reservoir (described in the base case) is estimated to have a production capacity of 1.6 million BOPD by 1977 assuming the present development plan (according to the Project Independence Blueprint, Oil Task Force Report, Exhibit IV-2). Therefore, to operate the Trans-Alaska pipeline at its design capacity of 2 million BOPD, an additional 400,000 BOPD will be needed. Potential sources of this additional oil are: the Prudhoe Bay Kuparuk Reservoir, which extends west from the Prudhoe Bay Unit Area; the Prudhoe Lisburne Reservoir, which lies 500 feet beneath the Sadlerochit Reservoir; and a shallow, heavy oil accumulation located west of the Prudhoe Bay Unit. The potential amount of recoverable reserves in three areas are estimated at 1.5-2.0 billion barrels, 1.0-2.0 billion barrels, and 200 million barrels (of a total in place of 2 billion barrels), respectively. In addition to oil, the Lisburne formation is estimated to contain 8 trillion cubic feet of gas (RPA estimate). At $7.00/barrel, the heavy oil deposit is not commercially viable, but new technology is assumed to make heavy oil production feasible by 1985.

Other development on state lands and lands open to native withdrawal appear possible. The potential area extends from the Canning River (Arctic Wildlife Refuge) to the east to the Colville River (Naval Petroleum Reserve No. 4) to the west. Recoverable potential is estimated at 300 million barrels of oil and 2 trillion cubic feet of gas (RPA estimate). Gas potential includes the Kavik, Kemik, and Gubik gas fields, which have been discovered but whose total potential is not known.

Exploration

No new exploratory drilling is assumed in the Kuparuk and Lisburne fields. In the heavy oil area, 10 exploratory wells are likely to be drilled beginning in 1980, followed by 10 delineation wells beginning in 1983. Other North Slope exploration is assumed to require 25 exploration wells, followed by 10 delineation wells. Exploration of this latter area will proceed 1 year after state and native leasing takes place over the period of 1976 to 1980.

Development and Production

Development of the Kuparuk Reservoir is expected to begin in 1978 and be completed by the end of 1981. Production from the reservoir is expected to reach 400,000 BOPD by 1982, with an average production rate of 2,000 BOPD per well. Approximately 250 development wells will be drilled with 320 acre spacing. Very little gas has been discovered in the Kuparuk Reservoir to date. Therefore, no gas development or production is assumed.

The first development wells will be drilled at the Lisburne Reservoir in 1980 and the last by the end of 1985. Initial production from the reservoir is expected to be 450,000 BOPD in 1981, building to a peak of 600,000 BOPD in 1986. At peak production, approximately 200 wells will be producing an average of 3,000 BOPD. From this peak, reservoir production is expected to decline at about 14 percent per year without secondary recovery. Overall life of the reservoir is estimated at 16 years.

Gas will also be produced from the Lisburne Reservoir, both as a by-product of oil production and from separate gas wells. It is assumed that each oil well will produce 1 MMCFGPD. Each gas well will produce 8 MMCFGPD. Gas development is assumed to lag oil development by two years, with gas and oil production beginning simultaneously. Gas production is assumed to peak at 1 BCFGPD within two years of production. Overall life of the gas reservoir is estimated at 16 years.

With the advent of new technology by 1985, development at the Heavy Oil Reservoir will likely begin in 1985 and be concluded by the end of 1985. Initial production is assumed to be 80,000 BOPD in 1986, reaching a peak of 100,000 BOPD in 1989. At maximum production, approximately 200 wells will be producing at a rate of 500 BOPD, with 320 acre spacing.

Development is expected to begin on Other North Slope (onshore, private) in 1985 and be completed by the end of 1992. By 1990, production from these smaller reservoirs is estimated to reach, in aggregate, 100,000 BOPD and 400 million cubic feet of gas. Assuming 320 acre spacing for oil wells and 640 acres for gas, average production per well is assumed to be 1,000 BOPD and 10 million cubic feet of gas for the 100 oil and 40 gas wells likely to be developed.

Facilities

The development of these additional North Slope reservoirs requires very few additional facilities relative to the massive Prudhoe Bay development. In Kuparuk, two gathering centers of 200,000 BOPD capacity will probably be needed, while for the Lisburne Reservoir, two 300,000 BOPD gathering centers are more likely. Small collection systems are required for the heavy oil and other reservoir production. Small diameter pipes will have to be laid to connect the gathering systems to TAPS.

Other than piping, other new facilities will probably be needed for development and pipeline construction, especially between the Kavik airstrip and the Sagavanirktok River.

Impact Areas

Since the Kuparuk and Lisburne Reservoirs are adjacent to the massive Prudhoe developments, additional land impacts are relatively insignificant. Heavy Oil Reservoir and Other Development Reservoir, on the other hand, are expected to affect about 50,000 acres and 150,000 acres, respectively. Of the latter figure 50,000 acres will be affected by oil development, with 100,000 acres impacted by gas.

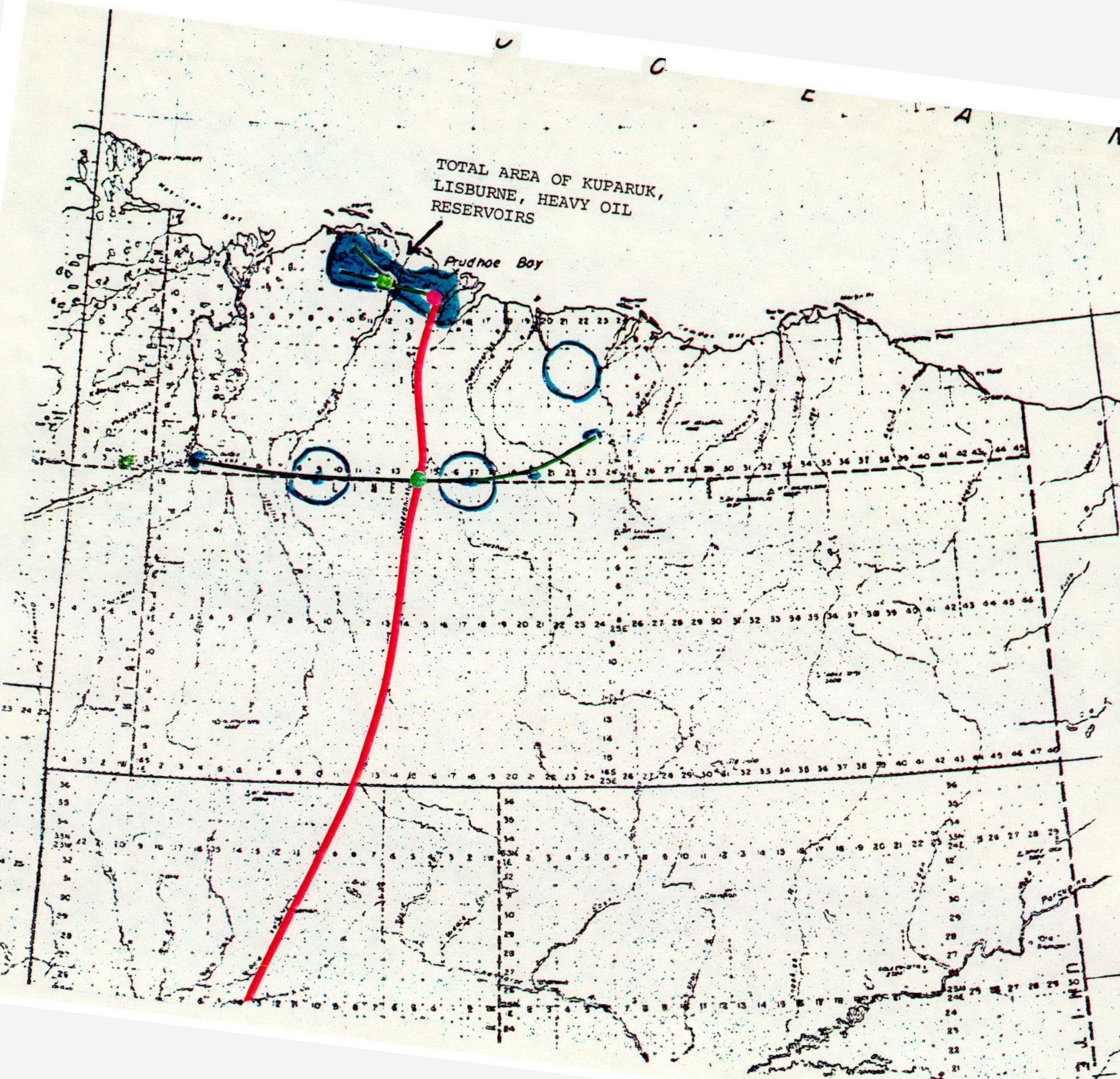


Exhibit 8
PRUDHOE PRIVATE
PRIMARY IMPACT AREA

SOUTHERN COOK INLET

General Assumptions

This alternative involves development in the southern portion of the Cook Inlet Basin. Six oil fields and 21 gas fields have been discovered in the northern portion of the basin. Four lease sales are assumed under the U.S. Department of the Interior schedule for 1975-1978, with one sale occurring each year. As many as 2.5 million acres could potentially be leased by a joint federal/state program through the mid-1990's. The State of Alaska Division of Oil and Gas estimated the potential recoverable reserves in the Southern Cook Inlet at 2.5 billion barrels of oil and 18.4 trillion cubic feet of gas (1974 estimate). As this estimate may include additional production in the northern portion of the Cook Inlet, especially the Kenai Field, we assumed a potential of 2.4 billion barrels of oil and 12 trillion cubic feet of gas as a reasonable estimate of Southern Cook Inlet potential.

