ALASKA NATURAL GAS TRANSPORTATION SYSTEMS

Final Environmental Impact Statement

FEDERAL POWER COMMISSION STAFF

VOL. I

GENERAL
ECONOMIC ANALYSIS
COMPARISON OF SYSTEMS

April 1976

FEDERAL POWER COMMISSION STAFF

FINAL ENVIRONMENTAL IMPACT STATEMENT FOR THE ALASKA NATURAL GAS TRANSPORTATION SYSTEMS

VOLUME I

EL PASO ALASKA COMPANY
Docket No. CP 75-96, et al.

APRIL 1976

FOREWORD

The Federal Power Commission, pursuant to the Natural Gas Act, is authorized to issue certificates of public convenience and necessity for the construction and operation of natural gas facilities subject to its jurisdiction, on the conditions that:

> /a / certificate shall be issued to any qualified applicant therefore, authorizing the whole or any part of the operation, sale, service, construction, extension, or acquisition covered by the application, if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Act and the requirements, rules, and regulations of the Commission thereunder, and that the proposed service, sale, operation, construction, extension, or acquisition, to the extent authorized by the certificate, is or will be required by the present or future public convenience and necessity; otherwise such application shall be denied.

15 U.S.C. 717

The Commission shall have the power to attach to the issuance of the certificate and to the exercise of the rights granted thereunder such reasonable terms and conditions as the public convenience and necessity may require.

Section 1.6 of the Commission's Rules of Practice and Procedure allows any person alleging applicant's non compliance with such conditions to file a complaint noting the basis for such objection for the Commission's consideration.

18 C.F.R. §1.6 (1972).

Section 2.82(c) of the Commission's General Rules allow any person to file a petition to intervene on the basis of the staff draft environmental statement.

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FINAL ENVIRONMENTAL IMPACT STATEMENT
Summary Sheet

El Paso Alaska Company Docket No. CP75-96 et al.

1. The Final Environmental Impact Statement(FEIS), prepared by the staff of the Federal Power Commission, is related to an administrative action.

2. This action arised from proposals to bring Alaskan natural gas from the Prudhoe Bay Field in Alaska, and in one proposal to also bring gas from the MacKenzie Delta region of Canada, to market areas in the lower 48 states. Two separate natural gas transportation systems have been proposed. The Arctic Gas Pipeline System would utilize a land route through Canada whereas the El Paso Alaska Company System would utilize a land-sea route with liquefied natural gas facilities and tankers.

3. Environmental impacts resulting from the construction and operation of these systems would include effects on man, wildlife, vegetation, soil, water quality, air quality, and noise levels. This FEIS, including portions adopted from Staff's DEIS, also describes the measures which would be taken to avoid or mitigate the identified potential impacts and those impacts which cannot be prevented or mitigated.

4. Alternatives to the proposed actions include different pipeline routes, LNG terminal sites, alternative gas supplies and other energy sources, and the alternative of not constructing the projects.

5. Written comments received on the DEIS were reviewed and evaluated by Staff and considered during the preparation of the FEIS. All commenting letters are reproduced in Volume IV, Parts 1 and 2. Staff responses are shown in the margin of the photo reduced comment letters. Comments were received from the following Federal, state and local agencies, private individual and groups, and industries:

FEDERAL

Advisory Council on Historic Preservation

Committee on Interior and Insular Affairs, U.S. Congress

Environmental Protection Agency

Executive Office of the President, Council on Environmental Quality (Additional comments/responses on P. 833.)

Federal Energy Administration

Nuclear Regulatory Commission

U.S. Department of Agriculture
- Forest Service
- Soil Conservation Service

U.S. Army Corps of Engineers
- Detroit, Michigan
- San Francisco, California

U.S. Department of the Army, Office of the Chief of Engineers

U.S. Department of Commerce, Assistant Secretary for Science and Technology

U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service

U.S. Department of Defense, Assistant Secretary for Health and Environment

U.S. Department of Health, Education and Welfare

U.S. Department of the Interior
- Alaska Power Administration

U.S. Department of State

U.S. Department of Transportation

STATE

Alaska State Senate, Jalmar Kertula, Majority Leader

California Coastal Zone Conservation Commission

North Dakota Public Service Commission

North Dakota State Planning Division

Ohio Environmental Protection Agency

Ohio River Basin Commission

Pennsylvania State Clearinghouse

Resources Agency of California

State of Alaska, Attorney General

State of California
- Public Utilities Commission
- State Lands Commission

State of Idaho

State of Montana, Fish & Game

State of Nevada, Governor's Office of Planning Coordination

State of North Dakota, Attorney General

State of Oregon, Office of the Governor

University of Alaska
- Dr. Albert A. Dekin, Jr.
- Dr. John A. Kruse

Washington State Highway Commission

LOCAL AND REGIONAL

Association of Interior Eskimos

City and Borough of Juneau, Alaska

City of Cordova, Alaska

City of Seward, Alaska, City Manager

City of Skagway, Alaska

City of Spokane, Washington

Cordova Chamber of Commerce

County of Santa Barbara, California

The Eyak Corp.
Joe P. Josephson, EYAK Attorney

Fairbanks Town & Village Association for Development, Inc.

Gillam, Harold, Mayor of Fairbanks, Alaska

Greater Anchorage Chamber of Commerce

Greater Fairbanks Chamber of Commerce

Kline, Ginny, Mayor of Juneau, Alaska

Matanuska - Susitna Borough, Inc.

Port of Los Angeles, California

Port of Seattle, Washington

Seattle Chamber of Commerce

Southern California Association of Governments

Spokane Regional Planning Conference

PRIVATE CITIZENS AND CITIZENS' GROUPS

Alaska Conservation Society

Alaska Democratic State Central Committee

Bergman, Lynn A.

Conservation Intervenors (Ron Wilson)

Denali Citizens Council

Endangered Species Productions, Inc.

Everett, James C.

Fairbanks Environmental Center

Federation of Western Outdoor Clubs

Friends of the Earth
Fairbanks, Alaska
Washington, D.C.

Haggard, Paul K.

Jones, Darlene

Larson, Enid A.

Lindquist, Clara

National Audubon Society

North Dakota Wildlife Federation

Organization for the Management of Alaska's Resources

Scenic Shoreline Preservation Conference, Inc.

Sierra Club
Anchorage, Alaska
San Francisco, California

GAS INDUSTRY

Alaskan Arctic Gas Pipeline Company

Chevron Shipping Company

Columbia Gas Transmission Corporation

El Paso Alaska Company

Kenai Pipe Line Company

Northern Borders Pipeline Company

Pacific Gas Transmission Company - Interstate Transmission Associates (Arctic)

Standard Oil Company of California

Texas Eastern Transmission Corp.

Western LNG Terminal

OTHER INDUSTRY

Alaska Miners Association, Inc.

Allen and Associates

American Water Resources Associates

Associated General Contractors of America, Inc.

Beluga Coal Co.

Cordova District Fisheries Union

Engineered Equipment Company

International Brotherhood of Boilermakers, Ship Builders, etc., Local No. 104

Iroquois Research Institute

Maritime Trades Department, AFL-CIO

Prince William Sound Aquaculture Corporation

Utah Mining Association

6. Environmental Impact Statements were made available to the Council on Environmental Quality and the public on the following dates:

Draft EIS: November 28, 1975
Final EIS: April 9, 1976

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SECTION A - SUMMARY AND CONCLUSIONS

1. Introduction

Two transportation systems have been proposed to carry natural gas from fields in northern Alaska to markets in the lower 48 states -- the Arctic Gas System and the El Paso Alaska System.

The Arctic Gas System application has been filed with the Federal Power Commission by a group of six companies. These companies, plus a seventh Canadian pipeline company, propose to construct a pipeline from the Prudhoe Bay Field of Alaska and from the Mackenzie Delta area of the Northwest Territories of Canada to markets in the lower 48 states and Canada.

The environmental impact of the Arctic Gas System is contained in a final environmental impact statement circulated by the U.S. Department of the Interior in March 1976. The staff of the Federal Power Commission relies on that final document, with certain stipulations, for its environmental assessment of that proposal.

The FPC staff has prepared this environmental impact statement on the competing proposals by El Paso Alaska Company (Docket No. CP75-96) and Western LNG Terminal Company (Docket No. CP75-83-1) which collectively constitute the El Paso Alaska System.

This system would carry natural gas by an 809-mile chilled, underground pipeline from Prudhoe Bay in northern Alaska south across the state to a port site at Port Gravina on Prince William sound. A liquefaction plant, at Port Gravina would convert the gaseous natural gas to liquefied natural gas (LNG) which would then be transported by a fleet of eleven LNG tankers to western LNG's receiving terminal and regasification plant located at Point Conception in southern California. After regasification, the natural gas would be transmitted by pipeline to existing pipeline systems for delivery to markets in the United States.

The environmental assessment of this proposed system is presented in four volumes. Following is a brief description of the contents of each volume.

Volume I - This volume contains comparative economic and environmental analyses of the Arctic Gas and El Paso Alaska Systems. Additional sections described the parts of the Interior's FEIS accepted by FPC staff, modifications proposed by applicants for portions of the Arctic Gas System in the lower 48 states, and staff's conclusions.

Volume II - This volume covers the environmental impacts associated with the proposal by El Paso Alaska Company to transport natural gas across Alaska by pipeline, convert the gas to LNG for shipment via LNG tankers to southern California, where it is regasified and distributed to markets in lower 48 states. Specific alternatives to system are discussed.

Volume III- This volume covers the environmental impacts associated with the proposed marine terminal facilities, regasification plant and associated pipelines operated by Western LNG Terminal Company at Point Conception, California where Alaskan LNG would be received and processed. Specific alternative to facilities are discussed.

Volume IV - This volume, in two parts, contains the comments received on the DEIS, and staff's responses to these comments.

The components of the FEIS which have received major emphasis are those dealing with the analysis of the proposal's impacts on the environment, the impact of reasonable alternatives, and staff's handling of comments received on the DEIS. Those portion's of the DEIS which did not require significant changes, or which contained detailed and repetitive information, descriptions, charts and other material, are adopted as the respective section of this FEIS. These adopted sections are shown in script in the Table of Contents. The Comparative Analysis in this volume provides the reader with an environmental overview of the two proposals. Readers interested in more detailed information on topics such as the description of the proposed actions and the existing environment are referred to the appropriate sections in the DEIS which have been adopted.

2. Parts of U.S. Department of the Interior's Final Environmental Impact Statement Accepted by the FPC Staff

The Federal Power Commission(FPC) and the U.S. Department of the Interior(USDI) have concurrent applications before them from the participants of the Arctic Gas System requesting an FPC certificate of public convenience and necessity and permits from USDI for the proposed pipeline system to cross Federal lands.

In connection with these applications, the USDI, on July 28, 1975, issued a DEIS upon which FPC staff commented and subsequently accepted in part, in lieu of preparing a duplicate DEIS of its own.

USDI has used staff's comments to revise and prepare its FEIS, which was circulated on March 29, 1976. The FPC staff has reviewed that FEIS and accepts the following parts of it in lieu of preparing a full impact statement of its own:

(i) Alaska Volume - This volume covers the 195-mile proposal of the Alaskan Gas Arctic Pipeline Company originating at Prudhoe Bay and terminating at the Alaska-Yukon Border and alternative routes.

(ii) Canada Volume - This portion of the environmental impact statement analyzes the 2,435-mile pipeline proposal of Canadian Arctic Gas Pipeline, Ltd., beginning at the Yukon-Alaska Border and proceeding generally southward to Caroline Junction in Alberta where it forks, one leg entering Idaho, near Kingsgate, British Columbia, and the other entering Montana, near Monchy, Saskatchewan. Discussions of route alternatives are also presented.

(iii) San Francisco Volume - This volume analyzes the 917-mile portion proposed by Pacific Gas Transmission Company which passes through Idaho, Washington, and Oregon to Antioch, California. Discussions of route alternatives are presented.

(iv) North Border Volume - This volume is an analysis of the 1,619-mile pipeline proposed by the Northern Border Pipeline Company. It covers the area from the United States-Canada border, crossing Montana, North and South Dakota, Minnesota, Iowa, Illinois, Indiana, Ohio, and West Virginia, to a termination near Delmont, Pennsylvania. Discussions of route alternatives are presented.

(v) Alternatives Volume(PP. 1-171 except Paragraph 8-C-3., Deregulation Effects)- This volume covers courses of action open to the Secretary of the Interior to approve, deny, postpone, or accept and delay or deny part of the proposal; effects of gas deregulation and conservation; other natural gas sources; alternative energy sources and modes of transportation.

The Federal Power Commission recognizes that deregulation of natural gas has the potential for increasing the supply of this energy source. However, staff is not presently in a position to offer a definitive opinion on deregulation since the exact extent of available potential gas supplies in the contiguous U.S. in being investigated. In any event, deregulation of natural gas would require Congressional action of some form. Staff's position is that regulation of natural gas should be enforced until such time as amendments to the National Gas Act are passed.

(vi) Glossary - This volume provides the reader with definitions of technical words or phrases used in the environmental impact statement.

2. Descriptions of Proposals and Preferred Alternatives 1/

a) Applicants' Proposals

i. Arctic Gas Proposal

Arctic Gas proposes to construct an all pipeline system to deliver natural gas from the Prudhoe Bay area on the North Slope of Alaska and the MacKenzie Delta area in northwest Canada to markets in Canada and the United States. The system would consist of approximately 4,504 miles of large diameter pipeline.

The proposed Arctic Gas system is a combination of four projects. Alaskan Arctic Gas - 195 miles of 48-inch diameter pipeline running from Prudhoe Bay to the Alaska-Canada border. Capacity - 2.25 billion cfd; no compression.

Canadian Arctic Gas - 2,297 miles of 48-inch diameter pipeline running from the Alaska-Canada border east to receive MacKenzie Delta gas, then south, dividing at Caroline Junction, Alberta, and terminating at Kingsgate, British Columbia, near the Idaho border and Monchy, Saskatchewan near the Montana border. Capacity - 4.5 billion cfd; 36 compressor stations.

Northern Border Pipeline - 1,138 miles of 42-inch diameter pipeline running from the Montana-Canada border through Montana, the Dakotas, Minnesota, and Iowa terminating at Kankakee, Illinois near Chicago. Capacity - 1.5 billion cfd; approximately 10 new compressor stations.

1/ Figure 1 depicts the routes of the applicant's proposals and staff's preferred alternative.

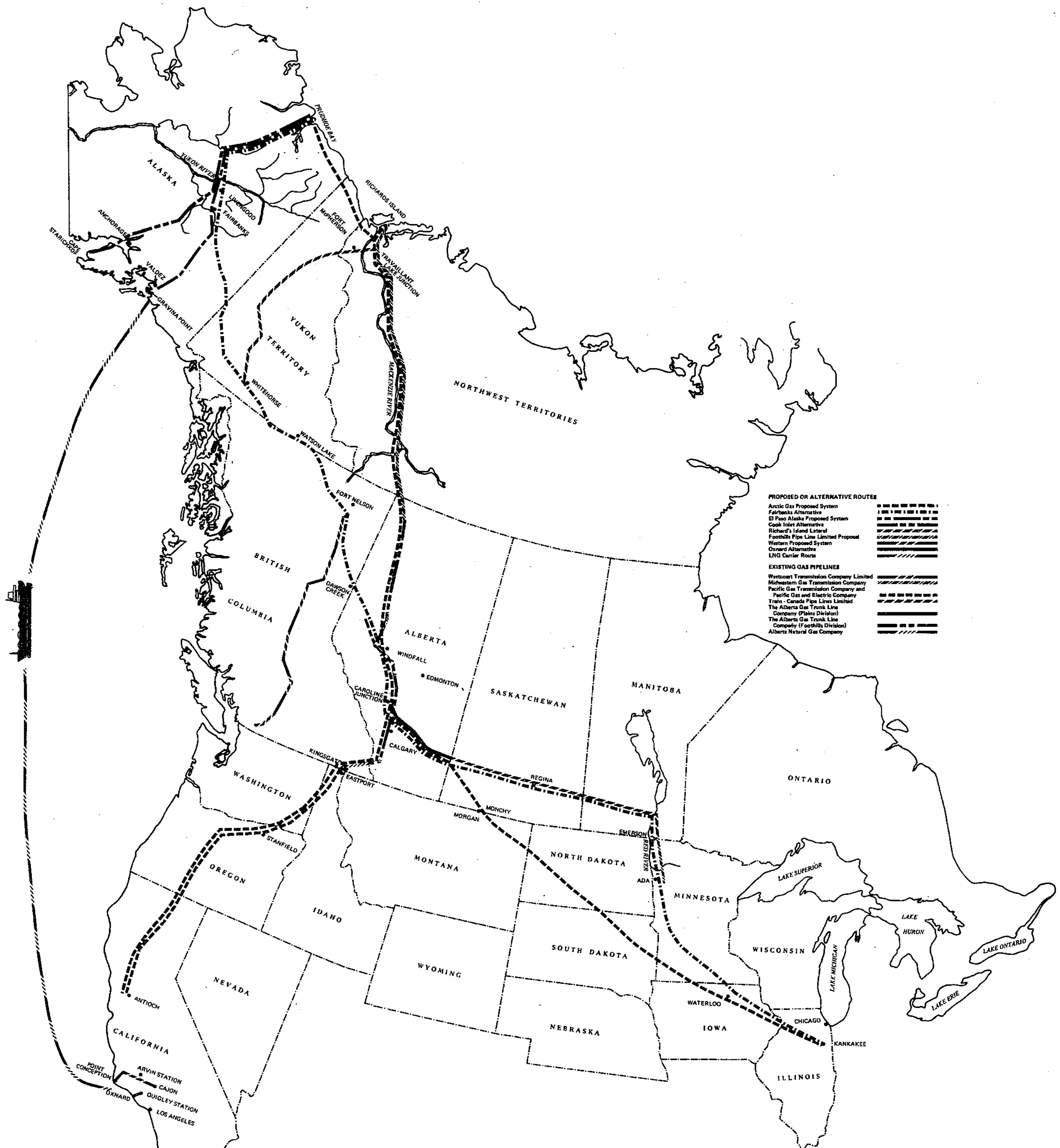


Figure 1. Applicants' Proposed and Environmental Staff's Preferred Alternative Pipeline Systems for the Delivery of Natural Gas from the North Slope of Alaska and the MacKenzie Delta of Canada.
(See Enlarged Reproduction of This Map at the End of This Volume.)

Pacific Gas Transmission and Pacific Gas and Electric - 874 miles of 36-inch diameter pipeline loop (97 percent on existing pipeline rights-of-way), running from the Idaho-Canada border south through Idaho, Washington, and Oregon and terminating at Antioch, California, near San Francisco. Capacity - 0.85 billion cfd; no additional compressors.

The capacities of each of these components could be increased with additional compression and/or looping.

In addition to the pipeline and compressors, the proposed system would require the construction of other related facilities including aircraft landing facilities, delivery taps, communication sites, and roads. A detailed description of the proposed system is given in the DOI Alaskan Arctic Gas Transportation Systems FEIS.

Since the DEIS was circulated, several changes to the Arctic Gas System as originally proposed have been presented by the applicants. First, ITAA has withdrawn its application in this proceeding and will no longer construct any portion of the Kingsgate to Los Angeles leg. Second, PGT and PG&E will no longer construct a parallel system, but will loop the existing PGT-PG&E pipeline. This will result in a reduction of the four proposed compressor stations and the utilization of several security crossings reducing pipeline installation by approximately 43 miles. The revised system of PGT and PG&E would transport those volumes of gas committed to ITAA, with the possibility of additional pipeline in southern California. And lastly, Northern Border presented a statement on the record stating that it would be modifying its application to terminate at Kankakee, Illinois rather than Delmont, Pennsylvania. This would result in a net reduction of 481 miles of pipeline, compressor stations, and other facilities.

b) Staff's Preferred Alternatives

i. Fairbanks Alternative

The Fairbanks Alternative would follow the Alyeska oil pipeline route south from Prudhoe Bay for 520 miles. From there, it would pass northeast of Fairbanks and follow the Alaska Highway into Canada, pass Whitehorse, to Watson Lake, Yukon Territory, and continue along the Alaska Highway where it would rejoin the Arctic Alaska proposed route at Windfall, Alberta. At this point, the line would parallel the Alberta Gas Trunkline Pipeline Company System to the Alberta-Saskatchewan Border at which time it would parallel Trans-Canada Pipe Lines Limited to a point along the Red River at Emerson, Manitoba, where it would enter the United States. The right-of-way would proceed south along Midwestern Gas Transmission Company to Ada, Minnesota, and on to Kankakee, Illinois, along the proposed Dome Oil Pipeline Corridor. The PGT-PG&E route would not be constructed at this time since the volumes of Alaskan natural gas which would be committed to these companies could be handled by means of exchange of gas agreements.

With Richard Island Lateral

The Fairbanks Alternative would be the same as that described above, except that to attach those volumes of Mackenzie Delta gas, a 756-mile long lateral pipeline would need to be constructed from the Mackenzie Delta area south to Whitehorse, Yukon Territory, along the Demster Highway corridor, then join the Fairbanks Corridor Route.

ii. El Paso Alaska Alternative

The environmental staff's preferred alternative involves the construction and operation of one LNG liquefaction, storage, and sendout terminal at Cape Starichkof, Alaska, for the volumes of gas associated with both the El Paso Alaska project and Pacific Alaska (Docket No. CP75-140 et al.) project. The pipeline route proposed to connect the Prudhoe Bay Field with Cape Starichkof would generally parallel the Alyeska oil pipeline route from Prudhoe Bay to Livengood, located just north of Fairbanks. From Livengood, the route would proceed south and west along the corridor utilized by the Alaska Railroad to Anchorage and from there would continue south to the Cook Inlet area. The pipeline would then be routed down the eastern shore of Cook Inlet to its terminus at Cape Starichkof.

At the California end of the project, the environmental staff's preferred alternative involves the construction and operation of one LNG unloading, storage, revaporization, and sendout terminal at Oxnard, California, for the three volumes of gas associated with the El Paso Alaska, Pacific Alaska, and Pacific Indonesia (CP74-160) projects.

ii. El Paso Alaska Proposal

The facilities as proposed by El Paso Alaska would transport 3.2 billion cubic feet of natural gas per annual average day from the Prudhoe Bay Field through approximately 809 miles of 42-inch diameter chilled gas pipeline to a gas liquefaction and LNG storage plant and marine terminal at Gravina Point, in Prince William Sound, Alaska. The pipeline facilities to Gravina Point would include gas separation facilities at Prudhoe Bay, 12 compressor stations, additional appurtenant facilities and a dispatching and control center. The proposed route would essentially follow the pipeline corridor established for the Alyeska oil pipeline except for the portion of the route south of Valdez and the LNG plant site which would traverse undisturbed sections of the Chugach National Forest.

The 500-acre LNG terminal site at Gravina Point would receive approximately 3.1 billion cfd of gas for processing through proposed gas treatment, dehydration, liquefaction and storage facilities. LNG in amounts equivalent to 2.809 billion cfd of gas would be transferred from 550,000-barrel LNG storage tanks, along a 1,200-foot long marine trestle, to a twin berth marine loading terminal. The LNG would be loaded onto 165,000-cubic meter capacity cryogenic tankers for shipment 1,900 nautical miles south to a receiving terminal and regasification plant near Point Conception in southern California.

The Point Conception LNG terminal, to be constructed by Western LNG Terminal Company (Western), would consist of a twin berth marine unloading terminal, a 4,600-foot long trestle and land-based LNG transfer, storage, and regasification facilities on a 227-acre site. The Point Conception LNG terminal would have a design baseload sendout rate of 2.803 billion cfd of gas with a 3.103 billion cfd peaking capacity. Western has proposed to construct a pair of 142.3-mile long, 42-inch diameter parallel pipelines from Point Conception to Arvin, California, and a 108.9-mile long, 42-inch diameter pipeline from Arvin to Cajon, California, to transport the revaporized LNG to existing mainline gas transmission systems owned by Pacific Gas and Electric Company (PG&E) and Southern California Gas Company (So Cal).

In addition to the facilities described above, El Paso Alaska has described a preliminary proposal that would be necessary in order to transport either directly or by displacement 1.55 billion cfd of the 3.1 billion cfd available as peak day supply from the Western LNG terminal to markets east of the Rocky Mountains. Applications to construct such facilities have not as yet been filed with the Commission.

3. Environmental Conclusions

a) Applicants' Proposals

The staff's conclusions about the environmental impact of the El Paso Alaska and Arctic Gas proposals have been based on a recognition that if gas is to be transported from Prudhoe Bay to the lower 48 states there is a need for construction of facilities.

It is concluded that there are undesirable aspects of both proposals which can reasonably be avoided. The major significant areas which should be avoided are as follows:

1) Arctic Gas Proposal

a) The Arctic National Wildlife Refuge in Alaska and its counterpart in Canada.

b) The Badlands and prairie pothole region.

c) The Ordway Memorial Prairie.

d) The Killdeer Mountains.

e) The Starved Rock Nature Preserve and State Park.

f) Proposed Wild and Scenic River Crossings-Moyie, Sacramento, John Day, Wapsipinicon, Little Missouri.

2) El Paso Alaska Proposal

a) The Chugach National Forest and LNG terminal site at Gravina Point.

b) Prince William Sound.

c) Proposed Wild and Scenic River Crossing-Gulkana River

d) Point Conception.

e) The Los Padres National Forest.

f) The Commanche Point/Tejon Hills botanic area and the proposed Tejon Ranch California Condor Critical Habitat Area.

Avoidance of these areas is recommended either because of direct impacts, or due to increased pressure which might result from the construction in those areas that would "open the door" to future development.

When viewed in the context of the need for the facilities, however, the overall projects as proposed by El Paso Alaska and Arctic Gas are both considered to be acceptable, presuming that the mitigating measures proposed by the applicants and those that will be developed by Federal agencies will be implemented and successfully enforced. These mitigating measures would significantly reduce potential impacts and environmental damage would be held to a minimum.

The staff has concluded that the Arctic Gas proposal is environmentally preferable to the El Paso Alaska proposal for the following reasons:

a) It would eliminate pipeline construction through a higher seismic risk area.

b) It would eliminate the hazards of siting two LNG terminals in high seismic risk areas.

c) It would eliminate the construction of a large industrial site in a totally undeveloped area of Alaska and in a remote area of California, which would significantly alter the land use, biological, aesthetics, and topographical features of these areas in addition to providing a catalyst for future development of these areas.

d) It would eliminate the potential impacts on the marine environments in Prince William Sound and Point Conception from the seawater system and LNG plant discharges and from the LNG tanker traffic.

e) The all pipeline system would provide a more operationally reliable system. It would also eliminate the potential operational and safety hazards of handling LNG and the possible disruptions and accidents related to shipping the LNG.

f) It would have a substantially lower fuel consumption during operation.

Although different magnitudes of socioeconomic impacts in Alaska were protected for the Arctic Gas and El Paso Alaska proposals the analysis of these impacts did not result in conclusions indicating that one route was preferable to the other on the basis of of these different impacts.

The environmental staff further concludes that although the Arctic Gas proposal is more environmentally preferable, both the Arctic Gas and the El Paso Alaska proposals traverse areas which are highly worthy of preservation. For this reason, it is strongly recommended that neither of the applicants' proposals be approved as proposed.

b) Staff's Preferred Alternatives

The staff's analysis of alternatives to transport Prudhoe Bay gas to the lower 48 states has indicated that the following alternatives would be preferable to the respective applicant's prime proposal.

1) Preferred alternative to the Arctic Gas System - Fairbanks Alternative without PGT and the Richards Island Lateral as described in Section 2b(i) of the preceeding section. This route would possess the following environmental benefits over the proposed system:

   a) Less total pipeline mileage; 3,711 miles vs. 4,504 miles. Reduced disruptions to vegetation, wildlife, land use and aesthetics.

   b) Significantly less new ROW would be required, 650 miles * vs. 2583 miles.

   c) Avoidance of 495 miles of wilderness in the Arctic National Wildlife Refuge and its counterpart in Canada and related waterfowl breeding areas.

   d) Avoids the crossing of caribou calving grounds.

   e) Avoids Badlands areas.

   f) Avoids new crossings of prairie pothole and wetlands areas.

   g) Avoids Killdeer Mountain crossing (a unique area).

* If the Dome Pipeline Corporation pipeline is constructed, this figure would be significantly reduced.

h) Avoids Missouri River crossings.

i) Avoids Wild and Scenic River Crossings - Moyie, Sacramento, John Day, Wapsipinicon, Little Missouri.

j) Crosses the Mississippi River at a more environmentally acceptable location.

Although different magnitudes of socioeconomic impacts in Alaska were projected for the Arctic Gas prime route and the Fairbanks Corridor alternative, the analysis of these impacts did not result in conclusions indicating that one route was preferable to the other on the basis of these different impacts.

If Mackenzie Delta Gas is made available for transportation, either a 756-mile lateral pipeline would need to be constructed which would follow the existing Demster Highway corridor to the Fairbanks alternative pipeline at Whitehorse, Yukon Territory or the Maple Leaf pipeline, as proposed by Foothills Pipe Lines, Ltd., would be constructed along the Mackenzie River Valley to connect to the Alberta Gas Trunk Line Company natural gas pipeline in northwestern Alberta.

2) Preferred Alternative to the El Paso Alaska System - Cape Starichkof LNG terminal site and related pipeline from Prudhoe Bay and LNG tanker transport to Oxnard, California, as described in Section 2b(ii) of the preceeding section. This alternative would possess the following environmental benefits over the proposed system.

a) LNG terminal siting in an area of Alaska which is more suited to industrial use.

b) Would eliminate destruction of the wilderness qualities of the Gravina Point/Prince William Sound area.

c) Avoidance of critical and intensive wildlife habitat along the pipeline route in the Chugach National Forest and bald eagle nesting sites at Gravina.

d) Avoids crossing a proposed wild and scenic river - Gulkana.

e) The Cape Starichkof site would be less likely to experience an earthquake of the size of the 1964 event (8.5 Richter) than the proposed Gravina site.

f) Existing highway and railroad facilities with links to Anchorage would be available for supply during construction.

g) Both LNG terminals would be in areas better able to absorb the large influx of construction and operation personnel.

h) The volumes of gas associated with the Cook Inlet gas production can be incorporated into the El Paso LNG terminal, thereby eliminating the need for separate terminals in Prince William Sound and Cook Inlet with the associated environmental impacts.

i) Avoids new right-of-way clearing in Los Padres National Forest in California.

j) Avoids LNG terminal siting at Point Conception in favor of an industrial site at Oxnard which is located further from active faults than is Point Conception.

k) Reduces the number of miles of pipeline necessary in California.

l) Eliminates potential impacts from cold water discharge in favor of using a heated discharge from an existing electric powerplant for revaporization.

Very little difference in the magnitude of socioeconomic impacts in Alaska was projected for the El Paso Alaska prime route and the alternative route ending at Cape Starichkof. Although the distribution of impacts on specific localities will be different, the analyses of these impacts did not result in conclusions indicating that one route was preferable to the other.

The staff concludes that the alternatives described in 1) and 2) above are each environmentally superior to the proposals of the respective applicant and that the Fairbanks Alternative without the Richards Island lateral is the most environmentally acceptable system to transport Prudhoe Bay gas to the lower 48 states.

4. ECONOMIC CONCLUSIONS

The net national benefits of the applicants proposed transportation systems, together with the FPC staff's preferred Fairbanks alternative, have also been analyzed. Net national benefits are defined as the dollar value of the benefits that flow from consumption of Alaskan gas less the costs, apart from environmental costs, to the nation of producing and delivering the gas. Naturally, the net national benefits depend, for a given system, upon the price of alternative fuels, the quantity of non-Alaskan gas supplies and the quantity of Alaskan supplies. For those systems that transport Mackenzie Delta gas, as well as Prudhoe Bay gas, the benefits also depend upon the quantity of Mackenzie Delta supplies through their effect upon the United States share of the transport costs. Because the gas flows over about 20 years, and the costs are incurred over a similar period, the net national benefits also depend upon the discount rate applied to net national benefits in future years. The results are summarized below for plausible values of these quantities. The systems considered are those proposed by the applicants, using their costs, and the variants costed by the Department of the Interior (references 12, 13 and 14) plus the FPC staff's preferred alternative.

In addition, the returns to the applicants on their proposed systems have been analyzed for similar scenarios. The principal methodological difference arises from the fact that United States taxes are costs to the applicants. However, from a national standpoint they are transfers of funds and not resource costs. These results indicate the rates of return to the applicants and the revenues remaining to cover wellhead prices under the various scenarios. In a rough way they also confirm the comparative system rankings found in the net national benefit comparison.

Net National Benefits

In Table I-A-1 are summarized the net national benefits for a relatively large Alaskan supply and two prices for oil as the alternative fuel. The alternatives are the Department of Interior variants using Department of Interior costs. High and low non-Alaskan supplies represent, respectively, optimistic and pessimistic levels of the quantity of future non-Alaskan supplies. The lower 48 transportation costs are assumed to be 2¢/MCF/100 miles beyond the system's terminal point in the United States. Table I-A-2 contains results for the same assumption except that the Alaskan supply is smaller.

Table I-A-1

Net National Benefits
(Billions of Dollars)

Alaskan Supply - 23.6 TCF

10% Discount Rate - 2¢/MCF/100 miles lower 48 Costs

Non-Alaskan Supply	$12 per barrel oil High	$12 per barrel oil Low	$8 per barrel oil High	$8 per barrel oil Low
Improved El Paso [a]	5.73	7.57	1.70	3.48
Alaskan Arctic [b]				
Mackenzie Delta - 5.9 TCF	5.68	8.65	1.73	4.74
0 TCF	4.91	7.88	.96	3.97
Fairbanks Alternative [c]	5.55	8.55	1.60	4.64

a) Termed "Improved Alaskan-LNG" in the analysis.
b) Termed "Alaska-Canada" in the analysis.
c) Termed "Fairbanks-Alcan" in the analysis.

Table I-A-2

Net National Benefits
(Billions of Dollars)

Alaskan Supply - 17.8 TCF

10% Discount Rate - 2¢/MCF/100 miles lower 48 Costs

Non-Alaskan Supply	$12 per barrel oil High	$12 per barrel oil Low	$8 per barrel oil High	$8 per barrel oil Low
Improved El Paso	4.20	5.69	1.10	2.55
Alaskan Arctic				
Mackenzie Delta - 7.1 TCF	4.69	7.16	1.49	3.95
0 TCF	3.67	6.14	.47	2.93
Fairbanks Alternative	3.99	6.49	.75	3.23

Noteworthy among the results are the following:

1) When non-Alaskan supplies are low, and Mackenzie Delta supplies about as expected, the Alaskan Arctic and Fairbanks alternatives yield higher benefits than El Paso. Fairbanks is superior to Alaskan Arctic when no Mackenzie Delta supplies are available.

2) When non-Alaskan supplies are high and the lower of the Alaskan supplies are available the net benefits ranking is Alaskan Arctic, El Paso and Fairbanks.

3) In all other cases the three alternatives yield about the same benefits.

4) The Fairbanks alternative is superior when no Mackenzie Delta gas is available and non-Alaskan supplies are low.

5) In no case does the Fairbanks alternative have benefits that fall below the highest by more than $.7 billion. This means that its superior environmental features are available at a maximum cost, over 20 years, of $35 million per year.

The rankings are not changed by changes in the discount rate. However, for high non-Alaskan supplies and $8 oil the net benefits for all alternatives are negative at a 15% discount rate.

Table I-A-3 contains the net national benefits calculated for the applicants proposals. Although the flows are not entirely comparable, the comparative rankings observed above are preserved for the El Paso 2.4 BCFD proposal and the Alaskan Arctic.

Table I-A-3

Net National Benefits
(Billions of Dollars)

10% Discount Rate - 2¢/MCF/100 miles lower 48 Costs

$12 per Barrel Oil

Non-Alaskan Supply	High	Low
Alaskan Arctic		
2.25 BDFD Prudhoe and 2.25 Delta	3.87	6.75
El Paso		
2.4 BCFD Prudhoe	3.98	5.92
3.3 BCFD Prudhoe	6.21	8.44

Returns to the Applicants

The results of the analysis of the rates of return to the applicants are comparable to those found in the analysis of net national benefits. In every case simulated, Alaskan Arctic earns a higher rate of return than El Paso. With $12 oil and low non-Alaskan supplies Alaskan Arctic can earn a 15 percent rate of return on equity and still cover the estimated wellhead cost of the gas. Under the same circumstances El Paso can only earn a 10 percent rate of return. Even with a reduced flow of gas from the Mackenzie Delta (and hence higher costs for Alaskan Arctic), earnings for Alaskan Arctic are superior to those of El Paso.

The feasible rates of return are highly sensitive to the supplies of substitute fuels. An increase in the supply of non-Alaskan gas from low to high reduces Alaskan Arctic's rate of return to 10 percent and El Paso's to less than 5 percent. Neither applicant is able to sustain a positive rate of return if, in addition to relatively high supplies of non-Alaskan gas, the price of oil drops from $12 to $8. El Paso's position is sufficiently vulnerable that even with low supplies of non-Alaskan gas, a drop in the price of oil to $8 prevents a positive rate of return.

Construction cost contingencies in the Arctic Circle have a similar but moderate impact on both project designs, and do not seriously reduce the discounted cash flows. El Paso is more vulnerable to changes in the cost of transporting gas within the continental United States, but the impact of such changes on the rates of return is insignificant. Within the range considered, a diminished flow in the Delta does not severely reduce Alaskan Arctic's profitability. If alternative fuels are scarce, Alaskan Arctic can maintain a 10 percent rate of return despite a reduced flow in the Delta and 100 percent inflation in construction costs in the Arctic Circle.

SECTION B - COMPARATIVE ASSESSMENT

A. INTRODUCTION

1. Background of Discovery of Oil and Gas

A major oil find on the North Slope of Alaska was proven in 1968. According to the DeGolyer and McNaughton consulting firm, this 200-square mile area known as the Prudhoe Bay Field contains proven reserves of 22.5 trillion cubic feet of natural gas both in solution with the oil, and as free gas.

In 1970, following confirmation of the oil-gas discovery, the Alyeska Pipeline Service Company (Alyeska) was formed to construct and operate an oil pipeline system. This company applied to the Federal government for the necessary permits and rights-of-way to construct an oil pipeline extending from the Prudhoe Bay Field to Valdez, a deep water port located in southern Alaska on Prince William Sound. The applications for permits and rights-of-way for construction of the oil pipeline were in litigation until November 1973, when Congress passed an amendment to the Mineral Leasing Act of 1920 which included the authorization of the Trans-Alaska Pipeline System (TAPS). Congress authorized and directed the Federal agencies involved to issue the necessary permits and rights-of-way to Alyeska so that construction of TAPS could begin. Actual pipeline construction began in the winter of 1974-75 and, if construction is completed as scheduled, transport of the oil would begin in 1977.

The natural gas which exists in association with the oil in the Prudhoe Bay Field and which will be produced from these oil wells can either be reinjected into the field, marketed or wasted by flaring (burning gas in the open atmosphere). Since Alaska State law prohibits flaring, this Prudhoe Bay gas will be reinjected into the field when these oil wells are put into production until such time as a gas reservoir analysis can be made and a transportation system approved and constructed to deliver the gas to consumers.

Two major projects have been proposed to move this Prudhoe Bay gas to consumers (Figure 1). One project, referred to as the Arctic Gas System, proposes to transport the gas through approximately 4,512 miles of buried overland pipeline from northern Alaska through northern and western Canada, to two ultimate delivery locations in the 48 conterminous United States. The second project, referred to as the El Paso Alaska System, proposes to move this gas south from the Prudhoe Bay Field through buried overland pipeline across the State of Alaska to a port on the southern Alaskan coast. There the gas would be converted to liquid natural gas (LNG) and shipped via cryogenic tanker across the northeastern Pacific Ocean to a delivery point on the coast of California. The gas would then be regasified and distributed by buried overland pipeline for eventual consumer use.

2. An Overview of this Comparative Assessment

It is the intent of this comparative assessment to summarize these two proposed projects (Arctic Gas and El Paso Alaska) presently before the Federal Power Commission and to highlight the major environmental impacts which could occur as a result of the construction and operation of either of these two systems. This comparative assessment also addresses various possible alternate pipeline routings and facility sizings for each of these two projects.

B. ARCTIC GAS SYSTEM

1. Proposed Action

a) Location of Facilities and Companies Involved

The basic concept of the Arctic Gas System is the construction of a buried overland natural gas pipeline extending from northeastern Alaska and northwestern Canada to market areas across both Canada and the United States. The proposed pipeline would extend for approximately 4,512 miles from Prudhoe Bay to termination points in the conterminous United States located near Chicago and San Francisco. The following five companies, four American and one Canadian, have made application to appropriate agencies to obtain permits to construct and operate this system: Alaskan Arctic Gas Pipeline Company (Alaskan Arctic), Canadian Arctic Pipeline Company Limited (Canadian Arctic), Northern Border Pipeline Corporation (Northern Border), Pacific Gas Transmission Company (PGT), and Pacific Gas and Electric Company (PG&E).

Alaskan Arctic would own and operate a 48-inch chilled gas 1/ pipeline extending from Prudhoe Bay on the Beaufort Sea coast of northern Alaska to the Alaska-Canada border, approximately 195 miles to the east.

From the Alaska-Canada border, a pipeline constructed by Canadian Arctic would continue east along the Beaufort Sea coast and across the Mackenzie Delta area located in the northwestern part of the Northwest Territories. From there, the route would run south to Travaillant Lake Junction, Northwest Territories. From Travaillant Lake Junction, the pipeline would run in a generally southern direction to a point near Caroline Junction, Alberta. At Caroline Junction the line would divide, with the western leg running south to Kingsgate, British Columbia, near the northern Idaho border, and the eastern leg running to Monchy, Saskatchewan on the Montana border. This section of the Arctic Gas System would total 2,305 miles in length.

To carry arctic gas to the U.S. Midwest and East and regions south of there, six U.S. pipeline companies have created the Northern Border Pipeline Corporation. This corporation originally proposed to construct and operate a 1,619-mile long, 42-inch to 24-inch diameter pipeline extending from the Canadian border southeast through Montana, the Dakotas, across Minnesota, Iowa, Illinois, Indiana, Ohio, and West Virginia to a terminus in Delmont, Pennsylvania. However, on March 11, 1976, in FPC hearings before the Administrative Law Judge in the matter of El Paso Alaska Company *et al*., (Docket No. CP75-96, *et al*.), Northern Border council stated that they would be submitting a withdrawal of their original request for certificate authority for that portion of its system lying east of a point near Kankakee, Illinois. Along with this withdrawal they indicated they would be submitting a study on a feasible method of gas delivery through displacement for areas originally to be served by that section of the pipeline being eliminated. Numerous connection points would remain to be installed along the 1,138-mile pipeline from the U.S.-Canadian border to near Kankakee in order to facilitate delivery of gas to companies serving areas east of the Rocky Mountains.

1/ The pipeline in Alaska would be operated as a chilled gas pipeline in order to reduce damage to permafrost. By installing refrigeration chillers at the discharge side of the compressor stations, the temperature of the gas would be maintained between 32°F and -10°F.

There were originally two applications before the Commission to move Prudhoe Bay gas to areas of the United States west of the Rocky Mountains. One system originally proposed to be built by PGT and PG&E would extend for 917 miles from near Eastport, Idaho, on the U.S.-Canadian border, through Idaho, Washington, Oregon and California to a terminus at Antioch, California, near San Francisco. This pipeline would extend along an existing pipeline system route owned and operated by PGT and PG&E.

The second West Coast pipeline, originally proposed by Interstate Transmission Associates Arctic (ITAA), would also enter the United States near Eastport, Idaho, on the U.S.-Canadian border and would extend through Idaho, Washington, Oregon, Nevada, and California to a terminus at Cajon, near Los Angeles. However, the FPC has recently been notified that ITAA has withdrawn its application to transport Prudhoe Bay gas in the lower 48 states. The gas originally to be transported by ITAA would now be transported by the pipeline system proposed to be constructed and operated by PGT and PG&E.

In accordance with the withdrawal of the ITAA proposal and a revision in the quantities of gas expected to be made available from the Prudhoe Bay Field, PGT/PG&E intends to revise their originally proposed pipeline design. Although a definite design proposal has not been submitted to the FPC by PGT/PG&E at this time, they have indicated that their new system would probably consist of the complete looping (with 36-inch diameter pipe) of their existing 917-mile pipeline. Such a system would use existing right-of-way and would not require the construction of any new compressor stations. In order to make designated volumes of gas available to markets in the Los Angeles area using this design, PG&E would then need to construct additional facilities in southern California to connect to existing pipeline facilities.

b) Total Reserves and Volumes to be Transported

According to DeGolyer and McNaughton, the Prudhoe Bay Field contains a proven gas reserve of 22.5 trillion cubic feet while the Richards Island and Parsons Lake areas of the Mackenzie Delta region contain proven reserves of approximately 3.6 trillion cubic feet. According to the Department of the Interior, the State of Alaska also estimates a speculative resource of 41.8 trillion cubic feet of gas on the North Slope and an additional 46.5 trillion cubic feet in offshore deposits in the adjacent Beaufort and Chukchi Sea provinces.

Planned gas delivery from the Alaska natural gas pipeline is 2 billion cubic feet per day (cfd) after 1 year of operation and 2.25 billion cfd after 5 years of operation. When ultimately completed, the pipeline would have a capacity of 4.5 billion cfd. Approximately one-half of the total volume of gas of the Canadian pipeline is expected to be transported to Canadian markets. Therefore, approximately 2.25 billion cubic feet of gas per day would be available to the lower 48 states when the system was running at full capacity.

As presently proposed, the delivery capacity of the Northern Border leg to the Midwest and East sections of the United States would be 1.5 billion cfd. The capacity of the PGT/PG&E pipeline, if completely looped with the existing pipeline, and if no compressor station horsepower additions were made, would be 659 million cfd. Therefore, the probable combined delivery capacity of the pipelines in the 48 conterminous states would be 2.159 billion cfd. If additional gas volumes are made available, it is possible that these system capacities could be increased by additional compression and/or pipeline looping.

c) Related Facilities and Land Requirements

Pipeline laterals and other gas collection facilities, including compressors and chillers, in the Prudhoe Bay area would be constructed by the oil companies. No compressor facilities would be constructed on the 195-mile long, 48-inch diameter gas transmission pipeline in Alaska by Alaskan Arctic until available gas volumes increased beyond 2.25 billion cfd. At that time, Alaskan Arctic would install four compressors and gas chillers on the pipeline. Other ancillary facilities required for the pipeline in Alaska include 7 material stockpile sites (4 of which would be located at possible future compressor station sites), 2 seaport areas in addition to the Prudhoe Bay port facilities, 16 aircraft facilities, approximately 250 miles of temporary snow-ice roads, field operating headquarters at Prudhoe Bay, and operations headquarters in Anchorage. The Alaskan Arctic system would require the use of approximately 4,630 acres of land with 3,720 acres being permanently required for the life of the project. In addition, the applicant proposes to excavate 2.4 million cubic yards of mineral aggregate (sand, gravel, and/or crushed rock) for construction of maintenance site pads, airfields, and permanent roads for pipeline facilities. The applicant speculates that 700,000 cubic yards of select sand, gravel, or crushed rock materials would be required for backfilling the pipeline ditch.

Along their 1,619-mile pipeline, Northern Border originally proposed to construct 12 compressor stations, 11 offline delivery taps, and 87 communication sites. Northern Border originally indicated that land requirements for its system would total 21,250 acres with 11,740 acres being permanently retained for use for the life of the project. With their present commitment to withdraw their application for construction and operation of 481 miles of pipeline east of Kankakee, Illinois, these facility requirements would probably be modified. The exact facilities needed on a 1,138-mile long pipeline are not known at this time.

If PGT/PG&E decide to loop their entire 917-mile long pipeline system, they would need to construct 873.5 miles of 36-inch diameter pipeline loop. The remaining sections of loop were installed as secondary river crossings for pipeline system security purposes in 1970. This pipeline design would utilize existing pipeline rights-of-way and would use existing compressor facilities. PGT/PG&E would require the acquisition of an additional 1,743 acres of land for its presently proposed system with 1,201 acres being permanently retained for use for the life of the project. To accommodate the increased flow rate, additional metering facilities would be installed at the Malin, Oregon metering station located on the Oregon-California border.

There are no existing rights-of-way along the northern Alaska coast from the North Slope area to the Alaska-Canada border which could be utilized by Alaskan Arctic for its proposed project routing. Northern Border, however, indicates that their line would adjoin or abut 23.6 miles of existing rights-of-way. The PGT/PG&E proposed pipeline would be looped with their existing 917-mile long pipeline and would, therefore, use existing rights-of-way. However, one 21.4-mile long pipeline section in the John Day River area of Oregon would be installed on new right-of-way in order to avoid a hazardous flash flooding area.

It should be noted that the proposed PGT/PG&E pipeline would cross sections of three licensed PG&E hydroelectric power project lands in the State of California which are under the jurisdiction of the FPC. It is required by the FPC that PGT/PG&E receive approval from the Commission to cross these hydroelectric project lands with nonproject facilities. To the minimal extent that these power projects would be crossed by pipeline facilities, it appears that the environmental effects of such an action would be minor and insignificant.

d) Construction Schedule

Most companies propose to start construction approximately 1 year after approvals are received. Construction would be conducted concurrently on all pipelines with the timing of approval and construction of the Canadian segment a critical factor in any overall projection of delivery.

The construction of the gas pipeline in Alaska, including related facilities, would be phased over a 3-year period. Most construction work is planned to occur during the winter months, from November to April, and snow roads would be used to provide access throughout the pipeline construction area. The actual installation of the pipeline would be accomplished in the third winter construction season.

In Canada, the construction of the pipeline and related facilities and supply lines would not be completed until the seventh year of construction. Actual pipeline construction would begin late in the second construction year and be completed in the fifth construction year. Flow of the Prudhoe Bay gas at 2 billion cfd would start at that time. Compressor station construction would be accomplished between the third and seventh years of construction, thus increasing the final capacity of the line.

The Northern Border portion of the line would be completed in approximately 26 months. No winter construction is contemplated, and most work is proposed to be accomplished between May and November. It is anticipated that construction would be curtailed during March and April because of vehicle weight restrictions imposed on roads in this area during the spring season.

The general plan for PGT/PG&E would be to start construction after approvals are received and at a time scheduled from 18 to 24 months prior to initial flow of gas.

The Office of the Governor of the State of Oregon has advised that the construction of any pipeline of 16 inches or greater diameter or length greater than 5 miles used for transportation of natural gas or SNG through Oregon requires a site certificate from the Energy Facility Siting Council of Oregon. The council, acting as a one-step siting authority, requires 12 months to review the certificate application prior to submitting its conclusions and/or approvals. Therefore, final approval of the entire Arctic Gas System could be delayed an additional year while the State of Oregon acts on its certificate application.

e) Future Plans

Since the ultimate reserves of natural gas in this region of the Arctic have yet to be determined, the future plans of the companies constructing the pipeline are rather vague. Alaskan Arctic has no firm plan for termination and indicates a physical life of more than 50 years for the pipeline. If operations were to be terminated, removal of the pipe would be dependent on the economics of salvaging the steel at the time and the environmental consequences incurred in such an action. Other related aboveground facilities would be sold or salvaged or left in place.

Northern Border has stated that the project would have a life expectancy in excess of 30 years, based on the proven reserves in the Arctic. The pipeline would have a probable minimum life of 50 years with a 100-year life within the realm of possibility. It is also possible that the Northern Border pipeline could be used to transmit synthetic natural gas from gasification plants in Montana and North and South Dakota at some future time. In the event of abandonment or termination, all surface facilities would be removed and the sites restored. Northern Border stated that the pipe itself would also be removed and could either be reused or sold as scrap, depending on the condition of the steel.

PGT and PG&E did not provide information on the life expectancy of their proposed pipeline and facilities. They did indicate that if abandonment were necessary, the pipe would be removed and salvaged. Aboveground items would be salvaged and the sites restored.

2. Environmental Impacts of Proposed Action

The proposed Arctic Gas System pipeline would involve some 4,512 miles of steel pipe originating on the Arctic coast of Alaska and extending to southern California and central Illinois. It would cross the arctic tundra, subarctic boreal forests and muskegs, temperate coniferous forests, hardwood forests, and grasslands. It would cross mountains, rivers, lakes, reservoirs, highways, and railroads. A description of the existing environment along this 4,512 miles of proposed pipeline route is covered in detail in the appropriate volumes of the Alaska Natural Gas Transportation System Final Environmental Impact Statement prepared by the Department of the Interior and incorporated as a part of this FEIS. The impacts of building and operating a pipeline system in such a varied environment are diverse and are discussed at length in the volumes of the above-referenced document.

The following are impacts which have been identified as those which could possibly occur as a result of pipeline construction, operation, and maintenance. Some of these impacts would be minor and temporary while others could be significant and long-term.

a) Climate

I. Construction, operation, and maintenance of the pipeline system would have no significant effect on regional climate, but some microclimatic changes could result from operation of the completed system.

II. In the event that compressor stations are installed along the pipeline in the arctic regions, the resultant emissions could produce ice fog conditions causing visibility problems in the immediate vicinity of the stations.

b) Topography

I. Construction of the proposed pipeline system would change the character of the terrain in certain local instances. Alterations in topography would result from cut and fill operations, the pipeline ditch berm with its possible subsequent subsidence, elevated gravel areas, borrow pits, and spoil piles.

II. Under certain conditions, wind erosion of disturbed soils and gully erosion following construction could change the pipeline right-of-way topography and also cause secondary impacts by transporting the soil to other locations.

c) Geology

I. The installation of the pipeline and its associated airfields, roads, and communications network would stimulate prospecting and development of additional oil and gas reserves and mineral deposits in the arctic and might be a stimulus to the development of coal deposits for possible gasification in Montana and North Dakota.

II. On approximately 200 miles of United States land where the pipeline would be routed through the arctic region, the proposed pipeline would be buried in permafrost. Above this permanently frozen ground is a zone near the surface called the active layer which thaws each summer. Construction activities would cause increased thawing of this layer, which could lead to slope instability, erosion, sedimentation, and subsequent failure of man-made structures. Disturbance of this active layer due to construction could result in secondary impacts on vegetation, soils, and water quality. The disturbances in permafrost areas would most likely have long-term effects on the permafrost regime.

III. Large amounts of gravel and sand would be needed for installation of the pipeline through Alaska. Heavy demands would be placed upon these scarce commodities, which in many areas are obtained from riverbeds. Consequently, as gravel requirements increase, stream hydrology and water quality could also be adversely affected.

IV. Landslides might be induced at several places along the system if (1) the slope is greater than 30 percent (5 percent in permafrost regions), (2) the slope is underlain by clay and silt, claystone, shale or siltstone, and especially if these rocks and sediments contain swelling (bentonitic) clay, (3) slopes were undercut while the pipeline ditch was being excavated. The slides could cause immediate damage and/or loss of life, or they could occur at a later time and possibly rupture the pipeline.

V. Areas of intense flash flooding and high seismicity on the Antioch pipeline route could cause damage to pipeline installed in these areas.

d) Soils

I. Disturbance and mixing of the soil profile would alter its structural characteristics, microbiological activity, and the soil-climate relationships. This mixing of subsoil on the surface of the backfilled ditch would retard the full restoration of the site and cause a long-term loss of soil productivity affecting crop growth and grazing capacity.

II. Wind erosion of exposed soils along the ditch could be a major impact where detached fine silt and clay particles were exposed (especially as observed in areas between Spokane, Washington, and the Oregon border). Wind erosion could remove the disturbed soils to the pipeline depth, causing the pipeline to become exposed.

III. Wind erosion potential is also high along the 650 miles of the Northern Border route across the spring wheat region of Montana and North Dakota. Soil losses could be considerable and could cause severe seedling damage making revegetation of the right-of-way very difficult.

IV. Disruption of waterflow in water supply and irrigation ditches would occur in Idaho, Montana, and North Dakota, where the pipeline would cross such ditches. This disruption, though of major importance, would be temporary. Along the Northern Border route from North Dakota to Illinois, subsurface drainage tile systems would be locally disrupted.

e) Water Resources

I. The impacts of the project on water resources are, for the most part, expected to be minor to negligible. However, construction and maintenance of the proposed natural gas pipeline system would present potential water resource impacts at each stream crossing resulting from interruption of streamflow, erosion and sedimentation, and introduction of industrial chemicals and pollutants.

II. Hydrostatic testing of the completed pipeline would require huge volumes of water, and the indiscriminate use of surface waters for test fluids could cause temporary drawdown and possible interruption of flow in small streams.

III. Methanol, to be used in hydrostatic testing of the pipeline system in the far north, would also affect water quality. Aquatic biota appear relatively tolerant to 1 percent solutions of methanol in water. The effect of stronger concentrations, such as the 26 percent solution to be used to test the pipe, is unknown, but is presumed to be harmful.

IV. Release of large volumes of test water into dry stream channels on the western routes could cause streambed scour, erosion, increased sediment yields, and modification of stream channel configurations.

V. Indiscriminate withdrawal of water from springs and lakes in the arctic where water supply is a significant problem (most surface water would be frozen during the construction season) could have adverse effects on overwintering fish and aquatic invertebrates.

VI. Erosion resulting from construction site activity at stream crossings would cause a temporary reduction in downstream water quality.

VII. Fuel and lubricant spills from construction machinery, compressor stations, construction camps, and methanol (used for hydrostatic testing in Alaska) would pollute surface water and possibly groundwater supplies. Generally, the impacts of small petroleum spills are expected to be minor. Catastrophic spills on a body of water, however, may severely affect aquatic life.

VIII. If repair of the proposed pipeline in Alaska is required during the summertime using conventional heavy equipment, there would be immediate, significant impact on water quality and drainage. Movement of equipment and supplies across a thawed tundra surface would cause compaction and concentration of water almost instantaneously.

f) Vegetation

I. Vegetation and terrain surface integrity would be destroyed along the pipeline right-of-way and at construction camps. At landing sites, towers, permanent roads, and other permanent facilities, the impact would be long-term.

II. Vegetation would be destroyed and/or altered by one or more of the following: construction of winter roads; the alteration of associated drainage patterns; forest, grass and tundra fires; fuel and methanol spillage; and off-road vehicle use for pipeline emergency repairs.

III. A number of proposed ecological preserve sites such as the Arctic National Wildlife Range and the Ordway Memorial Prairie native grasslands in South Dakota, would be paralleled or crossed, thereby reducing, if not destroying, the purpose for which they are intended.

IV. The incidence of fire would probably increase in the forested, tundra, and grassland sections, especially during summer construction activities.

V. Where the pipeline would cross forests or woodlands, there would be a permanent change in vegetation, because in no case would forest or woodland vegetation be allowed to grow directly over the pipeline.

VI. Cropland production loss on the right-of-way would be considerable while construction was underway, but would be back to near normal levels within a few years.

g) Wildlife

I. Impacts on animal species and their habitats would range from insignificant to potentially very serious. The greatest relative changes would occur in arctic and subarctic areas which are presently the least altered. These areas and others would be affected by the clearing of vegetation for rights-of-way, pipeline ditching and project-related facilities, by pollutant spills, by continued suppression of tree and brush growth over the pipeline during the operation phase, and by the presence of humans in the area.

II. Caribou, particularly those in the internationally ranging Porcupine Caribou herd, face the greatest potential for serious impact. The section of the pipeline which would cross the Arctic National Wildlife Range in Alaska would bisect the caribou calving ground area. Adverse impacts and reduction in numbers would be expected to occur if pipeline construction or maintenance activity were carried out at a time coinciding with the presence of caribou.

III. If project disturbance would force an animal from a critical portion of its range or change its habitat, population numbers could be reduced. Disturbance factors would include noise from construction, maintenance, and operation machinery; aircraft used in pipeline inspection; and increased numbers of people in the area.

IV. Project-caused disturbance would drive birds from their nesting and resting areas and, in the case of waterfowl (such as snow geese on the Arctic Coastal Plain), could affect their molting and fall staging periods resulting in a possible drop in population numbers.

V. In the prairie pothole region, particularly in the Dakotas and Minnesota, important breeding habitat could be lost through dewatering or silting in of potholes resulting from or in conjunction with pipeline construction. This impact would be locally significant. This area is also an integral part of the Central and Mississippi Flyways. Construction during spring and fall would effectively reduce available resting and/or feeding habitat for migratory waterfowl and shorebirds.

VI. Increased turbidity and sedimentation from upstream erosion due to pipeline stream crossing activities could also affect fish and associated aquatic organism populations.

VII. Pollutants such as construction camp sewage plant effluents, spills of petroleum products, methanol spills, and pesticides; blasting near fish spawning areas where eggs are present; and increased or decreased water temperatures resulting from vegetative changes or pipeline operation could also adversely affect wildlife populations.

VIII. Alaskan Arctic has planned for a winter construction schedule and the use of snow roads for access and work space in the area. Such winter construction on snow roads is critical to mitigate damage to wildlife and vegetation on the North Slope.

h) Socioeconomic

I. During the construction phase, tax benefits to state and local governments along the pipeline corridor would come primarily from motor fuel taxes and personal and corporate income taxes.

II. Property taxes on the pipeline, compressor stations, and resultant project improvements would be the primary tax benefits to the governments through whose jurisdiction the pipeline would pass. New housing and business expansions resulting from the needs of new permanent employees would add to the local property tax base.

III. Alaska would have an additional benefit from its royalty interest (12.5 percent) on the natural gas produced there.

IV. During construction, production would be destroyed in agricultural and forest lands along much of the right-of-way. Some of the land would be out of production for only a short time, but other lands would be out of production for the life of the project.

i) Land Use

I. Soil disturbance could have long-range impacts upon the productivity of some types of farmlands, but use for pipeline purposes would not preclude use for agriculture.

II. In areas where irrigation is used in conjunction with agriculture, there would be additional problems of interference with irrigation ditches and drainage tiles.

III. In areas where the pipeline would cross large areas of commercial forested lands, there would be long-term loss of timber production along the right-of-way. In addition, there would be about 20 to 25 miles of commercial orchard lands which would be impacted in California.

IV. Residential, commercial, and industrial land uses would be precluded from the pipeline right-of-way and from sites of related facilities.

V. The existence of a pipeline transportation system would stimulate an increase in the further exploration and possible development of potential oil and gas basins in northern Alaska, as well as the coal fields in Montana and other parts of the United States. The impacts from this consequence could be major and of national significance. Such development in the Arctic National Wildlife Range would irreversibly impair the remaining wildlife and wilderness values of this area.

VI. One of the most destructive aspects of the Arctic Gas prime route would be the loss of the wilderness value of the Arctic National Wildlife Range which has been proposed for inclusion in the National Wilderness Preservation System. Industrial development across the fragile Arctic North Slope is incompatible with its wilderness character.

j) Paleontological, Archaeological, and Historical

I. The nature of the proposed project construction is such that if certain precautions are not observed, any cultural resource sites in the path of the pipeline, access roads, compressor stations, or other facilities could be damaged or destroyed. In most cases, the damage would be a direct consequence of site disruption and excavation by man and machine without knowledge of the paleontological or archaeological values present, but in other cases the impact would come as a consequence of increased access and vandalism to unprotected historic sites.

II. Very little is known about the prehistoric occupation of the Arctic Coastal Plain by man, but the coast and several of the rivers appear to have been trade routes where archaeological sites might be found. If the pipeline is constructed as proposed during the dark arctic winter, discovery, protection, and recovery of sites would be hindered.

k) Recreation and Aesthetics

I. The Arctic Slope of Alaska and the Arctic National Wildlife Range are largely uninhabited at this time, and the proposed pipeline with its associated transportation facilities would add noise, machinery, and people which would have long-term detrimental effects on the aesthetic resources of these areas.

II. Related pipeline system buildings, radio towers, airfields, and other facilities would continue to alter the aesthetic quality of areas not previously marred by the presence of man's technology. True wilderness quality would be destroyed and quasiwilderness further degraded.

III. The cleared and disturbed pipeline right-of-way would be a discordant element in the tundra and forest vegetation for many years and would show up as a long, straight line with a color and texture different from the surrounding landscape.

IV. Visual impacts would be most apparent in forested areas and in open range or desert country, while the visual impacts in agricultural and industrial areas would be much less.

V. Pipeline construction access roads would provide public vehicular access in previously inaccessible areas.

l) Air Quality

I. The only continuous long-term impacts on air quality would result from emissions at proposed compressor stations and at block valves (when venting becomes necessary) along the gas pipeline system.

II. Dust from construction activities, especially in the arid soils of the western states, would also create short-term adverse impacts on air quality and visibility.

m) Noise

I. Ambient noise levels along much of the proposed pipeline route are now very low, and any pipe hauling, pipeline construction, or operating noises would be noticeable.

II. Compressor station operating noises would be long-term. Compressor noise emissions could be audible for a radius of 6,000 to 7,000 feet.

III. Periodic venting of high-pressure gas from the pipeline and compressor stations would cause temporary but severe increases in sound level. These maintenance checks or emergency blowdowns occurring about once a year could be audible for 15 miles.

n) Health and Safety and Pipeline System Repairs

I. There are potentially severe fire and health hazards associated with the gas processing operation which would occur at Prudhoe Bay.

II. Natural gas is flammable at a 5 to 15 percent concentration, potentially explosive when confined, and pipeline quality gas is odorless and can act as an asphyxiant.

III. The propane which would be used as a refrigerant is also flammable and, being denser than air, could pose an even greater threat of fire than natural gas.

IV. Damage by outside forces, a construction defect, or a material failure could all cause a failure in the pipeline system resulting in a loss of gas and requiring emergency repair.

V. Repair activities at some locations and in some seasons may cause damage to the environment more severe than that resulting from the initial construction. This is particularly true in the areas of continuous permafrost in Alaska. Emergency repairs in the arctic would involve the movement of heavy equipment across the tundra without regard to the condition of the soil and without benefit of snow-ice roads. In winter, repair procedures would result in the destruction of plants and the insulating organic mat protecting the soil, with subsequent thaw consolidation and erosion a probable result. Summer repairs would cause considerable damage to arctic vegetation and soils and could cause severe disturbance to migrating caribou and waterfowl. The impact of repair activities would be determined by such factors as the extent of impacts already suffered, the availability of existing roads, the extent and effect of preventative maintenance programs, and the extent and emergency nature of the repairs required.

3. Arctic Gas System Route and Pipeline Size Alternatives

a) Alaskan Arctic Route Alternatives and Pipeline Size Changes

Various alternative route corridors have been proposed by Alaskan Arctic for the routing of the pipeline through Alaska. These alternatives would affect both the pipeline location in Alaska and its subsequent entrance into northern Canada. Two additional possible alternate routes have been suggested by the Bureau of Land Management (BLM), which would also change the routing within Alaska. These route alternatives are shown in Figure 2.

One alternative, the Offshore Route, would involve an offshore corridor that would include the installation of a 151-mile long section of underwater pipeline roughly paralleling the Alaskan coastline north of the Arctic National Wildlife Range. Such a

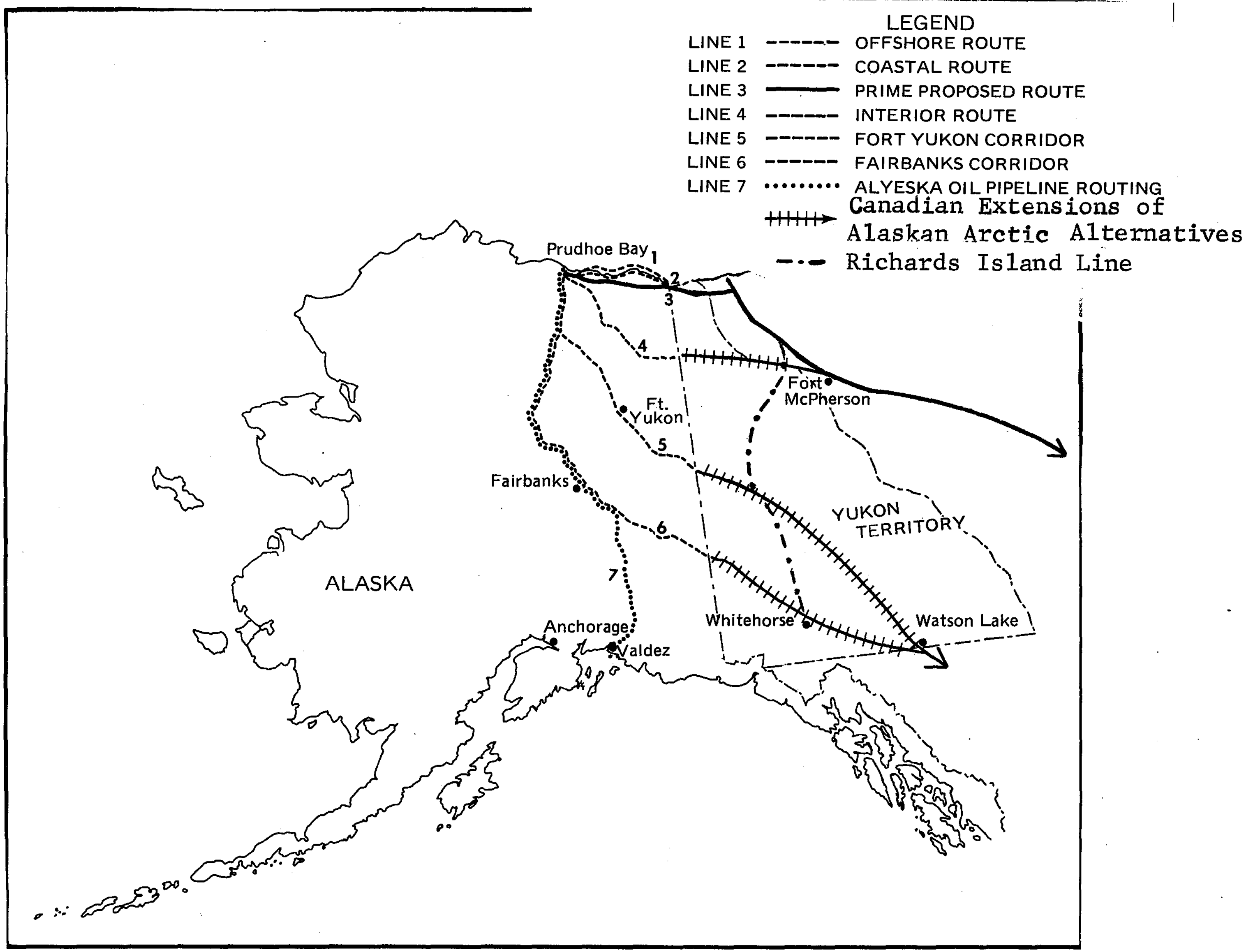


Figure 2 Major Alaskan Arctic Alternative Routes

route would avoid the Arctic National Wildlife Range, thereby resulting in a reduction in impacts on the Porcupine Caribou herd, as well as avoidance of the wilderness area. However, the technical feasibility of such a route is questionable at this time.

A second alternative, designated as the Interior Route, would roughly parallel the southwestern boundary of the Arctic National Wildlife Range. This route would tie into the prime proposed route just north of Fort McPherson, Northwest Territories. This alternative is preferred by the applicant, should its prime route be found unacceptable.

The Fort Yukon Corridor Route, a third alternative, would follow the Alyeska oil pipeline route south for about 100 miles, proceed southeast toward the Fort Yukon area, and then rejoin the proposed prime route near Windfall, Alberta. This alternate route would involve construction of approximately 495 miles of pipeline in Alaska. This route through the Yukon Valley could affect three areas presently being considered by Congress as nationally significant conservation areas as nominated by the Secretary of the Interior in the Alaska Conservation Act of 1975. These three proposed areas are a Yukon Flats National Wildlife Refuge, a Porcupine National Forest, and the Yukon-Charley National Rivers which would be a unit of the National Park System. This Fort Yukon Corridor Route alternative would require the construction of a Richards Island Canadian gas supply line extending for 475 miles from Richards Island on the Beaufort Sea coast to near Dawson, Yukon Territory.

The fourth alternative, designated as the Fairbanks Corridor Route, would follow the Alyeska pipeline route south for 460 miles. From there it would pass northeast of Fairbanks and then follow the Alaska Highway into Canada, past Whitehorse, to Watson Lake, Yukon Territory, where it would join with the Fort Yukon Corridor and eventually rejoin the prime proposed route at Windfall, Alberta. This alternative would require the construction of a Richards Island Canadian gas supply line extending for 760 miles from Richards Island on the Beaufort Sea coast to Whitehorse, Yukon Territory, where it would join the Fairbanks Corridor.

Two alternatives suggested by BLM are the Coastal Route alternative and the Beaufort Sea Shoreline alternative. The Coastal Route would follow the Alaskan coastline through the Arctic National Wildlife Range to the Canadian border. The Shoreline alternative would follow the Alaskan coastline for 64 miles to the Canning River delta. From there to the U.S.-Canadian border (141 miles), the pipeline would be buried in shallow offshore waters (5 to 10 feet deep) roughly following the contour of the Beaufort Sea coast. This alternative differs from the applicant's Offshore alternative in that they suggest burial of the pipeline in 20 to 30-foot water depths.

In addition to route alternatives, Alaskan Arctic has also filed a supplement to its application suggesting substitution of a 42-inch pipeline for the originally proposed 48-inch system. The initial installation of two compressor stations on a 42-inch pipeline would allow a throughput volume of 2.256 billion cfd while the addition of two more stations would give an ultimate throughput estimated at 3.5 to 4.5 billion cfd. The applicant has stated that it "has not determined whether it would be desirable to construct its system with 42-inch pipe, rather than 48-inch, and submits that further information relative to gas availability would be useful in making a determination."

b) Canadian Route Alternatives

Four proposed alternative routes are common to both southern Canada and the Northern Border routes (Figure 3).

The first Canadian alternative, the Liard River-Wolf Lake-Emerson-Red River Corridor, would depart from the prime proposed route at the Liard River in the Northwest Territories and lie east of the proposed Canadian prime route. This corridor would cross the United States - Canadian border in western Minnesota at the Red River. At Wolf Lake, Alberta, the pipeline would bifurcate, with one leg going southwest to Kingsgate.

A second corridor, the Edmonton-Regina-Red River Corridor, would closely parallel an existing oil line. It would leave the proposed prime route near the Hay River in Alberta and would lie east of the prime proposed route. This corridor would lie west of the Liard River-Wolf Lake-Emerson-Red River route in Canada, but would rejoin it at the United States - Canadian border. It would bifurcate near Edmonton, Alberta,with one leg going southwest to Kingsgate.

The Moose Jaw-Red River Corridor would follow the Trans-Canada Gas Pipeline east from a point on the proposed Canadian prime route near the Alberta-Saskatchewan border. It would join the Edmonton-Regina Corridor just east of Regina and would continue on to the United States - Canadian border in western Minnesota at the Red River.

The Moose Jaw-Northern Corridor would follow the Moose Jaw Corridor for a distance and then would proceed southeast to join the Northern Corridor alternative of the Northern Border route.

