SCOMM

28:27

Re: Dow-Shell Petrochemical Feasibility Study 9/5/80

COMMISSIONER'S FINDINGS

Under the authority invested through AS 38.05.020(b)(2), the Commissioner of Natural Resources may enter into agreements he considers necessary to carry out the purposes of the Public Lands chapter. In September , 1980, and after an extensive public process to be described hereinafter, the State of Alaska, acting through its Commissioner of Natural Resources, and Dow Chemical U.S.A. and/or Shell Chemical Company, together with "Participants" Alaska Interstate Company, Asahi-Dow, Ltd., Doyon, Ltd., E.I. duPont de Nemours, Earth Resources Company of Alaska, Mitsubishi Chemical Industries, Ltd. and Mitsubishi Corporation, and "Affiliate" Alaska Interior Resources Company will enter a Memorandum of Understanding and Intent. All the companies together, operating as the Dow-Shell Group (DSG), agreed to take certain actions toward the ultimate goal of establishing, if feasible, an in-state industry using natural gas liquids from Prudhoe Bay. A copy of the agreement is attached.

The State has demonstrated a long term interest in maintaining options and improving opportunities for future petrochemical manufacturing in Alaska. The State's Prudhoe Bay oil and gas leases require that one-eighth of all oil and gas produced under lease be granted to the State as royalty. As a matter of both law and policy, the State's foremost priority is that its royalty hydrocarbons be processed inside the State and that the products be distributed first within the State before product or raw material export takes place. Prudhoe Bay gas production is scheduled to commence within the next decade, probably by 1986. Approximately 2 billion cubic feet per day of sales gas will be produced for the 2-to-25 year life of the field, with the State's royalty share averaging 250 million cubic feet per day. On this date, no disposition of the State's royalty gas (methane) or royalty gas liquids, including ethane, from the Prudhoe Bay field unit, remains in effect.

The State has long supported making natural gas liquids available as feedstock for petrochemical manufacturing in Alaska. The State's attorneys, for example, have attempted to keep petrochemical development options open during the ongoing Federal Energy Regulatory Commission (FERC) hearings on gas pipeline issues. The State has consistently argued, in addition, that piecemeal disposition of the issues affecting availability of natural gas liquids is counterproductive and that the pipeline pressure issue should have been considered simultaneously with the issues of CO2 level and butane disposal.

On August 6, 1979, FERC issued its Order Approving Alaska Segment Design Specifications and Initial System Capacity.

In response to widespread concern about the implications of FERC's action, the Governor appointed a Working Group on Natural Gas Conditioning, with membership from the Administration, the Legislature and the municipalities. After a series of meetings in August and September at which the group identified issues surrounding instate use of royalty gas and royalty gas liquids, and development of an instate petrochemical industry, the Governor's Working Group resolved the following at its September 21 meeting: (1) the subcommittee's reports, as approved by the full Working Group, be transmitted to the Governor as the preliminary report; (2) the Governor be requested to determine the present day feasibility of an instate petrochemical industry, particularly by actively contacting and sol ...ing the interest of major petrochemical companies with regard to the feasibility of such development; and (3) the Governor be requested to preserve the State's options by requesting the FERC to re-open for hearing the project's size and pressure issue and, failing that, filing an appeal of the FERC size and pressure order in federal court no later than October 5, 1979. The Working Group's September 21 resolution was accompanied by another asking the Governor to continue the Working Group by allowing its members to serve as ex officio members of the Legislature's Joint Gas Pipeline Committee.

The Administration responded to the recommendations of the Governor's Working Group by authorizing the State's attorneys to file suit in U. S. District Court to overturn the FERC size and pressure order issued August 6. In addition, in late October and early November, 1979, Administration representatives and members of the Legislature met with North Slope gas producers, petrochemical firms, Northwest's investment advisors, congressional members and federal agency representatives to discuss the gas pipeline project and potential petrochemical development.

FERC public hearings on the Draft Environmental Impact Statement for the Prudhoe Bay project gave Alaska citizens and officials the opportunity to comment publicly on September 4 and 5, 1979, on the petrochemical development issues, such as location of the gas conditioning plant and availability of natural gas liquids. At issue were the conclusions and much of the content of FERC's Draft Environmental Impact Statement released July 27, 1979.

At the November 21, 1979 meeting of the Legislature's Joint Gas Pipeline Committee, Attorney General Avrum Gross announced the State's intention to seek formal proposals for petrochemical development. The Committee, with the Governor's Working Group, endorsed a resolution concerning Alaska's securing gas liquids for use in an Alaska petrochemical industry, and also endorsed a proposed schedule for further administrative action for acquisition and delivery of gas liquids and development of a related industry. Copies are attached.

The four Alaska mayors also reiterated their position on potential petrochemical development and State participation in the gas pipeline project. First, they supported maximum instate use of gas liquids. Second, they believed acquisition of liquids is the only basis for state financing of the gas pipeline. And, third, they urged the State to take the lead in purchasing negotiations of the producers' liquids.

In response, the Administration continued its conversations with producers concerning the possibility of an option to purchase, or an outright purchase, of all or a part of the producers' processing rights to Prudhoe Bay gas. By June of 1980, the State had received formal replies from the three major Prudhoe Bay gas producers (Exxon, Atlantic Richfield, and Sohio-BP), which indicated their willingness, under certain conditions, to enter into good faith negotiations with a financially responsible major petrochemical concern sponsored by the State of Alaska (copies attached). Exxon Chemical Company later indicated its intention of completing a major feasibility study to determine the economics of a gas based petrochemical industry in Alaska.

In January, 1980, Governor Hammond reconstituted the working group as the Alaska Natural Gas Task Force. Lt. Governor Terry Miller was named to chair the Task Force whose membership included the Commissioners of Revenue, Natural Resources, and Commerce, the Attorney General, four legislators and five mayors. At that time the State anticipated that the Phase I Letter of Intent for the Northwest Gas Pipeline Project would be signed by the Northwest partnership and the producers by February 1.

The role of the Task Force was to evaluate and monitor the developing plans for the Phase I design of the gas pipeline, particularly with respect to its impact on potential development of instate petrochemical facilities. Negotiations for the Phase I Letter of Intent, however, were slower than originally anticipated, with the parties signing the document on June 20, 1980. Accordingly, the role of the Governor's Task Force became focused on the State's solicitations for gas liquids development and selection of a company or companies to receive the State's backing for a feasibility study of petrochemical development.

On February 4, 1980, the Governor issued a "Solicitation of Interest" to more than seven hundred firms potentialy interested in development projects using Prudhoe Bay gas liquids. Firms were to respond to the initial solicitation by February 15; the deadline was later extended to March 30 at the request of several companies.

Spring, 1980, activities included the approval by the Joint Gas Pipeline Committee of a proposed FY 81 budget for studies and continued activities relating to the gas pipeline and petrochemical development. Administrative and legislative support was given to inclusion to the proposed funding in the State budget.

The Governor's Natural Gas Task Force continued its meetings, receiving updates on the Washington, D. C. gas pipeline project negotiations, firms' responses to the solicitation of interest, and proposed budget. In March, 1980 I issued a "Further Solicitation" to the firms that responded affirmatively to the initial solicitation.

In June, 1980, the State received several formal proposals in response to its "Solicitation" and "Further Solication." The firms and individual responding included Alaska Arctic Resources Group; Dow/Asahi-Dow, with Shell Petroleum; Earth Resources/Mitsubishi; Nissho-Iwai Group; Phillips Petroleum; Alaska Interior Resources; and Jerry McCutcheon. Exxon Chemical Company also indicated its intention of conducting its own independent examination of the feasibility of an Alaska petrochemical industry.

On July 18 and 19, 1980, the petrochemical firms made public presentations to the Governor's Task Force on their formal proposals. The public presentations were followed on August 7 by public hearings on the proposals in Fairbanks and Anchorage. Following the public hearings, a subcommittee of the Task Force (Lt. Governor Terry Miller, Commissioner LeResche, and Mayor Carlson) entered into initial negotiations with the petrochemical groups. At an August 15, 1980 meeting of the Task Force, the group moved to continue negotiations with three of the proposers: Dow/Shell; Alaska Arctic Resources Group; and Phillips Petroleum. Further negotiations the week of August 18-25 led to Phillips Petroleum withdrawing from the selection process and negotiated "Letters of Understanding and Intent" drawn up between the State and the Dow/Shell Group, and the State and Alaska Arctic Resources. The Governor's Task Force met again on August 28 to review the proposed Letters of Intent and to again consider the basic proposals, and at that time, decided to recommend Dow/Shell to the Governor as the group the Task Force recommends to complete a feasibility study of an instate gas-based petrochemical industry.

PURPOSE AND FINDINGS

The purpose of the memorandum of understanding and intent is to facilitate the wise development of Alaska's royalty gas liquids by providing means and procedures calculated to promote private economic growth consistent with applicable environmental standards and public fiscal stability. Alaska statutes provide that, at an appropriate time, the State will take, if possible, its royalty gas liquids in kind rather than in value. Alaska statute further provides that the sale of royalty hydrocarbons be by competitive bid except when the Commissioner determines that the best interest of the State does not require it.

Certain unknowns make it impossible to prudently dispose of the State's Prudhoe Bay royalty gas and royalty gas liquids at this time. These unknowns include: the yet undetermined value of the gas liquids; the uncertain economic feasibility of a gas-based petrochemical industry in Alaska, the financial and operational impacts, if any, of gas-based petrochemical development on the gas pipeline project; the impacts, such as field fuel requirements and line routing requirements, of gas-based petrochemical development on the TAPS line; timing of gas sales and delivery through the gas pipeline; and ownership and operation/management of the Prudhoe Bay gas conditioning plant.

At the same time, however, that many unknowns make final disposition of the State's Prudhoe Bay royalty liquids unwise at this time, other factors make it vital that the State take decisive actions to maintain the possibility and maximizing the probability of future gas-based petrochemical development. The Phase I agreement between the producers and the Northwest Pipeline sponsors has provided the gas pipeline project with a significant step toward a speedier completion of pipeline engineering and design. A bid package for a contractor to prepare the Phase I design work has been prepared and distributed to bidders. The signing of the contract and initiation of design work for the gas pipeline, including the gas conditioning plant, is scheduled for October 1, 1980. Selection of a gas conditioning process is set for February 1, 1981, with bids prepared for major equipment purchases by June 1, 1981. In other words, the timeline for the natural gas pipeline project has been set; the decisions made within the next few months will have a determinative effect on the options of a gas-based petrochemical industry.

Industry representatives and others examining the potential for petrochemical development in Alaska have often stated that project economics may demand that the entire volume of Prudhoe Bay natural gas liquids be available for use in the project. Securing a sufficient quantity of natural gas liquids, obtaining needed design changes on the gas conditioning plant to maximize liquids recovery, and obtaining design changes, if needed,on the gas pipeline itself will all require cooperative efforts by the producers, the Northwest partnership, the petrochemical firms and the State. Coordination of potential petrochemical development with gas pipeline and gas conditioning plant design, construction and operation is vital to resolving satisfactorily the issues of field fuel options, conditioning plant location, conditioning plant design, pipeline pressure and pipeline CO2 level. Linking the petrochemical feasibility studies with the on-going gas pipeline design work thus becomes a crucial factor in protecting the opportunities for instate petrochemical development.