Exploration

The closeness of the alternative area to known oil and gas production is likely to induce a high level of exploration. Assuming lease sales are conducted according to schedule, oil exploration would commence in 1975 and be completed by 1993; gas exploration would parallel that for oil. It has been assumed that 6 oil and 6 gas discoveries will occur during this period, the majority occurring within 10 years of the commencement of exploration. 5 delineation wells are assumed to be drilled in the two years subsequent to each discovery to outline the field.

Development

It is assumed that the discovery size will be 400 million barrels of oil and 2 trillion cubic feet of gas. These are the average sizes of the Northern Cook Inlet discoveries. Discoveries may consist of several smaller fields adjacent to one another that allow simultaneous development and utilize the same transport facilities. Four platforms, with 24 development wells each, are assumed to be necessary for each oil field development. Eight wells per year are assumed to be drilled on each platform until development of the platform has been completed. Gas development is assumed to require 320 acre spacing, with 8 wells being drilled from each platform.

Production

The initial well flow rate in the Southern Cook Inlet is assumed to be 1500 barrels per day. This will decline to 1000 barrels per day, at which time the field would be put on secondary recovery. Gas is assumed to be produced both as a by-product of oil production and from gas wells. Each oil well is assumed to produce 1.5 MMCFGPD, and each gas well 15 MMCFGPD.

Facilities

As production of oil and gas increases in Southern Cook Inlet, more oil and gas facilities will be constructed on the Kenai Peninsula to support producing activities. Offshore platforms will have the facilities for gas/liquid separation and self-sustaining power generation. Onshore, required new facilities will include a dock and loading facilities for oil and gas transport. Unlike more remote areas, housing for personnel will be in adjacent towns.

Oil produced offshore will flow to onshore gathering centers and from there to storage at a new terminal. If oil development occurs as expected, the new crude terminal will be built on the Kenai Peninsula adjacent to the producing areas, perhaps near Anchor Point at the end of Kachemak Bay.

Major facilities there would include:

- Buildings for offices, control and maintenance
- Power plant
- 2 berths, capable of handling 250,000 DWT tankers
- 7-500,000 barrel crude tanks initially and 10 tanks ultimately.

Gas produced in the Southern Cook Inlet will be processed and liquefied onshore in a new LNG plant(s). This facility in the Southern Cook Inlet area is expected to be built on the land near Anchor Point. Existing LNG facilities are currently operating in the Upper Cook Inlet. However, as oil and gas development occur in the Southern Section, new LNG facilities will be required there, because the volume of gas will be very much greater. To process and transport all of the gas anticipated from this province, gas processing and liquefaction facilities will have to have a total capacity of 1.5 to 2.0 billion SCFD, consisting of 3 or 4 500 MMSCFD refrigeration/compression units. The associated terminal would have two berths capable of servicing LNG carriers of up to 165,000 cubic meters capacity.

There is also the possibility for the construction of a large refinery (200,000 BPD) in the Cook Inlet to supply fuel oil and distillates to the West Coast in the mid to late 1980's. Production of crude would support such a refinery by 1985, but its construction depends on the need for new refinery capacity on the West Coast. It is more likely that a large refinery would be built near Seward utilizing crude oil from the Gulf of Alaska.

Impact Area

Oil and gas development in Cook Inlet could directly affect 80,000 offshore acres, as well as onshore acreage for the LNG plant and transport facilities.

PRUDHOE GAS - EL PASO

General Assumptions

There is no gas currently being produced from the Prudhoe Bay region, and none is expected under the base case scenario. Gas produced with the oil will be fed into a gas-injection plant to be directed back into the original producing zone until facilities are available for its production.

The El Paso Alaska Company, a subsidiary of El Paso Natural Gas Company, has estimated the in-place gas reserves at Prudhoe Bay to be 13.4 trillion cubic feet of solution gas and 21.7 trillion cubic feet of associated gas. Recoverable reserves are estimated to be in excess of 27 trillion cubic feet - 29.2 trillion cubic feet over a 25-year period (El Paso). This development alternative assumes that the El Paso Alaska Company will be able to render transportation service to "parties" who may own or control Alaskan gas in the Prudhoe Bay region. The El Paso Trans-Alaska Gas Project will include a gas pipeline system, a liquified natural gas plant, a marine terminal, and a liquefied natural gas carrier fleet.

Exploration and Development

It is expected that exploration and development for gas, which have already been initiated in Prudhoe Bay in conjunction with oil exploration and development, will continue until the pipeline is prepared to operate. An initial 800 million cubic feet per day of solution gas will be produced for 3 years from oil wells prior to the start-up of the pipeline system. Six-hundred-forty-acre development spacing is assumed for this development alternative.

Production

It is assumed for the purposes of the alternative that Federal Power Commission approval will be granted to the El Paso pipeline project by 1976, that accelerated construction activity will last through 1979, that construction of the compression stations will be completed in 1½ years, and that the pipeline will be ready to operate by mid-1980. Gas production during that year is expected to be 2,100 million cubic feet per day, and gas available to the pipeline is expected to be 1,600 million cubic feet per day. The production forecast is a gradual build-up to 4 billion cubic feet per day in the 10th year of operation, declining to 3.3 billion cubic feet per day by 2000.

Facilities

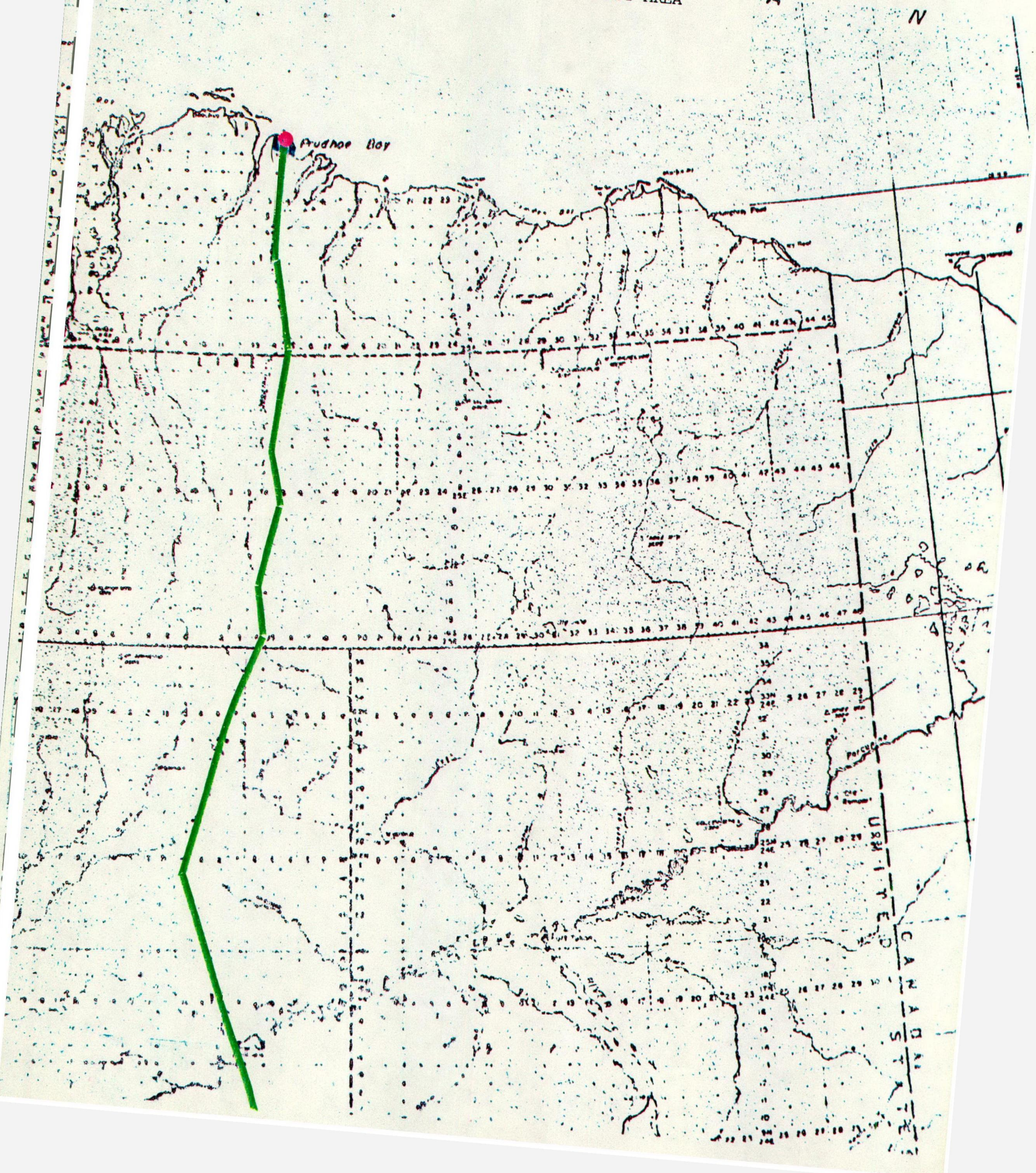
Necessary pipeline facilities will include a central gathering center at Prudhoe Bay; 809 miles of 42" pipeline from Prudhoe Bay to Gravina Point on the southeast coast of Alaska; and 12 compressor stations. The gas liquefaction plant will require:

- Carbon dioxide gas removal (50 ppm or less) facilities
- Molecular sieve dehydration units
- Eight refrigeration/compression modules of approximately 380 million SCFD capacity
- Four 550,000 barrel insulated storage tanks
- Vapor recovery system for tanks and vessel loading equipment
- A power plant - gas turbine driven with diesel engine backup
- Air fractionation equipment to provide nitrogen for purging and blanketing
- Buildings for administration, maintenance shops, warehouse space, process control and cafeteria
- Permanent onsite houses and a recreation facility
- Two berths each capable of handling LNG carriers of up to 165,000 cubic meters capacity.