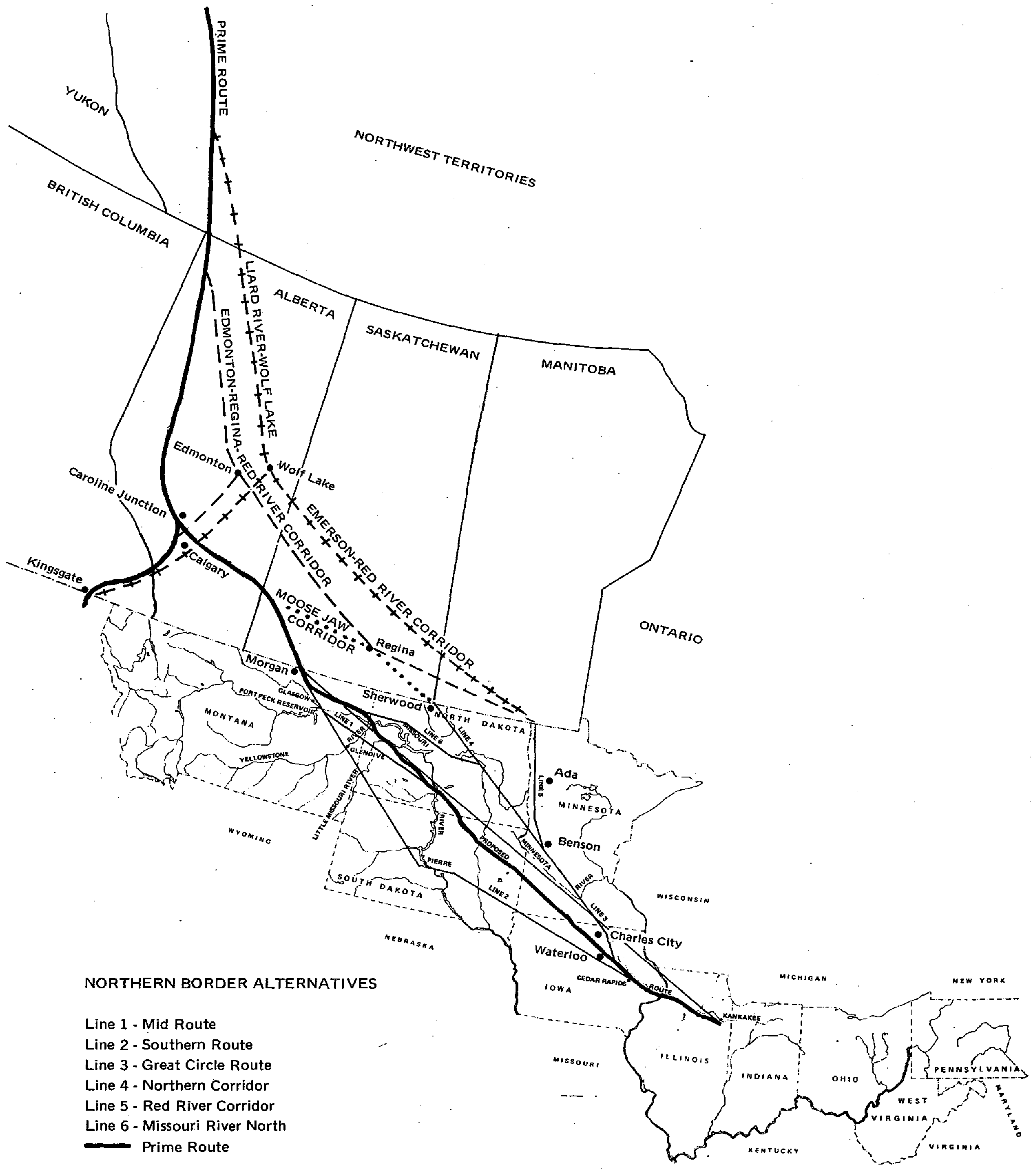


Figure 3 Proposed Prime Route and Northern Border Alternatives with Related Canadian Alternative Corridors

c) Northern Border Route Alternatives

Alternatives to the prime route proposed by Northern Border, all using Morgan, Montana, as point of entry, include the Mid-Route Alternative, the Southern Route, and the Great Circle alternative. Three additional alternate routes have been proposed by the Department of the Interior (DOI). (Figure 3)

The Mid-Route alternative would begin at the originally proposed starting point of Morgan, Montana, and would lie south of the prime proposed route for 340 miles in Montana and North Dakota where it would again rejoin the route originally proposed.

The Southern Route, would also begin at Morgan, Montana, but would extend further south into central South Dakota to near Pierre. From there the route would continue eastwardly where it would rejoin the prime proposed route just southeast of Cedar Rapids, Iowa.

The Great Circle alternative is a straight-line route from the Canadian - United States border near Morgan, Montana, to near Kankakee, Illinois. This route differs from the prime proposed route only in that it is a great circle line traversing the area between Monchy, Saskatchewan, and Kankakee, Illinois, while the proposed route represents a great circle route with adjustments to avoid critical environmental factors.

Three variations have been proposed by the Department of the Interior as possible alternatives to the prime proposed route of the applicant. The Northern Corridor alternative would extend southeast from the Canadian - United States border near Sherwood, North Dakota, to a point near Charles City, Iowa. This route variation would follow the proposed Dome Pipeline Corporation Corridor which is a proposed right-of-way for 10 to 12-inch diameter pipelines. From Charles City, this alternative route would proceed south to near Waterloo, Iowa, where it would rejoin the prime proposed route. This route would be approximately 233 miles shorter than the prime proposed route.

A second DOI alternative would be the Red River Corridor, which would be approximately 345 miles shorter than the prime proposed route. This alternative would begin at the United States - Canada border near St. Vincent, Minnesota, and would follow the Mid-Western Gas Transmission Company pipeline to the vicinity of Ada, Minnesota. From Ada, this route variation would extend southeast to Benson, Minnesota, where it would join the proposed Northern Corridor alternative which would then meet the proposed prime route near Waterloo, Iowa.

The Missouri River North alternative, also proposed by DOI, would be identical to the prime proposed route for the first 145 miles. This alternative would then leave the prime proposed route near Wolf Point, Montana, and proceed north of the Missouri River for about 285 miles until it would intersect the Northern Corridor alternative near Cathay, North Dakota.

If the prime proposed route of Northern Border is accepted, the FPC environmental staff suggests consideration of the route change suggested by the DOI (Figure 4). This deviation from the prime route would result in a crossing of the Illinois River in LaSalle County, Illinois, about 7 miles east of the present proposed crossing and 1 mile west of Ottawa. This realignment would avoid the Illinois River crossing, which would result in impacts on wildlife, archaeological and historical sites, recreational areas, and the aesthetic values of the region, which consists of a closed-canopy hardwood forest and a steep river bluff. The prime route deviation would also avoid crossing the Pecumsaugen Creek which runs through an unusual area recommended for state purchase by the Illinois Natural Preserves Commission. This rerouting would also avoid critical habitat of the endangered Indiana bat which hibernates in nearby Black Ball Mine. On the south side of the prime proposed Illinois River crossing, this segment would cross land recently acquired by the Illinois Department of Conservation which will be dedicated as a connective section between two sections of the Starved Rock Nature Preserve and State Park. In addition, to avoid this area, the proposed realignment would also avoid crossing a corner of Matthiesen State Park.

d) West Coast Route Alternatives and Pipeline Size Alternatives

Because the route proposed by PGT and PG&E would follow along existing rights-of-way for its entire length with the exception of a 21.4-mile relocation in the John Day River area of Oregon, no major route alternatives have been proposed by the applicant.

PGT/PG&E have submitted various alternate pipeline size designs for moving Prudhoe Bay gas to market.

To move minimum volumes of gas, PGT/PG&E have proposed an "1180 Design" which would require the construction of 485.4 miles of 36-inch diameter pipeline loop at 17 locations along their existing 917-mile long pipeline extending from the U.S.-Canadian border to Antioch, California. No compressor station horsepower additions would be required for this proposal. This system would transport 200 million cfd of gas.

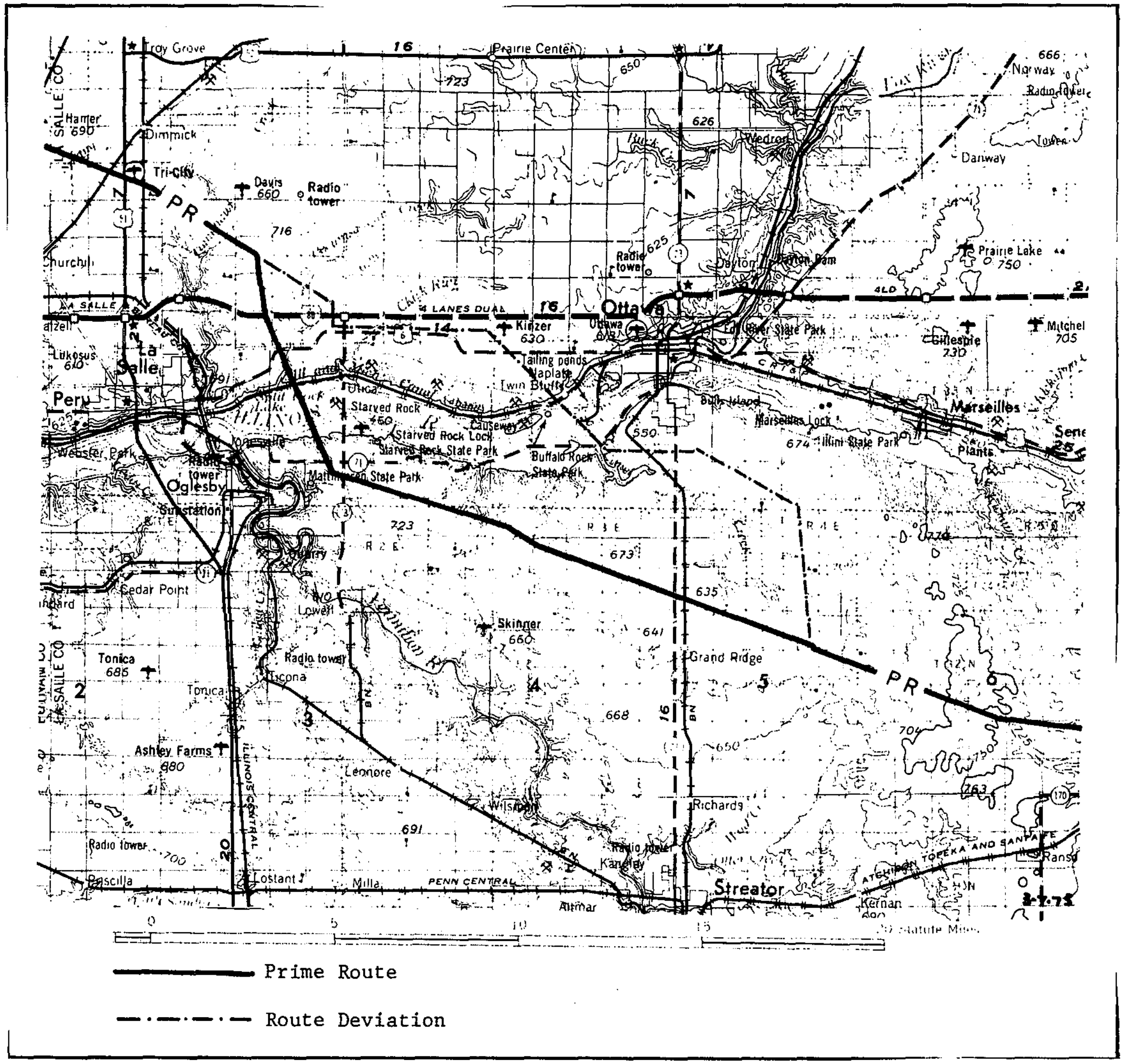


Figure 4. Illinois River Crossing Alternative as Proposed by DOI. (Taken from DOI-DEIS, Part V, Vol. 3, page 1338)

PGT/PG&E have also proposed two alternative pipeline designs which could be constructed to carry larger volumes of gas. Their "1830 Design" would require the construction of 917 miles of 36-inch diameter pipeline parallel to the existing system. This design would require the addition of four compressor stations and would have a capacity of 850 million cfd.

The second alternative proposed for transporting large volumes of gas would require 917 miles of 42-inch diameter pipeline installed parallel to the existing pipeline. This system would also require four compressor stations and would have a flow capacity of 1.2 billion cfd.

e) System Reduction Alternative

A possible alternative proposed by the staff of the Federal Power Commission suggests that initially the West Coast line not be constructed. This proposal suggests that all the Prudhoe Bay gas be delivered into the Northern Border system and volumes destined for the western United States be delivered by displacement to California through existing unused capacity of both El Paso and Transwestern Pipeline Company systems. With this approach, it could be recommended that the Permian Basin reserves, and to some extent the Hugoton-Anadarko supplies, be diverted for use on the west coast while equivalent volumes of Alaskan natural gas are delivered to the Midwest via Northern Border. It is also proposed that the Northern Border facilities be sized to accommodate the initial gas volumes of 2.2 billion cfd to be produced from Prudhoe Bay.

C. EL PASO ALASKA SYSTEM

1. Proposed Action

a) General Location and Companies Involved

The second major system being considered to move Prudhoe Bay gas, proposed by El Paso Alaska Company (El Paso), would transport natural gas from the Prudhoe Bay Field through approximately 809 miles of 42-inch chilled gas pipeline to a gas liquefaction plant and terminal located on Prince William Sound at Point Gravina, Alaska. There, the gas would be converted to liquid natural gas (LNG) and then shipped via cryogenic tankers, 1,900 miles south, to a receiving terminal and regasification facility on the southern California coastline near Point Conception in Santa Barbara County.

From there, the revaporized gas would be transported by a pair of proposed 142-mile, 42-inch parallel pipelines to existing mainline delivery facilities at Arvin Station, California, and then from Arvin Station via a proposed 105-mile, 42-inch pipeline to Cajon, California, for further distribution. The Point Conception terminal and related pipeline facilities would be constructed by the Western LNG Terminal Company (Western).

The proposed pipeline through Alaska would essentially follow the pipeline corridor delineated for the Alyeska oil pipeline from Prudhoe Bay to Valdez. It should be mentioned, however, that although both pipelines would be located in a common "utility corridor," they would not be located within a common right-of-way. As a result, the El Paso route would traverse non-impacted terrain, with 78 percent of the route being located greater than 1 mile from the existing oil pipeline. The remainder of the proposed route and the LNG terminal would be located in sections of the essentially undisturbed Chugach National Forest in Alaska.

The proposed Point Conception terminal would be located in a relatively undistrubed area of the southern California coastline.

b) Gas Volumes to be Transported

The proposed El Paso pipeline would receive 3.364 billion cubic feet of natural gas per day (cfd) at Prudhoe Bay and would deliver 3.278 billion cfd to the liquefaction plant at Point Gravina. The proposed revaporization facility at Point Conception would subsequently receive approximately 2.809 billion cfd and revaporize at a rate of 2.803 billion cfd with an additional peaking capacity of 0.30 billion cfd. This 2.803 billion cfd of gas would then be delivered to existing mainline pipeline systems via the proposed pipelines to be constructed to Arvin Station and Cajon, California.

c) Related Facilities and Land Requirements

The proposed 809-mile pipeline through Alaska would require 14,712 acres of land for construction right-of-way with 5,247 acres being permanently affected for the life of the project. Additional acreage would be required for the construction of the 12 proposed compressor stations, additional appurtenant facilities, and a single dispatching and control center to be located at Valdez, Gravina, or Cordova.

The proposed gas liquefaction facility and tanker terminal to be constructed at Gravina would require approximately 500 acres of land. The LNG plant would be composed of four operational facilities:

1. A gas treating facility.
2. A gas dehydration facility.
3. A refrigeration and compression facility to condense the gas to liquid form.
4. LNG product storage and handling facilities to accumulate and then transfer the LNG product to carriers.

The proposed LNG tanker terminal at Gravina would be located 1,200 feet offshore in Orca Bay. At this location, Orca Bay is approximately 6 miles wide, with waters in the immediate vicinity of the site ranging in depth from 50 to 300 feet. This terminal would be constructed to handle the loading of two LNG tankers at one time.

El Paso proposes to build eleven 165,000-cubic meter double-hull LNG carriers. These tankers would be equipped with either free standing or membrane tanks insulated to carry the LNG cargo.

The regasification facility, which would be located near Point Conception, California, and constructed by Western, would require 227 acres of land. The facilities proposed here would be designed to receive LNG transported by ship, unload and transfer it into double-walled insulated storage tanks, and withdraw and revaporize it for delivery into proposed gas transmission pipelines.

The marine berthing and unloading facilities at Point Conception, occupying 31 acres of leased subtidal land, would be located about 4,600 feet offshore and would accommodate and simultaneously unload two LNG ships of up to 165,000 cubic meters capacity.

A cryogenic LNG transfer system would be required to carry the LNG from the ships to the onshore storage tanks. This system would consist of four 16-inch diameter insulated cryogenic lines and one 16-inch vapor return line. This system would be approximately 6,000 feet long; 4,600 feet would be mounted on a trestle in the offshore area, and 1,400 feet would be installed aboveground on the plant site.

The construction of pipelines extending from the Point Conception terminal to Arvin Station and Cajon would require the clearing of 3,650 acres of land with 1,550 acres being permanently maintained for the life of the project.

d) Construction Schedule

The construction of the pipeline across Alaska and the LNG facility at Gravina would require an estimated 6½ years to complete. Two years would be required for accumulation of engineering design data, procurement of materials, and preparation for construction, while the actual construction work would span 4½ years.

A portion of the proposed El Paso project would cross the Chugach National Forest in an area inventoried and designated by the U.S. Forest Service as roadless and undeveloped. Before El Paso would be allowed to cross this area with a pipeline system and LNG terminal, it would need to submit a detailed environmental report to the Forest Service for its evaluation to ensure adequate consideration of the wilderness resources of these areas. This information received from the Department of Agriculture indicates that a delay of a year or more could occur after such an environmental statement had been received by the Forest Service, possibly delaying the construction time schedule for the El Paso System.

The overall construction period for the Point Conception plant facilities would be about 38 months. Total time to construct the related pipelines would be less than 26 months.

2. Environmental Impacts of Proposed Action

a) Climate

I. The construction and operation of this system should have no effect on the climatology of the region, except on the micrometeorological scale.

II. High temperature vapor effluents which would be emitted from the proposed compressor stations along the pipeline in Alaska could adversely affect the local area, primarily through the propagation of ice fog. This ice fog could result in a safety hazard by causing a serious reduction in local visibility. Such a problem could occur particularly in the interior of Alaska where there are little or no winds and frequent temperature inversions.

III. There are no anticipated significant impacts upon the climate at the Point Conception terminal area.

b) Topography

I. Changes in topography along the proposed pipeline routes would result from the presence of borrow areas, ditch mounds, bedrock cuts, gradings, and structures associated with pipeline construction and operation.

II. Construction of the LNG terminal facilities would also result in local terrain modification resulting from site grading and borrow pit formation.

III. Grading of the Point Conception LNG terminal site could involve up to 2 million cubic yards of material which would be a major impact on the local topography.

IV. Construction of the pair of 42-inch parallel pipelines from Point Conception to Arvin along the proposed route might require ridge cutting for 70.5 miles or about 50 percent of the 142.3-mile corridor. The leveling of the ridge crests would be a major direct adverse impact from the pipeline construction.

c) Geology and Soils

I. Alaska

1) The presence of both oil and natural gas pipelines in Alaska could make development of other mineral reserves in the area more attractive, with resultant additional environmental impacts.

2) Large amounts of gravel and sand are required for construction of the Alyeska oil pipeline through Alaska, and similar amounts would be needed for installation of this proposed El Paso gas pipeline. Heavy demands would be placed upon these scarce commodities, which in many areas are obtained from riverbeds. Consequently, as gravel requirements increase, stream hydrology and water quality could also be adversely affected.

3) Disturbance to the permafrost areas along the pipeline route in Alaska could result in long-term effects on the permafrost regime. Resultant erosion, subsidence, slumping, gullying, and establishment of new drainage patterns could occur along the pipeline route.

4) Disruption of the permafrost regime could cause secondary effects of frost heave, solifluction, deep-seated creep, and mass wasting which could subsequently dislodge and possibly rupture buried pipeline. This would result in safety hazards as well as renewed environmental disruption caused by the repair work needed to rectify the problem.

5) The occurrence of large-scale earthquakes is a potentially serious hazard to the integrity of the LNG plant and pipeline system. Large earthquakes could trigger landslides, and failure of the foundation material of the area that could jeopardize the integrity of the pipeline, the LNG plant, loading dock, and tankers. Tsunamis resulting from such earthquakes could endanger the loading docks and tankers.

6) Because of the possibility of the existence of a fault within 2 miles of the property proposed for LNG facility construction and the fact that this area is on the strike of the major faults involved in the 1964 event, it would be unwise to discount the possibility of ground rupture at the site.

7) Preconstruction and construction activities at the proposed LNG site would increase erosion, with resultant impacts to the immediate offshore area.

II. California

1) Discharge of water used for hydrostatic testing could have significant erosional impact if improperly released. In addition, such discharges upon the surface within the San Joaquin Valley or the Mojave Desert could create problems with the expansive and collapsible soils of these areas. Expansive soils may increase their volumes and move retaining walls, lift foundations, and adversely affect associated structures. Collapsing soils, on the other hand, are susceptible to hydro-compaction and also pose severe construction problems. These soils are extremely common in the San Joaquin Valley.

2) Ridge cut areas along the proposed Point Conception to Arvin pipeline corridor would be difficult to maintain, and long-term erosion problems should be expected.

3) The proposed pipeline route in California crosses at least 22 mapped fault traces. If the maximum probable event for any one of these took place, it is conceivable that it could cause rupture of the Point Conception to Cajon pipelines.

4) Earthquake activity in the area could cause soil liquefaction, subsidence, mass wasting and tsunamis. At the least this would cause disruption of normal operation of the proposed facilities if preventative steps were not taken.

5) Preconstruction and construction activities in the coastal area of southern California would increase erosion, with resultant impacts to the immediate offshore water area.

d) Water Resources

I. Alaska

1) Streams north of the Yukon River could be dewatered if existing streamflow or groundwater flow were used as a source of water for construction activities during the winter. This would have a direct impact on fish overwintering in springs, overwintering fish eggs, and other aquatic organisms.

2) Removal of streambed gravel for construction would cause increased sediment transport in the streams as well as disruption of spawning beds.

3) The frost bulb which would develop around the chilled gas pipeline in Alaska could block groundwater flow in the aquifer under the streams and restrict flow within the streams. The direct effect in winter would be the development or enhanced development of aufeis (floodplain icing) resulting from blocked groundwater and streamflows being forced onto the surface of the ice. This would result in dewatering of the stream. The surface ice dam would also force high water flows out of the active stream channel, thus resulting in stream channel modification and streambank erosion.

4) In the event repair of the proposed pipeline in Alaska were required during the summertime using conventional heavy equipment, there would be immediate, significant impact on water quality and drainage. Movement of equipment and supplies across a thawed tundra surface would cause compaction and concentration of water almost instantaneously.

5) Construction in streams would increase the sediment load, which could increase the biological oxygen demand, thus putting an added strain on the water system.

6) The probability of major spills of fuels, lubricants, or toxic materials at storage sites and during tanker transportation of the LNG cannot be discounted. Should a major spill occur, there could be long-term adverse impacts on water quality, especially if such products as fuels and lubricants seeped into groundwater beds where they could remain for extended periods of time.

II. California

1) Water resources impacts, Alaska-- #5 and #6 mentioned above could also occur in the Point Conception area as a result of pipeline and LNG terminal construction and operation.

2) Release of large volumes of test water into dry stream channels on the western routes could cause streambed scour, erosion, increased sediment yields, and modification of stream channel configurations.

e) Vegetation

I. Alaska

1) Initial construction along the 809-mile long right-of-way would require the disturbance of 14,712 acres of land along with an additional 1,475 acres used for construction of compressor stations, maintenance facilities, and the LNG facility. Related impacts along the right-of-way would include complete destruction of vegetation and removal of the organic surface layer which, in Alaska, would result in reduced insulation of the permafrost.

2) Where the pipeline would cross forests and woodlands, there would be a permanent change in vegetation, because forest and woodland vegetation would not be allowed to grow directly over the pipeline.

3) The introduction of additional fire ignition sources related to pipeline construction machinery and increased presence of man could cause increased possibilities for fires in some areas.

4) There would be a short-term reduction of primary productivity in the offshore construction area around the LNG terminal due to limited light penetration caused by increased turbidity resulting from increased erosion stemming from marine and land construction.

II. California

1) An estimated 3,650 acres of land in California would be cleared for pipeline and LNG site construction, and 1,550 of these acres would be permanently maintained for the life of the project.

2) A variety of grasslands, cultivated lands, and orchard and grove areas would be impacted by construction of a pipeline and LNG terminal in the Point Conception area.

3) The arid desert area of California containing salt desert scrub, creosote bush, Joshua tree, and sagebush areas would require considerable time to recover due to reduced seed germination and plant growth capabilities characteristic of arid environments.

4) In the hot, arid desert portions of the Point Conception pipeline route, periodic inspection trips could produce long-lasting impacts on fragile desert vegetation and could prevent reestablishment of vegetation along periodically used vehicle paths for the life of the project.

5) The leveled, cleared path of the permanent right-of-way could attract additional use of four-wheel drive recreational vehicles and could greatly increase the damage to the area.

6) Impacts #3 and #4 listed under "Vegetation in Alaska" would also occur in the Point Conception area.

f) Wildlife

I. Alaska

1) The construction of this pipeline system could affect wildlife populations through direct or indirect harassment or project-caused disturbance during critical periods of animal life cycles, increased harassment and/or destruction of wildlife because of better access to the area, the introduction of pollutants to the ecosystem, the inability of certain species of wildlife to adapt to man's presence, and the direct or indirect destruction of wildlife habitats.

2) Pipeline construction and operation in Alaska could cause: interference with the migrating movements of caribou including those in the Arctic, Nelchina, and Central Brooks Range herds, resulting in delays or failure of the animals to reach traditional calving or seasonal grazing areas; alteration of the distribution of caribou in the future; and abandonment of portions of their range, to the detriment of the caribou population.

3) Construction of the pipeline to Gravina Point and the larger development there of facilities for liquefying and shipping natural gas could reduce habitat for Sitka black-tailed deer and make them more vulnerable to hunting through increased access to the area. Pipeline construction and operation would also cause increased harassment to the wolves, grizzly bear, and black bear found in the area.

4) A direct effect of related pipeline activities on Dall sheep would come from aircraft flights associated with construction and surveillance/maintenance activities.

5) Disturbance due to pipeline construction and operation could: increase stress and alter normal bird behavior patterns during critical life history phases such as spring migration, nesting, molting, or fall migration staging; decrease reproductive success; or cause the birds to desert traditional molting areas or nesting sites for which there may be no alternative site.

6) Pipeline construction and maintenance activity in the Franklin Bluffs area could be damaging to the endangered peregrine falcons nesting in this area.

7) The construction of a terminal at the Point Gravina site could result in the abandonment of some or all of the 16 bald eagle nesting sites known to occur in this area.

8) The applicant has planned for the use of a winter construction schedule and formation of snow roads for access and work space in the area. Such winter construction on snow roads would be critical to mitigate damage caused by the project to wildlife and vegetation on the North Slope.

9) Increases in suspended particles, reduction in dissolved oxygen, and introduction of pollutants into the water systems resulting from pipeline construction and operation could all be directly detrimental to fish and other aquatic life.

10) Pipeline and LNG plant development would have the potential to damage estuarine and migratory fish species that frequent these areas.

11) The proposed tanker route would cross one of the most productive tanner crab areas in Prince William Sound. Salmon netting, which also takes place in the Gravina area, would also be affected by tanker traffic.

12) During operation of the Gravina LNG plant, approximately 658,000 gallons of seawater per minute would be drawn into the plant, used once for cooling, and then discharged into Orca Bay as heated effluent. The effect of heated effluents on marine organisms in subarctic areas is largely unknown. Area avoidance and/or direct organism destruction are possible. The addition of heated brine and chlorine into the discharged cooling water from the LNG plant would have an additive adverse effect on marine organisms.

13) LNG facility operational impacts on the environment of the marine area would stem from increased traffic of LNG tankers, supply ships, and other small craft, from entrainment, impingement, and thermal effects of the seawater used in the vaporization system, from biocide and neutralizer use, and from discharges from the shore facility.

II. California

1) Wildlife impacts, Alaska-- #1 and 13 mentioned above could also occur in California as a result of pipeline and LNG terminal construction and operation.

2) The endangered San Joaquin kit fox may occur in the San Joaquin Valley area near the eastern sections of the Point Conception to Arvin pipeline route, and this particular route could destroy habitat used by this animal and cause population losses.

3) Due to a proposal by the U.S. Fish and Wildlife Service to establish a condor feeding and roosting sanctuary near the Tejon Ranch, a segment of the proposed Arvin to Cajon pipeline could adversely affect the sanctuary unless proper mitigating measures were taken or the route were altered slightly to avoid the area.

4) Impacts could be severe to the prairie falcon if nesting sites were encountered during right-of-way and access road construction. These activities would cause nesting failure of any nearby falcon pairs. Offroad vehicle use of the proposed right-of-way and access roads would also cause nesting failure. This represents a more severe adverse impact than the pipeline construction, due to the potential long-term nature of offroad vehicle use.

5) The effluent flow from the vaporizers at Point Conception would be considerably colder than ambient seawater temperature. This could inhibit growth, disrupt the reproductive cycles of species which require higher temperatures to initiate spawning, prevent the proper development of eggs and larvae, kill some organisms, and reduce the productivity of others within the effective plume area.

g) Socioeconomic Impacts

I. Alaska

1) The major revenue impacts of the gas pipeline on the State of Alaska would result from personal income taxes, certain excise taxes, gas production tax revenues, royalty payments to the state, and state property taxation of the pipeline and LNG terminal facility.

2) Construction of this gas transmission system would have a multi-faceted impact on the socioeconomic environment of the State of Alaska. It would produce jobs, generate state and local revenues, and further stimulate the Alaskan economy. It would attract immigrants to the state, increasing the population over what it would otherwise have been. This in turn, would create demand for jobs, social services, schools, housing, health care, and public safety.

3) Gas pipeline construction might have a direct adverse impact on the fishing industry, especially in the Prince William Sound area, and minimal impact on the forest industry. Mining could be expected to grow somewhat because of the increased access to mineral rich areas. Agriculture would continue to diminish in importance in relation to the entire economy, but tourism could be expected to grow. Pipeline construction would create a demand for transportation services. The construction effort would utilize the barging, trucking, and aircraft resources of the state.

4) The construction of this pipeline system could have a significant influence on Alaskan Natives. The growing demand for material goods is a major feature that has resulted from the exposure of the Natives to non-Native culture. Since these goods must be bought, the Natives have become increasingly dependent upon a cash economy. There has also been a decline in the harvesting of subsistence resources and alterations in the nature and significance of the social institutions derived from that activity.

5) The potential pipeline-related causes of interference with the subsistence resources utilized by the Natives consist of disruptions to the habitat of fish and game as the result of construction or operational activities and increased competition from the non-Native population for the limited available resources.

II. California

1) Santa Barbara County, California, would benefit from an increased tax base resulting from taxation of the LNG facility and related pipeline. Temporary increases in payroll spending for food and other necessitites would be felt in the area during the construction period.

2) The socioeconomic impact of the construction of the LNG facility on the Point Conception area would be felt largely in temporary demands on local housing and public services.

3) The construction of the two segments of pipeline related to the Point Conception terminal should have no significant long-term impact on the existing housing characteristics of the communities situated near to the pipeline corridor.

h) Land Use

I. Alaska

1) Between 85 and 95 percent of the proposed route of the El Paso pipeline could be within the Utility Corridor designated for use by the Alyeska Oil Pipeline. As such, the impact on designated local land use and land use planning would be minimal.

2) However, the construction, operation, and maintenance of a large diameter natural gas pipeline and associated liquefaction plant located in the Chugach National Forest would have collective impact on this management unit, affecting its roadless and undeveloped character.

3) The existence of a pipeline transportation system would stimulate an increase in the further exploration and possible development of potential oil and gas basins in northern Alaska. The impacts from this consequence could be major and of national significance.

II. California

1) The cumulative land use effects of an LNG facility at Point Conception would be substantial, because the project would involve

the installation of a major industrial facility in a primarily rural, agricultural area. The presence of an LNG facility could significantly affect future industrial development along the south coast region, along with increased potential for major environmental impact.

2) The construction and operation of the LNG facility would preclude agricultural activities for the life of the project on 227 acres of land. Strong efforts are currently being undertaken to restrict the conversion of prime agricultural lands to non-agricultural uses.

3) The presence of an LNG facility would disrupt the seclusion of the homeowners of Hollister Ranch and would significantly affect the low population density character of the area. The aesthetic nature of the area as well as the property values of portions of the Hollister Ranch would be adversely affected by the presence of an LNG facility.

4) Direct, conflicting impacts on recreational and commercial use of the beach and offshore areas would be felt during construction and operation of the LNG facility at Point Conception.

5) There would be long-term restriction upon building any permanent structures within the right-of-way corridors for the life of the project.

i) Historic and Archaeological

I. Alaska

1) Remnants of Alaska's early history are scattered along the proposed pipeline route. During construction of a gas pipeline along this route, the possibility of impacts on unknown archaeological resources

would still exist, although they would be somewhat lessened by previous development of the Alyeska oil pipeline.

2) The influx of additional workers and others would increase vandalism and artifact hunting in old mining areas. This could cause a significant impact if old buildings or artifacts were destroyed or removed.

II. California

1) The possibility of impacts on unknown archaeological resources due to pipeline and LNG terminal construction also exists in the Point Conception area.

2) No comprehensive field survey has been performed for the pipeline corridor; hence the actual numbers and locations of archaeological resources present cannot be known.

j) Recreation and Aesthetics

I. Alaska

1) The proposed gas pipeline route in Alaska would run parallel to, or a few miles away from, the main road in the area. Lateral access roads from the existing highway to the proposed route would, if open to the public, very likely be used by recreationists. This access would extend the use of the area and could significantly impact this zone. Unless steps were taken to provide adequate recreational facilities, damage to the terrain from uncontrolled recreational use and a general degradation of recreational and aesthetic points of interest could result.

2) Nearly all the proposed El Paso pipeline south of the Brooks Range would require the clearing of brush and forest cover. This would significantly alter the natural

environment and would degrade recreation and aesthetic values of the corridor, particularly where long, straight clearings are visible from the road. On-the-ground viewers would be able to see from great distances such facilities as communication towers, buildings at compressor sties, and block valve ports.

II. California

1) Recreational use of the beach and offshore areas near the Point Conception LNG facility would be hindered and/or curtailed for the life of the project.

2) The leveled, cleared path of the permanent right-of-way could attract additional use of four-wheel drive recreational vehicles and could increase the damage to the area.

k) Air Quality

I. Alaska

1) Ambient concentrations of sulfur oxides and nitrogen oxides are well below the Alaska and Federal standards set for these pollutants for all monitoring sites along the proposed route. The same is true for particulate matter except in downtown Fairbanks, where concentrations are much higher. The ambient standards are not exceeded at any location.

2) Emissions from the twelve proposed compressor stations would primarily be composed of nitrogen oxides with very small quantities of sulfur oxides, carbon monoxide, and particulates. The impact of these emissions on the local environment should be insignificant and thus would not cause a significant degradation of the air quality in the vicinity of the proposed route.

3) Various activities at a maintenance camp near Valdez, including auto and truck transportation, space heating, and construction work, would add an unknown quantity of air pollutants to the atmosphere in that region.

4) The operation of construction equipment could create an increase of fugitive dust in the immediate vicinity of the construction site, but this incremental increase would be insignificant.

II. California

1) Ambient concentrations of air pollutants have not been determined at Point Conception, but it can be assumed that background levels of pollutants should be very low.

2) The LNG facility and the tankers are the only sources of emissions for the California sector of the project. No compressor stations are planned. The impact of these emissions on the local environment would be very small, even during adverse meteorological conditions.

1) Noise

I. The El Paso project would add an incremental but unknown level of noise in the vicinity of the proposed pipeline due to periodic venting of high pressure gas from the compressor stations.

II. Where this pipeline route would traverse the Chugach National Forest, it would traverse an area experiencing little previous environmental disturbance. Because of this, impacts would be more severe on existing wildlife, particularly caribou and Dall sheep, causing a possible reduction in their range or habitat resulting from area avoidance. If sufficient habitat were lost, population reductions of these species could occur.

m) Pipeline System Repairs and Safety Hazards of LNG

I. Repair activities at some locations, and in some seasons, might cause damage to the environment more severe than that resulting from the initial construction. This is particularly true in the areas of continuous permafrost in Alaska. Emergency repairs in the Arctic would involve the movement of heavy equipment across the tundra without regard to the condition of the soil and without benefit of snow-ice roads. In winter, repair procedures would result in the destruction of plants and the insulating organic mat protecting the soil, with subsequent thaw, consolidation, and erosion a probable result. Summer repairs would cause considerable damage to arctic vegetation and soils and would cause severe disturbance to migrating caribou and waterfowl. The impact of repair activities would be determined by such factors as the extent of impacts already suffered, the availability of existing roads, the extent and effect of preventative maintenance programs, and the extent and emergency nature of the repairs required.

II. The bulk handling of LNG involves some risk to public health in terms of potential operational accidents associated with the transport of LNG on the ocean by ships, the operation of large LNG ships, the loading and unloading of LNG ships, and the storage of LNG in land-based tanks at the terminals.

III. The largest risk to public safety is believed to be associated with the harbor operation of oceangoing LNG ships. In the case of a major collision resulting in the rapid release of an entire LNG cargo (165,000 M^3), persons situated up to 7,000 feet from LNG ships operating in a harbor could be subject to a methane fire. Although a major accident of this type is recognized as possible, it is considered to be unlikely.

3. El Paso Alaska System Alternatives

a) Alternatives in Alaska

Several major regions in Alaska studied both by El Paso and by the FPC staff have been considered as alternate site locations for the proposed LNG facility (Figure 5). Of these regions (Norton Sound, Cook Inlet, Prince William Sound, and Haines), Norton Sound was rejected due to the icing conditions in the Bering Sea which would seriously restrict reliable year-round operations of the proposed LNG tankers. The Haines region was also rejected as a possible alternative since it would necessitate a pipeline corridor which would cross Canadian lands.

In the two remaining regions, Cook Inlet and Prince William Sound, numerous areas were considered by El Paso and the FPC staff for alternate LNG site locations. As many as 26 locations were originally examined in Cook Inlet, with 11 being chosen for final consideration (Figure 6). The FPC staff also examined 10 alternate sites in Prince William Sound (Figure 7). Of these 21 locations, 10 in Cook Inlet and 7 in Prince William Sound were rejected as technically unacceptable sites for reasons such as geologic instability, terrain requiring extensive site preparation, navigational unsuitability, cryogenic transfer pipeline problems, potential for heavy site damage resulting from seismically induced sea waves, adverse meteorological and marine conditions, and land use conflicts.

The four locations considered by the FPC staff to be technically feasible LNG facility sites in Alaska are the Cape Starichkof alternative in Cook Inlet and the Hawkins Island and Bidarka alternatives, along with the prime proposed Point Gravina location in the Prince William Sound area.

The Cape Starichkof site is readily accessible by highway from the major towns and cities on the Kenai Peninsula, yet it is not too near any major population centers. The environment is not as pristine as much as the Prince William Sound area due to the existence of scattered residences, roads, and light construction in the area. Black bear and moose are present in the site area but do not occur in large numbers and have no critical habitats in the site's vicinity. Stariski Creek, located in the immediate area of the site, receives attention from recreational fisherman and a major commercial salmon fishery is present in Cook Inlet nearby. The pipeline route to Cape Starichkof would be 6 miles longer than the route to Gravina Point.

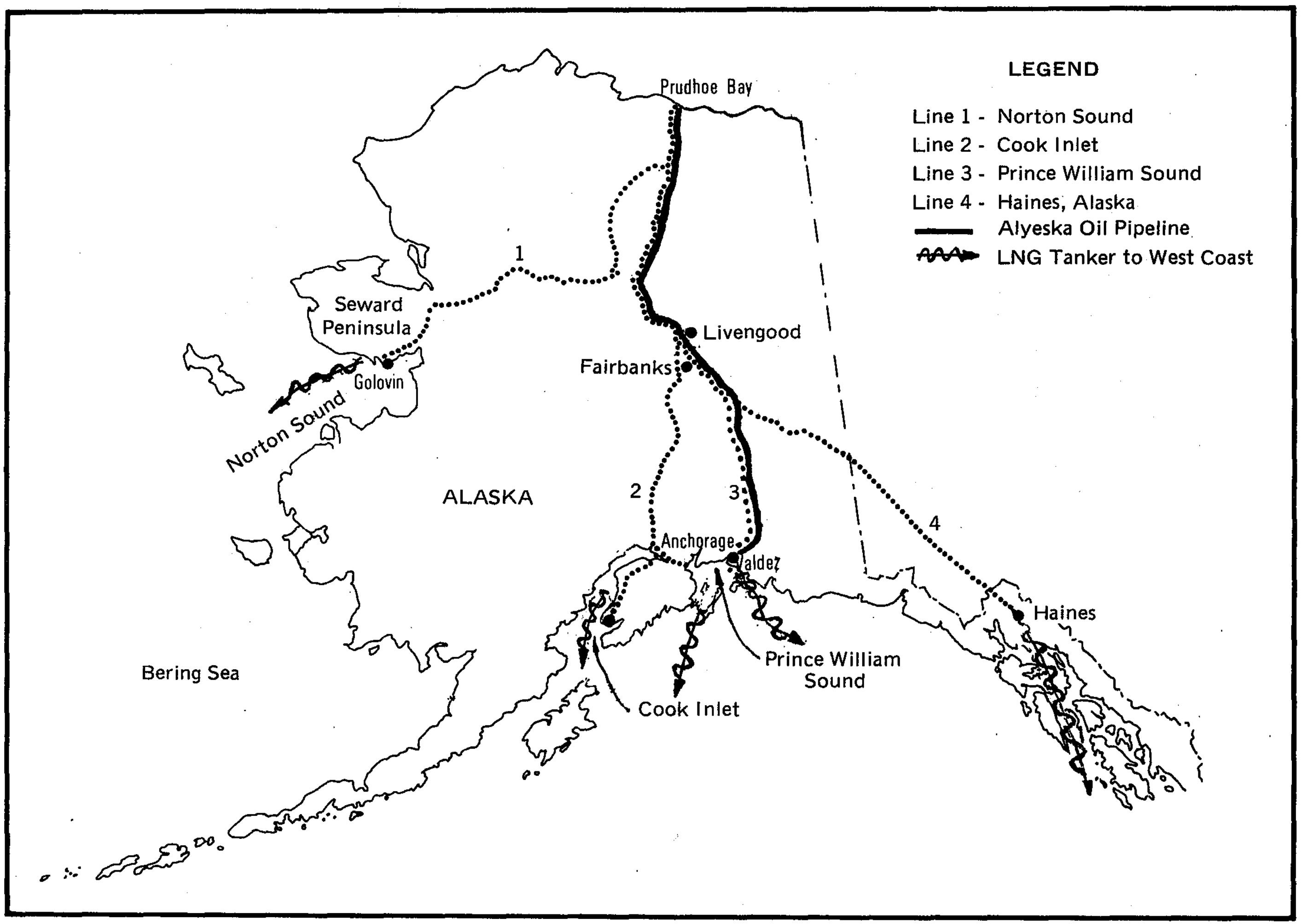


Figure 5 Regions Considered in Alaska for LNG Site Locations with Related Pipeline Route Corridors

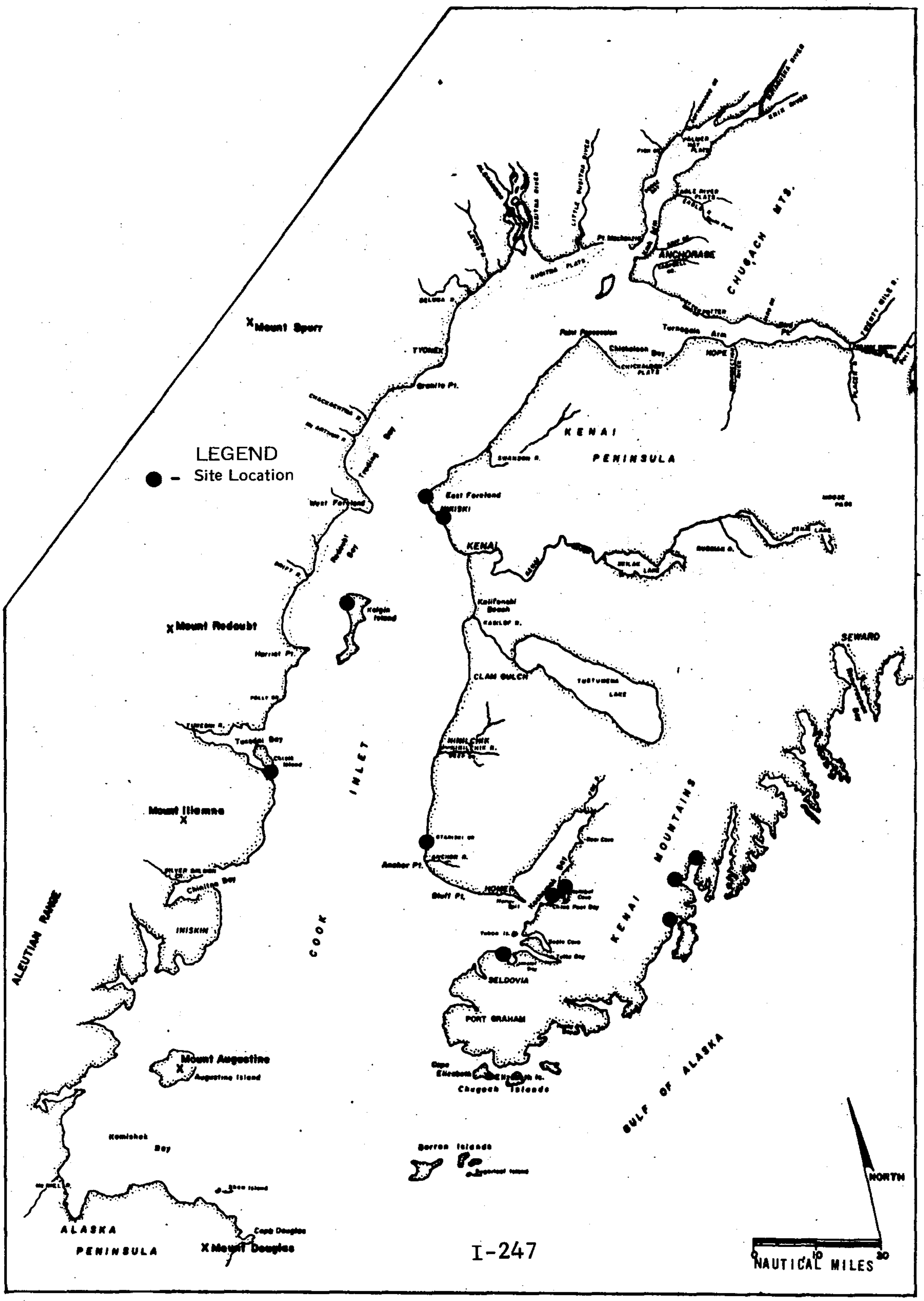


Figure 6 Location of sites analysed in Cook Inlet

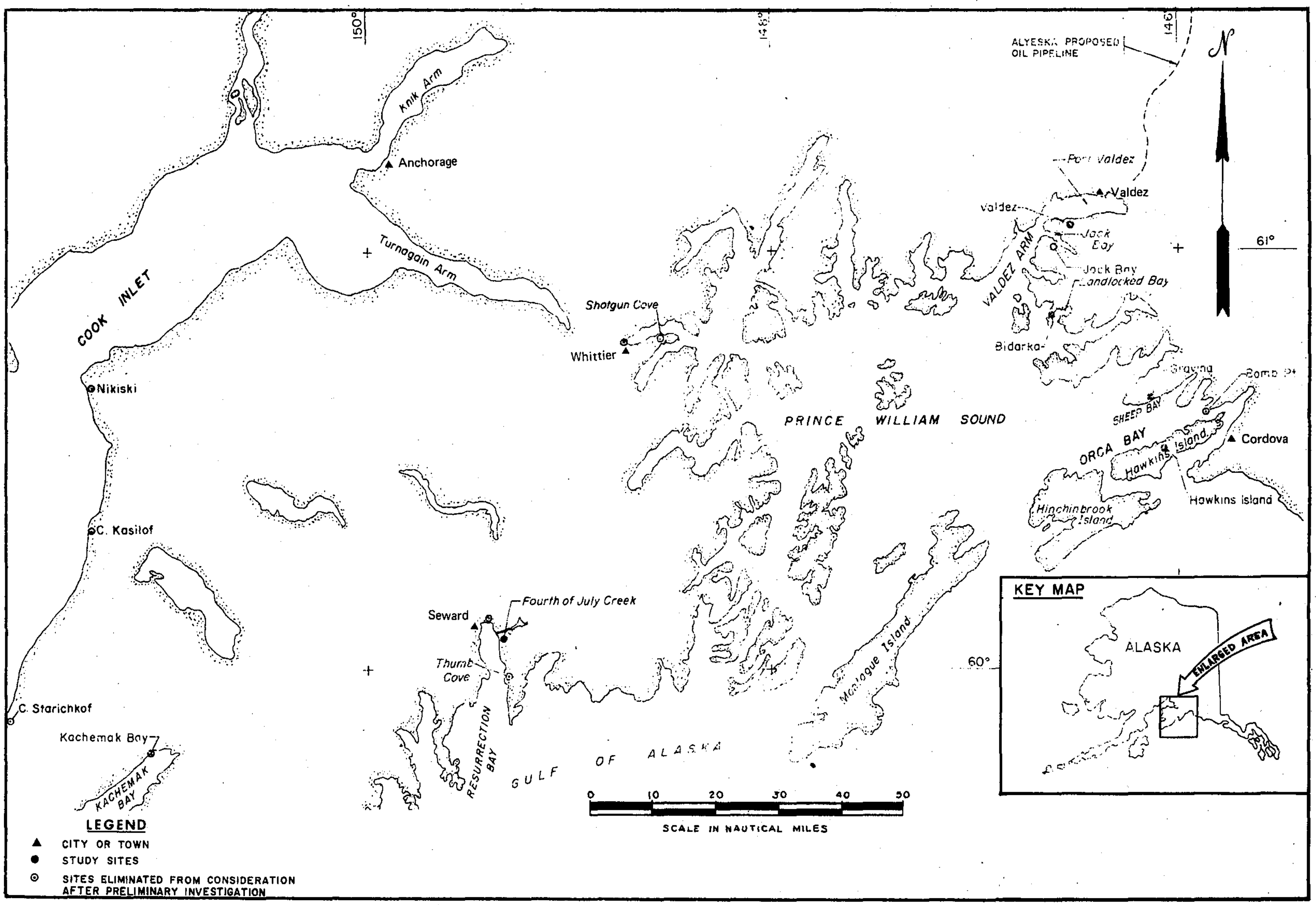


Figure 7 Prince William Sound Sites

REFERENCES: U.S.C. and GS. Map No. 8502

The three sites (Gravina, Hawkins Island, and Bidarka) located in the Prince William Sound region would be situated in previously unimpacted and relatively isolated areas which support various forms of wildlife. The only means of reaching these areas is by boat or plane. Though technically feasible, a facility at Hawkins Island would require the construction of approximately 1 mile of submarine pipeline in waters 240 feet deep. The Bidarka site would necessitate the installation of connecting pipeline through extremely rugged terrain to the north and west.

The pipeline route proposed to connect the Prudhoe Bay Field with the Cook Inlet area would generally parallel the Alyeska oil pipeline route from Prudhoe Bay to Livengood, located just north of Fairbanks. From Livengood, the route would proceed south and west along the corridor utilized by the Alaska Railroad to Anchorage and from there would continue south to the Cook Inlet area. To reach the Cape Starichkof area on the Kenai Peninsula, the pipeline could be routed down the eastern shore of Cook Inlet to its terminus. Such a route down the eastern shore of the inlet would transect the Kenai National Moose Range.

The pipeline routing needed to reach the Prince William Sound area would follow the Alyeska oil pipeline corridor for its entire length to Valdez. From there, the gas pipeline would cross essentially undisturbed areas of the Chugach National Forest to reach site locations on the sound.

b) Alternatives in California

Six sites (Oxnard, Los Angeles, Port Hueneme, Carlsbad, Border Field, and El Segundo), identified and studied by Western in its application to FPC, as well as three additional sites (Drake, Mandalay, and San Onofre), identified by an independent contractor, have been considered by the FPC staff as alternate site locations for the LNG facility proposed for Point Conception. Site locations are shown in Figure 8.

Five of these sites (Los Angeles, Port Hueneme, Carlsbad, Border Field, and El Segundo) were initially rejected from further consideration for various reasons. The Los Angeles site, located on a landfill area and underlain by the Palos Verdes Hills fault zone, has the potential for a high magnitude earthquake and, therefore, has been rejected. The Port Hueneme, Carlsbad, and El Segundo sites were initially rejected because of technical difficulties associated with the cryogenic transfer lines which would be used to transfer LNG from the tanker terminal to the onshore storage facility. The Border Field site was rejected because of the land use conflicts involved with having an LNG site border a state park area.

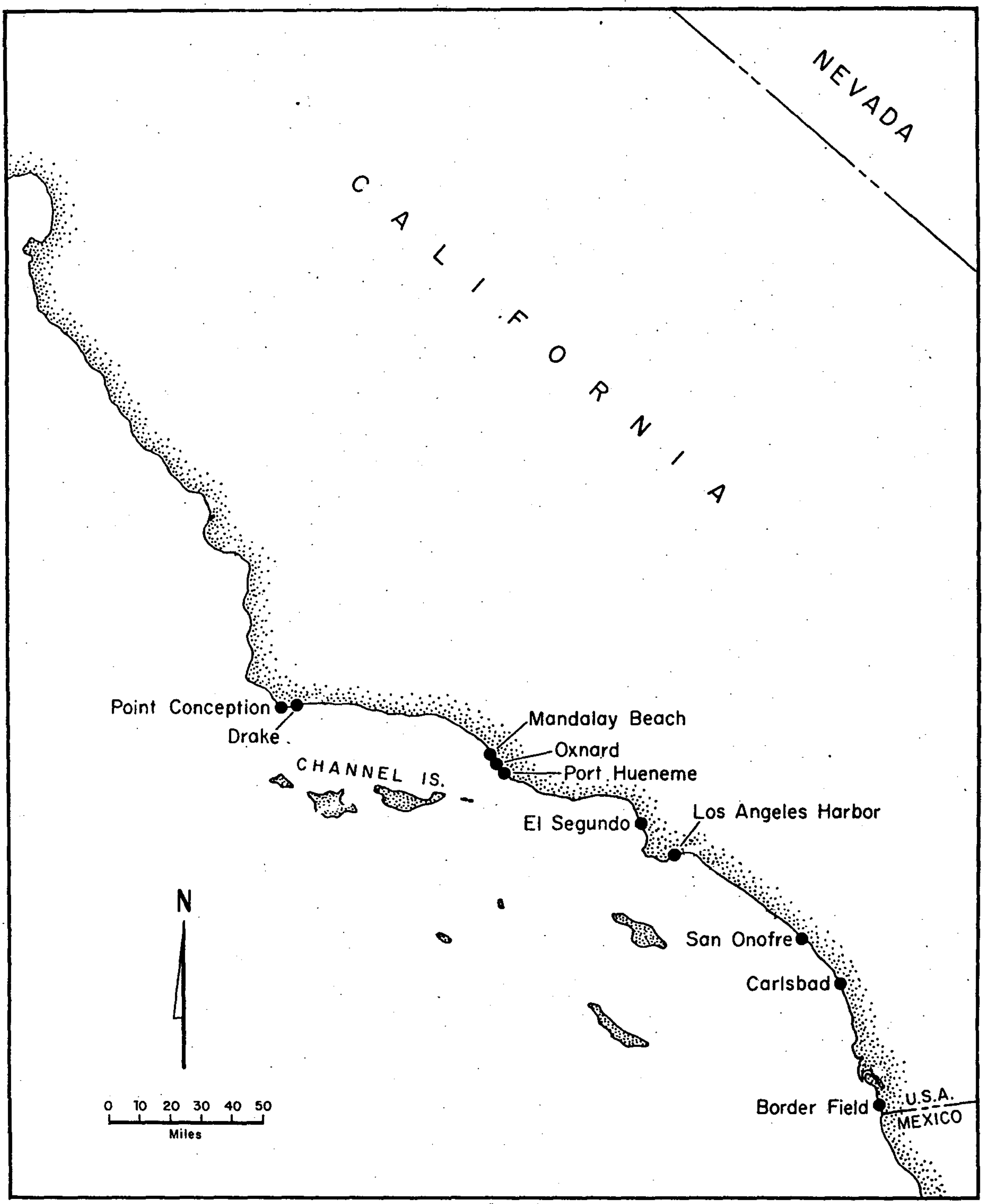


Figure 8 Location of Sites Analyzed in Southern California

The four alternative locations which do remain as technically acceptable sites for an LNG plant and related facilities on the southern California coast are Drake, Mandalay, Oxnard, and San Onofre. Although technically feasible, the acceptability of the San Onofre site is somewhat questionable, due to the fact that the operation of an LNG facility here could cause possible problems for the Marines at Camp Pendleton who use the offshore area in this locality for training maneuvers. Figure 9 shows the location of these four site alternatives in addition to the Point Conception prime proposed site along with the related pipeline systems needed to transport the revaporized gas to existing mainline systems.

The Mandalay, Oxnard, and San Onofre sites exhibit the potential for the development of a seawater exchange system with nearby power plant installations. Such a system would involve the pipeline transfer of the heated seawater effluents from the power plant to the LNG facility for use in the revaporization process. Such a system would reduce the total water intake needed to operate each plant separately and would abate the severe temperature reductions of the LNG revaporization process effluent which would be released back into the natural environment.

From a biological standpoint, an LNG site at Oxnard would cause the least amount of damage to presently existing natural habitats. Oxnard has a definite land use classification directed toward heavy manufacturing or industrial use, where extensive industrial use is planned for the future. Mandalay and San Onofre would both receive greater relative impact to their existing environments than Oxnard. Point Conception and Drake, being relatively the least developed, would be the most disturbed by LNG facility and pipeline construction and operation.

Construction and development of any of the four alternate pipeline routes, as well as the Point Conception pipeline route, would be well within the limits of technical feasibility. Of obvious importance from the combined standpoints of technology, environmental concerns, and economics, is the length of pipeline that would be required to connect the LNG terminal facility with existing mainline systems. Point Conception and Drake would need the longest connecting pipelines, requiring 142 and 140 miles, respectively. San Onofre, Mandalay, and Oxnard would require the construction of 47.5, 50, and 53.3 miles of connecting pipeline, respectively. The Point Conception and Drake pipeline routes would each follow existing rights-of-way for 9 percent of their length, while the percentages for Mandalay, Oxnard, and San Onofre would be 78, 96.25, and 100 percent, respectively.

The public safety based on risk analysis of the marine transport of LNG appears to be adequately maintained for the proposed terminals at Gravina and Starichkof in Alaska and Point Conception and Oxnard in California. For Los Angeles Harbor, the risk from LNG tanker operations appears to be marginal.

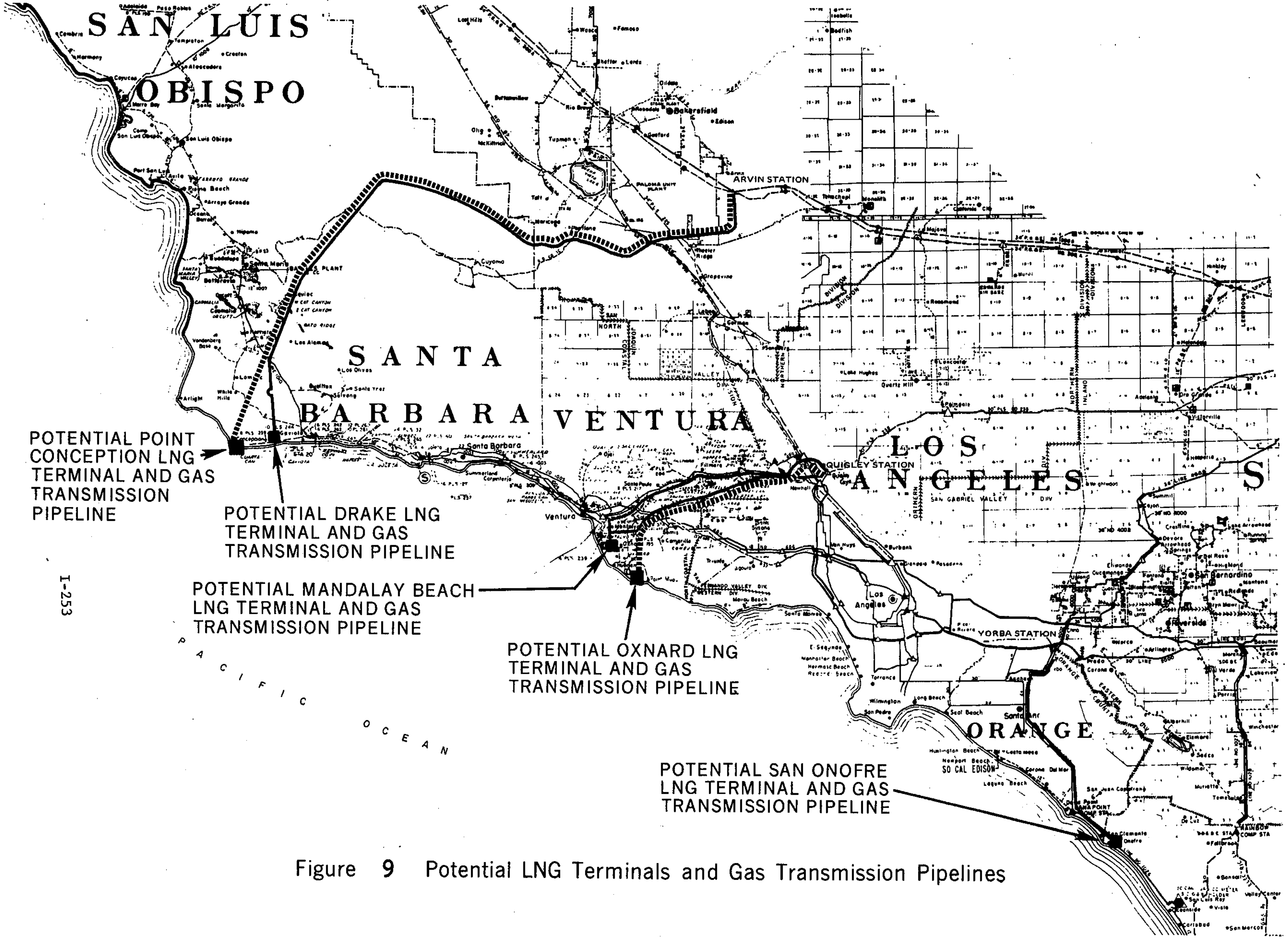


Figure 9 Potential LNG Terminals and Gas Transmission Pipelines

C. ECONOMIC ANALYSIS

1. Comparative Economic Benefits and Costs of the Alternative Transportation Systems

a. Summary of Findings

In this section the net national benefits of the applicants proposed transportation systems, together with the FPC staff's preferred Fairbanks alternative, are analyzed. Net national benefits are defined as the dollar value of the benefits that flow from consumption of Alaskan gas less the costs, apart from environmental costs, to the nation of producing and delivering the gas. Naturally, the net national benefits depend, for a given system, upon the price of alternative fuels, the quantity of non-Alaskan gas supplies and the quantity of Alaskan supplies. For those systems that transport Mackenzie Delta gas, as well as Prudhoe Bay gas, the benefits also depend upon the quantity of Mackenzie Delta supplies through their effect upon the United States share of the transport costs. Because the gas flows over about 20 years, and the costs are incurred over a similar period, the net national benefits also depend upon the discount rate applied to net national benefits in future years. The results are summarized below for plausible values of these quantities. The systems considered are those proposed by the applicants, using their costs, and the variants costed by the Department of the Interior (references 12, 13 and 14) plus the FPC staff's preferred alternative.

In addition, the returns to the applicants on their proposed systems have been analyzed for similar scenarios. The principal methodological difference arises from the fact that United States taxes are costs to the applicants. However, from a national standpoint they are transfers of funds and not resource costs. These results indicate the rates of return to the applicants and the revenues remaining to cover wellhead prices under the various scenarios. In a rough way they also confirm the comparative system rankings found in the net national benefit comparison.

Net National Benefits

In Table I-A-1 are summarized the net national benefits for a relatively large Alaskan supply and two prices for oil as the alternative fuel. The alternatives are the Department of Interior variants using Department of Interior costs. High and low non-Alaskan supplies represent, respectively, optimistic and pessimistic levels of the quantity of future non-Alaskan supplies. The lower 48 transportation costs are assumed to be 2¢/MCF/100 miles beyond the system's terminal point in the United States. Table I-A-2 contains results for the same assumption except that the Alaskan supply is smaller.

Table I-A-1

Net National Benefits
(Billions of Dollars)

Alaskan Supply - 23.6 TCF

10% Discount Rate - 2¢/MCF/100 miles lower 48 Costs

Non-Alaskan Supply	$12 per barrel oil High	$12 per barrel oil Low	$8 per barrel oil High	$8 per barrel oil Low
Improved El Paso a)	5.73	7.57	1.70	3.48
Alaskan Arctic b)				
Mackenzie Delta - 5.9 TCF	5.68	8.65	1.73	4.74
0 TCF	4.91	7.88	.96	3.97
Fairbanks Alternative c)	5.55	8.55	1.60	4.64

a) Termed "Improved Alaskan-LNG" in the analysis.
b) Termed "Alaska-Canada" in the analysis.
c) Termed "Fairbanks-Alcan" in the analysis.

Table I-A-2

Net National Benefits
(Billions of Dollars)

Alaskan Supply - 17.8 TCF

10% Discount Rate - 2¢/MCF/100 miles lower 48 Costs

Non-Alaskan Supply	$12 per barrel oil High	$12 per barrel oil Low	$8 per barrel oil High	$8 per barrel oil Low
Improved El Paso	4.20	5.69	1.10	2.55
Alaskan Arctic				
Mackenzie Delta - 7.1 TCF	4.69	7.16	1.49	3.95
0 TCF	3.67	6.14	.47	2.93
Fairbanks Alternative	3.99	6.49	.75	3.23

Noteworthy among the results are the following:

1) When non-Alaskan supplies are low, and Mackenzie Delta supplies about as expected, the Alaskan Arctic and Fairbanks alternatives yield higher benefits than El Paso. Fairbanks is superior to Alaskan Arctic when no Mackenzie Delta supplies are available.

2) When non-Alaskan supplies are high and the lower of the Alaskan supplies are available the net benefits ranking is Alaskan Arctic, El Paso and Fairbanks.

3) In all other cases the three alternatives yield about the same benefits.

4) The Fairbanks alternative is superior when no Mackenzie Delta gas is available and non-Alaskan supplies are low.

5) In no case does the Fairbanks alternative have benefits that fall below the highest by more than $.7 billion. This means that its superior environmental features are available at a maximum cost, over 20 years, of $35 million per year.

The rankings are not changed by changes in the discount rate. However, for high non-Alaskan supplies and $8 oil the net benefits for all alternatives are negative at a 15% discount rate.

Table I-A-3 contains the net national benefits calculated for the applicants proposals. Although the flows are not entirely comparable, the comparative rankings observed above are preserved for the El Paso 2.4 BCFD proposal and the Alaskan Arctic.

Table I-A-3

Net National Benefits
(Billions of Dollars)

10% Discount Rate - 2¢/MCF/100 miles lower 48 Costs

$12 per Barrel Oil

Non-Alaskan Supply	High	Low
Alaskan Arctic		
2.25 BDFD Prudhoe and 2.25 Delta	3.87	6.75
El Paso		
2.4 BCFD Prudhoe	3.98	5.92
3.3 BCFD Prudhoe	6.21	8.44

Returns to the Applicants

The results of the analysis of the rates of return to the applicants are comparable to those found in the analysis of net national benefits. In every case simulated, Alaskan Arctic earns a higher rate of return than El Paso. With $12 oil and low non-Alaskan supplies Alaskan Arctic can earn a 15 percent rate of return on equity and still cover the estimated wellhead cost of the gas. Under the same circumstances El Paso can only earn a 10 percent rate of return. Even with a reduced flow of gas from the Mackenzie Delta (and hence higher costs for Alaskan Arctic), earnings for Alaskan Arctic are superior to those of El Paso.

The feasible rates of return are highly sensitive to the supplies of substitute fuels. An increase in the supply of non-Alaskan gas from low to high reduces Alaskan Arctic's rate of return to 10 percent and El Paso's to less than 5 percent. Neither applicant is able to sustain a positive rate of return if, in addition to relatively high supplies of non-Alaskan gas, the price of oil drops from $12 to $8. El Paso's position is sufficiently vulnerable that even with low supplies of non-Alaskan gas, a drop in the price of oil to $8 prevents a positive rate of return.

Construction cost contingencies in the Arctic Circle have a similar but moderate impact on both project designs, and do not seriously reduce the discounted cash flows. El Paso is more vulnerable to changes in the cost of transporting gas within the continental United States, but the impact of such changes on the rates of return is insignificant. Within the range considered, a diminished flow in the Delta does not severely reduce Alaskan Arctic's profitability. If alternative fuels are scarce, Alaskan Arctic can maintain a 10 percent rate of return despite a reduced flow in the Delta and 100 percent inflation in construction costs in the Arctic Circle.

b. Introduction

In this section a comparative analysis of the economic benefits and costs, as distinguished from the environmental benefits and costs, of the applicants' proposals and the FPC staff alternative is undertaken. This analysis provides estimates of the net national benefits that can be expected from each transportation system. The differences between the net national benefits of two systems measure the economic cost of choosing one system rather than the other. These economic costs can thus be compared with the qualitatively relative environmental benefits and costs of the systems.

An economic analysis of the proposals from the viewpoint of the private benefits to the applicants, as distinguished from the national view above, is also undertaken. This analysis enables an exploration of the differences between the national and the private benefits and thus supplements the national analysis.

For the Draft Environmental Impact Statement the Department of Interior economic analysis was adopted together with the FPC staff comments upon it. In response to the comments of respondents, and of the staff, the staff has undertaken its own economic analysis. That analysis still relies heavily upon the Department of the Interior study as many of the essential ingredients are not available from any other source.

c. Comparative National Benefits and Costs

i. Purpose and Definitions

Among the essential elements in judging the relative merits of the competing systems for transporting Alaskan gas are the prospective benefits and costs they offer. In the analysis presented here estimates of these key ingredients are made, from a particular viewpoint, and a comparison of the systems undertaken. The viewpoint is that of the nation as a whole.

Benefits are represented by the savings that result from the voluntary purchase by consumers of Alaskan gas, rather than alternative fuels, plus the cost of the gas to the consumer. The cost to the consumer is included because the costs to the nation as a whole will be estimated separately and subtracted to find net national benefits. To the extent that the consumers cost exceeds the national cost there will be a transfer of funds from consumers to transporters and producers; that is, from one group in the nation to another so that the national costs remain the same. Of course, if the consumer cost is less than the national cost the transfer is from producers and transporters to consumers. This view has the merit that it facilitates the choice of the most beneficial transport system and is largely independent of the distribution of the benefits among the nation's population. It avoids the difficulty of opting for smaller benefits for the purpose of obtaining a particular benefit distribution which can usually be obtained in other and less expensive ways. This savings concept applies to industrial uses through decreases in the production costs of goods for sale and to households through cheaper production of services, such as heating, for use in the household. Naturally, the savings that can be realized will depend upon the total gas demand at each gas price, and thus on the prices of competitive fuels; the non-Alaskan supplies of gas and the Alaskan supply. Among the alternative transportation systems the savings will vary according to the gas losses in transport to the point of entry and the transport cost of Alaskan gas from the entry point to the points of consumption. The national view here means that the maximum of aggregate savings is sought and no benefit is attached to giving preferential treatment, that reduces the aggregate savings, to uses in a particular consuming category or geographical region.

There is widespread agreement that a domestic source of fuel, such as Alaskan gas, confers an additional benefit by reducing reliance upon insecure sources of foreign oil. Agreement ends at that point, however, and there seems to be no method that commands confidence for estimating such benefits.

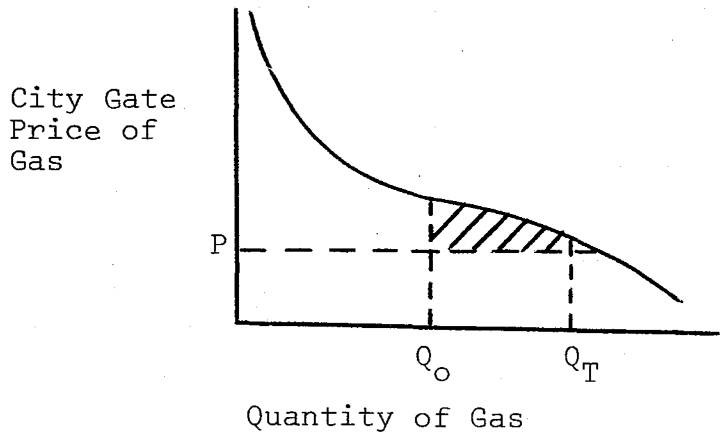
However, the results of this study show that the magnitude of these benefits has little effect on the feasibility or comparative ranking of the transport systems. Therefore, no attempt is made to estimate the magnitude of such benefits.

Costs, from a national standpoint, are the values of the resources used in the construction, operation and maintenance of the system. Values, in turn, are the resource unit prices that reflect the value of the services the resources could provide in alternative uses if the system were not built and operated. Thus, the costs already incurred for exploration and development on the North Slope and for existing pipelines are not counted. The resources so used can no longer yield services in any other way. Items such as income and property taxes paid in the United States, although costs from a private viewpoint, are simply transfers of funds on a national view and represent no application of resources. However, payment of foreign taxes can represent a transfer of resources, as a result of the fund transfer, to another nation. Such taxes are, therefore, costs to the United States. Furthermore, in one proposed alternative gas belonging to the United States is commingled with that belonging to Canada. In such cases, the costs are allocated between the two nations on the basis of proportionate MCF-miles of commingled transport. Finally, certain deviations from private cost accounting procedures are required. Capital costs are counted in the year incurred rather than being depreciated. An interest rate is applied, however, to account for the cost of using resources earlier rather than later. To avoid double counting, this interest rate substitutes for the bond interest and equity return in a private accounting.

No attempt is made here to value environmental costs and benefits. However, the difference between the net national benefits obtained for two delivery systems can be used to evaluate the cost of choosing an environmentally superior alternative.

ii. Benefits from Consumption

Consumption benefits, it will be recalled, are defined as the cost of Alaskan gas to the consumer plus the savings that result from its use rather than alternative fuels. The savings are, of course, the net benefit from the consumption of the additional gas. Its cost to the consumer is also included here because the social cost of producing and delivering the gas will be estimated separately. This definition is put into practice as follows. For each census region 1/ and each year that Alaskan gas flows a demand function, described in sub-section (f), that relates the total quantity of gas consumed to the city gate price of gas has been estimated. The graph of one of these functions is depicted below.



1/ Census Region 1: New England: Connecticut, Maine, New Hampshire, Vermont, Massachusetts, Rhode Island.

Census Region 2: Middle Atlantic: New Jersey, New York, Pennsylvania.

Census Region 3: East North Central: Illinois, Indiana, Michigan, Ohio, Wisconsin.

Census Region 4: West North Central: Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota.

Census Region 5: South Atlantic: Delaware, Florida, Georgia, Maryland, District of Columbia, North Carolina, South Carolina, Virginia, West Virginia.

Census Region 6: East South Central: Alabama, Kentucky, Mississippi, Tennessee.

Census Region 7: West South Central: Arkansas, Louisiana, Oklahoma, Texas.

Census Region 8: Mountain: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming.

Census Region 9: Pacific: Alaska, California, Oregon, Washington.

Suppose that a total quantity, Q_T, of gas is consumed of which the quantity, Q_o, is not Alaskan. If P is the price of Alaskan gas then an amount $P(Q_T - Q_o)$ is paid for Alaskan gas. The curve is constructed so that at each quantity the gas price on the curve is the one at which alternative fuels and gas are equally expensive in use. If the price is below that on the curve the difference represents the saving available from using gas at that price. Then the shaded area represents the net saving from buying Alaskan gas at price P. That price will depend on the wellhead and delivery cost of Alaskan gas which may differ among the transportation systems. It is necessary, then, to estimate the gross benefit, $P(Q_T - Q_o)$ plus the shaded area, and later subtract the estimated costs. The gross benefits are added over census regions to obtain the gross national benefit for the year.

The gross national benefit for a given year depends on the manner in which both the Alaskan and non-Alaskan gas available to the nation are allocated among regions in that year. This allocation has been carried out in two ways. In the first method, the non-Alaskan gas was allocated so as to maximize the gross national benefit from its use. Then all the gas was allocated according to the same criterion. The gross benefit attributable to Alaskan gas is the difference between the two gross benefit figures. In the second method, the non-Alaskan gas was allocated according to projections made of plausible distribution of future supplies. Then, the Alaskan gas was distributed so as to maximize its gross benefits. The second method yields larger benefits to Alaskan gas, and is a less desirable method, because its benefits result in part from correcting misallocations of non-Alaskan gas.

In both methods account was taken of the cost of transporting Alaskan gas from the point of entry, Chicago or Los Angeles. These lower 48 transport costs were deducted from the gross benefits. Operating and maintenance costs alone are included since depreciation and equity return on existing pipelines are not, as noted above, costs to the nation. Capital costs for new lower 48 pipeline construction, where necessary, are added to the system costs. Naturally, the maximization of gross benefits, less lower 48 transport costs, results in different benefits and Alaskan gas allocations for the two points of entry.

The gross national benefits obtained differ according to the assumptions made regarding the price of alternative fuels, the non-Alaskan supply, the Alaskan supply, the system transmission losses and the lower 48 transport costs. Alternative assumptions have been introduced as follows:

* Alternative fuel prices: separate functions for $8, $12, and $15 prices for oil. These demand functions are described in sub-section (f).