A second major crucial factor is the ability of the petrochemical firms to negotiate with the producers to acquire producers' liquids, as there is common agreement that the State's royalty gas liquids alone are not sufficient feedstock for an economically sound petrochemical venture. The short critical timetable and the need for close cooperation and/or negotiations with the gas producers led the Task Force and myself to making a decision to recommend only one company to continue with a petrochemical feasibility study. The DSG has agreed to immediately negotiate contracts(s) with North Slope producers for the purchase of natural gas liquids. It has also agreed to provide appropriate engineering expertise to the State during the conditioning plant and gas pipeline design process, and to the State's contractor for the liquids pipeline design/cost study. In addition, DSG has specifically committed to providing an analysis of the Selexsol gas conditioning process and the Sulfinol gas conditioning process during conditioning process during conditioning plant design.

Another factor in the decision to select only one company rather than to continue working with two or more companies was the position taken by the firms. The Alaska Arctic Resources Group stated that it would not be willing to continue its work in this area if more than one company were selected; the DSG maintained that it would continue, but on a reduced basis, its efforts at examining instate petrochemical feasibility, were more than are group chosen. The selection of only one group to continue with a petrochemical feasibility study, however, does not bind the State in any way to ultimately negotiate a royalty liquids sales agreement with that group. As is explicitly stated in the Memorandum of Understanding and Intent, the State reserves the right to determine after the submittal of the feasibility study if the DSG project is in the State's best interest and if the State's royalty gas liquids should be sold to DSG. The Memorandum also cites provisions which would be included in any sales agreement for the State's royalty gas liquids, including pricing and instate use provisions. The memorandum also emphasizes that the State reserves the right to act in its best interests, require due diligence from DSG and prohibit DSG from assigning the memorandum without first obtaining the written consent of the State.

In making a final determination as to whether to negotiate a royalty gas liquids sales agreement between the State and DSG, I must consider the criteria cited in AS 38.06.070: the basic economic feasibility of the project; the revenue needs and projected fiscal condition of the State; the existence and extent of present and projected local and regional needs for gas products and by-products; the desirability of localized capital investment; increased payroll, secondary development and other possible effects of the sale, exchange or other disposition of royalty gas liquids; the projected social impacts; the projected additional costs and responsibilities which could be imposed upon the State and affected political subdivisions by the project; the projected positive and negative environmental effects; the projected effects of the project upon existing private commercial enterprise and patterns of investments; and the potential processing and sale of products instate. This consideration cannot be competently made without facts that will become available during the next 12-18 months, as a result of the feasiblity study, state studies, and work done by and decisions made by the Design and Engineering (Phase I) Board, the pipeline partnership, and the producers.

Robert E. LeResche

Commissioner

5 September 1980

Date

Alaska State Legislature

Gas Pipeline Committee
1024 W. 6th Avenue
Anchorage, Alaska 99501
(907) 279-1243

September 30, 1980

Dear Member of the natural gas or pipeline industry:

Attached is a request for proposals to study the design and costs of the extraction and transportation of Prudhoe Bay gas liquids to an instate petrochemical facility. The study is sponsored by the Gas Pipeline Committee of the Alaska State Legislature. Its results will be used by state policy-makers, and the cost estimates will be used to aid private industry in making investment decisions.

We would appreciate your consideration of the research project, and look forward to the receipt of your proposal. Please contact me at the above address, if you have any questions.

Sincerely,

Mark Wittow

Mark Wittow
Study Manager

Senator Mike Colletta
Representative Bill Miles
Co-Chairmen

REQUEST FOR PROPOSALS - ALASKA STATE LEGISLATURE

GAS LIQUIDS LINE STUDY

This is a request for proposals of study of the engineering, design, construction and operation, and respective cost estimates, for a natural gas liquids (NGL) pipeline (and related extraction facilities) for transportation of Prudhoe Bay liquids to an instate petrochemical facility. The construction and operation cost estimates are to be used to establish realistic cost-of-service or tariff figures which shippers, producers, gas transmission firms, and others can use to make an investment decision.

I. BACKGROUND

Gas production from Alaska's Prudhoe Bay will commence within the next decade, probably by 1986 or 1987. Approximately two billion cubic feet per day of sales gas will be produced for the 20 to 25 year life of the field. The volume of ngls, including ethane, will be approximately 150,000± b/d. The State and private industry have demonstrated a longterm interest in examining opportunities for future gas-based petrochemical manufacturing in Alaska. The State recently entered into a Memorandum of Understanding and Intent with a petrochemical consortium headed by Dow Chemical U.S.A. and Shell Chemical Company. The Dow-Shell Group has agreed to undertake an indepth feasibility study of an instate petrochemical industry.

The study to be conducted through this Request for Proposals focuses, however, on one segment of the proposed instate industry, the transportation of the gas liquids to the facility site.

II. STUDY SPONSOR

The research will be conducted in consultation with the Joint Gas Pipeline Committee of the Alaska State Legislature. Mark Wittow will be the day-to-day study manager for the committee.

III. STUDY SCOPE

The goal of the study is to establish reasonable cost estimates for construction and operation of a gas liquids pipeline to transport Prudhoe Bay liquids to an instate petrochemical facility site. In addition, the study should identify costs of liquids extraction at Prudhoe Bay or other extraction points on the Alaska Natural Gas pipeline. The study should indicate realistic cost-of-service or tariff figures for the various transportation scenarios.

A. assumptions

The study should be based on the assumption that construction of the petrochemical system will be completed no earlier than 1986. The life of the liquids line should be calculated at 20 to 25 years, concurrent with the life of the Prudhoe Bay field. Phased-in construction of one to three world-scale (1 billion pounds/year) ethylene plants built to come on line four years apart should be assumed. The study should be based on the ultimate maximum economic utilization of recoverable ethane for ethylene production. Cost estimates should be in nominal dollars. For the purposes of this study, natural gas liquids is defined so as to include ethane. To the extent technically feasible, it should be assumed that the liquids line will follow the routing of the Trans-Alaska Pipeline System.

B. <u>cases/scenarios</u>

The following cases should be examined:

1. Modified conditioning plant at Prudhoe Bay, additional low temperature refrigeration added to current Parsons design for the conditioning plant, with no liquid fractionation. A separate NGL line would be constructed from Prudhoe Bay to a tidewater location, with ethane then delivered to ethylene plant(s). The tidewater locations include the following: Kenai, North Cook Inlet, Point Gravina, and Valdez. The cost estimate should include the costs of liquids extraction equipment designed to take out 30,000 b/d of ethane at Prudhoe Bay for each ethylene plant, with either one, two or three ethylene plants ultimately being phased into production.

2. Modified conditioning plant at Prudhoe Bay, with additional low temperature refrigeration added to current Parsons design for conditioning plant and no liquid fractionation. A separate NGL line from Prudhoe Bay to Fairbanks, with ethylene complex at Fairbanks, and the rest of the liquids delivered in another liquids line to tidewater for export. Tidewater sites are the sa e as in Case No. 1 above.

3. Conditioning plant at Prudhoe Bay remains the same as designed by Parsons, with approximately two billion cubic feet per day of conditioned gas delivered to the Alaska Natural Gas Pipeline. At Fairbanks, the ethane and propane-plus are extracted and placed in a liquids pipeline and transported to a tidewater petrochemical facility site. The tidewater sites are the same as in Case No. 1 above.

C. cost considerations

The Contractor will want to examine the following possible construction and operating cost consideration:

1. Cost of delivery of construction materials, including size and weight limitations of transportaton by Alaska Railroad for equipment shipments to Fairbanks and elsewhere, and barge transportation constraints.

2. Labor costs.

3. Construction cost adjustment factors for different locations in Alaska (Prudhoe, Fairbanks/the Interior, and tidewater sites) as compared to a U.S. Gulf Coast facility.

4. Adverse effect, if any, of major construction demands of the Alaska Natural Gas Pipeline system and related facilities which could require most readily available resources and thus impact construction costs for other facilities during the same time period.

5. Costs of special environmental requirements, if any, for potential routing and siting.

6. Penalties for reduction of BTU's in the Alaska Natural Pipeline stream (NGL shrinkage charges).

7. Wellhead values, state severance taxes and Alaska Natural Gas Pipeline BTU/mile tariff for those liquids recovered at Fairbanks.

8. Conditioning plant tariff.

9. Extraction plant cost, probably allocated to the recovered NGL on a liquid volume basis.

The study results should indicate the varying costs associated with only one ethylene plant in operation, with two ethylene plants in operation, and with three ethylene plants in operation. If the phased-in construction would appear to indicate a phased-in cost-of-service or tariff rather than a steady tariff over the life of the liquids line, that too should be clearly indicated.

D. additional work

In a separate section, the Contractor shall also examine the construction and operation costs of an all-methanol line from (a) Prudhoe Bay to Fairbanks and (b) Prudhoe Bay to tidewater.

IV. OTHER RESEARCH WORK

The Contractor will be furnished with other applicable research work done to date. Prior work has delineated the rate of gas production at Prudhoe Bay, and the various possible compositions and volumes of the gas stream. Other work has delineated probable pipeline sizes.

V. OTHER CONTRACT PROVISIONS

(A) At least two on-site consultations will be required. The first will take place at the study's outset for research design, and the second before the submission of the final report for a review of the draft report. Each consultation may require two days. Contract proposals should also discuss the ability of the contractor to provide continuing technical advice and assistance to the State after completion of the final report.

(B) The study will become the property of the State of Alaska.

(C) The study must be written in language and style readily understood by persons who are not economists or gas transmission experts.

(D) Ten copies of a final report and one original that can be readily duplicated must be submitted. Ten copies of the draft report must also be submitted.

VI STUDY TIMEFRAME

Proposals must be received no later than October 31, 1980. A bid will be awarded no later than November 14, 1980. Preferably by December 1, 1980 a research work program will be finalized, and by February 20, 1980 the draft report will be submitted for review. An on-site consultation with the study manager would occur the ensuing week, and a final report prepared and submitted no later than March 20, 1980. The deadlines cited above may be treated as approximate ones.

VII COSTS

A maximum of $200,000 has been allocated for this study. Bids exceeding this amount will not be considered on the same basis as bids within the cost limit.

VIII CONTENTS OF PROPOSALS

For full consideration, the proposal should contain the following:

A. a general description of proposed methodology

B. vitae of principals who would be assigned to the project, with proposed allocations of responsibility and time

C. summary of comparable work performed by the firm with references and samples, if available for public release

D. timeframes as closely corresponding with those cited above as can be feasibly met by the firm

E. a cost quotation

F. general informational material on the firm

G. A description of contacts with the following companies that may pose a conflict of interest:

Northwest Energy Co.
American Natural Resources Co.
Northern Natural Gas Co.
Panhandle Eastern Pipe Line Co.
United Gas Pipeline Co.
Pacific Lighting Corp.
Pacific Gas & Electric Co.
Columbia Gas System
Texas Eastern Corp.
Texas Gas Transmission Corp.
TransCanada Pipelines Ltd.
Foothills Pipe Lines, Ltd.
Alberta Gas Trunk Line Co. Ltd.
West Transmission Co. Ltd.
Atlantic Richfield Corp.
Sohio Corp.
Exxon Corp.
Mobil Corp.
Chevron Corp.
Phillips Corp.
Dow Chemical Co.
Shell Oil Corp.

IX. EVALUATION

The proposals will be judged on the basis of the quality of the proposed methodology, the experience and involvement of the principal investigators, cost and timeframe.

If you have any questions, please contact Mark Wittow, Study Manager, Joint Gas Pipeline Committee, 1024 West Sixth, Anchorage, Alaska 99501, phone (907) 279-1243. Proposals should be submitted to Mr. Wittow at this address.