The land requirement for the plant is approximately 1200 acres of which 395 acres is for the plant, 55 acres for support facilities (e.g., housing, heliport) and 750 acres for a green belt around the plant.

Exhibit 15

EL PASO GAS
PRIMARY IMPACT AREA



GULF OF ALASKA

General Assumptions

The Gulf of Alaska's potential reserve area encompasses a large offshore section of the Pacific Ocean, stretching from the tip of Kodiak Island north along the coast and then south to the Alexander Archipelago. Both federal and state lease sales are scheduled for locations within this area in the near future. Federal sales are planned for 1975 and 1976 by the Department of the Interior, with the 1975 sale area extending off Alaska's southern shores seaward from the 3-mile state territorial water boundary out to the 200-mile line, from the central Prince William Sound area east to Yakutat and down to Cape Fairweather. It is on a general east-west line north of Juneau. The federal sale scheduled for 1976 will occur in a region east and south of Kodiak Island. A state sale is scheduled for 1977 in the Yakutat Bay region. This development alternative assumes that leasing and exploration will commence according to the above-mentioned leasing schedule, although weather conditions which are somewhat severe, and the substantial potential for earthquake occurrence may alter this schedule.

Recoverable reserves have been estimated at 10 billion barrels of oil and 40 trillion cubic feet of gas (RPA).

Exploration

Fifty geologic structures and 340 exploratory wells are assumed for this development alternative. Exploration is expected to commence in 1977 and cease in 1996. Further, the exploration and discovery process will occur in "jumps" - i.e., if one field were discovered in an area, exploration would most likely be intensified, resulting in the high probability of discovery of other, smaller fields. Oil discoveries are assumed for 1979, 1981, 1983, 1985, and 1990, with 2 billion barrels of oil per discovery. Gas discoveries are assumed to parallel oil discoveries. Fifteen delineation wells are expected for each oil field, five for each gas field. Delineation wells are drilled from rigs similar to those used for exploration.

Development

Development is assumed to begin in 1983 and to be completed by 1998. Three-hundred-twenty-acre spacing is assumed for development, with eight wells to a platform. Moreover, since we assumed 200 wells will be required to develop each oil field, 25 platforms will be needed per field. It will take 1 year to move each platform into location and to begin operations. Gas development is assumed to lag oil development by one year, with 64 wells being drilled for each gas field (320-640 acre spacing).

Production

Initial oil production is assumed to occur in the fourth year of development, with full production estimated for the fifth year. When production begins in the Gulf of Alaska, the output is estimated to be 480,000 BOPD. Total production is expected to peak in 1997, with an annual output of over 2.0 million BOPD. Initial production from each well is assumed to be 3,000 BOPD, declining to 2,000 BOPD. When waterflood occurs, 100 wells in each field will be producers, each producing 4,000 BOPD. The normal life for each field is projected to be 16 years.

Gas production includes both production as a by-product from oil production and production from gas wells. Each oil well is assumed to produce gas at a rate of 2 MMCFGPD. Each gas well produces at 20 MMCFPD. Thus each oil field has a production capacity of 400 MMCFGPD, each gas field a production capacity of 1280 MMCFGPD.

A total of 1,719 wells are estimated for the Gulf of Alaska region, 1,384 of which will be production wells (500 water injection). The remaining 435 will be exploratory and delineation wells.

Facilities

The land facilities required to support such production levels will include docks and the construction or expansion of air strips at Yakutat, Cape Yakutaga, Cape Junken, Seward, Kodiak and Sitkalidak island. An alternative site for development of facilities is Cordova which might serve areas off Montague and Hinchinbrook Islands.

Each field would require construction of sea-floor gathering centers and pipelines to onshore gas facilities. Oil production from each of the six discovery areas is assumed to be loaded onto tankers via less expensive single point moorings and floating storage systems developed for North Sea use.

Gas produced from the Gulf is assumed to be shipped to the contiguous 48 states for sale. Consequently, processing and liquefaction plants, and terminals for LNG carriers will be required for each of the six major offshore areas. The sequence of probable construction and estimated size ranges are:

	Plant Location	Production Rate	Probable Date of Initial Production
1.	Yakutat	1.5-2.0 Billion SCFD	1985
2.	Cape Yakataga (Cape Suckling to Icy Bay area)	1.5-2.0 Billion SCFD	1987
3.	Cape Junken (offshore production South of Montague and Hinchinbrook Islands)	0.5-1.5 Billion SCFD	1990-95
4.	Seward Area (Resurrection Bay or Day Harbor)	0.5-1.5 Billion SCFD	1990-95
5.	Kodiak (or Maimot Island)	1.0-2.0 Billion SCFD	1985-95
6.	Sitkalidak Island	1.0-2.0 Billion SCFD	1985-95

As discussed in more detail in the appendix on oil and gas facilities, there is a significant possibility of a large 200,000 barrel per day refinery being built in Alaska after 1985. By that time oil development will have begun in the Gulf of Alaska, making crude available adjacent to good prospective deepwater terminal sites. In this alternative it is expected then that one 200,000 BPD refinery will be built on the Gulf of Alaska by 1990, probably on Ressurrection Bay near Seward.

As a potential refinery site (if oil is discovered within a reasonable proximity), Seward has several advantages over other locations. The most important advantage is that the city of Seward has an infrastructure capable of absorbing the increased social and economic activity resulting from the operation of a large plant employing approximately 400 workers. An additional favorable aspect of a Seward site is that a refinery built on Resurrection Bay near Seward would have road access to Anchorage and other areas of the State. Its proximity to the population center of Alaska would increase the access to more goods and services for the plant as well as for the employees. Unlike the TAPS terminal at Valdez, a Seward/Resúrrection Bay site would have relatively clear access to open seas in the Gulf of Alaska, thus minimizing the risk of oil spill from an accident at sea.

Any site along the rim of the Gulf of Alaska raises the spector of damage caused by seismic activity. In the Seward area the risk of earthquake damage is relatively low compared to other sites. Few geologic faults exist in the vicinity and the rock base in the area is not as unstable during an earthquake as the area around the Cook Inlet and Anchorage.

An alternative to a Seward site would be a refinery on the Kenai Peninsula in the Cook Inlet. Crude oil production is expected to reach 200,000 BPD there by 1985, which would support a large refinery. However, whether a site is selected at Seward or Kenai will depend to a large extent on the time at which large refining capacity additions will be required on the West Coast and may be supplemented by Alaskan refining capacity.

BEAUFORT SEA

General Assumptions

This alternative involves development of the Alaskan offshore area extending from the U.S.-Canadian border to Point Barrow in the Beaufort Sea. In developing the initial exploration and production projections for this alternative, we assumed that drilling in ice-bound waters will be limited to depths of 20 feet or less until about 1985.

Currently, federal and state lease sales are scheduled for 1975, 1976, 1977, and 1978. Given the existence of some promising geologic structures offshore from (and also within) the National Arctic Wildlife Refuge, significant offshore discoveries in the Beaufort Sea would probably result in a lease sale off the coast of the Refuge. To consider the near maximum impact of oil and gas development, it was assumed that even this sensitive offshore acreage will be leased in 1980.

Estimates of economically recoverable oil reserves in the Beaufort Sea are about 8 billion barrels, and it was assumed this oil will be discovered in four major pools.

Exploration

Until 1985 exploration will be confined to water depths of 20 feet and/or to offshore islands. Beyond 1985, new technology will allow drilling in deeper water.

Beginning with announced plans and projecting exploration paralleling the Prudhoe "model," exploration will begin in 1975 and is expected to continue until about 1990. Discoveries are assumed to occur in 1978, 1979, 1980, and 1990, consisting of an average of 2 billion barrels of recoverable oil reserves and 3 trillion cubic feet of gas per discovery. A discovery may actually consist of several smaller pools in the same general area, which are thus economic to develop. Each discovery is assumed to contain both oil and gas in economic quantities. Given the experience of North Slope development, we assumed 15 delineation wells will be drilled per discovery.

Development

Completion of development wells is assumed to lag discoveries by 4 years. Therefore, oil development wells, with 320 acre spacing, will be drilled beginning in 1982 and completed in 1996. Gas development, utilizing 640 acre spacing will lag oil development by one year. Gathering centers are assumed to be connected to the system feeding TAPS or another parallel pipeline of roughly equivalent capacity.

Production

Oil production is expected to follow exploration by 4 to 6 years. Average production rate per well is assumed to be 6,000 BOPD initially, declining to 4,000 BOPD, then remaining relatively constant over time because of the application of waterflooding to the reservoirs to maintain an economic producing rate. The floor rate will be 480,000 BOPD in 1984, reaching a maximum of 1.68 million BOPD in 1994.

Gas production is assumed to result both as a by-product of oil production and from the gas wells. Each oil well will produce gas at a rate of 1 MMCFGPD, each gas well at a rate of 8 MMCFGPD. Gas production is assumed to begin in 1985 at a rate of 800 MMCFGPD, peaking in 1990 at 3 BCFGPD. A 12 year life is assumed for the gas cap of each field.

Facilities

The onshore facilities required to support this development will be a dock for summer use, permanent quarters with 200 beds, and an airstrip for delivering supplies in the winter. Other than the wells and rigs, additional producing facilities required will be an onshore gathering center and separation oil/gas facilities, and a small topping (distillation) plant with a capacity of 4,500-5,000 barrels per day to provide fuel oil to power the equipment.