* Non-Alaskan supply: three sets of supply assumptions; representing low, intermediate and high supplies. These assumptions are also described in sub-section (f).

* Alaskan supply: daily flow rates of 2.5 Bcf/day for 20 years; 2.5 Bcf/day for 3½ years and 3.5 Bcf/day for the subsequent 16½ years; 2.25 Bcf/day for 25 years for Alaskan Arctic only and rates of 2.4 and 3.3 Bcf/day for El Paso only.

* Lower 48 Transport Costs: 1, 2 and 4¢/Mcf/100 miles.

* Transmission losses:

	2.5 Bcf/day	3.5 Bcf/day
Alaskan Arctic	6.4%	10.4%
El Paso	11 %	12.4%
Improved El Paso	8.5%	9.9%
Fairbanks-Alcan	5.4%	9.5%

The annual gross national benefits are added together using a discount rate of 10% to reflect the fact that earlier consumption is more valuable than later. More precisely, the present value of the benefits as of January 1, 1977 is found. Results representative of the effects of different assumptions are presented in the tables below for the applicants proposals and the FPC Staff Fairbanks-Alcan Highway alternative. All the tables are based upon the first method of allocating non-Alaskan supplies.

Table I-B

Gross Benefits-Billions of Dollars
Discount rate 10%, $12/barrel oil, o¢ lower 48 Transport Costs

Non-Alaskan Supply	High		Low	
Alaskan Supply	2.5	2.5 to 3.5	2.5	2.5 to 3.5
Arctic	11.43	14.07	13.76	16.91
El Paso	10.87	13.66	13.09	16.42
Improved El Paso	11.17	14.05	13.45	16.89
Fairbanks-Alcan	11.55	14.22	13.91	17.09

Table I-C

Gross Benefits-Billions of Dollars
Discount rate 10%, $12/barrel oil, 2¢ lower 48 Transport Costs

Non-Alaskan Supply	High		Low	
Alaskan Supply	2.5	2.5 to 3.5	2.5	2.5 to 3.5
Arctic	10.57	13.07	13.04	16.04
El Paso	10.30	12.86	11.73	14.65
Improved El Paso	10.57	13.22	12.06	15.06
Fairbanks-Alcan	10.68	13.21	13.18	16.21

Table I-D

Gross Benefits-Billions of Dollars
Discount rate 10%, $8/barrel oil, 0¢ lower 48 Transport Costs

Non-Alaskan Supply	High		Low	
Alaskan Supply	2.5	2.5 to 3.5	2.5	2.5 to 3.5
Arctic	8.15	10.05	10.48	12.92
El Paso	7.75	9.76	9.97	12.56
Improved El Paso	7.97	10.03	10.24	12.91
Fairbanks-Alcan	8.24	10.16	10.59	13.06

Table I-E

Gross Benefits-Billions of Dollars
Discount rate 10%, $15/barrel oil, 0¢ lower 48 Transport Costs

Non-Alaskan Supply	High		Low	
Alaskan Supply	2.5	2.5 to 3.5	2.5	2.5 to 3.5
Arctic	13.89	17.09	16.28	20.04
El Paso	13.21	16.60	15.48	19.47
Improved El Paso	13.58	17.07	15.91	20.01
Fairbanks-Alcan	14.04	17.27	16.45	20.25

In a qualitative way these results do not deviate from those that intuition suggests. The benefits increase with increasing oil prices, increasing Alaskan supply, decreasing non-Alaskan supply and decreasing lower 48 states transport costs. Naturally, they also decrease when the discount rate is increased. This variation is more conveniently introduced, however, when the benefits and the costs are considered jointly.

Transport costs in the lower 48 have a striking effect on the geographic distribution of Alaskan gas. For example, with zero transport costs in Table I-B, the geographic distribution is about the same for both Chicago and Los Angeles points of entry and the differences in gross benefits are due to transmission loss differences. However, when the 2¢ transport cost is introduced, as in Table I-C, with the high non-Alaskan supply, all the gas entering at Los Angeles is distributed to the Pacific and Mountain regions, while none of the gas entering at Chicago goes to these regions. This suffices to decrease the gross benefits from Los Angeles entry less than those from Chicago entry. That edge is lost, however, when the non-Alaskan supply is low as the optimal distribution from Los Angeles then requires sending more Alaskan gas into the interior. Generally, an entry point like Chicago, nearer the center of the consumption areas, is more advantageous, from the standpoint of lower 48 distribution costs, when the non Alaskan supply is low. This effect is exaggerated somewhat in the results presented, however, because the non-Alaskan supplies are distributed costlessly.

iii. Costs of Gas Production and Transportation

There are four major categories of costs to the nation involved in producing Prudhoe Bay gas and transporting it to lower 48 points of consumption.

1) Costs of Gas Production. These include costs of the further field development to make gas production possible plus the value of any oil not produced because gas is produced rather than reinjected. All exploratory and developmental costs incurred in the past are excluded.

2) Transportation Costs to the United States. These costs include, as costs to the nation, each system's construction costs plus operating and maintenance costs to its terminal point in the United States. Taxes paid to Canada are, of course, real resource costs to the United States, when they have been adjusted for inflation and balance of payments effects. Transmission losses are incorporated as a cost by appropriately reducing the amount of gas distributed and thus the gross benefits. No other costs to private parties are, in fact, costs to the nation as a whole.

3) Distribution Costs Within the United States. These costs include the operating and maintenance costs, allocable to Alaskan gas, of existing pipelines in the lower 48 states used for transporting Alaskan gas plus the construction costs of any new pipelines required for delivering Alaskan gas.

4) Environmental Costs. Costs in this category are not included in the present analysis, in part because they are difficult to quantify in an objective fashion. However, the difference between systems in net national benefits calculated here can be compared with the qualitative differences in their environmental effects.

In this section details are provided on the cost categories 1) and 3) above that are common to all the systems. The costs of gas production are taken from reference 9 , apparently the only available study of the development process and its costs. One method of development appears to minimize these costs over a considerable range of oil prices and discount rates, while providing a flow of 2.5 Bcf/day. In this method, development begins two years prior to the commencement of oil production and gas production begins in the seventh year at a rate of 2.5 BCFD. The total production of gas is 17.79 TCF. Scheduled in a fashion consistent with the assumed schedule for gas production, the present value of the cost at Jan., 1977 for various discount rates and oil prices is given in Tables I-F and I-G. The oil prices are at Prudhoe Bay and assumed to be $3 per barrel below those in the lower 48 states. Adjustments to these costs for higher gas flows can be found in reference 13.

Table I-F

Cost of Gas Production

Discount Rate	Maximum Oil, No Gas Gas and Water Injection		Optimal Mix of Oil and Gas		
	Oil Production (Billions of Barrels)	Costs (Billions of Dollars)	Oil Production (Billions of Barrels)	Gas Production (Tcf)	Costs (Billions of Dollars)
	(1)	(2)	(3)	(4)	(5)
0	8.40		8.01	17.80	
.05	5.23	5.75	5.09	8.43	7.96
.10	3.51	4.42	3.46	4.52	5.85
.15	2.50	3.62	2.48	2.29	4.62
.20	1.86	3.10	1.85	1.42	3.84

Table I-G

Cost of Gas Production
(Billions of Dollars)

Discount Rate	Oil Price Per Barrel: $5 a/	$9 b/	$12 c/
	(1)	(2)	(3)
0			
.05	2.91	3.46	3.88
.10	1.69	1.90	2.06
.15	1.11	1.19	1.23
.20	0.78	0.81	0.84

a/ For each discount rate, the entry equals, except for rounding, (Col. 1 - Col. 3, Table I-F) x $5 + (Col. 5 - Col. 2, Table I-F).

b/ For each discount rate, the entry equals, except for rounding, (Col. 1 - Col. 3, Table I-F) x $9 + (Col. 5 - Col. 2, Table I-F).

c/ For each discount rate, the entry equals, except for rounding, (Col. 1 - Col. 3, Table I-F) x $12 + (Col. 5 - Col. 2, Table I-F).

The lower 48 states transportation costs were modelled by measuring distances along major pipelines to the Census region centers of consumption from each of the two Alaskan gas delivery points, Chicago and Los Angeles. These distances were multiplied by approximations to the operating and maintenance costs for existing pipelines. Three approximations, 1, 2 and 4 cents per Mcf per 100 miles, were used.

"Census regional center of consumption" was defined as the centroid of the gas consumption in the states included in the region, locating each state's consumption at its population centroid.

The distances so found are shown in the following table in miles to the nearest hundred:

	1	2	3	4	5	6	7	8	9
Chicago to Region	1000	800	200	400	1100	600	800	1500	2100
Los Angeles to Region	3100	2800	2300	1800	2300	2000	1500	700	200

System-specific transportation costs are given in section (g) and include construction and operating and maintenance costs for new pipelines in the lower 48 states distribution system, that is, the displacement costs.

iv. Comparative Analysis of Alternatives

The plan of this section is as follows: First, the four alternatives costed by the Department of the Interior, i.e., Alaska-Canada, Alaskan-LNG, Improved Alaskan-LNG and Fairbanks-Alcan are compared. The Alaska-Canada alternative is essentially the routing currently proposed by Alaskan Arctic with the new Pacific Gas Transmission and Pacific Gas Electric facilities eliminated. Fairbanks-Alcan is the FPC staff Fairbanks alternative except that it follows the proposed Alaskan Arctic route all the way to Chicago rather than utilizing the Trans-Canada pipeline route. Because the cost of Fairbanks-Alcan and the FPC Staff alternative are about the same after their routes diverge, Fairbanks-Alcan can be regarded as the staff alternative for the purposes of this analysis. The two Alaskan-LNG proposals are essentially El Paso's proposed systems with, and without, the more efficient liquefaction plant. Second, the applicants proposals will be compared. Since the flow rates and costing methodologies differ, the applicants proposals cannot be compared directly with Fairbanks-Alcan. If, however, the Alaska-Canada and Alaska-LNG alternatives compare favorably with those proposed by Alaskan Arctic and El Paso, the comparison of the former with Fairbanks-Alcan can be presumed to indicate the nature of its merits compared with the applicants systems.

In table I-H the costs, discounted at 10%, are summarized for the first set of alternatives at Prudhoe Bay flow rates of 2.5 BCFD from mid 1982 through 1985 and 3.5 BCFD from 1986 through 2001.

Table I-H
Systems Costs
(Billions of Dollars)
Flow 2.5 to 3.5 BCFD, Discount rate 10%
$12/Barrel Oil

	Gas Transportation	Gas Production	Canadian Taxes	Displacement	Total
Alaskan-LNG	4.79	2.372	0	.327	7.489
Alaska-Canada					
Delta .5 to .9 BCFD	4.516	2.372	.462	.008	7.389
Delta 0 BCFD	5.22	2.372	.563	.008	8.163
Fairbanks-Alcan	4.93	2.372	.353	.008	7.663

Two cases are considered for Alaska-Canada, one with a Mackenzie Delta flow of .5 BCFD from mid 1982 through 1985 and .9 BCFD thereafter and one with no Mackenzie Delta flow. The cost difference between the two cases is due entirely to the fact that the United States bears all the costs when the Mackenzie Delta flow is zero. The proper interpretation of the latter case is that the system is built for a Mackenzie flow which does not materialize.

Combining these results with the gross benefits from Table I-C and other computations, the net national benefits exhibited in Table I-I are obtained. In the high non-Alaskan supply case the

Table I-I

Net National Benefits
(Billions of Dollars)

Alaskan Supply 2.5 to 3.5 BCFD

10% Discount Rate - 2¢/MCF/100 miles lower 48 Costs

	$12 per barrel oil		$8 per barrel oil	
Non-Alaskan Supply	High	Low	High	Low
Improved Alaskan-LNG	5.73	7.57	1.70	3.48
Alaska-Canada				
Mackenzie Delta - 5.9 TCF	5.68	8.65	1.73	4.74
0 TCF	4.91	7.88	.96	3.97
Fairbanks-Alcan	5.55	8.55	1.60	4.64

net benefits are substantially the same when the Mackenzie Delta flow is high. However, the LNG system is disadvantaged, relatively, when the non-Alaskan supply is low. This effect is due mainly to the fact, noted above, that Los Angeles is not a good entry point when non-Alaskan supplies are low. Then a relatively small amount of gas distributed to the Pacific and Mountain regions reduces its value there sufficiently that it is socially advantageous to being shipping gas to more distant points. Under these circumstances a system with an entry point, like Chicago, nearer the center of the consuming regions gains an additional advantage.

For the lower value for the Alaskan supplies the results appear in Table I-J. In this case, Alaskan Arctic obtains an advantage, relative to the other two alternative, when the Mackenzie Delta supply is positive, mainly because the proportion of the costs borne by Delta gas is higher than before.

Table I-J

Net National Benefits
(Billions of Dollars)

Alaska Supply 2.5 BCFD

10% Discount Rate - 2¢/MCF/100 miles lower 48 Costs

	$12 per barrel oil		$8 per barrel oil	
Non-Alaskan Supply	High	Low	High	Low
Improved Alaskan-LNG	4.20	5.69	1.10	2.55
Alaska-Canada				
Mackenzie Delta - 7.1 TCF	4.69	7.16	1.49	3.95
0 TCF	3.67	6.14	.47	2.93
Fairbanks-Alcan	3.99	6.49	.75	3.23

It is noteworthy that the net national benefits to the Fairbanks alternative are never more than .75 billion below those of the best alternative.

In Table I-K are presented results, analogous to those in Table I-J, for various values of the discount rate. The net benefits are lower for higher discount rates because the bulk of the costs prescribe the benefits. Variations in the discount rate, it is seen, do not change the net national benefit ranking. Indeed, the difference in the net benefits for the alternatives are reasonably stable with discount rate changes. However, for the worst case all the net national benefits are negative for discount rates of 15% and above.

Table I-K
Net National Benefits
(Billions of Dollars)
Flow 2.5 BCFD, High Non Alaskan Supply
$8/Barrel Oil, 2¢ lower '48 transport costs

Discount Rate	Improved Alaskan LNG	Alaska-Canada 1 BCFD Delta	Alaska-Canada 0 Delta	Fairbanks Alcan
.05	4.66	5.005	3.76	4.35
.10	1.098	1.49	.47	.75
.15	- .45	- .06	- .89	- .73
.20	- .93	- .56	-1.26	-1.19

The results of this analysis can be summarized as follows.

1) With the relatively low price of $8 per barrel for oil representing the cost of alternative fuels and a relatively large flow of Alaskan and Mackenzie gas there is little difference in the net national benefit of these three alternative transportation systems.

2) With a higher price for oil, large Alaska and Mackenzie Delta flows, and relatively large supplies of non-Alaskan gas there is again little difference between the alternatives. However, with relatively small non-Alaskan supplies, Alaskan LNG has lower net national benefits than the other two alternatives.

3) With relatively low oil prices, high non-Alaskan supply, and a low Prudhoe flow, Alaska-Canada is superior, when there is Delta gas, to both the Alaska LNG and Fairbanks Alcan alternatives. However, at a discount rate of 15% all the alternatives have a negative net national benefit.

4) Staff's Fairbanks alternative has a $1 Billion advantage over the best alternative when oil prices and the Alaska flow are high and non-Alaskan and Delta flows are low. Its worst disadvantage is $.75 Billion, when oil prices and the Alaska flow are low and non-Alaska and Delta flows are high. Thus, Fairbanks is the superior alternative in all cases if its lower environmental costs are judged to be worth $.75 Billion in economic benefits.

The comparative analysis of the applicants proposals, using their cost data (references 1 through 8), proceeds as follows. Table I-L presents the applicants construction, operating and maintenance costs and, in the case of Alaskan Arctic, Canadian taxes discounted at 10% to the assumed go-ahead date of January 1, 1977.

Table I-L

Applicants System Social Costs
(Billions of Dollars)
10% Discount Rate

	Alaskan Arctic	El Paso	
Flow	2.25 Prudhoe, 2.25 Delta	2.4 Prudhoe	3.3 Prudhoe
Applicants Costs	4.76	4.74	5.68
Gas Production	1.907	1.907	2.372
Displacment	--	.238	.327
Total	6.67	6.89	8.38

The national costs of gas production and displacement, where appropriate, have been added to the applicant's costs. Net national benefits, for $12 oil and 2¢ lower 48 transport costs, are shown in Table I-M

Table I-M

Net National Benefits
(Billions of Dollars)
$12/Barrel oil, 2¢ lower 48 transport costs
High non Alaskan Supplies

	Alaskan Arctic	El Paso	
Alaska Flow	2.25 Prudhoe, 2.25 Delta	2.4 Prudhoe	3.3 Prudhoe
Gross Benefits	10.54	10.87	14.59
Total Costs	6.67	6.87	8.38
Net National Benefits	3.87	3.98	6.21
Net National Benefit/Cost	.58	.58	.74

These figures yield comparisons that are similar to those obtained earlier. Namely, that for similar Prudhoe Bay flows, Alaska Arctic is somewhat superior for lower non-Alaskan supplies while the two applicants are almost even for the case of high non-Alaskan supplies. The case of the higher Prudhoe flow of El Paso is difficult to compare with the lower flow for Alaskan Arctic, since the net national benefits and the net national benefits per unit cost both rise as the Prudhoe Bay flow rises. However, the net national benefits for unit cost for the earlier comparison shown in Tables I-H, I-I, and I-K yield some additional insight.

Table I-N

Net National Benefits per Unit Cost

	Alaskan LNG	Alaska Canada High Delta Flow	Fairbanks-Alcan
From Tables I-H & I-I			
Non-Alaska Supply			
High	.77	.77	.72
Low	1.01	1.17	1.12
From Tables I-H & I-K	.15	.20	.10

These figures confirm that the Alaskan Arctic and El Paso comparison behaves like the Alaska-Canada and Alaska-LNG comparison; that is Alaskan Arctic, and Alaska-Canada, have an advantage over El Paso, and Alaska-LNG, when non-Alaskan supplies are low. Otherwise the alternatives are quite comparable. They strongly suggest, also, that the comparison of the Fairbanks-Alcan alternative with the applicants proposals, on the same basis, would yield results similar to those previously obtained. Namely, that in certain cases the FPC Staff Fairbanks alternative is superior on economic as well as environmental grounds and the economic cost of its superior environmental features is in no case more than about $.75 Billion spread over the 20 year period.

d.) Market Analysis

The social economic costs and benefits associated with the production, transportation, and consumption of Alaskan gas differ from the revenues that will accrue to and the costs that will be incurred by the corporations involved in the project. The revenues that the firms can receive from the sale of Alaskan gas (the equilibrium price times the quantity sold) are less than the area under the demand curve (the estimated social benefits). Further, the firms will incur costs which are not included in the estimated social costs: financing costs, property taxes, and income taxes.

There are potential social costs (primarily environmental costs) which are not costs to the firms. Since the alternative proposals include measures designed to prevent environmental damage, potential environmental costs have been internalized in the cost estimates. Estimates of possible environmental damages over and above those already internalized in the project designs are not included in the above estimates of social costs.

Since revenues necessarily fall short of estimated social benefits and private costs exceed social costs, it is conceivable that even though net social benefits are positive, net benefits to the applicants may not be. Alternatively expressed, although there may be sufficient revenues available to provide a positive rate of return to the applicants, there may not be enough to permit the rate of return requested by them. Thus, a market analysis was conducted in order to examine the net private benefits.

i.) Methodology

Discounted cash flows to the equity holders (the owners) were computed under a variety of assumed circumstances: four alternative discount rates (.05, .10, .15, and .20), two oil prices ($12/BBL and $8/BBL), three supplies of gas from other sources to customers in the continental United States (high, medium, and low), two charges (exclusive of capital costs) for transporting the Alaskan gas from the point of arrival in the continental United States to city gates (1¢ and 2¢ per MCF per 100 miles), three rates of inflation for construction costs in the Arctic Circle (0, 50, and 100 percent), and two alternative flows of gas from the Mackenzie Delta (2.25 and 1.5 BCFD). The discounted cash flows are higher the lower the discount rate, the higher the price of oil, the lower the supply of gas from other sources, the lower the transportation charges in the United States, the lower the construction costs in the Arctic Circle, and (for Alaskan Arctic) the higher the flow of gas from the Mackenzie Delta. (If the flow from the Delta diminishes, a larger percentage of Canadian Arctic's costs are charged for transporting Alaskan gas.)

The discounted cash flows do not include wellhead charges for the gas or income tax reductions from being able to carry tax losses forward or from the 10 percent investment tax credit. Ignoring the tax benefits, the discounted flows may be interpreted as the discounted revenues available for paying wellhead charges after providing the equity holders with a rate of return on their investment equal to the discount rate. Dividing a given discounted cash flow by the discounted flow of gas associated with it provides a wellhead price for gas. The omission of the tax benefits biases the results downward, and implies that either a higher rate of return could have been paid on equity or a higher wellhead price for gas or both. Estimates have been made of the maximum value of the investment tax credit to the companies. These estimates make it apparent that the credit will have an insignificant impact on the results.

Construction is assumed to begin on Jan. 1, 1977. This starting date implies an initial flow for El Paso Alaska in 1982 and for Alaskan Arctic in 1981. For purposes of estimating revenues, initial year production is assumed to be .67 of full flow for El Paso Alaska and .5 of full flow for Alaskan Arctic. All subsequent production years are assumed to be years of full production: 2.4 BCFD for El Paso Alaska and 2.25 BCFD for Alaskan Arctic, 365.25 days per year. Analysis is restricted to the 2.4 BCFD and 2.25 BCFD designs in order to make the alternative projects as nearly comparable as possible. Production is assumed to terminate in 2005. These assumptions imply total wellhead production of 20,749 TCF for El Paso Alaska and 20,134 TCF for Alaskan Arctic.

Revenues from the sale of Alaskan gas are estimated using the gross benefits model. Demand curves for Alaskan gas at the delivery point in the continental United States are determined in the same manner as for the social benefits. A market clearing price for each year is determined from the assumed production less the shrinkage consistent with the applicants filed designs.

The cost data employed are the applicants' most recent estimates. (References 1-8, supplemented by working papers supplied by the applicants. The working papers provide cost projections beyond the first three years of operation.) Canadian Arctic's costs are allocated between Mackenzie Delta and Alaskan gas on the basis of MCF miles. (Reference 4, Sections 8a and 11.) Taxable income is taxed at 53 percent in the United States and 47 percent in Canada. These rates reflect a combination of national, state, and provincial taxes.

ii.) Results of the Market Analysis

The results of the market analysis appear in Tables I-O to I-U. Tables I-O, I-Q, and I-S give the values of the discounted cash flows for alternative oil prices and supplies of non-Alaskan gas. Tables I-P, I-R and I-T provide the maximum wellhead prices for gas consistent with these flows and the indicated rates of return on equity.

Table I-O displays the most favorable case from the point of view of the applicants' profitability; Table I-S, the least favorable. Table I-O assumes a price of $12/BBL for oil and low supplies of non-Alaskan gas. Since these assumptions imply a relative scarcity of substitutes for Alaskan gas, it is not surprising that they generate the highest rates of return on equity. The assumptions in Table I-S (an $8/BBL price for oil and high supplies of non-Alaskan gas) imply that Alaskan gas will face competition from relatively abundant substitutes, and consequently lower rates of return will be generated.

In every case simulated, Alaskan Arctic earns a higher rate of return than El Paso. With $12 oil and low non-Alaskan supplies (Table I-P) Alaskan Arctic can earn as much as a 15 percent rate of return on equity and still cover the estimated wellhead cost of the gas. (The Department of Interior estimates that development and production costs will be approximately $.47 per MCF.) Under the same circumstances El Paso can only earn a 10 percent rate of return. Even with a reduced flow of gas from the Mackenzie Delta, Alaskan Arctic's position is superior to that of El Paso.

Because El Paso has a larger amount of investment eligible for the investment tax credit than Alaskan Arctic, El Paso's profitability is more sensitive to omission of the credit. However, estimates of the maximum value of the investment tax credit to each applicant suggest that its inclusion in the model will not significantly alter the results in Tables I-O to I-T. Table I-U provides estimates of the maximum addition to wellhead prices at each rate of return that inclusion of the credit will permit. For example, in Table I-P, El Paso can pay $.49 per MCF at the wellhead and still earn a 10 percent rate of return (if construction costs in the Arctic Circle do not increase). The value of the investment tax credit to El Paso is such that it can pay $.55 at the wellhead and still maintain a 10 percent rate of return. Inclusion of these investment tax credit values in Tables I-P, I-R and I-T has no significant impact on the rates of return to the applicants.

The supplies of substitute fuels influence the profitability of both applicants more than any other variable. An increase in the supply of non-Alaskan gas from low to high (Table I-P to Table I-R) reduces Alaskan Arctic's rate of return to 10 percent (at an assumed wellhead price of \$.47/MCF) and El Paso's to less than 5 percent. Neither applicant is able to sustain a positive rate of return (and cover the wellhead cost of gas), if, in addition to relatively high supplies of non-Alaskan gas, oil becomes relatively abundant (Table I-R to Table I-T). El Paso's position is sufficiently vulnerable that even with low supplies of non-Alaskan gas, a drop in the price of oil to \$8 prevents a positive rate of return. (Not shown in the tables.)

Construction cost contingencies in the Arctic Circle have a similar but moderate impact on both project designs, and do not seriously reduce the discounted cash flows. El Paso is more vulnerable to changes in the cost of transporting gas within the continental United States, but the impact of such changes is insignificant. (Not shown in the tables.) Within the range considered, a diminished flow in the Delta does not severely reduce Alaskan Arctic's profitability. If alternative fuels are scarce, Alaskan Arctic can maintain a 10 percent rate of return despite a reduced flow in the Delta and 100 percent inflation in construction costs in the Arctic Circle (Table I-P).

Table I-0

P = $12
M = 2
OS= low

Discounted Cash Flow (1977-2005)
($ millions)

		DF=2.25			DF=1.5		
	B / r	1	1.5	2.0	1	1.5	2.0
Alaskan Arctic	.00	21,750	21,219	20,687	20,866	20,209	19,551
	.05	8,564	8,214	7,865	7,968	7,528	7,087
	.10	3,713	3,462	3,210	3,279	2,958	2,637
	.15	1,684	1,491	1,298	1,349	1,101	853
	.20	738	582	426	468	268	68
El Paso	.00	16,229	15,802	15,376			
	.05	5,980	5,729	5,479			
	.10	2,378	2,212	2,047			
	.15	956	838	720			
	.20	339	250	162			

Table notes:
- P = price of oil/BBL
- M = transportation cost within the continental United States (¢/MCF mile)
- OS = supply of non-Alaskan gas (high, medium, low)
- r = discount rate
- B = multiplier for construction costs in the Arctic Circle
- DF = rate of flow of gas at full production in Mackenzie Delta (BCFD)

Table I-P

P = $12
M = 2
OS= low

Wellhead Price of Alaskan Gas
(¢/Mcf)

	r \ B	DF=2.25 1	DF=2.25 1.5	DF=2.25 2.0	DF=1.5 1	DF=1.5 1.5	DF=1.5 2.0
Alaskan	.00						
Arctic	.05	90	86	82	84	79	74
	.10	73	68	63	64	58	52
	.15	56	49	43	44	36	28
	.20	38	30	22	24	14	3
El Paso	.00						
	.05	63	60	58			
	.10	49	45	42			
	.15	34	30	26			
	.20	20	14	9			

Table notes: P = price of oil/BBL
M = transportation cost within the continental United States (¢/MCF mile)
OS = supply of non-Alaskan gas (high, medium, low)
r = discount rate
B = multiplier for construction costs in the Arctic Circle
DF = rate of flow of gas at full production in Mackenzie Delta (BCFD)

Table I-Q

Discounted Cash Flow (1977-2005)
($ millions)

P = 12
M = 2
OS= High

	r \ B	DF=2.25: 1	DF=2.25: 1.5	DF=2.25: 2.0	DF=1.5: 1	DF=1.5: 1.5	DF=1.5: 2.0
Alaskan Arctic	.00	16,632	16,068	15,499	15,651	14,993	14,336
	.05	6,331	5,957	5,578	5,661	5,220	4,779
	.10	2,580	2,309	2,034	2,086	1,765	1,444
	.15	1,035	826	614	652	404	156
	.20	331	163	-8	23	-177	-377
El Paso	.00	12,136	11,709	11,282			
	.05	4,367	4,117	3,866			
	.10	1,635	1,470	1,305			
	.15	566	448	330			
	.20	113	24	-65			

Table notes:
P = price of oil/BBL
M = transportation cost within the continental United States (¢/MCF mile)
OS = supply of non-Alaskan gas (high, medium, low)
r = discount rate
B = multiplier for construction costs in the Arctic Circle
DF = rate of flow of gas at full production in Mackenzie Delta (BCFD)

P = $12
M = 2
OS= high

Table I-R

Wellhead Price of Alaskan Gas
(¢/Mcf)

	B / r	DF=2.25: 1	DF=2.25: 1.5	DF=2.25: 2.0	DF=1.5: 1	DF=1.5: 1.5	DF=1.5: 2.0
Alaskan	.00						
	.05	66	62	58	59	55	50
Arctic	.10	51	45	40	41	35	28
	.15	34	27	20	22	13	5
	.20	17	8		1		
El Paso	.00						
	.05	46	43	41			
	.10	33	30	27			
	.15	20	16	12			
	.20	6	1				

Table notes:
P = price of oil/BBL
M = transportation cost within the continental United States (¢/MCF mile)
OS = supply of non-Alaskan gas (high, medium, low)
r = discount rate
B = multiplier for construction costs in the Arctic Circle
DF = rate of flow of gas at full production in Mackenzie Delta (BCFD)

Table I-S

P = $8
M = 2
OS= high

Discounted Cash Flow (1977-2005)
($ millions)

		DF=2.25			DF=1.5		
	B / r	1	1.5	2.0	1	1.5	2.0
Alaskan Arctic	.00	10,327	9,721	9,090	9,340	8,633	7,882
	.05	3,393	2,987	2,563	2,718	2,240	1,731
	.10	1,005	710	402	507	158	-213
	.15	96	-131	-369	-290	-560	
	.20	-274					
El Paso	.00	6,252	5,791	5,314			
	.05	1,722	1,447	1,162			
	.10	276	92	-97			
	.15	-210	-341				
	.20						

Table notes: P = price of oil/BBL
M = transportation cost within the continental United States (¢/MCF mile)
OS = supply of non-Alaskan gas (high, medium, low)
r = discount rate
B = multiplier for construction costs in the Arctic Circle
DF = rate of flow of gas at full production in Mackenzie Delta (BCFD)

Table I-T

Wellhead Price of Alaskan Gas
(¢/Mcf)

P = $8
M = 2
OS= high

	r \ B	DF=2.25: 1	DF=2.25: 1.5	DF=2.25: 2.0	DF=1.5: 1	DF=1.5: 1.5	DF=1.5: 2.0
Alaskan Arctic	.00						
	.05	36	31	27	28	24	18
	.10	20	14	8	10	3	
	.15	3					
	.20						
El Paso	.00						
	.05	18	15	12			
	.10	6	2				
	.15						
	.20						

Table notes:
- P = price of oil/BBL
- M = transportation cost within the continental United States (¢/MCF mile)
- OS = supply of non-Alaskan gas (high, medium, low)
- r = discount rate
- B = multiplier for construction costs in the Arctic Circle
- DF = rate of flow of gas at full production in Mackenzie Delta (BCFD)

Table I-U

Maximum Increases in Wellhead Prices Due to 10% Investment Tax Credit (¢/MCF)

r	El Paso	Alaskan Arctic
.05	4	2
.10	6	2
.15	8	3
.20	10	4

e. References

Alaskan Arctic Submissions

1. Alaskan Arctic Gas Pipeline Company, FPC Docket No. CP74-239, Capital Costs and Pro-Forma Financials, 1975 Cost Estimates, (Alaskan Company), Applicant Exhibit No. AA-31, filed Nov. 18, 1975, Supplemented by working papers supplied by the applicant.)

2. Alaskan Arctic Gas Pipeline Company, FPC Docket No. CP74-239, Capital Costs and Pro-Forma Financials, 1975 Cost Estimates, (Canadian Company), Applicant Exhibit No. AA-30, filed Nov. 18, 1975. (Supplemented by working papers supplied by the applicant.)

3. Canadian Arctic Gas Pipeline Limited, Financing Plan, Section 15, Prerequisite Authorizations, Section 16, Exhibits in Support of an Application to the National Energy Board of Canada.

4. Canadian Arctic Gas Pipeline Limited. Exhibit Consolidating Canadian Filings, Sections 8a, 8b1, 8b4, 8b7, 10, 11, 12, 13a, 13b, 14dN. (Supplemented by working papers supplied by the applicant.)

5. Pacific Gas Transmission Company, FPC Docket No. CP74-241, Election of Primary Pipeline Design Together with Supporting Exhibits and Testimony, Feb., 1976. (Supplemented by working papers supplied by the applicant.)

6. Northern Border Pipeline Company, FPC Docket No. CP74-290, Exhibits in Support of 1975 Cost Estimate. (Supplemented by working papers supplied by the applicant.)

El Paso Submissions

7. El Paso Alaska Company, Docket Nos. CP75-96, et al., Further Prepared Direct Testimony and Proposed Hearing Exhibits, Dec. 19, 1975, (Exhibit Nos. EP 196-230). (Supplemented by working papers supplied by the applicant.)

8. El Paso Alaska Company, et al., Western LNG Terminal Company, Point Conception Supplement No. 1, FPC Docket Nos. CP75-96, et al., Additional Prepared Direct Testimony and Proposed Hearing Exhibits on Behalf of Western LNG Terminal Company, filed Jan. 26, 1976, (Exhibit Nos. WL 39-47).

9. H.J. Gruy and Associates, Inc. Gas Supply Study, Alaskan Natural Gas Transportation System, Sadlerochit Reservoir, Prudhoe Bay Field, Alaska. Two volumes. Dallas, Texas (May, 1975).

10. Sherman H. Clark Associates. Demand for Natural Gas from the North Slope. Menlo Park, California (May, 1975). Subcontract for Aerospace Corporation study for Department of the Interior.

11. Sherman H. Clark Associates. North American Gas Supply and Demand. Menlo Park, California (October, 1975). Subcontract for Aerospace Corporation study for Department of the Interior.

12. United States Department of the Interior: Alaskan Natural Gas Transportation Systems: Economic and Risk Analysis. Study prepared by the Aerospace Corporation under contract to the Department of the Interior (June, 1975).

13. United States Department of the Interior. Alaska Natural Gas Transportation Systems: Economic and Risk Analysis. Final Conclusion and Results. Study prepared by the Aerospace Corporation under contract to the Department of Interior (Draft, February, 1976)

14. United States Department of the Interior. Alaska Natural Gas Transportation Systems. A Report to the Congress, Pursuant to Public law 93-153. December, 1975.

f.) Appendix - Demand and Supply Analyses

i. Non-Alaskan Supply Analysis

In the two volumes prepared by Sherman H. Clark Associates (references 10 and 11) a rather exhaustive compilation of non-Alaskan gas supply projections are summarized, compared and analyzed. For the purposes of the analysis presented here it is not necessary to document and justify particular supply assumptions in detail. It is important that the supply projections used include one that represents the highest range that is plausible, one that represents the lowest plausible range and an intermediate case. The fact that the analysis discriminates among the effects of various quantities of non-Alaskan supplies in the ranking of the transportation systems suggests that a broader range of assumptions is unnecessary.

The following supply projections, the ones employed, are the product of the study team's judgment applied to the projections presented in the referenced volumes.

Non-Alaskan Gas Supply
Tcf/Year

	1980	1985	1990	1995	2000	2005
High	21.2	23.9	25.9	26.9	27.9	28.9
Intermediate	16.7	17.0	17.6	18.1	18.6	18.6
Low	16.7	14.3	12.6	10.9	9.6	8.5

ii. Demand Analyses

The demand projections prepared by Sherman H. Clark Associates were also adopted (references 10 and 11). Naturally, any forecasts of gas demand over a period of 25 to 30 years may deviate considerably from the consumption that actually eventuates. For the following reasons, however, the adopted projections seem quite appropriate for net national benefit comparisons. The projections were developed in two stages. First, total energy consumption projections by end use were made. Then, for each of several oil prices, a careful analysis of the fuel substitution possibilities in the various end uses resulted in the share of gas in total energy consumption over a wide range of prices for gas. As a result, the gas demand forecasts at various oil and gas prices, given total energy consumption, are more reliable than the total energy consumption projections.

It can be expected, therefore, that the difference in the net national benefits, for given total energy consumption projections, are more reliable than the values of the net national benefits. Thus, the comparison of transportation systems is not affected by the principal source of unreliability in the demand forecasts. That source of unreliability may affect, however, the estimates of whether systems are feasible; i.e., whether the net national benefits are positive.

Tables I-V, I-W and I-X contain the demand schedules for all United States gas that were employed.

Table I-V

CITY GATE PRICE/DEMAND SCHEDULE FOR GAS-$12/Barrel Oil
(Billions of Cubic Feet at 1,000 Btu per Cubic Foot)
1980-2000

Price (cents per thousand cubic feet)	1980	1985	1990	1995	2000
New England					
320¢	221	229	252	282	338
300	221	241	269	292	351
280	252	290	336	391	445
260	360	529	653	757	851
240	444	691	853	987	1,122
220	485	785	949	1,103	1,275
200	511	831	1,003	1,219	1,383
180	530	891	1,073	1,303	1,488
160	546	928	1,131	1,385	1,601
140	569	968	1,192	1,472	1,710
120	585	1,010	1,268	1,566	1,832
Middle Atlantic					
320¢	996	990	1,111	1,223	1,330
300	1,132	998	1,128	1,246	1,357
280	1,385	1,223	1,145	1,271	1,390
260	1,752	2,008	2,598	2,168	2,271
240	2,700	3,452	3,854	4,412	4,721
220	2,798	3,833	4,410	4,948	5,470
200	2,919	4,016	4,632	5,220	5,800
180	2,979	4,080	4,711	5,348	5,958
160	3,025	4,141	4,805	5,461	6,072
140	3,051	4,191	4,879	5,564	6,193
East North Central					
320¢	2,478	2,601	2,718	2,913	3,107
300	2,510	2,635	2,750	2,955	3,173
280	2,873	3,018	3,221	3,461	3,730
260	3,003	3,322	3,681	4,220	4,652
240	3,430	4,149	4,738	5,255	6,517
220	3,528	4,293	5,257	6,386	8,052
200	3,552	4,447	6,207	7,661	8,765
180	3,645	5,422	6,682	7,868	8,958
160	3,975	5,596	6,862	7,979	9,092
140	4,058	5,675	6,934	8,073	9,200
120	4,103	5,731	6,999	8,151	9,301

Table I-V (continued)

Price (cents per thousand cubic feet)	1980	1985	1990	1995	2000
West North Central					
320¢	978	890	982	893	880
300	1,081	1,120	1,126	1,107	1,126
280	1,201	1,300	1,405	1,441	1,496
260	1,455	1,533	1,807	1,998	2,289
240	1,457	1,759	2,110	2,399	2,858
220	1,520	1,885	2,335	2,935	3,620
200	1,560	2,111	2,685	3,216	3,744
180	1,634	2,223	2,769	3,324	3,958
160	1,669	2,330	2,836	3,471	4,045
140	1,689	2,373	2,956	3,541	4,389
120	1,704	2,470	3,009	3,862	4,477
South Atlantic					
320¢	612	677	752	833	912
300	661	748	847	915	1,032
280	768	861	935	1,073	1,225
260	983	1,148	1,330	1,551	1,970
240	1,119	1,466	1,724	2,251	2,624
220	1,448	2,192	2,799	3,440	3,935
200	1,705	2,605	3,382	4,116	4,815
180	1,761	2,759	3,546	4,313	5,002
160	1,804	2,819	3,613	4,398	5,170
140	1,837	2,862	3,669	4,465	5,254
120	1,859	2,898	3,715	4,526	5,327
East South Central					
320¢	485	574	661	749	838
300	566	633	718	762	858
280	707	825	943	1,159	1,336
260	794	981	1,088	1,448	1,682
240	823	1,034	1,260	1,770	2,326
220	852	1,186	1,605	1,982	2,553
200	922	1,282	1,633	2,233	2,680
180	930	1,307	1,863	2,314	2,739
160	955	1,477	1,915	2,349	2,771
140	995	1,518	1,936	2.367	2,800
120	1,029	1,538	1,955	2,392	2,825

Table I-V (continued)

Price (cents per thousand cubic feet)	1980	1985	1990	1995	2000
West South Central					
320¢	974	1,045	1,118	1,222	1,297
300	1,002	1,089	1,183	1,287	1,399
280	2,605	2,284	2,015	1,880	1,520
260	3,785	4,178	4,462	4,656	4,972
240	4,299	4,879	5,559	6,256	7,199
220	6,109	7,646	8,299	9,164	10,322
200	6,564	7,748	8,402	9,824	10,818
180	6,763	8,186	8,961	9,938	10,924
160	6,953	8,274	9,023	10,011	11,013
140	7,011	8,325	9,079	10,084	11,093
120	7,072	8,375	9,132	10,143	11,162
Mountain					
320¢	568	610	679	761	845
300	643	675	737	795	871
280	681	758	837	923	1,020
260	760	859	954	1,054	1,190
240	880	1,036	1,220	1,416	1,529
220	953	1,139	1,347	1,570	1,860
200	959	1,152	1,405	1,750	2,136
180	1,042	1,299	1,680	2,013	2,292
160	1,151	1,456	1,758	2,039	2,331
140	1,185	1,484	1,776	2,066	2,412
120	1,191	1,491	1,789	2,123	2,432
Pacific					
320¢	1,209	1,123	1,203	1,193	1,013
300	1,057	1,155	1,251	1,303	1,240
280	1,107	1,199	1,310	1,383	1,390
260	1,328	1,442	1,576	1,659	1,855
240	1,775	1,748	2,000	2,286	2,535
220	2,065	2,706	3,234	3,766	4,256
200	2,979	3,926	4,499	5,053	5,593
180	3,023	3,976	4,562	5,143	5,708
160	3,052	4,016	4,613	5,209	5,791
140	3,079	4,049	4,653	5,263	5,858
120	3,103	4,075	4,691	5,304	5,911

Table I-W

CITY GATE PRICE/DEMAND SCHEDULE FOR GAS-$15/Barrel Oil
(Billions of Cubic Feet at 1,000 Btu per Cubic Foot)
1980-2000

Price (cents per thousand cubic feet)	1980	1985	1990	1995	2000
New England					
240¢	221	238	265	265	348
220	244	278	319	319	422
200	258	319	564	564	750
180	423	651	803	803	1,054
160	475	762	925	925	1,214
140	505	820	990	990	1,356
120	525	876	1,056	1,056	1,462
100	542	919	1,117	1,117	1,573
80	563	958	1,177	1,177	1,683
60	581	1,000	1,249	1,249	1,802
Middle Atlantic					
240¢	1,098	996	1,124	1,240	1,350
220	1,322	1,167	1,141	1,265	1,382
200	1,660	1,812	2,235	1,944	2,051
180	2,463	3,091	3,540	3,851	4,109
160	2,774	3,738	4,271	4,841	5,283
140	2,889	3,970	4,577	5,161	5,718
120	2,964	4,064	4,691	5,316	5,919
100	3,014	4,126	4,782	5,433	6,044
80	3,045	4,179	4,861	5,538	6,163
60	3,068	4,222	4,929	5,629	6,279
East North Central					
240¢	2,502	2,627	2,742	2,945	3,157
220	2,782	2,922	3,103	3,335	3,591
200	2,971	3,246	3,566	4,030	4,422
180	3,323	3,942	4,474	4,996	6,051
160	3,504	4,257	5,127	6,103	7,668
140	3,546	4,409	5,970	7,342	8,587
120	3,622	5,178	6,563	7,816	8,910
100	3,893	5,553	6,817	7,951	9,059
80	4,037	5,655	6,916	8,050	9,173
60	4,092	5,717	6,983	8,132	9,276

Table I-W (continued)

Price (cents per thousand cubic feet)	1980	1985	1990	1995	2000
West North Central					
240¢	1,055	1,063	1,090	1,054	1,065
220	1,171	1,255	1,335	1,358	1,404
200	1,392	1,474	1,706	1,859	2,087
180	1,457	1,703	2,034	2,299	2,715
160	1,504	1,854	2,297	2,801	3,430
140	1,550	2,055	2,598	3,146	3,713
120	1,616	2,195	2,748	3,297	3,905
100	1,660	2,303	2,819	3,434	4,023
80	1,684	2,362	2,926	3,524	4,303
60	1,700	2,445	2,996	3,782	4,455
South Atlantic					
240¢	649	730	823	895	1,002
220	741	833	913	1,034	1,177
200	929	1,076	1,231	1,432	1,784
180	1,085	1,387	1,626	2,076	2,461
160	1,366	2,011	2,530	3,143	3,607
140	1,641	2,502	3,236	3,947	4,595
120	1,747	2,721	3,505	4,264	4,955
100	1,793	2,804	3,596	4,377	5,128
80	1,829	2,851	3,655	4,448	5,233
60	1,854	2,889	3,704	4,511	5,309
East South Central					
240¢	546	618	704	759	853
220	672	777	887	1,060	1,217
200	772	942	1,052	1,376	1,596
180	816	1,021	1,217	1,690	2,165
160	845	1,148	1,519	1,929	2,496
140	905	1,258	1,626	2,170	2,648
120	928	1,301	1,806	2,294	2,724
100	949	1,435	1,902	2,340	2,763
80	985	1,508	1,931	2,363	2,793
60	1,021	1,533	1,950	2,386	2,820

Table I-W (continued)

Price (cents per thousand cubic feet)	1980	1985	1990	1995	2000
West South Central					
240¢	995	1,078	1,167	1,271	1,374
220	2,204	1,985	1,807	1,732	1,490
200	3,490	3,705	3,850	3,962	4,109
180	4,171	4,704	5,285	5,856	6,642
160	5,657	6,954	7,614	8,437	9,541
140	6,451	7,723	8,376	9,659	10,694
120	6,713	8,077	8,821	9,910	10,898
100	6,906	8,252	9,008	9,993	10,991
80	6,997	8,312	9,065	10,066	11,073
60	7,057	8,363	9,119	10,128	11,145
Mountain					
240¢	624	659	723	787	865
220	672	737	812	891	983
200	740	834	925	1,021	1,148
180	850	992	1,154	1,326	1,444
160	935	1,113	1,315	1,532	1,777
140	958	1,149	1,391	1,705	2,067
120	1,021	1,262	1,611	1,947	2,253
100	1,124	1,417	1,739	2,033	2,321
80	1,177	1,477	1,772	2,059	2,329
60	1,190	1,489	1,786	2,109	2,427
Pacific					
240¢	1,051	1,147	1,239	1,276	1,183
220	1,095	1,188	1,295	1,363	1,353
200	1,272	1,381	1,510	1,590	1,739
180	1,663	1,672	1,894	2,129	2,365
160	1,993	2,467	2,926	3,396	3,826
140	2,751	3,621	4,183	4,731	5,259
120	3,012	3,964	4,546	5,121	5,679
100	3,045	4,006	4,600	5,193	5,770
80	3,072	4,041	4,643	5,250	5,841
60	3,097	4,069	4,682	5,294	5,898

Table I-X

CITY GATE PRICE/DEMAND SCHEDULE FOR GAS-$8/Barrel Oil
(Billions of Cubic Feet at 1,000 Btu per Cubic Foot)
1980-2000

Price (cents per thousand cubic feet)	1980	1985	1990	1995	2000
New England					
360¢	221	235	261	287	345
340	237	266	303	342	398
320	306	410	495	574	648
300	402	610	753	872	987
280	465	738	901	1,045	1,199
260	498	808	976	1,161	1,329
240	521	861	1,038	1,261	1,436
220	538	910	1,102	1,344	1,545
200	558	948	1,162	1,429	1,656
180	577	989	1,230	1,519	1,771
Middle Atlantic					
360¢	1,064	994	1,120	1,235	1,344
340	1,259	1,111	1,137	1,259	1,374
320	1,569	1,616	1,872	1,720	1,831
300	2,226	2,730	3,226	3,290	3,496
280	2,749	3,643	4,132	4,698	5,096
260	2,859	3,925	4,521	5,102	5,635
240	2,949	4,048	4,672	5,284	5,879
220	3,003	4,111	4,758	5,405	6,015
200	3,038	4,166	4,842	5,513	6,133
180	3,063	4,212	4,913	5,607	6,250
East North Central					
360¢	2,494	2,618	2,734	2,934	3,140
340	2,692	2,827	2,986	3,208	3,452
320	2,938	2,979	3,451	3,841	4,191
300	3,217	3,736	4,210	4,738	5,585
280	3,479	4,221	4,998	5,821	7,285
260	3,540	4,370	5,732	7,024	8,409
240	3,599	4,935	6,445	7,765	8,912
220	3,810	5,509	6,772	7,924	9,125
200	4,017	5,636	6,898	8,026	9,146
180	4,081	5,703	6,967	8,112	9,251

Table I-X (continued)

Price (cents per thousand cubic feet)	1980	1985	1990	1995	2000
West North Central					
360¢	1,030	1,005	1,054	1,000	1,003
340	1,041	1,210	1,266	1,274	1,311
320	1,328	1,417	1,606	1,720	1,890
300	1,456	1,646	1,959	2,199	2,571
280	1,489	1,822	2,223	2,667	3,239
260	1,540	1,998	2,510	3,076	3,682
240	1,597	2,167	2,727	3,270	3,851
220	1,652	2,277	2,803	3,398	4,002
200	1,679	2,352	2,896	3,506	4,217
180	1,697	2,421	2,983	3,702	4,433
South Atlantic					
360¢	637	713	800	874	972
340	715	805	891	994	1,129
320	876	1,005	1,133	1,312	1,598
300	1,051	1,307	1,527	1,901	2,297
280	1,284	1,829	2,262	2,846	3,280
260	1,577	2,399	3,091	3,778	4,375
240	1,733	2,682	3,464	4,215	4,909
220	1,783	2,789	3,580	4,356	5,086
200	1,821	2,841	3,641	4,432	5,212
180	1,848	2,880	3,692	4,496	5,291
East South Central					
360¢	526	604	690	756	848
340	637	729	831	961	1,097
320	751	903	1,016	1,304	1,509
300	809	1,008	1,174	1,609	2,004
280	838	1,110	1,433	1,876	2,440
260	887	1,234	1,619	2,108	2,617
240	926	1,296	1,748	2,274	2,710
220	943	1,392	1,869	2,332	2,755
200	975	1,498	1,926	2,358	2,786
180	1,012	1,528	1,946	2,380	2,813

Table I-X (continued)

Price (cents per thousand cubic feet)	1980	1985	1990	1995	2000
West South Central					
360¢	984	1,067	1,151	1,255	1,348
340	1,804	1,687	1,599	1,584	1,460
320	3,195	3,231	3,239	3,268	3,246
300	4,042	4,529	5,011	5,456	6,086
280	5,204	6,263	6,929	7,710	8,761
260	6,337	7,697	8,351	9,494	10,570
240	6,664	7,967	8,682	9,881	10,871
220	6,858	8,230	8,992	9,975	10,969
200	6,982	8,300	9,051	10,048	11,053
180	7,042	8,350	9,106	10,114	11,128
Mountain					
360¢	606	643	708	778	858
340	662	717	787	859	946
320	721	809	896	989	1,105
300	820	948	1,087	1,235	1,360
280	917	1,088	1,284	1,493	1,695
260	956	1,146	1,376	1,660	1,998
240	1,001	1,226	1,543	1,882	2,214
220	1,047	1,378	1,719	2,026	2,312
200	1,168	1,470	1,767	2,053	2,372
180	1,188	1,488	1,783	2,095	2,422
Pacific					
360¢	1,043	1,139	1,227	1,248	1,127
340	1,082	1,177	1,281	1,343	1,315
320	1,218	1,321	1,443	1,521	1,623
300	1,552	1,595	1,788	1,973	2,195
280	1,920	2,227	2,617	3,026	3,396
260	2,522	3,316	3,867	4,410	4,925
240	3,001	3,951	4,531	5,098	5,651
220	3,038	3,996	4,588	5,176	5,750
200	3,066	4,033	4,633	5,236	5,825
180	3,091	4,062	4,672	5,284	5,885

g.) Appendix - System Descriptions and Costs

Alaska-Canada

This system essentially follows Alaskan Arctic's route except that the leg into California is eliminated. The pipeline from Prudhoe Bay to Travaillant Lake has been changed from the applicant's 48 inch to 42 inches, with a decrease in capital costs and an increase in operating costs and transmission losses, and the pipeline from the Mackenzie Delta to Travaillant Lake has been changed from 48 inches to 30 inches to accommodate the assumed Mackenzie Delta flow. The Prudhoe Bay (and Mackenzie Delta) flow is assumed to be 2.5 BCFD (5.BCFD) for the first 3½ years and 3.5 BCFD (.9 BCFD) for 16 years thereafter. A variant provides for flows of 2.5 BCFD and 1 BCFD from Prudhoe Bay and the Mackenzie Delta respectively. Further description can be found in references 13, 14 and 15. It is assumed that approval is given on Jan. 1, 1977 and first flow is mid 1982.

The costs for the two flows are given in Tables I-Y and I-Z.

Table I-Y

Alaska-Canada Costs
2.5 to 3.5 BCFD Prudhoe Bay Flow
0.5 to .9 BCFD Mackenzie Delta
(Billions of Dollars)

U.S. Share of Canadian Costs .82

	Capital	Operating and Maintenance	Canadian Taxes	United States Share
1977	.134	-		.115
1978	.372	-		.319
1979	1.291	-		1.106
1980	1.907	-		1.634
1981	2.056	-	-.008	1.762
1982	.732	.019	-.021	.644
1983	0	.038	-.028	.033
1984	0	.038	-.029	.033
1985	.625	.038	.026	.658
1986	0	.077	.194	.067
1987		.077	.187	.067
1988		.077	.179	.067
1989		.077	.169	.067
1990		.077	.157	.067
1991		.077	.146	.067
1992		.077	.136	.067
1993		.077	.125	.067
1994		.077	.115	.067
1995		.077	.106	.067
1996		.077	.099	.067
1997		.077	.091	.067
1998		.077	.084	.067
1999		.077	.077	.067
2000		.077	.070	.067
2001	0	.077	.064	.067

Transmission losses to Chicago in % Btu: 6.4% for 2.5 BCFD
10.4% for 3.5 BCFD

Table I-Z

Alaska-Canada Costs
2.5 BDFD Prudhoe Bay Flow
1.0 Mackenzie Delta Flow
(Billions of Dollars)

U.S. Share of Canadian Costs .75

	Capital	Operating and Maintenance	Canadian Taxes	United States Share
1977	.134		0	.103
1978	.375		0	.291
1979	1.308		0	1.013
1980	1.838		0	1.471
1981	1.872		-.007	1.572
1982	.662	.028	-.017	.571
1983	0	.057	-.023	.030
1984			-.024	.029
1985			.022	.063
1986			.161	.167
1987			.155	.163
1988			.148	.158
1989			.140	.152
1990			.130	.144
1991			.121	.138
1992			.113	.131
1993			.103	.125
1994			.095	.118
1995			.088	.113
1996			.082	.108
1997			.075	.103
1998			.070	.099
1999			.064	.095
2000			.058	.090
2001	0	.057	.053	.088

Transmission losses to Chicago in % Btu: 6.4%

Alaskan - LNG

The Alaskan-LNG system is generally similar to that proposed by El Paso but differs in various respects relating to the assumed flows and the use of the Alyeska right-of-way. The two flow assumptions for Prudhoe Bay are identical with those used for Alaska-Canada. Further description can be found in references 13, 14 and 15.

The costs are given in Tables I-AA and I-BB.

Table I-AA

Alaskan LNG
2.5 to 3.5 BCFD Prudhoe Bay Flow
Billions of Dollars

	Capital Costs	Operating and Maintenance	Displacement Capital Costs
1977	.089		
1978	.414		
1979	1.176		
1980	1.709		
1981	1.553		.290
1982	.592	.070	.023
1983	.298	.109	
1984	.291	.109	
1985	.308	.109	.279
1986 thru 2001	0	.149	

Table I-BB

Alaskan LNG
2.5 BCFD Prudhoe Bay Flow
Billions of Dollars

	Capital Costs	Operating and Maintenance
1977	.089	
1978	.424	
1979	1.211	
1980	1.757	
1981	1.570	
1982	.551	.070
1983 thru 2001		.109

Transmission losses to Arvin in % Btu:

	2.5 BCFD	3.5 BCFD
Initial Proposal	11%	12.4%
Improved Proposal	8.5%	9.9%

Fairbanks-Alcan

This system transports only Prudhoe Bay gas. It follows the Alyeska right-of-way to Fairbanks and then runs parallel to the Alcan Highway until it reaches the Alaska-Canada route near Edmonton. From that point it follows the Alaska-Canada route to the United States border. This routing differs from the FPC Staff alternative which moves to the Trans-Canada right-of-way at its intersection with the Alaska-Canada route and enters the Unites States at Emerson. For the purposes of the analysis in this section the only relevant difference between Fairbanks-Alcan and the Staff alternative are their costs and transmission losses. The Staff alternative has not been separately costed south of Edmonton, but its cost should be substantially the same as that for the Alaska-Canada route below Edmonton. Further description can be found in references 13, 14 and 15.

The costs are given in Table I-CC.

Table I-CC

Fairbanks-Alcan Costs
Billions of Dollars

	2.5 BCFD Capital	2.5 BCFD Operating and Maintenance	Increment for 3.5 BCFD	Canadian Taxes
1977	.322	0		0
1978	.324			0
1979	1.191			0
1980	1.796			0
1981	1.957	0		0
1982	.634	.015		-.006
1983	0	.028		-.016
1984				-.022
1985			.573	-.020
1986			.022	.148
1987				.143
1988				.137
1989				.129
1990				.120
1991				.112
1992				.104
1993				.096
1994				.088
1995				.081
1996				.076
1997				.070
1998				.064
1999				.054
2000				.054
2001	0	.028	.022	.049

Transmission losses to Chicago in % Btu - 5.4% for 2.5 BCFD,
9.5% for 3.5 BDFD

2. Projected Socio-Economic Impacts of End-Use in Lower 48 States

The socio-economic impacts of Alaskan Gas delivery to the contiguous states will clearly be marginal. The volume of gas, roughly 2.5 BCFD (Billion Cubic Feet per Day) will constitute from 4% to 7% of U. S. consumption of natural gas in the 1980-1990 time frame, and less than 1% of total fuel consumption.

In the case of such long-run variations, always assuming reasonable planning horizons, a difference of 1% in total fuel or 5% in gas availability does not have a qualitatively different effect on economic aggregates than a change of 1% or 5% in the production of such other "necessities" as wheat or automobiles. Money is not transferred from consumers to gas producers and is not spent by the producers, but instead goes from consumers to the providers of alternative goods and services, who will generally tend to employ from the same labor force and purchase from the same gross product as the gas producers would have. The major difference, in this regard, lies in the specific Alaskan regions where the gas-producer activities would take place.

On the consumption side, the absence of this gas would cause similar, but much smaller, effects on the location of producing industries which would use the gas if it is available. The effect is smaller for two reasons. First, the percentage impact is small because the base in the lower 48 is so much larger than for Alaska alone. Secondly, there are so many even if the only alternative to Alaska Gas were Mid-East LNG imports, some of these imports could be brought to the West Coast more economically than for the affected industries to relocate to the East Coast. However, alternatives such as the use of coal or electricity are viable, at moderately higher price, for many of the consumers in question. More important, at the higher prices, various non-fuel alternatives also become viable.

Staff believes that the long-run impacts of the transportation alternatives on the end users of gas in the contiguous states can adequately be modelled within a very closely defined framework. This framework consists solely of the industrial users of natural gas, their levels of expenditure for direct, or first-round, purchases of gas, their long-run price elasticities, and the differences in gas price which will probably arise under the alternatives being considered.

Unfortunately, it has not been possible to model even this much of the impact adequately, because full analysis of the substitutions between fuels has not yet been performed. However, the relative impact of gas prices on total fuel costs can be estimated, and seems to provide a reasonable estimation of the impacts in question.

a) Socio-Economic Description

The starting point for the analysis must be the level of economic activity and energy requirements which follow from that level. It is not possible to enter a major discussion of the costs and benefits of economic growth versus, for example, a "zero-growth" scenario. It is possible, however, to perform a careful differential analysis of small perturbations to the economy. This is the procedure which will be followed.

I. National Energy Availability

It is assumed throughout this analysis that the issue of energy availability is one of price, rather than of quantity. That is, the existence of OPEC pricing is accepted, but a physical embargo on imports is not included. If the OPEC cartel can function as a perfect monopoly, the profit-maximizing strategy might, as a first approximation, lead to a price which cuts their total export volume in half. It is difficult to estimate this price, since it clearly depends on the production possibilities and the demand patterns of all the rest of the world, but it is probable that current OPEC prices are very close to such a level. It is also difficult to estimate the reduction in U. S. imports which follows from such a price, but it has been estimated 1/ that OPEC prices justify U. S. self-sufficiency between 1982 and 1987. To the extent that this is true, our model is realistic in assuming that energy availability is an economic, rather than a physical, issue.

In short, the question revolves around the price at which domestic energy supply will equilibrate with demand. To address this question, it is reasonable to start with the established

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1/ Seidel, M. R., Demand Curtailment and Conservation Scenarios, FEO, January 7, 1974.

patterns of supply, demand, and price. These patterns can then be modified to reflect major changes in the historic trends.

II. National Energy Use Patterns

A broad consensus of energy projections prior to the embargo envisioned a growth of energy consumption from the 70 Quads (Quadrillion British Thermal Units) of 1970 to roughly 140 Quads in 1990 and 190-200 Quads by 2000, with an annual growth rate of roughly 4%. This pattern envisioned a steady 25% share of energy going to transportation, while industry's share rose from 42% to between 45% and 55% by 2000 when utility consumption is fully allocated to end uses. (Electric output was generally expected to grow at an annual rate of 7%.)

Since the 1973 embargo and the OPEC price increases, it has been widely agreed that fuel consumption is price elastic, but there is little agreement on the most accurate set of premises on which to base a model of responses. Thus, there are many views on the way the economy will ultimately respond to decreased fuel consumption, or the patterns of fuel use which will ultimately emerge.

The construct which is generally followed here is the following: (1) the pattern of increasing reliance on oil imports during 1970-1973 rose from the simultaneous imposition of environmental costs and price controls in 1970-1971; (2) the national choices expressed in our environmental legislation lead to a set of fuel prices some 30% higher, compared to all other goods and services, than in the 1960's; (3) such fuel prices induce, over a moderate period of time, significant shifts in the fuel-intensity of processes and goods in the economy, but should not subtract from the economy by any more than the total cost of environmental protection itself, which has been estimated to lie in the range of 2% to 4% of GNP; (4) the impact on the energy sectors of the economy is such that total energy use will decline by 25% to 35% from the levels projected prior to 1973.

III. National Economic Growth

A one-time decision to internalize environmental costs 2/ of about 3% of GNP will necessarily lead, over some period of time, to the following effects on the economy: (1) a once-for-all decrease of some 3% (or one year's growth, effectively) of real GNP as currently defined; (2) no change in dollar GNP, since goods and services are simply diverted from purchases which go into the consumer's market bundle, to purchase environment quality which has been ratified by political processes but is not included in our measures of national product; (3) since dollar GNP stays the same while real GNP (as defined, excluding the worth of environmental quality) declines, inflation as measured by the GNP deflator rises 3% and (4) if an appropriate degree of environmental control has been chosen, the worth of an improved environment is up by more than real GNP is down, so that the Nation shows a net gain.

In the process, pollution-producing activities become relatively more expensive, so that (1) pollution-producing firms shift to cleaner processes; (2) firms which have cleaner processes gain an economic advantage; and (3) products which produce pollution that is hard to eliminate face the market test of whether consumers wish to buy those products at higher prices. The shifts between industries can be much more severe than the broad economic picture.

IV. Regional Economic Growth

For the same reason, the shifts among regions can be more severe than the national economic impact. Most of the analysis conducted on this subject seems to indicate, however, that neither the impacts on particular industries or the impact on particular regions will be unduly harsh. In many cases, the impact is simply a matter of altering the growth rate expected by an industry or region. It appears that some of the most rapid kinds of anticipated growth would have been at the expense of the environment, and the new trends simply mean that growth in these specific sectors will be much more modest. This change in expectations is a hardship for those who have anticipated and discounted the higher growth, but the hardship is not to be

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2/ Environmental Quality - 1972, CEQ, August, 1972.

compared to actually driving industries out of business, or turning regions into poverty pockets. As a general rule, the regions whose economies will be most impacted are the regions which otherwise would have had very high growth rates and significant environmental degradation as a result.

V. Regional Impacts of Energy Availability

To the extent that most environmental degradation (perhaps 80% or more) is directly or indirectly associated with the uses of fuels, most of the costs of environmental protection will have to show up in relatively higher fuel bills, either as higher prices for burning clean fuels or as higher costs for the cleanup of processes which use dirtier fuels. This effect will have differential impacts on various industries that have varying needs for particular fuels. But since fuel costs and availabilities vary greater from region to region, and since the most fuel-intensive industries tend to locate near the cheapest sources of their fuel, regions will feel much of the industry-specific variations as well as their own region-specific variations.

It is necessary to look at the degree to which higher fuel costs will impact different regions. It is not intuitively obvious, for example, whether a higher fuel price will have the harshest effects on regions which "depend on cheap fuels to attract industries" or on regions where fuel is so expensive that "if fuel costs rise any more all the industry will leave." Both arguments can be heard, coming from the affected local protagonists. It may be very difficult to resolve such issues.

b) Socio-Economic Model

To answer these regional impact questions, the FPC Office of Energy Systems prepared an analysis ("Regional Impacts of Industrial Fuel Use," September 1975) which addressed this topic. The analysis dealt with the extent to which higher fuel prices and conservation might cause changes in the patterns of fuel use and economic growth, at the levels of the Nation, region and state. The analysis of extrapolations to 1990 led to the inferences that (1) growth of energy demand may have been overestimated, (2) significant price-induced conservation is likely, (3) conservation will not be disastrous to any industry,

(4) prices will indeed target the fuel-wasters accurately, (5) no state or region will be impacted very seriously, and (6) state and regional differences will not be very large.

I. Regional Impacts of Industrial Fuel Use

This same "Regional Impacts" model has been applied to the question of the economic impact of transportation alternatives for Alaskan natural gas. The mocel begins with BEA (Bureau of Economic Analysis of the U. S., Department of Commerce) regional estimates of future activity in the manufacturing sectors of the economy, combined with industrial fuel requirements as they have been observed to vary across states.

Fuel price alone explains about 50% of the observed variation in fuel efficiency (in terms of earnings per unit of fuel used) in the most fuel-intensive industries, and price plus the scale of the industry in a state explains over 80% of the variation (over 90% in 8 of the 11 most fuel-intensive industry groups). We can with some confidence estimate the increase in fuel costs which will balance a future change in fuel availabiligy, and the increase in product costs (and loss of product sales) as a result of these fuel costs.

The basic question, of course, is whether such a model can indeed encompass very much of the total impact of changes in fuel availability. Staff believes that it can, and does. We will specifically consider the errors introduced by looking only at industry (ignoring residential and utility fuels), and by looking only at first-round or direct uses of fuel.

The analysis has the industrial sector absorbing the fuel-cost impacts. For the relatively small amount of gas under consideration, we believe that responses by the residential and utility sectors will not be significantly impacted, since the former will probably have priority for gas in any event, and the latter will probably not be using gas in either event. While there is a slight distortion in assuming that the entire impact is borne by the industrial sector, this distortion is only a second-order discrepancy.

Industries purchase fuel directly, and also purchase goods and services which embody indirect energy use. Such fuel is already counted in the consumption by the selling industry. It seems safe to ignore indirect consumption, for the differences between industries in their respective purchases or indirect or embodied fuel are relatively small. Even more important, this can only be analyzed by input-output methods, and inter-regional input-output tables are not available for this purpose. By the same token, the indirect fuel purchases are likely to be less regionalized than the direct purchases, so they can be omitted.

II. Baseline Projections of Historic Trends

Among the fundamental projections of future energy demand, two of the most widely accepted are the Reference Energy System of Brookhaven National Laboratory, 3/ and the West-Dupree "United States Energy Through the Year 2000." 4/ Unfortunately, neither these nor any other set of projections seems to have been thoroughly and consistently regionalized.

The FPC "Regional Impacts" model starts with Census of Manufactures data by industry group within state, adds the consumption of captive and feedstock fuels not included by Census, and correlates this fuel use with industry earnings and fuel prices. When the resulting correlation is extrapolated to the BEA Economic Projections to 1990, a continuing decline of real fuel prices by some $.07/MBtu (Million British Thermal Units) from 1971 levels (as projected before 1973) produces a match, within one percent, to the fuel use projected by West-Dupree and the Reference Energy System. More important, this projection has energy demand detailed by industry and by state.

3/ Associated Universities, Inc., Reference Energy Systems and Resource Data, AET-8, National Science Foundation, April, 1972.

4/ Dupree, W. G., and J. A. West, United States Energy Through the Year 2000, U. S. Department of Interior, December, 1972.

However, the decreasing-fuel-cost assumption is no longer suitable as a baseline. Instead, we have used a fuel price which is $.08/MBtu higher than 1971 prices in constant-dollar terms; this leads to a 1990 level of fuel use some 35% lower than the West-Dupree projections. These projects, applied to 1980 and 1990 compared with 1971 levels, are shown in Table 2.

III. Trends Modified by Energy Prices

The amount of gas to be delivered to the contiguous U. S. is estimated at about 2.25 BCFD, or about 850 TBtu per year. In Table 3, we show that an average fuel price about $.011/MCF lower will increase demand for total fuel and decrease product costs by enough to account for this amount of extra fuel. 1990 earnings in manufacture would increase (compared to the Baseline) by $250 million, which is about $.30 of extra earnings for each MCF of incremental gas.

This representation implies that the industrial demand for gas will exist if the incremental gas lowers the average price of all industrial fuel by $.011/MBtu, which will happen if the gas can be delivered at a price about $.30/MBtu lower than the price of the average Btu. This is not feasible, since the average price being modelled in the Baseline Case is only $.52/MBtu. (This is in 1971 dollars, but so is the $.30/MBtu mentioned above.)

This inconsistency is a function of the kinds of pricing policy which are in effect. We will deal with this subject at greater length below, in the discussion of regional effects.

IV. Model of Affected Regions Without Alaska Gas

If the increment of Alaskan gas is added to only a specific region of the country, the first-order effect of that gas will clearly be to make all fuel prices somewhat lower than they would otherwise have been, while leaving prices in other parts of the country unchanged. If the price difference is large compared to transportation costs, the differential will not remain localized; but if the price effect is moderate, such a regional analysis is adequate. There have always been regional variations in fuel costs and availability. As it develops, the demand side of the market will absorb the added gas without a large change in price, so it seems safe to confine the analysis to the affected states. The price levels observed in each State in the 1971 Census of Manufactures are taken to be as close an approximation to equilibrium as will be available, so these state-by-state prices have been modified by the necessary constant amount to accommodate demand for the added gas.

At the lower fuel prices, product costs are lower than they would otherwise have been. The model assumes that demand for these products is unit-elastic, and that production is not merely shifted from other states, but shows an absolute increase while production stays the same in regions which have no change in fuel availability.

c. Socio-Economic Impact of Alternative Availability

In Table 4 we show the Baseline activities in the nine affected States: Kansas, Oklahoma, Texas, New Mexico, Colorado, Utah, Arizona, Nevada, and California. These are the States which would seem directly affected by the El Paso preliminary proposal to transport Alaskan gas directly and by displacement eastward from the California-Arizona border. The Table shows sets of values for 1971, 1980, and 1990. For 1971, the "Earnings" from BEA's "Economic Projections to 1990" are given in 1971 dollars (these are 20.5% higher than the values tabulated by BEA in terms of 1967 dollars). The 1971 "Fuel" estimates are given in TBTU's, and come from the 1971 Census Report SR-6, with the addition of estimates of consumption of captive and feedstock fuels (which are omitted from SR-6) as detailed in the FPC/OES "Regional Impacts" analysis.

For 1980 and 1990, estimates are made, in the same units, using the econometric model and the assumption of 1971 constant-dollar state-by-state fuel prices modified by the amounts shown as "DP80" and "DP90". For the case with DP90 = $.08/MBTU, these fuel prices translate (in terms of 1975 dollars) into fuel prices of $.74/MCF, $6.95/barrel, $19.60/ton, and 16.3 mills/kwh for gas, oil, coal, and electricity. This set of prices is somewhat above the average price which is being paid for industrial consumption at the present time, though they are below the spot prices being paid at the margin. An equilibrium set of fuel prices will probably have gas and oil somewhat above these levels, with coal lower. (These "prices" represent the average of all consumption by manufacturing industries, including their captive consumption.)

Finally, for 1980 and 1990 we show the percentage growth from 1971 for Earnings and for Fuel consumption.

In Tables 9 through 11 we show a similar set of Baseline details for the twenty states which will receive significant shares of the gas under the Arctic Gas proposal.

I. Regional Industry Growth Expectations

Table 4 shows the growth anticipated for each industry affected by the El Paso proposal, and also shows the large disparities in the intensity of fuel use per dollar of earnings. While the Baseline growth for the entire Nation is 88% between 1971 and 1990 (from Table 2), Table 4 shows a growth of 102% for this 9-state region even without the Alaskan gas. Every state except Kansas would already be growing faster than the national average. The model also indicates that in the Baseline, the affected region's fuel use would go up only 37% to accommodate this 102% growth, while the Nation's fuel use would rise 43% to accommodate only 88% growth. This happens because the Baseline's higher prices cut the Southwest's energy waste.

Table 9 shows a somewhat different Baseline picture for the states affected by the Arctic Gas proposal. The states have a rather slower rate of economic growth (79% during 1971-1990) than the rest of the Nation (106%), and their fuel demand grows 39%, slightly below the 45% growth of the rest of the Nation.

II. Projections of Impact of El Paso Proposal

Table 5 shows the effect, on the 9-state El Paso region, of a $.03/MBTU decrease in the average price of industrial fuels used in the region. The effect is to increase fuel consumption by 850 TBTU in 1980 and 1990, compared to Baseline consumption. This is an increase of 15% in 1980's fuel use, and 13% in 1990's fuel use.

The lower price means that the fuel used in the Baseline case (6,738 TBTU in 1990) costs industry $202 million ($.03/MBTU * 6,738 TBTU) less than in the Baseline. But this saving is only 3.5% of the industry Earnings of $57,648 billion in the Baseline, and less than 3% of the Gross Product originating in the region. For this reason, Earnings are estimated to increase to $57,792; and at the lower price, this production uses a total of 7,581 TBTU.

It is instructive to compare each of the industries shown in Table 5 with the corresponding industry in Table 4. The general pattern which emerges is one of fuel-use increases which are disproportionate to the increase in production which is modelled. For the entire region, the effect seems to be only about $.17 of extra earnings in 1990 ($.13 in 1980) for each MBTU of total fuel, or MCF of gas, which is utilized.

The Baseline case for the rest of the Nation is shown in Table 6 for comparison. The general pattern is one in which the affected region has faster growth and higher fuel-intensiveness than the rest of the Nation. In Table 7 we show the total National picture when the gas is provided to the affected nine-state region. This bears comparison with Table 2, showing the National Baseline, and Table 3 showing the case when the gas is evenly distributed to the entire country.

III. Projections of Impact of Arctic Gas Proposal

Table 12 shows the effect of a $.027/MBTU decrease in the average cost of fuel in the 20 states affected by the Arctic Gas proposal. (As above, this value was chosen to accommodate an additional 850 TBTU of demand.)

The rate of growth in earnings is essentially the same as in the Baseline (79%), but fuel growth is up from 39% to 46%. Earnings in 1990 are $220.5 billion while using 16.55 QBTU in the Baseline, while the lower price and extra gas yeilds earnings of $220.8 billion while using 17.40 QBTU. This means the productivity of fuel drops from $13.3/MBTU to $12.7/MBTU, still much higher than the $9.3/MBTU of the remaining states which already have more cheap fuel.

d. Summary of Prime and Alternative Route Impacts

Table 8 is an explicit comparison of the 9-state effect with the Baseline case for each of the states, for the affected region, and for the entire Nation. In general, the region would be growing faster than the rest of the Nation with or without the added gas, and the presence of the gas does not change things very much.

On this basis, the added gas will serve to maintain a business-as-usual basis of rapid growth based on the presence of cheap fuel. But since the Alaskan gas will be far from cheap when it arrives, this model may not be realistic.