We appreciate your consideration of the research project, and look forward to receipt of your proposal.

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT

MEMORANDUM

TO: Interested Parties

FROM: Mark Wittow, Staff
Joint Gas Pipeline Committee MW

DATE: March 17, 1981

RE: Why Alaska needs an in-state natural gas and gas liquids use study.

Last year's Joint Gas Pipeline Committee made a committment to sponsor a study of in-state gas uses, and obtained an appropriation of $150,000 for that purpose (March 1980 meeting). A detailed request for proposals was issued and distributed statewide and nationally; five proposals were received and evaluated by legislative and executive branch staff. For a variety of reasons, no contract has been let to perform the study. Since a good deal of time has passed since the study was originally conceived, I thought an updated statement of the reasons for conducting an in-state use study would be useful. Specific reasons include:

1) Assessment of Dow-Shell Group Petrochemical Feasibility Study Results

The Dow-Shell Group will report on the results of their work in September 1980. Alaska policymakers should have an independent analysis of the range of uses for State royalty gas and gas liquids (see attachment) before making a decision on disposition of the State's royalty interest. Such an analysis is vital if a petrochemical venture is to take shape in a form that confers as many benefits as possible on Alaskans. The Prudhoe Bay producers, who control seven-eighths of the available gas and gas liquids, will also play a major role in determining the nature of any proposed petrochemical development. Again, some independent analysis of possible in-state uses is required for the State to adequately present its interests. Many of the in-state uses for gas liquids would also greatly enhance the economic viability of petrochemical development.

2) Natural Gas Pipeline Corridor Use

Additional analysis of the potential for natural gas use in corridor communities (North Slope to Fairbanks to Tok) is necessary for determination of offtake points, taps, city gate station, and required volumes of gas. This portion of the study is fairly straightforward and could be handled by the executive branch.

3) **Alternatives to the Natural Gas Pipeline**

In the event that the gas pipeline project does not move forward within the next year or two, the State may want to investigate alternative methods for using North Slope gas. An in-state use study would help determine which of the possibilities offers the greatest benefits to the State.

4) Alaska Energy Needs

An anlysis of in-state uses would greatly improve the planning necessary for meeting energy needs in the State during the next two to twenty years. Natural gas and gas liquids are a clean, efficient source of fuel that can be used in a variety of ways. Their use would be especially compatible with the construction of hydro-electric projects for long-term needs. The Citizen's Advisory Committee on Petrochemicals has also made a strong written recommendation in favor of a legislative in-state use study.

In closing I offer an excerpt from a recent memorandum by Arlong Tussing concerning the legislature's in-state natural gas use study proposal:

> "My main concern, however, is that 13 years after the Prudhoe Bay discovery and 4 years after the completion of TAPS, neither Alaska's Executive Branch nor its Legislature has ever contemplated the big picture with respect to ANS natural gas and NGLS --- to consider the relations between the design and timing of ANGTS; potential in-state residential, commercial, and utility uses; instate processing for export; and the State's fiscal in the gas and NGL...
>
> The need will not go away. Over the next few years, the State will be faced with a stream of decision points --- about proposals from the Dow-Shell group, new demands that it commit its ANS royalty gas, and very likely with the choice of taking the entrepreneurial and financial initiative in getting ANGTS built, letting it die without a viable successor, or actively promoting an alternative strategy for use of the gas. I don't believe that anyone has even a workable conceptual framework yet in which to consider these issues rationally, and no agency of the State (or anyone else, for that matter) has even expressed an intention of trying to relate them coherently."

Attached is a list of some of the possible uses for State royalty gas and gas liquids. Please let me know if you desire any further information.

Attachments

IV. INSTATE GAS USE STUDY

A. The Investigation of Potential Instate Gas Uses of Prudhoe Bay Natural Gas

The following list includes the most readily apparent potential instate uses for Prudhoe Bay natural gas, and some that may not be so readily apparent. In the course of the study, the investigators are likely to reject some of these alternatives as patently unfeasible, while they may uncover other, more promising potential uses.

1. Gas-utility distribution of Prudhoe Bay natural gas for residential, commercial, industrial, and agricultural use in the Fairbanks area and possibly elsewhere along the ANGTS corridor.
2. Gas-utility distribution of Prudhoe Bay natural gas for residential, commercial, industrial, and agricultural use at a distance from ANGTS requiring one or more spur pipelines. (E.G., the Anchorage area, the Railbelt, Copper Valley, Haines, and Skagway.)
3. Electric-utility use of Prudhoe Bay natural gas in the Fairbanks area, along the ANGTS pipeline, or on one or more spur pipelines.
4. Exchange of Prudhoe Bay royalty gas for Cook Inlet gas (or, possibly, yet-undiscovered gas from the Gulf of Alaska or elsewhere), to be used for residential, commercial, industrial, or electric utility consumption in Southcentral Alaska.
5. Liquefacation of Prudhoe Bay natural gas at a tidewater location (Nikiski, Pac-Alaska, Haines, or Skagway) for shipment to Southeast and Southwest Alaska.
6. Conversion of methane and (CO_2) to methanol fuel at Prudhoe Bay for distribuiton on the North Slope or through an NGL s

line to other parts of Alaska as a substitute for petroleum products for home heating, transportation, and electric utility fuel.

7. Production of methanol fuel for instate consumption from methane and (CO_2) as a byproduct of the North Slope production of MTBE (methyl tertiary butyl ether), an octane-enhancing gasoline additive which might be exported either through TAPS or through an NGLs pipeline. (The Arctic Slope Regional Corporation [ASRC], together with DMI, ARTA, and others, is investigating the feasibility of a Prudhoe Bay methanol-MTBE facility.) (See Appendix C.)

8. North Slope production of methanol fuel plus methanol-based synthetic gasoline for export and/or instate distribution. (Mobil has a methan-to-methanol-to-gasoline process that is currently being investigated in Canada.)

9. Extraction and instate distribution of LPG "bottle gas" from Prudhoe Bay NGLs for residential, commercial, agricultural, and transportation use.

10. Distribution of compressed natural gas as a transportation fuel. (This scheme and the necessary automotive retrofitting are currently being investigated by the Province of British Columbia and by private enterprise in Alberta.)

11. Use of Prudhoe Bay NGLs as electric-utility fuel in the Fairbanks area, the Railbelt, the Anchorage area, or elsewhere in Southcentral Alaska.

12. Use of Prudhoe Bay ethane and/or propane, diluted with air, nitrogen, CO_2, or low-BTU synthetic gas from coal, waste or biomass, as gas-utility fuel in the Fairbanks area, the Railbelt, or Southcentral Alaska.

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT

FORMAL STATE REVIEW OF THE
DOW/SHELL GROUP FEASIBILITY STUDY REPORT

At the request of Governor Jay Hammond and with coordination provided by the Department of Natural Resources, the State of Alaska undertook a review of the Dow/Shell Group Feasibility Study Report submitted to the State on September 9, 1981. The review was structured around the Governor's stated policies on petrochemical development, the Department of Natural Resources' legal requirements, Dow/Shell's obligations under the Memorandum of Understanding with the State, and a modified "Major Project Review" process adapted for use on this project.

Review responsibilities were undertaken by the following agencies: Alaska Power Authority; Budget and Management, Office of the Governor; Department of Community and Regional Affairs; Department of Environmental Conservation; Department of Fish and Game; Department of Health and Social Services; Department of Labor; Department of Natural Resources; Department of Public Safety; Department of Revenue; and Department of Transportation/Public Facilities. Work was also undertaken by one consultant, Keown & Associates.

State personnel assigned to the review group were often the same staff who worked on the initial general assessment of petrochemicals under the direction of the Department of Environmental Conservation.

The attached memorandums are the result of this formal review work. It should be noted that the memorandums are in response to specific legal and policy parameters. State agencies were not asked to prepare an environmental impact statement, or were they asked to balance the "positive" and "negative" factors affecting this project. In general, the State also found that a detailed cost-benefit analysis is not possible at this time; that analysis must await additional information such as site selection and market value of the natural gas liquids.

As many of the memorandums refer back to the recommendations and general conclusions reached by the agencies in the earlier September 14, 1981, report to Governor Hammond, a summary of those recommendations is included as an appendix to this document.

ALASKA POWER AUTHORITY

334 WEST 5th AVENUE - ANCHORAGE, ALASKA 99501

Phone: (907) 277-7641
(907) 276-0001

October 13, 1981

Ms. Mary Halloran
Special Assistant to the Commissioner
Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Dear Ms. Halloran:

According to the Memorandum of Understanding and Intent between the State and the Dow/Shell Goup, Dow/Shell is required to describe the project's electrical power requirements and alternative means of meeting those requirements. The feasibility study is also to include the projected energy requirements of communities directly affected by the project and is to address the merits of interconnecting with local power utilities and power grids to facilitate more economical power for Interior and Southcentral Alaskan consumers. The power supply systems to be evaluated include onsite generation, cogeneration, mine-mouth wheeled power, expansion of existing utility systems, and hydroelectric power.

Specific comments on Volume 8, Energy Study:

1. Page 5. In a recent study for the Power Authority, Commonwealth Associates advised that the North Star Borough should maintain installed reserve generation at least equal to the capacity of the two largest units in service. For Fairbanks, this amounts to 130 MW. Subtracting this reserve margin from the 292 MW installed leaves an upper limit on peak demand of 162 MW. If this conservative approach is adopted, we estimate that Fairbanks, as an isolated load center, has sufficient capacity until about 1985-86. If the Anchorage and Fairbanks systems were to be interconnected, existing generation capacity is probably sufficient until the late 1980's. Dow/Shell, on the other hand, assumes fewer reserve requirements and forecasts that existing power-producing capability would be sufficient to supply the borough until the mid-1990's or later.

   Since reserve requirements must be taken account of in power system planning, we question the suggestion on page 5 that available capacity in Fairbanks might be available to provide estimated power needs for the Phase I Complex until the mid - 1990's or longer. For the same reason, we also question the similar suggestion on Page 8 that the existing capacity of an intertied Railbelt system might be sufficient to power the Phase I Complex until 1993.

2. Page 9. Recent capital cost estimates for coal-fired power plants developed by our consulting engineers differ somewhat from those used by Dow/Shell. Specifically, we would estimate about 50 percent higher for the coal-fired power plant at tidewater. Taking account of this difference, of course, would serve to strengthen Dow/Shell's preference for combined cycle combustion turbines over coal-fired generation.

   Page 10. While the Dow/Shell report identifies the base year for capital costs (1981), there is no similar identification for fuel costs. It is not clear from the information provided whether the fuel costs used in the analysis are meant to be indicative of present day costs or whether they incorporate some expectation of future price increases. The Power Authority, in similar analyses, has found it imperative to consider more than just the first year cost of power. We find that comparative energy costs are very sensitive to forecasted differential fuel price/value trends. Despite this caveat, Dow/Shell's preferred generation option of combined cycle gas turbine cogeneration seems well suited to the nature of the Dow/Shell enterprise and its requirement for both electrical energy and process steam.

   Page 10. Dow/Shell mentions the possibility of exporting excess power to the Railbelt grid prior to operation of the Phase 2 Complex. This temporary source of power could be very valuable to Anchorage and Fairbanks as the Railbelt proceeds to develop long term power supplies such as the Susitna Hydroelectric Project or Beluga coal fired generation. It is doubtful that either alternative could be operational until about 1993. Temporary use of excess Dow/Shell power until that time would very much compliment Railbelt power system planning.