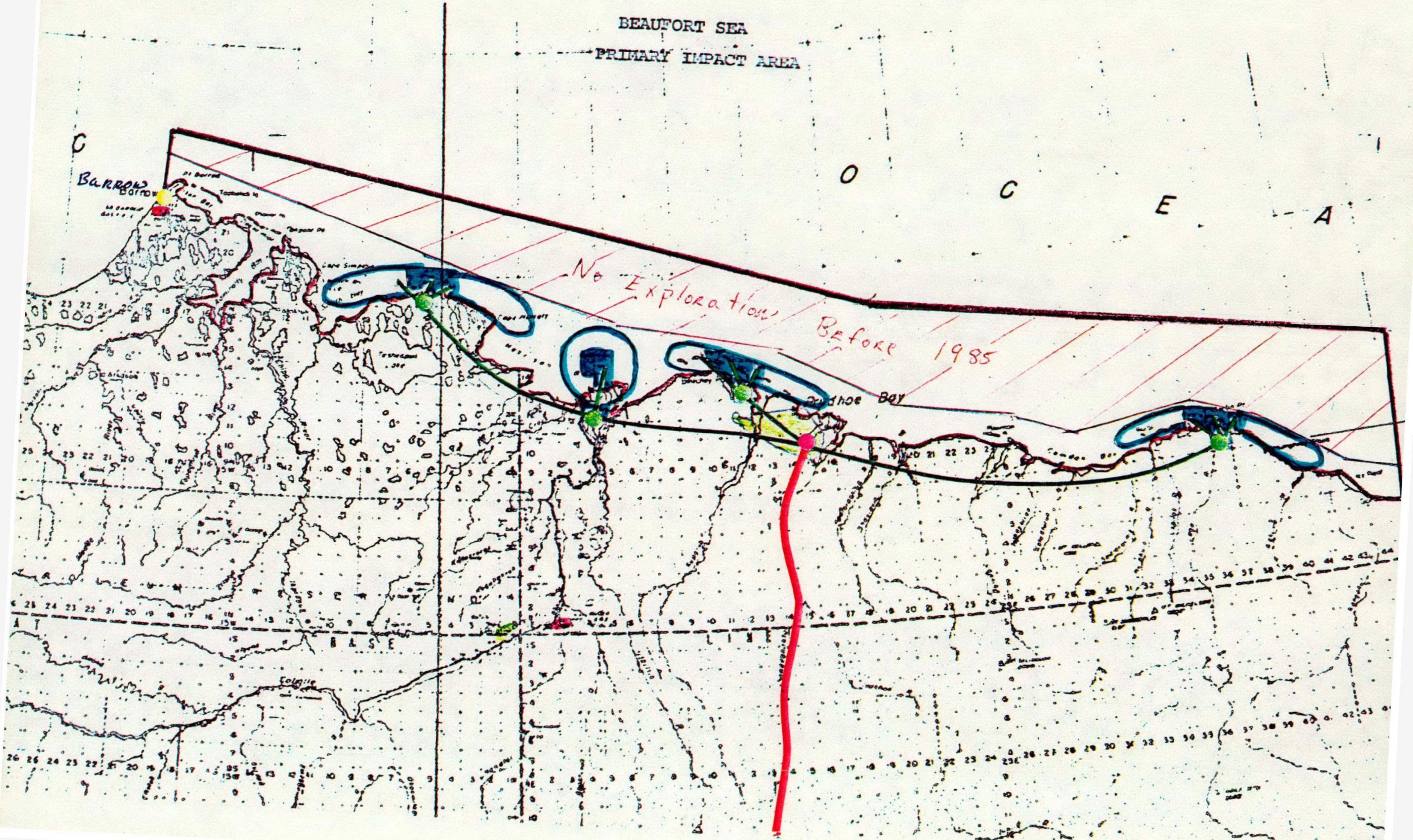
Impact Area

The area directly affected by the producing operations is expected to be some 50,000 acres per field offshore. Not all of the area will be covered by facilities; rather, the figure represents the total acreage traversed by pipelines and bounded by wells. Onshore support facilities such as the airstrip and housing will affect an estimated 10,000 acres per field.

Exhibit 19

BEAUFORT SEA

PRIMARY IMPACT AREA



NAVAL PETROLEUM RESERVE #4 (SLOW)

General Assumptions

Naval Petroleum Reserve (NPR) #4 encompasses an extensive area of northern Alaska, from the Colville River on the east to approximately Icy Cape on the west. It extends from the coast of the Arctic Ocean to at least 50 miles south of Lookout Ridge in the Brooks Mountain Range.

Potential reserves are estimated at 10 billion barrels of oil and 14 trillion cubic feet of gas (RPA). The normal leasing procedure is not expected to occur within NPR-4 unless Congress places the area under the aegis of the U.S. Department of the Interior. Unless this occurs, it is assumed the Navy will continue to manage and thus control exploration and development of oil and gas in the region. However, the Navy has let contracts for exploratory drilling services in the past, but in any case, all development will be conducted under contract to either the Navy or the Department of the Interior.

Exploration

It is assumed that exploration will be pursued on the basis of maximizing reserves rather than following a competitive strategy. The first 10 years of exploration are expected to be concentrated in the northern half of NPR-4, with further exploration (1985-2000) focusing on the southern portion.

The first stage of exploration is assumed to commence after 1975, with discoveries assumed in 1978, 1980, 1982, and 1983. The 1978 discovery is expected to be a medium-size reservoir resembling the Sadlerochit Reservoir of Prudhoe Bay. This would consist of a potentially recoverable 4 billion barrels of oil and 8 trillion cubic feet of gas. The subsequent discovery of three smaller fields in 1980, 1982, and 1983 could reveal the potential of 2 billion barrels of recoverable oil and 2 trillion cubic feet of recoverable gas per field. (It should be noted that discovery of a field would not necessarily encourage accelerated exploration in this alternative.)

The second stage of exploration, projected to occur from 1988 to 2000, is assumed to lead to discoveries of several small fields the size of Umiat (100 million barrels of oil) or of Gubik (500-1000 billion cubic feet of gas). These would be developed in the late 1990's on a basis similar to the development alternative for Prudhoe Private.

Development

Development of the medium-size field assumed to be discovered in the northern portion of NPR-4 in 1978 would commence in 1983 and be completed by 1989. Development of the three smaller fields would begin in 1983, 1985, and 1988, and end in 1988, 1990, and 1993, respectively.

Production

A 14-year life for oil fields and a 12-year life for gas fields is assumed. Initial production from the medium-size oil field is expected to be 750,000 BOPD in 1986. Total production will rise to a peak of 2.0 million BOPD the following year as the smaller fields are brought into production. Gas production is estimated to commence at 1.0 billion cubic feet of gas per day in 1989, reaching a high of 3.5 billion cubic feet of gas per day by 1990. The production rate for the medium-size oil field is assumed to be 5,000 BOPD initially, declining to 3,000 BOPD; the rate for the smaller fields is assumed to be 3,000 BOPD initially declining to 2,000 BOPD.

Three-hundred-twenty acre spacing is assumed for oil development; 640 acre spacing is assumed for gas wells.

Facilities

The NPR-4 (Slow) alternative assumes an original plan to loop into the TAPS pipeline. However, as smaller field discoveries demand additional capacity in 1983, a new pipeline(s) will have to be constructed along the TAPS route. Work on this additional pipeline is expected to commence in 1983 and be completed by 1987. A 150-mile extension from the TAPS route to the medium-size field will be completed in 1989.

An alternative route South from NPR-4 is also feasible linking with East-West pipelines to the TAPS route in the East or a new Western Alaskan pipeline to the West. Though this is possible the more likely occurrence is a pipeline to the origin of the TAPS line. The reason for this judgment is that in the course of constructing the TAPS pipeline all major support structures (such as bridges) have been designed to accommodate a second crude pipeline should it become necessary. As a result, a considerable construction cost saving would be achieved by using the TAPS route and a major parallel pipeline.

Smaller-diameter pipelines will connect the fields to a central gathering center with facilities of Prudhoe Bay size. Each field is expected to have large, temporary facilities during development, with small-to-medium permanent facilities during actual production. Two dock facilities will also be required.

Impact Area

The area of direct development impact is assumed to be 64,000 acres for each of the three smaller fields and 96,000 for the medium-size field. Each gathering center will require the use of 20,000 acres.