Table 14 is a similar comparison for the 20-state region to be served by the Arctic Gas proposal. This region would be growing slower than the rest of the Nation, with or without the added gas, as again the added gas does not have a very large effect on total Earnings. However, the effect is about 2½ times larger than for the El Paso route. Each extra MBTU adds some \$.39 to Earnings (compared to only \$.17 along El Paso).

The difference is mainly that the gas affects a region of higher-priced fuel, where more energy-efficient processes seem to prevail on average. The average Baseline price of fuels in the El Paso region is about \$.77/MBTU, but in the Arctic Gas region it is about \$1.12/MBTU. This automatically means that the incremental fuel will have a higher marginal product when it is introduced into the higher-cost region. (This is an elementary principle of economics; the present model is a complex quantification of this simple principle.)

Part of the reason why it contradicts the intuitive perception of the benefits of added fuel is that it does not try to take any account of industrial relocation. As stated above, it is assumed that lower fuel prices permit lower product costs and higher product sales, but not at the expense of other regions. In fact, the lower prices would also encourage some relocation of production, but any regional gains of this type would also have to be considered losses of production to the rest of the country, and would generally be netted out of a general equilibrium model.

In the economy at present, regulatory strategy permits a great deal of discriminatory pricing. This means that many industries have access to large amounts of cheap fuel, while many other firms have to pay much larger prices in order to obtain extra fuel for their needs. This means that the gas, as delivered, might indeed be cheaper, at the margin, than some of the alternative fuels or even the average of all the fuels being used.

Finally, the way in which prices are rolled into the average price will also have a major effect which we have not tried to model here. The effect is to make prices a little higher for a large number of established and relatively inelastic users, while keeping the marginal cost of extra fuel much lower for new users. When Alaskan gas is actually introduced into lower-48 pipelines, it will make a great deal of difference whether the higher-cost gas is paid for only by users at the receiving end, or by users all along the system.

Baseline Energy Demand for Entire Nation

BEA	Industry Group	SIC	1971 Earnings	1971 Fuel	1980 Earnings DP80=$0.050	1980 Fuel	Grwth Erngs	Pct. Fuel	1990 Earnings DP90=$0.080	1990 Fuel	Grwth Erngs	Pct. Fuel
493	Primary Metals	33	14309.	5797.6	16952.	6359.5	18.	10.	19237.	6942.5	34.	20.
450	Chemicals & Allied Prd.	28	12313.	4235.5	18706.	4977.8	52.	18.	26878.	6228.2	118.	47.
492	Petroleum & Coal Prdcts	29	3269.	3201.1	3991.	3162.6	22.	-1.	4875.	3477.5	49.	9.
495	Other	21,30,31,32,38,39	22353.	2155.0	33794.	2741.3	51.	27.	47031.	3405.2	110.	58.
491	Paper & Allied Products	26	6827.	1566.2	10027.	1996.5	47.	27.	13495.	2435.0	98.	55.
410	Food & Kindred Products	20	15901.	1285.2	19255.	1520.2	21.	18.	22813.	1769.2	43.	38.
480	Transportation Equip.	37	24122.	584.2	32668.	800.9	35.	37.	42189.	1037.9	75.	78.
420	Textile Mill Products	22	6379.	540.5	8069.	742.4	26.	37.	9719.	946.9	52.	75.
471	Machinery, Non-Elec.	35	20221.	525.9	29521.	797.9	46.	52.	38708.	1076.7	91.	105.
494	Fabr.Metals & Ordn.	19,34	15916.	496.3	23436.	712.2	47.	43.	31394.	934.7	97.	88.
472	Electrical Machinery	36	17752.	441.3	30196.	712.3	70.	61.	44738.	1010.9	152.	129.
460	Lumber & Furniture	24,25	8094.	383.2	10728.	498.5	33.	30.	13550.	632.3	67.	65.
440	Printing & Publishing	27	10563.	172.6	15663.	256.2	48.	48.	21590.	350.7	104.	103.
430	Apparel & Fabric Prods.	23	7732.	105.2	10506.	143.1	36.	36.	13282.	181.9	72.	73.
400	TOTAL MANUFACTURES		185738.	21488.8	263498.	25420.3	42.	18.	349484.	30428.5	88.	42.

FPC/OES STAGE ONE TEST RUN:

Captive, feedstock & State elec.shares estimated by OES
Earnings in $M(71) from "Area Economic Projections 1990"
Fuels in TBTU based on 1972 Census of Manufactures SR-6

Data covers some 75% of industrial fuels, 32% of all fuel
Data has the following significant omissions:
(1) Fuels in Residential & Transport Sectors;
(2) Effects of post-1971 prices and technology;
(3) Fuels used by Non-Manufacture industries.

Table 2 - Baseline Energy Demand for Entire Nation

Lower-Price Energy Demand for Entire Nation

BEA	Industry Group	SIC	1971 Earnings	1971 Fuel	1980 Earnings	1980 Fuel DP80=$0.037	Grwth Ernqs	Pct. Fuel	1990 Earnings	1990 Fuel DP90=$0.068	Grwth Ernqs	Pct. Fuel
493	Primary Metals	33	14309.	5797.6	17024.	6582.9	19.	14.	19313.	7152.9	35.	23.
450	Chemicals & Allied Prd.	28	12313.	4235.5	18739.	5282.6	52.	25.	26920.	6548.3	119.	55.
492	Petroleum & Coal Prdcts	29	3269.	3201.1	4013.	3358.4	23.	5.	4900.	3655.9	50.	14.
495	Other	21,30,31,32,38,39	22353.	2155.0	33818.	2822.6	51.	31.	47059.	3491.1	111.	62.
491	Paper & Allied Products	26	6827.	1566.2	10044.	2026.8	47.	29.	13514.	2466.2	98.	57.
410	Food & Kindred Products	20	15901.	1285.2	19266.	1523.6	21.	19.	22825.	1772.7	44.	38.
480	Transportation Equip.	37	24122.	584.2	32674.	797.3	35.	36.	42196.	1034.0	75.	77.
420	Textile Mill Products	22	6379.	540.5	8075.	732.4	27.	36.	9725.	936.0	52.	73.
471	Machinery, Non-Elec.	35	20221.	525.9	29529.	797.8	46.	52.	38717.	1076.7	91.	105.
494	Fabr.Metals & Ordn.	19,34	15916.	496.3	23444.	714.1	47.	44.	31403.	936.8	97.	89.
472	Electrical Machinery	36	17752.	441.3	30201.	710.8	70.	61.	44744.	1009.1	152.	129.
460	Lumber & Furniture	24,25	8094.	383.2	10733.	507.5	33.	32.	13556.	642.1	67.	68.
440	Printing & Publishing	27	10563.	172.6	15665.	253.8	48.	47.	21593.	347.9	104.	102.
430	Apparel & Fabric Prods.	23	7732.	105.2	10507.	143.2	36.	36.	13283.	182.0	72.	73.
400	TOTAL MANUFACTURES		185738.	21488.8	263716.	26252.8	42.	22.	349733.	31250.3	88.	45.

FPC/OES STAGE ONE TEST RUN:
Captive, feedstock & State elec.shares estimated by OES
Earnings in $M(71) from "Area Economic Projections 1990"
Fuels in TBTU based on 1972 Census of Manufactures SR-6

Data covers some 75% of industrial fuels, 32% of all fuel
Data has the following significant omissions:
(1) Fuels in Residential & Transport Sectors;
(2) Effects of post-1971 prices and technology;
(3) Fuels used by Non-Manufacture industries.

Table 3 - Lower-Price Energy Demand for Entire Nation

Baseline Energy Demand for El Paso Route, California-Kansas

BEA	Industry Group	SIC	1971 Earnings	1971 Fuel	1980 Earnings DP80=$0.050	1980 Fuel	Growth Erngs	Pct. Fuel	1990 Earnings DP90=$0.080	1990 Fuel	Growth Erngs	Pct. Fuel
493	Primary Metals	33	1313.	635.0	1710.	764.6	30.	20.	2044.	878.8	56.	38.
450	Chemicals & Allied Prd.	28	1618.	1234.8	2556.	1395.6	58.	13.	3864.	1782.0	139.	44.
492	Petroleum & Coal Prdcts	29	1402.	1888.6	1697.	1814.2	21.	-4.	2048.	1954.9	46.	4.
495	Other	21,30,31,32,38,39	2970.	434.0	4950.	570.2	67.	31.	7443.	738.5	151.	70.
491	Paper & Allied Products	26	595.	99.6	917.	151.2	54.	52.	1280.	205.2	115.	106.
410	Food & Kindred Products	20	3022.	234.9	3690.	280.7	22.	20.	4470.	334.4	48.	42.
480	Transportation Equip.	37	4277.	78.6	5692.	113.4	33.	44.	6796.	140.8	59.	79.
420	Textile Mill Products	22	146.	8.8	203.	12.9	39.	47.	275.	18.6	88.	112.
471	Machinery, Non-Elec.	35	2877.	56.2	4613.	105.7	60.	88.	6345.	159.1	121.	183.
494	Fabr.Metals & Ordn.	19,34	3062.	77.2	4453.	117.8	45.	53.	5970.	160.8	95.	108.
472	Electrical Machinery	36	3490.	61.5	6299.	117.8	81.	91.	9312.	175.2	167.	185.
460	Lumber & Furniture	24,25	1253.	62.2	1675.	84.1	34.	35.	2138.	110.6	71.	78.
440	Printing & Publishing	27	1633.	24.3	2608.	38.6	60.	59.	3728.	54.5	128.	124.
430	Apparel & Fabric Prods.	23	927.	10.6	1380.	16.7	49.	58.	1936.	24.5	109.	132.
400	TOTAL MANUFACTURES		28584.	4906.3	42444.	5583.4	48.	14.	57648.	6737.9	102.	37.

FPC/OES STAGE ONE TEST RUN:
Captive, feedstock & State elec.shares estimated by OES
Earnings in $M(71) from "Area Economic Projections 1990"
Fuels in TBTU based on 1972 Census of Manufactures SR-6

Data covers some 75% of industrial fuels, 32% of all fuel
Data has the following significant omissions:
(1) Fuels in Residential & Transport Sectors;
(2) Effects of post-1971 prices and technology;
(3) Fuels used by Non-Manufacture industries.

Table 4 - Baseline Energy Demand for El Paso Route, California-Kansas

Alaska-Augmented Energy Demand for El Paso Route, California-Kansas

BEA	Industry Group	SIC	1971 Earnings	1971 Fuel	1980 Earnings DP80=$0.017	1980 Fuel	Growth Erngs	Pct. Fuel	1990 Earnings DP90=$0.050	1990 Fuel	Growth Erngs	Pct. Fuel
493	Primary Metals	33	1313.	635.0	1734.	860.9	32.	36.	2071.	974.4	58.	53.
450	Chemicals & Allied Prd.	28	1618.	1234.8	2582.	1735.8	60.	41.	3900.	2139.4	141.	73.
492	Petroleum & Coal Prdcts	29	1402.	1888.6	1729.	2156.8	23.	14.	2085.	2264.5	49.	20.
495	Other	21,30,31,32,38,39	2970.	434.0	4963.	629.5	67.	45.	7460.	803.3	151.	85.
491	Paper & Allied Products	26	595.	99.6	921.	162.6	55.	63.	1284.	217.2	116.	118.
410	Food & Kindred Products	20	3022.	234.9	3695.	282.7	22.	20.	4475.	336.5	48.	43.
480	Transportation Equip.	37	4277.	78.6	5694.	111.5	33.	42.	6798.	138.8	59.	77.
420	Textile Mill Products	22	146.	8.8	203.	12.4	39.	41.	276.	18.0	89.	104.
471	Machinery, Non-Elec.	35	2877.	56.2	4615.	105.6	60.	88.	6348.	159.1	121.	183.
494	Fabr.Metals & Ordn.	19,34	3062.	77.2	4456.	119.0	46.	54.	5974.	162.1	95.	110.
472	Electrical Machinery	36	3490.	61.5	6301.	116.9	81.	90.	9315.	174.1	167.	183.
460	Lumber & Furniture	24,25	1253.	62.2	1677.	89.5	34.	44.	2141.	116.6	71.	88.
440	Printing & Publishing	27	1633.	24.3	2609.	37.4	60.	54.	3729.	53.1	128.	119.
430	Apparel & Fabric Prods.	23	927.	10.6	1380.	16.8	49.	59.	1936.	24.5	109.	132.
400	TOTAL MANUFACTURES		28584.	4906.3	42561.	6437.4	49.	31.	57792.	7581.4	102.	55.

FPC/OES STAGE ONE TEST RUN:
Captive, feedstock & State elec.shares estimated by OES
Earnings in $M(71) from "Area Economic Projections 1990"
Fuels in TBTU based on 1972 Census of Manufactures SR-6

Data covers some 75% of industrial fuels, 32% of all fuel
Data has the following significant omissions:
(1) Fuels in Residential & Transport Sectors;
(2) Effects of post-1971 prices and technology;
(3) Fuels used by Non-Manufacture industries.

Table 5 - Alaska-Augmented Energy Demand for El Paso Route, California-Kansas

Alaska-Augmented Energy Demand for Remainder, non El Paso

BEA	Industry Group	SIC	1971 Earnings	1971 Fuel	1980 Earnings DP80=$0.017	1980 Fuel	Growth Erngs	Pct. Fuel	1990 Earnings DP90=$0.050	1990 Fuel	Growth Erngs	Pct. Fuel
493	Primary Metals	33	12996.	5162.5	15241.	5594.9	17.	8.	17192.	6063.6	32.	17.
450	Chemicals & Allied Prd.	28	10695.	3000.7	16150.	3582.2	51.	19.	23014.	4446.3	115.	48.
492	Petroleum & Coal Prdcts	29	1867.	1312.5	2294.	1348.4	23.	3.	2827.	1522.6	51.	16.
495	Other	21,30,31,32,38,39	19383.	1721.0	28844.	2171.2	49.	26.	39588.	2666.7	104.	55.
491	Paper & Allied Products	26	6232.	1466.6	9110.	1845.3	46.	26.	12216.	2229.8	96.	52.
410	Food & Kindred Products	20	12879.	1050.3	15564.	1239.4	21.	18.	18344.	1434.8	42.	37.
480	Transportation Equip.	37	19846.	505.6	26976.	687.5	36.	36.	35393.	897.1	78.	77.
420	Textile Mill Products	22	6233.	531.7	7866.	729.5	26.	37.	9443.	928.3	52.	75.
471	Machinery, Non-Elec.	35	17344.	469.7	24908.	692.2	44.	47.	32364.	917.6	87.	95.
494	Fabr.Metals & Crdn.	19,34	12854.	419.1	18983.	594.4	48.	42.	25424.	773.8	98.	85.
472	Electrical Machinery	36	14263.	379.8	23897.	594.4	68.	57.	35426.	835.7	148.	120.
460	Lumber & Furniture	24,25	6841.	321.0	9053.	414.4	32.	29.	11412.	521.7	67.	63.
440	Printing & Publishing	27	8930.	148.3	13055.	217.7	46.	47.	17863.	296.1	100.	100.
430	Apparel & Fabric Prods.	23	6805.	94.6	9126.	126.4	34.	34.	11346.	157.4	67.	66.
400	TOTAL MANUFACTURES		157157.	16582.6	221057.	19837.0	41.	20.	291839.	23690.7	86.	43.

FPC/OES STAGE ONE TEST RUN:
Captive, feedstock & State elec.shares estimated by OES
Earnings in $M(71) from "Area Economic Projections 1990"
Fuels in TBTU based on 1972 Census of Manufactures SR-6

Data covers some 75% of industrial fuels, 32% of all fuel
Data has the following significant omissions:
(1) Fuels in Residential & Transport Sectors;
(2) Effects of post-1971 prices and technology;
(3) Fuels used by Non-Manufacture industries.

Table 6 - Alaska-Augmented Energy Demand for Remainder, non El Paso

Alaska-Augmented Energy Demand for Entire Nation

BEA	Industry Group	SIC	1971 Earnings	1971 Fuel	1980 Earnings DP80=$0.017	1980 Fuel	Growth Erngs	Pct. Fuel	1990 Earnings DP90=$0.050	1990 Fuel	Growth Erngs	Pct. Fuel
493	Primary Metals	33	14309.	5797.6	16975.	6455.9	19.	11.	19264.	7038.0	35.	21.
450	Chemicals & Allied Prd.	28	12313.	4235.5	18732.	5318.1	52.	26.	26914.	6585.7	119.	55.
492	Petroleum & Coal Prdcts	29	3269.	3201.1	4024.	3505.3	23.	10.	4912.	3787.2	50.	18.
495	Other	21,30,31,32,38,39	22353.	2155.0	33807.	2800.6	51.	30.	47048.	3469.9	110.	61.
491	Paper & Allied Products	26	6827.	1566.2	10030.	2007.9	47.	28.	13500.	2447.0	98.	56.
410	Food & Kindred Products	20	15901.	1285.2	19260.	1522.2	21.	18.	22819.	1771.2	44.	38.
480	Transportation Equip.	37	24122.	584.2	32670.	799.0	35.	37.	42192.	1035.9	75.	77.
420	Textile Mill Products	22	6379.	540.5	8069.	741.9	26.	37.	9719.	946.3	52.	75.
471	Machinery, Non-Elec.	35	20221.	525.9	29524.	797.8	46.	52.	38712.	1076.7	91.	105.
494	Fabr.Metals & Ordn.	19,34	15916.	496.3	23439.	713.4	47.	44.	31398.	936.0	97.	89.
472	Electrical Machinery	36	17752.	441.3	30198.	711.4	70.	61.	44741.	1009.8	152.	129.
460	Lumber & Furniture	24,25	8094.	383.2	10730.	503.9	33.	31.	13552.	638.3	67.	67.
440	Printing & Publishing	27	10563.	172.6	15663.	255.1	48.	48.	21591.	349.3	104.	102.
430	Apparel & Fabric Prods.	23	7732.	105.2	10506.	143.2	36.	36.	13282.	181.9	72.	73.
400	TOTAL MANUFACTURES		185738.	21488.8	263614.	26274.3	42.	22.	349628.	31272.0	88.	46.

FPC/OES STAGE ONE TEST RUN:

Captive, feedstock & State elec.shares estimated by OES
Earnings in $M(71) from "Area Economic Projections 1990"
Fuels in TBTU based on 1972 Census of Manufactures SR-6

Data covers some 75% of industrial fuels, 32% of all fuel
Data has the following significant omissions:
(1) Fuels in Residential & Transport Sectors;
(2) Effects of post-1971 prices and technology;
(3) Fuels used by Non-Manufacture industries.

Table 7 - Alaska-Augmented Energy Demand for Entire Nation

Energy and Earnings in Region Affected by El Paso Proposal

Case, State/Region	1971 Earnings	1971 Fuel	1980 Earnings	1980 Fuel	Growth Erngs	Pct. Fuel	1990 Earnings	1990 Fuel	Growth Erngs	Pct. Fuel
Baseline, Kansas	1260.	159.1	1744.	192.6	38.	21.	2296.	233.1	82.	46.
Alaskan Gas, Kansas	1260.	159.1	1748.	214.6	39.	35.	2301.	255.0	83.	60.
Differential Impact			4.	21.9	1.	14.	5.	21.9	1.	14.
Baseline, Oklahoma	1175.	157.6	1811.	183.1	54.	16.	2617.	235.4	123.	49.
Alaskan Gas, Oklahoma	1175.	157.6	1815.	213.0	54.	35.	2622.	264.7	123.	68.
Differential Impact			4.	30.0	0.	19.	5.	29.3	0.	19.
Baseline, Texas	6846.	2924.4	10441.	3121.4	53.	7.	14767.	3727.5	116.	27.
Alaskan Gas, Texas	6846.	2924.4	10506.	3778.2	53.	29.	14849.	4372.6	117.	50.
Differential Impact			65.	656.8	0.	22.	82.	645.1	1.	23.
Baseline, New Mexico	163.	23.4	255.	27.3	57.	17.	363.	32.6	123.	39.
Alaskan Gas, New Mexico	163.	23.4	256.	28.6	57.	22.	364.	33.8	123.	45.
Differential Impact			1.	1.3	0.	5.	1.	1.2	0.	6.
Baseline, Arizona	889.	93.9	1488.	118.6	67.	26.	2219.	147.8	150.	57.
Alaskan Gas, Arizona	889.	93.9	1491.	121.2	68.	29.	2222.	150.8	150.	61.
Differential Impact			3.	2.6	1.	3.	3.	3.0	0.	4.
Baseline, Colorado	1204.	97.2	1908.	132.5	58.	36.	2495.	169.7	107.	75.
Alaskan Gas, Colorado	1204.	97.2	1911.	143.2	59.	47.	2498.	180.7	108.	86.
Differential Impact			3.	10.7	1.	11.	3.	11.0	1.	11.
Baseline, Utah	485.	71.9	693.	85.7	43.	19.	952.	103.3	96.	44.
Alaskan Gas, Utah	485.	71.9	695.	91.8	43.	28.	954.	109.6	97.	52.
Differential Impact			2.	6.1	0.	9.	2.	6.3	1.	8.
Baseline, Nevada	84.	24.2	140.	28.4	66.	17.	210.	32.9	149.	36.
Alaskan Gas, Nevada	84.	24.2	141.	29.5	67.	22.	210.	34.0	150.	41.
Differential Impact			1.	1.1	1.	5.	0.	1.1	1.	5.
Baseline, California	16478.	1354.7	23964.	1694.0	45.	25.	31730.	2055.7	93.	52.
Alaskan Gas, California	16478.	1354.7	24000.	1817.5	46.	34.	31771.	2180.2	93.	61.
Differential Impact			36.	123.5	1.	9.	41.	124.5	0.	9.
* Baseline, El Paso Route	28584.	4906.3	42444.	5583.4	48.	14.	57648.	6737.9	102.	37.
* Alaskan Gas, El Paso Route	28584.	4906.3	42561.	6437.4	49.	31.	57792.	7581.4	102.	55.
* Differential Impact			117.	854.0	1.	17.	144.	843.5	0.	18.
* Baseline, U.S. Remainder	157157.	16582.6	221057.	19837.0	41.	20.	291839.	23690.7	86.	43.
* Alaskan Gas, U.S. Remainder	157157.	16582.6	221057.	19837.0	41.	20.	291839.	23690.7	86.	43.
* Differential Impact			0.	0.0	0.	0.	0.	0.0	0.	0.
** Baseline, Entire Nation	185738.	21488.8	263498.	25420.3	42.	18.	349484.	30428.5	88.	42.
** Alaskan Gas, Entire Nation	185738.	21488.8	263614.	26274.3	42.	22.	349628.	31272.0	88.	46.
** Differential Impact			116.	854.0	0.	4.	144.	843.5	0.	4.

Table 8 - Energy and Earnings in Region Affected by El Paso Proposal

Baseline Energy Demand for Arctic Gas Route

BEA	Industry Group	SIC	1971 Earnings	1971 Fuel	1980 Earnings DP80=$0.050	1980 Fuel	Growth Erngs	Pct. Fuel	1990 Earnings DP90=$0.080	1990 Fuel	Growth Erngs	Pct. Fuel
493	Primary Metals	33	11385.	4640.1	13251.	5009.4	16.	8.	14794.	5383.2	30.	16.
450	Chemicals & Allied Prd.	28	8202.	1836.5	12259.	2229.8	49.	21.	17151.	2745.4	109.	49.
492	Petroleum & Coal Prdcts	29	1460.	716.9	1778.	769.9	22.	7.	2167.	887.0	48.	24.
495	Other	21,30,31,32,38,39	15641.	1279.5	22514.	1559.8	44.	22.	29825.	1847.8	91.	44.
491	Paper & Allied Products	26	4197.	733.7	6016.	945.4	43.	29.	7904.	1152.0	88.	57.
410	Food & Kindred Products	20	9570.	739.9	11478.	870.5	20.	18.	13346.	997.9	39.	35.
480	Transportation Equip.	37	16995.	438.2	22787.	584.8	34.	33.	29685.	754.8	75.	72.
420	Textile Mill Products	22	1982.	162.0	2289.	197.9	16.	22.	2466.	219.6	24.	36.
471	Machinery, Non-Elec.	35	15410.	420.3	21804.	616.0	41.	47.	27730.	804.0	80.	91.
494	Fabr.Metals & Ordn.	19,34	10917.	357.7	15806.	493.5	45.	38.	20844.	629.8	91.	76.
472	Electrical Machinery	36	12084.	312.4	19554.	470.2	62.	51.	28194.	641.9	133.	105.
460	Lumber & Furniture	24,25	3016.	94.6	3902.	128.4	29.	36.	4820.	166.1	60.	76.
440	Printing & Publishing	27	7590.	121.7	10888.	176.1	43.	45.	14659.	236.5	93.	94.
430	Apparel & Fabric Prods.	23	4727.	59.1	5959.	76.3	26.	29.	6923.	90.1	46.	52.
400	TOTAL MANUFACTURES		123172.	11911.9	170279.	14127.5	38.	19.	220502.	16555.5	79.	39.

FPC/OES_STAGE_ONE_TEST_RUN:

Captive, feedstock & State elec.shares estimated by OES
Earnings in $M(71) from "Area Economic Projections 1990"
Fuels in TBTU based on 1972 Census of Manufactures SR-6

Data covers some 75% of industrial fuels, 32% of all fuel
Data has the following significant omissions:
(1) Fuels in Residential & Transport Sectors;
(2) Effects of post-1971 prices and technology;
(3) Fuels used by Non-Manufacture industries.

Table 9 -- Baseline Energy Demand for Arctic Gas Route

Baseline Energy Demand for Remainder, non-Arctic

BEA	Industry Group	SIC	1971 Earnings	1971 Fuel	1980 Earnings DP80=$0.050	1980 Fuel	Growth Erngs	Pct. Fuel	1990 Earnings DP90=$0.080	1990 Fuel	Growth Erngs	Pct. Fuel
493	Primary Metals	33	2925.	1157.5	3701.	1350.1	27.	17.	4443.	1559.3	52.	35.
450	Chemicals & Allied Prd.	28	4111.	2399.0	6447.	2748.0	57.	15.	9727.	3482.9	137.	45.
492	Petroleum & Coal Prdcts	29	1808.	2484.2	2213.	2392.7	22.	-4.	2708.	2590.5	50.	4.
495	Other	21,30,31,32,38,39	6712.	875.5	11280.	1181.6	68.	35.	17206.	1557.4	156.	78.
491	Paper & Allied Products	26	2631.	832.6	4011.	1051.1	52.	26.	5591.	1283.0	113.	54.
410	Food & Kindred Products	20	6330.	545.3	7777.	649.6	23.	19.	9467.	771.3	50.	41.
480	Transportation Equip.	37	7127.	146.1	9881.	216.1	39.	48.	12504.	283.1	75.	94.
420	Textile Mill Products	22	4398.	378.5	5780.	544.5	31.	44.	7253.	727.3	65.	92.
471	Machinery, Non-Elec.	35	4811.	105.5	7717.	181.9	60.	72.	10979.	272.7	128.	158.
494	Fabr.Metals & Ordn.	19,34	4999.	138.7	7630.	218.7	53.	58.	10550.	304.9	111.	120.
472	Electrical Machinery	36	5669.	129.0	10643.	242.1	88.	88.	16543.	369.0	192.	186.
460	Lumber & Furniture	24,25	5077.	288.6	6826.	370.1	34.	28.	8730.	466.2	72.	62.
440	Printing & Publishing	27	2973.	50.9	4775.	80.1	61.	57.	6931.	114.2	133.	124.
430	Apparel & Fabric Prods.	23	3005.	46.1	4547.	66.8	51.	45.	6359.	91.8	112.	99.
400	TOTAL MANUFACTURES		62574.	9577.0	93225.	11292.9	49.	18.	128986.	13873.1	106.	45.

FPC/OES STAGE ONE TEST RUN:
Captive, feedstock & State elec.shares estimated by OES
Earnings in $M(71) from "Area Economic Projections 1990"
Fuels in TBTU based on 1972 Census of Manufactures SR-6

Data covers some 75% of industrial fuels, 32% of all fuel
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(2) Effects of post-1971 prices and technology;
(3) Fuels used by Non-Manufacture industries.

Table 10 -- Baseline Energy Demand for Remainder, non-Arctic

Alaska-Augmented Energy Demand for Arctic Gas Route

BEA	Industry Group	SIC	1971 Earnings	1971 Fuel	1980 Earnings DP80=$0.020	1980 Fuel	Growth Erngs	Pct. Fuel	1990 Earnings DP90=$0.052	1990 Fuel	Growth Erngs	Pct. Fuel
493	Primary Metals	33	11385.	4640.1	13382.	5408.1	18.	17.	14933.	5761.3	31.	24.
450	Chemicals & Allied Prd.	28	8202.	1836.5	12291.	2467.9	50.	34.	17191.	3002.0	110.	63.
492	Petroleum & Coal Prdcts	29	1460.	716.9	1789.	853.2	23.	19.	2180.	969.2	49.	35.
495	Other	21,30,31,32,38,39	15641.	1279.5	22544.	1656.0	44.	29.	29861.	1947.6	91.	52.
491	Paper & Allied Products	26	4197.	733.7	6034.	977.7	44.	33.	7925.	1185.8	89.	62.
410	Food & Kindred Products	20	9570.	739.9	11493.	874.9	20.	18.	13361.	1002.3	40.	35.
480	Transportation Equip.	37	16995.	438.2	22798.	579.3	34.	32.	29697.	748.6	75.	71.
420	Textile Mill Products	22	1982.	162.0	2293.	192.2	16.	19.	2469.	214.0	25.	32.
471	Machinery, Non-Elec.	35	15410.	420.3	21818.	615.9	42.	47.	27746.	804.0	80.	91.
494	Fabr.Metals & Ordn.	19,34	10917.	357.7	15818.	496.2	45.	39.	20858.	632.8	91.	77.
472	Electrical Machinery	36	12084.	312.4	19561.	468.1	62.	50.	28204.	639.4	133.	105.
460	Lumber & Furniture	24,25	3016.	94.6	3905.	134.3	29.	42.	4823.	172.6	60.	82.
440	Printing & Publishing	27	7590.	121.7	10892.	172.5	44.	42.	14664.	232.2	93.	91.
430	Apparel & Fabric Prods.	23	4727.	59.1	5961.	76.4	26.	29.	6925.	90.2	46.	53.
400	TOTAL MANUFACTURES		123172.	11911.9	170573.	14972.4	38.	26.	220831.	17401.5	79.	46.

<u>FPC/OES STAGE ONE TEST RUN:</u>

Captive, feedstock & State elec.shares estimated by OES
Earnings in $M(71) from "Area Economic Projections 1990"
Fuels in TBTU based on 1972 Census of Manufactures SR-6

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(2) Effects of post-1971 prices and technology;
(3) Fuels used by Non-Manufacture industries.

Table 11 -- Alaska-Augmented Energy Demand for Arctic Gas Route

BEA	Industry Group	SIC	1971 Earnings	1971 Fuel	1980 Earnings DP80=$0.020	1980 Fuel	Growth Erngs	Pct. Fuel	1990 Earnings DP90=$0.052	1990 Fuel	Growth Erngs	Pct. Fuel
493	Primary Metals	33	2925.	1157.5	3701.	1350.1	27.	17.	4443.	1559.3	52.	35.
450	Chemicals & Allied Prd.	28	4111.	2399.0	6447.	2748.0	57.	15.	9727.	3482.9	137.	45.
492	Petroleum & Coal Prdcts	29	1808.	2484.2	2213.	2392.7	22.	-4.	2708.	2590.5	50.	4.
495	Other	21,30,31,32,38,39	6712.	875.5	11280.	1181.6	68.	35.	17206.	1557.4	156.	78.
491	Paper & Allied Products	26	2631.	832.6	4011.	1051.1	52.	26.	5591.	1283.0	113.	54.
410	Food & Kindred Products	20	6330.	545.3	7777.	649.6	23.	19.	9467.	771.3	50.	41.
480	Transportation Equip.	37	7127.	146.1	9881.	216.1	39.	48.	12504.	283.1	75.	94.
420	Textile Mill Products	22	4398.	378.5	5780.	544.5	31.	44.	7253.	727.3	65.	92.
471	Machinery, Non-Elec.	35	4811.	105.5	7717.	181.9	60.	72.	10979.	272.7	128.	158.
494	Fabr.Metals & Ordn.	19,34	4999.	138.7	7630.	218.7	53.	58.	10550.	304.9	111.	120.
472	Electrical Machinery	36	5669.	129.0	10643.	242.1	88.	88.	16543.	369.0	192.	186.
460	Lumber & Furniture	24,25	5077.	288.6	6826.	370.1	34.	28.	8730.	466.2	72.	62.
440	Printing & Publishing	27	2973.	50.9	4775.	80.1	61.	57.	6931.	114.2	133.	124.
430	Apparel & Fabric Prods.	23	3005.	46.1	4547.	66.8	51.	45.	6359.	91.8	112.	99.
400	TOTAL MANUFACTURES		62574.	9577.0	93225.	11292.9	49.	18.	128986.	13873.1	106.	45.

FPC/OES STAGE ONE TEST RUN:
Captive, feedstock & State elec.shares estimated by OES
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(2) Effects of post-1971 prices and technology;
(3) Fuels used by Non-Manufacture industries.

Table 12 -- Alaska-Augmented Energy Demand for Remainder, non-Arctic

Alaska-Augmented Energy Demand for Entire Nation

BEA	Industry Group	SIC	1971 Earnings	1971 Fuel	1980 Earnings DP80=$0.020	1980 Fuel	Growth Erngs	Pct. Fuel	1990 Earnings DP90=$0.052	1990 Fuel	Growth Erngs	Pct. Fuel
493	Primary Metals	33	14309.	5797.6	17083.	6758.2	19.	17.	19376.	7320.6	35.	26.
450	Chemicals & Allied Prd.	28	12313.	4235.5	18738.	5215.9	52.	23.	26917.	6484.9	119.	53.
492	Petroleum & Coal Prdcts	29	3269.	3201.1	4003.	3246.0	22.	1.	4889.	3559.7	50.	11.
495	Other	21,30,31,32,38,39	22353.	2155.0	33825.	2837.5	51.	32.	47067.	3505.0	111.	63.
491	Paper & Allied Products	26	6827.	1566.2	10045.	2028.8	47.	30.	13516.	2468.8	98.	58.
410	Food & Kindred Products	20	15901.	1285.2	19269.	1524.5	21.	19.	22828.	1773.6	44.	38.
480	Transportation Equip.	37	24122.	584.2	32678.	795.5	35.	36.	42202.	1031.7	75.	77.
420	Textile Mill Products	22	6379.	540.5	8073.	736.7	27.	36.	9722.	941.3	52.	74.
471	Machinery, Non-Elec.	35	20221.	525.9	29534.	797.8	46.	52.	38724.	1076.7	92.	105.
494	Fabr.Metals & Ordn.	19,34	15916.	496.3	23448.	714.9	47.	44.	31408.	937.7	97.	89.
472	Electrical Machinery	36	17752.	441.3	30204.	710.2	70.	61.	44747.	1008.4	152.	128.
460	Lumber & Furniture	24,25	8094.	383.2	10731.	504.4	33.	32.	13553.	638.8	67.	67.
440	Printing & Publishing	27	10563.	172.6	15666.	252.6	48.	46.	21595.	346.4	104.	101.
430	Apparel & Fabric Prods.	23	7732.	105.2	10508.	143.2	36.	36.	13284.	182.0	72.	73.
400	TOTAL MANUFACTURES		185738.	21488.8	263791.	26265.1	42.	22.	349813.	31274.5	88.	46.

FPC/OES STAGE ONE TEST RUN:
Captive, feedstock & State elec.shares estimated by OES
Earnings in $M(71) from "Area Economic Projections 1990"
Fuels in TBTU based on 1972 Census of Manufactures SR-6

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Data has the following significant omissions:
(1) Fuels in Residential & Transport Sectors;
(2) Effects of post-1971 prices and technology;
(3) Fuels used by Non-Manufacture industries.

Table 13 -- Alaska-Augmented Energy Demand for Entire Nation

Energy and Earnings in Regions Affected by Arctic Gas Proposal

Case, State/Region	1971 Earnings	1971 Fuel	1980 Earnings	1980 Fuel	Growth Erngs	Pct. Fuel	1990 Earnings	1990 Fuel	Growth Erngs	Pct. Fuel
Baseline, New England	12549.	566.5	17172.	737.7	37.	30.	21500.	894.4	71.	58.
Alaskan Gas, New England	12549.	566.5	17181.	751.4	37.	33.	21510.	908.6	71.	60.
Differential Impact			9.	13.7	0.	3.	10.	14.2	0.	2.
Baseline, Middle Atlantic	40252.	4328.1	54066.	4948.4	34.	14.	68570.	5618.1	70.	30.
Alaskan Gas, Middle Atlantic	40252.	4328.1	54168.	5256.6	35.	21.	68681.	5918.9	71.	37.
Differential Impact			102.	308.2	1.	7.	111.	300.8	1.	7.
Baseline, East North Central	58267.	5673.2	81191.	6782.4	39.	20.	106018.	8027.1	82.	41.
Alaskan Gas, East North Central	58267.	5673.2	81338.	7204.7	40.	27.	106185.	8452.7	82.	49.
Differential Impact			147.	422.3	1.	7.	167.	425.6	0.	8.
Baseline, West North Central	8431.	748.2	12317.	942.9	46.	26.	16546.	1147.9	96.	53.
Alaskan Gas, West North Central	8431.	748.2	12330.	969.8	46.	30.	16562.	1176.8	96.	57.
Differential Impact			13.	26.9	0.	4.	16.	28.9	0.	4.
Baseline, South Atlantic	21379.	2237.7	31966.	2904.7	50.	30.	44975.	3723.0	110.	66.
Alaskan Gas, South Atlantic	21379.	2237.7	31988.	2978.4	50.	33.	45001.	3799.5	110.	70.
Differential Impact			22.	73.7	0.	3.	26.	76.5	0.	4.
Baseline, Arctic Gas Route	123172.	11911.9	170279.	14127.5	38.	19.	220502.	16555.5	79.	39.
Alaskan Gas, Arctic Gas Route	123172.	11911.9	170573.	14972.4	38.	26.	220831.	17401.5	79.	46.
* Differential Impact			294.	844.9	0.	7.	329.	846.0	0.	7.
Baseline, U.S. Remainder	62574.	9577.0	93225.	11292.9	49.	18.	128986.	13873.1	106.	45.
Alaskan Gas, U.S. Remainder	62574.	9577.0	93225.	11292.9	49.	18.	128986.	13873.1	106.	45.
* Differential Impact			0.	0.0	0.	0.	0.	0.0	0.	0.
Baseline, Entire Nation	185738.	21488.8	263498.	25420.3	42.	18.	349484.	30428.5	88.	42.
Alaskan Gas, Entire Nation	185738.	21488.8	263791.	26265.1	42.	22.	349813.	31274.5	88.	46.
** Differential Impact			293.	844.8	0.	4.	329.	846.0	0.	4.

Table 14. -- Energy and Earnings in Regions Affected by Arctic Gas Proposal

3. Projected Socio-Economic Impacts in State of Alaska

a) Socio-Economic Description

i. Population and Demographic Characteristics

Alaska's population has grown very rapidly since 1940, exceeding the rate of growth in the lower 48 states. The 1975 population is estimated to be 384,400. See Table 15 for population totals by decades from 1880 to 1975.

Both natural increases (excess of births over deaths) and net migration have been important in Alaska's population growth. About 70 percent of the population increase between 1950 and 1970 was due to natural increase.

Migration to Alaska has been made up of both civilian and military components. Increases in military population were significant from 1940 to 1960. Not reflected in the military population shown on Table 15 are totals of over 150,000 during World War II and about 50,000 during the Korean War. Recently there has been substantial in-migration as a result of construction of the trans-Alaska oil pipeline system.

In 1970 only 1/3 of those living in Alaska had been born there. About 31 percent had lived in some other state in 1965.

Table 16 shows the regional distribution of Alaska's population in 1975. Figure 10 shows the location of each of these regions within the state. Anchorage and Fairbanks account for almost 60 percent of the population with Anchorage alone making up over 40 percent.

Selected demographic characteristics for Alaska and the total U. S. are shown in Table 17 . As compared with the U. S., Alaska (based on average figures) has a more rural, younger and more highly educated population. About 80 percent of Alaska's population is white, with the largest non-white segment represented by the native population (Eskimos, Aleuts, and Indians). The 17.1 percent native population shown in Table 17 for 1970 had decreased to 14.9 percent in 1975.

TABLE 15

ALASKA POPULATION 1880-1975

Year	Alaska Total	Native	Non-Native	Military
1880	33,426	32,996	430	--
1890	32,052	25,354	4,298	--
1900	63,592	29,542	30,450	--
1910	64,356	25,331	36,400	--
1920	55,036	26,558	28,228	250
1930	59,278	29,983	29,045	250
1940	72,524	32,458	39,566	500
1950	128,643	33,863	74,373	20,407
1960	226,167	43,081	150,394	32,692
1970	302,173	50,554	221,619	30,000
1975 a/	384,400	57,200	299,700	27,500

Sources: (1) Alaska State Department of Economic Development, Alaska Statistical Review (December, 1972). Source for 1880-1970 data

(2) Institute of Social, Economic and Government Research, University of Alaska, Outline of 1990 Projections Using Map Statewide and Regional Economic Models (June 27, 1975). Source for 1975 data

a/ Because of minor changes made in the MAP model, many 1975 figures shown in the socio-economic description section will differ slightly from 1975 figures in the socio-economic impact section.

TABLE 16

1975 POPULATION IN ALASKA BY REGION

Region	Number	Percent
South Central	53,661	14.2
Interior	9,966	2.6
Southeast	51,526	13.6
Southwest	27,644	7.3
Northwest	13,752	3.6
Anchorage	164,073	43.4
Fairbanks	57,829	15.3
Total	378,450 a/	100.0

Source: Institute of Social, Economic and Government Research, University of Alaska, Outline of 1990 projections using MAP Statewide and Regional Economic Models (June 27, 1975). The location of each region within the state is shown in Figure H-1.

a. The state total shown here is taken from the MAP regional model and is therefore different than the state total shown on table H-1, which is taken from the MAP state model.

TABLE 17

SELECTED 1970 DEMOGRAPHIC CHARACTERISTICS: ALASKA AND U.S.

Demographic Characteristic	Alaska	U.S.
Net migration 1960-70(percent)	7.1	1.7
Percent female	45.7	51.3
Percent Urban	48.8	73.5
Median age	22.7	28.3
Percent under 5 years of age	10.7	8.4
Percent 18 years and older	60.1	65.6
Percent 65 years and older	22.7	28.3
Median education, persons 25 years old and over	12.4	12.1
Percent completing four years of high school or more	66.7	52.3
Percent completing four years of college or more	14.1	10.7
Percent white	78.9	87.6
Percent native	17.1	--
Percent Black	3.0	11.1
Percent other	1.0	1.3

Sources: (1) U.S. Department of commerce, Bureau of the Census, County and City Data Book 1972, Washington, D.C.: U.S. Government Printing Office (March 1973). Source for everthing but racial data.

(2) Arbon R. Tussing and others, Alaska Pipeline Report University of Alaska: Institute of Social, Economic and Government Research, 1971. Source for racial data.

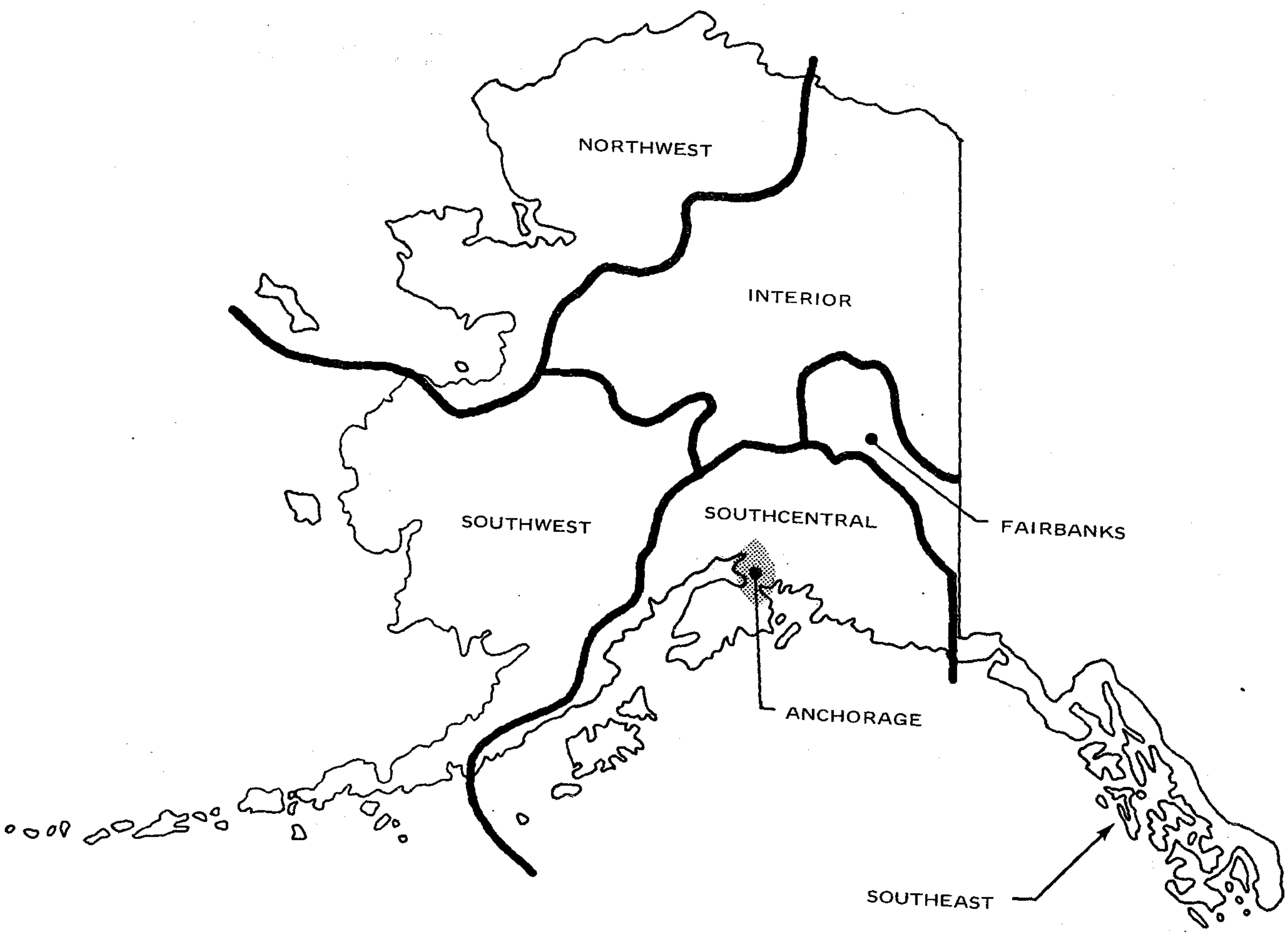

Figure 10 . Seven Alaska Geographic Regions

ii. The Alaskan Economy and Selected Economic Data

a. Brief Discussion and History of Alaskan Economy

Alaska's remoteness and climate set it apart from all other states. The distance from the lower 48, limited road and rail access, limited population, and the impact of the weather have all limited the developments of a self sufficient state economy. Due largely to its historical dependence on outside funds and markets, Alaska has had a tendency to undergo boom and bust cycles throughout its history. These booms have been based upon fur, gold, copper, timber and oil. The most recent boom began with the discovery of oil on the Kenai Peninsula in 1957. Other important contributions to the Alaskan economy have been made by railroad construction up to 1920 and by the military since 1940.

Table 18 shows the percentage of employment and Gross State Product (GSP)1/ accounted for by broad economic sectors for selected years. Although its relative importance is decreasing, government continues to be the largest single contributor to the Alaskan Economy. In 1975, it accounted for 40 percent of the employment and about 19 percent of the GSP.

If the broad economic sectors shown in Table 18 were broken down into their individual industries, the leading industry in terms of GSP would be the petroleum industry which accounted for over 80 percent of the GSP in the mining sector in 1973. The fishing industry has the highest peak season employment. Until it was recently surpassed by the petroleum industry, the fishing industry for many years had also been the major industry in terms of value of production.

An important feature of the Alaskan economy is the change in basic structure that has been taking place since statehood in 1959. During the period 1960-75 there has been considerable change in the relative importance of both broad economic sectors and individual industries within those sectors. Prior to 1960, Alaska's major industries, excluding government,

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1/ GSP can be defined as the total value of all goods and services produced in the state for a given period of time.

TABLE 18

PERCENTAGE OF GROSS STATE PRODUCT AND EMPLOYMENT ACCOUNTED FOR BY ECONOMIC SECTOR

Economic Sector	Gross State Product			Employment		
	1961	1970	1975	1960	1970	1975
Mining	5.4	24.8	17.9	1.0	2.1	1.1
Contract Construction	4.9	4.2	7.8	5.4	4.8	9.5
Manufacturing	10.3	7.7	7.7	5.3	5.4	5.6
Transportation, Communication and Public Utilities	16.9	14.4	17.2	6.2	6.3	6.7
Trade	9.9	10.6	13.4	7.1	10.7	13.2
Finance, Insurance and Real Estate	5.9	6.6	8.8	1.3	2.2	3.0
Services	4.7	5.1	6.8	5.1	7.9	11.5
Government	37.5	23.5	18.9	58.8	51.8	40.0
Federal	32.9	18.2	12.4	52.3	39.0	23.7
State and Local	4.5	5.3	6.5	6.5	12.8	16.3
Agriculture, Forestry Fisheries and Other	4.5	2.9	1.5	10.0	8.8	9.3
Total Percent	100.0	99.8	100.0	100.2	100.0	99.9
Total Number (Thousands)	683.6	1290.8	1754.1	109.2	143.9	188.7

Sources: Tables

were fishing, construction, and forest products. These industries are highly labor intensive, highly seasonal, and subject to cyclical fluctuations.

Since 1960, the major industries of the past have all shown a decline in relative importance, with the exception of construction. At the same time the petroleum industry as well as industries in the trade, services, and finance, insurance, and real estate sectors have made a substantial increase in relative importance. Table shows the percentage increase in both GSP and employment made by each economic sector from 1960-75. This changing structure should contribute to the stabilization of the Alaskan economy, although large scale petroleum construction projects tend to be cyclical and seasonal.

Anchorage has become the manufacturing and service center for the entire state, while Fairbanks has become a commercial and trade center for central and northern portions of the state.

TABLE 19

PERCENT INCREASE GROSS STATE PRODUCT
AND EMPLOYMENT BY ECONOMIC SECTOR
1960-75

Economic Sector	Gross State Product 1961-75	Employment 1960-75
Mining	750	91
Contract Construction	307	203
Manufacturing	93	81
Transportation, Communication and Public Utilities	162	85
Trade	246	225
Finance Insurance and Real Estate	283	307
Services	270	289
Government	29	18
Federal	-3	-22
State and Local	264	334
Agriculture, Forestry Fisheries and Other	-5	61
Total	264	73

Source: Table

b. Gross Product, Employment and Income

A detailed discussion, including appropriate tables, of gross state product, employment and income is provided in Appendix A. In most cases, only highlights of the discussion are provided in this section.

The 1975 GSP in Alaska could be over $3,000 million. 1975 real GSP (1958 dollars)1/ is estimated to be almost $1,800 million. Since 1961, Alaska's rate of growth in real GSP has exceeded that for the total U. S. GNP. As a result of the extensive petroleum development activities in Alaska since statehood, mining has been the fastest growing economic sector in terms of GSP.

The average annual employment in Alaska for 1975 is estimated to be almost 190,000. This represents a total increase of over 70 percent since 1960. During this period of time, state and local government has been the fastest growing economic sector in terms of employment. Alyeska oil pipeline construction is estimated to have accounted for about 8 percent of total 1975 employment.

Important characteristics of the Alaskan labor force include:2/

1. High labor force participation rates (ratio of work force to population). In 1970 the rate was 48.7 percent for Alaska as compared to 39.4 percent for the total U. S.

2. Chronically high unemployment rates. These rates have averaged over nine percent since statehood and have usually been at least double the national rate. In 1974 the unemployment rate was estimated to be

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1/ Real GSP eliminates the effect of inflation and therefore results in a lower figure than if measured in current dollars.

2/ Most of the information about these characteristics was taken from Tussing and others (1971), Alaska State Department of Economic Development (Dec. 1972), and the U. S. Department of Commerce (March 1973).

about 9.7 percent. In the past, growth of employment has had little if any impact in reducing unemployment due to the large amount of in-migration to the state.

3. High seasonality of employment. Average total employment in the high month (July) is typically 25% higher than that of the lowest month (January). During the period 1966-70 the ratio high month to low month employment was over 2 for the construction industry and over 4 in food processing.

4. High proportion of government employment. The percent of total employment accounted for by government in Alaska (40 percent in 1975) is about double the national percentage.

The 1975 personal income in Alaska could be over $2,500 million. This would represent a total increase of over 70 percent since 1961. Real per capita income is lower than for the U. S. as a whole. Government wages and salaries account for the largest share of personal income among economic sectors.

c. Cost of Living

The price level in Alaska has historically been higher than for the U. S. as a whole. Within Alaska prices vary widly with the lowest prices occurring in Anchorage and the highest prices occurring in the northern and western regions. Prices in the more remote areas of Alaska are sometimes two or three times national averages. Price differentials also vary by commodity, with housing being the highest priced consumer items in relation to total U. S. prices.

The estimated annual budget for a family of four living at a moderate level of living in Anchorage was 31 percent higher than the U. S. urban average in October 1973. Housing was 56 percent higher. Anchorage is the only place in Alaska for which the U. S. Department of Labor, Bureau of Labor Statistics publishes consumer price information and estimated family budgets.

Living cost differentials between Alaska and other states are more severe for low income families. The October 1973 estimated budget for a family of four in Anchorage at the BLS lower level of living was 47 percent higher than its U.S. urban average counterpart. For the BLS higher level of living the Anchorage budget was 26 percent higher. 1/

Cost of living differentials between Anchorage and other states declined during the 1960's and early 1970's. However, in 1974 the CPI rose faster for Anchorage than for the Nation as a whole for the first time since statehood. Prices are also rising at a more rapid rate of increase than at any time since statehood.

Undoubtedly part of the increase in Alaskan price levels can be attributed to the impacts of Alyeska pipeline construction. This has been especially true for certain places such as Valdez and Fairbanks, and for certain commodities and services such as housing and transportation, all of which have received considerable publicity for large price increases alleged to have been caused by Alyeska construction. Further discussion of the costs of certain goods and services is presented later in the section dealing with the supply of selected private services.

1/ Information for the above three paragraphs was taken from ISEGR (October 1974). For Anchorage, the higher budget was $23,011, the moderate budget was $16,520, and the lower budget was $12,010.

d. Native Economy

Much of the Alaskan native community is not fully integrated into the overall state money economy. A significant share of the native population, particularly in northwest and westward Alaska, continue to derive a large portion of their livelihood from traditional subsistence activities such as hunting, fishing, and berry picking.3/ It has been estimated that approximately 75 percent of the people living in small and medium sized native villages obtained at least 50 percent of their food by subsistence activities. The gross value of subsistence activities per capita has been estimated to range from about $500 to $1,000.1/

The Alaskan native population has a lower rate of labor force participation than the total population. This is due in part because subsistence patterns have kept them from being considered a part of the state's work force, and results in native unemployment being undercounted. Even for those natives who are counted in the labor force, the unemployment rate is higher than the state average. Per capita income for natives is lower than the state average.2/

Even though there is heavy dependence on subsistence in some parts of the native population, the overall trend is that natives are participating to a greater and greater extent in the money economy of the state. Both the employment opportunities created by the Alyeska oil pipeline and the implementation of the Alaskan Native Claims Settlement act are contributing to this continuing transition to a money economy.

1/ Source for material in this paragraph are (1) Alaska State Department of Economic Development (Dec. 1972), and (2) U.S. Department of the Interior, Alaska Natural Gas Transportation System, Draft Environmental Impact Statement. Part II Alaska, Vol. 1 (June 1975).

2/ Alaska State Department of Economic Development (Dec. 1972) and Tussing and others (1971).

3/ Subsistence use of natural resources is defined as the use of a natural resource by a person or group to meet personal needs in terms of life essentials such as food, clothing and shelter. It may be contrasted with commercial use of natural resources or non-essential use of such as for recreation.

iii. The Supply of Selected Private Services

a. Housing

Even before construction of the Alyeska oil pipeline, housing in Alaska was expensive and scarce relative to the lower 48. The median value of owner occupied housing in 1970 was 35% higher than in the lower 48 and median contract rent, 93% higher. Alaska rentals averaged 130% more per room than rentals in the rest of the country. Fairbanks housing was the most expensive with the housing index there 134% of the statewide figure. The expensive housing was only partly offset by higher wages paid Alaskan workers. Most of the private sector, with the exception of those employed in mining and contract construction, exceeded the national average in pay by only 20% to 24%. 1/

Coupled with the expense of housing was its relative scarcity. From 1960 to 1970, year-round housing in Alaska increased 38.1% while the population grew 33%. This rather significant increase in year-round housing units notwithstanding, the housing supply remained tight with an only 4.0% vacancy ratio (those units available for sale or rent).2/ In Fairbanks in 1970 the ratio of available vacant units to all units was a mere 3.3%.3/

Work on the Alyeska pipeline officially began in the spring of 1974. The influx of construction workers and those seeking work on the pipeline and the concomitant expansion of the economy placed severe strains on this already tight Alaskan housing market. During 1974 the population of Anchorage increased by 13,100 persons; the rate of vacancy fell to less than 4%. As recently as February 1975, the vacancy rate stood at 2%. At the same time costs of housing have risen by 15% above 1974 figures. 4/

1/ Impact Information Center, Pipeline Impact Information Center Report No. 10 (Nov. 1975); Fairbanks, Alaska. p. 5-6.

2/ Mathematical Sciences Northwest, Inc., An Economic and Social Impact Study of Oil Related Activities in the Gulf of Alaska (May 1975), Bellevue, Washington; p. IV-43.

3/ El Paso Alaska Company, Application for a Certificate of Public Necessity, Docket No. CP75-96, Sept. 1974; Vol IV; p. 2A.7-94.

4/ Greater Anchorage Area Borough Planning Dept., Pipeline Impact: Anchorage, 1975 (May 1975), p. 10, 11.

Serious shortages of housing exist elsewhere in Alaska in those areas on or near the pipeline corridor. Housing in the Copper Valley is reported to be at 100% occupancy.1/ At Valdez a similar situation exists. Delta Junction recently passed an ordinance forbidding camping within the city limits except at established campgrounds after having problems with people living in campers parked on private property and parking lots.2/

Nowhere has the housing shortage been better documented than in Fairbanks, due largely to the efforts of the Pipeline Impact Information Center. As of February 1975, the Fairbanks Board of Realtors stated that there was a zero vacancy rate in rental housing in the city and in April 1975, the occupancy rate was said to be around 103%.3/ The greatest demand for single family housing is for those houses costing under $55,000, which suggests that the problem of buying a house may be more a function of price than of physical scarcity. 4/

Much of the growth in Fairbanks' population has been from those coming into the city from the surrounding countryside and from outside Alaska to seek work on the pipeline. As a result rental housing has been in much demand. The rental housing market in Fairbanks remained predictably tight from September through December 1974, as the Alyeska construction effort expanded. At the same time there was a gradual upward trend in rent ranges and averages. By February 1975, an apartment that rented for $375 the previous August was going for $500.5/ It should be noted , however, that rent increases in Fairbanks on the whole seem not to have been exorbitant. In one housing survey taken for the year ending June 1975, rent increases ranged from $2 to $460. The largest percentage of increases was under 10%. The modal increase -- that which occurred most frequently -- was $25. The average

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1/ Copper River Native Association, Pipeline Impact Report: Copper River Valley, (Oct. 1974), P. 16.

2/ Fairbanks Town and Village Assoc. for Development, Inc., Rural Pipeline Impact Information Report No. 3 (May 1975), p. 2.

3/ Impact Information Center, Report No. 15 (April 1975), p. 12.

4/ Impact Information Center, Report No. 18 (August 1975), p. 12.

rent increase, which included several extreme rent gouging cases, was $57.56 or 49.6%. Half of the rent increases were over $25 and more than 20%. 1/

In June 1975, there was a perceptible easing in the rental housing situation as the numbers and availability of units increased. The increase in new housing in the community resulted from increased construction, the greater use of camper-trailers and other types of shelter not previously utilized, an increase in the numbers of sleeping rooms and from the greater numbers of persons willing to share housing. 2/ Yet, the August peak of construction employment brought about a reverse in this trend toward an easing in the housing situation. 3/

Another source of housing for those entering Fairbanks is in the hotels and motels. By July 1974, hotel and motel managers reported a 100% occupancy rate with turnaways reaching unprecedented numbers. (This statistic only partly reflects the impact of pipeline construction as July is in the summer tourist season.) 4/ Other sources of transient housing are the dormitories operated by the Salvation Army and the Rescue Mission. Those unable to find work or housing and those marginal families hard pressed by rising costs have turned to these organizations for food and shelter. In January 1975, the Salvation Army reported an average of 400 to 500 bed/nights shelter and 1,500 meals which it provided monthly. 5/ The Rescue Mission provided 1,564 bed/nights and 2,857 meals in January; 1,967 bed/nights and 3,411 meals in March. 6/

1/ Impact Information Center, Senior Citizens: The Effects of Pipeline Construction on Persons Living in Fairbanks (June 1975), Fairbanks; p. 26.

2/ Impact Information Center, Report No. 17 (June 1975), p. 9.

3/ Impact Information Center, Report No. 20 (Sept. 1975), p. 8.

4/ Impact Information Center, Report No. 2 (July 1974), p. 4.

5/ Impact Information Center, Report No. 12 (Jan. 1975), p. 9.

6/ Impact Information Center, Report No. 16 (April 1975), p. 15.

As of this writing the housing situation in Alaska and in Fairbanks in particular remains in a strained condition. The Greater Anchorage Borough Planning Department expects a housing deficit in Anchorage of 2,883 units by the end of 1975. 1/ The situation in Fairbanks does not promise to be any better, despite the fact that the supply of housing has been expanding. In 1975 Fairbanks issued five times as many building permits as it did in 1973 and the Borough twice as many. (This latter figure is deceptive since the Borough does not require building permits.) 2/ By July 1975, there were 333-363 new housing starts financed in Fairbanks and a new 350 unit mobile home development scheduled to open in nearby North Pole by October 1975. 3/ It is interesting to note that 75% of the new housing starts are being financed for entrepeneurs, not for owner-builders, because bankers feel these homes are constructed faster and the money turnover is much more rapid. 4/

If the Alyeska construction schedule is maintained, the wind-down in effort and the decline in employment will begin in the fall of 1976. It is to be expected that this would result in an easing of pressure on the housing market, perhaps to the point that a surplus of units would develop.

1/ Greater Anchorage Area Borough Planning Dept., p. 10

2/ Impact Information Center, Report No. 13 (Feb. 1975), p. 30.

3/ Impact Information Center, Report No. 18, (July 1975), p. 1; Report No. 14 (March 1975), p. 18.

4/ Impact Information Center, Report No. 18 (July 1975), p. 1.

b. Private Health Services

Despite the low numbers of physicians in Alaska relative to the lower 48 states -- there is one physician per 976 non-Native civilian Alaskans, whereas the ratio for the rest of the country is 1:625 -- the trans-Alaskan oil pipeline construction seems not to have caused any serious difficulties in private health care.1/ This is partly due to the free medical services provided the employees of Alyeska, Bechtel, Fluor and their subcontractors. The Bechtel Medical Program includes health screening, medics stationed in construction camps, emergency evacuation and control of camp sanitation facilities. Three medical doctors direct the program and make routine visits to the camps.2/

Since 1972, the demand for health care has increased for reasons independent of the pipeline. Reductions in military health care have sent many military persons into the private sector, especially in obstetrics cases. Hospitals and clinics have also experienced an increase in use by Natives, attributable in part to their growing affluence and health care knowledge. The general growth in population, which is related to the pipeline, also accounts for greater public use of health care facilities. Also since more services are offered and more doctors present, in Fairbanks at least, fewer people leave the area for health care needs. And finally, the expansion of medicare has resulted in more medicare patients exercising their options.3/

Impacts associated with the pipeline, mainly population increases, nevertheless have placed strains upon the existing health care facilities and in some cases have precipitated an expansion of those facilities. The growth in population and spread of hazardous construction projects brought Anchorage's Providence Hospital emergency room usage up 80% in July-September 1975, over the same period in 1974.4/ The bed occupancy rate at Fairbanks Memorial Hospital went from 67.7% in November 1974, to 80% in February 1975, even after a 28 bed orthopedic unit was added.5/ The Careage North Hospital, a private facility in Fairbanks, reported a 90%

1/ Department of the Interior, Alaska Natural Gas Transportation System, DEIS, Part II, Vol I (June 1975), p. 527.
2/ Impact Information Center, Report No. 5 (Sept. 1974), p. 10.
3/ Impact Information Center, Report No. 3 (Aug. 1974), p. 5.
4/ Greater Anchorage Area Borough Planning Dept., p. 19.
5/ Impact Information Center, Report No. 14 (March 1975), p. 14.

occupancy rate in March 1975.1/ Two additional facilities in Fairbanks, the Fairbanks Medical and Surgical Clinic and Tanana Valley Medical and Surgical Group, reported increased activity attributable to the pipeline in August 1974. (Both facilities were performing physical examinations for pipeline workers' employment physicals.)2/

The demands placed on medical services have, in Fairbanks' case at least, resulted in an expansion of facilities. (Fairbanks has traditionally been a major regional center for health care, with persons in the Arctic, Upper Yukon, Yukon Koyukuk region all going to Fairbanks for hospitalization.) Plans have been drawn up for a 100 bed addition for the Fairbanks Memorial Hospital to be completed in 1978. 3/ Already the Careage North Hospital has allocated a separate bed unit to the Bechtel Medical Program and plans further to increase the hospital size from the present 100 beds to 145 or 164, 15 to 20 of which would be for mental health patients. 4/ Other hospital expansion is being contemplated. The Teamster's Union is considering building an additional facility for its members. (See Letter of Comment, University of Alaska. Kruse.)

An interesting sidelight to the impact of Alyeska construction on private health care has been the controversy that has developed around the increasing use of physician's assistants in the construction camps and elsewhere. While this development has been generally lauded as an economical expansion of health care personnel, questions have arisen concerning qualifications, State licensing, and over the issue of whether or not people seeing physician's assistants should be charged the same rate as for seeing the physicians.6/

In general impacts associated with construction of the oil pipeline have placed some strains on the private health care sector. One result has been the expansion of facilities and personnel which may prove salutary to the State once the Alyeska project is completed.

1/ Ibid, p. 13.
2/ Impact Information Center, Report No. 3 (Aug. 1974), p. 7.
3/ Ibid, p. 5.
4/ Impact Information Center, Report No. 14 (March 1975), p. 14.
5/ Impact Information Center, Report No. 10 (Nov. 1974), pp. 12-13; Report No. 14 (March 1975), p. 13.
6/ Impact Information Center, Report No. 11 (Dec. 1974), p. 7.

The degree to which Alyeska's prohibition policy has contributed to outside drinking problems is not determined but both the NIAA and the State of Alaska have questioned the policy saying that it has not worked. Alyeska stated that prohibition of alcohol in construction camps was instituted for reasons of safety, pointing out that 90% of cold weather injuries were alcohol related. Despite the company's own program for alcoholism identification and treatment, few cases have been referred to the Bechtel Medical Program. It would appear then, as Fairbanks program leaders have maintained, that much of the pipeline related alcohol problems are surfacing in the community.1/

c. Family Disintegration

From 1967 to 1973 the average yearly increase in divorce complaints in Fairbanks was approximately 12%. In 1974, the year Alyeska construction began, the divorce complaints increased over 25% and for 1975 the first nine months saw an increase of 38% over the same period in 1974.2/ The numbers of divorce complaints have increased as the Alyeska effort has expanded. One explanation for the jump in divorce cases is that the stresses caused by the pipeline -- housing shortages, inflation, etc. -- have precipitated the breakup of many already shaky marriages.3/ Nevertheless, no causal links have been established between pipeline impact and the divorce rate.

Statistics on child related problems -- child abuse, runaways, juvenile crime -- are less clear, yet it is reported that these problems too have increased as a

1/ Impact Information Center, Report No. 6 (Sept. 1974), pp. 3-4.
2/ Impact Information Center, Report No. 21 (Oct. 1975), p. 13.
3/ Impact Information Center, Report No. 13 (Feb. 1975), p. 10.

result of the pipeline impact. In the Copper Valley attention has been called to an increased incidence of teenage drinking problems, an increase in juvenile offenses and complaints of young people wandering roads at night.1/

In October of 1974 the Impact Information Center reported a 179% increase in severe child neglect and abuse cases and an 84% increase in child welfare cases. Later these figures were disputed by the Division of Family and Children Services who stated that these increases represented investigations and not actual cases. The Division stated there has been no real increase in either child welfare or abuse cases.2/

d. Quality of Life

Construction of the Alyeska oil pipeline has had both short term and possible long term impacts on the Alaskans' perceptions of the quality of life. These impacts have in some areas generated considerable life-style adaptations -- as where natives have become increasingly dependent on a cash economy -- or have affected changes in community social and political structure. In addition the impacts of Alyeska have been unevenly distributed in Alaska and among its people. This along with the fact of social change has in some quarters generated a feeling of hostility toward the pipeline and its workers.

The attractive wages paid by Alyeska have led many persons to abandon jobs for pipeline employment. For example, it has been reported that some farmers in the Fairbanks and Delta Junction areas have, for one season at least, ceased to farm in order to contract themselves

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1/ Copper River Native Association, pp. 12-13.
2/ Impact Information Center, Report No. 21 (Oct. 1975), p. 13.

and their equipment to pipeline related work. In other areas rural villagers have left home for pipeline employment bringing about a decline in the traditional subsistence activities like hunting and fishing.1/ It is to be expected that once pipeline construction ceases these people would return to their former activities. However, natives may find it difficult to readjust to subsistence living after such an introduction to the white man's cash economy.

Rural communities have experienced special problems because of the pipeline. One complaint has been that leadership in these areas has been decimated as large numbers of men have departed for pipeline employment. In addition villagers have complained of a loss of community spirit and well-being in the face of economic change. As one villager put it, "Where the whole community used to go out and cut logs for someone's new home, now no one will do anything for nothing. . .."2/

Implicit in complaints such as this is a measure of hostility toward the pipeline, its workers and, of course, the changes wrought by both. A survey of senior citizens by the Impact Information Center in Fairbanks elicited comments like these:

> "Being an old-timer from the Territorial days, I resent the influx of rabble looking for the 'easy-buck' and caring little for our traditions . . ."

> "Their big wages and money always help to get what they want. I do not think the pipeline people should be allowed to take over here from us poorer people."3/

The growth of the urban areas of Anchorage and Fairbanks engendered in part by Alyeska appears to be permanent. The increased population, conjestion, traffic, crime and

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1/ Fairbanks Town and Village Assoc. for Development, Inc., Report on Questionnaire Surveys (June 1975), p. 2.
2/ Fairbanks Town and Village Assoc. for Development, Inc., Report No. 4 (June 1975), pp. 8-9.
3/ Impact Information Center, Senior Citizens: The Effects of Pipeline Construction on Persons Living in Fairbanks (June 1975), pp. 3-5.

urban ills add another dimension to the change brought about in the last several years. In comparison to the lower 48, Anchorage and Fairbanks remain relatively small cities, but to Alaska the change is significant as to one longtime Fairbanks resident who summed his feelings with, "You just can't drive your dogsled to the post office anymore."1/

1/ *Ibid.*, p. 37.

V. Government Receipts and Outlays in Alaska

Overview

In 1975, the government sector dominated the Alaskan economy. Federal, State, and local governments provided 40 percent of the total employment in the State. Moreover, government (Federal, State, and local) was the largest economic sector contributing nearly 19 percent of the Gross State Product (GSP). By 1980, State of Alaska revenues (excluding federal grants) are projected to jump from their 1975 level of about $300 million to nearly $1,450 million. This jump in State receipts is projected for a period when the Alyeska pipeline construction employment will have mostly terminated. Alaska probably will spend most of its revenues or invest them in Alaska. Thus, government may become even more dominant in Alaska's economy during the period in which a natural gas transportation system would be built.

Construction of a gas transportation system (hereafter, gas pipeline 1/) is scheduled to follow completion of TAPS, 2/ the Alyeska oil pipeline. Therefore, the relevant description of the public sector, which would be impacted by a gas pipeline, is necessarily a projection of the period following completion of the Alyeska pipeline. Since Alyeska is scheduled for completion in Fall, 1977, the following years will serve as the "base case."

Projection of a base case is especially difficult for Alaska. First, the State is not "typical" of lower 48 states. Second, the State will be experiencing a decline in private sector construction employment as Alyeska is completed although service industry employment may offset this decline. Earnings may fall, however, with lower wages and less overtime. Third, this decline will follow a major "boom" in the economy and its attendant problems. Fourth, the State's probable use of its extraordinary increase in revenues is unknown. Fifth, actual State revenue increments depend on several variables that cannot be easily projected. In summary,

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1/ In the case of the El Paso Alaska, Inc. proposal the term "gas pipeline" includes liquification and shipping facilities as well as a gas pipeline.

2/ Trans-Alaska Pipeline System (i.e., oil pipeline).

projecting a "base case" cannot be done with a high degree of confidence and depends in large measure on the assumptions used for the analysis.

In contrast to the Alyeska project, the impacts on the public sector from constructing and operating alternative natural gas pipelines may not appear large. Firstly, much of the adjustment in the economy attendant to a major construction project has or will have already occurred. This adjustment has not occurred, however, for certain communities that may be impacted under a gas pipeline's construction. Secondly, the State's projected revenues related to the proposed gas pipeline facilities and to gas production are only a fraction of the projected oil revenues from Alyeska. The State's incremental revenues would not only be much less than from Alyeska, but also would be adding revenues to a substantially larger State revenue base.

Federal Government

Among the levels of government, the Federal government has historically been dominant in its effects on the Alaskan economy. Variations in national defense activity levels in the State have been a major force in economic fluctuations. Now, however, Federal government employment in Alaska is declining relative to State and local government employment and to private sector employment. Also, the Federal contribution to GSP is declining relative to that of State and local governments. Since the role of the Federal government in the Alaskan economy is becoming less important, and because construction and operation of a gas pipeline is not expected to impact this Federal role significantly, the emphasis here will be on Alaskan State and local public finances.

Less than half of one percent of total Federal outlays are made in Alaska. Nevertheless, the Federal budget has an important impact on Alaska's economy. In fiscal 1974, Federal outlays in Alaska totaled $1,136 million. In comparison, the Federal "Tax Burden" in Alaska that year amounted to $447 million, only 39 percent of Federal outlays. Thus, the Federal government injected twice as much into the Alaskan economy as it took out.

On a per capita basis, 1974 Federal outlays in Alaska ranked the highest of any State (except the District of Columbia) at $3,402 per person compared to a national average of $1,322 per person and far above second ranked Hawaii with $1,948. In that same year, Alaska ranked ninth in per capita "Tax Burden" at $1,398 per person which was above the national average of $1,232 per person, but behind Connecticut which was first with $1,581 per capita in Federal taxes. Thus in 1974, net Federal outlays in Alaska were $2,004 per person. In comparison, the state with the next largest net Federal outlays that year was Mississippi with only an $821 per capita figure.

Federal aid to Alaska doubled between 1970 and 1974 from $116 to $234 million. This was in step with the national growth in Federal aid to states. In 1974, the largest aid programs (over $5 million) were, in millions:

Highway Trust Fund		$ 76.1
School Assistance in Federally affected areas		33.3
Federal Airport Program		15.4
Public Assistance:		14.7
Maintenance Assistance	$ 7.8	
Medical Assistance	4.1	
Construction of waste treatment facilities		8.2
Revenue Sharing		7.9
Food Stamp program		7.0
Elementary and Secondary Schools		6.7
Mineral Leasing Act Shared Revenues		6.0
Other		58.7
		$234.0

Federal aid to Alaska may change, of course, at the end of the decade, particularly when the State begins to obtain large amounts of revenues from North Slope oil and gas. On the other hand, some aid to the State could increase. In particular, severe and continuing post Alyeska construction unemployment could lead to increased Federal aid.