In general, the report fully responds to the requirements of the Memorandum of Understanding and Intent.

It was a pleasure to offer our comments.

Sincerely,

Eric P. Yould

Eric P. Yould
Executive Director

STATE of ALASKA

MEMORANDUM

TO: Mary Halloran
Special Assistant to the Commissioner
Department of Natural Resources

Thru: Ronald D. Lehr, Director
Division of Budget & Management
Office of the Governor

FROM: Ronald D. Rippley, Economist
Division of Budget & Mangement
Office of the Governor

DATE: September 25, 1981

FILE NO.

TELEPHONE NO.

SUBJECT: Dow-Shell Feasibility Study

The purpose of this memo is to identify deficiencies in the method of ethane valuation at Alaska tidewater as presented in the Dow-Shell Group (D-S) study. The impact of the deficiencies on the wellhead value (and thus state royalties) is also noted.

The process whereby the D-S study determines the natural gas liquids (NGL) - and therefore the liquid petroleum gas (LPG) and ethane - value at tidewater Alaska is acceptable only for determining the feasibility of a NGL project if no Alaska petrochemical project is pursued. The tidewater-Alaska, NGL value that would make an Alaskan NGL project profitable is stated to equal the U.S. Gulf Coast (USGC) NGL value minus the cost of transporting the NGL from Alaska to the USGC. This is because if no petrochemical industry exists in Alaska and NGL's are not exported they would most likely be shipped to existing facilities at the USGC. Thus, the NGL value would be determined by the NGL value at the USGC less the cost of getting them there. This valuation process does not hold once we turn to development of a petrochemical industry in Alaska. In the case of a tidewater petrochemical complex, the ethane will not be shipped to the USGC, so the Alaska-USGC transportation costs are irrelevant with respect to ethane value. If an LPG export license were to be obtained the Alaska-USGC transportation costs would not be meaningful at all in determining the NGL value at tidewater.

Setting aside the issue of LPG exports, what is the appropriate method for determining the value of ethane at a tidewater petrochemical facility? Ethane is used as an input to the production of ethylene. Ethylene can be sold as a final product (with respect to an Alaska operation) or it can be used as a building block for other petrochemicals produced in Alaska. An Alaska petrochemical facility is envisioned to compete in the Pacific Rim marketplace. Hence, the value of ethane at tidewater is dependent on and determined by the market price for petrochemicals in the Pacific Rim markets and the transportation costs between an Alaska facility and the final markets. Alaska's proximity to the Pacific Rim markets is one reason for considering a petrochemical industry in Alaska.

The effect of the above stated valuation procedure is that the projected ten cent per pound differential in capital and operating costs - Alaska relative to USGC - does not have to be made up completely by reduced ethane values at tidewater Alaska. The tidewater value of ethane will be determined by subtracting the transportation savings from the ten cent differential - transportation costs from Alaska to Japan, for example, would be less than transportation costs from USGC to Japan.

The effect of this method of ethane valuation is to increase the tidewater value. Given a tariff structure which is providing adequate revenues to the pipeline owners, the increased tidewater value implies an increased wellhead vaule, hence increased state royalties.

Note that if LPG exports are undertaken, the above analysis is also the relevant method for tidewater LPG valuation.

State of Alaska MEMORANDUM

TO: Mary Halloran
Special Assistant to the Commissioner
Department of Natural Resources

DATE: October 8, 1981

FILE NO:

TELEPHONE NO:

SUBJECT: Dow/Shell Feasibility Study

FROM:
Thru: Ronald D. Lehr, Director RL
Division of Budget & Management
Office of the Governor

From: Ronald D. Ripple, Economist RDR
Division of Budget & Management
Office of the Governor

The purpose of this report is to summarize my review of The Dow/Shell Group study on Alaska Petrochemical Industry Feasibility. To this end, I will respond to the issues and questions set out in "Dow/Shell Feasibility Study Review - Economics" which I received from you.

Policy and Legal Parameters

Although the state can have an impact on the profitability of this project, the determination of the economic soundness of the project is a private sector matter. The impact of the state could be felt through the price charged for royalty natural gas liquid (NGL), the amount of infrastructure provided at state expense, state regulation and/or the state's role as tax collector. The most appropriate way for the state to determine that the project is economically sound is to price the royalty NGL at the world market price, provide only "traditional" levels of infrastructure that meet the criterion of public purpose, and/or tax this project the same as existing corporate entities. Should the state follow this plan and Dow/Shell proceeds with the project, the project is economically sound. If Dow/Shell chooses not to pursue the project it would then be necessary to determine if the reason for secession of interest is current state policy. If an element of state policy diminishes project feasibility, the State should decide if it is in its best interest to alleviate the situation. Alleviation of any "problem" presented by a given, "equitably" applied state policy implies providing a subsidy to a specific project. The state should provide no subsidy unless it is determined that one is needed and in the best interest of the state.

In general, determination of the best interest of the State (as prescribed by AS 38.05.182 and AS 38.05.183) for the disposition of royalty NGL requires a comparison of the thoroughly analyzed alternative uses of the state's royalty share of NGL. The State's best interest involves more than simply obtaining the highest dollar value per unit of royalty NGL. Best interest includes all elements of social and economic impacts, fiscal concerns, resource utilization and environmental quality, as well as the effect of the proposed project(s) on the stability of the state's economy.

Pursuant to the Memorandum of Understanding and Intent, the Dow/Shell study is not of such quality as to justify an irrevocable investment decision. Although considerable information and detail have been provided, significant elements of costs and the responsibility for these costs have not been determined. For example, neither the costs of the dock facilities nor the ownership and operation of the dock facilities have been determined. Moreover, there has not been a decision on the site. Infrastructure costs will vary across the potential sites and will therefore have an impact on economic feasibility.

The test of public purpose for elements of infrastructure has not been conducted, and hence, the method of apportioning infrastructure costs cannot yet be negotiated. Furthermore, an "irrevocable investment decision" cannot be made until the availability and price of the NGL's has been determined.

The importance of the state's royalty share of the NGL's to the success of the proposed petrochemical industry has not been established. It has been determined that the state's share alone would not be sufficient to establish a feasible petrochemical industry. From a negotiating point of view it is important to know if the state's share is necessary. Furthermore, if the producers sell their NGL's to Dow/Shell and a NGL pipeline is built, what options remain for the state?

Modified Major Project Review

Economics

1. Real per capita personal income. Nominal income will certainly increase. Dow/Shell estimates the statewide, wage and salary income of the permanent, direct workforce to be $125 million per year (in 1981 dollars). Dow/Shell also estimates that 80 to 85 percent of the permanent workforce "could be" Alaskan residents. This would imply that $100 - $106 million per year could come to current residents.

Given the present population of approximately 400,000, the $100 - $106 million per year coming to current residents implies an average increase in per capita personal income of approximately $250 - $265 per year. This increase equates to approximately $4.80 - $5.10 per week. These figures are in 1981 dollars. Real per capita income, however, depends on changes in the price level as well as the changes in nominal income. The question then is whether or not the increase in the statewide price index will be enough to offset the statewide per capita income increase.

On a regional basis, Dow/Shell estimates that $93 million of the $125 million will accrue to the permanent labor force located at tidewater. In most cases, the tidewater-site, community per capita personal income would increase substantially. The 1980 U.S. Census showed the City of Seward to have a population of 1842. Dow/Shell estimates that the population increase for Seward would be 6588, at the operational stage of Phase 2. If 80 percent of this population increase came from migration of resident Alaskans, the current resident Alaska population in Seward would grow to 7112 (a migration of 5270).

If 80 percent of the $93 million accrues to current residents, their gross personal income would increase by $74 million. Hence, on a regional basis, the $74 million would be "split" among 7112 current resident Alaskans to provide an increase of $10,000 per year, or $190 per week, in per capita personal income. Again, real per capita income is also dependent on the change in the price level. It is true that the regional price level will be pushed up by a greater amount than the statewide price level because of the heavier concentration of the nominal income increase. For example, there would be considerable real estate demand with the attendant price level increase. However, it is not clear that the price level will increase enough to offset the income increase. Hence, we might expect an increase in real per capita personal income.

During the construction phase we would expect the price level and nominal income to rise. However, since the personal income and resident Alaska employment proportion estimates from Dow/Shell are for permanent, i.e., operational, employment and population changes, we cannot say anything substantive about short-run, construction-phase real per capita personal income.

Over the life of the project we might expect real per capita personal income to increase. The post-TAPS construction period has seen inflation in Alaska moderate and decline. Given this experience and the fact that the Alaska economy is larger and stronger, we could expect the economy to be even more resilient at the time of construction for a petrochemical industry than it was at the time of TAPS.

2. Long-run economic stability - the broadening of the economic base of the state which would occur due to the establishment of a petrochemical industry would, in general, increase the stability of the Alaska economy. However, the petrochemical industry is closely tied to world market conditions. As noted throughout the Dow/Shell study, the feasibility of the project depends upon the world price of crude oil and the world -- in particular the Pacific Rim -- markets for petrochemicals. Therefore, given the uncertainty surrounding these economic factors, we would have to view the impact of this project on long-run economic stability as uncertain.

3. Administrative roadblocks - the potential for administrative impediments exists. However, since most of these would be tied to infrastructure questions, and socioeconomic and monitoring cost mitigation, the degree of significance of these potential roadblocks cannot be assessed at this time.

Fiscal

1. Net balance of state and local government - the determination of the net balance of either state or local government is unclear at this time because no site selection has been made. Although the revenues derived from a petrochemical industry -- and the attendant service community -- will not vary widely over the potential sites, the costs to governments will. The major costs will arise from state and local expenditures on infrastructure. Although the infrastructure needs for the project have been laid out in a general manner for each site, the actual costs and the burden of those costs

have not been determined. The impact on community services -- schools, medical, etc. -- would be quite different depending on the site selected. For example, the projected population increase of 5576 in Anchorage, relating to the Fire Island site, implies a 3 percent growth. However, the projected population increase of 6588 for Seward implies a 358 percent growth. The impact on Anchorage would be minimal given its already broad range of community services and the belief, by Dow/Shell, that the population increase would be spread widely over the city and not significantly affect "any one neighborhood or specific service." On the other hand, Seward would require major expansion to accommodate the population growth. For example, Dow/Shell estimates -- as set out in the Appendix on employment and population effects -- that 25 percent of the population change for the operation phase will be school age children. For Seward, this amounts to an increase in school age children of 1647. This is nearly the size of the present city population and would require extensive expansion of the school district. Furthermore, considerable differences exist in the difficulty -- and thus cost -- of providing some elements of the infrastructure. For example, the Complex would require 25 million gallons of fresh water per day and the ability of each community to provide this amount of water varies. Hence, the impact on government expenditures is uncertain at this time.

2. State subsidies - although masked requests for subsidies are in the Dow/Shell study -- below market ethane values, potential of "non-traditional" infrastructure -- the exact nature of the subsidies will not be known until negotiations begin between the State and Dow/Shell.