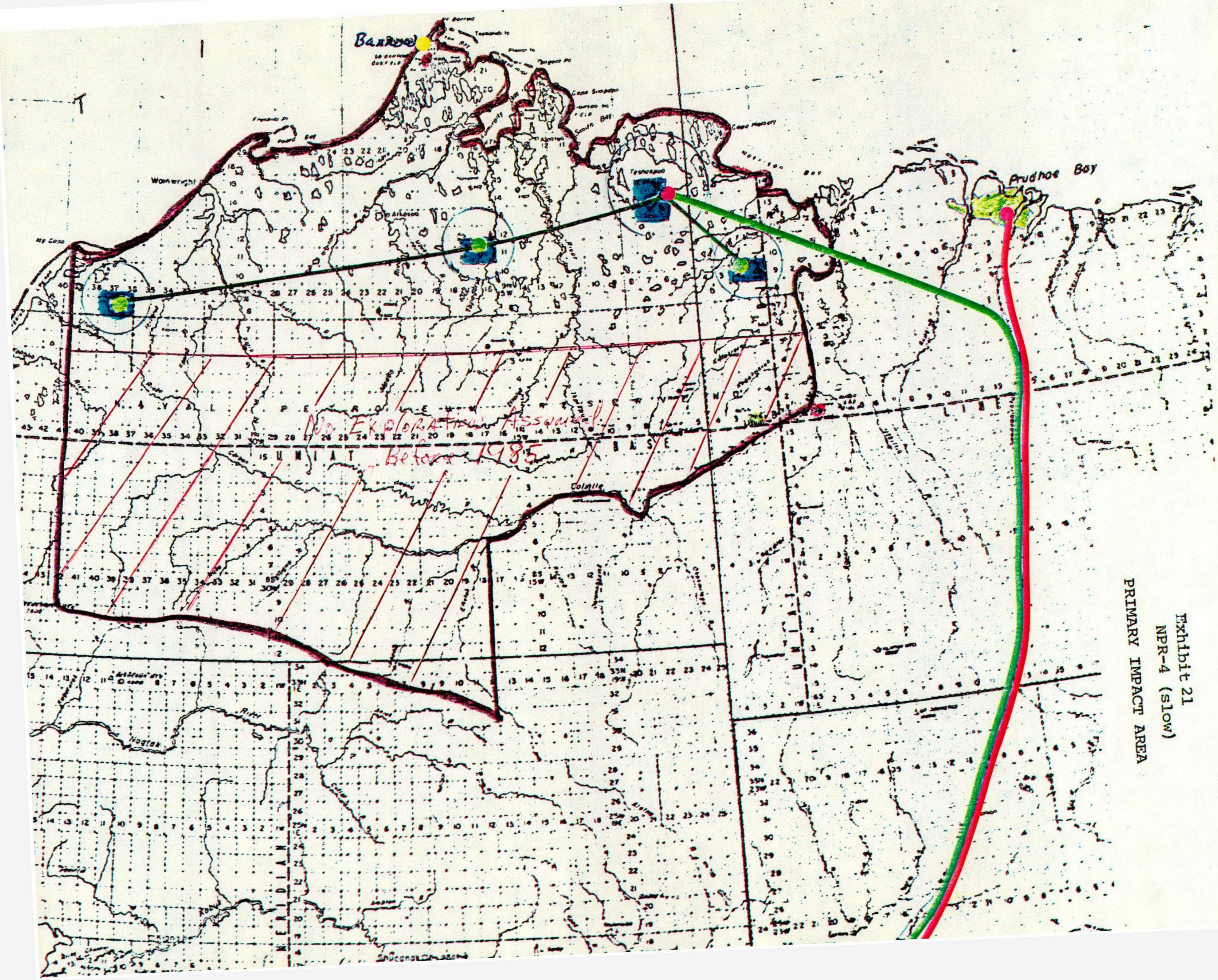


Exhibit 21
NPR-4 (slow)
PRIMARY IMPACT AREA

KOTZEBUE - KOTZEBUE SOUND AREA

General Assumptions

This arm of the Chukchi Sea was considered a separate oil and gas subregion because it consists primarily of native- and state-controlled acreage and because exploratory drilling is already under way on native lands, which distinguishes Kotzebue from the much later development expected in the Chukchi Sea.

Estimates by the State of Alaska's Department of Natural Resources puts potential recoverable reserves at 700 million barrels of oil, 5 trillion cubic feet of gas.

Exploration and Development

Assuming the state will obtain leasing rights to a majority of Kotzebue Sound, exploration will probably proceed rapidly. Indeed, native lands will be explored under concession agreements already negotiated.

Onshore and offshore leasing is expected to occur over the 1975-1983 period, and will result in two discoveries in 1977 and 1979 of about 350 million barrels each: An average of five delineation wells are assumed per discovery well. Development will probably cover the period from 1978 to the end of 1985.

Production

Initial oil production is likely to occur in 1980, reaching a peak of 200,000 BOPD in 1985. Gas production is not considered in the scenario, principally due to transportation requirements. These would probably make gas production uneconomic until the Chukchi Sea production begins in the late 1990's.

Facilities

Support facilities are likely to include the expansion of the airstrip at Kotzebue, the construction of a dock, a small topping plant (2,000-2500 BOPD) for fuel oil and permanent living quarters for approximately 200 persons. An onshore gathering center with 170,000 BOPD capacity will also be required.

North of the Aleutian Island chain the existence of pack ice is fairly common and the likelihood of technology becoming available to permit year-round tanker operation in the Bering Sea is unlikely. Even if tankers like the ESSO Manhattan were fitted or designed with special hulls, the ice movements would undoubtedly damage any kind of fixed berth or single point mooring device now known. Consequently, it is estimated* that a second major crude oil pipeline will probably be required to deliver oil from Kotzebue and Norton Sounds to the ice-free Gulf of Alaska.

The oil flow from Kotzebue, which is expected to reach 170,000 BOPD by 1985, will not justify a new 650-700 mile pipeline to the Gulf of Alaska. However, given the potential for oil in Norton Sound, the Bethel Basin, and Bristol Bay, a Western Alaska pipeline route is feasible. The portion of such a pipeline originating at Kotzebue Sound will be necessarily small (perhaps 24" diameter) connecting with larger pipe at Koyukuk.

Another possibility for transport would be the construction of a large pipeline in Western Alaska to carry oil from the Chukchi Sea province. While this is certainly feasible, it is more likely that Chukchi oil will be transported via the TAPS route. The late development of Chukchi would permit an increasing quantity of Chukchi oil to fill the capacity of the TAPS (1st or 2nd) line as North Slope production declines.

Should no oil be found in Norton Sound or the Bethel Basin (Kuskokwim Bay area) a western route seems less likely. In that case, a line may be constructed eastward to connect with the TAPS line.

Impact Area

An estimated 22,000 acres per field offshore and another 10,000 acres per field onshore will be affected by Kotzebue development.

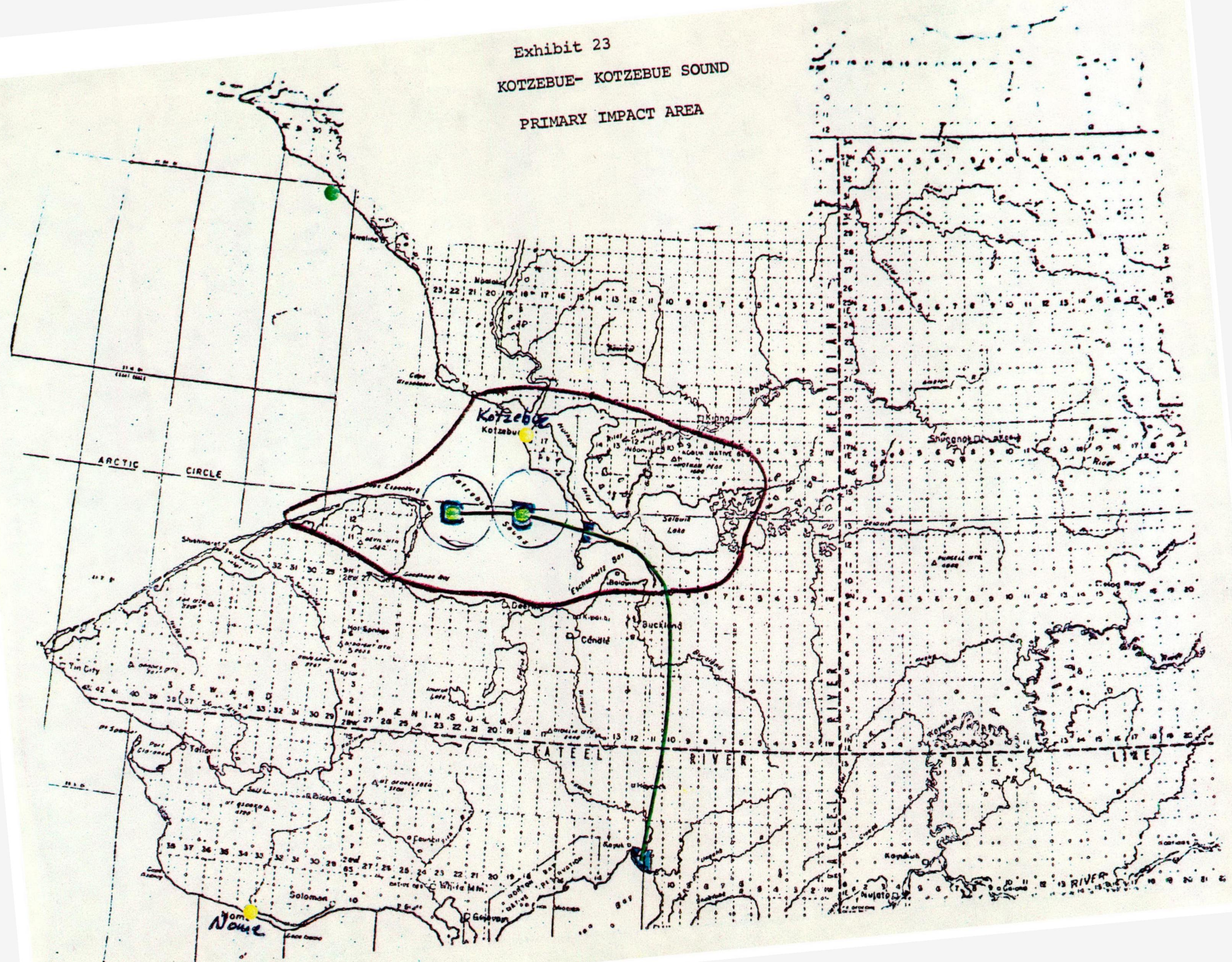
---

*RPA estimate.