Alaska State Government - Overview

From 1965 to 1969, Alaska State General Governmental annual expenditures climbed from $175 million up to $245 million (Table 21), an increase of $70 million in four years. In September 1969, the Prudhoe Bay bonus lease sales brought the State $900 million in FY 1970. Moreover,

Table 21

State of Alaska

General Revenues and Expenditures
1965 - 1974
(millions of current dollars)

Fiscal Year	General Governmental Expenditures 1/ 2/	General Revenues	Annual Surplus or (Deficit)
1965	$ 175	$ 164	$ (11)
1966	173	168	(5)
1967	240	219	(21)
1968	250	221	(29)
1969	245	200	(45)
1970	296	1,157	861
1971	406	352	(54)
1972	673	370	(303)
1973	543	377	(166)
1974	597	424	(173)

1/ An element of Shared Revenue and State Aid exists in this category since it includes funds disbursed to aid local school districts, e.g., in 1974 a total of $95 million.

2/ The State appropriates Federal grant monies as well as funds from State sources.

Source: State of Alaska, Annual Financial Report, FY1974, November 19, 1974, Tables I and III.

the State anticipated large increases in revenues from early completion of the oil pipeline. Between 1970 and 1974, annual State expenditures jumped by $300 million, but the pipeline was not completed. Thus, revenues did not keep pace with expenditures. The annual deficits were financed from the Prudhoe bonus sale assets, and these assets are now about depleted. Unfortunately, the pipeline is not scheduled for completion until the Fall of 1977.

To make up the budget deficit as the State's assets or General Fund Surplus runs out, and until Prudhoe oil production begins, the State is relying on a new oil and gas in-place reserves tax. At present, this tax is only to be in effect for two years, calendar years 1976 and 1977. Then it is scheduled to terminate. Payments made under the reserves tax will be a tax credit offsetting future production taxes. The reserves tax is expected to generate close to $500 million in State revenues during its two year term. Nevertheless, it appears that the State will require additional revenues during this period to balance its budget given anticipated outlays. New "stopgap" revenue sources are being considered.

The Alaska State Constitution does not permit borrowing for operating expenditures. Nevertheless, the State budget is in "deficit" in the sense that the State (1) is depleting its assets and (2) is "borrowing" against future expected revenues by use of the temporary oil and gas reserves tax. The first action reduces the State's annual income from investments. The second action reduces the future <u>net</u> oil and gas receipts available to the State since the tax law provides that any oil and gas reserves taxes paid may be used as a credit against oil and production (severance) taxes as they become due.

When the Prudhoe oil revenues become available, the State's revenue situation will undergo a dramatic change. Non-federal revenues in FY 1980 should be about five times greater than in FY 1975. State oil receipts are based on oil production and the net-back wellhead value of the oil. 1/ Increases in the U.S. West Coast price of oil will increase State revenues. Cost overruns on Alyeska construction will

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1/ The net-back wellhead value is the West Coast price of oil less transportation costs. Alternatively, State oil taxes may be calculated using a specific cents per barrel schedule as adjusted by the Wholesale Price Index for crude petroleum. This method is now in use.

serve to decrease State receipts because they decrease the net-back value while at the same time increasing property tax revenues. In the initial years of operation, the Alyeska pipeline may not operate at full capacity, thus limiting State receipts. In addition, credits under the reserves tax, and payments under the Native Claims Settlement Act, both will temporarily reduce somewhat the annual receipts from oil available for spending. Finally, tax revenues related to Alyeska employment will decline as construction is completed although increased service industry may offset this decline, particularly since Alaska residents would spend a greater percentage of their income in the State.

It is difficult to predict the State's fiscal balance at the end of the decade during construction of a gas transportation route. The receipt side of the budget would show a dramatic rise, but it will come belatedly after an extended period of rapidly rising outlays, current account deficits, and a depletion of Prudhoe lease sale assets. The outlay side of the budget could, given recent experience, easily rise to at least match current receipts. The State has, apparently, many needs and wants. Although some persons foresee the State rebuilding its assets by saving a part of its oil receipts, it is not at all certain that this will occur. If the State does save, it may invest its funds within the State and thus have an initial effect on the State's economy similar to what would have occurred if it had spent all of its receipts. The longer term impact might differ, however, if "saved" receipts augment investment in the State compared to the alternative of spending on social programs.

Alaska State Government - Revenues

In 1975, Alaska State revenues (i.e., excluding federal grants) totaled $297 million (Table 22). Taxes of $163 million accounted for 54 percent of this total. Nearly half of this tax revenue, $75 million, came from the individual tax (Table I.B.3.a.V.3). Severance taxes of $30 million contributed about a fifth of the tax revenues, and selective sales and use taxes of $24 million were almost as important. The gross receipts and business taxes of $16 million added 10 percent to tax revenues and property taxes added $7 million, roughly 4 percent of tax revenues.

Table 22

ALASKA STATE REVENUES

FISCAL YEARS 1975 AND 1980

(Thousands of dollars)

Receipt Source	1975 Revised Estimate	1980 Estimate
TAXES	162,617	753,394
Property taxes	6,501	108,001
Selective Sales and Use Taxes	24,366	46,316
Income taxes	84,575	97,633
Corporation/Fiduciary	9,659	21,754
Individual	74,915	75,878
Gross Receipts/Business Taxes	15,723	22,723
Severance Taxes	29,574	476,546
Other Taxes	1,877	2,173
LICENSES AND PERMITS	11,888	15,978
Business Licenses and Permits	4,150	4,762
Non-Business Licenses and Permits	7,737	11,216
INTERGOVERNMENTAL RECEIPTS		
Federal Shared Revenue	10,475	11,713
STATE RESOURCE REVENUES	110,919	662,175
Facilities Related Charges	16,830	22,887
Services Related Charges	3,697	6,278
Sale/Use of State Resources	90,391	633,009
MISCELLANEOUS REVENUES		
Returns, etc.	1,135	1,667
TOTAL UNRESTRICTED REVENUES	297,036	1,444,929
SPECIAL FUNDS	28,308	49,517

Source: State of Alaska, Revenue Sources-Alaska-Fiscal Years 1974-80, undated.

Table 23

ALASKA STATE REVENUES

FISCAL YEARS 1975 AND 1980

Percentage of Total

Receipt Source	1975 percent	1980 percent
TAXES	54	52
Property Taxes	2	7
Selective Sales and Use Taxes	8	3
Income Taxes	28	7
Corporation and Fiduciary	3	2
Individual	25	5
Gross Receipts and Business Taxes	5	2
Severance Taxes	10	33
Other Taxes	1	0
LICENSES AND PERMITS	3	1
Business Licenses and Permits	1	0
Non-Business Licenses and Permits	2	1
INTERGOVERNMENTAL RECEIPTS		
Federal Shared Revenue	3	1
STATE RESOURCE REVENUES	36	46
Facilities Related Charges	5	2
Services Related Charges	1	0
Sale and Use of State Resources	30	44
MISCELLANEOUS REVENUES		
Returns, etc.	4	0
TOTAL UNRESTRICTED REVENUES	100	100

Source: State of Alaska, Revenue Sources-Alaska-Fiscal Years 1974-80, undated.

The State estimates that tax revenues will climb threefold to $753 million by 1980. Since most of the increase is expected from severance taxes and property taxes related to oil production and transportation, the relative importance of the State's several taxes would change markedly. Tax revenues as a percentage of total receipts, however, is expected to stay about the same. Severance taxes are anticipated to yield $476 million in 1980, about 63 percent of tax revenues and a third of the State's total revenues that year. The revenue from property taxes is expected to climb to $108 million and thus yield 14 percent of the State's tax revenues.

In the 1975-1980 period, individual income taxes are not expected to grow and would produce by 1980 only 10 percent of State tax receipts. Corporation and fiduciary taxes and selective sales and use taxes both are expected to more than double during this period and together would yield $68 million or 9 percent of State taxes in 1980. Thus, severance taxes which are now relatively unimportant in the State's tax revenue structure will become the dominate factor, and therefore projections of the government base economy depend importantly on the projection of this tax revenue source.

The State of Alaska also obtains revenues from four other revenue categories: licenses and permits; intergovernmental receipts (i.e., Federal shared revenues); State resource revenues; and miscellaneous sources. In 1975, State resource revenues contributed $111 million, or 36 percent, to total State revenues while the other three added $23 million, or about 8 percent, to State revenues. Royalties on production of State owned minerals dominated the State's resource revenue category in 1975 and this is projected as the largest source of the tremendous growth in State revenues by 1980. In 1975, the sale or use of State resources brought the State $90 million; by 1980 this source is projected to jump to $633 million.

In summary, between 1975 and 1980 the State projects oil production, royalty, and transportation property tax revenues to the State to climb by about $1,100 million. How this tremendous increase in State revenues is spent will in large part determine Alaska's base economy during the period in which a gas pipeline would be constructed and operated.

e. Alaska State Government - Outlays

In 1975, operating budget outlays from State sources, i.e., the General Fund, by the State of Alaska amounted to $455 million while total State outlays from all sources was $651 million (Table 24). The nearly $200 million difference was in Federal aid. Since we are primarily interested in how the State allocates its own funds, the discussion here will focus on State outlays from its own sources.

The largest program category in the State's budget is Education. In 1975, this program absorbed 39 percent of the operating budget with outlays of $178 million (Table 25). Although outlays on Education rose by $36 million over the 1974 level, Education fell in relative importance from its 1974 level of 42 percent of outlays.

After Education, the next most important program was Transportation. In 1975, Transportation outlays were $72 million, nearly 14 percent of State expenditures. In comparison to 1974 budget levels, Transportation outlays climbed 23 percent but like Education, became relatively less important. Also important in State outlays in 1975 were the Development program and the Administration of Justice program. Development was allocated $48 million or 11 percent of total General Fund spending while Justice received $43 million which was 9 percent of the budget.

The other budget categories were of less importance to the budget although social services and health when combined were 12 percent of 1975 General Fund outlays. Both of these categories, however, declined in relative importance compared to 1974 although together they grew by $35 million from 1974 to 1975.

The State of Alaska's operating budget by agency is shown in Table 26 . In 1975, the Department of Education spent $118 million and the State-Operated Schools spent an additional $12 million. The Department of Health and Social Services, the next largest, spent $53 million. Each with roughly $30 million were the Departments of Public Works, of Highways, of Community and Regional Affairs, and the University of Alaska. The other departments and agencies were less important in the budget.

Table 24

ALASKA STATE
OPERATING BUDGET BY PROGRAM CATEGORY

(millions of dollars)

	FY 74 Actual		FY 75 Adjusted	
	General Fund	Total	General Fund	Total
Education	151.8	207.8	177.5	243.9
Social Services	29.4	61.5	31.1	93.7
Health	20.5	27.6	23.4	30.8
Natural Resource Management and Environmental Conservation	19.8	27.6	25.8	38.1
Public Protection	7.1	9.4	9.7	13.5
Administration of Justice	33.0	34.9	42.7	46.4
Development	20.7	21.8	47.5	49.0
Transportation	58.7	70.4	72.0	87.8
General Government	22.2	35.3	25.5	48.0
Total Operating Budget	363.2	496.3	455.2	651.2

Source: State of Alaska, Budget Document-Alaska-Fiscal Year 1975-76, February 10, 1975.

Table 25

ALASKA STATE
OPERATING BUDGET - BY CATEGORY

Percentage of Total Operating Budget

	1974 Actual		FY 75 Adjusted	
	Total	General Fund**	Total	General Fund**
Education	41.8	41.8	37.5	39.0
Social Services	12.4	8.1	14.4	6.8
Health	5.6	5.6	4.7	5.1
Natural Resource Management and Environmental Conservation	5.6	5.4	5.9	5.7
Public Protection	1.9	2.0	2.1	2.1
Administration of Justice	7.0	9.1	7.0	9.4
Development	4.4	5.7	7.5	10.5
Transportation	14.2	16.2	13.5	15.8
General Government	7.1	6.1	7.4	5.6
Total Operating Budget	100.0	100.0	100.0	100.0

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* Allocation of Salary increase items and revised programs.

** Includes Federal Revenue Sharing Fund appropriations; FY 74 $69.7, FY 75 $7,206.6, FY 76 $-0-.

Source: State of Alaska, Budget Document-Alaska-Fiscal Year 1975-76, February 10, 1975.

Table 26

ALASKA STATE

OPERATING BUDGET BY AGENCY

(millions of dollars)

	TOTAL ALL FUNDS		STATE GENERAL FUNDS*	
	FY 74 Actual	FY 75 Adjusted***	FY 74 Actual	FY 75 Adjusted***
Governor's Office	7.3	39.3	4.2	22.0
Administration	24.0	23.5	21.7	21.6
Law	3.6	4.7	3.1	3.9
Revenue	9.6	12.8	9.5	12.5
Education	120.5	136.0	103.4	118.1
Health and Social Services	73.0	79.5	49.2	52.6
Labor	11.9	30.5	1.4	2.3
Commerce	3.4	4.8	3.0	4.1
Military Affairs	2.7	3.1	1.3	1.6
Natural Resources	8.9	8.7	7.7	7.7
Fish and Game	12.5	17.0	6.1	8.8
Public Safety	11.8	18.5	11.3	16.9
Public Works	37.5	45.4	26.7	32.5
Highways	31.1	47.4	22.2	29.5
Economic Development**	1.9	2.1	1.9	2.1
Environmental Conservation	1.6	3.6	1.3	1.9
State-Operated Schools	37.4	48.5	9.4	11.7
Community & Regional Affairs	15.2	29.3	13.3	27.6
Legislative Branch	3.7	3.7	3.7	3.6
Judicial Branch	10.4	11.8	10.2	11.7
University of Alaska	40.5	46.0	26.6	30.7
Bond Committee	27.7	34.5	25.8	31.6
TOTAL	496.3	651.2	363.2	455.2

* Includes Federal Revenue Sharing Fund appropriations - FY 74 $69.7, FY 75 $7,260.6,

** This Department has been phased out

*** Adjusted mid-year FY 1975

Source: State of Alaska, Budget Document-Alaska-Fiscal Year 1975-76, February 10, 1975.

Alaska's budget will undoubtedly grow as the Alyeska pipeline related revenues are realized. Assuming that the State spends most of its revenues, the 1980 budget from the General Fund would be roughly three times its 1975 level. Projecting the budget categories which are most likely to see large growth is at best difficult. Education should grow because of the policy of regionalization of secondary education, the movement to greater local antonomy in education policy, the increasing percentage in the State's share of the basic need formula, the growth of the basic need amount (perhaps faster than inflation), and the higher expectations for State outlays on education by Alaska residents.

Spending on transportation is likely to grow rapidly. Proposals for new roads, improved roads, for a new railroad, and for water transport all have support. Even if only a few are funded the expense of construction in Alaska would make transportation an obvious candidate for growth. Social Services and Health could grow rapidly. The disparities in the standard of living among residents in Alaska is pronounced, and these types of services may be increased to offset some of the apparent inequities. Finally, there is interest in expanding Alaska's base economy through State government action. Whether the State invests directly, makes low interest loans, gives reduced taxes for new investments, or adopts other measures, the development category of the budget could also grow rapidly. In particular, there is strong interest in expanding the renewable resource industries such as forestry, fisheries, and tourism.

f. Local Government

In 1975, local governments in Alaska spent over $207 million (Table 27). This was an increase of 20 percent over the 1974 level and more than double the 1970 amount. Since the data are for four main population centers they understate somewhat total local government finances. About half of the expenditures were for education, roughly $100 million. General government outlays were $26 million, public safety took $18 million, public works absorbed $9 million, and other functions totaled $53 million in outlays. Since some local governments include utility systems, e.g., electric utilities, in their budgets, their local government outlays may be higher per capita than for communities that do not include them.

Table 27

ALASKA
LOCAL GOVERNMENT 1/
RECEIPTS AND OUTLAYS
(millions of current dollars)

Selected Local Government Receipts

	FY 1970	FY 1974 2/	FY 1975 2/
Property Taxes	$27.8	$52.2	$65.2
Sales Taxes	6.7	9.5	10.4
Other	9.2	27.6	27.2
Total Local Sources	43.7	89.3	102.8
Federal & State Revenue	40.7	99.2	114.0
Total All Sources	$84.4	$188.5	$216.8

Selected Local Government Outlays

	FY 1970	FY 1974 2/	FY 1975 2/
General Government	$ 7.3	$20.5	$25.7
Public Safety	7.1	15.3	17.6
Public Works	3.9	8.0	9.2
Education	47.1	86.2	99.1
Other	19.8	42.4	52.7
Total	$85.3	$172.4	$206.8

1/ Aggregate statistics are presented for the cities and boroughs of Anchorage, Fairbanks, Juneau and Ketchikan.

2/ Estimate.

Source: City and Borough Annual Financial Reports reported in State of Alaska, Department of Economic Development, A Performance of the Alaskan Economy, Volume Three, Number One.

Some local government budgets are expanding to meet the increased demands for services from construction workers. The need for expansion because of Alyeska construction should have evaporated by the time the gas pipeline construction is started. In fact, the demand for many local government services may be falling at the time construction of the gas pipeline is expected.

The primary source of local government receipts is from the Federal and the State governments. In 1975, over half of local government receipts came from this source. Local government revenues from their own sources are dominated by property taxes. In 1975, about 63 percent of local government revenues were from property taxes and 10 percent came from sales taxes. In the 1978-1980 period, property taxes in some areas will have grown from the value of Alyeska property, although there are State imposed limits to the amount of taxation local governments can place on this source. Other increases in the property tax base probably would slow with the completion of Alyeska. The sales tax base, i.e., gross sales, may decline as Alyeska construction workers are laid off and as some of these workers leave Alaska. Since the State is apparently committed to paying an increasing percentage of education costs, variations in enrollment should not be a major problem to local governments. However, capital costs may be a cash flow problem as the State government does not reimburse local governments for education capital outlays except after several years delay.

As in the past, the financial strength of Alaskan local governments in the base case years will depend primarily on property tax revenues and on the State's transfer of its financial resources to the local governments for education and other purposes. With reduced impacts from Alyeska, with the large jump in State financial resources, and with the Alaskans' preference for localized spending decisions, the several local governments should, overall, be in a strong financial posture.

b) Socio-economic Impacts

i. Model Used for Impact Projection

The basic estimates of natural gas transportation system socio-economic impacts in Alaska made in this FEIS are derived through the use of a computer simulation model of the Alaskan economy developed by the Institute of Social Economic and Government Research (ISEGR) of the University of Alaska. The model was developed as part of the Institute's Man in the Arctic Program (funded in part by the National Science Foundation.) The model is therefore referred to as the MAP model. Specifically, data used for pipeline impact projections came from several computer runs of the MAP model done for the FPC and the U. S. Department of the Interior by ISEGR in January 1976.

Many of the 1975 figures presented in this socio-economic impact section will differ slightly from 1975 figures presented earlier in the socio-economic description section. This is due to minor changes made in the MAP model between June 1975 and January 1976 which are reflected only in the impact section.

a. <u>General Discussion</u>

The generalized structure of the MAP statewide economic model is shown in Figure 11. A discussion of the model including the complete set of equations used in the statewide model is provided in Appendix B. The relationships in the model are based on econometric analysis of Alaskan data covering the period since statehood.

In very general terms, the model operates sequentially to estimate industrial output, industry employment, wages and salaries, and finally real disposable personal income. The determination of industrial output is the key element in the model and determining relationships vary significantly from one industrial sector to another.

Once output has been determined in each of the major industrial sectors, the next step in the model is to determine industry employment based on historical relationships between industry output and employment. Industry wage rates are then calculated as a function of projected wage rates in the U. S. and/or relative prices in Alaska. The projections of industry employment and wage rates are then combined to estimate wages and salaries. Total personal income is estimated as a function of total wages and salaries, and then disposable personal income is estimated as a function of personal income.

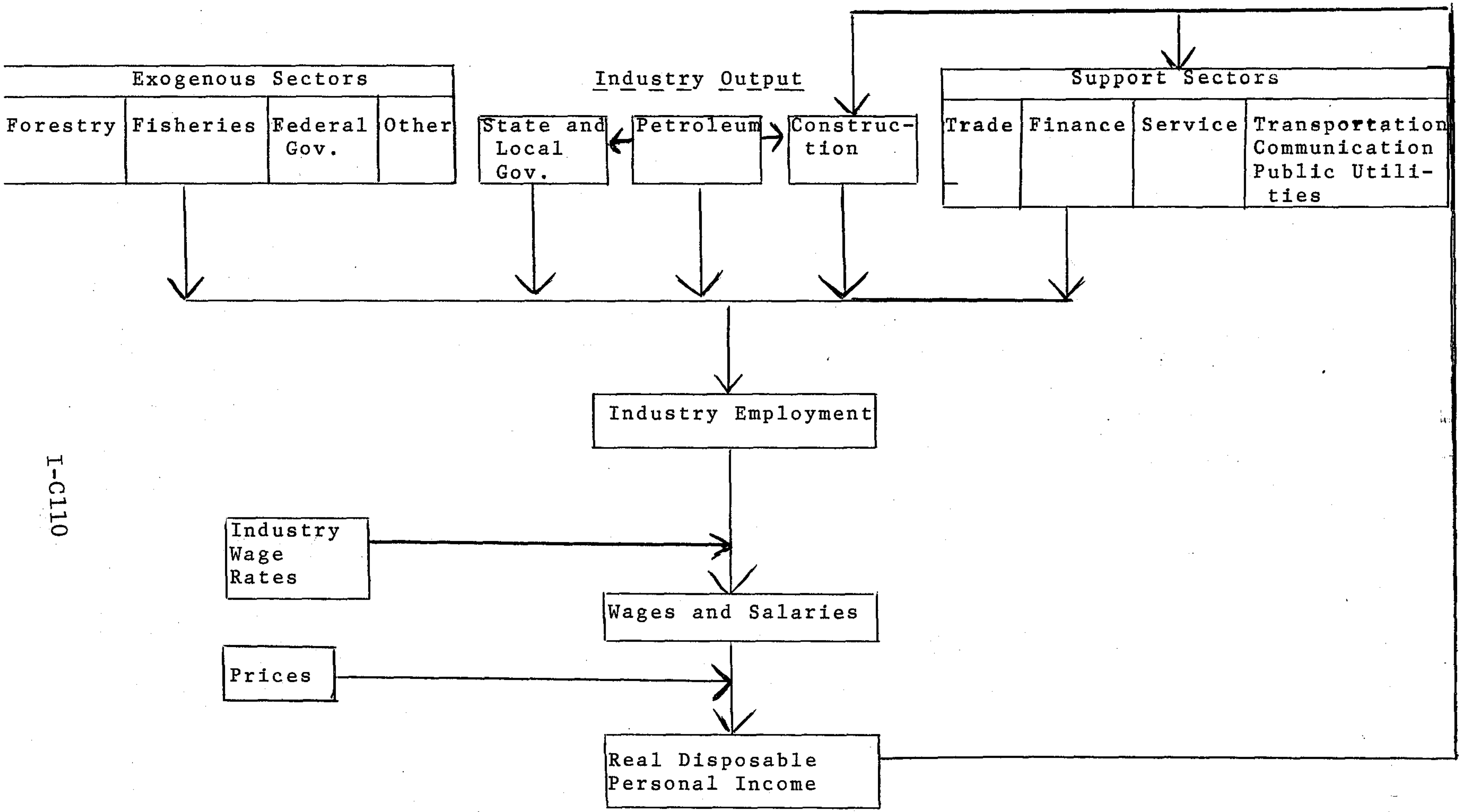

Figure 11 Simplified Structure of MAP Statewide Economic Model

As shown by the feedback loop in Figure 11 real disposable personal income is a principal determinant of output in the support sector and in the construction industry. Anything which affects personal income will affect support sector and construction output and vice versa. To reflect these interrelationships, industrial output and personal income are simultaneously determined in the model.

In addition to the economic variables discussed above, the MAP model has the capability for projecting population and state and local government revenues and expenditures. The equations used for these projections depend upon estimates derived from the economic projections, and are shown in Appendix B.

b. Impact Evaluation Process

The MAP model was first used to project Alaska's development under the assumption that no gas pipeline is constructed. A second projection was then made which incorporates the Arctic proposal, and a third projection incorporated the El Paso proposal. The impacts of the two proposals were then measured as the differences between each of the gas pipeline projections and the no-gas-pipeline projection. A major factor determining the economic impact of either proposal is the amount of revenue generated for the state of Alaska.

c. Regional Model

Unless otherwise noted, the impact projections shown in this EIS were generated by the MAP regional model. An advantage of this model is that it allows regional impacts as well as statewide impacts to be projected. The seven regions considered in these projections have been previously shown in Figure 10. The overall structure of the regional model and the relationships used take the same general form as the statewide model. The regional model however, includes greater industry detail and takes into account differences in regional behavior patterns. For the sake of brevity, the equations for the regional model have not been reproduced in the FEIS.

d. Assumptions

Among the key explicit and implicit assumptions used by ISEGR for the FPC which are reflected in the impact projections of the FEIS are the following:

1. Oil from the Alyeska oil pipeline will begin to flow in 1978.

2. Significant construction will begin in 1977 for both the Arctic and El Paso proposals. Once started both projects would be completed on the schedules estimated by Arctic and El Paso.

3. Both proposals would have equal natural gas throughout reaching a level of 2.5 bcf per day from Alaskan sources.1/

4. The wellhead price of gas would be $.50 per Mcf.

5. The wellhead price of oil would be $7.00 per barrel. Since transportation costs to the lower 48 states were assumed to be $4.00 per barrel, this wellhead price would correspond to a refinery gate price of $11.00 per barrel in the lower 48.

6. The state would save 25 percent of recurring petroleum revenues and 50 percent of lease bonus payments and the savings would be placed in an interest-earning investment trust fund.

7. A set of so-called accelerated petroleum development policies would be followed. The term "accelerated" is a word used by ISEGR to differentiate this petroleum development scenario from limited development and maximum development scenarios

1/ The Arctic proposal also includes gas from the McKenzie Delta in Canada. The availability of this gas would influence the unit transportation costs of the Arctic gas system, but since a $.50 wellhead price is assumed for the model, the effect on Alaska is not shown (i.e., changes in Alaskan resources).

which can also be incorporated into the MAP model. Among the key aspects of the accelerated petroleum development scenario are:

(a) The development of the Naval Petroleum Reserve IV. Production would start in 1983 and a second oil pipeline would be constructed.

(b) A series of other oil leases and corresponding production would take place including development in the Gulf of Alaska, the North Slope uplands, and lower Cook Inlet.

(c) State oil production, including the above oil development and Alyeska, would result in 2 million barrels per day production by 1980, 5 million by 1985, and 7.7 million by 1990.

8. Applicants' cost and related data is that utilized in the MAP model reported in Institute of Social, Economic and Government Research, University of Alaska, Impact on the Alaska Economy of Alternative Gas Pipelines, prepared for the Aerospace Corporation, (April, 1975).

ii. Population

Table 28 shows the projected population increases due to the Arctic and El Paso proposals. By 1990, economic activity associated with the Arctic proposal would generate a population increase of about 10 thousand as compared with more than 26 thousand for the El Paso proposal. For both proposals, over sixty percent of the population increase will take place in the Anchorage region.

The population increases generated by the Arctic proposal show a steady increase each year through 1990. In contrast, the El Paso increase fluctuates, reaching a temporary peak of about 24 thousand in 1980, declining somewhat for two years and then steadily increasing through 1990.

During the peak year of construction in 1978, the population increase generated by El Paso would represent about a four percent increase over the baseline population projection without the project. The peak percentage increase of about five percent would be reached in 1979-80. In 1990 the percentage increase would be about three percent. For Arctic the percentage increase would be about one percent for both the peak year of construction (1979) and 1990. See Table 29 for the base case population figures as well as total population figures including gas pipeline impacts.

During construction, the El Paso project would likely stimulate continued migration into Alaska by job seekers. However, the amount of immigration would likely be less than during Alyeska oil pipeline construction. A number of workers now filling oil pipeline jobs are expected to work on gas pipeline construction under either proposal.

In making regional projections staff assumed that in general construction workers would reside in the region in which they worked. As a result of this assumption, all construction workers for the LNG plant and marine terminal were located in the South Central region. In their letter of comment on the DEIS, El Paso informed staff that they assumed the majority of households of construction workers employed in the South Central region would be maintained in the Anchorage area. If the El Paso assumption is correct the regional projection for population, GSP, employment, and wages and salaries will be overstated for the South Central region and understated for the Anchorage region. The combined totals for the two regions would still be the same, and statewide totals would, of course, be unaffected.

TABLE 28

ESTIMATED POPULATION GENERATED AND REGIONAL DISTRIBUTION
(in thousands)

Pipeline & Year	State Total	Region			
		Anchorage	Southcentral	Fairbanks	All Others
Arctic					
1977	.4				
1978	1.8	.8	.2	.1	.7
1979	3.0	1.4	.3	.3	1.0
1980	5.3	2.9	.9	.5	1.0
1981	5.9	3.3	1.0	.6	1.0
1982	6.4	3.6	1.0	.7	1.1
1983	6.9	3.9	1.1	.7	1.2
1984	7.3	4.2	1.1	.7	1.3
1985	7.7	4.5	1.2	.8	1.2
1986	8.1	4.8	1.2	.8	1.3
1987	8.6	5.2	1.2	.8	1.4
1988	9.0	5.6	1.3	.9	1.2
1989	9.6	6.0	1.3	.9	1.4
1990	10.2	6.5	1.4	.9	1.4
El Paso					
1977	6.6	-0.5	6.8	0.5	-0.2
1978	17.4	1.1	15.0	1.3	0
1979	23.5	5.0	14.8	2.4	1.3
1980	24.1	10.6	7.6	2.5	3.4
1981	20.8	11.1	4.1	2.2	3.4
1982	20.0	10.7	4.0	2.1	3.2
1983	20.2	10.9	3.9	2.1	3.3
1984	20.7	11.4	4.0	2.1	3.2
1985	21.4	12.0	4.0	2.1	3.3
1986	22.2	12.6	4.1	2.1	3.4
1987	23.0	13.3	4.2	2.2	3.3
1988	24.2	14.4	4.3	2.2	3.3
1989	25.3	15.3	4.4	2.2	3.4
1990	26.8	16.6	4.5	2.3	3.4

Source: January, 1976 runs of MAP regional model

TABLE 29

PROJECTED POPULATION FOR ALASKA INCLUDING
PIPELINE GENERATED POPULATION
(In Thousands)

Year	Base Case Without Gas Pipeline	Total Including Pipeline Generated	
		Arctic	El Paso
1975	381.8		
1980	482.9	488.2	507.0
1985	633.3	641.0	654.7
1990	802.5	812.7	829.3

Source: January 1976 runs of MAP regional model

iii. Selected Private Sector Economic Impacts from Construction and Operation

a. Overview

Following the sequence shown in Figure 11 , a very general description of the economic impact process that would be generated by either gas pipeline would be as follows:

During construction the primary statewide impact would be to increase output and employment in the construction industry. Then, employment and output in the mining industry would increase as the project began operation. Also output and employment in the state and local government sector would increase as a result of tax revenues generated by the project. Finally as workers in the mining, construction, and government sectors spend their additional income, the economic multiplier process would produce an increase in the output of the support sector industries of Alaska.

The Arctic project would have a relatively small impact on the state economy. By 1990, the increases in GSP and employment generated would represent only about a one percent increase over base case figures without the project. The support sectors would account for most of the long run economic impact.

The impact of the El Paso proposal on the statewide economy would be much greater than that of Arctic. The 1990 increases in GSP and employment generated would be about five and three percent respectively over base case figures without the project. As with Arctic, a significant part of long run impact would be attributed to the support sector industries. However, the mining industry would account for the greatest share of GSP increase by 1990 due mainly to the operation of the LNG facility and marine terminal.

Although total personal income would increase as a result of either proposal, neither would result in a significant lasting increase in real per capita income.

Because of its role as the manufacturing and service center for the entire state, the Anchorage region would account for about half of the statewide employment and income impacts under either project.

b. Gross State Product

Table 30 shows the projected real gross state product (GSP) that would be generated by the alternative gas pipeline proposals. The El Paso proposal would increase real GSP by about $282 million in 1980. After declining somewhat through 1984, the El Paso impact on real GSP reaches $286 million in 1990. The Arctic proposal would increase real GSP by $32 million in 1980 and by $49 million in 1990.

As shown in Table 30 the increase in real GSP is distributed among a number of industries for both proposals. The large component under the "mining and pipeline construction" column for El Paso is due in large part to the operation of the LNG terminal, which is classified in the mining sector. This component accounts for about 65 percent of the 1990 increase in real GSP.

Table 31 shows the regional distribution of real GSP impacts. Over half of the 1990 impact would be in the Anchorage region under the Arctic proposal and in the South Central region under the El Paso proposal.

In 1980, the El Paso generated real GSP would represent a 8.7 percent increase over the baseline GSP projection without the project. In 1990 the percentage increase would be 5.3 percent. For Arctic the percentage increases would be about one percent for both years. See Table 32 for the base case real GSP projections as well as total real GSP figures including gas pipeline impacts.

TABLE 30

REAL GROSS STATE PRODUCT GENERATED
(Millions of 1958 Dollars)

Pipeline and Year	Total	Economic Sector Grouping			
		Mining and Pipeline Construction	State and Local Government	Trade and Services	Other Support Industries a/
Arctic					
1977	3.2	1.2	0.1	1.4	0.5
1978	14.1	4.6	0.5	6.7	2.3
1979	19.5	5.7	1.3	8.7	3.8
1980	31.7	8.4	6.2	8.5	8.6
1981	33.4	8.4	6.5	9.2	9.3
1982	34.3	8.3	6.4	9.7	9.9
1983	35.2	8.2	6.4	10.2	10.4
1984	36.2	8.1	6.3	10.7	11.1
1985	37.7	8.3	6.3	11.3	11.8
1986	39.2	8.3	6.3	12.0	12.6
1987	41.1	8.5	6.3	12.8	13.5
1988	43.4	8.6	6.3	13.7	14.8
1989	46.0	8.7	6.4	14.8	16.1
1990	49.1	8.8	6.5	16.2	17.6
El Paso					
1977	47.5	24.4	0.2	15.3	7.6
1978	114.0	50.6	4.1	38.5	20.8
1979	235.3	149.6	9.4	45.5	30.8
1980	282.4	200.0	16.8	40.6	25.0
1981	268.5	196.7	15.9	27.5	28.4
1982	256.2	191.6	13.3	25.0	26.3
1983	252.1	187.9	12.5	25.1	26.6
1984	251.7	185.2	12.3	26.2	28.0
1985	255.6	185.8	12.3	27.8	29.7
1986	259.6	185.5	12.4	29.7	32.0
1987	264.2	185.3	12.6	31.9	34.4
1988	271.4	185.4	12.8	35.1	38.1
1989	277.4	184.8	13.3	37.9	41.4
1990	286.1	184.9	13.7	41.6	45.9

Source: January, 1976 runs of MAP regional model

a/ Includes manufacturing; transportation; communications; public utilities; finance, insurance, real estate, agriculture, forestry, fisheries and Federal Government.

TABLE 31

REGIONAL DISTRIBUTION OF REAL GSP
GENERATED BY ARCTIC AND EL PASO PIPELINES
(Millions of 1958 Dollars)

Pipeline & Year	State Total	Region			
		Anchorage	Southcentral	Fairbanks	All Others
Arctic					
1977	3.2	.7	.0	.1	2.4
1978	14.1	3.1	.2	.2	10.6
1979	19.5	5.4	.5	.6	13.0
1980	31.7	14.9	2.1	2.9	11.8
1981	33.4	16.1	2.2	3.1	12.0
1982	34.3	16.8	2.2	3.2	12.1
1983	35.2	17.7	2.3	3.3	11.9
1984	36.2	18.7	2.3	3.4	11.8
1985	37.7	19.7	2.3	3.5	12.2
1986	39.2	20.9	2.3	3.6	12.4
1987	41.1	22.3	2.4	3.8	12.6
1988	43.4	24.0	2.4	4.0	13.0
1989	46.0	26.1	2.5	4.2	13.2
1990	49.1	28.5	2.6	4.4	13.6
El Paso					
1977	47.5	8.2	20.6	6.1	12.6
1978	114.0	26.3	45.0	12.8	29.9
1979	235.3	45.1	126.8	20.7	42.7
1980	282.4	57.8	158.5	17.7	48.4
1981	268.5	52.2	166.9	13.3	36.1
1982	256.2	47.7	162.1	12.4	34.0
1983	252.1	48.2	158.7	12.2	33.0
1984	251.7	50.3	156.2	12.4	32.8
1985	255.6	53.1	154.4	12.7	35.4
1986	259.6	56.4	156.2	13.1	33.9
1987	264.2	60.3	155.6	13.5	34.8
1988	271.4	66.3	155.4	13.9	35.8
1989	277.4	71.1	155.0	14.6	36.7
1990	286.1	78.0	155.3	15.3	37.5

Source: January, 1976 runs of MAP regional model

TABLE 32

PROJECTED GROSS STATE PRODUCT INCLUDING
GAS PIPELINE GENERATED GROSS PRODUCT
(Millions of 1958 Dollars)

Year	Base Case Without Gas Pipeline	Total Including Pipeline Generated	
		Arctic	El Paso
1975	1,680.8		
1980	3,255.6	3,287.3	3,538.0
1985	4,321.1	4,358.8	4,576.7
1990	5,402.2	5,451.3	5,688.3

Source: January, 1976 runs of MAP regional model.

c. Employment and Unemployment

Two kinds of employment will result from construction and operation of both pipelines. The first category of employment would be direct employment made up of workers who actually construct and operate the pipelines and associated facilities. Direct employment is shown in the second and third columns of Table 33 for Arctic and on columns two, three and four of Table 34 for El Paso. Both projects have been assumed to start construction in 1977.

The second category of employment is secondary and indirect employment. Secondary employment consists of jobs in industries, such as transportation, which are linked to pipeline construction. Indirect employment results from the general economic expansion of the state generated by pipeline construction and operation. The figures for total employment in Tables 33 and 34 include secondary and indirect employment as well as direct employment. Table 35 shows the projected base case employment in Alaska for selected years without gas pipeline generated employment as well as total projected employment, including that generated by pipeline construction and operation.

The El Paso proposal would increase employment by over 16,000 in 1979. After declining sharply in the early years of pipeline operation, the El Paso impact on employment reaches 12,800 by 1990. The Arctic proposal would increase employment by 2,107 in 1979 and by 5,241 in 1990. The trade and services sector would account for the largest share of total 1990 employment increase under both proposals, accounting for over 40 percent of the increases in both cases.

In 1979, the El Paso generated employment would represent a 7.5 percent increase over the baseline employment projection without the project. In 1990 the percentage increase would be 3.2 percent. For Arctic the percentage increases would be just over one percent for both 1980 and 1990.

Table 36 shows the regional distribution of employment impacts. The Anchorage region would receive about half of the employment impacts under both proposals by 1990.

The percentage of Alaskan residents hired during construction of either of the two pipelines would be expected to be as high as or higher than the approximately 60 percent figure achieved up to this point during construction of the Alyeska oil pipeline. It has been estimated that 85 percent of Arctic's employees will be Alaskan residents.1/

1/ Urban and Rural Systems Associates. An Analysis of the Socio-Economic Impact in Alaska of the Alaskan Arctic Gas Pipeline Company Pipeline (January 1974).

TABLE 33

ESTIMATED EMPLOYMENT GENERATED BY ALASKAN ARCTIC PIPELINE
(Workers)

	Direct Construction & Operation		Total Employment, Including Direct, by Economic Sector				
Year	Pipeline Const.	Pipeline Oper.	Mining and Const.	State & Local Govt.	Trade and Service	Other Support Industries	Total
1977	137		142	37	132	26	337
1978	567		586	133	594	104	1,417
1979	682		726	369	821	191	2,107
1980		39	227	1,757	1,079	559	3,622
1981		39	240	1,836	1,169	596	3,841
1982		39	245	1,825	1,232	614	3,916
1983		39	251	1,810	1,297	633	3,991
1984		39	257	1,802	1,367	656	4,082
1985		39	265	1,793	1,450	678	4,190
1986		39	273	1,791	1,543	713	4,320
1987		39	283	1,795	1,651	749	4,478
1988		39	294	1,807	1,781	795	4,677
1989		39	308	1,831	1,938	852	4,929
1990		39	326	1,870	2,126	919	5,241

Source: Direct construction and operation figures were taken from table II.F-1(P.47) and Section II-G(P. 71) of Alaskan Arctic Gas Pipeline Company's Environmental Report. Other figures were taken from January 1976 runs of MAP regional model.

TABLE 34

ESTIMATED EMPLOYMENT GENERATED BY EL PASO ALASKA PIPELINE
(Workers)

Year	Direct Construction & Operation			Total Employment, Including Direct, by Economic Sector				
	Pipeline Const.	LNG Plant & Terminal Const.	Pipeline Terminal & LNG Plant Oper.	Mining & Const.	State & Local Govt.	Trade and Service	Other Support Industries	Total
1976								
1977	1,265	1,538		3,100		1,600	600	5,300
1978	3,073	2,609		6,300	1,100	4,100	1,700	13,200
1979	3,196	2,017	340	6,300	2,600	5,000	2,200	16,100
1980	1,246	642	558	3,200	4,800	4,600	2,000	14,600
1981			624	1,100	4,500	3,300	1,800	10,700
1982			624	1,100	3,800	3,000	1,500	9,400
1983			624	1,000	3,600	3,000	1,600	9,200
1984			624	1,100	3,500	3,100	1,700	9,400
1985			624	1,100	3,500	3,300	1,800	9,700
1986			624	1,100	3,500	3,600	1,900	10,100
1987			624	1,100	3,600	3,900	1,900	10,500
1988			624	1,200	3,700	4,400	1,900	11,200
1989			624	1,200	3,800	4,700	2,200	11,900
1990			624	1,200	3,900	5,200	2,500	12,800

Source: Direct construction figures came from testimony filed by El Paso on November 28,1975 (Docket Nos. CP75-96, et at). Direct operation figures came from a study entitled "Mid-1975 Socioeconomic Report: Trans Alaska Gas Project filed as testimony by El Paso on October 9, 1975. Other figures were taken from January, 1976 runs of MAP regional model.

TABLE 35

PROJECTED TOTAL EMPLOYMENT IN ALASKA INCLUDING GAS PIPELINE GENERATED EMPLOYMENT
(Thousands of Workers)

Year	Base Case Without Gas Pipeline	Total Including Pipeline Generated	
		Arctic	El Paso
1975	183.1		
1980	235.0	238.6	249.6
1985	317.6	321.8	327.3
1990	403.8	409.0	416.6

Source: January, 1976 runs of MAP regional model

TABLE 36
REGIONAL DISTRIBUTION OF EMPLOYMENT
GENERATED BY ARCTIC AND EL PASO PIPELINES
(IN THOUSANDS)

Pipeline & Year	State Total	Region			
		Anchorage	Southcentral	Fairbanks	All Other
Arctic					
1977	.3	.1	.0	.0	0.2
1978	1.4	.3	.0	.0	1.1
1979	2.1	.5	.1	.1	1.4
1980	3.6	1.8	.4	.4	1.0
1981	3.8	1.9	.4	.4	1.1
1982	3.9	2.0	.4	.4	1.1
1983	4.0	2.1	.4	.4	1.1
1984	4.1	2.1	.4	.4	1.2
1985	4.2	2.2	.4	.5	1.1
1986	4.3	2.4	.4	.5	1.0
1987	4.5	2.5	.4	.5	1.1
1988	4.7	2.6	.4	.5	1.2
1989	4.9	2.8	.5	.5	1.1
1990	5.2	3.1	.5	.5	1.1
El Paso					
1977	5.3	.5	2.9	.6	1.3
1978	13.2	2.2	6.4	1.4	3.2
1979	16.1	4.0	6.2	2.0	3.9
1980	14.6	5.8	3.0	1.7	10.5
1981	10.7	5.4	1.5	1.2	2.6
1982	9.4	4.7	1.4	1.0	2.3
1983	9.2	4.7	1.3	1.0	2.2
1984	9.4	4.9	1.3	1.0	2.2
1985	9.7	5.1	1.4	1.0	2.7
1986	10.1	5.4	1.4	1.0	2.3
1987	10.5	5.8	1.4	1.1	2.3
1988	11.2	6.4	1.4	1.1	2.3
1989	11.9	6.8	1.5	1.1	2.5
1990	12.8	7.5	1.5	1.2	2.6

Source: January, 1976 runs of MAP regional model

The impact of either of the proposed gas pipelines on unemployment in Alaska will depend on the timing of Alyeska completion and gas pipeline construction start-up. If gas pipeline construction were to start up as Alyeska construction was winding down, gas pipeline construction could help dampen the high unemployment rates anticipated after Alyeska construction. In the present analysis, it is assumed that Alyeska construction would start winding down in 1976 and that construction will be finished by 1977. Thus, gas pipeline construction (assumed to begin in 1977) should exert a dampening influence on the extent of post Alyeska unemployment. The El Paso proposal would result in a significantly greater dampening influence than would Arctic.

As was noted in the socio-economic description section, past employment growth in Alaska (such as would be expected from gas pipeline construction) has had little if any impact in reducing unemployment due to large amounts of immigration to the state. This phenomenon would be expected to occur in the future. The lower manpower requirements and remote location of construction under the Arctic proposal would be expected to encourage much less immigration than would occur under the El Paso proposal. During the construction wind down of both projects, there would likely be higher unemployment in the state than would have occurred without the project. The extent of this unemployment would be influenced by other economic activity in the state, such as from OCS development and the spending of state oil revenue, which might result in increasing employment demands as gas pipeline construction was winding down.

d. Income

As shown in Table 37 the El Paso proposal has a much greater impact on personal income than does the Arctic proposal. In 1979 the El Paso impact on personal income is almost $364 million compared to about $53 million for Arctic. Over the longer run the gap between the two proposals is somewhat reduced, but by 1990 the El Paso impact is still over twice as large as the Arctic impact.

Table 37 also shows that neither pipeline would produce a significant lasting impact on personal income per capita. During the construction phase, both proposals, especially El Paso, would result in some increase in per capita income, but by 1990 the increase in population would have negated practically all of the previous per capita income increase for Arctic and resulted in a negative figure for El Paso. Thus, even though both pipeline proposals would increase gross economic indicators in the state, the personal income impact on the average individual in Alaska would be minimal or negative by 1990.

In Alaska, wages and salaries account for over 80 percent of total personal income. Table 38 shows the impact of both pipelines on wages and salaries broken down by economic sector groupings. During construction, the largest impact is in the mining and pipeline construction grouping. By 1990, state and local government would exhibit the largest impact, accounding for about 39 percent of the increase under El Paso and about 46 percent under Arctic.

Table 39 shows a breakdown of real wage and salary impact by region. The Arctic proposal would result in the Anchorage region receiving the largest portion of real wages and salaries for every year considered after 1979. Under the El Paso proposal, the south central region accounts for the largest share of real wages and salaries up to 1980. After 1980 the Anchorage region accounts for the largest share. By 1990 the Anchorage region accounts for over half of total real wage and salary impact under both proposals.

TABLE 37

IMPACT OF ALTERNATIVE PIPELINES ON PERSONAL INCOME

Pipeline & Year	Personal Income (Millions of Dollars)	Personal Income Per Capita (Dollars)	Real Per Capita Personal Income (1967 Dollars)
Arctic			
1977	8.4	11	5.1
1978	36.3	49	19.8
1979	53.3	53	22.1
1980	73.2	38	14.9
1981	81.5	37	14.1
1982	87.7	30	11.1
1983	94.2	22	7.9
1984	101.6	18	5.9
1985	109.9	13	4.1
1986	119.3	9	2.9
1987	130.2	6	1.9
1988	143.0	4	1.2
1989	158.5	4	0.9
1990	177.1	3	0.9
El Paso			
1977	121.0	151	67.5
1978	296.5	315	135.7
1979	363.9	289	119.9
1980	322.1	141	56.5
1981	234.2	28	10.8
1982	216.3	9	-3.1
1983	222.9	-27	-9.4
1984	238.8	-32	-10.8
1985	258.9	-36	-11.7
1986	283.2	-36	-11.4
1987	311.3	-36	-11.0
1988	350.4	-31	-9.0
1989	388.6	-30	-8.5
1990	437.4	-26	-6.9

Source: January, 1976 runs of MAP regional model.

TABLE 38

WAGES AND SALARIES GENERATED
(MILLIONS OF DOLLARS)

Pipeline & Year	State Total	Economic Sector Groupings: Mining and Pipeline Const.	State and Local Govt.	Trade and Service	Other Support Industries
Arctic					
1977	7.3	4.9	.6	1.5	.3
1978	31.6	21.0	2.4	6.7	.6
1979	46.4	26.8	7.0	10.0	2.6
1980	63.5	6.3	35.6	15.2	6.4
1981	71.3	7.0	39.7	17.3	7.3
1982	76.8	7.5	42.1	19.3	7.9
1983	82.7	8.0	44.5	21.3	8.9
1983	89.3	8.4	47.2	23.7	10.0
1985	96.8	9.1	50.1	26.4	11.2
1986	105.3	9.7	53.4	29.6	12.6
1987	115.1	10.5	57.0	33.3	14.3
1988	126.6	11.3	61.2	37.8	16.3
1989	140.6	12.3	66.1	43.3	18.9
1990	157.4	13.6	72.0	50.1	21.7
El Paso					
1977	105.5	80.8	0.7	18.8	5.2
1978	257.5	172.6	20.3	50.1	14.5
1979	316.4	178.8	50.1	65.0	22.5
1980	280.0	93.9	96.4	64.1	25.6
1981	203.4	33.7	97.2	49.9	22.6
1982	189.4	33.3	86.9	47.2	22.0
1983	195.6	34.6	87.4	50.1	23.5
1984	210.0	36.6	91.9	55.3	26.2
1985	228.1	39.0	98.0	61.9	29.2
1986	249.9	41.6	105.3	69.9	33.1
1987	275.2	44.4	113.8	79.3	37.7
1988	308.3	47.8	123.8	92.8	43.9
1989	344.7	51.4	136.9	106.0	50.4
1990	388.7	55.7	150.8	123.7	58.5

Source: January, 1976 runs of MAP regional model

TABLE 39

REGIONAL IMPACT ON REAL WAGES AND SALARIES
(Millions of 1967 Dollars)

Pipeline & Year	Total	Region: Anchorage	Southcentral	Fairbanks	All Others
<u>Arctic</u>					
1977	3.3	.4	.1	.1	.7
1978	13.6	1.8	.2	.2	11.4
1979	19.3	3.6	.5	.6	14.6
1980	25.4	12.4	2.6	3.2	7.2
1981	27.4	13.4	2.8	3.5	7.7
1982	28.4	14.1	2.9	3.5	7.9
1983	29.4	14.8	2.9	3.6	8.1
1984	30.6	15.7	3.0	3.7	8.2
1985	31.9	16.6	3.1	3.8	8.4
1986	33.4	17.6	3.2	4.0	8.6
1987	35.1	18.8	3.3	4.1	8.9
1988	37.2	20.3	3.4	4.3	9.2
1989	39.7	22.0	3.6	4.5	9.6
1990	42.8	24.2	3.8	4.7	10.1
<u>El Paso</u>					
1977	47.3	3.7	24.6	5.6	13.4
1978	111.0	15.2	53.3	12.0	30.5
1979	131.4	27.6	51.9	16.7	35.2
1980	111.9	40.3	24.4	13.4	33.8
1981	78.2	37.6	11.8	9.4	19.4
1982	70.1	33.7	11.0	8.3	17.1
1983	69.6	33.9	11.0	8.1	16.6
1984	72.0	35.6	11.2	8.3	16.9
1985	75.2	37.8	11.4	8.5	17.5
1986	79.3	40.6	11.8	8.9	18.0
1987	84.0	43.8	12.2	9.3	18.7
1988	90.6	48.5	12.6	9.7	19.8
1989	97.4	52.9	13.2	10.4	20.9
1990	105.7	58.7	13.8	11.1	22.1

Sources: January, 1976 runs of MAP region model.

e. Cost of Living

In discussing the impacts of gas pipeline construction and operation on the cost of living in Alaska, it is important to differentiate between short to intermediate run and long run impacts. In the short to intermediate run, there is a possibility that construction related shortages or bottlenecks, such as in transportation, could exert upward pressure on prices. If such price increases take place, they would likely be of much lesser magnitude than occurred during the Alyeska construction, with the possible exception of certain individual communities such as Cordova. This would be true because of the increased supply of goods and services and expansion of distribution channels resulting from Alyeska. Because of the much greater amount of construction that would take place in Alaska, the El Paso project would be expected to have a greater impact on short to intermediate run prices than the Arctic proposal.

In the longer run, a gas pipeline may result in lower prices in Alaska than would have occurred without the pipeline. This would be due to the expanded population, economic infrastructure and support sector that would result, making possible larger local and regional markets, economies of scale, more competition and expanded import substitution.1/ The El Paso proposal would have a greater impact than would Arctic due to its much larger impact on the Alaskan economy.

1/ ISEGR (October 1974) has pointed out that transportation costs and especially the small size of Alaskan markets which limits competition and gains from scale economies are among the reasons for high price levels in Alaska.

f. Native Economy

Either gas pipeline proposal would directly impact the Alaskan native community by providing some employment opportunities during construction and operation and by disrupting the subsistence activities of some native communities.

Through June of 1975, the percentage of total Alyeska construction employment accounted for by natives had been about seven percent. There is a possibility that this seven percent figure could be exceeded during gas pipeline construction due to the higher native membership in unions that has been achieved during Alyeska construction and job training that has been received. Some of the native employment on Alyeska is a result of contracts awarded to native claims act coprorations or other native owned firms. These contracts have been for the provision of such services as security guards, supply of gravel, clearing at the terminal site, haul road maintenance, work camp maintenance, and food service catering. It is likely that similar contracts would be awarded during gas pipeline construction.

The potential pipeline-related cause of interference with the subsistence resources utilized by the natives consist of disruptions to the habitat of fish and game as a result of construction and operation and increased competition from the non-native population for the limited resources available.

The U. S. Department of the Interior has provided a rather extensive discussion of the possible impacts of construction and operation of the Arctic proposal on subsistence activities of the village of Kaktovick, a small native village located on the Arctic coast east of Prudhoe Bay (1970 population - 123).1/ As described by the USDI, Kaktovik would probably be an extreme example of impact, and therefore should not be interpreted as being representative of the extent of impact on other villages. Nevertheless it is an example of the variety of kinds of impacts that might be felt by a number of villages along either pipeline route.

1/ USDI, Part II Alaska, Vol. 1 (June 1975), pages 871-79.

Because of the greater amount of facilities in Alaska, the El Paso proposal would be expected to provide more native employment opportunities and cause greater disruption to native subsistence activities than would Arctic. Because the El Paso pipeline will generally follow the route of the Alyeska oil pipeline, the impact on subsistence resources would not likely be as great as the Alyeska impact. However, the cumulative impact of both El Paso and Alyeska would be expected to surpass that of Alyeska alone. Under both proposals, the employment and subsistence impacts would likely hasten the integration of those natives affected into the cash economy.

g. Impact on Specific Localities

With the exception of Anchorage and Fairbanks, the ISEGR model is not capable of projecting impacts on specific villages, towns, and cities in Alaska. In addition to Anchorage and Fairbanks, several other communities would experience population, employment, and commercial development, and other private sector economic impacts of varying degrees as a result of gas pipeline construction and operation.

The El Paso proposal would impact a greater number of communities than would Arctic. Due to construction and operation of the LNG plant and marine terminal, Cordova would probably be subject to the greatest impacts relatively, and would be the only community which will have had few impacts from Alyeska.

El Paso plans to have more than 2,000 workers employed in the Cordova area over the peak two-year period of construction on the LNG plant and marine terminal. The actual peak year of construction would employ about 2,600 workers. In addition to LNG facility workers, there would be a number of pipeline construction workers (about 1,000 during the peak year) employed in the area. The LNG plant and marine terminal would employ about 350 operating personnel, 65 of whom would live on Gravina Point.

El Paso estimates that during the peak year of construction population will increase from an approximate pre-project level of 3,000 in 1977 to about 9,000. After construction, the permanent increase in Cordova's population as a result of the project is estimated to be about 1,800. The operational crews for the LNG facilities will be on a 10 day on, 5 day off rotational schedule; thus El Paso expects many of their families to locate in Anchorage, with El Paso providing transportation for R&R. Many of the supervisory personnel both during construction and operation are expected to locate in Cordova.

The added population and employment opportunities should result in higher total income and increased commercial development in Cordova. This would help to broaden the economic base of Cordova, which up to this point has consisted mainly of the fishing industry. Rather substantial price inflation impacts would also be expected in Cordova, particularly for items, such as housing which will be in very limited supply.

Other communities that would be impacted by the El Paso proposal will have already experienced similar impacts from Alyeska, and gas pipeline related impacts would in general be a continuation of impacts already encountered. These communities include Valdez (where El Paso estimates the possibility ofa short run construction population impact of 1,200 as well as some permanent population increases), Glenn-allen, Copper Center, Delta Junction, Anaktuvuk Pass, Prudhoe Bay, Barrow and Kaktovick. In general, the gas pipeline impact should be of lesser magnitude than the Alyeska impacts.

In addition to Fairbanks and Anchorage, the main communities experiencing population, employment or commercial development impacts under the Arctic proposal would be Prudhoe Bay, Barrow and Kaktovick. As with El Paso, these impacts would in general be a continuation of impacts already encountered as a result of Alyeska.

iv. Use of Prudhoe Bay Gas in Alaska

At the present time, it is impossible to come to any firm conclusions about the use of Prudhoe Bay gas in Alaska because of the number of uncertainties and unanswered questions that surround this issue. Depending on the assumptions one wishes to make about these uncertainties and unanswered questions, it could be argued that all or none of the royalty gas would be used in Alaska. See Appendix C for a discussion of the potential for the use of Prudhoe Bay gas in Alaska and for the identification of selected socio-economic impacts that might occur as a result of this use.

v. The Supply of Selected Private Services

Neither the El Paso proposal nor the Arctic proposal approaches Alyeska in size of the construction endeavor or magnitude of the socio-economic impacts. With less than 200 miles of its route falling within Alaska, Arctic would employ at its peak only 1/5 of the Alyeska work force peak. The El Paso impact would be considerably more significant, yet it too would fall well below the levels of Alyeska. In addition to the difference in size, gas pipeline impact will also be dampened by the fact that the Alaskan economy has expanded in the last few years to meet the demands of the Alyeska buildup. The gas pipeline proposals therefore would be both smaller than Alyeska and would impact on an economy that has expanded well beyond pre-Alyeska levels.

Because of this, the impacts of gas pipeline construction on housing, private health care, utilities, transportation, retail and financial services would be either a continuation of the Alyeska impacts albeit at a lower level, or of little significant impact at all. The latter would seem to be the case should the Arctic proposal be approved. (See the socio-economic description section for a discussion of the Alyeska impacts.)

One important exception should be noted. Both El Paso and Arctic would impact on areas left untouched or only minimally impacted by Alyeska and in these areas gas pipeline impact could be quite significant. Under the Arctic proposal there would be the possible impacts on the native village of Katovik where changes in native lifestyles would probably occur during the construction. This would arise both from natives accepting pipeline work and from the construction activity interfering with wildlife hunted by the natives.

The town of Cordova, which has been unaffected by Alyeska, would experience great changes during construction of the El Paso line, the LNG facility and tanker terminals. Cordova also would see, unlike Kaktovick, a long term change once the LNG facility, which would employ 350 people, becomes operational. During the construction phase the population of Cordova would almost treble. This would likely cause severe problems in housing and other private services not to mention the public utilities sector -- water, sewage and so forth. Cordova's present public services are geared for a population of around 4,000 persons (current population is 2,500) and would meet the anticipated long-term population growth predictions. However, the surge in population during the construction period would for the short-term place severe strains on the water and sewage systems. (See letter of Comment, Cordova Chamber of Commerce.)

A preview of the impacts that Cordova can expect can be seen in the Valdez experience during construction of the Alyeska pipeline terminus. Impacts on Valdez have included substantial financial gains with a median income for the residents of $35,000, increased financial investment, severe housing shortages, high prices, and the displacement of long-time businesses by outside interests.1/ Perhaps the largest single change for Cordova would be in the character of the town itself; it would likely change from a rather isolated small village dependent on fishing and tourism to an industrial town where significant numbers of residents would work at the LNG facility.

1/ Baring-Gould, Michael, "Valdez Project," University of Alaska; quoted in John A. Kruse, et al., A Cursory Comparison of Social Impacts of Alternative Gas Pipeline Routes From Prudhoe Bay, Alaska, Institute of Social, Economic and Government Research, University of Alaska, 1975.

vi. Selected Social Impacts of Gas Pipelines

As has been previously stated, neither gas pipeline would impact upon Alaska with the magnitude of the Alyeska impacts. A refinement of this statement must be made however to take into account the relative impacts of gas pipeline construction on certain areas and segments of Alaskan society. The severity of impacts will usually depend on the types of communities, their relationship to the pipeline and the duration of the impact period. Major social as well as economic impacts can be expected in those areas left relatively untouched by Alyeska. Dislocations and social problems of a significant magnitude are more likely to occur in small villages than in the cities like Fairbanks and Anchorage. Of these small villages, those whose economic and social structure is based on subsistence activities will more likely experience disruption than non-subsistence villages. Men leaving the village for pipeline work and, if the village lies near the right-of-way, the disturbance of local game would have important consequences for village life. Furthermore, native villages would more likely experience greater impacts than white communities due to clash of the diverse cultures, racial tension and the like.1/

Potentially severe impacts can be expected in the Cordova area as the population expands during the construction period. To the extent that crime, family problems, drug abuse and other social problems are a result of pipeline generated impacts, Cordova could be faced with serious difficulties. Kaktovik too could be severly impacted by nearby pipeline construction. Here the problem is compounded by the local dependence on subsistence activities and the predominantly native population. However the short duration of the construction period as proposed by Arctic would serve to lessen the impacts on the village.

1/ John A. Kruse, et al., A Cursory Comparison of Social Impacts of Alternative Gas Pipeline Routes From Prudhoe Bay Alaska, Institute of Social, Economic and Government Research, University of Alaska, Dec. 1975.

vii. Government Receipts and Outlays in Alaska

Overview

The impacts on Alaskan State and local government outlays and receipts will differ markedly between the Arctic Gas and the El Paso alternative gas transportation systems. Moreover, on either route the impacts will differ between the construction and operation phases. In addition, there are potential longer term impacts under either proposal from the eventual depletion of gas (and oil) reserves. These reserve depletion impacts will not be addressed here, although the fact of eventual depletion will be a consideration for the State in planning the use of its revenues.

The State's financial structure and pattern, and the size of its outlays, will no doubt exhibit significant changes as oil revenues begin to flow. Because of the potential range in the scope and magnitude of government responses and initiatives, and the resulting impacts in the face of these changes, projecting impacts onto this "volatile" projected base case cannot be done with great precision. This "volatility" has several causes. The greatest sources of gas impact receipts to the State are based on the wellhead price, production volumes, and the cost of the transportation system. The wellhead price is not known, production volumes are not known but the Applicant's proposals differ markedly, the actual cost of the transportation systems may differ from current estimates, and Alaskan tax rates may be changed. Moreover, the State's expenditures are, of course, determined by political processes and are thus also difficult to project. Finally, given the lack of certain types of data, some projected impacts can only be stated in qualitative terms.

The impacts projected from alternative transportation systems reported here for the public sector of the economy are from the MAP Model discussed above.[1/] The analysis in this section will evaluate in more detail those assumptions used in the MAP Model which most strongly influence the projections for the public sector. Then the projected construction and operation impacts from the MAP Model are discussed and changes in impacts from modifications in the assumptions are analyzed.

1/ See p.109 above for a description of the MAP Model.

MAP Model Assumptions

The most important assumptions in the MAP Model with regards to government impact projections are as follows. First, it is assumed that the State will save 25 percent of recurring petroleum revenues and 50 percent of lease bonus payments and the savings would earn interest. Second, the wellhead value for gas is assumed to be equal for both the Arctic Gas and the El Paso alternatives, and the wellhead value adopted is $.50 per Mcf. Third, the throughput of Prudhoe gas also is assumed to be equal under each alternative, and the throughput assumed is 2.5 Bcf/day. Fourth, the LNG facility (i.e., El Paso's proposed liquification plant) is assumed to be subject to the property tax. Fifth, the production tax rate and the property tax rate are assumed constant (the royalty rate is fixed). Sixth, the costs of pipeline construction are those originally submitted by the Applicants.

The percentage of State oil revenues and lease bonus payments saved will effect the size and structure of the base case. In addition, the percentage of gas revenues saved will influence the magnitude and pattern of the impacts on the State's economy from gas production and transportation. Moreover, how the saved funds are used or placed is important. If the funds are placed in loans for making investments in Alaska which otherwise would not be made, then the impacts initially would be similar in effect to direct State expenditures. Compared to State expenditures, however, investments are likely to have a greater long term impact on the economy. On the other hand, if the saved funds only displace other sources of investment funds that would have been placed in Alaska, or if the funds are placed in the lower 48 states or elsewhere, the immediate impact on the Alaskan economy will be less than if they are invested in Alaska. Saving and investing a percentage of State revenues will also increase future State revenues from investment income.

The wellhead value of the gas produced is critical in determining Alaska State revenue impacts from the alternative projects. State royalties at the Prudhoe field are generally 12½ percent of the wellhead value, and the severance tax is currently 4 percent. The severance tax may be increased by the State. The wellhead price of gas for tax and royalty purposes may be calculated on a net-back basis, i.e. the price of the gas when sold at the market to a lower 48 gas distribution company or industrial customer less the transportation costs of delivery. Thus, the gas transportation system that results in the lowest unit transportation costs will, at the same market price, give Alaska the larger severance tax revenue and royalty receipts per Mcf produced. On the other hand, if gas sales take place at the wellhead, the State may choose to base its taxes and royalties on the contracted wellhead price if it is higher than the net-back value. Finally, the State may take its royalties, and perhaps its severance taxes, in kind.

The wellhead price for new gas dedicated to interstate commerce is now (at least) $.52 per Mcf in the lower 48. The wellhead price used in the MAP Model for estimating royalty and severance tax revenues to Alaska is $.50 per Mcf. Selection of a common wellhead price between the alternative transportation systems will not, however, expose the potential of differential State revenues, and thus impacts, which would result from differences in wellhead prices.

In contrast to the MAP Model assumption of a daily throughput of 2.5 Bcf/day, Arctic Gas plans gas throughputs from Prudhoe of 2.25 Bcf/day and El Paso projects transporting 3.2 Bcf/day. If the wellhead price to gas producers were equal between transportation systems then the actual throughputs should be equal. Specifically, the economic rate of production should be the same. The State of Alaska may limit production, perhaps to 2.0 Bcf/day.

El Paso's LNG liquification plant probably will be subject to the property tax and is thus included in the tax base for the MAP model. However, if it is not taxable, or subject only to reduced taxes, the revenue advantage to the State from the El Paso route would be reduced.

The construction costs utilized in the MAP model runs reported here are those used in the MAP model study completed in April 1975. 1/ To the extent that these costs have been modified by the subsequent filings of the Applicants to reflect non-inflation cost changes, and to the extent that resizing of the El Paso system is required for the 2.5 Bcf throughput assumption, this original data base may not exactly reflect the latest cost modifications.

The gas severance tax rate and the property tax rate are both assumed in the MAP Model to be constant during the period of analysis. The gas severance tax may be low relative to the oil severance tax and the Alaska State Legislature could move to gain more revenues from gas production. Similarly, the property tax on oil and gas production and transportation facilities could be considered low relative to lower 48 property tax rates and could be increased. In the MAP model the property tax base is not adjusted for depreciation and thus may be overstated. Royalty rates were, of course, fixed for the Prudhoe field at the time of the Bonus lease sale and will not change.

There are other assumptions in the MAP Model of relatively less importance for projecting impacts. The payments being made over the next two years under the reserves tax are not considered either as a revenue source or as an offset of future production tax revenues. The timing of construction both in initiation and in completion could differ from existing plans as could the planned yearly buildup in gas throughputs. Cost overruns could increase property tax revenues, but may decrease royalties and severance tax revenues due to a lower net-back wellhead price. Overall, the structure of the MAP Model is based on recent past structure and patterns of the Alaskan economy and these too could undergo some changes in the base period. Nevertheless, the MAP Model provides a systematic analysis of the relative potential impacts between routes and of the interrelationships between the many ingredients of the State's economy.

1/ Institute of Social, Economic and Government Research, University of Alaska, Impact on the Alaska Economy of Alternative Gas Pipelines, April, 1975.

Construction Period

During the construction period, the impact of the El Paso alternative on both governmental outlays and receipts will be larger than that for the Arctic Gas proposal. The construction workforce for El Paso will be larger and will work in Alaska over a longer period than for Arctic Gas. Compared to the ongoing Alyeska Construction, however, the workforce for El Paso will be smaller and may have a larger percentage of Alaskans in the workforce. Both of these factors lessen the impact on the need for additional governmental services, e.g., education. Table 40 reproduces the MAP Model projections of impacts on State and Local Government Expenditures under the alternative pipeline systems starting with the construction period and extending into the initial years of production. The magnitude of the impact from El Paso is several times that from Arctic Gas. The growth in expenditures initially is to meet construction impact demands but in later years also reflects additional general State spending as gas related revenues become available. Part of the buildup in revenues comes from taxes on the incomes and spending of construction workers.

Table 41 shows the buildup by year in the cumulative capital costs and estimated property taxes as the pipelines are constructed. The capital cost of the El Paso system in Alaska is several times that of Arctic Gas in Alaska and property tax revenues to the State reflect this difference.

Thus, during the construction period the El Paso alternative will have a significantly greater impact on revenues because of greater property taxes and greater total construction worker income and spending. Similarly, the El Paso alternative will require more governmental services than the Arctic Gas route to the extent that workers do not already live in Alaska, but bring their families.

Table 40

MAP Alaska Model
Gas Pipeline Impact Measures 1/
(millions of dollars)

	Incremental State and Local Government Expenditures	
	Arctic Gas	El Paso
1978	$ 5	$ 46
1979	15	113
1980	79	216
1981	88	217
1982	93	193
1983	98	193

1/ Institute of Social, Economic and Government Research, University of Alaska, January, 1976.

Table 41

MAP Alaska Model
Cumulative Capital Costs
and Estimated Property Taxes 1/
(Thousands of Dollars)

	Alaskan Arctic Gas Pipeline Co.		El Paso Alaska Co.	
	Gas Pipeline	Property Taxes 2/	Gas Pipeline Marine Terminal and LNG Plant 3/	Property Taxes 2/ 3/
1976	$ 3,000	$ 60	$ 34,502	$ 690
1977	6,000	120	73,853	1,477
1978	138,000	2,760	845,150	16,903
1979	306,000	6,120	1,862,191	37,244
1980	406,500	8,130	2,741,101	54,822
1981	474,500	9,490	3,395,602	67,912
1982	500,000	10,000	3,599,325	71,987

1/ Institute of Social, Economic and Government Research, University of Alaska, Impact on the Alaska Economy of Alternative Gas Pipelines, prepared for the Aerospace Corporation, (April, 1975), Tables 2-6 and 2-7.

2/ Current State property tax rate: 20 mills.

3/ At present, the LNG Plant is not taxable. If this exemption from taxation is continued; the property tax revenues to the State under the El Paso Alaska Co. Alternative would be less in each year, e.g., in 1982 they would be about $32 million less.

d. Operation Period

During the operation period, Alaska will receive greater revenues from the El Paso alternative than from Arctic Gas. This assumes the same throughput of Prudhoe gas and an identical wellhead price. The difference in revenues is from the property tax. The annual property tax payment would total $10 million for Arctic Gas, $40 million for El Paso without the LNG facility in the tax base, or $72 million if the LNG facility becomes taxable. The MAP Model projections of royalties and of production and property taxes for Prudhoe gas are shown in Table 42. These estimates assume a Prudhoe throughput of 2.5 Bcf/day for either proposal by 1983, a $.50 Mcf wellhead value, and that the LNG facility is taxable. MAP Model projections indicate that the El Paso alternative would generate $147 million per year in State receipts. This is about 73 percent more direct revenue to the State than the $85 that Arctic Gas would contribute. In either case the dollar amounts are large, but they nevertheless are small compared to the projected Prudhoe oil revenues.

For comparison, the applicants' projected throughputs can be used to make estimates of revenues to the State. Arctic Gas plans throughputs of 2.25 Bcf/day from Prudhoe, and El Paso plans 3.2 Bcf/day. With a $.50 Mcf wellhead price, Alaska State royalty receipts and production tax revenues would amount to $68 million a year under Arctic Gas or $96 million from El Paso. When property taxes are added, the amounts would total $78 million from Arctic Gas, $168 million from El Paso with the LNG plant taxable, or $136 million if the LNG plant is not taxable.

In addition to the direct revenues from gas production and transportation, Alaska State revenues would be greater from income and spendings taxes under the El Paso route because of the larger permanent workforce. The incremental impact, relative to the operation period, will be negative since the permanent workforce will be smaller than the construction workforce. If many of the permanent workers settle in Cordova with their families, there would be a relatively large impact on the local government. The local government may have to finance capital improvements or obtain State or Federal assistance to provide services to the new population. Cordova could also have some short-term problems in financing increasing operating expenses while its tax base grows.

Table 42

MAP Alaska Model
(2.5 Bcf/day and $.50 Mcf)

Estimated Royalties and Production
and Property Taxes for Prudhoe Gas
(Thousands of Dollars) 1/

	Alaskan Arctic Gas Pipeline Co.	El Paso Alaska Co. 2/
1976	60	690
1977	120	1,477
1978	2,760	16,903
1979	6,120	37,244
1980	68,355	115,047
1981	75,738	134,160
1982	79,259	141,246
1983	85,281	147,268

1/ Annual Royalties (12½ percent) and Production Taxes (4 (4 percent) are derived by multiplying 16½ percent times 2.0 Bcf/day (in 1980, but climbing to 2.5 Bcf/day by 1983) times 365 days/year, times $.50 per Mcf. Property taxes are those estimated in Institute of Social, Economic and Government Research, University of Alaska, Impact on the Alaska Economy of Alternative Gas Pipelines, prepared for The Aerospace Corporation, (April, 1975), Tables 2-6 and 2-7.

2/ At present, LNG facilities are not taxable. If this exemption form taxation is continued, the tax revenue to the State from property taxes would be less, e.g., would be about $32 million less.

c) Socio-Economic Impact of Alternative Routes

i. Introduction

This section discusses socio-economic impacts in Alaska of two alternative routes to the proposals which have been submitted to the FPC. One route is an alternative to the Arctic proposal and the other route is an alternative to the El Paso proposal.

The Arctic alternative is known as the Fairbanks Corridor route. From Prudhoe Bay this route would proceed south to an area near Livengood. It would then turn southeast, pass by Fairbanks to Delta Junction and then generally parallel the Alaska highway to the Canadian border.

The El Paso alternative would follow the El Paso prime route to Livengood. It would then proceed almost directly south to Nenana and generally follow the Alaskan Railroad corridor to Talkeetna, continuing along the eastern side of the Susitna River to Cook Inlet. An underwater route across Cook Inlet would surface at Possession Point and the route would follow the western coast of Kenai Peninsula to an LNG facility at Cape Starichkof.

ii. Arctic Alternative Route

a. Population and Selected Private Sector Economic Impacts

The Arctic alternative route would have a substantially greater socio-economic impact on the state than the prime route. It would have almost as many miles of pipeline in Alaska as the El Paso prime route.

Direct employment during construction and operation would be expected to be similar to the non-LNG facility related direct employment of the El Paso prime route. Statewide impacts on population, GSP, employment and income would be much greater than those projected for the Arctic prime route, but would not reach the levels projected for the El Paso prime route. As compared with the prime route, several more individual communities, such as Delta Junction, would experience construction related impacts. The impacts on Fairbanks and Anchorage would be more extensive than under the prime route.

b. Supply of Selected Private Services

Where the Arctic prime route would probably have few impacts on the supply of private services, the alternative route, which would be considerably longer, would pass through less isolated areas of the state, and would employ greater numbers of workers over a longer period of time, would have significantly greater impacts. Under this alternative route, Fairbanks would experience a greater amount of impacts on private services, especially in the areas of housing, private health care, utilities, communication, transportation, financial, retail and leisure services. However, these impacts would not be of the magnitude of the Alyeska impacts since the numbers of workers would be less than Alyeska and since services have expanded in the last few years under the pressures generated by Alyeska.