Risk

1. Uncertainty about technological, environmental, financial, and/or economic factors the greatest uncertainty is likely to evolve from the economic factors surrounding the viability of the petrochemical project. As noted above, the project will be influenced by the world price of crude oil and the world supply and demand for petrochemical products. The first-half 1981 U.S. Gulf Coast price for crude oil was $37.50 per barrel. Dow/Shell suggests that to make a natural gas liquids line attractive as an investment the real price of crude at the U.S. Gulf Coast should be over $50 per barrel. An natural gas liquids line is required to make a petrochemical industry possible. Furthermore, the present world demand for petrochemicals is depressed and the present projected demands make it questionable as to the need for -- and hence the feasibility of -- a petrochemical industry in Alaska. World demand has to increase more rapidly than presently projected, while world supply from more competitive sources does not increase such as to make an Alaska industry superfluous. Hence, some of the uncertainty about the feasibility of this project derives from international markets and conditions. Furthermore, the Alaska Natural Gas Transportation System (ANGTS) will have an impact on the feasibility of the project. Shipping ethane and some of the propanes and butanes down the ANGTS will increase the Btu value of the natural gas. This constitutes an alternative use for the NGL's. In that ANGTS is dependent upon national markets -- both for sale of natural gas and financing -- uncertainty surrounding the petrochemical industry also [illegible] from the national level.

2. Adequate information - as noted in numerous places throughout this report, the information provided by the Dow/Shell study is insufficient for purposes of determining the best interest of the state for the disposition of royalty NGL's. For example, the opportunity cost of not including the NGL's in the natural gas being sent down the ANGTS has not been adequately examined. Furthermore, the impacts on communities and government expenditures cannot be adequately determined because no site has been selected. Moreover, the information, as presented, is not sufficient for the Dow/Shell Group to make an "irrevocable investment decision."

3. External factors - it has been noted elsewhere in this report that external factors may well be the actual driving force with respect to project feasibility. These factors include the world price of crude oil, world markets for petrochemicals and U.S. markets for natural gas.

Conclusion

The Dow/Shell Study has not provided sufficient information to allow for adequate determination of the benefits and costs to the state of petrochemical development. The two most important missing pieces are the evaluation of alternative uses of NGL's and a specific site selection.

MEMORANDUM State of Alaska

DEPARTMENT OF COMMUNITY AND REGIONAL AFFAIRS

TO: John Katz
Commissioner
Department of Natural Resources

DATE: October 9, 1981

FILE NO:

TELEPHONE NO: 465-4750

FROM: Lee McAnerney
Commissioner
Department of Community
and Regional Affairs

SUBJECT: Comments on the Alaska Petrochemical Industry Feasibility Study

Introduction

In the Petrochemical Industry Assessment prepared by the Interagency Technical Team, the Department of Community and Regional Affairs presented three questions that should be addressed in the Dow-Shell petrochemical feasibility report:

1. What are the current and anticipated public service and facility short falls?;

2. Is there a need to strengthen local planning, fiscal, and management capabilities?; and,

3. What local, state, and industry investments are necessary in light of these shortfalls?

To determine social costs and benefits, the Governor's Community Well-Being concerns also should be addressed in this report including estimations of consumer goods and services shortages and price inflation; housing availability, price inflation and quality; rate of population growth; expected changes in lifestyle and social patterns; and the level of local growth management capabilities including land use plans, ordinances, and revenue generating mechanisms.

It was believed that a detailed analysis covering these questions and concerns would address the key socioeconomic issue of petrochemical development, i.e., the local government's ability to respond to the increased public service and facility demands generated by petrochemical development and the related rapid population growth.

The Department presented this as a central issue because it is local government which has primary responsibility to anticipate public facility and service demands and to make planning and fiscal decisions that will result in a managed development benefiting both local residents and industry alike.

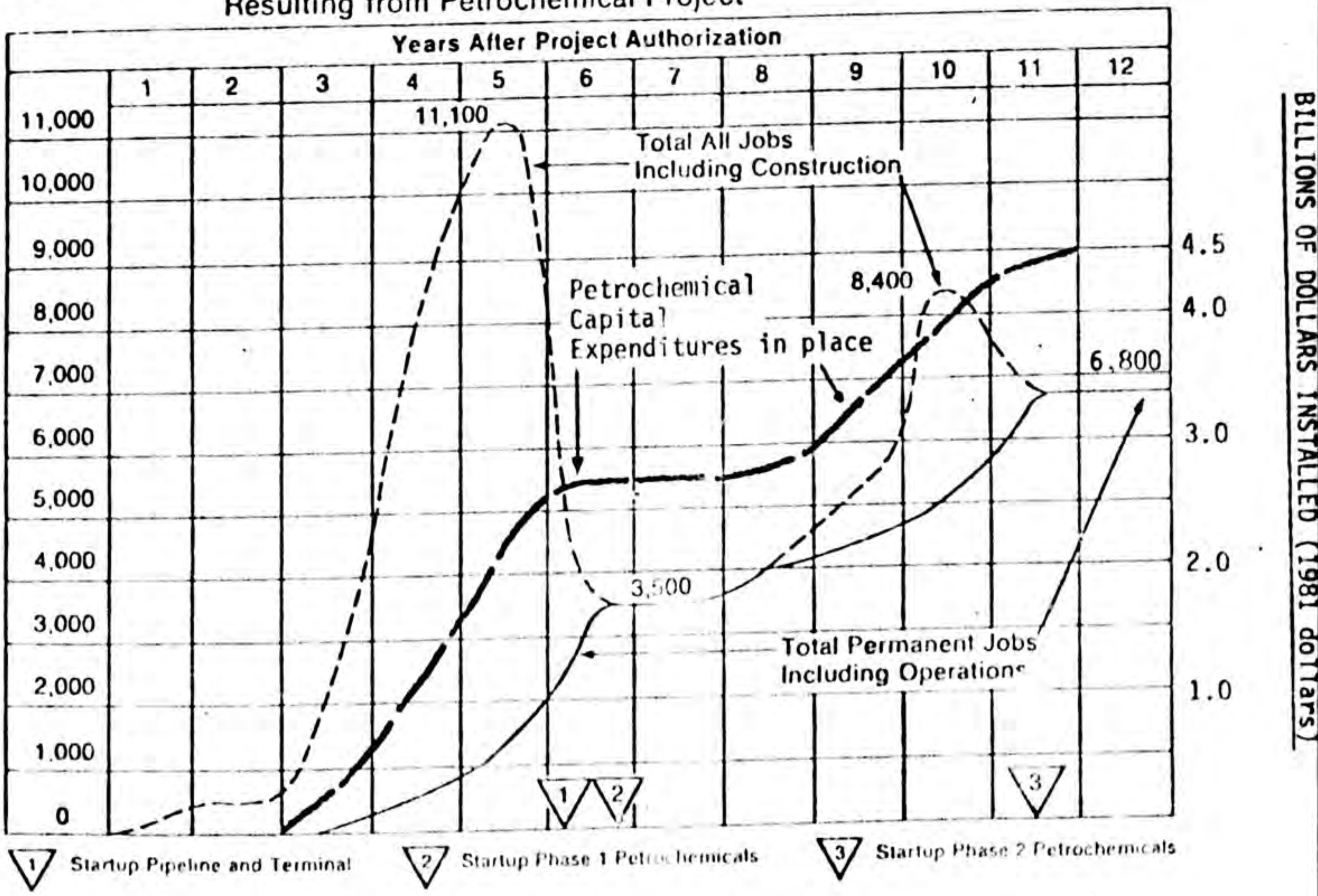
Comments on the Petrochemical Feasibility Study

The Department has reviewed the Alaska Petrochemical Industry Feasibility Study released by the Dow-Shell Group on September 9, 1981, and finds that while the study does give merit to the concerns expressed above by readily admitting that the project would create significant demands on most communities' facilities, services, land use, and lifestyle, it did not provide the detailed analysis necessary to assess the local governments' ability to respond to these petrochemical development demands. In fact, in the report Dow-Shell places much of the burden on the selected community to solve these problems by stating that they do not intend to pay for those facility and service costs not directly related to plant development and operation. Instead, they propose that the increased tax base of approximately $4.5 billion due to petrochemical development would be sufficient pay for many of the community needs.

An example of a shortcoming in their analysis with respect to socioeconomic concerns is indeed this idea that the petrochemical industry tax base would generate the necessary community revenues. While in the long run this may true, this study did not relate the dollar amount and timing of such tax revenues to the timing of needed capital improvements and service delivery. Figure 1 illustrates that if taxable, petrochemical capital value in place is overlayed onto the total employment figures over time, a discrepancy in timing and possibly dollar amount exists between peak employment periods (signifying the greatest demands on public services and facilities) and the amount of taxable capital in place (the supposed source of revenue to meet increased public costs). If an initial tax holiday is granted, a suggestion mentioned in the report to achieve economic feasibility, this discrepancy could be substantially increased. To give proper consideration to fiscal matters the study should have made detailed approximations of community costs and timing of such costs and compared them to the revenues expected during this period.

Even if a community was to have ample revenues or their bond rating increased substantially with the prospect of a major development in the community, it still must have sufficient lead time (at least two years) before project construction start up to adequately upgrade and coordinate its fiscal management and planning responsibilities. The study did not provide a detailed explanation of what Dow-Shell anticipates each community must accomplish during the preparatory period to ensure a controlled growth, e.g., the need for capital improvements programs, upgrading municipal staff, and the development of land use plans or zoning ordinances.

Figure 1 — Projected Total Alaska In-State Direct and Indirect Employment Resulting from Petrochemical Project



Recommendations

To allow for adequate consideration of Department concerns and to benefit the affected communities, it is recommended that over the next two or three years the following actions be undertaken or financially supported by The Dow-Shell Group.

1. For each site under consideration, Dow-Shell should conduct a detailed analysis of the local government's ability to respond to increase public services and facility demands generated by petrochemical development and the related rapid population growth during both construction and operation. Analysis should cover current and anticipated public service and facility shortfalls; the need to strengthen local planning, fiscal and management capability; and identification of local, state and industry investments necessary in light of the identified shortfalls.

2. Dow-Shell should fund independent research into how other petrochemical facilities in the lower 48 and Canada have been able to work compatibly with communities under similar conditions in terms of cooperation between industry and government and identification of mechanisms for sharing the cost of providing public services and facilities.

3. The final site for the development should be selected as soon as practicable after obtaining the information requested above. Timely selection of a community would allow for optimal use of state and local staff and would permit a more focused approach to community analysis.

4. A task force should be designated which would be responsible for making recommendations to the selected community for producing a "Master Plan for Petrochemical Development" or a comprehensive plan as appropriate. This task force would be ~~comprised of~~ state and local officials, industry representatives and local residents. The charge would be to establish goals and objectives to ensure controlled growth and would include implementation measures such as capital improvement programs, a land use plan, and subdivision, building, zoning and housing ordinances. This effort should begin at least two years before anticipated project construction start-up.

5. The Dow-Shell Group should provide timely information to local governments and the state regarding changes in construction schedules, anticipated manpower needs, and facility and service requirements.

6. The Dow-Shell Group should fund an impact coordination center within the selected community which would facilitate project data dissemination and exchange of information to handle socioeconomic concerns between the community and Dow-Shell.