Exhibit 23

KOTZEBUE- KOTZEBUE SOUND

PRIMARY IMPACT AREA



BRISTOL BAY

General Assumptions

The Bristol Basin is a potential oil-producing area that covers about 95,000 square miles of Bristol Bay (a section of the Bering Sea) and adjacent onshore areas. Development of this region will be complicated by the fact that federal, state, and native leasing programs must be taken into consideration. However, since the higher potential areas lie in the 80 percent of the basin that is offshore, most of the exploration, development, and production is assumed to occur in the federal and state offshore acreage.

Leasing in the Bristol Basin area is expected to follow three separate schedules, depending on whether the acreage is federal-, state-, or native-owned. Federal sales are expected to begin in 1976 and recur at 2-year intervals until 1984. Only one state sale is expected to occur (in 1980), while native concession agreements with oil companies are likely to be made by 1986.

Exploration

To date nine exploratory wells have been drilled onshore. Another 10 wells are expected to be drilled onshore in the next 2 years, primarily to satisfy native concession agreements. Offshore exploration, on the other hand, will not begin until 1977, and will probably be completed only by 1995.

The potential recoverable reserves are assumed to be 5 billion barrels of oil, of which 90 percent is offshore. In the basin, approximately 25 oil-bearing structures are assumed, requiring 50 exploratory wells. Discoveries are anticipated in 1979, 1981, and 1985; the discoveries are assumed to be 2 billion barrels each. In actuality, however, each discovery may consist of several smaller fields found during delineation. In this case, 15 delineation wells are expected per discovery.

Development

Development (mainly offshore) of the Bristol Bay area is expected to begin in 1981 and be completed by 1992. As in other areas, wells are assumed to be drilled with 320 acre spacing, with eight wells drilled per platform.

Production

Initial total production (i.e., in 1981) is expected to be 200,000

BOPD, peaking in 1987 at 500,000 BOPD. The average rate per well in 1981 will be 3,000 BOPD. As the well-production rate declines to 2,000 BOPD, water flooding will be instituted to sustain that rate until the field is depleted.

Facilities

Since most of the production will be offshore, and since tankers will take on the oil offshore, it is assumed that permanent onshore facilities requirements will be small. However, a dock for summer use, an airstrip for access throughout the year, and living and service facilities for approximately 400 persons will be necessary.

An alternative to offshore tanker transport is a pipeline to Cook Inlet, from which transport to the lower 48 states would be effected. This alternative is discussed in the Kotzebue alternative.

Impact Areas

The areas affected by this development are assumed to be 60,000 acres offshore and 10,000 acres onshore for each of the first two discoveries. The third discovery will affect 30,000 acres offshore and another 5,000 onshore.

NAVAL PETROLEUM RESERVE #4 (FAST)

General Assumptions

Naval Petroleum Reserve (NPR) #4 encompasses an extensive area of northern Alaska, from the Colville River on the east to approximately the Kokolik River on the west. It extends from the coast of the Arctic Ocean to at least 50 miles south of Lookout Ridge in the Brooks Mountain Range.

Potential reserves are estimated to be 20 billion barrels of oil and 27 trillion cubic feet of gas (RPA). The normal leasing procedure is not expected to occur within NPR-4 unless Congress places the area under the aegis of the U.S. Department of the Interior. Unless this occurs, it is assumed the Navy will continue to manage and thus control exploration and development of oil and gas in the region. However, the Navy has let contracts for exploratory drilling services in the past, but in any case, <u>all</u> development will be conducted under contract to either the Navy or the Department of the Interior.

Exploration

Exploration is assumed to pursue a maximum-discovery strategy, with the first 10 years of exploration (1975-1985) concentrated in the northern half of NPR-4; further exploration (1985-1995) will be concentrated in the southern portion of NPR-4. Small field development in the late 1990's will be similar to that described in the NPR-4 (Slow) alternative.

Discovery of a giant field is expected in 1978, with the potential recovery of 10 billion barrels of oil and 15 trillion cubic feet of gas. As a result of this discovery, exploratory activity will be accelerated, thereby leading to discoveries of five smaller fields in 1979, 1981, 1982, 1983, and 1985.

Development

Development of the giant oil field will begin in 1981, with over 200 wells to be drilled by 1987. Oil development in the giant field will be completed by 1988; waterflood, by 1988. Oil development in the smaller fields will commence in 1982 and be completed by 1995. Gas development would last from 1983 to 1990.

Production

Average production in the giant field is assumed to commence at 8,000 BOPD, declining to 5,000 BOPD; thereafter, the field will be put on waterflood, producing 10,000 BOPD per well (assuming 200 producers). Average oil production for the smaller fields is expected to be 4,000 BOPD per well, declining to 2,000 BOPD; thereafter, these fields will be put on waterflood (assuming 100 producers), producing 4,000 BOPD per well. Three-hundred-twenty acre spacing is assumed for all oil development.

Gas production beginning in 1986 will last until 1997. Six-hundred-forty acre spacing for additional gas development (i.e., beyond the time oil development has ceased) is assumed. Gas production will consist of gas produced as a by-product of oil production, as well as gas produced from gas wells.

Facilities

Development of the giant field will require an additional 48" oil pipeline along the TAPS route plus a 150-mile extension along the North Slope to the field; a gas pipeline along the same route plus a 150-mile extension; facilities on the scale of Prudhoe Bay; and two docks.

Smaller-field development will require an additional oil and gas pipeline along the TAPS route; a 150-mile extension along the North Slope to a central gethering center; small-diameter pipelines from the central gathering center to the fields; facilities at the gathering center; temporary development facilities and small permanent production facilities at each field; and two docks.

Gas production would require pipeline and liquefaction facilites similar to those for the El Paso alternative.

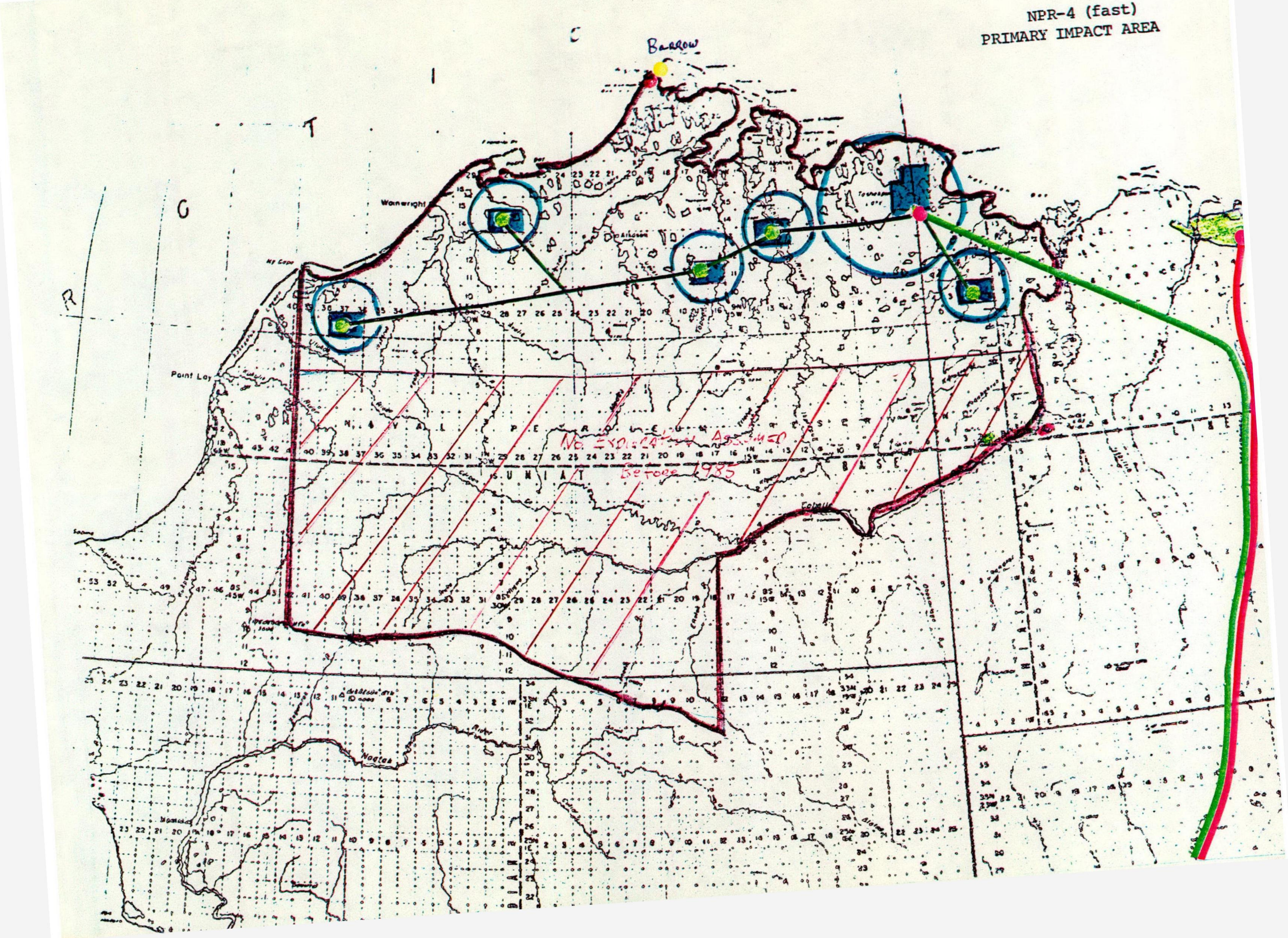
Several alternative pipeline routes are possible other than the one shown in Exhibit 27. One route would consist of running the pipeline through Anaktuvuk Pass to the west of the pipeline route, than joining TAPS at a point further to the south. Another route would involve a western pipeline to Kotzebue, then to Cook Inlet (see Bering Sea alternative). The route chosen would probably depend on the combined amount of oil and gas from the alternative areas and the capacity constraints of existing pipeline and transport facilites.