The Arctic alternative could have more serious effects on those areas outside the oil pipeline corridor, that is from Delta Junction southeast to the Canadian border. While the towns along the Alcan highway escaped the direct impacts of Alyeska -- such as happened in Valdez or Fairbanks -- they did experience increased demands on services due to those people moving into Alaska along the highway. As a result, towns like Tetlin Junction experienced some economic expansion that would tend to absorb to some degree the impacts generated by the Arctic alternative.

c. Selected Social Impacts

Social impacts generated by the Arctic alternative would fall on areas already impacted, directly or indirectly, by the Alyeska oil pipeline. These include the actual oil pipeline corridor and the Alcan highway corridor. Since both of these areas have been affected by the construction of Alyeska, the impacts of gas pipeline construction would not be as great as it would be on areas left unaffected by Alyeska.

d. Government Receipts and Outlays

The impact on government receipts from the alternative route of the Arctic Gas pipeline would be larger than from the Arctic Gas primary route. During the construction period, the longer pipeline needed within Alaska for the alternate route will require a larger workforce. Thus, property taxes would be greater and worker income and expenditure tax revenues would be greater. During the operation period, revenues from the property tax would be larger. But in both the construction and operation periods the impacts would be less than for the El Paso proposal. State revenues from the production tax and from royalties may also differ if the net-back wellhead price between routes will be different. If more out-of-state workers bring their families, to Fairbanks, the impact there also will be larger than for the primary route.

iii. El Paso Alternative Route

a. Population and Selected Private Sector Economic Impacts

The El Paso alternative route would involve approximately the same pipeline mileage and LNG facilities as the prime route. Thus, the alternative would be expected to have about the same total impact (in terms of population, GSP, employment, and income) on the state as the prime route. Even the distribution of the impact among the seven major regions of the state would be about the same. However, the distribution of the impact on specific localities would be different. The impacts discussed earlier for communities, such as Cordova and Valdez, along the Alyeska Corridor and near Prince William Sound, would be transferred to communities along the Alaskan Railroad Corridor and on the Kenai Peninsula. Communities (and their 1970 populations) especially likely to be impacted by LNG facility construction and operation include Kenai (3,533), Soldotna (1,202), Homer (1,083), Ninilchi (134), Anchor Point (102), and Kachemak (76).

b. Supply of Selected Private Services

The major difference in impact between the El Paso prime and alternative routes would be in the geographic areas affected by the projects. Both would employ approximately the same numbers of people over similar distances for similar lengths of time. Where the prime LNG facilities would impact on Cordova, the alternative facilities would be located near Cape Starichkof.

Under the El Paso alternative, Fairbanks and Anchorage would continue to attract the bulk of the social and economic impacts. However, because the alternative would route the pipeline nearer Anchorage, more construction workers' R&R activities might take place there and it is possible that certain private services -- retail and leisure -- would experience more pipeline generated increases that would occur under the prime route. It should be noted that more towns are located along the alternative Alaskan Railroad corridor, hence it is possible that impacts would be more evenly spread out among the population.

c. Selected Social Impacts

In the main social impacts generated by the El Paso alternative would fall on areas already impacted, directly or indirectly, by the Alyeska pipeline. These include the actual oil pipeline corridor and the Alaskan Railroad Corridor. Since these areas have been affected by the Alyeska construction, the impacts of gas pipeline construction would not be as great as it would be on areas left unaffected by Alyeska.

d. Government Receipts and Outlays

The impact on State and local government receipts and outlays from the alternate route of the El Paso pipeline would be about the same as that of the primary route. However, the geographic impact of certain local government receipts and needed outlays will change from the Cordova area to the Kenai Peninsula.

d) Summary of Impacts

i. Arctic Proposal

The statewide impact of the Arctic proposal on population and the private sector would not be substantial. The absolute and relative impact on selected variables is summarized below:

Variable	Amount of Impact	Percent Increase Over Base Case Without Project
Population, 1990	10,200	1.3
Real GSP, 1990 (Millions of 1958 dollars)	49.1	0.9
Employment, 1990	5,241	1.3
Personal Income, 1990 (Millions of dollars)	177.1	1.3
Real Per Capita Income (1967 dollars)		
1980 (Peak Year)	22.1	0.6
1990	0.9	negligible

Most of the long run economic impact would be reflected in the support sector industries, especially trade and services. Due to the substantial government revenues generated, the state and local government sector would also account for a large share of long run impact. Because of its role as the manufacturing and service center for the entire state, the Anchorage region would account for over half of the statewide population, output, employment, and income impacts. Few individual communities in addition to Anchorage and Fairbanks would be impacted by the Arctic proposal.

The proposed Arctic Gas pipeline would have a small impact in Alaska on government receipts and outlays during the construction period, but will produce additional annual State receipts during the operation period.

ii. El Paso Proposal

As can be seen from the summary below, the statewide impact of the El Paso proposal on population and the private sector would be significant, especially during the peak years of percentage impact 1978-1980.

Variable	Amount of Impact	Percent Increase Over Base Case Without Project
Population		
1979	23,500	5.2
1990	26,800	3.3
Real GSP (millions of 1958 dollars)		
1980	282.4	8.7
1990	286.1	5.3
Employment		
1979	16,100	7.5
1990	12,800	3.2
Personal Income (Millions of dollars)		
1979	363.9	8.4
1990	437.4	3.2
Real Per Capita Income (1967 dollars)		
1978	129.8	3.5
1990	6.9	decrease

A significant part of the long run economic impact would be attributed to the support sector industries, especially trade and services. However, the mining industry would account for the greatest share of GSP increase by 1990 due mainly to the operation of the LNG facility and marine terminal. Due to the substantial government revenues generated, the state and local government sector would also account for a large share of long run impact. Because of its role as the manufacturing and service center for the entire state, the Anchorage region would account for over half of the statewide output, employment and income impacts.

In addition to Anchorage and Fairbanks, the El Paso proposal would impact a number of other smaller communities near the pipeline route. Cordova would probably be subject to the greatest impacts relatively. For example, it is estimated that the population of Cordova during the peak year of construction on the LNG plant and marine terminal would tripple temporarily as compared with pre-project levels. There would also be a substantial increase in the permanent population of Cordova.

The El Paso proposal would be more likely to continue the social impacts of the Alyeska pipeline albeit to a smaller degree. Excepted of course would be the Cordova area which would experience significant impacts on the private services sector and where the lifestyles of the town and its inhabitants would likely undergo a great change.

The proposed El Paso pipeline, LNG plant, and marine terminal facilities would have a construction period impact on government receipts and outlays less than for the ongoing Alyeska oil pipeline project. In comparison, the El Paso pipeline will be less expensive in current dollars and therefore will produce less in property taxes. Also, it will employ fewer workers with a result of lower state revenue from income and expenditure taxes. However, the impact of construction workers and operating workers and their families on Cordova will be large and result in a need to increase government operating and capital outlays. During the operation period, the El Paso proposal will generate additional annual State revenues.

iii. Alternative Routes

An Alternative route to each of the Arctic and El Paso proposals has been discussed previously. The Arctic alternative would pass near Fairbanks and follow the Alaska Highway to the Canadian Border. The El Paso alternative would pass near Fairbanks and follow the Alaskan Railroad corridor to an LNG facility on the Kenai Peninsula at Cape Starichkof.

The Arctic alternative would have substantially greater impacts in terms of population, the private economic sector, private services, and social impacts on the state of Alaska than the prime route. Even though these impacts would probably reach significant levels, they would not be expected to be as great as under the El Paso proposal. Construction and operation period revenues from property taxes and the construction period workforce income and expenditure taxes would be increased. Local govenment outlays, especially in Fairbanks, might also need to be increased.

The El Paso alternative would result in approximately the same statewide impacts as the prime route. A major difference is that different small communities along the pipeline route would be impacted, especially communities on the Kenai Peninsula.

APPENDIX A

ALASKAN GROSS PRODUCT, EMPLOYMENT, AND INCOME 1960 - 1975

Gross State Product

Gross State Product (GSP) is considered the single most comprehensive measure of economic activity in Alaska. It can be defined as the total value of all goods and services produced in the state for a given period of time. As derived by the Institute for Social, Economic, and Government Research (ISEGR), University of Alaska, gross product for each industrial sector is calculated by either (1) figuring how much of the total value of a given industry's output exceeds the cost of materials used in production or (2) figuring the sum of the industry's payments for employee compensation, profits, and other such production costs as indirect business taxes and depreciation.1/

Table 43 shows real GSP by economic sector in Alaska for the years 1961, 1970, and 1975. Table 18 showed the percentage of GSP accounted for by each sector for these three years and Table 19 showed the percentage increase in real GSP from 1961 to 1975. Government is the largest sector and mining is a close second. Spured by the tremendous upsurge in petroleum related activity, the mining sector has grown by 750 percent since 1961, more than twice as much as the next most rapidly growing sector.

In 1975, real GSP for Alaska was estimated to be $1,754 million. Real GSP eliminates the affect of inflation and therefore results in a lower figure than if measured in current dollars. Current dollar GSP is not available for 1975, but it would be well over $3,000 million or about twice the Real GSP figure. Since 1961

1/ Institute of Social, Economic and Government Research, "Estimated Gross State Product for Alaska," Alaska Review of Business and Economic Conditions (April 1974).

TABLE 43

ALASKA GROSS PRODUCT IN CONSTANT DOLLARS BY INDUSTRY, 1961-1975
(Millions of 1958 Dollars at Average U.S. Price)

Economic Sector	1961	1970	1975
All Sectors	683.6	1290.8	1753.9
Agriculture, Forestry and Fisheries	30.9	37.6	26.1
Mining	36.9	319.7	313.5
Contract Construction	33.6	54.6	136.9
Manufacturing	70.2	99.3	135.3
Transportation	42.5	89.7	132.7
Communication	60.8	64.3	97.8
Public Utilities	11.9	31.5	71.7
Trade	68.0	137.3	235.2
Finance, Insurance and Real Estate	40.2	85.3	153.9
Services	32.4	68.3	119.8
Government	256.2	303.2	331.0
Federal	225.1	234.4	217.8
State and Local	31.1	68.8	113.2

Sources, ISEGR (April, 1974) 1961 and 70 Data; ISEGR(June 27,1975) 1975 data

Real GSP in Alaska has grown at an average rate of about 11 percent per year. This rate of growth exceeded that for the total U. S.

Between 1961 and 1975 the total growth in Real GSP was $1,070.5 million or a 264 percent increase. The sector contributing most to this total growth was mining, which accounted for over 25 percent of the total. The so-called support sectors (transportation, communication and public utilities; trade; finance, insurance and real estate; and services) accounted for over 50 percent of the total growth. The renewable resource industries (agriculture, forestry, and fisheries), along with Federal government had a slight decline in Real GSP.

Table 44 shows the regional distribution of Real GSP for 1965 and 1975. Anchorage was the dominant region for both years, containing over 40 percent of the state total. The largest change during the ten-year period occurred in the south central region which almost doubled its share of Real GSP and in the Fairbanks region which saw its share decrease from 17.1 to 11.7 percent of the total. Table 45 shows regional Real GSP by economic sector for 1973.

TABLE 44

REGIONAL DISTRIBUTION OF REAL GSP
1965 and 1975

Region	1965	1975
	Percent of Real GSP	
South Central	11.7	20.9
Interior	4.6	6.8
Southeast	15.1	12.5
Southwest	7.6	5.0
Northwest	2.5	3.0
Anchorage	41.4	40.1
Fairbanks	17.1	11.7
Total	100.0	100.0

Sources: (1) Institute of Social, Economic and Government Research, University of Alaska, "Estimates of Alaska Gross Product By Region, 1965-1973", Alaska Review of Business and Economic Conditions (March, 1975) Source for 1965 figures

(2) ISEGR (June 27,1975). Source for 1975 figures

TABLE 45

ALASKA GROSS PRODUCT IN CONSTANT DOLLARS BY REGION, BY INDUSTRY,1973
(Millions of 1958 Dollars at Average U.S. Prices)

Economic Sector	N.W.	S.W.	S.E.	S.Cen.	Anch.	In.	FBKS.	State
All Sectors	46.4	77.3	183.9	295.3	592.1	43.4	165.1	1403.5
Agri., Forestry and Fisheries	--	2.5	3.9	7.3	.1	0	--	13.9
Mining	15.6	1.6	3.3	182.7	57.6	13.8	6.8	281.4
Contract Construction	1.2	1.8	9.8	5.1	31.9	.9	8.9	59.6
Manufacturing	--	18.8	55.1	34.2	14.7	0	--	125.5
Transportation, Communication, Public Utilities	--	--	33.7	22.7	112.2	19.1	31.5	245.6
Trade	--	4.9	20.7	11.2	103.0	--	23.2	165.8
Finance, Insurance Real Estate	2.4	--	13.0	6.3	78.5	--	15.5	117.5
Services	2.6	2.2	10.0	7.7	48.1	.8	15.1	86.5
Government	8.7	31.0	34.4	18.1	146.0	8.2	61.3	307.7
Federal	5.0	26.5	12.1	6.8	115.2	6.4	45.6	217.6
State and Local	3.7	4.5	22.3	11.3	30.8	1.8	15.7	90.1

Source: ISEGR (March, 1975)

Employment

The average employment in Alaska for 1975 was estimated to be 188,700. This represents a total increase of 79.300 or about 73 percent since 1960. Table 46 shows total employment by economic sector for 1960, 1970 and 1975, while Table 18 shows the percentage of the total employment accounted for by each sector. Table 19 shows the percentage increase in employment by sector since 1960.

Government is by far the largest employer of any economic sector in the state, accounting for 40 percent of estimated total employment for 1975. The largest percentage increases in employment between 1960 and 1975 were made by state and local government; finance insurance and real estate; services, and trade. Federal government employment declined by 22 percent during the same period of time.

The major portion of the total increase in employment between 1960 and 1975 was accounted for by the support sector. These four economic sectors accounted for almost 55 percent of the increase. Another 30 percent of the increase took place in state and local government.

In comparing employment and GSP figures in Table 19 it is interesting to note that the second largest economic sector in terms of GSP in 1975, the mining sector, is the smallest sector in terms of employment. This reflects the capital intensity of the sector.

The 1975 distribution of employment by region is shown in Table 47 . Anchorage accounted for about 44 percent of the total.

During the past two years, the construction of the Trans Alaskan oil pipeline has had considerable impact on total employment in Alaska. Assuming an average employment of 15,000 workers for the year, Alyeska employment represented about eight percent of total employment for the state in 1975. In June 1975, 19,221 workers were employed in constructing the pipeline and the summer peak has been reported to have exceeded 20,000. About 14.3 percent of the June workers were from minority races, including 7.3 percent native.

TABLE 46

EMPLOYMENT AND UNEMPLOYMENT IN ALASKA
(in Thousands)

	1960	1970	1975
Total Civilian Work-Force	73.6	114.8	--
Total Unemployment	5.9	9.9	--
Percentage Unemployment	8.0	8.6	--
Military Employment	41.5	39.0	27.5
Civilian Employment	67.9	104.9	161.2
Total Employment by Sector			
Mining	1.1	3.0	2.1
Contract Construction	5.9	6.9	17.9
Manufacturing	5.8	7.8	10.5
Trans., Comm. and Pub. Util.	6.8	9.1	12.6
Trade	7.7	15.4	25.0
Fin., Ins., and Real Estate	1.4	3.1	5.7
Services	5.6	11.4	21.8
Government	64.2	74.6	75.5
Federal (includes military)	57.1	56.1	44.7
State	3.9	10.4	30.8
Local	3.2	8.1	
Self Employed, Agriculture and other	10.9	12.7	17.6
Total Employment	109.4	143.9	188.7

Sources: (1) Alaska State Department of Economic Development (December, 1972). Source for 1960 and 70 data except for military employment which was taken from Tussing and others (1971).

(2) ISEGR (June 27, 1975). Source for 1975 data

TABLE 47

EMPLOYMENT IN ALASKA BY REGION-1975

Region	Number in Thousands	Percent
South Central	21.52	12.0
Interior	8.69	4.8
Southeast	27.06	15.0
Southwest	11.19	6.2
Northwest	4.48	2.5
Anchorage	79.37	44.1
Fairbanks	27.58	15.3
Total	179.89[a]	99.9

Source: ISEGR (June 27, 1975)

a/ This figure was generated by the MAP regional model, and is therefore different than the figure of 188.7 on the preceding table which was generated by the MAP statewide model.

Female workers represented 10 percent of the total. Since construction started, about 60 percent of the workers have been residents of Alaska. A resident is defined as a person who has resided in Alaska for one year. 1/

1/ This information on oil pipeline employment is based mostly on data given to FPC staff during a visit to the Alyeska Pipeline Service Company office in July 1975.

Income

Total personal income in Alaska for 1970 was $1,442.7 million, more than double the 1961 level. A 1975 estimate is not available, but it could be over $2,500 million. Table 48 shows total personal income by major source for 1961 and 1970. Wage and salary disbursements accounted for more than 80 percent of the total in 1970 with the government sector making up almost half of this amount. 1/

Table 49 shows selected per capita and family income characteristics for Alaska and the U. S. The per capita personal income of Alaska in current dollars has consistently been more than 20 percent higher than for the total U. S. In 1974, Alaska had the top ranking in the Nation for per capita income. 2/ However, because higher money incomes in Alaska have been more than offset by higher prices, real per capita income in Alaska has been lower than the U. S. average. In 1970, Alaska was about 14 percent lower than the average figure for the U. S. 1/

Per capita income in Alaska varies considerably by region. In 1969, the range was from a low of $516 in the Angoon census division to a high of $4,353 in the Valdez-Chitina-Whittier division. In general, the highest per capita incomes are found in the urban areas and the lowest in the rural areas with predominantly native populations. 3/

1/ Information in these paragraphs which was not taken from Tables 11 or 12 was taken from ISEGR (August 1974) and an FPC staff estimate.

2/ Bureau of Economic Analysis, U. S. Department of Commerce, as reported in the Washington Star (September 17, 1975). The 1974 figures are $7,062 for Alaska and $5,448 for the U. S. average.

3/ Institute for Social, Economic and Government Research, Consumer Prices, Personal Income and Earnings in Alaska," Alaska Review of Business and Economic Conditions (October 1974).

TABLE 48

TOTAL PERSONAL INCOME IN ALASKA
BY MAJOR SOURCES
1961 and 1970
(Millions of Dollars)

Source of Income	1961 amount	1961 percent	1970 amount	1970 percent
Wage and Salary Disbursements	538.3	80.7	1217.7	81.7
Mining	11.5		52.0	--
Contract Construction	47.1	--	125.8	--
Manufacturing	40.1	--	83.9	--
Transportation Communication and Public Utilities	62.3	--	111.5	--
Trade	54.2	--	132.0	--
Finance, Insurance and Real Estate	9.3	--	27.6	--
Services	33.5	--	88.9	--
Government	279.6	--	593.6	--
Agriculture, Forestry, Fisheries	0.8	--	2.5	--
Other Labor Income	15.0	2.2	38.0	2.5
Proprietors' Income	47.0	7.0	74.0	5.0
Property Income	39.0	5.8	82.0	5.5
Transfer Payments	28.0	4.2	79.0	5.3
Less Personal Contribution to Social Insurance	16.0	--	48.0	--
Total	651.3	99.9	1442.7	100.0

Source: ISEGR (August, 1974)

TABLE 49

SELECTED INCOME DATA FOR ALASKA AND U.S.

Income Characteristic	1961 Alaska	1970 Alaska	1970 U.S.	1975 Alaska
Per Capita Personal income (current prices)	$2752	$4771	$3935	$7878
Real Per Capita Personal Income (1967 prices)	$2094	$2904	$3383	$3869
Median Family Income (current prices)		$12,441	$9586	
Percent Families Below Low Income Level		9.3	10.7	

Sources: (1) ISEGR (August, 1974) lines 1 and 2 for 1961 and 1970.
(2) ISEGR (July 27, 1975) lines 1 and 2 for 1975.
(3) U.S. Department of Commerce (March, 1973) lines 3 and 4.

APPENDIX B

MAP STATEWIDE MODEL

Description of Economic Model [1/]

The determination of industrial output is the key element in the model and determining relationships vary significantly from one industrial sector to another. The output of the petroleum industry is determined outside the economic model as part of [assumed] petroleum development scenarios ... In contrast, the output of the support industries (consisting of trade, finance, services, transportation, communication, and public utilities) is produced to meet local demands and thus responds to changes in the level of economic activity in Alaska. To reflect this, support sector output is generally made a function of Alaska real disposable personal income.

The output of the construction industry is determined by a combination of internal and external factors. Part of construction activity is designed to supply the needs of the expanding Alaska economy. As in the support sector, construction output is made a function of real disposable personal income. Over the foreseeable future, there will also be construction activity involved in building pipelines, terminals and other facilities required for petroleum production. This portion of construction output is exogenously determined in accordance with the relevant petroleum development scenarios.

Employment and output in the state and local government sector is determined by the level of state and local expenditures which are in turn a function of available revenues. To be precise, expenditures are equal to total revenues minus a portion of petroleum revenues and to changes in the level of economic activity which affects general revenues and to changes in petroleum production which affects petroleum revenues.

1/ Quoted directly from ISEGR (June 27, 1975), pages 1-4.

The remaining industrial sectors are assumed to have their output determined by exogenous factors. These factors include such things as prices on world markets, demand for export commodities, supplies of natural resources and policy decisions made by the Federal government. One of the exogenous industries is the Federal government sector itself. In making projections, it is assumed that Federal government employment and output in Alaska remains constant over the projection period.

Growth in the fisheries industry is expected to be constrained by the availability of natural resources. As a result, real output in Alaska's fishing industry is projected to expand at just one percent a year. Like fisheries, the output of the forest products industry will be determined primarily by the supply of natural resources. The supply of Alaskan timber is a function of the amount of exploitable forest land and the Federal policies governing allowable cut in Alaska's national forests. The forest products industry is projected to nearly double its output by 1990 but the industry growth rate declines from 6 percent in the early part of the projection period to 2.5 percent by the end. By 1990, the industry is expected to be approaching the maximum long-run sustainable yield.

Once output has been determined in each of the major industrial sectors, the next step in the model is to determine industry employment. In general, a statistical relationship derived from the Alaska data is used to project industry employment as a function of industry output. Industry wage rates are then calculated as a function of projected wage rates in the U. S. and/or relative prices in Alaska. The projections of industry employment and wage rates are then combined to estimate wages and salaries.

Wages and salaries are generally the largest component of personal income and this is particularly true in Alaska. Sources of income other than wages and salaries are a much smaller component of personal income in Alaska than in the rest of the U. S. Total personal income in Alaska is estimated as a function of total wages and salaries and disposable personal income is estimated as a function of personal income.

Since virtually all consumer goods are imported from the "Lower 48" and wage rates in Alaska are closely related to comparable wages in the U. S., relative prices in Alaska are projected as a function of the U. S. consumer price index. As the Alaska economy expands, there will be a certain amount of import substitution and economies of scale that will tend to lower costs in some industries. As a result, prices in Alaska are expected to increase somewhat less rapidly than prices in the rest of the U. S. The price and personal income projections are combined to estimate Alaska real disposable personal income in terms of constant 1967 U. S. prices.

.... Real disposable personal income is a principal determinant of output in the support sector and in the construction industry. Thus, anything which affects personal income will affect support sector and construction output, and anything which affects support sector and construction output will affect personal income. To reflect these interrelationships, industrial output and personal income are simultaneously determined in the model.

Equations 1/

KEY TO ALASKA ECONOMIC MODEL VARIABLES

For industry variables beginning in XX, EM, WS, WR:

XX = Real output

EM = Employment

WS = Wages and salaries

WR = Wage rates

Industry identification codes:

A9	Agriculture, Forestry and Fisheries
P9	Mining
CN	Construction (CN° is non-pipeline construction)
M9	Manufacturing
T9	Transportation
CM	Communications
PU	Public Utilities
D9	Trade
FI	Finance, Insurance, Real Estate
S9	Service
GF	Government-Federal
GA	Government-State and Local
99	Total
CV	Civilian
OT	Other

Definition of other variables

BSGS	State Government Revenue from Business License Taxes and Selective Sales and Gross Receipts
CPIU	U.S. Consumer Price Index
ECONX	Employment in Pipeline Construction
ECPS	State Government Construction Bond Funds
E99L	Local Government Total Expenditure
E99S	State Government Total General Expenditure
GFBAL	State Government and General Fund Balance
PI	Personal Income
PIBR	Real Personal Income
PINW	Nonwage Personal Income
POP	Population
POPM	Population, Military
POPMD	Population, Military Dependents
POPN	Population, Native
PPX	Population excluding Natives, Military, and Military Dependents
RFDL	Local Government Revenue from Federal Government
RFDS	State Government Revenue from Federal Government

1/ Quoted directly from ISEGR (April 1975)

RINS	State Government Interest Revenue
RMCL	Local Government Charges and Miscellaneous General Revenue
RM9S	State Government Revenue, Miscellaneous
RN	Rate of Natural Increase for Native Population
ROR	Rate of Return earned on the State General Fund Balance
RPBS	State Government Revenue Bonuses from Mineral Leases (State Lands)
RPI	Relative Price Index
RP8S	State Government Petroleum Revenue Other than Bonuses
RP9S	State Government Total Petroleum Sector Revenue
RSFS	State Government Total Special Fund Revenue
RSTL	Local Government Revenue From State Government
RTCS	State Corporate Income Taxes
RTIS	State Individual Income Taxes
RTOL	Local Government Other Taxes
RTPL	Local Government Property Taxes
R99L	Local Government Total General Revenue
R99S	State Government Total Revenue
SAVR	Proportion of State Government Petroleum Revenue placed in an Investment Trust Fund
SAVS	Amount of State Government Petroleum Revenue placed in an Investment Trust Fund
SLGEXP	State and Local Government Expenditures
T	Time
WEUS	U.S. Average Weekly Earnings

<u>Note:</u>

A "1" added to the end of a variable name indicates that the variable has been lagged one time period.

A "L" added to the end of a variable name indicates that the natural logarithm of the variable has been taken.

ALASKA ECONOMIC MODEL

Agriculture, Forestry and Fisheries

XXA9 exogenous
EMA9 exogenous
EMOT exogenous
WRA9L = 7.71921 + .433 WEUSL

Mining

EMP9 exogenous
XXP9L = 4.35829 + 1.50338 EMP9L
WRP9L = 5.52326 + .88036 WEUSL

Construction

ECONX exogenous
$XXCNL^{\circ} = -2.22252 + .92144\ PIBRL$
$EMCNL^{\circ} = -2.30714 + 1.05848\ XXCNL^{\circ}$
$XXCN = [(EMCN^{\circ} + ECONX)/EMCN^{\circ}]\ XXCN^{\circ}$
$EMCN = EMCN^{\circ} + ECONX$

Manufacturing

XXM9 exogenous
EMM9L = -.45625 + .23307 XXM9L + .71225 EMM91L
WRM9L = 2.07508 + 1.41076 RPIL

Transportation

XXT9L = -.94592 + .67173 PIBRL + .14876 XXP9L
EMT9L = -.55993 + .40059 XXT9L + .33149 EMT91L
WRT9L = 4.94191 + .90331 WEUSL

Communications

XXCML = 3.38979 + .16404 PIBRL
EMCML = -4.64274 - .03751T + 1.34452 XXCML
WRCML = 6.63249 + .62714 WEUSL

Public Utilities

XXPUL = -7.06537 + 1.56139 PIBRL
EMPUL = -3.01585 - .02040T + .86732 XXPUL
WRPUL = 4.26448 + 1.09146 WEUSL

Trade

XXD9L = -2.46867 + 1.03333 PIBRL + .06377 XXP9L
EMD9L = -1.72460 + .90468 XXD9L
WRD9L = 5.90984 + .65622 WEUSL

Finance, Insurance, Real Estate

XXFIL = -3.17268 + 1.12331 PIBRL
EMFIL = -1.77193 + .03116T + .57861 XXFIL
WRFIL = 4.17482 + 1.02939 WEUSL

Services

XXS9L = -4.25405 + 1.24981 PIBRL
EMS9L = -.68919 + .35580 XXS9L + .69514 EMS91L
WRS9L = 2.22973 + 1.32098 RPIL

Federal Government

XXGF exogenous
EMGFL = -1.69731 - .00375T + 1.02948 XXGFL
WRGFL = 3.53628 + 1.15614 WEUSL

State and Local Government

WSGAL = -.86658 + 1.01196 SLGEXPL
WRGAL = 4.53025 + .98515 WEUSL
EMGA = WSGAL/WRGAL
XXGAL = 1.38405 + .97604 EMGAL

Personal Income

PINWL = -.83235 + .88192 WS99L
PI = WS99 + PINW
PIBR = PI/RPI
RPIL = 1.17055 + .82072 CPIUL

Population

POPM exogenous
RN exogenous
POPMD = 1.12 POPM
POPN = (1. + RN) POPN1
EMCV = EM99 - POPM
PPXL = .86443 + .94466 EMCVL
POP = PPX + POPN + POPM + POPMD
POPC = POP - POPM

State and Local Government Revenues and Expenditures

```
RP8S    exogenous
RFDS    exogenous
RPBS    exogenous
ROR     exogenous
RINS    = ROR (GFBAL1)
RTISL   = -6.08130 + 1.32952 PI1L
RTCSL   = -9.29373 + 1.52890 PI1L
BSGSL   = -3.20382 + .89666 PI1L
RM9SL   = -6.65284 + 1.39523 PI1L
RSFSL   = -9.05880 + 1.61653 PI1L
RP9S    = RP8S + RPBS
R99S    = RTIS + RTCS + RSGS + RM9S + RINS + RSFS + RP9S + RFDS + ECPS
ECPS    exogenous
SAVR    exogenous
SAVS    = SAVR (RP8S)
E99S    = R99S - SAVS
GFBAL   = GFBAL1 + R99S - E99S
SLGEXP  = E99S + E99L - RSTL
RFDL    exogenous
RTPLL   = -6.02962 + 1.31906 PI1L
RTOLL   = -6.75126 + 1.25343 PI1L
RMCLL   = -8.88866 + 1.71968 PI1L
R99L    = RTPL + RTOL + RMCL + RSTL + RFDL
E99L = R99L
```

APPENDIX C

USE OF PRUDHOE BAY GAS IN ALASKA

Introduction

The possible use of north slope natural gas in Alaska for industrial, commerical, and residential purposes has been widly discussed. Because of their different locations within the state, it has been alledged that the Arctic and El Paso proposals offer vastly different possibilities for using the gas within Alaska. To assist FPC staff in evaluating the questions relating to the potential for using Prudhoe Bay natural gas in Alaska and the socio-economic impacts that would result from use of the gas in-state, a contract was let to do a study of these issues. Both the Arctic and El Paso proposals as well as two other alternative routes were evaluated. This section is based on the findings of the Contractor's final report.1/

The next subsection entitled "Summary of RPA Study" is based entirely on the Contractor's final report. Another subsection immediately following entitled "Supplemental Analysis" expands upon the RPA study.

The basic question which this analysis examines is what are potential impacts *if* the state makes its royalty share of Prudhoe Bay gas available for use in Alaska, not whether or not the state will in fact choose to use the gas in state. Thus, any reference or assumption relative to in-state use is for the purpose of analysis and is not a projection that state royalty gas will actually be available for in-state use. It should be emphasized that this analysis relative to use of gas in Alaska had no influence upon any staff recommendations concerning route location that appeared in the DEIS or that appear in the FEIS.

A separate section in this volume examines the socio-economic impact of alternative routes to the Arctic and El Paso proposals. However, to facilitate comparison these alternative routes are also evaluated in this section. One is an alternative route for the Arctic proposal and the other is an alternative route for the El Paso proposal.

The Arctic alternative is known as the Fairbanks Corridor route. From Prudhoe Bay this route would proceed south to an area near Livengood. It would then turn southeast, pass by Fairbanks to Delta Junction and then generally parallel the Alaska highway to the Canadian border.

1/ Resource Planning Associates. *Evaluating the Use of North Slope Natural Gas in Alaska*. Cambridge, Massachusetts. (October 1975).

The El Paso alternative would follow the El Paso prime route to Livengood. It would then proceed almost directly south to Nenana and generally follow the Alaskan Railroad corridor to Talkeetna, continuing along the eastern side of the Susitna River to Cook Inlet. An underwater route across Cook Inlet would surface at Possession Point and the route would follow the Western coast of Kenai Peninsula to an LNG facility near Nikishka.

Summary of RPA Study

Availability of Gas for Use in Alaska

There are two, large, known sources of natural gas in Alaska, both of which would have potential supplies available for use in Alaska. One source is the Prudhoe Bay fields which are the subject of the Arctic and El Paso proposals. The other source is the Kenai/Cook Inlet fields which have been producing natural gas commercially since 1960.

Of the existing reserves in Prudhoe Bay, the Alaska Department of Natural Resources estimates that 81 percent has been allocated by North Slope producers to lower 48 buyers. Another 12.5 percent belongs to the state as a royalty share, leaving 6.5 percent uncommitted. The RPA study assumed that the only Prudhoe Bay gas available for in-state use would be royalty gas. Thus, the potential amount of gas available in 1990 under proposed Arctic throughput would be about 103 Bcf. Under the proposed El Paso throughput, the potential 1990 amount available would be about 150 Bcf.1/

In the Kenai/Cook Inlet fields 3.1 trillion cubic feet or about half of the estimated 6.6 trillion cubic feet of reserves have been committed. The remaining, uncommitted 3.5 trillion cubic feet of reserves could provide production potential for Alaskan in-state usage of 117 Bcf per year for 30 years. The State's royalty share of these uncommitted as well as the committed reserves is estimated by the state to be 29 Bcf annually at projected production levels.2/

1/ In reality there will likely be little or no difference between the two proposals in the amount of throughput. The amount of gas to be transported in 1990 will be determined by what can be and what is allowed to be produced.

2/ This estimate is based on an August 1975 progress report entitled Oil & Gas Demand, Progress Report prepared for the Alaska Oil & Gas Development Advisory Board by the Alaska Dept. of Natural Resources, Division of Geological and Geophysical Surveys.

Delivered Price of Prudhoe Bay and Kenai/Cook Inlet Gas

To answer the question whether potential in-state users would choose Kenai/Cook Inlet gas (assuming it were available) or Prudhoe Bay gas, the RPA study made a detailed comparison of the delivered city gate price of gas from each source. The comparison involved computing a delivered price to four locations: Fairbanks, an assumed new state capital, Anchorage, and the LNG terminal locations. The assumed new capital site was in the Talkeetna area slightly more than 90 miles north of Anchorage.

The delivered price of Prudhoe Bay gas was computed for both the Arctic and El Paso proposals as well as for the alternative route for each proposal. The delivered price of gas consisted of a wellhead price, a mainline tarriff, and a branch line tarrif. The assumptions and methodology employed by RPA in calculating delivered price were as follows:

<u>Wellhead Price</u> -- The wellhead price for Kenai/Cook Inlet gas was assumed to be $.15 per mcf. For Prudhoe Bay, state royalty gas a wellhead price of zero was assumed, so as to estimate the maximum potential usage of North slope gas.

<u>Mainline Tariff</u> -- The starting point for calculating mainline tariffs was a recent U. S. Department of the Interior draft report1/ which estimated a transportation charge or tariff per Mcf (based on utility cost of service methods) for the total Alaska segments of the Arctic

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1/ U. S. Department of the Interior. <u>Alaskan Natural Gas Transportation Systems: Economic and Risk Analysis.</u> Draft of Conclusions and Results. (June 1975). Study done under contract to the Aerospace Corporation.

and El Paso proposals. Costs were then apportioned linearly on the basis of pipeline miles from the wellhead to the branching point. As an example, assume an 800 mile Alaska based segment of a pipeline with a branch line taking off at mile 400 from the wellhead. If the USDI estimated tariff for the total Alaska segment of the pipeline were $.50, that part of the total tariff allocated in the above example would be $.25 (400/800 x $.50 = $.25).

Branch Pipeline Tariff -- In general a utility cost-of-service methodology was followed. Costs were calculated for a 16" pipeline which would be used if all of the state's royalty gas were transported, a 10" pipeline for half the royalty gas, and a 8" pipeline for one quarter of the royalty gas. Pipeline construction costs were assumed to be three times the average cost for comparably sized gas transmission pipelines in the lower 48. Annual operating costs were based on the following formula:

$$\frac{\text{Mainline Capital Cost/Mile}}{\text{Mainline Operating Cost/Mile}} = \frac{\text{Branchline Capital Cost/Mile}}{\text{Branchline Operating Cost/Mile}}$$

(unknown variable in equation)

The mainline capital to operating cost ratio was taken from data in the El Paso application. Capital and operating costs, along with financial assumptions were then run through a computer program to get an annual cost of service for each branch pipeline. Total cost of service was then divided by miles and Mcf levels to get an annual cost of service per mile per Mcf. The branchline tariff to a particular city gate was derived by multiplying this figure times the number of miles in the branchline to that city.

The results of the delivered price calculations for 1990, assuming all royalty gas is used in-state, are shown in Table 50 . For all four pipeline routes, Kenai/Cook Inlet gas has a lower delivered price than Prudhoe Bay gas, except in Fairbanks. North slope natural gas would be competitive for in-state use only at Fairbanks and along possible major pipeline routes. Similar results are obtained when different state royalty volumes are considered and for all years up to 1990.

Assuming that Kenai/Cook Inlet gas is available for use in-state, Prudhoe Bay gas would not likely be used south of Fairbanks, except along major pipeline routes. However the availability of Kenai/Cook Inlet gas for future use in Alaska through 1990 cannot be conclusively determined. Increasing wellhead prices and curtailments in the lower 48 states, foreign demand, or other factors may result in new commitments of remaining Kenai/Cook Inlet reserves, thus making them unavailable for long term in-state use. If this occurs Prudhoe Bay gas may have a potential for use in other Alaskan markets, besides Fairbanks and along mainline routes.

TABLE 50

DELIVERED PRICE OF NORTH SLOPE AND KENAI/COOK INLET
NATURAL GAS TO SELECTED CITY GATES - 1990 a/
(¢/Mcf)

City Gate Delivery Point	Kenai/ Cook Inlet	Alternative Pipeline Routes			
		Arctic Prime	Arctic Alter- native	El Paso Prime	El Paso Alter- native
Fairbanks					
Wellhead Price	15	0	0	0	0
Mainline Tariff			35	29	27
Branchline Tariff	38	36			04
Total	53	36	35	29	31
State Capitol					
Wellhead Price	15	0	0	0	0
Mainline Tariff			35	44	44
Branchline Tariff	17	57	21	15	
Total	32	57	56	59	44
Anchorage					
Wellhead Price	15	0	0	0	0
Mainline Tariff			35	44	45
Branchline Tariff	12	64	29	10	03
Total	27	64	64	54	48
LNG Terminal	15-20			53	52

a/ assumes 16" branch pipeline and that all of the state's royalty gas is used in-state at a daily annual average flow of 250,000 MMCF/D

SOURCE: RPA (October 1975)

Potential In-State Demand for Prudhoe Bay Gas

In evaluating the potential demand for Prudhoe Bay gas, the RPA study considered three major categories of demand: industrial; large fuel user, such as utilities and institutions; and residential and commercial. Because of the uncertainty about the future availability of Kenai/Cook Inlet gas for in-state use, it was assumed that gas from this source would be available in-state to serve only traditional market areas in Anchorage and on the Kenai Peninsula, and that all new gas users in the state from different market areas would use Prudhoe Bay gas. This assumption results in a "maximum" demand estimate for Prudhoe Bay gas.

New industrial user demand. -- The RPA examination of potential new industrial demand considered 47 industries. From these industries, 33 were grouped into four categories (forest products, construction materials, mining and mineral processing, and petrochemicals) for further analysis. The findings from this analysis, which included industry interviews, are summarized as follows in the RPA report.1/

> "Further analysis of these four industries indicated they had given little thought to the possibility of locating in Alaska, and of those that had, only a few had conducted their own feasibility studies of Alaska as a potential site. Moreover, we could identify no fully developed proposals that would indicate North Slope gas will actually attract new industrial users to the state. Several major uncertainties have discouraged prospective consumers of North Slope gas from investigating fully the merits of locating in Alaska, including which pipeline route will be selected; when the pipeline selected will actually be completed; delivered prices of natural gas in the Lower 48 five to eight years in the future, given shifting world energy prices; final settlement of Alaskan native claims; and future Alaskan price levels, given the currently high price levels for labor, construction materials, and transportation services."

1/ RPA (October 1975) Summary letter, p. 6.

Based on the RPA study, no future new industrial development resulting from the availability and use of Prudhoe Bay gas can be projected with much certainty. However four projects were identified that had some potential for development: (1) a methanol plant located on the coast, (2) a polyethylene and ethylene glycol complex located on the coast, (3) an iron ore mining operation located at Haines, and (4) a copper mine located in the Brooks mountain range. All four are highly speculative projects. See Table 51 for the amount of gas each development would consume in 1990 and for the applicable gas pipeline proposals.

Large Fuel User Demand. -- In the RPA study each pipeline alternative, with the exception of the Arctic prime route generated demand for Prudhoe Bay gas by electric utilities and institutions in the Fairbanks area. They currently pay more than \$.80 per million Btu for coal and an estimated \$2.46 per million Btu for diesel oil as compared with the projected city gate price to Fairbanks of \$.29 to \$.35 per million Btu for Prudhoe Bay gas. These large fuel users tend to be price conscious and would be expected to switch to a cheaper fuel if supply reliability were demonstrated. See Table 51 for a listing of Fairbanks area large fuel users and their potential 1990 demand.

In addition to the Fairbanks area large fuel user demand, the El Paso prime route generated a demand for natural gas by two utilities and one institution south of Fairbanks along the pipeline route. See Table 51 for the identity of these users. All three currently use diesel oil at prices ranging from \$2.18 to \$2.41 per million Btu.

Residential and commercial demand. -- With the exception of the Arctic prime route, each alternative route in the RPA study generated demand on the part of Fairbanks residential and commercial fuel consumers. In 1970 about 80% of all housing units in Fairbanks used heating oil, and current fuel oil prices are about \$3.90 or more per million Btu's. Assuming a distribution cost of \$1.50 to \$2.25 per Mcf from the city gate to the individual consumer, natural gas was cheaper than fuel oil. The RPA study estimated that 50 percent of existing fuel users in the core city would switch to gas and that 80 percent of all new users would use gas. Under these conditions, Fairbanks demand could reach 4 Bcf by 1990 (See Table 51 .)

The El Paso alternative route would pass by the city gate of the assumed new state capital. This could generate a demand for 1.9 Bcf by 1990 if all residential consumers in the city used natural gas.

TABLE 51

POTENTIAL 1990 DEMAND FOR PRUDHOE BAY NATURAL GAS
(Bcf/Year)

Categories of Demand	Alternative Pipeline Routes Arctic Prime	 Arctic Alternative	 El Paso Prime	 El Paso Alternative
Induced Industrial				
Copper Processing Facility	22	22	22	22
Iron Ore Processing Facility		29	29	29
Methanol Plant			24	24
Polyethylene Plant			6	6
Subtotal	22.0	51.0	81.0	81.0
Fairbanks Utilities and Institutions				
Golden Valley Elec. Assn.		.9	.9	.9
Fairbanks Municipal Utility		3.1	3.3	3.3
Eielson Air Force Base		2.3	2.3	2.3
Fort Wainwright		3.1	3.1	3.1
University of Alaska			.5	.5
Subtotal		9.4	10.1	10.1
Utilities and Institutions South of Fairbanks				
Cordova Public Utilities Copper Valley Elec. Co. a/			1.2	
Fort Greely			.5	
Subtotal			1.7	
Residential & Commercial				
Fairbanks		4.0	4.0	4.0
Assumed State Capital				1.9
Subtotal		4.0	4.0	5.9
Total	22.0	64.4	96.8	97.0

a/ serves Copper Valley, Glenallen, & Valdez

SOURCE: RPA (October 1975)

Selected Socio-Economic Impacts

The extent of socio-economic impacts resulting from the use of Prudhoe Bay gas in Alaska will depend on how much of the potential demand for this gas shown on Table 51 becomes actual use. In order to show the maximum possible socio-economic impacts, the RPA study assumed that all potential uses of gas shown on Table 51 would actually take place.

Table 52 shows the "maximum" population and employment impacts from industrial use that would occur in 1990 under the "maximum" actual demand assumption. For comparison, the 1990 impacts from pipeline construction and operation are also shown for the Arctic and El Paso prime route alternatives. The maximum projected population and employment impacts are substantial for all routes except the Arctic prime route. For the two El Paso route alternatives, these 1990 projections exceed estimated impacts from construction and operation of the El Paso prime route. Although not shown on Table , other socio-economic impacts, such as increases in GSP and income would also be expected to occur as a result of industrial use of Prudhoe Bay natural gas.

To estimate related population and employment impacts of new industrial development, RPA used a base econometric model previously developed by Human Resources Planning Institute for estimating impacts from the Alyeska oil pipeline.1/ This model assumes that certain export oriented, or basic industries provide the stimulus for economic activity in the service or nonbasic sectors.

To the extent that the potential industrial uses of Prudhoe Bay gas shown on Table 51 do not actually take place, corresponding reductions in the population and employment projections of Table 52 will be necessary. Any population and employment projections based on new industrial development would be in addition to impacts from construction and operation discussed elseshere in this volume.

1/ For a detailed description of the model, see Human Resources Planning Institute and Urban and Rural Systems Associates. Manpower and Employment Impact of the Trans-Alaska Pipeline. Vol. II Technical Report. (November 1974)

TABLE 52

POTENTIAL 1990 IMPACTS ON POPULATION AND EMPLOYMENT FROM INDUSTRIAL USE OF PRUDHOE BAY STATE ROYALTY GAS

	Atlernative Pipeline Routes			
	Arctic Prime	Arctic Alternative	El Paso Prime	El Paso Alternative
POPULATION				
Industrial Use	2,819	23,959	32,897	32,897
Pipeline Construction and Operation	10,200		26,800	
EMPLOYMENT				
Industrial Use - Direct				
Copper Development	200	200	200	200
Iron Ore Development		1,500	1,500	1,500
Methanol Plant				
Polyethylene and Glycol Complex			710	710
Subtotal	200	1,700	2,410	2,410
Industrial Use - Secondary and Induced				
Industrial	97	822	1,129	1,129
Trade and Services	685	5,814	8,161	8,161
Fire [a]	48	407	635	635
Transportation	203	1,720	2,033	2,033
Subtotal	1,033	8,763	11,958	11,958
Total From Industrial Use	1,233	10,463	14,368	14,368
Total From Pipeline Construction and Operation	5,241		12,800	

a/Finance, Insurance, and Real Estate.

SOURCES: RPA (October 1975) for impacts from industrial use; Tables H-13,H-17 and H-18 for pipeline construction and operation impacts.

Socio-economic impacts would also result from use of the gas by large fuel users and residential and commercial users. An obvious impact would be a reduction in fuel costs by these end use consumers. Other impacts, such as decreased electricity prices and economic hardships on the suppliers of coal and diesel oil replaced by gas might also occur. For example, it has been suggested that the availability of natural gas in Fairbanks which was competitive with other fuels might undercut the economic viability of a proposed oil refinery that would be located near Fairbanks at North Pole.1/

The RPA study also examined the impact of in-state use of Prudhoe Bay gas on state government expenses and revenues. There would be a possible loss in state revenues depending on the price, if any, that the state charged for gas sold and used in Alaska. In addition the state would incur increased public services expenditures as a result of any increased population generated by in-state use of gas. Revenue benefits from in-state use of the gas would accrue to the state from various taxes paid by the increased population and new gas induced industry. Under the zero wellhead price assumption used in the RPA study, the loss of royalty revenues and additional public service expenditures estimated as a result of using the gas in Alaska were substantially greater than the additional tax revenues gained.

1/ ISEGR (April 1975).

Supplemental Analysis

As stated earlier, a number of assumptions and calculations in the RPA study, particularly those relating to Prudhoe Bay wellhead price and availability of Kenai/Cook Inlet gas to serve new markets, were made in order to generate a "maximum" demand estimate for use of gas in Alaska. These assumptions should not be interpreted as projections of what state decision makers and others will ultimately decide with respect to use of gas in Alaska. Rather, they were made to show what socio-economic impacts might occur if "maximum" utilization of Prudhoe Bay gas in-state did take place.

These "maximum" demand assumptions and other aspects of the RPA study were viewed as being too unrealistic by several commenters on the FPC draft environmental impact statement (DEIS). The subsections that follow attempt to be responsive to these comments.

Wellhead Price

If the state decides to receive it's royalty payments in kind, it is likely that there would be some charge for this gas, in contrast to the zero wellhead assumed in the RPA study. This possibility is acknowledged on page 4-5 of the RPA study.

It is also very unlikely that future contracts for Kenai/Cook Inlet gas will ever be negotiated at the 15¢ per Mcf figure assumed in the RPA study. While it is true that the price of some gas from the Kenai/Cook Inlet fields is now being sold for as low as 16¢ per Mcf under old contracts, the price received in some of the more recent contracts has been about 50¢ per Mcf.

No attempt will be made to predict future wellhead prices, but the RPA conclusions concerning the relative competitiveness of Prudhoe Bay gas and Kenai/Cook Inlet gas at various locations in Alaska (see Table   ) could be affected under different wellhead price assumptions. For example, if one assumed that the wellhead price at both Prudhoe Bay and Kenai/Cook Inlet were the same, the competitive advantage of Prudhoe Bay gas indicated in the RPA study for Fairbanks (using RPA tariff calculations) becomes much narrower and less clear cut. None of the routes would show a differential of greater than 9¢ per Mcf.

Pipeline Tariffs

Three major problems with the RPA pipeline tariff calculations were identified in letters of comment on the FPC DEIS. These problems were: (1) use of different throughputs for calculating the Arctic and El Paso mainline tariffs; (2) possible underestimation of the branch pipeline tariff from Prudhoe Bay to Fairbanks; and (3) failure to include a demand adjustment in branchline tariff calculations.

RPA mainline tariff calculations were based on the previously cited U. S. Department of the Interior draft report which used a 2.5 Bcf per day throughput as a base for its tariff calculations. In calculating El Paso tariffs, RPA made a downward adjustment to the USDI report figures to reflect the higher throughput (3.283 Bcf per day) proposed by El Paso. In reality the amount of throughput will be the same or nearly the same regardless of which pipeline is built. Thus, there should be no difference in mainline tariff figures based on throughput. Elsewhere in the analysis of socio-economic impacts in Alaska, a throughput of 2.5 Bcf per day has been assumed for both proposed pipelines. If this figure is used, for example, the mainline tariff to Fairbanks for the El Paso prime route shown on Table should be the same as for the Arctic alternative route. Similar upward adjustments would need to be made for all El Paso mainline tariffs shown on this table.

Comments received from or studies done for both applicants suggest that the branchline tariffs from Prudhoe Bay to Fairbanks calculated by RPA are too low. A study done for Arctic estimated average cost of service of approximately 99¢ per Mcf for a 16-inch pipeline from Prudhoe Bay to Fairbanks which would service domestic, commercial and industrial loads as well as seven Alyeska pump stations.1/ El Paso's comments suggest a tariff range of from $1.08 - $1.26 per Mcf. These figures compare with the 36¢ per Mcf shown on Table which was calculated by RPA.

Another criticism of the RPA branchline tariff calculations shown on Table is that they fail to include a demand adjustment. A demand adjustment is necessary to reflect uneven load demands that a pipeline will service. The pipeline capacity has to be built to service the peak demand rather than average

1/ Alaskan Resource Sciences Corporation. Study of Potential Alternate Fuels for Fairbanks, Alaska. Anchorage. (April 1974) p. X-40.

demand, thereby resulting in a higher cost of service than would occur if the pipeline needed to handle only a steady (average) flow of gas. RPA recognized this omission in their calculations and pointed out that this demand adjustment could add half again as much to the average cost of service.1/ The Alaskan Resource Sciences Corporation study suggests even higher demand adjustments. For example, the 99¢ per Mcf average cost of service figure for a 16-inch pipeline to Fairbanks is increased to $1.90 per Mcf when a demand adjustment figure is included.2/

Additional Delivered Price Calculations

Table 53 shows an alternative set of delivered price comparisons incorporating a 50¢ wellhead price, adjustments in El Paso mainline tariffs reflecting a 2.5 Bcf throughput,3/ and a 50% increase in all branchline costs to reflect the potential demand adjustment identified in the RPA study, all of which have been discussed earlier.

In general the same conclusions can be drawn as from Table 50 using RPA calculations. The delivered price of Kenai/ Cook Inlet gas is cheaper to all locations except Fairbanks and only two changes occur in the relative rank of delivered prices from Prudhoe Bay among pipeline alternatives.

1/ See p. 2-6 of the RPA study.

2/ ARSC (April 1974) p. X-40.

3/ The adjustment for El Paso mainline tariffs (except for the prime route to Fairbanks) was made by assuming that the El Paso prime route to Fairbanks would be the same as the Arctic alternative route (35¢) and then employing the following ratio:

$$\frac{\text{RPA mainline tariff to a particular location}}{\text{RPA mainline tariff to Fairbanks for El Paso route}} \bullet \frac{\text{New mainline tariff to a particular location (unknown)}}{\text{New El Paso Prime route tariff to Fairbanks (35¢)}}$$

For example, the following ratio was used to calculate the new El Paso alternative route tariff to Fairbanks

$$\frac{27}{29} \bullet \frac{X}{35} \quad X = 33$$

TABLE 53
ALTERNATIVE DELIVERED PRICE CALCULATIONS OF
NORTH SLOPE AND KENAI/COOK INLET
GAS TO SELECTED CITY GATES-1990 a/
(¢/Mcf)

City Gate Delivery Point	Kenai/ Cook Inlet	Alternative Pipeline Routes			
		Arctic Prime	Arctic Alter-native	El Paso Prime	El Paso Alter-native
Fairbanks					
Wellhead Price	50	50	50	50	50
Mainline Tariff			35	35	33
Branchline Tariff	57	54			6
Total	107	104	85	85	89
State Capitol					
Wellhead Price	50	50	50	50	50
Mainline Tariff			35	53	53
Branchline Tariff	25	86	32	23	
Total	75	136	117	126	103
Anchorage					
Wellhead Price	50	50	50	50	50
Mainline Tariff			35	53	54
Branchline Tariff	18	96	44	15	5
Total	68	146	129	118	109
LNG Terminal	23-30			64	63

a/ Assumes 16-inch branch pipeline and that all of the state's royalty gas is used in-state at a daily annual average flow of 250,000 MMCF/D.

Distribution and Conversion Costs

The RPA study did not do a detailed analysis of the costs of distributing natural gas from city gate to end user. However, RPA did recognize the importance of including distribution costs in arriving at total gas costs at the burner tip, and identified distribution costs calculated in another study for alternative distribution systems in Fairbanks.1/ The following distribution costs were identified in this study:

$/mm Btu	Class of Customer
.11	industrial only
.13	industrial and commercial only
.18	industrial, commercial and domestic
2.23	commercial and domestic only

For potential natural gas users now using other fuels, another cost that may need to be included in arriving at total cost of natural gas to compare with alternate fuels would be the cost of converting to natural gas. The ARSC study estimated that these conversion costs could be as high as $1,300 for a house.2/

Costs of Competing Fuels

The two fuels that would likely be most competitive with natural gas in Fairbanks would be coal and fuel oil. The RPA study did not attempt to project future prices for these fuels. Reference was made to current prices which were as follows:

Fuel	$/mm Btu	Class of Service
Coal	about .80	industrial
Fuel Oil	2.46	industrial
	3.90	industrial and commercial

1/ See Alaskan Resource Sciences Corp. (April 1974) pp. IV-9 through IV-10.

2/ See Alaskan Resource Sciences Corp. (April 1974) p. IV-2. These costs consisted of house piping for gas, furnace, water heater, and oven and range.

Future fuel oil prices in Fairbanks would be affected if a proposed oil refinery to be located near Fairbanks at North Pole is built. The ASRC study estimated 1983 prices in Fairbanks for fuel oil produced from this plant as well as 1983 prices for coal and fuel oil in the absence of a local refinery.1/ These projected prices at Fairbanks for 1983 are as follows:

Fuel	$/mm Btu	Class of Service
Coal	1.29	industrial
	1.65	commercial and domestic
Fuel Oil (N. Pole Ref.)	2.70	industrial
	3.30	commercial and domestic
Fuel Oil (No Local Refinery)	3.91	commercial and domestic

Future Availability of Kenai/Cook Inlet Gas

The RPA study assumption that Kenai/Cook Inlet gas would not be available for in-state use outside of the Anchorage and Kenai peninsula market areas was made in part to generate a maximum demand estimate for Prudhoe Bay gas. In reality, there is a possibility that Kenai/Cook Inlet reserves will be available for other in-state use. If Kenai/Cook Inlet gas were available for other markets, the delivered price calculations of the RPA study would suggest that the potential demand projections shown on Table could be affected as follows:

(1) Elimination of methanol and polyethylene and ethylene glycol complex under the El Paso prime and alternative routes.

(2) Possible elimination of iron ore processing plant under all alternative routes depending on the costs of branchlines from various origin points to the plant and the cost and feasibility of using LNG from Kenai/Cook Inlet.

(3) Elimination of new state capital demand under the El Paso alternative route.

1/ Alaskan Resource Sciences Corporation (April 1974), pp. I-7 through I-11.

If the above sources of potential demand were eliminated, the remaining demand would consist of the copper processing facility in the Brooks Range, Fairbanks large fuel users and residential/commercial users, and large fuel users south of Fairbanks along the El Paso prime route.

Other Potential Sources of Gas in Alaska

In addition to existing Kenai/Cook Inlet reserves and anticipated Prudhoe Bay gas supplies, other potential sources of gas supply exist in Alaska. Some of these potential supply areas include south of the Alaska Range, particularly offhsore areas; lower Cook Inlet beyond the three mile limit; Northern Gulf of Alaska; and Bristol Bay. If these areas begin production, and certain amounts (such as state royalty shares) were available for use in Alaska, they would likely be competitive in certain locations with any Prudhoe Bay gas made available for use in Alaska.

Potential End Use Restrictions for Natural Gas

Some of the potential gas demand shown in the RPA study would be for use as a boiler fuel. Federal end use restrictions prohibiting use of natural gas as a boiler fuel have been proposed, but are not yet in existence. If Federal end use controls become a reality, it is possible that some of the uses underlying the potential industrial demand shown in the RPA study (including all of the Fairbanks utility and other utility demand) would be prohibited.

Potential Industrial Demand

Even though several industrial uses of Prudhoe Bay natural gas were identified as being possible under "maximum demand" assumptions, a conclusion of the RPA study was that any new industrial development in Alaska based on Prudhoe Bay natural gas is highly speculative.

Some of the comments received on the FPC DEIS suggested that the potential for future natural gas based industrial development is much greater than suggested in the RPA study. Among the potential new industrial users of natural gas identified were: a cement plant, a gas liquids processing facility, fertilizer production facilities, a nickel-copper mine and smelter, and developments related to the zinc industry.

Only the future will tell whether these or other industrial developments actually take place as a result of the availability and use of Prudhoe Bay gas. Assuming a throughput of 2.5 Bcf per day, the maximum amount of state royalty gas that could be available for in-state use would be 114 Bcf per year. The four industries analyzed under the RPA "maximum demand" assumptions would consume up to 81 Bcf per year.

Recent State of Alaska Thinking

On February 12, 1976, Mr. Guy Martin, Commissioner of Natural Resources for the State of Alaska, testified at the ongoing FPC hearing related to the Arctic and El Paso applications.1/ Mr. Martin is Chairman of the Alaska Royalty Oil and Gas Development Advisory Board which would make any recommendations to the State Legislature relative to the disposition of Prudhoe Bay Royalty gas taken in kind.

Although no final decision has been made at this time, Mr. Martin indicated that there is a strong probability that he would recommend to the Advisory board that Prudhoe Bay royalty gas be taken in kind. The question of whether this gas would be sold to intrastate or interstate markets is now being studied.

For any gas taken in kind, a state law requires that special priority be given to sales which will lead to the establishment of facilities within the state which would utilize the gas. Before any in-kind royalty gas can be sold interstate, it must be determined that the royalty gas is surplus to the intrastate needs of Alaska.

Mr. Martin testified that preliminary studies conducted by the state indicate that a demand for an amount of natural gas equal to the Prudhoe Bay state royalty share could exist within the state. However, no determination has been made whether this demand could best be met from Prudhoe Bay royalty shares or from other sources if it does materialize in the future. Thus, there is a possibility that any Prudhoe Bay royalty gas taken in kind could be declared as surplus to intrastate needs and sold interstate.

1/ Docket No. CP75-96, et al. His direct testimony appears in a document entitled "Prepared Direct Testimony and Exhibits of the State of Alaska (Phase I)" dated Feb. 2, 1976. Cross examination of Mr. Martin appears in Volume 99 of the hearing transcript.

Concluding Comments

The purpose of this supplemental analysis was to discuss significant matters relating to the use of gas in Alaska raised in comments received on the FPC DEIS. An attempt was made to present a wide range of viewpoints and possibilities.

Perhaps the main conclusion of this supplemental analyses is that very little can be said with much certainty regarding the use of Prudhoe Bay gas in Alaska. Even so the following general statements can be made:

1. The level of wellhead price for Prudhoe Bay state royalty gas will be very important in determining the potential for its use in Alaska. This wellhead price will play a large role in determining whether Prudhoe Bay gas will be competitive with gas from other sources and whether or not Prudoe Bay gas will be competitive with other fuels.

2. If gas is available for use in Alaska from the Kenai/Cook Inlet fields or from other possible sources, it is not likely that much use of Prudhoe Bay gas would take place south of Fairbanks except along a major pipeline route. This determination could be modified if there were significant wellhead price differentials among various sources of gas.

3. In Fairbanks, the cost of competing fuels as well as the total cost of bringing gas to the burner tip will be important in evaluating the economic feasibility of using gas. If one were to assume the delivered city gate prices shown in Table , and the distribution costs and competing fuel prices developed by the Alaskan Resource Sciences Corporation in their previously cited study, natural gas would appear to have potential for use in Fairbanks. Other assumptions regarding price and cost variables could lead to a different conclusion.

4. If Federal end use restrictions were imposed permitting only commercial and domestic use of gas in Fairbanks, the potential for using natural gas in Fairbanks would be greatly decreased.

5. Depending on the circumstances, the potential for industrial development (and accompanying socio-economic impacts) based on use of Prudhoe Bay gas could be greater or less than that shown in the RPA study under the "maximum demand" assumptions.

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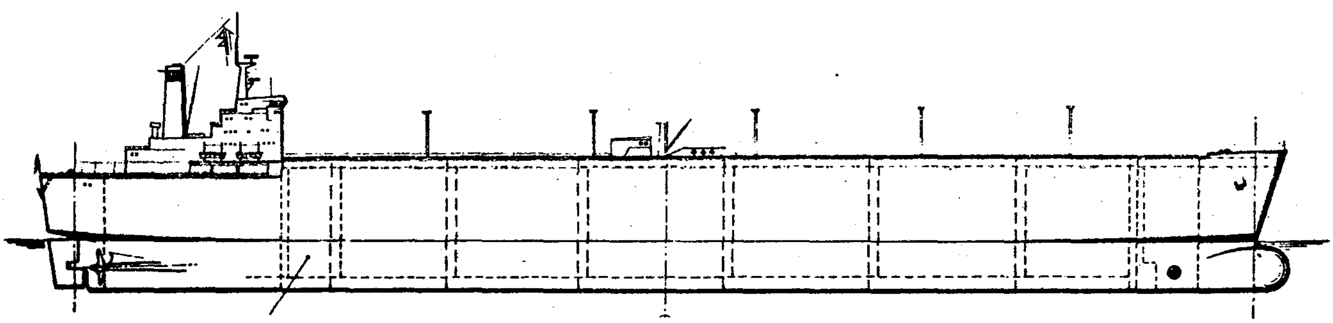
APPENDIX A

ANALYSIS OF THE RISK TO PUBLIC SAFETY DUE TO THE MARINE TRANSPORTATION OF LIQUEFIED NATURAL GAS



MARCH 19, 1976

Introduction

The transportation of liquefied natural gas (LNG) poses an unusual hazard not found with most flammable materials. Due to the low atmospheric boiling point of natural gas, -258.7°F (-161.5°C or 112°K), LNG must be handled and stored in well-insulated containers in order to maintain a liquid state. In the event of an accidental release, LNG would contact a warmer environment allowing it to accept heat and vaporize. Initially cold and negatively buoyant, the LNG vapors would gradually gain heat from the surroundings and would achieve positive buoyancy at temperatures above -148°F (151°K). Until either atmospheric dispersion or buoyancy dilute the concentration of the LNG vapors below the lower flammable limit (LFL) of 5 percent, a source of ignition could initiate a fire and endanger public safety.

It is especially important to consider the risks involved with the marine transportation of LNG due to the large quantities involved. The proposed projects which are the subject of this study would employ LNG tankers with cargo capacities ranging from 125,000 to 165,000 cubic meters (m^3) of LNG (125,000 m^3 is equivalent to about 4.42 million cubic feet of gas or 33 million gallons). The possibility of an accident in transit could result in the rupture of one or more cargo tanks and the spillage of large quantities of LNG over water. LNG upon contacting water would vaporize and form a potentially flammable vapor cloud. Should the spill occur near shore, it is possible that populated areas could be affected.

It is the purpose of this study to assess the risk to the general public posed by the marine transportation of LNG for several proposed projects currently under review by the Federal Power Commission. The study will estimate a numerical value for this risk and compare it to risks experienced in everyday life. Through the use of an accident sequence model, the probability of a casualty is calculated as the product of the conditional probabilities of all intermediate events considered necessary in order for a casualty to occur. The sequence of events has been divided into four major problem areas:

A. The annual probability of an accident occurring to an LNG tanker while in transit.

B. The probability of a spill of LNG occurring in the event of a tanker accident.

C. The probability of the formation of a flammable vapor cloud and its affecting populated areas.

D. The probable number of casualties resulting from exposure to a flammable vapor cloud.

The product of the above four events yields the annual probability of fatalities.

The basis for the study is an analysis of historical accident data of marine casualties. Since the operating experience of LNG tankers is too limited at the present time for a valid data base, casualty statistics for petroleum tankers will be used instead. It is thought that the design and operation of petroleum tankers most closely approximates the proposed LNG tankers although the latter incorporates superior design and operational features. In those areas where it can be demonstrated that features of the LNG tankers provide for safer operation than common petroleum tankers, appropriate reduction factors will be used.

In most of the proposed projects to be studied, the actual design of the LNG tankers has not yet been determined, although the tanker capacities are known. Cargo containment systems for LNG tankers are presently divided into two general categories: (1) "free-standing" self-supported tanks which have sufficient strength when properly mounted in the hull to support their own weight and the weight and dynamic forces of the cargo, and (2) "membrane" tanks in which a thin metal barrier supported by insulation contains the liquid and which in turn transmits the weight and dynamic forces of the cargo to the inner hull structure of the vessel. Of these systems, five designs are normally considered for use in the LNG fleet. These include spherical tank designs by either Kvaerner-Moss or Chicago Bridge and Iron, the Conch freestanding tank, and membrane tank designs by either Gaz Transport or Technigaz.

Although different in design and construction, the various types of cargo containment systems incorporate similar basic safety standards so that the risk analysis is valid for any design finally chosen. Table 1 lists the characteristics of two typical LNG tankers of the size considered in the various projects. Figure 1 illustrates a typical 165,000 m^3 tanker employing the rectangular freestanding cargo containment system offered by Conch.

Table 1

Principle Characteristics of Typical LNG Tankers

LNG Capacity (cubic meters)	130,000	165,000
Number of Cargo Tanks	5	5
Length, Overall (feet)	989	1,002
Beam (feet)	136	150
Draft (feet)	38	40
Displacement (tons)	100,700	122,000
Service Speed (knots)	23	18.50

The proposed, ultimate, and possible alternative projects which are the subject of this study are listed in Table 2 along with shipping requirements and the location of terminals.

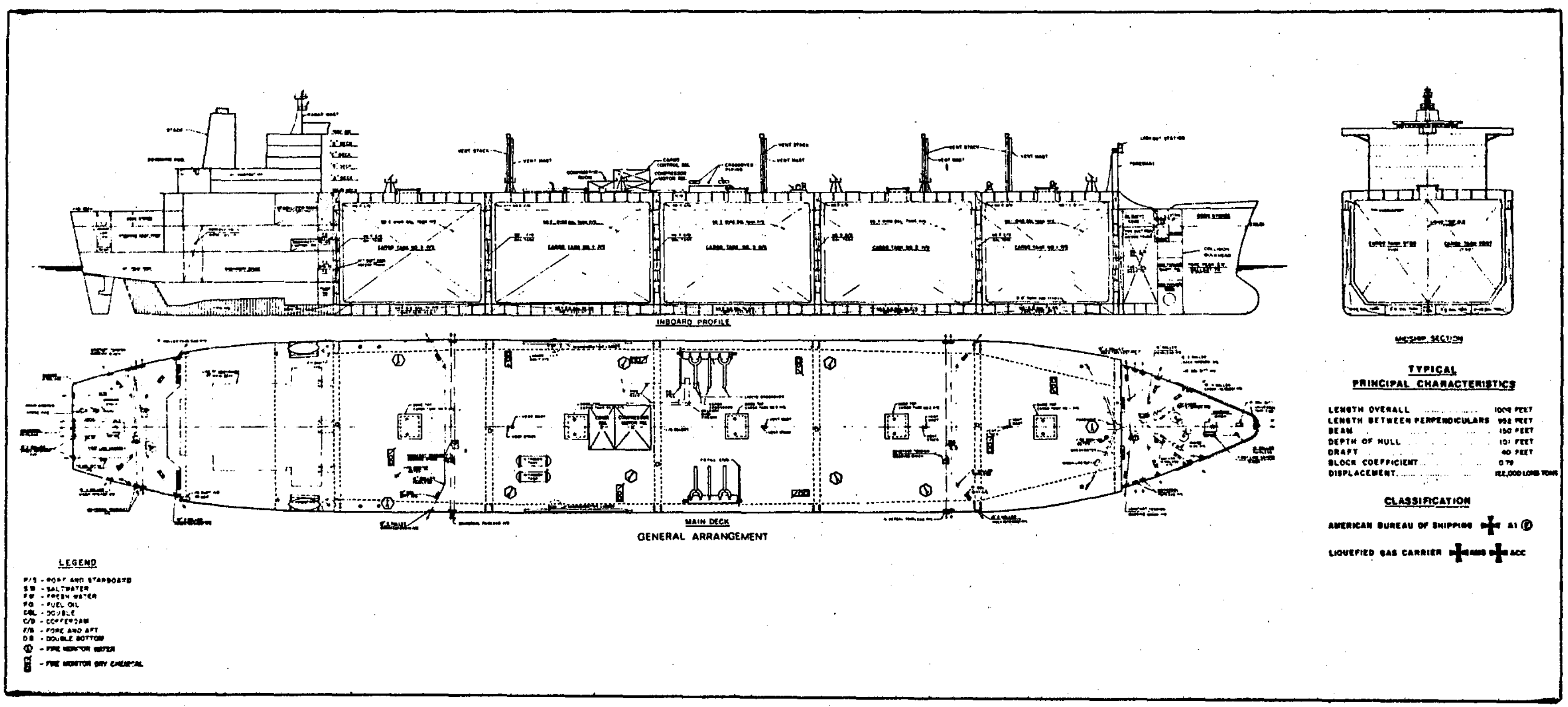


Figure 1

TYPICAL 165,000 M^3 LNG TANKER- CONCH CARGO SYSTEM

Table 2

PROPOSED LNG PROJECTS

Docket No.	Applicant	Tanker Capacity	Fleet Size	Total Annual Trips	Liquefaction Terminal(s)	Receiving Terminal(s)
CP75-140	Pacific Alaska	130,000 m^3	2	52	Nikiski, Alaska	Los Angeles Harbor, California
CP75-83-2	Western Terminal					
CP75-96	El Paso	165,000 m^3	11	308	Gravina Point, Alaska	Point Conception, California
CP75-83-1	Western Terminal					
CP74-160	Pacific Indonesia	130,000 m^3	8	75	Republic of Indonesia	Oxnard, California
CP75-83-3	Western Terminal					

ULTIMATE AND ALTERNATE LNG PROJECTS

CP75-83-2	Western Terminal	Up to 165,000 m^3	To be determined	425-565	Alaska and Republic of Indonesia	Los Angeles Harbor, California
CP75-83-1	Western Terminal	Up to 165,000 m^3	To be determined	425-565	"	Point Conception, California
CP75-83-3	Western Terminal	Up to 165,000 m^3	To be determined	425-565	"	Oxnard, California
CP75-96	El Paso, Pacific Alaska	(1) 165,000 m^3 (2) 130,000 m^3	13	360	Cook Inlet (Combined Terminal)	Southern California

A. ANNUAL PROBABILITY OF AN LNG TANKER ACCIDENT

1. An estimate of the probability of an LNG tanker becoming involved in an accident is based on an analysis of historical data for petroleum tankers with appropriate reduction factors to account for the superiority of the proposed LNG tankers. The number of petroleum tankers now in service of comparable size to the proposed LNG tankers is relatively limited for a valid data base. The world tanker fleet consisted of approximately 350 tankers of that size range (50,000 to 70,000 deadweight tons) during 1969 and 1970.1/ However, an analysis of 1,416 tanker casualties was unable to determine any clear relationship between tanker size and casualty frequency. 2/ Therefore, in order to expand the data base, this study will consider a wide range of tanker sizes, but such tankers will be large enough to be comparable to the LNG vessels.

The U.S. Coast Guard Information and Analysis staff in Washington, D.C., complies casualty data for various waterways in the United States. A casualty report is required whenever a casualty occurs in U.S waterways which results in actual physical damage in excess of $1,500, injury causing anyone to be incapacitated for more than 72 hours, or loss of life. Beginning with fiscal year 1969, computer printouts are available for individual waterways which list information on the type of casualty, extent of damage, characteristics of the vessel involved and conditions existing at the time of the accident.

Since the purpose of this study is to estimate the impact of LNG tanker accidents on the general public, only those casualties which could result in an LNG spill and the formation of a flammable vapor cloud are considered. Those types of casualties are collisions (ship to ship), rammings (ship to object), and groundings. Explosions and/or fires could pose a danger to the operating personnel of the LNG tanker; however, the presence of flames would preclude the formation of a flammable vapor cloud. Other casualties, such as equipment or structural failures, are more prevalent among older tankers and it is difficult to correlate these casualties to the new LNG vessels. In any event, it is unlikely that casualties of this nature could result in a cargo tank rupture. The cargo containment systems are unique to the LNG vessels and their susceptibility to mechanical failure is not known at this time. Whether the sophisticated monitoring and precautionary systems will mitigate mechanical failures or will become additional equipment subject to breakdown is debatable.

1/ An Analysis of Oil Outflows Due to Tanker Accidents, A Note by the United States, U.S. Coast Guard, Page 16.

2/ Ibid., Page 44.

A casualty rate per transit is developed by relating tanker casualties to the number of tanker trips for the same location and time period. Annual summaries of vessel trips and cargo volume throughput for ports in the United States and its territories are available in Waterborne Commerce in the United States, compiled by the U.S. Army Corps of Engineers. The number of inbound and outbound trips are classified by ship draft and vessel type (self propelled, non-self propelled, passenger and dry cargo, tanker, tugboat, or towboat). However, the U.S. Coast Guard printout lists casualties by fiscal year and classifies vessel size according to gross tons and length. In order that the sample sets for both trip and casualty data include the same size range of vessels, it is necessary to relate ship draft to either gross tons or ship length. Unfortunately, no direct relationship exists and individual casualty files must be examined.

For this study, the average annual number of round-trips for a particular port is the average of inbound and outbound transits for all self-propelled tankers having a draft of 18 feet or greater. The U.S. Coast Guard casualty printout for the corresponding waterway includes all vessels greater than 100 gross tons. Initial screening of the printout eliminates all vessels except self-propelled tankers. The examination of individual accident reports for the remaining cases determines the date, the tanker draft, and the exact location of the casualty in order to correspond with the trip data.

The single-trip accident rate for a particular waterway is calculated by dividing the number of casualties by the number of trips for the same period of calendar years. The use of casualty data and tanker trips for a period of several years should provide an adequate data base for estimating the mean casualty rate. This figure reflects the most probable number of accidents which may occur. Because casualties fluctuate from year to year, the actual number of accidents in any particular year may exceed the mean accident rate.