The Department would like the opportunity to provide further explanation and justification for each of these recommendations when deemed appropriate.

cc: Richard Aks
Deputy Commissioner
Department of Community and
Regional Affairs

Lawrence H. Kimball, Jr.
Director
Division of Community Planning
Department of Community and
Regional Affairs

Richard Spitler
Planning Supervisor
Division of Community Planning
Department of Community and
Regional Affairs

Mary Halloran
Assistant to the Commissioner
Department of Natural Resources

Debra Kirk
Project Coordinator
Department of Environmental Conservation

Mary Jo Waits
Project Analyst
Lieutenant Governor's Office

Bob Dale
Planner IV
Division of Community Planning
Department of Community and
Regional Affairs

MEMORANDUM

State of Alaska

TO: John Katz, Commissioner
Department of Natural Resources

DATE: October 9, 1981

FILE NO:

TELEPHONE NO:

FROM: Ernst W. Mueller, Commissioner
Department of Environmental Conservation

SUBJECT: ADEC Review of the Dow-Shell Feasibility Study

The Department of Environmental Conservation has been involved with the Dow-Shell Group project for the past year as a result of its responsibilities in assessing public attitudes, providing information to the public and in coordinating the Interagency Technical Team. As a result of these efforts, we have reached conclusions on various aspects of the project and questions facing the state. The following is a response to your specific concerns. Attached is our review of the Dow-Shell feasibility study.

It is in the state's best interests to ensure that any petrochemical development is environmentally compatible with Alaska's other resources. Any agreement concerning the sale of the gas liquids affords the state an opportunity to influence new development and hence direct it toward the state's best interests. We must recognize, however, that an industry could develop regardless of the state's decision on the royalty gas liquids.

We have concluded that there are no environmental factors which would absolutely preclude development of the industry at any of the sites discussed. Phase I and II development could be controlled with appropriate technology and a commitment by the state and local governments to adequate planning, zoning and other regulatory activities necessary to protect the state from adverse impacts of the industry. This is based on very preliminary information supplied by Dow-Shell and the state's independent analysis of the industry. We do not rule out the possibility that further studies will preclude development at one site or another. Also, we remain extremely concerned about related or dependent industrial developments which may occur at some future time. Those industries have greater potential for environmental problems and have historically been more difficult to control. Methods of managing these problems will need to be developed.

The Dow-Shell Group has not, in our opinion, supplied sufficient information to justify an irrevocable investment decision by the state. Nor is the environmental impact analysis in sufficient detail to allow the state to determine precise environmental costs and benefits. These two conditions of the Memorandum of Understanding were, perhaps, overly optimistic with regard to environmental concerns. Such decisions imply for this department that permits could be issued. That level of detail cannot and should not be expected in a feasibility study.

The uncertainties expressed by the Dow-Shell Group on economic issues argue against any irrevocable commitments at this time. These economic issues will be very closely tied to the state's concern over environmental issues. The uncertainties surrounding potential processes and products, the lack of site selection, and the lack of detail in the analyses prevent any definitive determinations on environmental costs and benefits. These determinations are best made in conjunction with actual site selection, design criteria development, permit applications and/or EIS preparation.

We do not find that such development would be precluded; there does need to be substantial additional work done to determine the conditions of any development. If the state's overall interests are best served by further agreements with Dow-Shell, then we request that the recommendations of the state's technical team be considered for inclusion as a part of that agreement. I will provide, under separate memo, DEC's recommendations for the state and for Dow-Shell.

Attachment

Department of Environmental Conservation
Summary Review of
The Dow-Shell Feasibility Study

The Department of Environmental Conservation has reviewed the Dow-Shell feasibility report, as well as some additional information supplied by Dow-Shell. It is understood that the development of a feasibility study does not address environmental issues in sufficient detail to determine compliance with possible permit requirements. The Dow-Shell study did not identify any environmental factors which would preclude its proposed project in Alaska. At this time, we would have to agree, however, the level of detail was so general that further studies may identify factors which alone, or in conjunction with other factors, would preclude use of one or more of the currently proposed sites.

The feasibility study is so nonspecific that a detailed review of individual issues is not generally possible. The additional information supplied by Dow-Shell did not rectify this situation. At a minimum, Dow-Shell could have identified the most critical issues at each site or phase of development. Means of addressing these issues could have been suggested as well. This would have provided all parties with a better understanding of the project and its impacts. The State, in fact, did provide much of this type of information in its own reports.

There are many questions regarding some of the general statements on design issues, such as tank storage, runoff treatment needs, etc. Since Dow-Shell has limited current evaluations to general considerations, there is little point in addressing these issues at this time. When design criteria are being selected, when definitive site evaluations are undertaken, and/or when product slates and design processes are determined, we will be happy to work with Dow-Shell on these matters. Some of the types of design concerns will be included in our recommendations for further action. The real concern is that sufficient lead time for resolving such concerns be built into any state/Dow-Shell agreements.

The Dow-Shell report supported the State's contention that downstream development of other industries should be anticipated. Should a petrochemical industry develop in Alaska, the sponsors should be aware that specific evaluation of the proposals would, of necessity, include evaluation of downstream related industries. This would include identification of the most likely industries to develop, who the sponsors might be, potential markets and associated environmental risks. This type of analysis is common should an EIS be required.

The landlord concept of wastewater management would require careful analysis and information beyond that contained in the feasibility study. Examples will be needed of other similar systems, how treatment upsets can be traced, how liability is determined in the event of permit violations, and the landlord's powers of enforcement. The operation of a facility of this type would be closely tied to the DEC permits and their conditions.

The discussion on regulatory requirements is occasionally misleading. This may be due to oversimplifying the regulatory framework, however, there are certain errors which should be noted. In Table 6-4-A, the standards should be in micrograms rather than milligrams. Also, Table 6-4-C is misleading; the statements concerning percentages of industrial growth are essentially meaningless and will cause confusion. One other statement which will likely cause confusion is on Page 24, under Effluent Standards. A discussion of EPA's effluent technologies is mixed with statements on Alaska's receiving water standards and again milligrams was a typographical error. These are all explainable, if unfortunate.

Dow-Shell supplied us with the Oceanographic Institute of Washington's marine risk assessment. The assumptions used in this study are general, over simplified and potentially misleading. While this analysis may be suitable for a feasibility study, it would be insufficient as the only marine risk assessment. Limited data, lack of inclusion of other types of marine traffic (such as fishing vessels, other cargo vessels, etc), the apparent use of two years of spill data averaged over a four year period, size of spills, etc., limit the usefulness of this study to a preliminary effort to determine the gross likelihood of a spill. Future work would have to consider a more realistic set of circumstances in assessing both the probability and consequences of spills. Individual sites will also present problems requiring more detailed analysis--such as ice and shoaling in upper Cook Inlet and delays of ships in Prince William Sound due to weather.

Nothin in the analyses reviewed to date adequately address the issues surr ding rail transport of petrochemicals in Alaska. The condition of railroad, type of tank cars, applicable regulations and liability iss should be clearly defined. DEC would be very concerned about the sa ransport of any of the currently proposed materials. It is our un standing that the Department of Transportation is evaluating these is s.

MEMORANDUM State of Alaska

TO John W. Katz, Commissioner
Department of Natural Resources

DATE October 16, 1981

FILE NO

TELEPHONE NO 465-4100

FROM Ronald O. Skoog, Commissioner
Department of Fish and Game

SUBJECT Review of Dow-Shell Petrochemical Feasibility Study

The Department of Fish and Game has completed its review of the "Alaska Petrochemical Industry Feasibility Study" prepared by the Dow-Shell Group. Our comments are confined to the general effects that the project may have on the fish and wildlife resources of the State including the human use of fish and wildlife resources.

In general, the report was well organized and packaged, but lacked specificity in the areas of fish and wildlife resources portrayal and the environmental protection measures necessary to prevent adverse impacts on fish and wildlife resources. While we laud Dow-Shell's claim that "there would be no need to seek variations from Federal and State regulations with regard to air emissions or effluents and solid wastes," the report contains scant information on how this can be accomplished. The Department has detailed its concerns in the report titled, "Potential Impacts of the Proposed Dow-Shell Petrochemical Complex on Fish and Wildlife Resources in Alaska" which was submitted to the Interagency Petrochemical Technical Team for inclusion in "Petrochemical Industry Assessment for the State of Alaska." Based on our analysis a world class ethylene plant and gas liquids pipeline of the size and scope proposed by the Dow-Shell Group will potentially have significant effects on fish and wildlife resources and human use of fish and wildlife resources.

The Department has analyzed potential impacts of the project based upon the limited information provided to us by the Dow-Shell Group and the existing fish and wildlife data for the proposed sites. The Dow-Shell Group report does not address many of the potential problems identified in our report. For example, if the plant is located at the Wildwood site, up to 25 million gallons of water per day may be appropriated from the Kenai River. An out-of-stream diversion of this magnitude will have an undetermined effect on the habitat quality of the Kenai River and potentially cause damage to a highly important sport and commercial fish resource. The Dow-Shell report made no mention of the fish entrainment and impingement problems attendant with massive appropriation of water from the Kenai River.

The influx of employees to construct and operate a petrochemical facility will have a significant effect upon the local utilization of fish and wildlife resources. Past history has taught us that the disturbance and influx of people associated with major construction projects will lead to the type of fish and wildlife allocation conflicts which are now occurring in the Cook Inlet region. Moreover, it can be assumed that most of the skilled employees needed to construct and operate the facility will come from outside of Alaska and will result in an increased local competition for the relatively finite fish and wildlife resources. The Dow-Shell Group estimates a peak in-State workforce of 11,100 with a permanent employment base of 6,800 after ten years. The results of this population increase on fish and wildlife resources will likely be reflected in shorter seasons, smaller catch size, smaller bag limits, lower success/effort ratios, and more resource user conflicts as well as additional fish and wildlife habitat being lost to urbanization and associated developments. It is unfortunate that few Environmental Impact Statements or Socio-economic studies ever adequately address the subject of increased population demand on fish and wildlife resources and habitats. This subject was not addressed at all in the Dow-Shell report.

While the Department recognizes that the Dow-Shell report was only intended to be a "feasibility study," we are concerned about the brevity with which fish and wildlife impacts were addressed. Insufficient information was provided on pipeline routing, effluent composition, water appropriation, and toxic materials transportation to enable the Department to determine whether the project is environmentally safe. Part 1(c) of the Memorandum of Understanding and Intent between the State and the Dow-Shell Group requires Dow-Shell to provide an "environmental and social impact analysis in sufficient detail to allow the State to determine environmental and social costs and benefits." In the Department's opinion, the State cannot make this determination based upon the Dow-Shell report. In lieu of additional project details the Department will report to the Governor that the proposal at this time involves many technological, environmental, financial and economic factors that have a high degree of uncertainty and risk.

Recommendations

The Department recommends that the following be made conditions of the State's future involvement with the Dow-Shell Group:

1. Dow-Shell shall furnish the State with a detailed product slate including a description of each industrial process sufficient in detail to determine the composition and volume of the waste stream and the volume and nature of chemical materials used in the manufacture of products that must be stored or transported in-State.

2. Dow-Shell shall furnish the State with the corporate structure, scope of concern, and authority for industrial management for environmental protection. In particular, specific commitments will be required for fish and wildlife protection in both the construction and operation phases of all proposed facilities.

3. Dow-Shell will make the final site(s) selection for the manufacture, storage and transportation of petrochemical products and will coordinate with the Department of Fish and Game and other State resource agencies prior to beginning environmental baseline studies to insure that the studies are adequate to address State concerns.

4. Dow-Shell shall furnish to the State detailed water appropriation specifications at the primary manufacturing site and any planned subsidiary manufacturing sites. Included will be peak demand, average demand, expected seasonal or daily variations in demand, source(s) of water to be appropriated, and the location and type of intake facility required.