Impact Area

The primary area of impact of oil and gas development will involve 120,000 acreas at the giant field and 64,000 acres for each of the smaller fields. The pipeline(s) route would require a 100 right-of-way. Each gathering center would necessitate the use of 20,000 acres.

Exhibit 27

NPR-4 (fast)
PRIMARY IMPACT AREA



BERING SEA

General Assumptions

This development alternative assumes that leasing and exploration will commence in late 1976, when the U.S. Department of the Interior has scheduled a sale, despite the lack of environmental impact studies on the area and the fact the area has not yet been divided into leasing blocks. This sale will be in the St. George Basin, in the area near the Pribilof Islands. Subsequent sales, beginning with Norton Sound, are assumed to occur at 2-year intervals, ending in 1986. (The Bristol Basin, which consists of Bristol Bay and adjacent onshore areas, is considered in a separate development alternative.)

The Bering Sea alternative is complicated by potential native and state leasing in the Bethel Basin, which extends to Kuskokwim Bay and includes the land area surrounding Norton Sound. It is assumed that some exploratory activity will commence in these areas prior to federal lease sales in the Bering Sea; this will tend to escalate the potential of the outer continental shelf areas.

At present, only geophysical surveys have been conducted in the Bering Sea; as a result, the potential of the area is undetermined. We have therefore assigned a potential of 8 billion barrels of oil to the area. Gas is <u>not</u> considered in the development alternative.

Exploration

Assuming exploration and development will be similar to the Gulf of Alaska alternative, and drillships will be available to explore without competition for rigs from the Gulf of Alaska, we estimated there will be 50 geologic structures requiring 100 exploratory wells.

Exploration is assumed to begin in 1977 and be completed by 1990, resulting in discoveries in 1979, 1981, 1985, and 1987, with 2 billion barrels of oil per discovery. (Each discovery may in fact consist of several smaller discoveries in the same area.) Smaller discoveries may continue into the 1990's, which will tend to extend the life of development and production facilities, but will be too tentative to incorporate in this development alternative. For this offshore area, approximately 10 delineation wells will be drilled per discovery.

Development

Development will commence in 1982 and be completed by 1994. (Gas development, which is not considered in this alternative, would probably extend development to 1999.) To determine the maximum reasonable impacts of development, we assumed the level of development will not be impaired by competition for resources from the Gulf of Alaska development. As in the case of other regions, 320 acre spacing for development wells, with eight wells to a platform, is assumed.

Production

When the Bering Sea begins oil production in 1985, the total output is estimated to be 300,000 BOPD, increasing to 500,000 BOPD in 1986 and peaking in 1991 at 1 million barrels per day. Average production per well is estimated at 4,000 BOPD initially, declining to 3,000 BOPD, at which point waterflooding will probably be used to sustain an economic rate until the fields are depleted.

Facilities

The large distances between potential fields make separate development and production facilities necessary for each field. The land facilities required to support production consist of a dock for water access in the summer, an airstrip (and/or an expanded airstrip in Kuskokwim or Nome) for continuous access, and additional permanent quarters equipped with 200 beds.

Production itself will be almost entirely sea-based, except for the state- or native-controlled areas, which will require land-based facilities.

Gathering centers associated with each field will be connected to flow centers, pooling flows to a major pipeline.

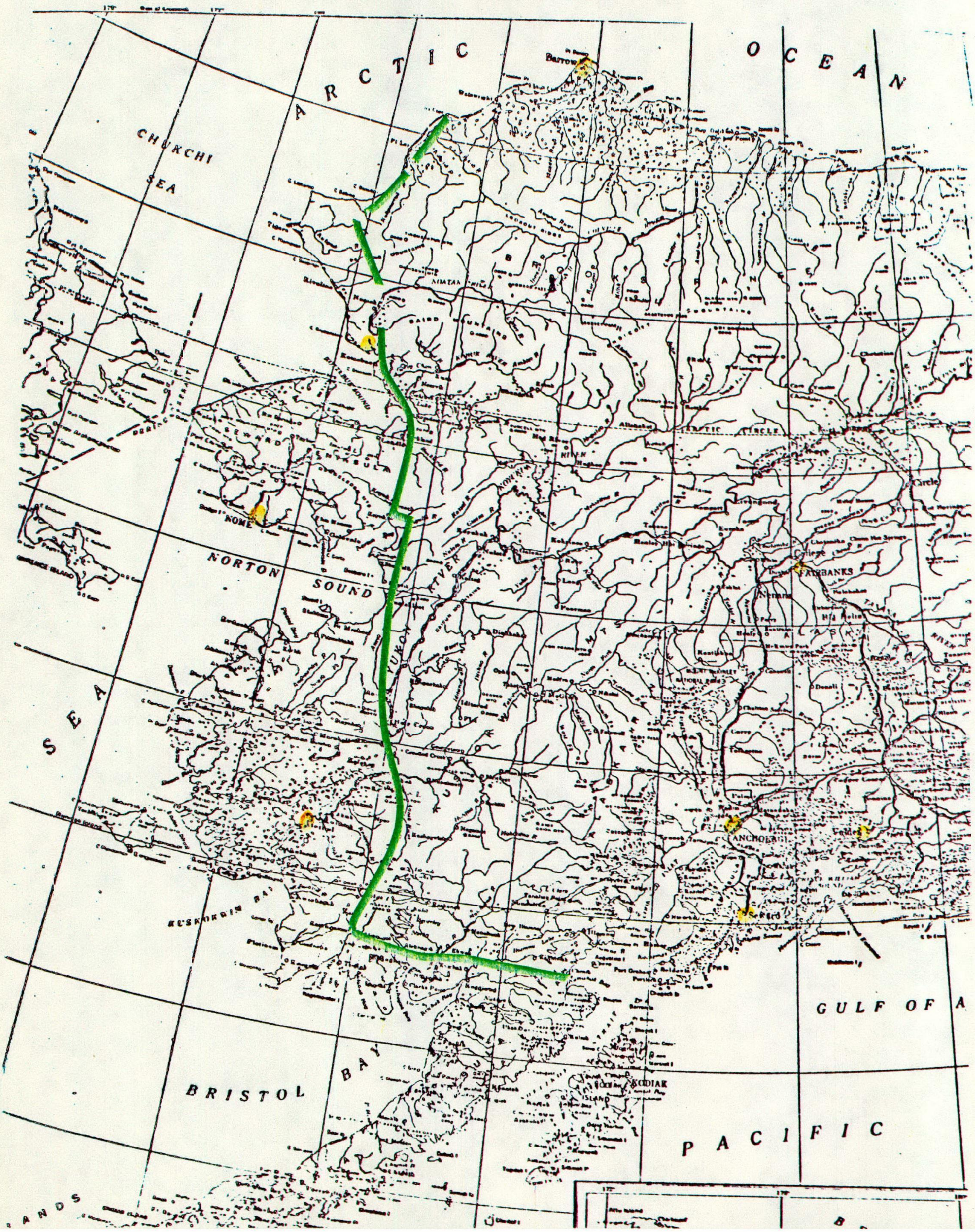
As noted in the Kotzebue scenario the construction of a Western Alaska pipeline is expected to transport oil to the ice-free Gulf of Alaska. At Norton Sound, spur pipelines of about 200 miles will be needed to connect to the large pipeline system at Koyukuk. Farther south at Kuskokwim, another pipeline spur would originate at gathering centers around the mouth of the Kuskokwim river and follow the river basin to a junction with the anticipated Western pipeline.

Impact Area

The area directly impacted by production (bounded by gathering lines and wells) is estimated to be about 50,000 acres per field. The onshore area affected by temporary exploratory facilities and permanent land-based, production-related facilities is estimated to be another 10,000 acres per field.

Exhibit 29

KOTZEBUE-NORTON SOUND-BRISTOL BAY-COOK INLET
PIPELINE
(CHUKCHI SEA EXTENSION DASHED)



CHUKCHI SEA

General Assumptions

This development alternative assumes leasing and exploration in this region will not commence until 1985, when technology to permit year-round exploration and development in ice-bound waters deeper than 20 feet will have been developed. It also assumes that federally-sponsored development of NPR-4 and private development in the Point Bay area (west of NPR-4) will provide geologic information about this unexplored area.

Leasing in the Chukchi Sea is not expected to occur before 1985, at which time both state and federal offshore areas are assumed to be available.

Exploration

Without detailed seismic analyses to draw upon, we have assumed 20 geologic structures will be needed, requiring 40 exploratory wells. Exploration beginning in 1985 will be completed by 1995. Two discoveries are expected to be made in 1988 and 1990, each containing approximately 2 billion barrels of oil. (Actually, each discovery may consist of several smaller discoveries in the general area.) Potential discoveries after 1990 will have no effect in the timeframe of this study, and have therefore been disregarded. Gas has not been included in this alternative, as any gas production would occur late in the 1990's. An average of 15 delineation wells will probably be drilled per discovery.

Development

Chukchi Sea development is expected to lag discoveries by about 3 years. Therefore first development will occur in 1991, and subsequent development will commence around 1993. As in other areas, 320 acre spacing is assumed.

Production

Initial total production from Chukchi in 1994 is anticipated to be 500,000 BOPD, with peak total production of 1 million BOPD occurring in 2000. The average well size is assumed to be 4,000 BOPD. The fields will be put on waterflood after 3 years for the remainder of their 12-year life to maintain the average well production at 3,000 BOPD.