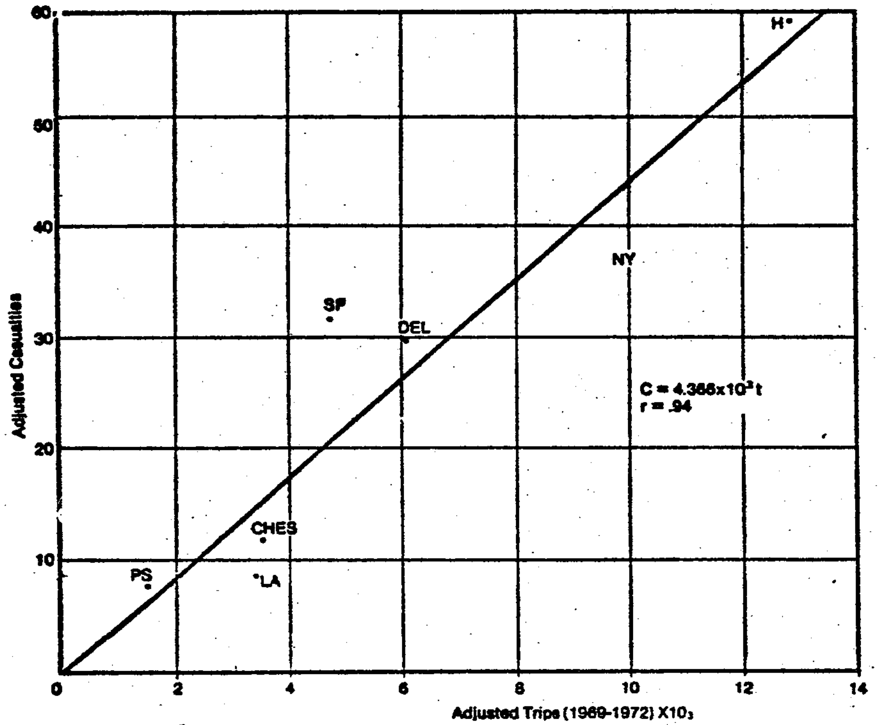
Several of the proposed LNG terminals would be located on waterways which have not had a history of tanker traffic. In the absence of casualty statistics and trip data from which to calculate a mean accident rate, an estimate is made based on the experience of other port areas. A survey by the Oceanographic Institute of Washington 1/ of tanker casualties for seven major port areas in the United States found that a strong correlation exists between tanker casualties and tanker trips. The data consisted of a total

1/ Offshore Petroleum Transfer System for Washington State, A Feasibility Study, Prepared by the Oceanographic Institute of Washington for the Oceanographic Commission of Washington, December 16, 1974.

of 185 tanker casualties and 41,908 tanker trips occurring over the 4-year period 1969 through 1972. The resultant plot of casualties versus trips for each port, as shown in Figure 2, can best be approximated by a straight line having a slope of 4.4×10^{-3} casualties/trip. In most cases it is appropriate to apply this value as the mean accident rate for those waterways lacking historical casualty data.

Figure 2

TANKER CASUALTIES VERSUS TANKER TRIPS FOR SEVEN U.S. PORT AREAS 1/



Legend:

Ches - Chesapeake Bay
Del - Delaware Bay
H - Gulf Coast
LA - Los Angeles/Long Beach
NY - New York
PS - Puget Sound
SF - San Francisco

1/ Source: Offshore Petroleum Transfer System For Washington State, A Feasibility Study; prepared by the Oceanographic Institute of Washington for the Oceanographic Commission of Washington, December 16, 1974, Page V-45.

2. The single-trip accident rate from the preceeding section is the sum of three types of casualties-collisions, rammings, and groundings, based on historical data for petroleum tankers. In subsequent sections, it will be shown that certain design features of the LNG tankers should make them less susceptible to casualties and spills than common petroleum tankers. Appropriate reduction factors will be introduced in order to apply the tanker casualty rates to the LNG tankers. However, the reduction factors do not apply equally to each type of casualty, so it will be necessary to distribute the casualty rate among the three types.

Where sufficient data is available for a particular waterway, the casualty statistics may be distributed directly into the three categories. However, in many locations the number of casualties on record is too low for a valid distribution. In these areas, average distribution figures for that particular type of waterway (harbor, coastal, etc.) will be employed.

An analysis by Porricelli 1/ of 1,416 casualties occurring during 1969 and 1970 provides a breakdown of casualties by type and location. The casualty types include groundings, rammings, collisions, fires, explosions, structural failures, mechanical breakdowns, and other types. The location where a casualty occurred is classified according to the following types of waterways: piers, harbors, entrances, coastal, sea, and unknown. The number of casualties for each type and location is presented in Table 3 based on the data from Porricelli. The numbers in parenthesis indicate the fraction of a casualty type for a particular waterway. Since this study is concerned only with collisions, rammings, and groundings, the remaining casualties have been eliminated from the analysis.

TABLE 3

TANKER CASUALTY BY TYPE AND LOCATION

Location	Casualty Type: Collisions	Rammings	Groundings	Total
Piers	19 (.12)	138 (.86)	4 (.02)	161
Harbors	136 (.47)	50 (.17)	105 (.36)	291
Entrances	80 (.30)	18 (.07)	170 (.63)	268
Coastal	76 (.52)	10 (.07)	59 (.41)	145
Sea	12 (.80)	2 (.13)	1 (.07)	15
Unknown	15 (.33)	4 (.09)	27 (.59)	46
Total	338 (.36)	222 (.24)	366 (.40)	926

1/ J.D. Porricelli, V.F. Kieth, R.L. Storch, "Tankers and the Ecology", Transactions of the Society of Naval Architects and Marine Engineers, Vol. 97, 1971.

The use of this information allows a casualty rate to be distributed into the three types of accidents, regardless of the data available for a particular waterway.

3. A U.S. Coast Guard study 1/ of 22 major U.S. ports and waterways concluded that some types of casualties could be avoided by the implementation of vessel traffic systems (VTS). Each area was evaluated on the basis of economic losses, pollution incidents, and deaths and injuries resulting from vessel casualties, and the effectiveness of various levels of VTS in reducing those losses. Those areas studies are listed in Table 4 in descending order beginning with the ports and waterways most in need of VTS. For each location, an estimate has been made of the effectiveness of the recommended level of VTS in reducing casualties. The levels of VTS referred to in Table 4 are as follows:

1. Vessel Bridge-to-Bridge Radio Telephone (L_O).
2. Regulations (L_R)- For example, regulations establishing a relationship between tow boat characteristics and size of tow.
3. Traffic Separation Scheme (TSS) (L_1).
4. Vessel Movement Reporting System (VMRS) (L_2)- A system where vessels relay navigational information to a shore-based control center.
5. Basic Surveillance (L_3)-Shore-based radar for observing vessel positions and movements.
6. Advanced Surveillance and Automated Advanced Surveillance (L_4 L_5)-Collision avoidance radar and computer interfaced components.

The effectiveness of a VTS at a particular location would depend on the level of VTS and the nature of the casualty. VTS appears most effective in reducing collision casualties and least effective in rammings. VTS would not prevent casualties directly resulting from mechanical failures, grounding and rammings due to winds or currents, collisions caused by pleasure craft, and rammings at piers and docks.

In areas where a VTS is scheduled to become operational coincident with the startup of an LNG project, reduction factors should be applied to the risk analysis. Because VTS does not uniformly reduce all types of casualties, reduction factors must be applied by casualty type.

1/ Vessel Traffic Systems Analysis of Port Needs, U.S. Coast Guard Study Report, August 1973.

TABLE 4

VTS REDUCTIONS FOR 22 U.S. PORTS OF WATERWAYS

Port or Waterway	FY69-72 Number of C/R/G Cases	FY69-72 # Vessels In C/R/G	FY69-72 # Vessels in Type 1 Accidents[2]	VTS Level Selections	Estimated % reduction in all C/R/G by selected VTS levels	Estimated % reduction in type 1 accidents by selected VTS levels[2]
New York	320	611	172	$L_0 2L_2 2L_3$	29	52
New Orleans	237	564	211	$2L_2 L_3$	19	33
Houston/Galveston	145	329	172	$L_2 L_3$	25	38
Sabine-Neches (ICW 265-290)	143	310	131	$L_0 2L_2$	23	24
Chesapeake Bay	116	229	64	$L_0 L_2 L_3$	17	52
ICW 80-99 (Morgan City)	83	248	126	$L_R L_2$	36	15
ICW 107-129 (Cote Blanche)	41	148	116	L_4	53	63
Baton Rouge	55	128	71	L_2	35	49
San Francisco	81	124	12	$L_2 L_5$	7	17
ICW 50-69 (Houma)	37	109	63	L_2	40	60
Chicago	58	118	16	L_R	-	-
Delaware River & Bay	107	167	28	L_0	-(1)	-(1)
Tampa	108	204	20	L_0	-	-
Puget Sound	42	83	33	L_2	5	12
Mobile	51	101	3	L_0	-	-
Detroit River	44	65	12	L_0	-	-
ICW 155-179 (Vermillion River)	26	82	59	L_0	-	-
St. Louis	29	114	8	L_0	-	-
Long Island Sound	30	55	13	L_0	-	-
LA/LB	29	53	4	L_0	-	-
Corpus Christi	30	48	7	L_0	-	-
Boston	15	29	3	L_0	-	-

[1] The presence of a dash (-) in these columns indicates that no VTS effort was recommended.
[2] Collisions in meeting, passing, and overtaking situations

Source: Vessel Traffic Systems, Analysis of Port Needs, U.S. Coast Guard Study Report, August 1973, Page D-1.

Two port areas, San Francisco Bay and Puget Sound, were selected as pilot projects for VTS. The San Francisco Bay VTS was commissioned in August 1972 while the Puget Sound VTS became operational in September 1972. VTS for the remaining locations have yet to become operational.

For the ports under evaluation in this study, only Los Angeles was included in the analysis of the 22 areas and no VTS was recommended for it. Preliminary plans, however, have been developed and approved for a VTS in Prince William Sound, Alaska, for the projected oil tanker traffic from Valdez.

Cook Inlet, Alaska

1. A computer printout of vessel casualties occurring in Cook Inlet, Alaska, for the period fiscal years 1969-1975 was prepared by the U.S. Coast Guard. 1/ The screening of the printout and the examination of individual reports was performed as previously described in Section A.1 of this report. The number of casualties involving self-propelled tankers having a draft greater than 18 feet are listed by type for each calendar year in Table 5. Rammings (ship to object collisions) are subdivided into two categories--rammings at docks and rammings with ice fields.

Table 5 provides an indication of the nature of the navigational hazards for tanker operations in Cook Inlet. The most frequent casualty type for the study period was ramming, either at docks or with ice fields. The harsh winters of 1970-71 and 1971-72 resulted in a large number of rammings with ice fields and ice-related casualties. In most cases, rammings at docks were found to result from severe environmental factors such as ice, strong winds, strong tidal current, or a combination of factors. These external forces were either the cause of the casualty or a contributing factor in all but 2 of the 19 total casualties.

Only one incident of a collision involving a tanker was recorded. In this case, a fishing craft struck a tanker in Kennedy Entrance. The tanker received little damage; however, the fishing craft sank. At this time, collisions appear to be a minor hazard for Cook Inlet due to the low volumes of traffic and wide areas of navigable waters.

1/ The staff is indebted to Lieutenant James Commerford and Lieutenant James Fernie, Information and Analysis Staff, Merchant Marine Safety Division, U.S. Coast Guard, for this data.

TABLE 5

TANKER CASUALTIES, 1969-1974
COOK INLET, ALASKA

Calendar Year	Collisions	Rammings at Docks	Rammings with Ice	Groundings
	Casualty Types			
1969	0	2	0	1
1970	0	1	0	1
1971	1	2	3	0
1972	0	3	3	0
1973	0	0	1	1
1974	0	0	0	0
Total	1	8	7	3

The approximate locations of the casualties are shown in Figure 3. Most of the incidents are clustered around the petroleum docks at Nikiski and Drift River, and in the inlet's upper region where ice and tidal currents can be most severe. Far fewer casualties are found in the lower regions of Cook Inlet which experience less severe ice problems.

The annual number of tanker trips in Cook Inlet must be estimated, since complete trip data is not available. Data on tanker transits for Anchorage, Alaska, is tabulated by calendar year in Waterborne Commerce of the United States. However, this source does not include tanker trips for the petroleum docks at Drift River and Nikiski which account for a major portion of the tanker traffic in Cook Inlet. An estimate of tanker trips for these locations has been made based on oil production figures. 1/ Table 6 lists the estimated tanker trips in Cook Inlet for each calendar year.

The mean single-trip casualty rate for Cook Inlet is calculated from the total casualties in Table 5 by the total tanker trips from Table 6.

$$\text{Casualty Rate} = 19 \text{ casualties}/2{,}698 \text{ trips} = 7.04 \times 10^{-3} \text{ Casualties/trip}$$

1/ Alternative Sites for LNG Facilities in the Cook Inlet/Kenai Peninsula, Alaska Area, submitted to the Federal Power Commission by the Oceanographic Institute of Washington, Contract No. FP-1773, Oct. 2, 1975, Page 4-12 to 4-15.

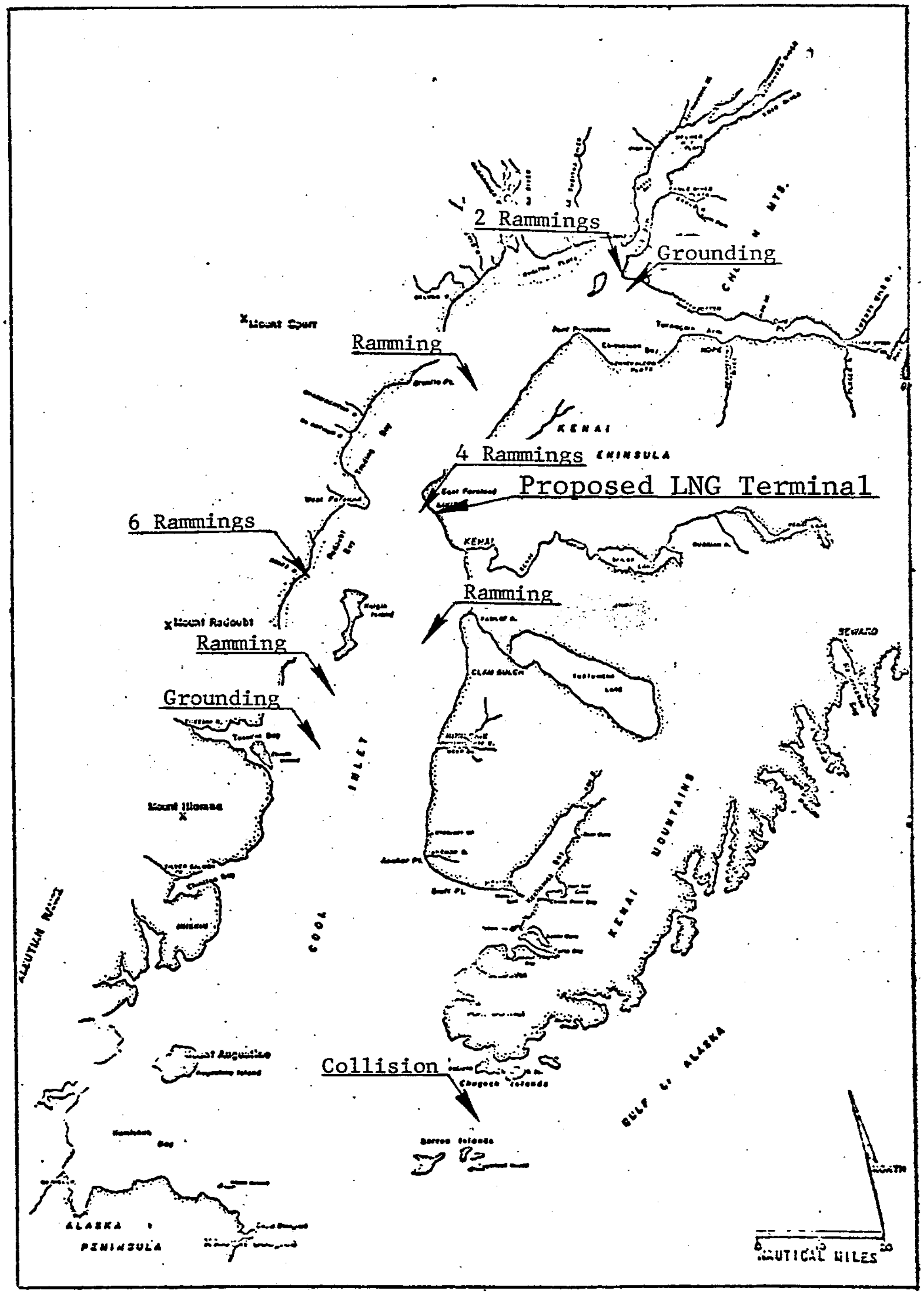


Figure 3
LOCATIONS OF TANKER CASUALTIES, 1969-1974
COOK INLET, ALASKA

TABLE 6

ESTIMATED ANNUAL TANKER TRIPS, 1969-1974
COOK INLET, ALASKA

Calendar Year	Anchorage	Nikiski	Other	Total
1969	91	129	245	465
1970	84	129	245	458
1971	70	129	245	444
1972	72	129	245	446
1973	65	129	245	439
1974	72	129	245	446
Total	454	774	1,470	2,698

In comparison with other waterways, the casualty rate for Cook Inlet is high, being nearly double the mean casualty rate of the seven U.S. ports. However, these ports do not have the ice hazard found in the upper and middle regions of Cook Inlet.

2. Due to the unique navigational hazards in Cook Inlet and the large number of casualties, it is appropriate to distribute the casualties among the three types directly from the data in Table 5. The average casualty distributions presented in Section A.2 of this report would not accurately characterize Cook Inlet.

Collisions - .05
Rammings - .79
Groundings - .16

3. In the absence of any proposal to implement a VTS in Cook Inlet, reduction factors do not apply.

Prince William Sound, Alaska

Prince William Sound currently experiences very little tanker activity, most of which is directed to the docking facilities at the port of Valdez. However, the completion of the Trans-Alaska Oil Pipeline will result in an increase of three tanker trips daily at Valdez. When the project achieves its maximum daily production, it is anticipated that about five or six tanker trips will be made daily. 1/

1/ Prince William Sound Vessel Traffic System, Final Environmental Impact Statement, Department of Transportation, U.S. Coast Guard, available to the public on February 12, 1975, Page 1.

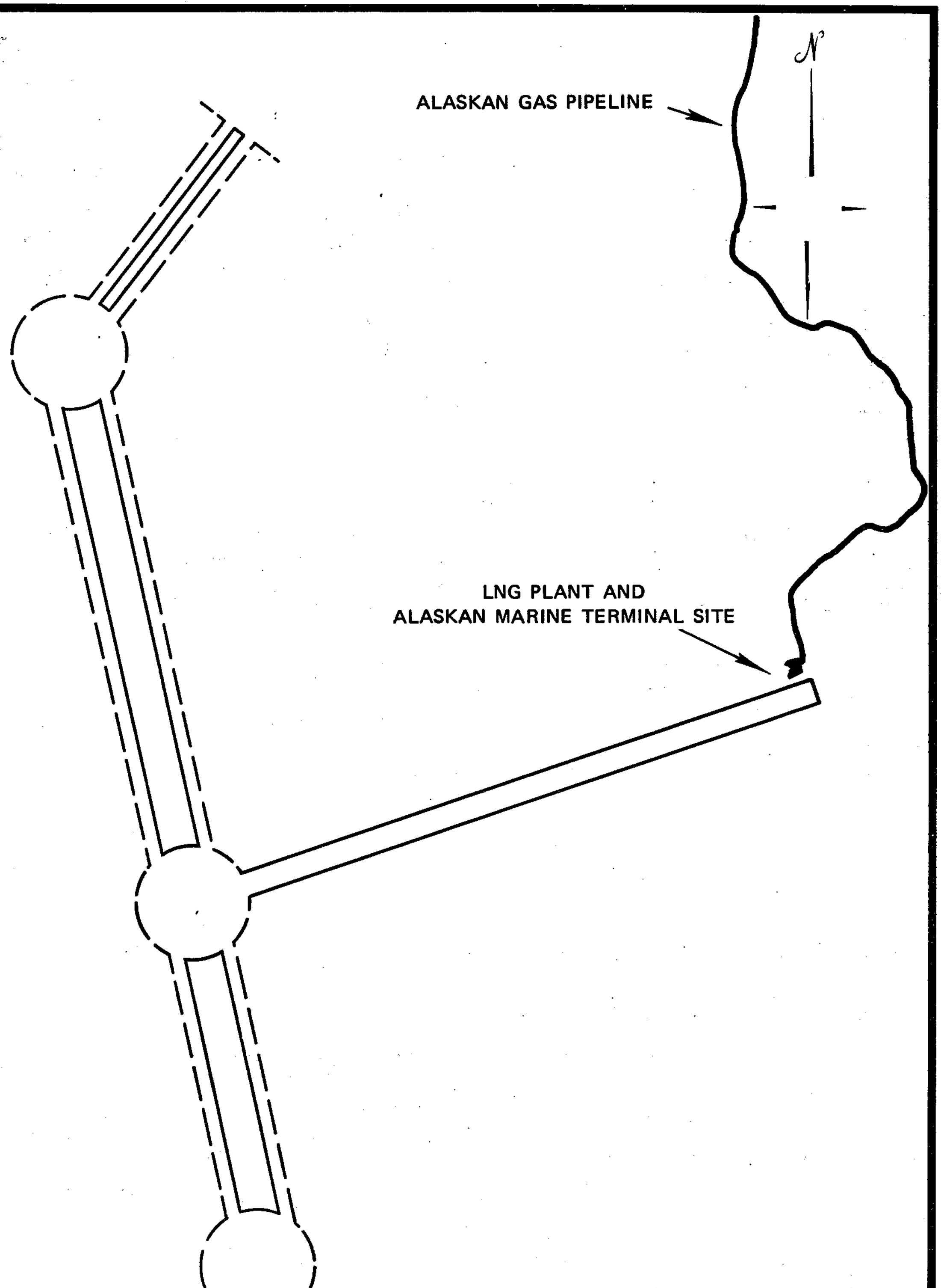


Figure 4

PRINCE WILLIAM SOUND, ALASKA

The proposed LNG terminal would be located at Gravina Point, as shown in Figure 4. Since the terminal would serve LNG tankers only, encounters with other vessels in the vicinity of the pier should be minimized. However, the LNG tankers would share the proposed shipping lanes in Hinchinbrook Entrance and the lower portion of Prince William Sound with petroleum tankers and other ships.

Table 7 lists the annual number of tanker trips for Valdez for calendar years 1969 through 1974. The data is obtained directly from Waterborne Commerce of the United States and includes only self-propelled tankers having a draft of 18 feet or greater.

TABLE 7

ANNUAL TANKER TRIPS, 1969 - 1974
VALDEZ, ALASKA

Calendar Year	1969	1970	1971	1972	1973	1974	Total
Tanker Trips	61	62	50	47	56	63	339

The U.S. Coast Guard's printout of casualties for southern Alaska lists only two minor tanker casualties in Prince William Sound. Both were groundings, with one occurring at Valdez and the other located in Orca Inlet. This information can be used to estimate a casualty rate for Prince William Sound.

$$\text{Casualty Rate} = 2 \text{ casualties}/339 \text{ trips}$$
$$= 5.9\text{x}10^{-3} \text{ casualties/trip}$$

Although the casualty rate is based on only a limited number of tanker trips and casualties, it compares favorably with the mean casualty rate for the seven U.S. ports -- $4.4\text{x}10^{-3}$ casualties/trip. To be conservative, the estimated casualty rate of $5.9\text{x}10^{-3}$ casualties/trip will be applied to Prince William Sound.

2. The data in Table 3 is used to distribute the casualties by type. The proposed LNG tanker route in Prince William Sound would consist of an entrance, a separated shipping lane, and a pier. Accordingly, the casualties are distributed by combined data for three types of waterways -- piers, harbors, and entrances.

Collisions - .32
Rammings - .29
Groundings - .39

3. A vessel traffic system for Prince William Sound is scheduled to become operational coincident with the startup of the Trans-Alaska Oil Pipeline. The VTS will include a traffic separation system from the Hinchinbrook Entrance to Valdez, as shown in Figure 4, with precautionary areas located at the Hinchinbrook Entrance and the entrance to Valdez Arm. A limited traffic area will be established in the Valdez Arm north of Rock Point to Port Valdez. Vessel movements in this area will be monitored and directed by a Vessel Traffic Center equipped with radar surveillance.

It is expected that the VTS will reduce the potential of collisions and groundings in Prince William Sound; however, a numerical value has not been assigned for the reduction. In the U.S. Coast Guard study of 22 major U.S. ports 1/, the estimated reduction in casualties was based on an examination of individual casualty files for each port. The percent reduction for each area reflects the portion of casualties which could have been prevented had a VTS been operational at the time of the incident. Unfortunately, Prince William Sound lacks sufficient historical casualty data from which to develop a VTS reduction factor.

In the absence of specific data for Prince William Sound, a reduction factor is estimated from the data in Table 4. For the 11 ports in which a VTS was recommended, total collisions, rammings, and groundings were reduced by an average of 25 percent. The VTS reduction factor for Prince William Sound, which indicates the fraction of total casualties which will not be prevented, is 0.75 (1 - .25).

Los Angeles Harbor, California

1. A U.S. Coast Guard printout was prepared for vessel casualties occurring in southern California waterways for the period fiscal years 1969-1975 2/. The screening of the printout and the examination of individual casualty reports was performed as previously described in Section A.1 with a minor modification. The annual trip data for Los Angeles Harbor does not categorize the number of trips according to draft for vessels having a draft less than 22 feet. As a result, tanker casualties and trips are limited to self-propelled tankers with a draft greater than 22 feet, instead of the 18-foot draft minimum used for other ports.

1/ Vessel Traffic Systems Analysis of Port Needs, U.S. Coast Guard Study Report, August 1973.

2/ The staff is indebted to Lieutenant James Commerford and Lieutenant James Fernie, Information and Analysis Staff, Merchant Marine Safety Division, U.S. Coast Guard, for this data.

The study area is confined to the harbor and channels located within the city limits of Los Angeles and the approach to this harbor. Some previous studies have developed casualty rates based on combined data for Los Angeles Harbor and the adjacent Long Beach Harbor. However, it is felt that limiting the data to the Los Angeles Harbor Zone would yield a casualty rate more characteristic of the proposed LNG facility location on Terminal Island.

Tanker casualties for the study area are listed in Table 8. The number of tanker trips for each calendar year was obtained directly from Waterborne Commerce of the United States and is presented in Table 9.

Table 8

TANKER CASUALTIES, 1969-1974
LOS ANGELES HARBOR, CALIFORNIA

Collisions	Rammings	Groundings
2	3	2

Table 9

ANNUAL TANKER TRIPS, 1969-1974
LOS ANGELES HARBOR, CALIFORNIA

Calendar Year	1969	1970	1971	1972	1973	1974	Total
Tanker Trips	578	628	600	609	584	601	3,600

The mean single-trip casualty rate is calculated from the total casualties in Table 8 and the tanker trips from Table 9.

$$\text{Casualty rate} = 7 \text{ casualties}/3{,}600 \text{ trips}$$
$$= 1.9 \times 10^{-3} \text{ casualties/trip}$$

The casualty rate for Los Angeles Harbor is low, being less than half the mean casualty rate for the seven U.S. ports, and provides an indication of relatively safe harbor operations. This rate also compares favorably with the data for Los Angeles/Long Beach shown on Figure 2. Only two collisions involving tankers occurred over the 6-year period 1969-1974. In one case, a tanker collided with a tugboat while docking. The other case involved the collision of two tankers about 1.6 miles south-southwest of the Los Angeles Harbor entrance.

2. The number of tanker casualties in Los Angeles Harbor is considered too low to permit a valid distribution into casualty types directly from the data. Table 3, which distributes casualties by types for various waterways, is used instead. Since the study area included three types of waterways--an entrance, a harbor, and piers--the distribution of casualties is by the combined data for these three areas.

Collisions	- .32
Rammings	- .29
Groundings	- .39

3. The Los Angeles/Long Beach Harbor area was one of the 22 major ports studied by the U.S. Coast Guard to determine the need for VTS. 1/ As shown in Table 4, this area ranked low in need for VTS and, in fact, no VTS effort was recommended. Therefore, no VTS reduction factors apply.

Oxnard, California

1. Oxnard currently has no shoreside docking facilities for petroleum tankers and consequently lacks a recorded historical basis required in calculating the mean casualty rate. Port Hueneme, located adjacent to Oxnard, has experienced some tanker traffic, as shown in Table 10.

TABLE 10

ANNUAL TANKER TRIPS, 1969-74
PORT HUENEME, CALIFORNIA

Calendar Year	1969	1970	1971	1972	1973	1974
Trips	N 2/	N 2/	2	8	58	51

The analysis of the U.S. Coast Guard printout for southern California waterways, which included Port Hueneme, found no tanker casualties in the Port Hueneme/Oxnard area. In the absence of casualty data, the mean casualty rate from the study of seven U.S. ports is used for Oxnard.

Casualty rate = 4.4×10^{-3} casualties/trip

1/ Vessel Traffic Systems Analysis of Port Needs, U.S. Coast Guard Study Report, August 1973.

2/ N - Data not tabulated.

This casualty rate probably overestimates the potential hazards of the proposed Oxnard terminal since the mean accident rate was based on ports and harbors which have experienced a higher traffic density than that which is anticipated for Oxnard. Since the proposed Oxnard terminal and its access routes would be used only by LNG tankers, areas of potential collisions with other ships would be limited to the crossing of the northbound lane of the Santa Barbara Channel on the inbound voyage.

However, it must be noted that current levels of oil tanker traffic in the Santa Barbara Channel may increase as a result of the completion of the Trans-Alaska Oil Pipeline. It was originally projected that three tankers would depart daily from Valdez, Alaska, increasing to five or six daily departures at the project's maximum capacity. Various receiving terminals on the west coast of the United States have been suggested but at this time the exact route and destination of the tankers is uncertain. It is possible that all tankers may proceed to Long Beach Harbor which could cause a substantial increase of traffic in the Santa Barbara Channel.

2. The data from Table 3 is used to distribute the casualties by types. The proposed Oxnard terminal would consist of an entrance, a separated shipping lane and a pier. Accordingly, the casualties are distributed by the combined data for three types of waterways--piers, harbors, and entrances.

Collisions - .32
Rammings - .29
Groundings - .39

3. VTS has not been proposed for Oxnard so VTS reduction factors do not apply.

Point Conception, California

1. Point Conception currently has no commercial port facilities which would provide a basis for historical data on tanker traffic. The analysis of the U.S. Coast Guard printout for southern California waters found no tanker casualties in the vicinity of Point Conception. In the absence of both casualty and trip data, the mean accident rate from the seven port study is used.

$$\text{Casualty rate} = 4.4 \times 10^{-3} \text{ casualties/trip}$$

Using similar reasoning discussed under Oxnard, it is felt that this casualty rate overestimates the hazards of the proposed Point Conception terminal and introduces a conservative element. The majority of the LNG tanker route through California waterways would be well offshore in order to avoid coastal traffic. The tankers would begin an approach to Point Conception just off Point Arguello and follow a course north of the Santa Barbara Channel to the proposed LNG facility. Since the proposed terminal would be used only by the LNG tankers and barges delivering Bunker "C" fuel oil, the traffic density would be low for major portion of the tankers' voyage. However, at the approach to Point Arguello LNG tankers would encounter existing coastal traffic as well as increased oil tanker traffic resulting from the completion of the Trans-Alaska Oil Pipeline. Although small boat traffic around Point Conception is heavy in the summer season, boats of that size would be unable to inflict major damage on an LNG tanker in the event of a collision.

2. The casualties for Point Conception are distributed according to type in the same manner as described for Oxnard.

Collisions - .32
Rammings - .29
Groundings - .39

3. Since VTS has not been proposed for Point Conception, no VTS reduction factors apply.

B. PROBABILITY OF A SPILL FOLLOWING AN ACCIDENT

1. The accident rate from the preceeding section estimates the annual probability of an accident but without regard to the magnitude of damage. It is likely that only a small portion of accidents would be sufficiently severe to cause the rupture of a cargo tank and the spillage of LNG. This section estimates the probability of an LNG spill based on pollution-causing incidents (PCI) for petroleum tankers and the appropriate LNG reduction factors.

Of the 926 collisions, rammings and groundings investigated by Porricelli 1/, 175 were sufficiently severe to result in tanker damage and the spillage of oil. A spill frequency has been calculated by dividing the number of PCI's by the total number of casualties for each casualty type and location. Table 11 presents the number of PCI's, and the fraction of casualties which resulted in spills (indicated in parenthesis).

1/ J.D. Porricelli, V.F. Kieth, R.L. Storch, "Tankers and the Ecology", Transactions of the Society of Naval Architects and Marine Engineers, Vol. 97, 1971.

TABLE 11

FRACTION OF POLLUTION-CAUSING INCIDENTS BY CASUALTY TYPE AND LOCATION

Location	CASUALTY TYPE Collision	Ramming	Grounding
Piers	6 (.32)	15 (.11)	0 (0)
Harbors	18 (.13)	6 (.12)	17 (.16)
Entrances	25 (.31)	2 (.11)	26 (.15)
Coastal	29 (.38)	1 (.10)	25 (.42)
Sea	2 (.17)	0 (0)	0 (0)
Unknown	1 (.07)	0 (0)	2 (.07)
All Areas	81 (.24)	24 (.11)	70 (.19)

Table 11 provides a basis for estimating the fraction of casualties which could be of sufficient magnitude to cause a spill of LNG. It should be noted that the actual amount of oil spilled was not considered in determining what constituted a PCI. Oil outflows ranged from minimal outflows to the total loss of the tanker. Since this study is concerned only with spills large enough to endanger the public safety, only those PCI's with a discharge in excess of 1,000 tons will be considered as a large spill. The fraction of PCI's exceeding 1,000 tons were: collisions-0.11, groundings-0.19, and rammings -0.13.

2. The design of the proposed LNG tankers incorporates features which have been recommended for petroleum tankers in order to reduce the potential for oil spillage in the event of a casualty. Double-hull construction and lateral bow thrusters should make the LNG tankers less likely to incur cargo tank damage than the conventional petroleum tankers upon which the spill factors were developed. Appropriate reduction factors are discussed for each casualty type in the following sections.

Recent studies of grounding incidents by Card 1/ and Bovet 2/ suggest that a double-bottom hull structure having a height equal to one-fifteenth of the beam (B/15) would greatly reduce the likelihood of oil spills in grounding casualties. The data from both studies relating depth of grounding penetration to vessel beam have been combined and plotted in Figure 5. Of the total 43 cases, only six, or about 15 percent, were found to exceed the B/15 depth.

1/ J. C. Card, "Effectiveness of Double Bottoms in Preventing Oil Outflow from Tanker Bottom Damage Incidents," Marine Technology, January 1975, Pages 60-64.

2/ D.M. Bovet, Preliminary Analysis of Tanker Groundings and Collisions, U.S. Coast Guard, January 1973.

In the proposed LNG tankers, the individual cargo tanks would be contained within a double-hull structure. The bottom of the cargo tanks would be separated from the inner hull by a layer of insulating material approximately 1 foot thick. Therefore, in order for a grounding casualty to cause the rupture of a cargo tank, both the outer and inner hulls and the cargo tank would all have to be penetrated. The minimum penetration depths for the typical LNG tankers are shown in Table 12.

TABLE 12

BOTTOM PENETRATION DISTANCE FOR DOUBLE-HULL LNG TANKERS

Tanker Size (m^3)	Distance to Inner Hull	Distance to Cargo Tankers
130,000	8 ft-3 in. (B/16.5)	9 ft. 3 in. (B/14.5)
165,000	10 ft. (B/15)	Approx. 11 ft. (B/13.6)

The heights of the double-bottom hull structure for the 130,000 m^3 and 165,000 m^3 tankers have been plotted in Figure 5. When the actual height of damage is considered, only one case was sufficient to penetrate the cargo tanks in the 130,000 m^3 tanker, while none would have penetrated a cargo tank in the 165,000 m^3 tanker. To be conservative, a reduction factor is based on the B/15 double-hull height which was sufficient to prevent inner-hull penetration in 85 percent of the cases. Therefore, the reduction factor in grounding casualties is 0.15.

The probability of a tanker sustaining cargo tank damage in a collision-type casualty depends on several factors; the displacement and construction of both the struck and striking vessels, the velocity of the striking vessel and its angle of impact with the struck vessel, and the location of the point of impact along the struck vessel. An analysis has been made by Arthur D. Little, Inc. 1/ to determine the collision resistance of the Ben Franklin, a 120,000 m^3 LNG tanker employing the Conch Ocean membrance tank system. By using the empirical method developed by Minorsky 2/, it was determined that a striking ship speed in excess of 3.4 knots could damage the most vulnerable cargo tank. This critical velocity was based on a right-angle collision by a 38,000-ton displacement

1/ Arthur D. Little, Inc., "The Collision Resistance of the Ben Franklin"; Distrigas Corporation, et al., Docket No. CP73-38, et al., Exhibit No. 17 (PA-1), Witness P. Athens.

2/ V.U. Minorsky, "Analysis of Ship Collisions with Reference to Protection of Nuclear Power Plants," Journal of Ship Research, October 1959.

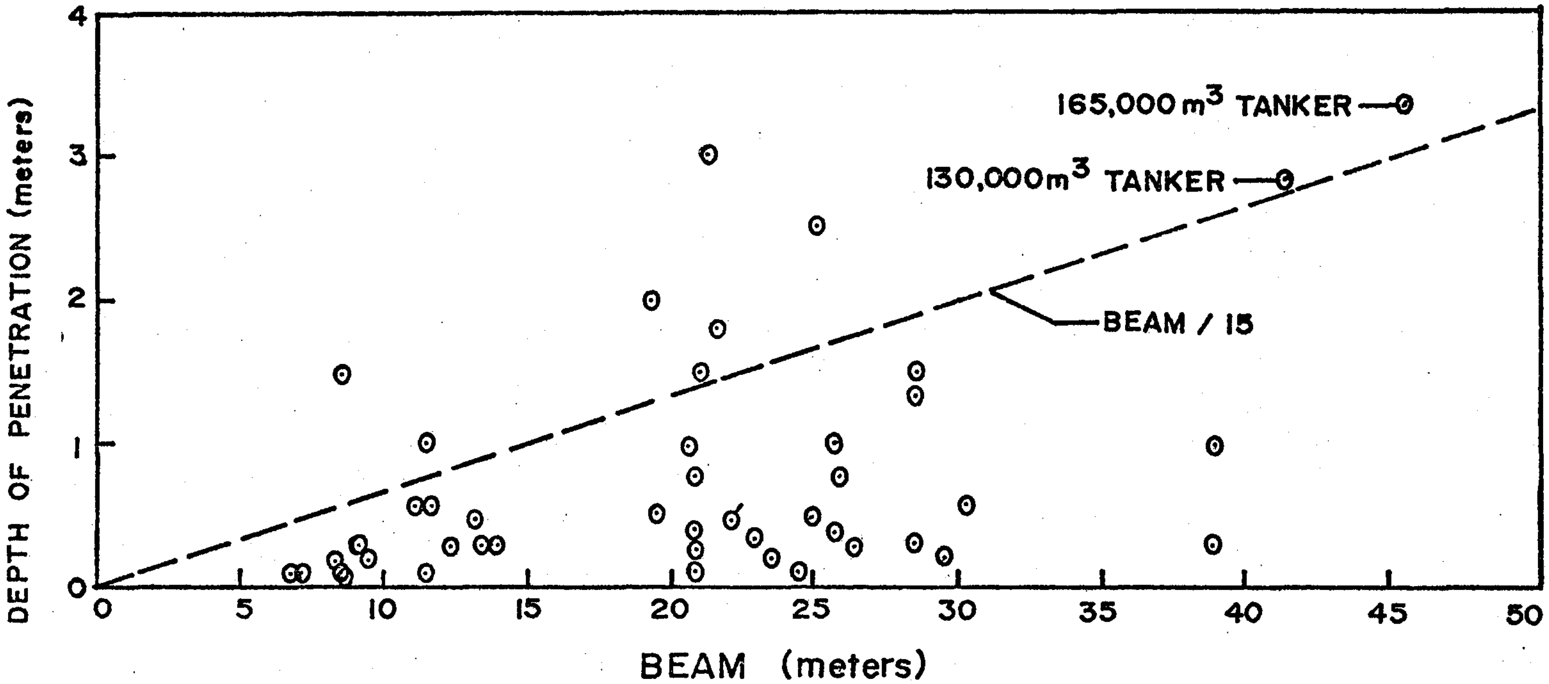


FIGURE 5

VERTICAL EXTENT OF GROUNDING DAMAGE VERSUS TANKER BEAM striking vessel. Obviously other angles of impact or striking ships of different displacement would result in different critical velocities. However, this does illustrate that the double-hull construction may not be effective in preventing cargo tank damage in many of the collisions which may be encountered.

Similar conclusions were found in analyses of historical collision data. A study by Bovet 1/ of 52 collisions found that the median depth of penetration was about 5.2 meters. This value compares favorably with Comstock's 2/ mean penetration depth of 4.8 meters in his analysis of 67 collisions. The minimum depths of the double hulls for the proposed LNG tankers are presented in Table 13.

TABLE 13

SIDE PENETRATION DISTANCE FOR DOUBLE-HULL LNG TANKERS

Tanker Size (m^3)	Distance to Inner Hull	Distance to Cargo Tanks
130,000	7 ft. (2.45m)	8 ft. 8 in. (2.65m)
165,000	Approx. 10 ft. (3.05m)	Approx. 11 ft. (3.35m)

Table 12 illustrates that the median penetration depths of the above studies would be sufficient to cause cargo tank damage in the LNG tankers. However, the double-hull construction should be effective in reducing the probability of spills in low energy collisions. In order to account for the protection of this design feature, a reduction factor is derived from the historical data of Bovet and Comstock. Bovet's data indicate that in 75 percent of the collisions studied, the collision penetration depth exceeded the depth of the double-hull of the 130,000 m^3 LNG tanker. Comstock's study found 75 percent exceeded the double-hull depth. A reduction factor of 0.75 will therefore be used for collision-type casualties. This factor should be considered as conservative because it was based on collisions with common vessels and as such does not account for the additional collision resistance provided by the structural presence of the inner hull and the cargo tank walls of the LNG tankers.

1/ D.M. Bovet, Preliminary Analysis of Tanker Grounding and Collisions, U.S. Coast Guard, January 1973.

2/ J.P. Comstock, J.B. Robertson, Jr., "Survival of Collision Damage versus the 1960 Convention on Safety of Life at Sea", Society of Naval Architects and Marine Engineers Transactions, Vol. 69, 1969.

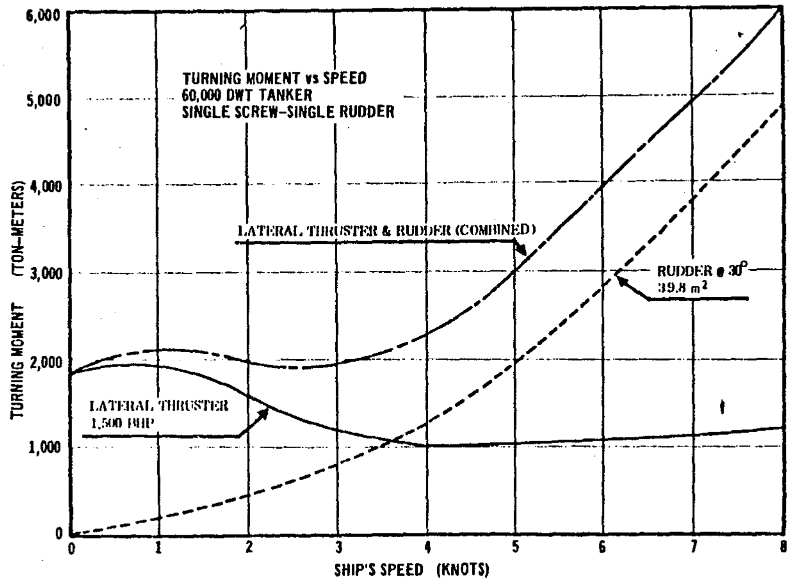


Figure 6

TURNING MOMENT CHARACTERISTICS

Source: J. D. Porricelli, V. F. Kieth, R. L. Storch, "Tankers and the Ecology," Transactions of the Society of Naval Architects and Marine Engineers, Vol. 97. 1971, Page 190.

Two design features of the LNG tankers should serve to reduce the likelihood of a cargo tank sustaining damage in a ramming-type casualty - 1) the lateral bow thruster, and 2) the structural material separating the forwardmost cargo tank from the bow.

Porricelli's study 1/ found that 60 percent of the ramming incidents occur at piers and at speeds generally less than 2 knots. It is at the low speeds around piers that rudder steering is least effective; however, the use of a lateral bow thruster can greatly increase maneuverability and aid in docking maneuvers. Figure 6 illustrates the turning moment characteristics (a measure of a vessel's maneuverability) for a 60,000-deadweight tonnage tanker equipped with a lateral bow thruster. At low speeds, where the rudder effect approaches zero, the bow thruster is most effective. At higher speeds the b w thruster serves as a safety feature by providing steering capability in the event of a rudder failure.

The forwardmost cargo tank in the proposed LNG vessels is separated from the bow by approximately 110 to 120 feet of structural material depending on tanker design. This barrier greatly reduces the potential for cargo tank rupture in ramming casualties. An analysis by Science Applications, Inc. 2/ of the ramming resistance of 125,000 m^3 LNG tankers found that a speed in excess of 30 knots, greater than the tankers are capable of traveling, would be required to rupture a cargo tank in a ramming with other ships. In rammings with fixed objects, a speed in excess of 10 knots would be necessary to cause cargo tank rupture.

Of the three casualty types under consideration, rammings are generally the least severe, resulting in the lowest fraction of PCI per incident and the lowest amount of oil outflow per PCI. Bovet's analysis of 1,416 casualties found that the 222 ramming incidents contributed only 1.08 percent of the total outflow 3/. Of the 23 outflows due to rammings, 2 occurred at entrances, 6 in harbors, and 15 at piers.

The combination of the lateral bow thrusters and the forward structural material should prevent cargo tank damage at piers and limit spills to high-speed rammings with fixed objects. There exists a lack of data from which to develop a reduction factor for these design features as well as a question with regard to a bow thruster being more of a necessity rather than an option as a ship's length increases. However, it is felt that the combination of both features are at least as effective in preventing cargo tank damage as the double-bottom hull structure is in grounding casualties. The same reduction factor, 0.15, will therefore be used for rammings.

1/ J.D. Porricelli, V.F. Kieth, R.L. Storch, "Tankers and the Ecology", Transactions of the Society of Naval Architects and Marine Engineers, Vol. 97, 1971, Pages 189 and 190.

2/ Science Applications, Inc., Risk Assessment of LNG Marine Operations for Racoon Island, New Jersey, Prepared for the Federal Power Commission, SAI-75-696-IJ, December 19, 1975, Pages 2-29,30.

3/ D.M. Bovet, Preliminary Analysis of Tanker Groundings and Collisions, U.S. Coast Guard, January 1973.

C. PROBABLILITY OF A PLUME AFFECTING POPULATED AREAS

During an accident of sufficient magnitude to cause the rupture of one or more LNG cargo tanks, it is possible that sparks or flames could ignite the vapor cloud at the spill site. Such an event would prevent the downwind spread of potentially flammable vapors and minimize the risk to the general public in more distant areas. However, an extreme hazard would exist for the tanker crew and to anyone in the proximity of the fire.

In the absence of an ignition source at the spill site, the potentially flammable vapor cloud would drift downwind until the forces of dispersion and buoyancy would dilute the vapor concentration below the lower flammability level (LFL). Until that point is reached, an ignition source could initiate a plume fire and endanger the nearby population.

1. The probablility of ignition of the LNG vapor cloud at the spill site gas been investigated for collision-type casualties.1/ In 12 collisions involving the spillage of a flammable, low flash point product, none of which was LNG, 11 cases resulted in immediate or nearly immediate ignition at the spill site. In the remaining case, a cargo of naptha spilled and formed a large vapor cloud. However, a nearby tugboat ignited the cloud about 2 minutes after the spill. The presence of ignition sources in a collision appears an almost certainity. To be conservative, it is assumed that in 90 percent of the collisions, ignition of the plume will occur at the spill site, yielding a reduction factor of 0.10.

Little data is available on the probability of plume ignition in groundings and rammings. Due to the high energy required to rupture a cargo tank in rammings and because the mechanisms involved in rammings are similar to collisions, it is felt that the same probability of ignition applies.

In groundings, the damage occurs beneath the water surface which should reduce the potential ignition sources when compared to the other casualty types. Due to the paucity of data and in the interest of conservatism, it is assumed that no ignition would occur, therefore, the reduction factor for groundings is 1.0.

2. The maximum range of potentially flammable vapors, the distance to the LFL, is a function of the volume of LNG spilled, the rate of the spill, and the prevailing meteorological conditions. Previous risk analyses performed by the FPC have considered the "worst case" event to be the instantaneous spillage of the entire contents of an LNG tanker. A spill of such magnitude would require the simultaneous rupturing of all five individually separated cargo tanks of the LNG tanker. Physical constraints on maximum vessel

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1/ Science Applications Inc. "LNG Terminal Risk Assessment Study for Los Angeles, California", Report No. SAI-75-614-LJ, Dec. 22, 1975.

speed and maximum casualty damages render the possibility of an instantaneous release of more than two tanks implausible. This is not to imply that the total destruction of a loaded LNG vessel and consequent loss of its entire contents is not possible. However, such a catastrophic event would require fire and explosive forces which would preclude the formation of a hazardous LNG vapor cloud.

This study considers the maximum credible event to be the instantaneous spillage of the contents of two cargo tanks. Non-explosive damage to three or more cargo tanks of sufficient magnitude for a sudden release of their contents is not considered to be a physically credible event. Analyses of historical data on casualty damages support this conclusion.

Robertson's analysis of the longitudinal extent of damage sustained by ships in collisions found that the median length of damage is about 26 feet.1/ From the graph in Figure 7, the relative probability of a ship sustaining greater damage rapidly decreases. Due to the design of the proposed LNG tankers, a damage length in excess of 150 feet would be required to cause the rupture of three adjacent cargo tanks. The probability of exceeding 150 feet is estimated to be about one percent. In only one of the cases investigated by Robertson the damage exceeded this length. The incident involved a severe raking collision resulting in about 230 feet of damage. Generally, raking type collisions are the mechanism for producing long damage lengths. Although it is conceivable that the outer hull of an LNG tanker could sustain damage in a raking-type collision, the double-hull design would prevent extensive damage from occurring to the inner hull and to the cargo tanks.

The rupture of one cargo tank in a severe collision is the most probable event. However, it is possible that a collision occurring at a bulkhead intersection between cargo tanks could cause the rupture of two adjacent tanks. The probability of damaging two cargo tanks can be estimated from historical data on the longitudinal distribution of damages sustained in collisions.

Comstock provides an estimation of the relative probability of damage with respect to length based on data from 51 collisions.1/ As shown in Figure 8, a typical 165,000 m^3 LNG tanker in which the cargo tanks occupy about 66 percent of the vessel's lenght, could experience damage in a vulnerable area in 82 percent of the collisions.

1/ J. P. Comstock, J. R. Robertson, Jr., "Survival of Collision Damage Versus the 1960 Convention on Safety of Life at Sea" Society of Naval Architects and Marine Engineers, Transactions, Vol. 69, 1969.

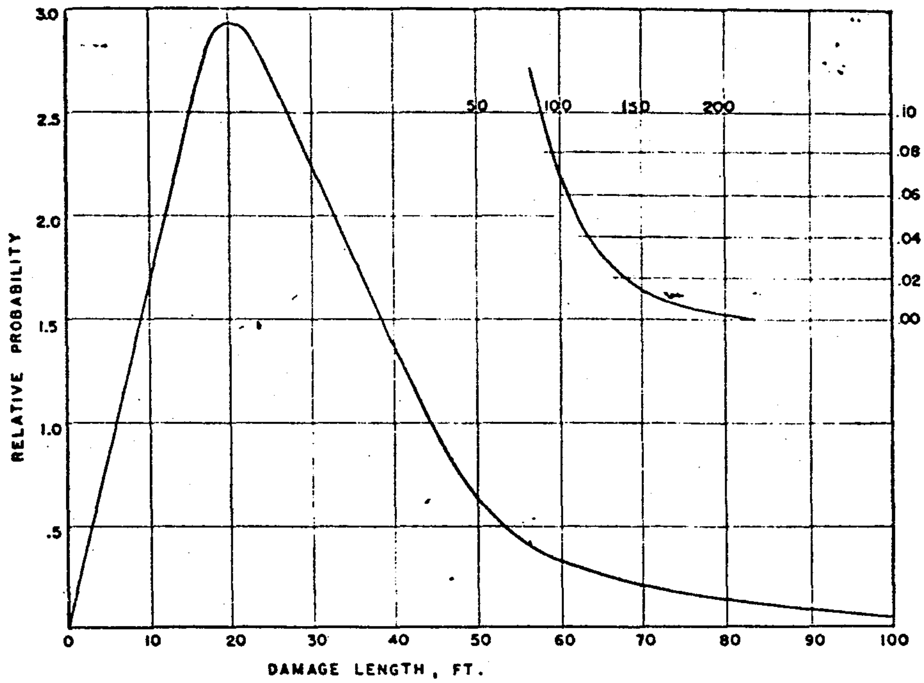

Figure 7 1/
PROBABILITY WITH RESPECT TO DAMAGE LENGTH

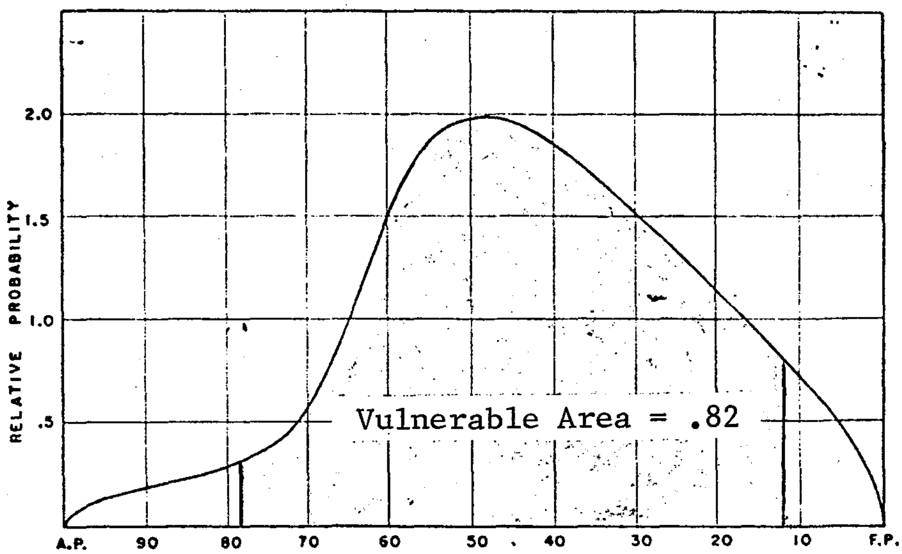

Figure 8 1/
DISTRIBUTION OF DAMAGE WITHIN VESSEL'S LENGTH

1/ J.P. Comstock, J.R. Robertson, Jr., "Survival of Collision Damage versus the 1960 Convention of Safety of Life at Sea", Society of Naval Architects and Marine Engineers, Transactions, Vol. 69, 1969.

A more recent study performed by the U.S. Coast Guard in which 296 collisions were examined suggests that damages were more frequent in the forward half of the ship than in the aft part.1/ The curve in Figure 9 describes a more uniform distribution of damage locations than that presented by Comstock. When a uniform distribution is assumed, the vulnerability becomes identical to the length of the ship occupied by cargo tanks, or about 66 percent.

Of the collisions causing damage in a vulnerable area, only those occurring at one of the four bulkhead intersections could result in the rupturing of two cargo tanks. In the case of a median damage length of 26 feet and assuming Comstock's distribution curve, about 30 percent of the collisions could occur at a location within 26 feet of a bulkhead intersection. With a uniform damage distribution, only 21 percent of the collisions could rupture two cargo tanks. Greater damage lengths increase the vulnerability of damage to two cargo tanks. However, the probability of sustaining damages in excess of the mean damage length decreases sharply, as shown in Figure 7. The portion of spills which could involve the contents of two cargo tanks can be approximated from the portion of collisions damaging two tanks divided by the total vulnerability. For the worst case, assuming Comstock's distribution, this fraction is 36.5 percent (.30/.82).

The suggestion that the loss of an entire cargo is implausible in collisions is supported by the analysis of historical data on oil outflows.2/

> "Except for some rather small tankers, no collisions resulted in the total loss of a loaded vessel. Such was not the case in groundings; five tankers which grounded subsequently broke up and sunk with a total outflow of 78,109 tons."

Unlike collisions, some grounding incidents have resulted in the total loss of cargo for pretroleum tankers. In these cases the grounding lead to the breakup of the tanker and the subsequent loss of the entire cargo. Due to the design features of the LNG tankers, the amount of cargo spillage or the rate of outflow resulting from a severe grounding should be less than the "worst case" incident--the instantaneous spillage of two cargo tanks.

The double-hull structure of the LNG tankers provides two means for reducing cargo spillage in groundings. First, by separating the cargo tanks from the outer hull bottom, only the most severe grounding could damage the inner hull and the cargo tanks. In the event of the outer hull receiving extensive damage in a

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1/ "Regulations on Subdivision and Stability of Passenger Ships as Equivalent to Part B of Chapter II of the International Convention for the Safety of Life at Sea, 1960", U.S. Coast Guard Commandant's International Technical Series, Vol. IV., USCGCITS 74-1-1, April 1974, Page 57.

2/ An Analysis of Oil Outflows Due to Tanker Accidents, A note by U. S. Coast Guard, Page 7.

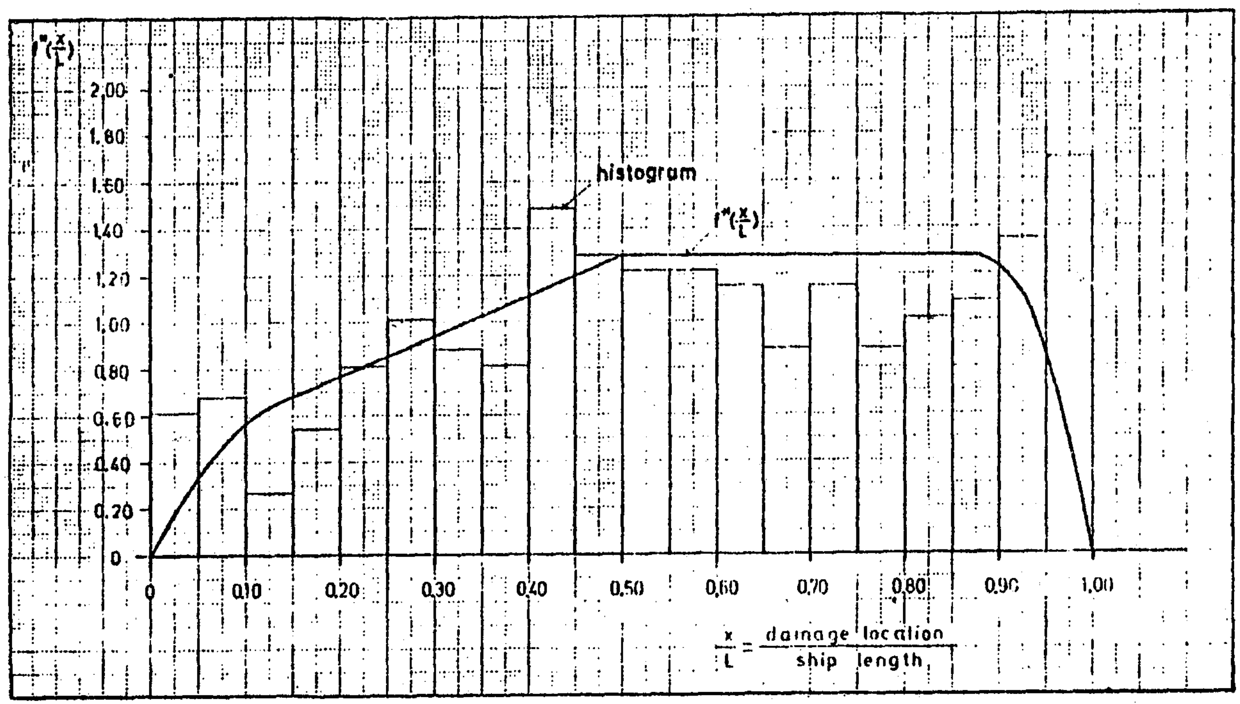


Figure 9

<u>DISTRIBUTION DENSITY OF NONDIMENSIONAL DAMAGE LOCATION</u>

SOURCE: "Regulations on subdivision and stability of passenger ships as equivalent to Part B of Chapter II of the International Convention for the Safety of Life at Sea", 1960, U.S. Coast Guard Commandant's International Technical Series, Vol. IV USCG Cits - 74-1-1, April 1974, Page 55.

grounding, considerably less damage would be inflicted on the cargo tanks. The result is that the amount and rate of cargo spillage is reduced.

The second benefit is that the space separating the inner and outer hulls serves as a containment area for spilled cargo, which serves to reduce the amount of oil outflow.

For these reasons, it is considered unlikely that the outflow from even a severe grounding could exceed the maximum credible spill. In order for a worse event to occur, the contents of more than two cargo tanks would have to spill within a period of 6 minutes or less. The rate of oil spillage in grounding incidents is generally measured in hours or days.

In ramming-type casualties the high speed required to rupture even the forwardmost cargo tank renders the probability of damaging more than two tanks implausible.

An unignited vapor cloud resulting from a one or two cargo tank spill could pose a threat to the general public depending on the local meteorological conditions existing at the time of the spill. A stable or neutral atmosphere and a low wind speed would be necessary in order to prevent the dilution of the plume below the LFL before reaching land. At the same time the proper orientation of the prevailing wind would be required to direct the cloud into a populated area.

The maximum distance to the LFL has been estimated for various spill sizes in attachment 1 to this study. The range of flammable vapors are estimated to extend 5,019 feet downwind for a one tank spill and 7,710 feet for the spillage for two cargo tanks. The calculations are based on dispersion parameters for a neutrally stable atmosphere and a wind speed of 5 MPH. These conditions are considered to yield the maximum range of flammable vapors for an LNG vapor cloud. Higher wind speeds and/or an unstable atmosphere would enhance the dispersion of the vapors and reduce the distance to the LFL.

For spills occurring within a channel or a confined harbor area, it is assumed that a hazard could exist regardless of the prevailing wind direction. However, for spills occurring in waters offshore of a terminal, some wind directions could direct a vapor cloud away from land and eliminate a potential hazard.

The probability of the proper combination of wind speed, wind direction, and atmospheric stability class can be estimated from the STAR Program1/ for the weather station nearest to the project

1/ STAR Programs are available for selected weather stations from the U.S. Department of Commerce, National Oceanic and Atomspheric Adminstration, National Climatic Center, Asheville, North Carolina.

area. The program provides the annual frequency of wind speed and direction by atmospheric stability class. For this study, only neutral and stable atmospheres are considered (Classes D,E, and F) since unstable conditions reduce the range of flammable vapors. By similar reasoning only wind speeds of 6 knots (6.9 mph) or less are considered. The range of wind directions which could cause a hazardous situation is unique for each project. The appropriate wind directions depend on the configuration of the shoreline in the project area and the locations of the nearby population. The reduction factors for the frequency of proper meteorological conditions have been calculated for each project as shown in Table 14.

TABLE 14

PROBABILITY OF PROPER METEOROLOGICAL CONDITIONS

LOCATION	REDUCTION FACTOR
Point Conception, Calif.	.11
Oxnard, Calif.	.16
Los Angeles Harbor, Calif.	.75
Nikiski, Alaska	.11
Gravina Point, Alaska	.15
Cape Starichkof, Alaska	.10

D. RISK TO THE GENERAL PUBLIC

Under most conditions, the greatest hazard to the general public would result from an unignited vapor cloud drifting over a populated area. The magnitude of the hazard would depend on the land use characteristics of the area swept by the cloud. It is possible that a vapor cloud drifting over rural or sparsely populated areas would not encounter ignition sources. In this case the plume would continue drifting downward until the forces of dispersion of buoyancy would dilute the vapors below the LFL and eliminate the potential hazard.

In residential or industrial areas a vapor cloud would be exposed to numerous potential sources of ignition. Under this situation, it is unlikely that the cloud would achieve its maximum range without ignition. Instead, the cloud would probably experience ignition soon after reaching land and burn back to the spill site.

For some locations it is possible that an LNG pool fire could pose a greater hazard than the hazards associated with an ignited vapor cloud. For LNG facilities located in remote areas or having marine terminals well offshore, the fatalities from exposure to radiation from a pool fire would be less than from an unignited vapor cloud drifting over land. However, an LNG pool fire occurring in a confined harbor or channel area could cause greater fatalities than a drifting vapor cloud. The evaporating pool of LNG would fuel an intense fire resulting in high levels of thermal radiation covering a wide area. The population located within this area and unshielded by buildings or other structures could sustain severe burns or death. The maximum range of hazardous radiation levels from an LNG pool fire has been calculated in Attachment 2 to this study.

Since the study is directed toward estimating the "worst case" hazard to the public, it is necessary to estimate the maximum probable number of fatalities. In the case where the proposed terminal's location is in a remote or sparsely populated area, the facility itself would represent the maximum concentration of population in the area. Therefore, the maximum expected fatalities are assumed to equal the maximum operational staff at the facility and any population in the nearby plant vicinity.

Of the projects under consideration, the proposed terminal sites at Point Conception and Gravina Point and the alternative site at Cape Starichkof would be located in unpopulated areas. The maximum probable fatalities for these locations are assumed to equal the operational staff at each facility. The proposed Nikiski site is located adjacent to a small industrial complex. For this location, the number of fatalities would equal the operational staffs of the proposed Nikiski facility and the nearby industrial plants. These estimates are listed in Table 15.

For populated areas, the fatalities resulting from a vapor cloud are assumed to equal the entire population within the swept area of the cloud. In theory, the number of fatalities could equal the population within the maximum range of the cloud. However, the likelihood of early ignition in most cases would limit the range of the cloud to less than the maximum. As noted in Attachment 2, the radiation hazard from a vapor cloud fire is not considered to be significant, so only those within the cloud are counted as fatalities.

The procedures for estimating the maximum range of a vapor cloud over populated areas is presented in Attachment 3 to this study. Based on this technique the maximum fatalities are estimated for Oxnard and Los Angeles Harbor. These results are also presented in Table 15 below.

TABLE 15

MAXIMUM PROBABLE FATALITIES

Location	Fatalities
Point Conception, Calif.	40
Oxnard, Calif.	340
Los Angeles Harbor, Calif.	1180
Nikiski, Alaska	150
Gravina Point, Alaska	250
Cape Starichkof, Alaska:	
a) Alternative to Nikiski	30
b) Combined Alaskan Terminal	250

E. CONCLUSION

The appropriate data and reduction factors for each of five proposed terminals and the proposed alternative site at Cape Starichkof appear in Tables 16 through 21. The results from these tables are used to estimate the risks associated with the ultimate development of the three receiving terminals proposed for California. The proposed site at Cape Starichkof is also evaluated as the location for a combined Alaskan liquefaction facility and marine terminal.

The relative risks associated with the proposed, ultimate, and alternate LNG projects are compared in Table 22. For the five proposed projects, the estimated annual fatalities range from 0.006 to 0.115. However, it should be realized that the variation is due in large part to the different levels in annual tanker trips (52 to 308) anticipated for each terminal.

A better comparison of the relative risks involved with the three proposed California terminals is found by comparing the projects at their ultimate development. Under this condition, the maximum annual number of tanker trips is kept constant at 565, so that the estimated fatality rates are more reflective of the general safety of the proposed terminal location. Based on this comparison, the risks associated with Point Conception and Oxnard appear to be acceptable, particularly when compared to the risks which would be associated with Los Angeles Harbor. Although the past shipping history of Los Angeles Harbor was found in Table 22 to be relatively safe, the high density of population in the area would result in a large segment of the public being exposed to a potential hazard. It is, therefore, the opinion of the staff that in determining a site for the importation of LNG into California, Los Angeles Harbor would be, by far, the poorest choice, particularly when other viable alternatives exist.

As can be seen in Table 22, the risks to the public safety are relatively low for all three Alaskan sites. However, the U.S. Coast Guard has recommended against the construction of a marine terminal at Nikiski based on the hazards to shipping in that area. The historical tanker casualty rate for this location was found to be the highest of all the project areas; a direct result of the severe ice, wind, and tidal currents common to the upper and middle regions of Cook Inlet. The U.S. Coast Guard has suggested that additional shipping activity in the Nikiski area would further compound an already marginal situation. As a result, the staff has recommended that Cape Starichkof be selected as the alternate site to Nikiski. Ice floes in Cook Inlet rarely extend as far south as Cape Starichkof, and tidal currents are much less severe than at Nikiski. Additionally, hazards due to other shipping activity would be reduced since the terminal would serve LNG tankers only. The staff has also considered Cape Starichkof as an alternative to Gravina Point and a combined terminal for both the El Paso and Pacific Alaska projects.

An even better indication of the actual risk to public safety at a particular terminal may be found in the third column of Table 22. The annual probability of a risk to the public is considered to be relatively low for most of the sites. The inverse of this value yields the frequency of occurrence of public exposure to a risk. These range from a high of once every 552 years for Los Angeles Harbor at its ultimate development to a low of once every 27,000 years for the proposed terminal at Nikiski.

Table 16

ACCIDENT SEQUENCE MODEL AND PROBABILITY FACTORS

LOCATION: POINT CONCEPTION, CALIF.

	CASUALTY TYPES			
	Collisions	**Groundings**	**Rammings**	**Total**
A. Annual Probability of An LNG Tanker Casualty 1/				
(1) Historical Casualty Rate (Casualty/Trip)	-	-	-	$4.4x10^{-3}$
(2) Casualty Type Distribution	.32	.39	.29	-
(3) VTS 2/ Reduction Factors	1.0	1.0	1.0	-
(4) Annual Number of LNG Tanker Trips	-	-	-	308
(5) Annual Casualty Rate (Casualty/Yr.) = (1)x(2)x(3)x(4)	.434	.529	.393	1.355
B. Probability of a Spill in the Event of a Casualty				
(6) Historical Spill Frequency (PCI 3//Casualty)	.023	.028	.014	-
(7) LNG Tanker Reduction Factors	.75	.15	.15	-
(8) Annual Spill Rate (Spills/Yr.) = (5)x(6)x(7)	$7.49x10^{-3}$	$2.22x10^{-3}$	$.83x10^{-3}$	$1.05x10^{-2}$
C. Probability of a Flammable Vapor Plume Affecting a Populated Area				
(9) Probability of no Ignition at Spill Site	0.1	1.0	0.1	-
(10) Probability of Favorable Circumstances (Location of Spill, Meteorology)				.11
(11) Annual Frequency of a Plume Reaching Land = (8)x(9)x(10)				$3.36x10^{-4}$
D. Risk to General Public				
(12) Probable Number of Fatalities From Plume Fire				40
(13) Annual Probability of a Fatality/(Fatality/Year = (11)x(12)				$1.34x10^{-2}$
(14) Expected Frequency of One Fatality (Years) = 1/(13)				74.6

1/ For the purpose of this report, a casualty is defined as an accident involving a ship and should not be construed as a human fatality or injury.

2/ VTS - Vessel Traffic System - Reduction factors apply only to waterways with VTS scheduled to become operational coincident with the proposed LNG project.

3/ PCI - Pollution Causing Incident

Table 17

ACCIDENT SEQUENCE MODEL AND PROBABILITY FACTORS

LOCATION: OXNARD, CALIF.

	CASUALTY TYPES			
	Collisions	**Groundings**	**Rammings**	**Total**
A. Annual Probability of An LNG Tanker Casualty 1/				
(1) Historical Casualty Rate (Casualty/Trip)	-	-	-	4.4×10^{-3}
(2) Casualty Type Distribution	.32	.39	.29	-
(3) VTS 2/ Reduction Factors	1.0	1.0	1.0	-
(4) Annual Number of LNG Tanker Trips	-	-	-	75
(5) Annual Casualty Rate (Casualty/Yr.) = (1)x(2)x(3)x(4)	.106	.129	.096	.331
B. Probability of a Spill in the Event of a Casualty				
(6) Historical Spill Frequency (PCI 3//Casualty)	.023	.028	.014	-
(7) LNG Tanker Reduction Factors	.75	.15	.15	-
(8) Annual Spill Rate (Spills/Yr.) = (5)x(6)x(7)	1.8×10^{-3}	$.54\times10^{-3}$	$.20\times10^{-3}$	2.57×10^{-3}
C. Probability of a Flammable Vapor Plume Affecting a Populated Area				
(9) Probability of no Ignition at Spill Site	0.1	1.0	0.1	-
(10) Probability of Favorable Circumstances (Location of Spill, Meteorology)	-	-	-	.16
(11) Annual Frequency of a Plume Reaching Land = (8)x(9)x(10)	-	-	-	1.18×10^{-4}
D. Risk to General Public				
(12) Probable Number of Fatalities From Plume Fire				340
(13) Annual Probability of a Fatality/(Fatality/Year = (11)x(12)				4.05×10^{-2}
(14) Expected Frequency of One Fatality (Years) = 1/(13)				24.7

1/ For the purpose of this report, a casualty is defined as an accident involving a ship and should not be construed as a human fatality or injury.

2/ VTS - Vessel Traffic System - Reduction factors apply only to waterways with VTS scheduled to become operational coincident with the proposed LNG project.

3/ PCI - Pollution Causing Incident

Table 18

ACCIDENT SEQUENCE MODEL AND PROBABILITY FACTORS

LOCATION: LOS ANGELES HARBOR, CALIF.

	CASUALTY TYPES			
	Collisions	Groundings	Rammings	Total
A. Annual Probability of An LNG Tanker Casualty 1/				
(1) Historical Casualty Rate (Casualty/Trip)	-	-	-	$1.9x10^{-3}$
(2) Casualty Type Distribution	.32	.39	.29	-
(3) VTS 2/ Reduction Factors	1.0	1.0	1.0	-
(4) Annual Number of LNG Tanker Trips	-	-	-	52
(5) Annual Casualty Rate (Casualty/Yr.) = (1)x(2)x(3)x(4)				$9.9x10^{-2}$
B. Probability of a Spill in the Event of a Casualty				
(6) Historical Spill Frequency (PCI 3//Casualty)	.023	.028	.014	-
(7) LNG Tanker Reduction Factors	.75	.15	.15	-
(8) Annual Spill Rate (Spills/Yr.) = (5)x(6)x(7)	$5.45x10^{-4}$	$1.62x10^{-4}$	$.60x10^{-4}$	$7.67x10^{-4}$
C. Probability of a Flammable Vapor Plume Affecting a Populated Area				
(9) Probability of no Ignition at Spill Site	0.1	1.0	0.1	-
(10) Probability of Favorable Circumstances (Location of Spill, Meteorology)				.75
(11) Annual Frequency of a Plume Reaching Land = (8)x(9)x(10)				$1.67x10^{-4}$
D. Risk to General Public				
(12) Probable Number of Fatalities From Plume Fire				1180
(13) Annual Probability of a Fatality/(Fatality/Year = (11)x(12)				$1.97x10^{-1}$
(14) Expected Frequency of One Fatality (Years) = 1/(13)				5

1/ For the purpose of this report, a casualty is defined as an accident involving a ship and should not be construed as a human fatality or injury.

2/ VTS - Vessel Traffic System - Reduction factors apply only to waterways with VTS scheduled to become operational coincident with the proposed LNG project.

3/ PCI - Pollution Causing Incident

Table 19

ACCIDENT SEQUENCE MODEL AND PROBABILITY FACTORS

LOCATION: NIKISKI, ALASKA

	CASUALTY TYPES			
	Collisions	Groundings	Rammings	Total
A. Annual Probability of An LNG Tanker Casualty 1/				
(1) Historical Casualty Rate (Casualty/Trip)	-	-	-	7.04×10^{-3}
(2) Casualty Type Distribution	.05	.16	.79	-
(3) VTS 2/ Reduction Factors	1.0	1.0	1.0	-
(4) Annual Number of LNG Tanker Trips	-	-	-	52
(5) Annual Casualty Rate (Casualty/Yr.) = (1)x(2)x(3)x(4)	1.83×10^{-2}	5.86×10^{-2}	2.89×10^{-1}	3.66×10^{-1}
B. Probability of a Spill in the Event of a Casualty				
(6) Historical Spill Frequency (PCI 3//Casualty)	.023	.028	.014	-
(7) LNG Tanker Reduction Factors	.75	.15	.15	-
(8) Annual Spill Rate (Spills/Yr.) = (5)x(6)x(7)	3.12×10^{-4}	2.46×10^{-4}	6.07×10^{-4}	1.17×10^{-3}
C. Probability of a Flammable Vapor Plume Affecting a Populated Area				
(9) Probability of no Ignition at Spill Site	0.1	1.0	0.1	-
(10) Probability of Favorable Circumstances (Location of Spill, Meteorology)				.11
(11) Annual Frequency of a Plume Reaching Land = (8)x(9)x(10)				3.72×10^{-5}
D. Risk to General Public				
(12) Probable Number of Fatalities From Plume Fire				150
(13) Annual Probability of a Fatality/(Fatality/Year = (11)x(12)				5.58×10^{-3}
(14) Expected Frequency of One Fatality (Years) = 1/(13)				179

1/ For the purpose of this report, a casualty is defined as an accident involving a ship and should not be construed as a human fatality or injury.