5. Dow-Shell shall furnish to the State a detailed description of the gas liquids pipeline. Included are: (a) the pipeline route and associated facilities delineated on photo-mosaic sheets (scale one inch = 1,000 feet) supplemented with color aerial photographs covering the entire pipeline system; (b) the basic criteria for pipeline design and associated facilities including substantiation of arctic engineering concepts employed for construction and operation; (c) requirements for the use of fill materials by geographic location in terms of type, quality, and quantity; (d) the location and size of all major temporary facilities, including work camps and staging areas; (e) the projected workforce requirements and distribution along segments of the pipeline; and (f) the overall project schedule including the proposed seasons of activities for all major components of pipeline construction.

The Department of Fish and Game will continue to actively participate in studies for an in-State petrochemical industry. At present, our level of participation is supported by a Coastal Energy Impact Program (CEIP (c)(1)) grant from the Department of Commerce. Funds for this grant are scheduled to terminate on September 30, 1982. If the State chooses to pursue continued involvement with the Dow-Shell project or others, we would support the establishment of a stable interagency petrochemical team with an assured source of funding and agency commitment.

Thank you for the opportunity to comment.

cc: Deborah Kirk, ADEC

MEMORANDUM State of Alaska

TO John Katz, Commissioner
Department of Natural Resources

DATE October 7, 1981

FILE NO

TELEPHONE NO 3030

Helen D. Beirne

FROM Helen D. Beirne, Commissioner
Department of Health & Social Services

SUBJECT Petrochemical Industry Assessment

Having reviewed reports submitted to the state regarding the feasibility and socio-economic impacts of petrochemical industry development in Alaska, we in the Department of Health and Social Services beliieve that our initial concerns, which were included in the Petrochemical Industry Assessment for the State of Alaska by the Interagency Technical Team, should be addressed if a decision is made to proceed with development of this industry. While Dr. John Middaugh, State Epidemiologist, will be sending you a separate report on his assessment of health risks, this memo summarizes the general concerns of all in this Department who have worked on this project.

Additional analysis of health and social services related issues should be undertaken if or when a particular site is selected. This should be done in cooperation with the individual community selected for site development.

It appears from the Dow-Shell Feasibility Study that industry planning for health and safety issues addresses only petrochemical workers, but does not involve planning for the surrounding community. Since hazardous chemicals must be transported into and out of the plant site, health, safety, and fire service planning should include all communities within the vicinity of petrochemical transport routes.

For example, the September, 1981, issue of the American Journal of Public Health notes that "Firefighters, particularly in rural areas, are seldom prepared to deal safely with such (chemicals) fires, and serious episodes of toxic inhalation have occurred among firefighters exposed to burning chemical wastes."

Furthermore, as our initial report recommended, the Alaska Division of Emergency Services, Department of Military Affairs, should be consulted regarding contingency plans for possible disasters which may involve petrochemical facilities. This recommendation is based in part on our review of a book titled The Peel Regional Police Force and the Mississauga Evacuation by Joseph Scanlon (1980), which describes a Canadian train derailment involving hazardous chemicals including caustic soda, propane, toluene, styrene, and chlorine (the most dangerous in terms of public health). As a result of this accident, 213,000 people were evacuated from the surrounding area.

Although we believe that such serious accidents are rare, we also believe that contingency planning for any possible disaster is in the best interests of our population. These issues should be addressed whether or not the Dow-Shell Petrochemical Industry is deemed feasible.

Such planning should include representatives from appropriate state agencies, industry experts, and local communities. We do not have any specific recommendations at this time on how to budget for these activities.

We appreciate the opportunity to have participated in the Petrochemical Industry Assessment, and we will be happy to offer additional assistance in the future.

of ALASKA

TO: The Honorable John W. Katz
Commissioner
Department of Natural Resources

DATE: October 8, 1981

FILE NO:

TELEPHONE NO:

FROM: Helen D. Beirne
Commissioner
Department of Health and
Social Services

SUBJECT: Formal State Review
of Dow/Shell Feasibility
Study

This memorandum transmits the report developed by the State Epidemiologist of the Division of Public Health assessing the Dow/Shell Feasibility Study as it relates to health hazards and risk assessment of the proposed petrochemical development in Alaska. We appreciate the opportunity to serve on the Petrochemical Technical Group and would be pleased to provide any additional information that you or the group would like.

Attachment: As Indicated Above

HEALTH HAZARD AND RISK ASSESSMENT
OF THE DOW-SHELL GROUP PROPOSED PETROCHEMICAL INDUSTRY
REVIEW OF THE DOW-SHELL ECONOMIC FEASIBILITY STUDY

John Middaugh
State Epidemiologist
Division of Public Health

October 9, 1981

My initial report of September 9, 1981 was the product of extensive literature research and numerous discussions with leading national experts on petrochemicals and health, including many Dow Chemical physicians, epidemiologists, and toxicologists. (See Appendix A, 9/9/81 Report) My review of the economic feasibility study since its release on September 9, 1981 has provided no new information that had not already been covered in much greater depth during prior research. Information in the feasibility study does not provide answers to the concerns and issues discussed in my earlier report.

In order to provide to the State information of the highest reliability, I sent copies of my September 9, 1981 report, "Health Hazard and Risk Assessment of the Dow-Shell Group Proposed Petrochemical Industry", to nine leading experts for critical review. (See Appendix B, 9/9/81 Report) To date, five of the nine reviewers have responded in writing and their comments are attached. (Attachment 1) The remaining four reviewers have indicated that they will soon provide their written comments which also will be made available upon receipt.

Other epidemiologic responsibilities required that I devote a great deal of my time during the past month to activities not related to petrochemicals. I have had only limited time to continue my evaluation of health impacts of the proposed petrochemical development in Alaska. Nevertheless, continued study has identified new concerns and recommendations.

1. The State should review carefully the possibility of prohibiting production of chlorinated petrochemicals altogether due to the serious environmental and health effects associated with many of the chlorinated hydrocarbons.

2. Fugitive emissions need to be examined in greater depth as does "state-of the-art" technology which may be inadequate to control emissions in Alaska.

3. The State should review its ability to control what petrochemical products may be produced in the event that the petrochemical industry proceeds. Dow-Shell has clearly indicated that Phase I and Phase II projected product slates are by no means inclusive. Many other potential "downstream" products are known to be even more hazardous than those proposed to date and should possibly be prohibited from manufacture in Alaska.

4. The State needs to obtain information on catalysts. This information has not been provided to date and adequate assessment of health risks and hazards is not possible without this information.

5. Standards significantly lower than those currently in effect have been proposed recently for Benzene, Ethylene Oxide, and Ethylene Dichloride. The State should insist that these lower standards be in effect if petrochemicals are produced in Alaska.

6. A thorough review of state and federal statutes and regulations by the Department of Law should be performed to identify gaps in authority and areas in which state standards may be preempted by federal standards. In view of potentially significant alterations in federal statutes under the current administration, State legislation may be essential simply to maintain present standards.

7. Recent study has brought forth new concerns related to explosion and fires. A particular hazard of chemical fires is the formation of toxic combustion products. Unprepared fire fighters have experienced serious episodes of toxic inhalation and chemical burns. Protective suits may be dissolved by corrosive chemical toxins. Protective suits have also led to heat exhaustion. Run-off of water needed to fight chemical fires has caused contamination of surface and ground water with toxic chemicals. Considerable study, education, and equipment will be required to assure adequate fire-fighting capability.

8. Considerable expertise is available to assist the state in thoroughly evaluating the proposed petrochemical industry. The State should consider developing carefully a formal comprehensive request for proposals (RFP) from national independent scientific consulting firms to obtain detailed information on the many areas of concern identified in the technical committee report.

9. The evaluation of health impacts of petrochemicals has clearly shown that severe staffing limitations exist for medical epidemiology within the State. Regardless of whether or not a petrochemical industry is ever pursued, the State could profit immensely from increasing epidemiology staff whose expertise will be increasingly required in the future. Specific recommendations include the addition of:

   1) One full-time medical epidemiology position, with extensive experience in chronic disease, environmental health, and occupational epidemiology.
   2) One full-time nurse epidemiology position.
   3) Appropriate clerical support staff.

10. Studies conducted since May, 1981 have been very productive. Expertise is being developed which will profit the State in the future. Valuable professional contacts have been made and should be maintained. Continued support for continued study is essential.

JM/cfe

DEPARTMENT OF HEALTH & HUMAN SERVICES

Public Health Service

Centers for Disease Control
National Institute for
Occupational Safety & Health
Robert A. Taft Laboratories
4676 Columbia Parkway
Cincinnati OH 45226

September 30, 1981

John Middaugh, M.D.
State Epidemiologist
Alaska Division of Public Health
338 Denali Street
Room 313, MacKay Building
Anchorage, Alaska 99501

Dear John:

Thank you again for having invited me to Alaska. I very much enjoyed the visit, and I was pleased by the course and tone of the discussions which we had with your Director, with Commissioners Katz and Muller, and with the Lieutenant Governor. You are to be congratulated for having so successfully introduced considerations of public health into the public policy debate surrounding the proposed Dow-Shell petrochemicals facility.

I have re-read your assessment of the health hazards which may be associated with the Dow-Shell plant. Although the document is brief and rather general, it does a good job of cataloging and assessing the major health hazards that have been shown in previous studies to be associated with the production of petrochemicals.

The principal potential hazards of such plants are as follows:

1. fire and explosion;
2. occupational exposure to toxic chemicals which may result either rapidly or after many years in:
    a. cancer;
    b. male sterility;
    c. other reproductive problems, e.g. miscarriages in workers' wives or genetic damage;
    d. other occupational disease, e.g. toxic hepatitis, chronic kidney disease, or neurological damage;
3. pollution of air and water;
4. accumulation of toxic wastes;
5. production of disease in children and adults in surrounding communities either as the result of their exposure to fugitive emissions or in consequence of parental occupational exposures to chemical toxins with subsequent transport home of those materials.

I was very pleased to see that each of those categories of hazard had already received active consideration in Alaska either by your Division or by other State agencies. As we discussed in our meetings, there are several points to be kept in mind in minimizing the risks associated with these potential hazards:

- exposures to all suspect carcinogens and reproductive toxins should be controlled to the lowest possible level. The existence of safe thresholds cannot be assumed. Achievement of control by application of state-of-the-art engineering technology is relatively easy in the design and construction of a new plant, but becomes much more difficult and expensive when it involves retrofitting an already existing facility. Hence there is an economic incentive to prevention.

- measures for the control of carcinogens and reproductive toxins should be designed not merely to meet present-day standards, but should additionally take cognizance of the fact that recommended exposure limits for such compounds as benzene, ethylene oxide, and ethylene dichloride (among others) will probably be made more stringent in the not too distant future. Accordingly, and to avoid the need for expensive retrofitting, initial plant design should be sufficiently tight so as to meet anticipated future levels of control. Specific recommendations on this point will require that one-at-a-time review be conducted of each chemical compound and of each process that is planned for the new facility.

- scheduled maintenance of the proposed facility should be required from the very beginning of the plant's operation. Preplanned maintenance which is conducted on an unvarying schedule and with State oversight is an excellent safeguard against the unanticipated spills and leaks from supposedly closed systems which constitute one of the major sources of human exposure at petrochemical plants.

- careful monitoring of in-plant and environmental exposures to toxic compounds should be undertaken on a regular and thorough schedule, and the results of that monitoring should be carefully scrutinized by the appropriate State agencies.

- careful personnel and medical records of all employees at the facility must be kept. Those records must include a listing of all jobs held by each worker and must be readily linked to exposure monitoring records and also to records of any spills or accidental releases to which a worker may have been exposed. The State must have immediate, open access to those records.