Facilities

The onshore facilities required to support this development are a dock for summer use, permanent quarters with 200 beds, and an airstrip for delivering supplies in the winter. Other than the wells and rigs, additional producing facilities required are an onshore gathering center and separation oil/gas facilities, and a small topping (distillation) plant with a capacity of 4,500-5,000 barrels per day to provide fuel oil to power the equipment.

Additional facilities required for Chukchi development are alternative pipeline connections to transport systems. The first and most likely alternative, given the timing of Chukchi growth, is a pipeline linking Chukchi gathering centers to the NPR-4 pipeline system, which will, in turn, connect to TAPS or a parallel pipeline to southern Alaska. The second alternative is the installation of a 24" pipeline connecting Chukchi to the transport facilities assumed to be developed in the Nome-Kotzebue area to handle production from Kotzebue Sound.

Impact Area

The total affected area is estimated to be 80,000 acres for each of the two offshore fields and 30,000 acres per field for onshore support facilities and the topping plant. An additional land impact will be created by the need for 150 miles of 100-foot right-of-way for the connecting pipeline.

ARCTIC WILDLIFE REFUGE

General Assumptions

The prospect of opening the Arctic Wildlife Refuge for oil exploration is bound to be an extremely sensitive issue, strongly opposed by environmental conservationists. However, the likelihood of significant discoveries in adjacent offshore areas of the Beaufort Sea and the existence of large, high-potential geologic structures in the Refuge make eventual development of some kind quite possible. Therefore, this projection assumes that, by 1985, sufficient environmental precautions will have been taken and the need for oil will be so great that the Refuge will be opened for exploration.

Exploration and Development

A cautious exploration program is expected to begin in 1985 and continue until 1990. One majore discovery, assumed to occur around 1986, of Prudhoe dimensions (i.e., 10 billion barrels) is plausible. Development of the field is likely to span the period 1988-1993.

Production

Production is expected to parallel the Prudhoe Sadlerochit development, but peaking at 2 million barrels per day by 1994. Initial production rates per well are expected to be 8,000 BOPD, declining to 5,000 BOPD, at which point this production level will be maintained by waterflooding.

Facilities

A pipeline will be required across the North Slope to TAPS, where oil from the refuge will fill the TAPS line as Prudhoe declines. Gas produced would be transported either by the proposed El Paso Trans-Alaska gas pipeline to Valdez or by the proposed Arctic Gas Pipeline through Canada. In either case a gas pipeline would be required to connect the Arctic Wildlife Field to a central flow station at the pipeline.

Impact Area

The estimated impact area is 120,000 acres.

Exhibit 33

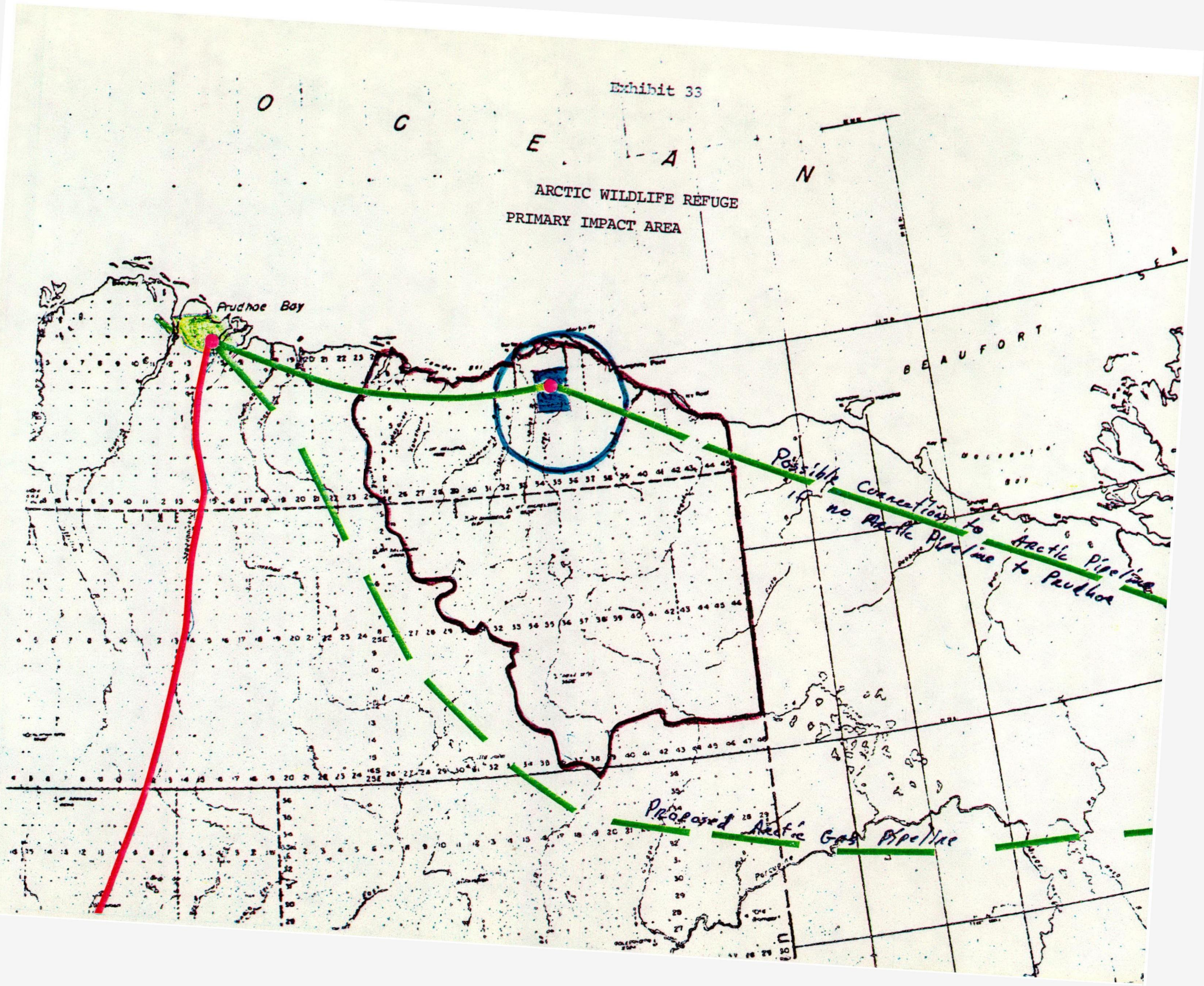

O C E A N
ARCTIC WILDLIFE REFUGE
PRIMARY IMPACT AREA
BEAUFORT
Prudhoe Bay
Possible Connection to Arctic Pipeline
if no Arctic Pipeline to Prudhoe
Proposed Arctic Gas Pipeline

Exhibit 35

Hypothetical Development Levels for
Alaskan Oil and Gas, 1977-2000

Development Alternatives	Recoverable Reserves		Initial Development Date	Production Schedule (thousand barrels per day; million cubic feet per day)												Transportation	
	Oil (billion barrels)	Gas (trillion cubic feet)		1977		1980		1985		1990		1995		2000		Facility	Location
				Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas		
Cook Inlet Base Case	0.8	5	1958	195	300	195	400	175	800	90	800		800		300	Pipelines	Anchorage and shipping terminals
Prudhoe Oil Base Case	9.6		1969	1200		1600		1600		1200						Pipeline (TAPS)	Prudhoe to Valdez
Prudhoe Private																	
Kuparuk	1.5-2.0	-	1978			384		250		250		100					
Lisburne	1.0-2.0	8.0	1980					500	1000	381	1000	179	1000	84	1000	Pipeline connections to TAPS	
Heavy Oil	0.2	-	1985							86		40					
Other	0.3	2.0	1985							100	400	47	400		400		
Sub-Total	2.5-4.5	10.0				384		750		817	400	366	400	84	400		
South Cook Inlet	2.4	12.0	1980					204	960	384	1600	428	1700		1500	Pipelines	Anchorage and shipping terminals
Prudhoe Gas-El Paso		29.2	1975-6				2100		3800		3900		4000		3300	Pipeline	Prudhoe to Gravina Pt.
Gulf of Alaska	10.0	40.0	1983					480	1700	1443	6300	1600	7500	1300	5000	Pipelines	Central offshore gathering stations for transfer to tankers
Beaufort Sea	8.0	16.0	1982					480	800	1240	3000	1680	3000	800	1400	Pipeline connections to TAPS	Onshore gathering centers
NPR-4 (Slow)	10.0	14.0	1982							2000	2000	2000	3500	660	3500	Connection to TAPS until new pipeline along TAPS route plus extension	
Kotzebue	0.7	5.0	1983					170		160		45				Pipeline	Kotzebue to Norton Sound
Bristol Bay	5.0	16.0	1981					200	600	1100	2800	1100	3000	800	1700	Pipelines	Central offshore gathering stations for transfer to tankers - onshore pipeline for native lands
NPR-4 (Fast)	20.0	27.0	1982					2000	3600	4000	7200	3700	7200	1560	3600	New pipeline along TAPS route for oil and gas plus extension	
Bering Sea	8.0	32.0	1981					700	1200	1700	6000	1700	7000	1200	4500		Central offshore gathering stations for transfer to tankers - onshore pipeline for native lands
Chukchi Sea	4.0	16.0	1991									340	700	1000	2700	New pipeline or extension to join NPR-4 system	Norton Sound to Kotzebue
Arctic Wildlife Refuge	10.0	30.0	1988									2000	3300	2000	3600	Pipeline to TAPS	