2/ VTS - Vessel Traffic System - Reduction factors apply only to waterways with VTS scheduled to become operational coincident with the proposed LNG project.

3/ PCI - Pollution Causing Incident

Table 20

ACCIDENT SEQUENCE MODEL AND PROBABILITY FACTORS

LOCATION: PRINCE WILLIAM SOUND, ALASKA

	CASUALTY TYPES			
	Collisions	**Groundings**	**Rammings**	**Total**
A. Annual Probability of An LNG Tanker Casualty 1/				
(1) Historical Casualty Rate (Casualty/Trip)	-	-	-	5.9×10^{-3}
(2) Casualty Type Distribution	.32	.39	.29	-
(3) VTS 2/ Reduction Factors				.75
(4) Annual Number of LNG Tanker Trips	-	-	-	308
(5) Annual Casualty Rate (Casualty/Yr.) = (1)x(2)x(3)x(4)	.436	.532	.395	1.363
B. Probability of a Spill in the Event of a Casualty				
(6) Historical Spill Frequency (PCI 3//Casualty)	.023	.028	.014	-
(7) LNG Tanker Reduction Factors	.75	.15	.15	-
(8) Annual Spill Rate (Spills/Yr.) = (5)x(6)x(7)	7.52×10^{-3}	2.23×10^{-3}	$.83\times10^{-3}$	1.06×10^{-2}
C. Probability of a Flammable Vapor Plume Affecting a Populated Area				
(9) Probability of no Ignition at Spill Site	0.1	1.0	0.1	-
(10) Probability of Favorable Circumstances (Location of Spill, Meteorology)				.15
(11) Annual Frequency of a Plume Reaching Land = (8)x(9)x(10)				4.60×10^{-4}
D. Risk to General Public				
(12) Probable Number of Fatalities From Plume Fire				250
(13) Annual Probability of a Fatality/(Fatality/Year = (11)x(12)				1.15×10^{-1}
(14) Expected Frequency of One Fatality (Years) = 1/(13)				87

1/ For the purpose of this report, a casualty is defined as an accident involving a ship and should not be construed as a human fatality or injury.

2/ VTS - Vessel Traffic System - Reduction factors apply only to waterways with VTS scheduled to become operational coincident with the proposed LNG project.

3/ PCI - Pollution Causing Incident

Table 21

ACCIDENT SEQUENCE MODEL AND PROBABILITY FACTORS

LOCATION: CAPE STARICHKOF, ALASKA (ALTERNATIVE TO NIKISKI)

	CASUALTY TYPES			
	Collisions	Groundings	Rammings	Total
A. Annual Probability of An LNG Tanker Casualty 1/				
(1) Historical Casualty Rate (Casualty/Trip)	-	-	-	4.45×10^{-3}
(2) Casualty Type Distribution	.08	.25	.67	-
(3) VTS 2/ Reduction Factors	1.0	1.0	1.0	-
(4) Annual Number of LNG Tanker Trips	-	-	-	52
(5) Annual Casualty Rate (Casualty/Yr.) = (1)x(2)x(3)x(4)	.019	.058	.155	.231
B. Probability of a Spill in the Event of a Casualty				
(6) Historical Spill Frequency (PCI 3//Casualty)	.023	.028	.014	-
(7) LNG Tanker Reduction Factors	.75	.15	.15	-
(8) Annual Spill Rate (Spills/Yr.) = (5)x(6)x(7)	3.28×10^{-4}	2.44×10^{-4}	3.26×10^{-4}	8.98×10^{-4}
C. Probability of a Flammable Vapor Plume Affecting a Populated Area				
(9) Probability of no Ignition at Spill Site	0.1	1.0	0.1	-
(10) Probability of Favorable Circumstances (Location of Spill, Meteorology)				.15
(11) Annual Frequency of a Plume Reaching Land = (8)x(9)x(10)				4.64×10^{-5}
D. Risk to General Public				
(12) Probable Number of Fatalities From Plume Fire				30
(13) Annual Probability of a Fatality/(Fatality/Year = (11)x(12)				1.38×10^{-3}
(14) Expected Frequency of One Fatality (Years) = 1/(13)				723

1/ For the purpose of this report, a casualty is defined as an accident involving a ship and should not be construed as a human fatality or injury.

2/ VTS - Vessel Traffic System - Reduction factors apply only to waterways with VTS scheduled to become operational coincident with the proposed LNG project.

3/ PCI - Pollution Causing Incident

TABLE 22

RELATIVE RISKS OF THE PROPOSED, ULTIMATE, AND ALTERNATE LNG PROJECT SITES

Terminal Location	Annual Tanker Trips	Estimated LNG Tanker Casualties Per Year	Annual Probability Of A Risk to The Public	Estimated Fatalities Per Year	Expected Frequency of One Fatality (Years)
Proposed Projects:					
1) Point Conception, Calif.	308	1.355	3.36×10^{-4}	.013	74.6
2) Oxnard, Calif.	75	.331	1.18×10^{-4}	.040	24.7
3) Los Angeles Harbor, Calif.	52	.099	1.67×10^{-4}	.197	5
4) Nikiski, Alaska	52	.366	3.72×10^{-5}	.006	179
5) Gravina Point, Alaska	308	1.363	4.60×10^{-4}	.115	8.7
Ultimate Development:					
1) Point Conception, Calif.	565	2.486	6.16×10^{-4}	.024	41.6
2) Oxnard, Calif.	565	2.494	8.89×10^{-4}	.301	3.3
3) Los Angeles Harbor, Calif.	565	1.076	1.81×10^{-3}	2.173	0.46
Alternate Site:					
1) Cape Starichkof					
a) Alternative to Nikiski	52	.231	4.64×10^{-5}	.001	723
b) Combined Alaskan Terminal	360	1.602	3.19×10^{-4}	.080	12.5

ATTACHMENT 1

VAPOR PLUME ANALYSIS FOR LNG SPILLS ON WATER

Nomenclature

a	-	function of stability class (m)
b	-	exponent to determine σ_y (dimensionless)
c,d	-	functions of stability class (degrees)
d'	-	diameter of the source measured at time of consideration (meters)
g	-	gravitational acceleration, 9.814 meters/sec^2
h	-	liquid regression rate, 1 inch/minute (assumed)
he	-	initial height of vapor cloud (m)
H	-	cloud height (m)
K	-	constant = 2 (assumed)
q	-	source strength at neutral buoyancy (gms/sec)
Q	-	heat transfer rate (lb/sec)
r	-	radius of pool (ft)
r_e	-	maximum pool radius (ft or m)
r_N	-	radius of vapor cloud at neutral buoyancy (m)
s	-	length of a side of an area source (meters)
t	-	time (sec)
te	-	time to LNG evaporation (sec)
T	-	temperature (^oK)
u	-	wind speed (m/sec)
V	-	volume of vapor cloud (m^3)
Vo	-	volume of spilled LNG (ft^3)
X	-	downwind distance from source (km)
Xo	-	normalizing distance = 1 km

x_y	-	distance to virtual source (km)
C	-	vapor concentration (gm/m^3)
ρ_a	-	density of air at 273°K, 1.293×10^{-3} gms/cm^3
ρ_L	-	density of liquid LNG, 28.3 lbs/ft^3
ρ	-	density of gaseous LNG (gms/cm^3)
ρ_w	-	density of water, 62.4 lb/ft^3
σ_y	-	standard crosswind deviation of the plume concentration (m)
σ_{y_0}	-	initial crosswind standard deviation (m)
σ_z	-	standard vertical deviation of the plume concentration (m)
θ_p	-	half angle of horizontal plume spreading (degrees)

SPREAD AND EVAPORATION OF LNG ON WATER

In the event of an LNG spill on water, the liquid will spread by diffusion to a maximum pool size and evaporate as it spreads. This maximum pool size and time to evaporation is of interest and can be quantitatively estimated. For an instantaneous spill of a volume of LNG on water, several models have been suggested to determine the maximum pool radius and evaporation time. A summary of the pertinent equations and authors is as follows. 1/

Author	Equation for Maximum Radius	Equation for Evaporation Time
Fay	$r_e = 4.70\ Vo^{5/12}$	$te = 3.3\ Vo^{1/3}$
Hoult 2/	$r_e = 10.4\ Vo^{5/12}$	$te = 14.5\ Vo^{1/3}$
Hoult 3/	$r_e = 7.3\ Vo^{3/8}$	$te = 7.9\ Vo^{1/4}$
Otterman	$r_e = \frac{7.6\ Vo^{3/8}}{h^{1/8}}$	$te = \frac{12.4\ Vo^{1/4}}{h^{1/2}}$
Raj/Kalelkar	$r_e = \frac{7.4\ Vo^{3/8}}{h^{1/4}}$	$te = \frac{8.8\ Vo^{1/4}}{h^{1/2}}$
Muscari	$r_e = \frac{9.07\ Vo^{3/8}}{h^{1/4}}$	$te = \frac{10.56\ Vo^{1/4}}{h^{1/2}}$

1/ B. Otterman, "Analysis of Large LNG Spills on Water; Part I: Liquid Spread and Evaporation," Cryogenics (August 1975), pp. 455-460; Elizabeth M. Drake, Testimony in Hearings before the Federal Power Commission, Nov. 26, 1975.

2/ Ice formation model.

3/ Nonformation of ice model.

where density of LNG was assumed to equal 28.3 lbs/ft^3

Vo = volume of spill (ft^3)

r_e = maximum pool radius (ft)

t_e = time to evaporation (sec)

h = liquid regression rate (inch/minute)

A comparison of each model for various size spills is shown in Table 1 for the case of a 1-inch per minute liquid regression rate, which is equivalent to a constant boiling rate of 30,000 $Btu/hr\text{-}ft^2$. As can be seen from Table 1, there is agreement in the models presented by Hoult (non-ice), Otterman, Raj/Kalelkar, and Muscari for the 1-inch per minute regression rate case. This is not surprising, since each of these models differ only in their constant values, i.e., the radius and time are functions to the three-eighth and one-fourth powers, respectively.

A sharp difference can be noted between these four models and Hoult's ice model. Oddly enough, Fay's predictions are in agreement with the four non-ice models. This is indeed suspicious, because the presence of ice would tend to decrease the vaporization rate per unit area with time as the ice thickness beneath the spill increases. Since both Hoult and Fay assumed ice formation, one would expect their respective estimates to be in agreement; however, the opposite is true.

The environmental staff's former plume analyses were based in part on Hoult's ice formation model. However, significant study has since indicated that conclusive experimental evidence does not currently exist which would clearly indicate whether ice formation occurs. The environmental staff now believes that an ice formation model does not accurately estimate the areal spread and rate of evaporation of a large LNG spill. While the environmental staff would agree that perhaps small amounts of "slosh" ice might exist, its presence would not be compatible with the formation of sheet ice of some finite thickness. In addition, Hoult's ice model neglects the sensible heat loss by the ice as it cools. Since this heat loss can be significant, Hoult's assumption is not fully justified. As a result, Hoult predicts larger ice growth, and consequently a longer time requirement for complete evaporation and a greater extent of pool spread.

TABLE 1

COMPARISON OF LNG SPREADING MODELS

Model	4,000 M^3		10,000 M^3		24,000 M^3		100,000 M^3		Heat Transfer Medium
	t_e (min)	r_e (feet)	t_e (min)	r_e (feet)	t_e (min)	r_e (feet)	t_e (min)	r_e (feet)	
Fay	2.9	656	3.9	960	5.2	1,385	8.4	2,510	Ice
Hoult	8.5	1,130	11.4	1,650	15.4	2,400	25	4,300	Ice
Hoult	2.5	628	3.2	890	4.0	1,250	5.7	2,100	1 inch per minute
Ottermam	4.0	650	5.0	915	6.3	1,270	8.9	2,170	Regression
Raj/Kalelkar	2.8	630	3.6	890	4.4	1,236	6.3	2,110	Regression
Muscari	3.4	774	4.3	1,092	5.3	1,516	7.6	2,589	Regression

For purposes of calculating the behavior of an instantaneous spill of LNG on water, the environmental staff has chosen the method of Raj and Kalelkar and a liquid regression rate of 1 inch per minute. This regression rate corresponds closely to a Bureau of Mines' average observed evaporation rate of 0.037 lbs/ft^2-sec., which corresponds closely to a heat flux rate of 30,000 Btu/ft^2-hr. Higher regression rates have been suggested; however, uncertainties of the regression rate do not have a major influence on predicted pool radius sizes, since r_e is proportional to $h^{-\frac{1}{4}}$. If, for example, the regression rate is doubled, the pool radius would decrease only by approximately 15 percent. The selection of the Raj/Kalelkar model does not imply that the other three suggested models cannot be used for estimation purposes; it simply means that the environmental staff's calculated predictions will be within ± 20 percent, allowing for differences between the various models and uncertainties in the estimation of boiling rates.

For a 37,500-cubic meter spill from a sudden and complete release of a single ship storage tank of the 165,000-cubic meter capacity vessels presently being designed, the maximum pool radius is estimated to be about 446 meters, which would evaporate in approximately 300 seconds (5 minutes). For a 25,000-cubic meter spill from a single ship storage tank of the 125,000-cubic meter capacity vessels presently under construction, the maximum pool radius is estimated to be about 383 meters, which would evaporate in approximately 270 seconds (4½ minutes).

GRAVITY SPREADING OF LNG VAPOR

After the liquid has evaporated, it is at 112°K, but has expanded to a negatively buoyant vapor with a volume of vapor to liquid ratio of approximately 250. Therefore, the initial height, h_e, of the cloud can be expressed as:

$$h_e = \frac{250\ Vo}{\pi r_e^2}$$

on the assumption that the negatively buoyant cloud is of circular shape. For a 37,500-cubic meter spill, the calculations show that the cloud is in the shape of a thin pancake about 892 meters in diameter and 15.0 meters thick. For a 25,000-cubic meter spill, the shape of the cloud is approximately 766 meters in diameter and 13.57 meters thick.

As the cloud continues to gain heat from both the water and surrounding air, the cloud will expand from negative to neutral buoyancy at which point the vapor density of the cloud equals the density of air, which occurs at a vapor temperature of 151°K. During this expansion process to neutral buoyancy, the primary mechanism for cloud spread is considered to be that of gravity spreading rather than atmospheric diffusion, i.e., the effects of atmospheric motion and the entrainment of air due to spreading motions are neglected in the analysis. A further assumption is that the rate of vapor spread is greater than local wind velocity. As the vapor cloud approaches neutral buoyancy, gravity spreading rates will decrease rapidly. When spreading rates become less than local wind velocity, gravitational effects also become negligible. Therefore, at the point of neutral buoyancy, all further dilution of the cloud is considered to be primarily due to atmospheric diffusion, although some gravitational effects may still influence additional mixing.

The spread equation as a function of time is: 1/

$$\frac{dR}{dt} = \left[Kg \left(\frac{\rho - \rho_a}{\rho_a} \right) H \right]^{1/2} \quad (1)$$

where g = acceleration of gravity

ρ = cloud density

ρ_a = density of ambient air at 273°K

K = constant = 2

H = cloud height

Substitution of $H = V/\pi r^2$ yields

$$\frac{dR}{dt} = \left[\frac{Kg}{\pi} \left(\frac{\rho - \rho_a}{\rho_a} \right) \frac{V}{r^2} \right]^{1/2} \quad (2)$$

1/ Otterman, p. 455-460.

Integration yields

$$r^2 = \left[\frac{4Kg}{\pi} \left(\frac{\rho - \rho_a}{\rho_a}\right) V\right]^{\frac{1}{2}} t \qquad (3)$$

From the ideal gas law:

$$\frac{dT}{T} = \frac{dV}{V} \qquad (4)$$

$$\text{where } \frac{dT}{T} = \frac{(151^{o}K - 112^{o}K)}{112^{o}K} = 0.348$$

or

$$V_N = 337\ V_o$$

From this amount of expansion, Equation 3 can then be used to calculate the radius of the cloud at neutral buoyancy for the 37,500-cubic meter spill in the following manner:

$$r^2 = \left[\frac{4Kg}{\pi} \left(\frac{\rho - \rho_a}{\rho_a}\right) V\right]^{\frac{1}{2}} t$$

where $k = 2$

$g = 9.814$ meters/sec^2

$\rho_a = 1.293 \times 10^{-3}$ gms/cm^3

$$\rho = \rho_{LOG}\ \text{mean} = \frac{1.747 \times 10^{-3} - 1.293 \times 10^{-3}}{\ln\left(\frac{1.747 \times 10^{-3}}{1.293 \times 10^{-3}}\right)}$$

$\rho = 1.51 \times 10^{-3}$ gms/cm^3

$$V = V_{AVG} = (37{,}500\ m^3)\left(\frac{250 + 337}{2}\right)$$

$$= (37{,}500\ m^3)\ (293.5)$$

$r^2 = 6796t$ where r in meters, t in seconds

If the specific heat of methane at $T_{AVG} = \frac{151^oK + 112^oK}{2} = 131.5^oK$ equals:

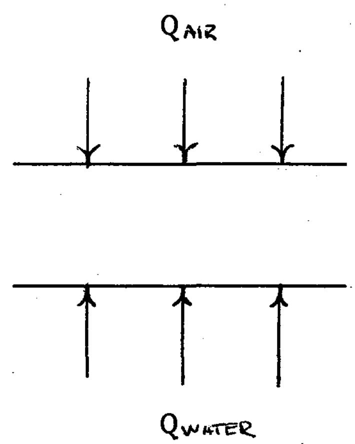
$$Cp \simeq 0.5 \text{ cal/gm}^oc \quad 1/$$

$$\therefore \quad q_N = Cp\,\Delta T = (0.5 \text{ cal/gm}^oc)\;(\Delta T = 39^oc)\;(454 \text{ gms/lb})$$

$$= 8853 \text{ cal/lb}$$

= 35.1 Btu/lb required to raise cloud from negative to neutral buoyancy.

Heat Input



$$Q_{TOTAL} = Q_{WATER} + Q_{AIR}$$

$$= \frac{kA\,\Delta T_W}{\sqrt{\pi \alpha t}}\;2/ + hA\Delta T_A$$

where $\alpha = (k/\rho\, C_p)_{water}$ = thermal diffusivity

$= 1.419 \times 10^{-7}$ meter^2/sec

k = thermal conductivity of water

$= 3.1259 \times 10^{-4}$ Btu/sec-meter-^oF

1/ Carl L. Yaws, "Physical and Thermodynamic Properties, Part II Alkanes: CH_4, C_2H_6, C_3H_8," Chemical Engineering, May 12, 1975, pp. 89-97.

2/ J.P. Holman, Heat Transfer, McGraw-Hill Inc., second edition, 1968, pp. 79-80.

$$A = \pi r^2 = \pi\ (6796t),\ \text{meter}^2 \text{ for } t = \text{sec.}$$

$$h = \text{heat transfer coefficient of air}$$

$$\simeq 2.9899 \times 10^{-3}\ \text{Btu/m}^2 - \text{sec} - {}^{\circ}\text{F}$$

$$\Delta T_A = \Delta T_w = (\Delta T)_{AVG} = \frac{\Delta T_2 - \Delta T_1}{\ln(\Delta T_2/\Delta T_1)}$$

$$\Delta T_2 = T_{water} - T_{negative\ cloud}$$

$$= 273^{\circ}\text{K} - 112^{\circ}\text{K} = 161^{\circ}\text{C}$$

$$= 289.8^{\circ}\text{F}$$

$$\Delta T_1 = T_{water} - T_{neutral\ cloud}$$

$$= 273^{\circ}\text{K} - 151^{\circ}\text{K} = 122^{\circ}\text{C}$$

$$= 219.6^{\circ}\text{F}$$

$$\Delta T_{Avg} = (289.8 - 219.6)/\ \ln\left(\frac{289.8}{219.6}\right)$$

$$= 253.1^{\circ}\text{F}$$

Defining $\dot{m} = \dfrac{Q}{q_n} = \dfrac{Q_w + Q_A}{q_n}$ and $\rho_{LNG}\ V = \displaystyle\int_0^t \dot{m}\, dt$

$$\dot{m} = \frac{(3.1259 \times 10^{-4})(3.14)(6796t)(253.1)}{(35.1)\left[(3.14)(1.419 \times 10^{-7})\right]^{\frac{1}{2}} t^{\frac{1}{2}}} + \frac{(2.9899 \times 10^{-3})(\pi)(6796t)^{(253.1)}}{35.1}$$

$$\dot{m} = 7.20588 \times 10^4\ t^{\frac{1}{2}} + 460.07\ t$$

and

$$\rho_{LNG}\ V = \int 7.20588 \times 10^4\ t^{\frac{1}{2}} + 460.07\ t$$

$$\rho_{LNG}\ V = \frac{7.20588 \times 10^4\ t^{3/2}}{3/2} + \frac{460.07\ t^2}{2}$$

$$\rho_{LNG} V = 4.8039 \times 10^4 \ t^{3/2} + 230.035 \ t^2 = 37.5 \times 10^6 \text{ lbs}$$
$$= 3.75 \times 10^7$$

$$\therefore t \simeq 82 \text{ seconds}$$

and

$$r_N = 746.5 \text{ meters}$$

Calculations for other spill sizes are given in later sections of this report. The corresponding times to go from negative to neutral buoyancy can be calculated by equation 3.

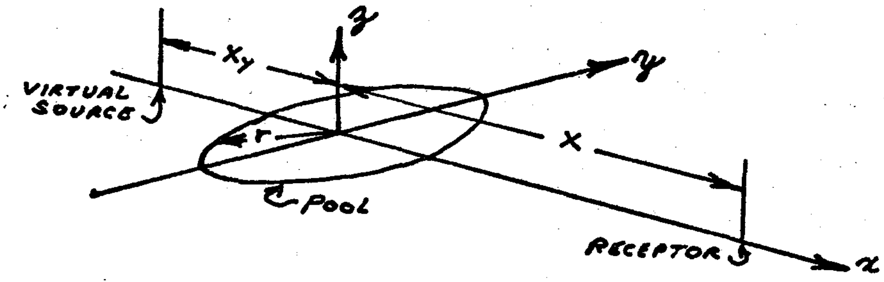
The above analysis assumed a "no wind" condition. If wind is present, the cloud will move in the direction of the wind, a distance of ut, i.e., wind speed multiplied by the time involved. However, it should be remembered that the above analysis would only be applicable for low wind speeds and/or until dR/dt equals the assumed wind speed, i.e., $\frac{dR}{dt} = u$.

DISPERSION BY WIND

Under conditions when there is a persistent wind from a given direction, the vapor plume from an open water spill of LNG will drift downwind and disperse laterally and vertically. In order to investigate the extent of the potentially flammable plume, the approximate procedure by Turner is used. 1/ This procedure describes the downwind dispersion of gas from an extended area source where the spread has a Gaussian distribution.

In this procedure, area sources are handled by converting them to equivalent or "virtual" point sources. In the conversion process, both the downwind distance and source strength are dependent on the particular source-receptor configuration. In the conversion process, the area is treated as a "virtual" point source with the area source having an initial horizontal standard deviation, σ_{y_0}. A "virtual" distance, Xy, can then be found that will give this standard deviation. Then equations for point sources may be used, determining σy as a function of X + Xy. This concept is illustrated in the following sketch:

1/ D. Bruce Turner, "Workbook of Atmospheric Dispersion Estimates," Environmental Protection Agency, Publication No. AP-26, 1972.



For a square area source σ_{yo} is given approximately by 1/

$$\sigma_{yo} = \frac{s}{4.3}$$

where s = length of a side of the area

For a circular source:

$$\sigma_{yo} = \frac{d'}{4.3} \qquad (5)$$

where d' = diameter of the source measured at the time of consideration.

The expression for σ_z remains unchanged in this treatment because it has been assumed that the emissions within the area are not from varying effective stack heights. Thus, the expressions for σ_y and σ_z can be expressed by:

$$\sigma_y = 465.1 \quad (X + Xy) \tan \theta p \quad 2/ \qquad (6)$$

$$\theta p = c - \left[d \ln \frac{X + Xy}{Xo} \right] \quad 2/ \qquad (7)$$

$$\sigma_z = a X^b \quad 2/ \qquad (8)$$

where

X = downwind distance, km

Xy = virtual distance for initial σ_{yo}, km

θp = half angle of horizontal plume spreading, degrees

1/ Turner, "Workbook of Atmospheric...".

2/ Derived from computer subroutines and other material sent by D. Bruce Turner to Robert Arvedlund of the FPC staff on April 16, 1975.

c, d = functions of stability class, degrees

X_o = normalizing distance, = 1 km

a = function of stability class, meters

b = exponent to determine σ_z, dimensionless

σ_y, σ_z = dispersion parameters, meters

Values of the parameters c and d are given in Table 2. 1/

TABLE 2. Values of c and d Used to Calculate θ_p

Stability Class	Value, degrees	
	c	d
A	24.167	2.5334
B	18.333	1.8096
C	12.500	1.0857
D	8.333	0.72382
E	6.250	0.54287
F	4.167	0.36191

Values of the parameters a and b for the D Class stability condition are given in Table 3. 2/

1/ John R. Zimmerman and Roger S. Thompson, "User's Guide for Hiway, a Highway Air Pollution Model," Environmental Protection Agency, Publication No. EPA-650/4-74-008, February 1975. Also used in Turner's computer subroutine for calculation of σ_y and σ_z values.

2/ Bruce Turner's computer subroutine for calculation of σ_y and σ_z values and followup personal communication between Bruce Turner and Robert Arvedlund of the FPC staff on April 23, 1975.

TABLE 3. Values of a and b Used to Calculate σ_z for D Class Stability Condition

Downwind Distance (km)	a (meters)	b (dimensionless)
0.3 - 1	32.093	0.81066
1 - 3	32.093	0.64403
3 - 10	33.504	0.60486
10 - 30	36.650	0.56589
> 30	44.053	0.51179

The point source equation also is given by Turner, and a simplified version is used here for ground level concentrations along the centerline of the plume. 1/ These simplifications yield:

$$C = \left[\frac{q}{\pi \sigma_y \sigma_z u}\right] \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] \qquad (9)$$

where

C = vapor concentration, gms/m^3

q = average vapor generation rate, gms/sec

σ_y, σ_z = crosswind and vertical standard deviations, meters

u = wind speed, meter/sec

H = effective emission height, meters

1/ Turner, "Workbook of Atmospheric...".

Equation 9 is based on the assumption that the vapor generation rate is constant over the considered period of time. Because the distribution of vapor is Gaussian, the plume dimensions are characterized by the standard deviations σ_y and σ_z, which are functions of the distance downwind. The concentration, C, is taken along the centerline of the plume at ground level as if there were no rise of the center of mass of the vapor as it warms.

In this analysis, the neutral "D" meteorological condition is used from the six stability categories given by Turner. The more stable "E" and "F" categories are normally limited to rural areas on clear nights and having a low wind. Under these conditions, the wind direction shifts frequently and tends to spread the plume horizontally. In addition, it is felt that the more stable "E" and "F" stability conditions would have little effect on a methane cloud with density much less than that of air. The neutral "D" condition is associated with overcast skies during day or night and occurs frequently in maritime climates.

The Pasquill stability classes are for gases, such as sulfur oxide, or aerosols which remain suspended in the air over long periods of time. These materials generally are more dense than the air in which they are undergoing diffusion. Methane, on the other hand, has a density much less than that of air. Thus, it is not entirely clear that the neutral "D" condition is the most appropriate for demonstrating the dispersion of such a light gas. The unstable "C" condition may be more suitable for such a demonstration. This condition gives an upward push to heavy pollutants, and thus may be more representative of the dispersive behavior of a light gas in air.

For all calculations, a 5 mph (2.235 meters/sec) wind is used, since that wind speed is thought to give the longest plumes. Although the use of a lower wind speed would predict a greater range of potentially flammable vapors, in practice, wind speeds below 5 mph are characterized by frequent shifts in direction which tend to increase horizontal dispersion and reduce the downwind range. Stronger winds disperse vapor plumes more readily and make them less of a downwind hazard.

In this analysis, a detailed quantitative treatment of the gain or loss of heat by methane from the air, from vapor condensation, or from solar radiation have been neglected. As previously mentioned, vapor condensation can be important because condensation of moisture releases heat which tends to increase the buoyancy of the cloud. In addition, the plume dispersion is assumed to be undisturbed by nearby land features such as hills, trees, or structures. Also, no consideration is given here to the possibility of plume ignition during its dispersion. The downwind distance to the lower flammable limit (LFL) of methane must now be determined. The LFL is represented by 5 percent concentration of methane vapor and is given by:

$$C = \frac{(.05)\ (\rho)}{620} = 36.6 \text{ gms/m}^3$$

where ρ = liquid LNG density

$= 4.54 \times 10^5$ gms/m^3

<u>For a 37,500-cubic meter spill</u>:

Solution of equation 5 yields

$$\sigma_{yo} = \frac{dn}{4.3} = \frac{2\ (746.5 \text{ meters})}{4.3}$$

$$\sigma_{yo} = 347.2 \text{ meters} \tag{10}$$

From Figure 3.2 of Turner or equations 6 and 7

$$Xy = 6.06 \text{ km} \tag{11}$$

Substitution of equations 6, 7, 8, 10 and 11 into 9 for a 2.235 meter/sec wind speed condition yields:

$$C = \frac{q \quad \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right]}{\pi\ (465.1)(X + 6.06)\tan\left[c-(d\ \ln(X + 6.06))\right]\ aX^b\ (2.235)}$$

where X = downwind distance, km

C = LFL concentration, gms/m^3

q = source strength

H = average effective emission height, meters

$$= \frac{V_{AVG}}{\pi r^2_{AVG}} = \frac{(293.5)(37{,}500 \text{ m}^3)}{(3.14)(596 \text{ m})^2}$$

H = 9.87 meters

At neutral buoyancy, the primary emission rate will be that from heat transfer from the air:

$$q = \frac{hA\ \Delta T}{C_p\ \Delta T} = \frac{(2.9899 \times 10^{-3}\ \text{Btu/m}^2\text{-sec-}^{\circ}\text{F})(\pi r_N{}^2)}{(0.5\ \text{Btu/lb}\ ^{\circ}\text{F})}$$

$$q = 1.0449 \times 10^4\ \text{lbs/sec}$$

$$q = 4.74 \times 10^6\ \text{gms/sec}$$

From Table 1 and by trial and error using Table 2, it can be determined that equation 9 takes on the form:

$$C = \frac{4.74 \times 10^6\ \exp\left[-\frac{1}{2}\left(\frac{9.87}{32.093\ X^{.64403}}\right)^2\right]}{\pi(465.1)(X+6.06)\tan[8.333-(0.72382\ln(X+6.06))]32.093X^{.64403}(2.235)}$$

or

$$C = \frac{45.25\ \exp\left[-\frac{1}{2}\left(\frac{9.87}{32.093\ X^{.64403}}\right)^2\right]}{(X+6.06)\tan[8.333-(0.72382\ \ln\ (X+6.06))]\ X^{.64403}}$$

By trial and error, a downwind distance, X, is found corresponding to a concentration, C, of 36.6 gms/m^3. Solution of this process shows that when X = 1.53 km, the given LFL concentration is found to be approximately 36.6 gms/m^3.

The same procedure can be carried out for various other LNG spill sizes, and these are shown in Table 4 and plotted in Figure 2. Of particular interest are the 1,250 and 25,000-cubic meter spills, which are the single storage tank capacities of the existing LNG barge "Massachusetts" and the 125,000-cubic meter vessels presently under construction, respectively.

TABLE 4

PARAMETERS FOR LNG SPILLS: NEUTRAL "D" CONDITION AND 5 MPH WIND

olume Spilled (10^3 m^3)	Maximum Pool Radius Re (meter)	Time to Evaporation Te (sec)	Cloud Radius To Neutral Buoyancy Rn (meter)	Time From Negative To Neutral Buoyancy Tn (sec)	σ_{yo} (meters)	Xy (km)	X = Downwind Distance to LFL (km)	(miles)	(feet)	σ_y (meters)	σ_z (meters)
100	644	384	1124	114	522.8	9.57	2.82	1.75	9252	657	63
75	578	355	995	103	462.8	8.35	2.35	1.46	7710	577	56
50	496	321	845	91	393.0	6.96	1.85	1.15	6069	485	48
37.5	446	300	746	82	347.2	6.06	1.53	0.95	5019	425	42
25	383	270	632	72	293.9	5.03	1.20	0.75	3937	356	36
10	272	215	435	54	202.3	3.32	0.73	0.45	2395	242	25
5	209	180	323	42	150.2	2.39	0.50	0.31	1640	178	18
1.25	124	128	183	27	85.1	1.28	0.3	—	—	—	—

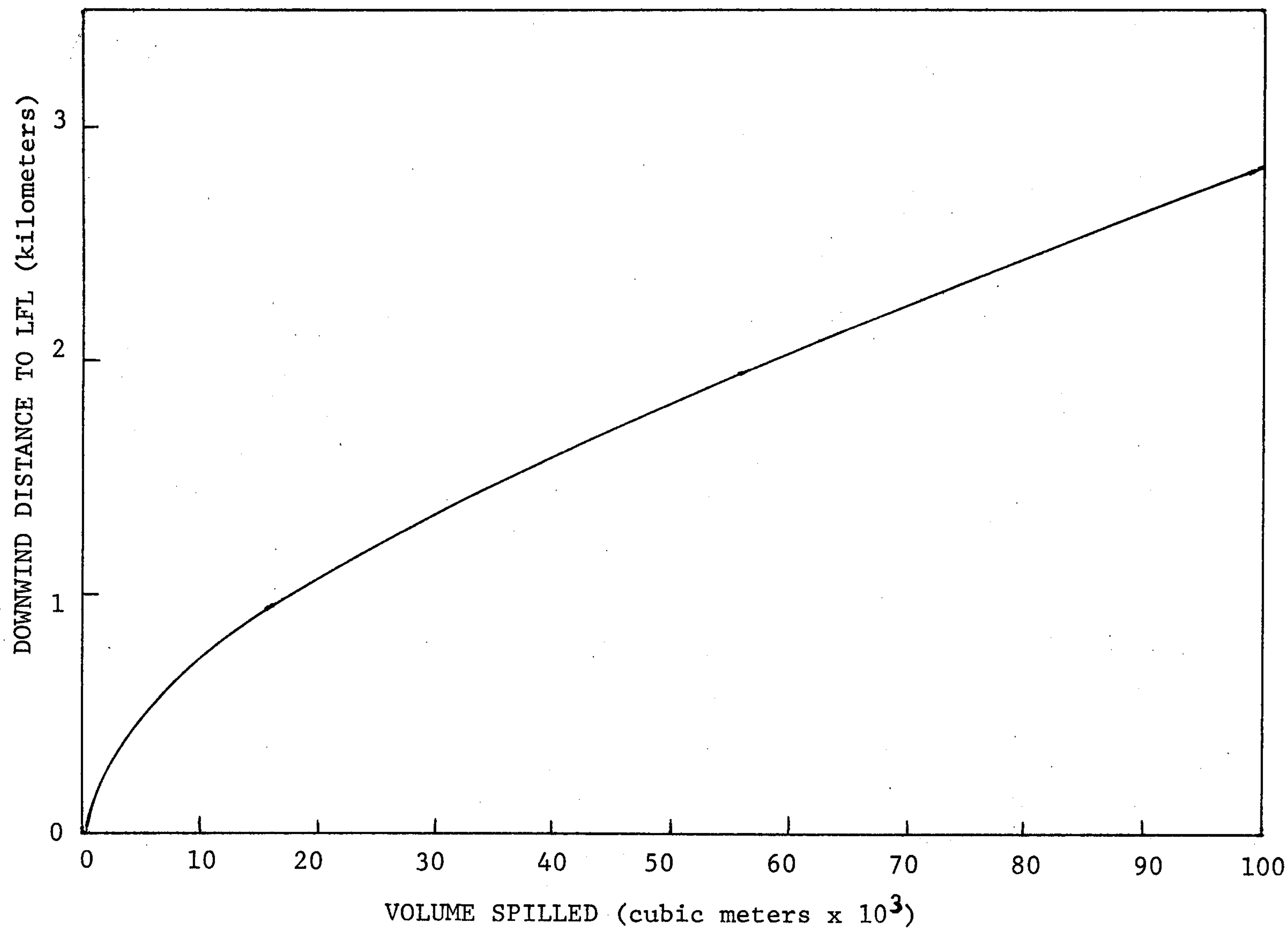


Figure 2

DISTANCE TO LFL FOR LNG SPILLS ON WATER

ATTACHMENT 2

THE RADIATION HAZARD FROM AN LNG FIRE ON WATER

If LNG is released on water, it will spread and evaporate to form a potentially flammable vapor cloud which may then drift to an ignition source. The resulting flame may flash back to the source of the spill, producing a burning pool of LNG. The thermal radiation emitted by this fire may present a serious hazard to the surroundings. Depending on the size and duration of the fire, the radiation may injure or kill people, ignite combustible materials (such as wood, plants, and cloth), and collapse steel or other metal structures from the developed thermal stresses.

In order to estimate the extent of this thermal radiation hazard, it is necessary to know the flame diameter, the angle of flame tilt (due to wind), and the burning rate.

The flame diameter is assumed to equal the pool diameter. Using a gravity spread model, an expression for the burning pool radius as a function of time was developed. The equations for the spread and evaporation of LNG on water as presented in the vapor plume analysis were used. The burning rate was used as the evaporation rate, since the fire actually serves to increase the evaporation rate.

It was assumed that the LNG ignited at or shortly after the beginning of the spill. After ignition, the burning pool spreads at a rate described by the gravity spread equation, equation (1):

$$\frac{dr}{dt} = \left[\frac{kg}{\pi}\left(\frac{\rho_w - \rho_{LNG}}{\rho_{LNG}}\right)\frac{V}{r^2}\right]^{\frac{1}{2}} \qquad (1)$$

Integration yields:

$$r^2 = \left[4\ \frac{kg}{\pi}\left(\frac{\rho_w - \rho_{LNG}}{\rho_w}\right)V\right]^{\frac{1}{2}} t \qquad (2)$$

For a burning pool, using the equations by Raj and Kalelkar:

$$r_e = \frac{7.4(1324125)}{(1.369)^{\frac{1}{4}}} = 1352 \text{ ft.} = 412 \text{ m}$$

The time to evaporation for a burning pool is given by:

$$te = \frac{8.8(1324125)^{\frac{1}{4}}}{(1.369)^{\frac{1}{2}}} = 255 \text{ sec.}$$

At evaporation:

$$\begin{aligned}
\rho_{LNG} &= 28.3 \text{ lb/ft}^3 \\
\rho_w &= 62.4 \text{ lb/ft}^3 \\
&= 32.2 \text{ ft/sec}^2 \\
&= 1{,}324{,}125 \text{ ft}^3 \\
&= 255 \text{ sec.} \\
&= 1352 \text{ ft.}
\end{aligned}$$

$$\text{kevap.} = \frac{(1352)^4}{4(32.2)(.55)(1{,}324{,}125)(255)^2} \doteq 1.72$$

Substituting this into equation (2) yields:

$$r^2 = 7166t \qquad (3)$$

A maximum allowable radiation intensity of 1500 BTU/hr-ft^2 is recommended by Louden 1/ for objects exposed less than 20 minutes. In this case, the duration of the fire is under 5 minutes. Furthermore, using this intensity value as a safety level allows sufficient time for any individuals to seek shelter from the radiation. For these reasons, 1500 BTU/hr-ft^2 was chosen as the safe heat radiation level in this study. In reference to equation (A-1), see Appendix A-1 to this section of the report:

$$E_f = 45{,}000 \text{ BTU/hr-ft}^2$$

$$Q = 1{,}500 \text{ BTU/hr-ft}^2$$

Rearranging equation A-1 and substituting the values of Q and E_f:

$$\tau = .033 \qquad (4)$$

1/ D.E. Loudon, API Proceeding, Vol. 43 (1963), p. 418.

A trial and error calculation was carried out to determine the dimensionless distance, X/R, at which the radiation level dropped to 1,500 BTU/hr-ft^2. The distance, X, is measured from the center of the fire to the radius, R. This value was found to be approximately 7.3. At this point, it should be noted that in determining the view factor, F, the curve for a flame tilt of 15^o was used. This was done because of the lack of data on view factors for upright cylinders. However, this adds some conservatism to the calculations, in that the view factors at a flame tilt of 15^o are approximately 20 percent higher than those of an upright flame. The flame height to radius ratio, L/R, was found to vary from 5.4 to 6.3, so the curve for L/R = 6 was used for all view factor calculations.

Figure 1 shows how the distance from the center of the fire to the safe radiation level varies with time.

Comments on the Vapor Fire Radiation Hazard

The environmental staff has addressed itself to the problem of heat radiation from a burning LNG vapor cloud. Because of limited information on this subject, however, no quantitative results are available at this time. Only two series of experiments have been conducted thus far to study the ignitability of the vapor, and data from them are very limited. From the available information, it was decided that most significant radiation hazard was presented by the pool fire, rather than the vapor fire, because the pool fire emits dangerous heat radiation for a much longer period of time.

When a vapor cloud is ignited, a flame front followed by a burning zone of finite width propagates through the cloud back to the source at a particular velocity. This flame velocity is strongly affected by wind.

The maximum radiant heat emission occurs at the maximum temperature attained by the burning vapor. The maximum temperature occurs at the moment of combustion, after which it decreases with time, as shown in Figure 2. 1/ Since heat radiation is primarily dependent upon temperature, 2/ this graph also shows that radiative heat emission also decreases with time. The result is that the

1/ Science Applications, Inc. "LNG Terminal Risk Assessment Study for Oxnard, California," SAI-75-615-LJ, (Jan. 26, 1976).

2/ W.H. McAdams, Heat Transmission (New York, 1954).

surroundings are exposed to dangerous heat radiation for only a very short period. The maximum heat emission is given by equation (5):

$$E = \sigma T^4$$

$$\sigma = .1714 \times 10^{-8} \text{ Btu/hr-ft}^2\text{-}^{\circ}\text{R}^4 \qquad (5)$$

(the Stefan-Boltzmann constant)

Since E is the emission rate of a "perfect radiator," the actual emission rate is lower. Figure 2 indicates that after only one second, the temperature of the burned gases is about 1500°F. From equation (5), E = 8,677 Btu/hr-ft^2. The actual heat emission would be less. Within seconds, this value would decrease even further, according to Figure 2. This number compares with a value of 45,000 Btu/hr-ft^2 from a pool fire, which is on the order of 4 to 5 minutes in duration. This is over 50 times the exposure time from a burning cloud.

FIGURE 1. DISTANCE FROM CENTER OF FIRE TO SAFE RADIATION LEVEL

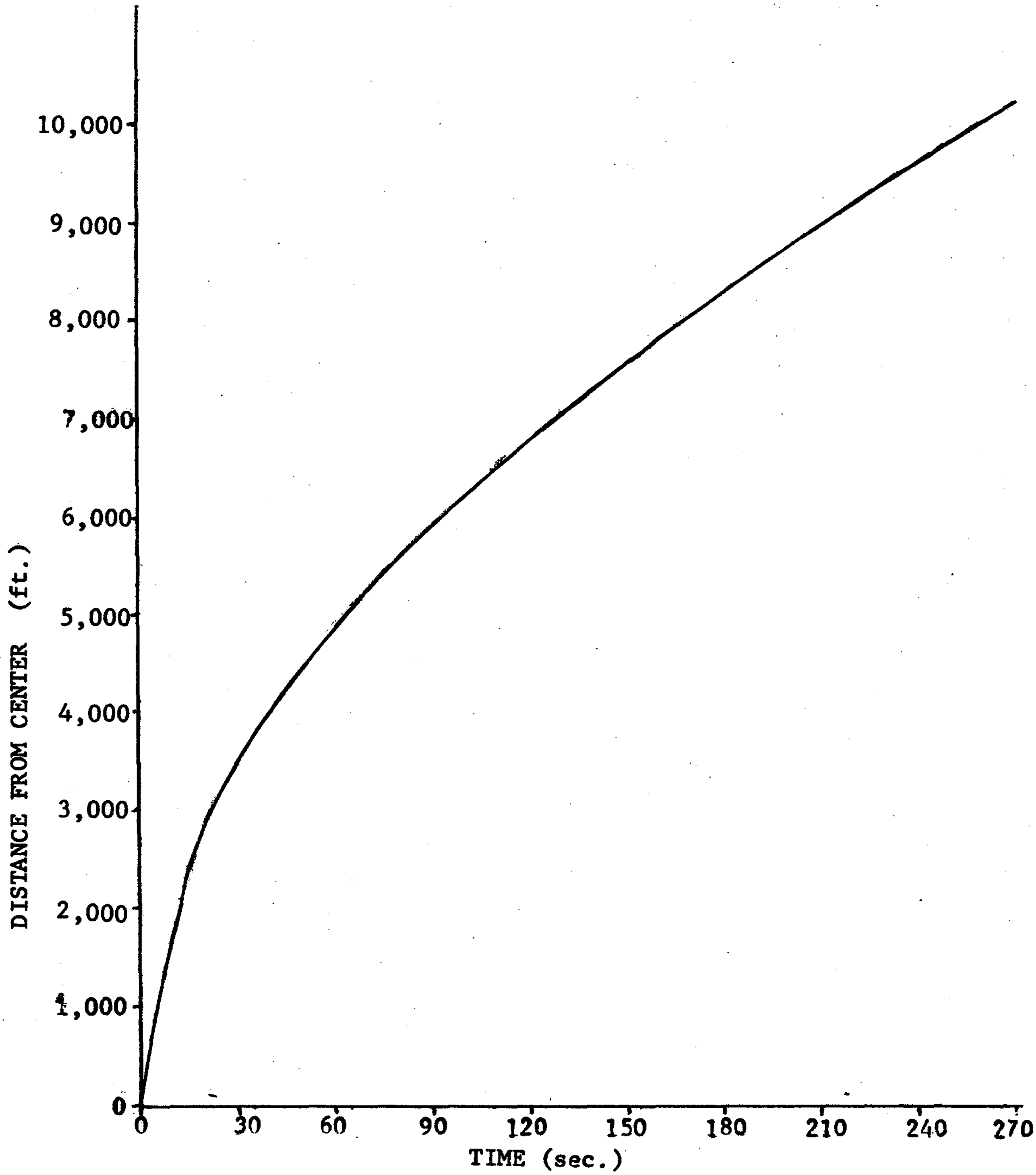
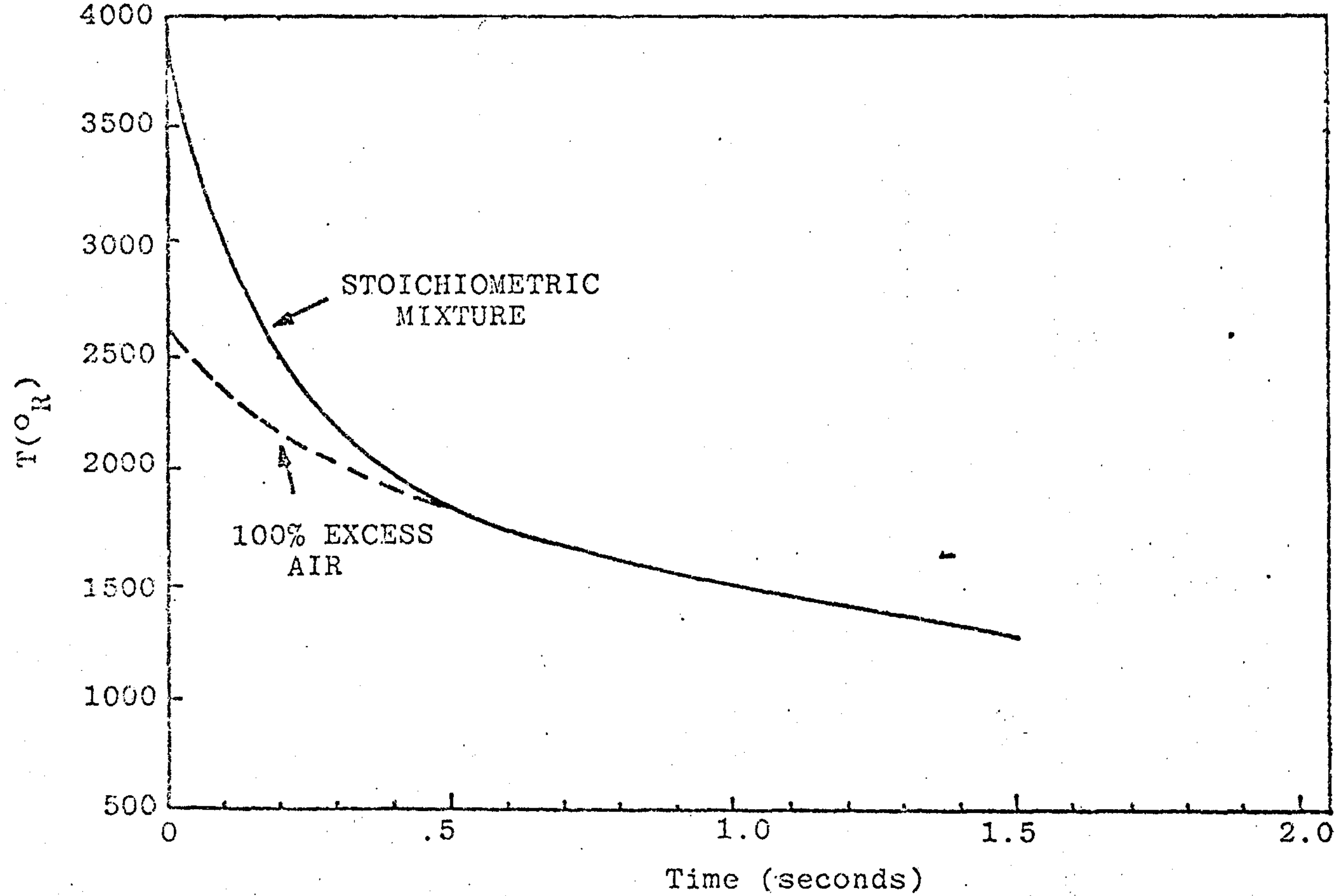


FIGURE 2. TEMPERATURE PROFILES FOR METHANE-AIR MIXTURES



The amount of heat radiated by an LNG fire that is intercepted by an object away from the fire is given by the following equation:

$$Q = F \cdot \tau \cdot \varepsilon_f \cdot E_f \qquad \text{(A-1)}$$

Q = intercepted heat, Btu/hr-ft^2
τ = transmissivity of the intervening air
ε = flame emissivity
E_f = total emissive power of the flame, Btu/hr-ft^2
F = view factor

The view factor, F, is the fraction of energy radiated by the fire that is incident on the object in question.

$$F_{dA_2 \rightarrow A_1} = \int_{A_2} \frac{\cos \beta_1 \cdot \cos \beta_2 \; dA_2}{r^2} \qquad \text{(A-2)}$$

(See Figure A-1 for the definitions of A_1, A_2, dA_2, β_1, β_2, and r.)

When the flame height, diameter, angle of tilt, and the distance between the flame and object are known, equation (A-2) may be used to calculate F. This must be done by computer. 1/ The results are presented in graphical form in Figure A-2.

The angle of tilt, ϕ , is given by equation (A-3).

$$\cos \phi = \frac{1}{\sqrt{u^*}} \quad \text{for } u^* \geq 1$$
$$\qquad\qquad\qquad\qquad \text{(A-3)}$$
$$= 1 \quad \text{for } u^* < 1$$

1/ R.G. Rein, Jr., C.M. Sliepcevich, and J.R. Welker, "Radiation View Factors for Tilted Cylinders," J. Fire and Flammability, (April 1970), p. 140.

where $u^* = {}^{u}/u_c$

u = wind velocity, ft/sec
u^* = characteristic velocity = $\left(\frac{\dot{m}'' g D}{\rho} \right)^{1/3}$

ρ_v = density of the gas at its boiling point, $^{lb}/ft^3$
$\dot{m}''$ = burning rate, $^{lb}/hr\text{-}ft^2$
D = flame diameter
g = 32.2 ft/sec^2

After the angle of tilt is calculated, it is necessary to determine the ratio of flame height to flame radius, L/R. This may be done using equation (A-4). 1/

$$L/D = \left(\frac{\dot{m}''}{\rho_a \sqrt{gD}} \right)^{-0.19} u^{*.06} \quad \text{if } u^* \geq 1$$

$$= \left(\frac{\dot{m}''}{\rho_a \sqrt{gD}} \right)^{-0.19} \quad \text{if } u^* < 1 \qquad \text{(A-4)}$$

ρ = density of ambient air
D = 2R

Figure A-2 may then be used to find F for any distance up to 50 diameters from the fire.

The transmissivity, τ , is a measure of the ability of the intervening air to transmit radiant heat. For a clear, humid day, water vapor will be the primary component of attenuation. Figure A-3 shows how transmissivity varies with distance at several relative humidities. A relative humidity of 50 percent was used in this study.

1/ American Gas Association, "LNG Safety Program, Phase II," Sections F and G (July 1, 1974).

The flame emissivity, ε_f , accounts for attenuation of flame radiation by components of the flame itself. This attenuation can be attributed to the nonluminous contributions of CO_2 and H_2O, as well as the presence of soot. The emissivity may be expressed as equation 5.

$$\varepsilon_f = 1 - e^{-kD} \qquad \text{(A-5)}$$

k = attenuation coefficient
D = flame diameter

The diameter of the flame being considered in this case, however, is so large that the flame may be considered as being "optically thick." In other words, $\varepsilon_f = 1$.

The total emissive power, E_f, is the maximum radiant heat flux at the flame surface that a fuel can release upon combustion. This quantity must be measured experimentally. For an LNG pool fire, a value of 45,000 Btu/hr-ft^2 has been measured.

The burning rate of LNG, m", is controlled by heat received from the water on which the pool is floating and from flame radiation. It has been noted that the regression rate of LNG on water is 1 inch per minute. This corresponds to an evaporation rate of 141.5 lb/hr-ft^2. 1/ The regression rate due to radiation is estimated by Raj and Atallah 2/ as .369 in/min. This corresponds to a burning rate of 52.2 lb/hr-ft^2. The total rate is the sum of the two, or 193.7 lb/hr-ft^2.

1/ D.S. Burgess, J.N. Murphy, M.G. Zabetakis, "Hazards Associated with the Spillage of Liquefied Natural Gas on Water," Bureau of Mines Report No. 7448 (1970).

2/ See footnote 1 on 3rd. preceding page.

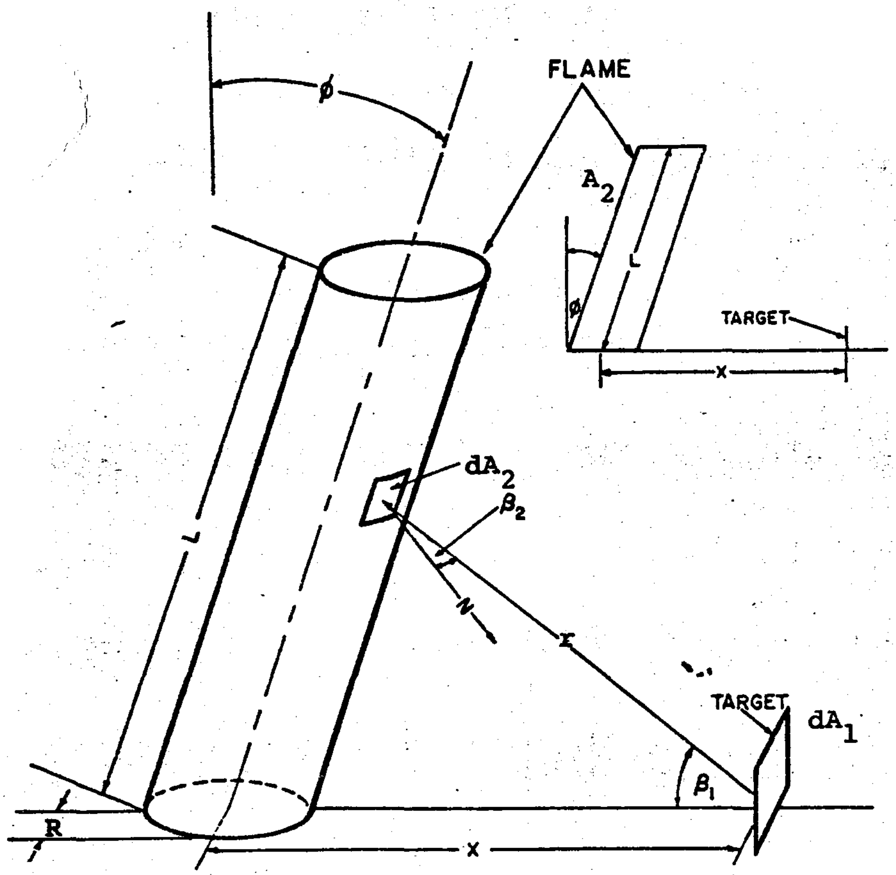


FIGURE A-1. GEOMETRY USED FOR CALCULATION OF VIEW FACTORS

FIGURE A-2. VIEW FACTORS FOR TILTED CYLINDERS, ϕ =15 degrees

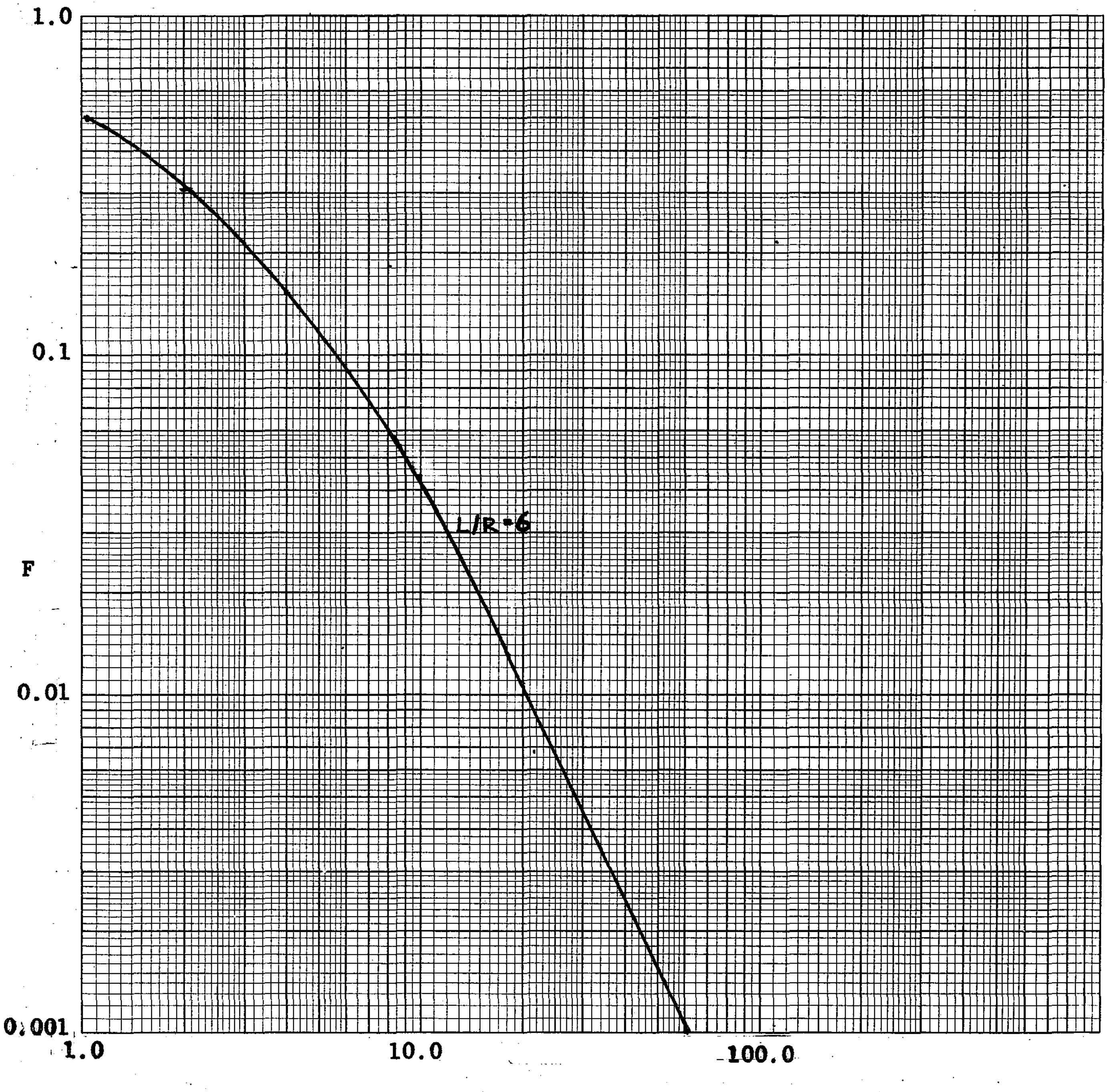
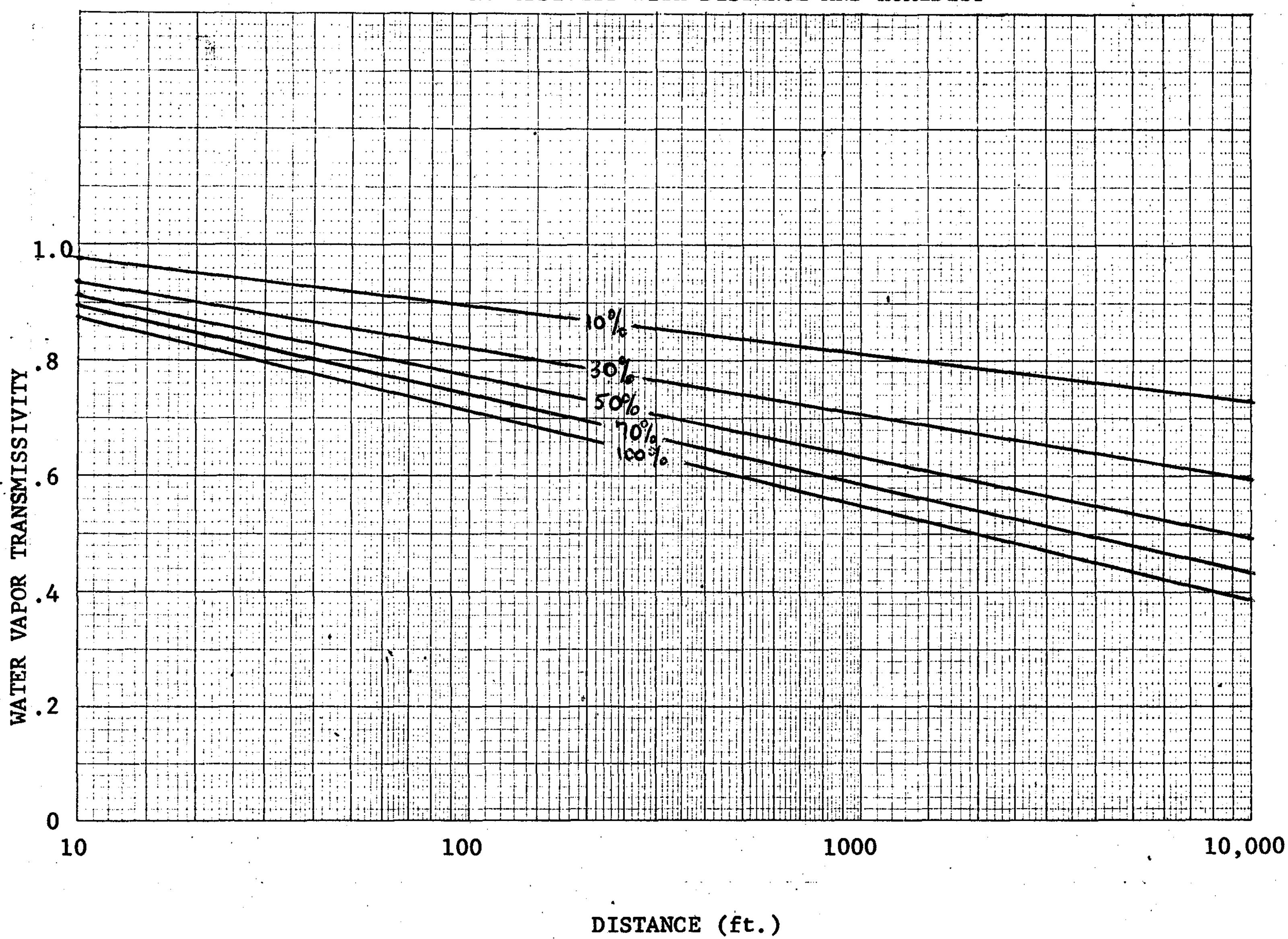


FIGURE A-3. VARIATION OF TRANSMISSIVITY WITH DISTANCE AND HUMIDITY



MAXIMUM PROBABLE FATALITIES FOR POPULATED AREAS

As a flammable vapor cloud advances over a populated area, an increasing segment of the public would be exposed to a hazard. At the same time, the cloud also encounters an increasing number of ignition sources with the result that the probability of the plume remaining unignited approaches zero.

For a flammable vapor cloud encountering independent sources of ignition (N), the probability of no plume ignition ($\overline{P}$) is the product of the individual probabilities of no ignition ($\overline{P}_s$) for each of the N sources:

$$(1)\quad \overline{P} = (\overline{P}_{s1})\ (\overline{P}_{s2})\ \ldots\ (\overline{P}_{sN})$$

When it is assumed that the probability of ignition is the same for all of the sources, the probability of no plume ignition in N sources becomes:

$$(2)\quad \overline{P} = (\overline{P}_s)^N$$

The probability that the plume will have been ignited (P) after encountering N sources is:

$$P = 1 - \overline{P}$$

$$(3)\quad = 1 - (\overline{P}_s)^N$$

The probability of no plume ignition versus the range of the plume has been plotted in Figure 1 for three values of $\overline{P}_s$: .50, .96, and .99, assuming an ignition source density of 500 sources per square kilometer. The figure illustrates that the probability of plume ignition is very sensitive to the value assumed for the probability of ignition for each source. However, for even the most conservative value, $\overline{P}_s = .99$ (each source has only a 1 percent probability of igniting the plume), the probability of no plume ignition after extending over area of one square kilometer is about .007. After covering three square kilometers, the probability of no plume ignition is less than 10^{-6}. The probability of ignition per source of one percent is considered to be very conservative. This value has been selected for the study since it permits a flammable vapor cloud to affect a larger area before ignition becomes a certainty.

When it can be assumed that both population and ignition sources are uniformly distributed within an area, the probability of no plume ignition and the number of fatalities can be illustrated as in Figure 1. The probable number of fatalities can be related to the product of these two variables. At the point where the product is maximum, the probable number of fatalities is also maximum. Although a greater plume area would yield a higher number of fatalities, the probability of no plume ignition rapidly vanishes.

The product of the expected fatalities (F) and the probability on no plume ignition can be expressed as:

(4) $F \quad (\overline{P}_s)^N$

In order to determine the maximum value of this product, it is necessary to relate fatalities to ignition sources. This can be accomplished when both the density of population (D_p) and the density of ignition sources (D_s) can be estimated. When it is assumed that the entire population within a plume is a fatality:

(5) $F = \dfrac{D_p}{D_s} N$

The maximum of the product occurs at the point where the first derivative is equal to zero:

$$\frac{d}{dn} \quad F \, (\overline{P}_s)^N = 0$$

$$\frac{d}{dn} \quad \frac{D_p}{D_s} \quad N(\overline{P}_s)^N = 0$$

(6) $N \max = -1/\ln\, (\overline{P}_s)$

When $\overline{P}_s = .01$
$N \max = 99$

Having determined Nmax, the maximum probable fatalities within the plume can be estimated from equation 5. The density of population within a study area can be estimated from 1970 census tract information from the U.S. Department of Commerce Census Bureau. Population growth projections are frequently made by local governments and these figures should be used when the information is available.

Very little information currently exists on the density of ignition sources on land areas. Recent studies by Science Applications Incorporated estimated the density of ignition sources in Los Angeles and Oxnard based on aerial photographic maps. 1/ The study estimated ignition source densities of 500 sources/square kilometer in residential areas; 100 sources/square kilometer in industrial areas; and 20 sources/square kilometer on Terminal Island, Los Angeles.

Nomenclature:

P_s	=	Probability of ignition for an individual source
$\overline{P}_s$	=	Probability of no ignition for an individual source
	=	$1 - P_s$
N	=	Number of individual ignition sources
P	=	Probability of plume ignition
$\overline{P}$	=	Probability of no plume ignition
	=	$1 - P$
F	=	Number of fatalities
D_s	=	Density of ignition sources
D_p	=	Density of population

1/ Science Application Inc., "LNG Terminal Risk Assessment Study for Los Angeles, California, "Report No. SAI-75-614, LJ, December 22, 1975 Draft.

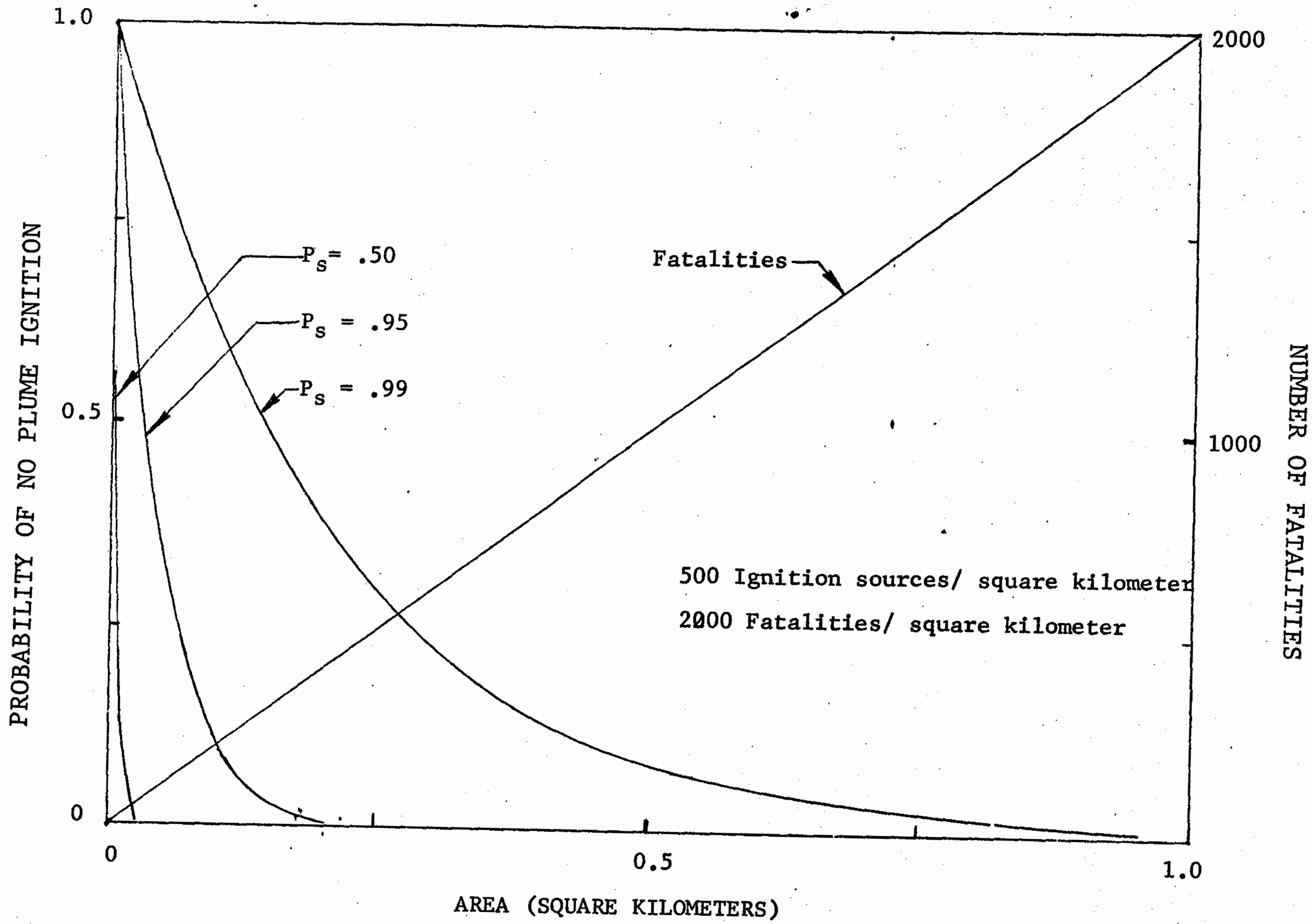


Figure 1

PROBABILITY OF NO IGNITION VERSUS AREA

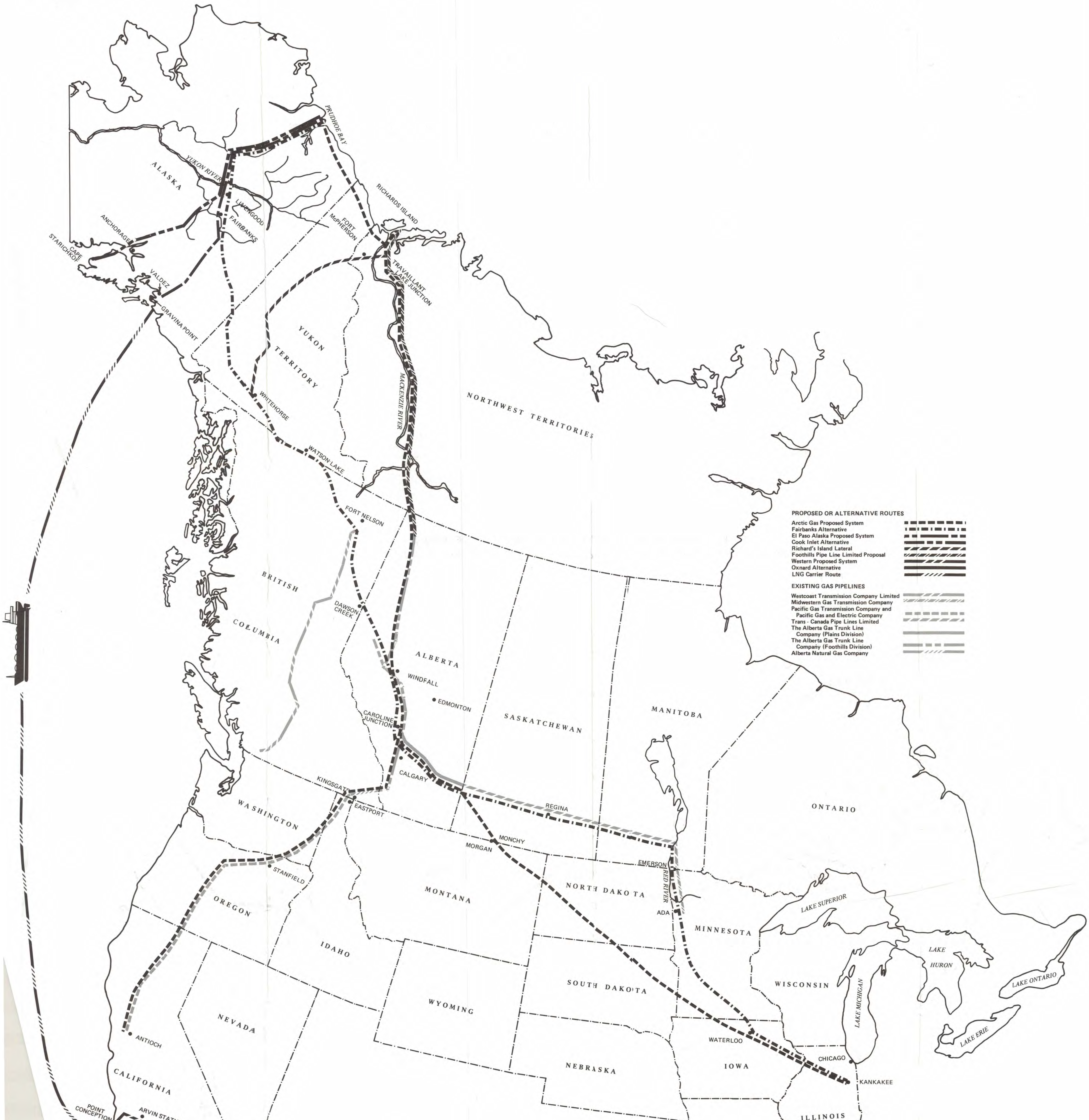


Figure 1. Applicants' Proposed and Environmental Staff's Preferred Alternative Pipeline Systems for the Delivery of Natural Gas from the North Slope of Alaska and the MacKenzie Delta of Canada.