- consideration should be given to establishing statewide cancer and birth defects registries. Such registries will serve as an additional monitoring system for detection of any diseases which may be associated with the proposed facility and will also provide useful information to the Division of Public Health on time trends and geographic variation in the incidence of cancer and birth defects in Alaska. All records in both such registries should take careful note of occupational histories.

- the importance of safe disposal of toxic wastes generated by the facility cannot be overemphasized. The hazards of improper waste disposal are manifold and are outlined in our recent editorial n the Journal of the American Public Health Association. Those hazards are, however, entirely preventable through adherence to EPA regulations and state law.

Perhaps the most important aspect of our meetings in Juneau was that at a very early stage of plant planning we were discussing the prevention of disease and genetic damage in Alaskans one or two or more generations hence. Such anticipatory discussion has been rare in our nation's industrial history and can only yield beneficial results. Virtually all of the diseases and public health problems which have previously been associated with petrochemical production elsewhere can be prevented in Alaska with appropriate planning and careful foresight. I commend you and your colleagues on having begun such planning.

The Centers for Disease Control and the National Institute for Occupational Safety and Health will be pleased to assist you and the State of Alaska in any way that we can in the continuing evaluation of the hazards which may be associated with petrochemicals development in Alaska. I enclose the materials on ethylene oxide and ethylene dichloride which you had requested. Please do not hesitate to call further upon us.

Sincerely yours,

Phil Landrigan

Philip J. Landrigan, M.D.
Director
Division of Surveillance, Hazard
Evaluations and Field Studies

DOW CHEMICAL U.S.A.

1803 Building
16 September 1981

MIDLAND, MICHIGAN 48640

John Middaugh, M.D.
State Epidemiologist
State of Alaska
Dept. of Health and
Social Services
Room 222 Mackay Building
338 Denali Street
Anchorage, Alaska 99501

Dear Dr. Middaugh:

Thank you for providing us the opportunity of reviewing your 9 September 1981 report, "Health Hazard and Risk Assessment of the Dow-Shell Group Proposed Petrochemical Industry." We recognize you had to assimilate a lot of information in a short period of time and, in turn, are trying to provide a distillation of your research to Governor Hammond so that he can factor health issues into his administrative decisions; however, our overall impression is that your writeup is too generic.

For example, in your first paragraph under the heading, "Health Effects", you make the comment, "These chemicals have caused human cancers, sterility, infertility, miscarriages, and congenital malformations. This is too broad a statement. To our knowledge, none of the chemicals proposed for production in either Phase I or Phase II (your Appendix D) have been related meaningfully to human sterility, infertility, miscarriages or congenital malformations.

Benzene has been associated with human leukemia, but only at high levels of exposure; levels considerable above those to be expected in the proposed plant, and much above those for the surrounding community. Ethylene dichloride has been hypothesized to be a possible human carcinogen based on a 1978 National Cancer Institute report of carcinogenicity in rats and mice after gavage. On the other hand, Maltoni (1979) has reported essentially negative results from a lifetime inhalation study of rodents exposed to 150 and 250 ppm of EDC; and Goldschmidt (quoted by NIOSH, 1978) was unable to show increased incidence of tumors in experimental animals after skin applications of EDC. The point that we're trying to make is, having obtained a broad overview of the topic, you probably should focus your research on a smaller subset of specific chemicals, those found in your Appendix D.

In paragraph two you mention a variety of human cancers that "have been caused by petrochemicals," but fail to mention which chemicals and that none of these chemicals (benzene being the exception) will be part of the project. Angiosarcoma of the liver, for example, is thought to be caused by excessive exposures to arsenicals, vinyl chloride and Thorotrast. The latter is a product formerly used primarily by radiologists. Further, recent studies by NIOSH (unpublished) are finding that previously reported two- to three-fold increased risks of brain cancer among petrochemical workers at Dow are not holding up after additional more rigorous research.

The concept of no threshold for a carcinogen is an administrative convenience, not a scientific fact. Medically, the concept of thresholds makes more sense to me. We use it in therapy, even for allergies. To rigorously prove a threshold is not feasible for essentially all toxicological responses. Indeed, even the simple LD_{50} is determined by using log probability models which inherently recognize no threshold. Moreover, not assuming a threshold for carcinogenesis is tantamount to accepting essentially all chemicals as carcinogens.

We support your argument that further research is needed and, if the project proceeds, would like to explore with you the most efficient and rigorous methods by which our respective organizations could perform this research.

In the meantime, we would suggest you attend either the epidemiology short courses at the University of Minnesota or Amherst. We realize funding may preclude this, but both are excellent and would be a great help to you. Members of our group have gone to both and found them up-to-date and quite thorough. Enclosed find recent information on each.

Sincerely yours,

Ralph R. Cook, M.D., M.P.H.
Director of Epidemiology
Health & Environmental Sciences

P. J. Gehring, D.V.M., Ph.D.
Vice-President, Agricultural Chemicals R&D
and Director, Life Sciences R&D

cc: [illegible]

Encs.

THOMAS D. BATH, CONSULTANT

GOVERNMENT RELATIONS · ENGINEERING · ENVIRONMENT

2555 M STREET, N.W. SUITE 404
WASHINGTON, D.C. 20037 (202) 293-6190

September 21, 1981

John Middaugh, M.D.
State Epidemiologist
State of Alaska
Dept. of Health and Social Services
Room 222 Mackay Building
338 Denali Street
Anchorage, Alaska 99501

Dear Dr. Middaugh:

I regret my tardy reply to your letter of September 2. I hope it does not inconvenience you. In general, I feel that your report on health hazards represents an excellent summary of current knowledge regarding health concerns related to increased exposures to organic chemicals. As you are aware, my technical background is in chemical engineering rather than toxicology or epidemiology and therefore my comments will be from a somewhat different perspective than many you may receive. I do, however, have in mind that your own responsibility is to advise the Governor from the public health point of view and so I have tried to direct my comments in a way which will be relevant to your needs. Here are my suggestions:

Product Mix - As I look at the product mix outlined on page fourteen of your report, it appears to me that the manufacture of chlorinated hydrocarbons may not be essential to the viability of the project. The environmental contamination associated with chlorine plants and the special toxicological concerns related to many of the chlorinated hydrocarbons are such that I would recommend making a special point of the implications of introducing any chlorinated compounds into the product mix. Usually, the capacity to carry out chlorinations leads to the consideration of the production of a variety of substances (vinyl chloride, pentachloro phenol, etc.) depending on their current economic desirability. Hence, either we should suggest that the consortium deliberately exclude chlorinated compounds, or, failing that, your report should review much more broadly the health concerns associated with chlorinated organics. I realize that you touch on this eliptically in your report (p.6), but I think it needs more emphasis.

Source Control - I was pleased to see you give explicit attention to the liklihood that "fugitive" organic emissions would likely be a major mechanism of exposure. I would suggest that your statement: "Even state-of-the-art technology cannot eliminate...Canada.", is not strong enough. "SOA technology" for control of these emissions is really a phantom. The industry may be able to do well (with the expenditure of enough effort) in controlling emissions in Texas and West Virginia, where they have extensive operating experience, but control here is mainly a matter of the long-term behavior of seals and packing glands, etc. and I am concerned about the lack of experience that the industry has operating such delicate systems in the Alaskan climate. Has anyone reviewed the performance of pumps/seals on the pipeline?

Facility Heat Rejection - Your paper does not mention any possible environmental or microclimatologic effects which can be expected from the hea rejection systems employed by such a large facility. Perhaps this is beyond the scope of your responsibility; however, let me suggest that "ice fog" and other such phenomena may provide a secondary mechanism for exacerbating the health impacts of other pollutants.

I hope you find these comments helpful. Certainly; isolated points of view such as mine, are not substitute for the concensus views of a committee or review board, and you migh want to suggest that the Governor consider setting up such a group. However, I think you have done an excellent job, so far, and I wish you well in your future efforts.

I did manage to escape from Colorado without any new parasites, having greatly enjoyed my trek along the Continental Divide (Zirkel Mountain Wilderness). I do hope that we have a chance to get together on your next visit East.

Sincerely,

Tom Bath

Thomas D. Bath

TDB:eac

UNIVERSITY OF CALIFORNIA, DAVIS

BERKELEY · DAVIS · IRVINE · LOS ANGELES · RIVERSIDE · SAN DIEGO · SAN FRANCISCO SANTA BARBARA · SANTA CRUZ

DAVID S. SAXON
President of the University

EMIL M. MRAK
Chancellor Emeritus

University House
Davis, California 95616

September 17, 1981

Dr. John Middaugh
State Epidemiologist
Dept. of Health and Social Services
Room 222 Mackay Building
338 Denali Street
Anchorage, Alaska 99501

Dear Dr. Middaugh:

I have read your report with great interest. Before making any comments, however, I would like to suggest that you give serious consideration to the possibility of attending a conference to be held in Washington on Dioxins October 4-7.

I am enclosing a copy of the program for this conference. You will note it is an International meeting and you will note that it does cover chemical spills and especially the one that occurred in Italy that caused so much comment. You will note, too, that there are people from other places in the world discussing this important area.

I would recommend very strongly that if you can attend the meeting, that you do so. If you wish further details, I would suggest you get in touch with Dr. Fred Coulston, 17 Woodlawn Avenue, RDZ, Rensselaer, New York 12144, phone (518) 489-8346 who is one of the leading organizers of the me ting and either write to him or phone him.

I think your attending this meeting might very well modify your report. Now about your report--

In the second paragraph you refer to chemicals that cause human cancers, sterility, and so forth. It should be pointed out that most of this work, and in fact almost all of it, has been done with animals, and an animal is not always a human. I would also like to point out that the dosages may have been extreme, not just one short or very mild.

With respect to your third paragraph, I can't refrain from pointing out that skin cancer is very common, but it is mostly caused by exposure to the sun. Some have raised the question of whether or not we should ban the sun.

With respect to the last part of the third paragraph, I would again urge that you attend the meeting in Washington.

With respect to the last paragraph on page two, the line that says "and, once an acute exposure occurs, continued progression of clinical manifestations of the adverse process can occur in the absence of continued exposure," I would precede this sentence by saying "it is believed." I am not sure that there is evidence to prove this. I think, too, that one needs to talk about the type of exposure and whether it is a one shot deal or continuous.

This same comment refers to the top paragraph on page three. With respect to the last two lines on the first paragraph on page three, it seems to me it would be better if it stated finally, the largest group might consist of the general population and so forth. I say this because of the reports that some of us are getting back from Italy. This will be reported on in the meeting in Washington in October.

Under the sub-heading Cancer - background When some of the people talk about environmental effects, they have in mind not only air, water, and so forth, but also food. In this connection you may wish to contact to Dr. Albert C. Kolbye, Associate Director for Sciences, Bureau of Foods, Food and Drug Administration, 200 C Street, S.W., Washington, D.C. 20204. He is an M.D. and also a lawyer. He is now trying to bring rational thinking into carcinogenesis.

With respect to the last paragraph, I think one needs again to consider types of exposure and age. When Dr. Schneiderman of the Cancer Institute talks about cancer, he indicates that if one corrects for age, cancer is really going down.

I would say on page four that the three topics you listed are good statements.

I would certainly agree with you under the statement number six on page eight, that OSHA is the key agency to monitor compliance. The thing that bothers me about some of the people that are doing this, however, is that they are at times bureaucrats rather than good scientists. I am sure you are well aware of this.

I must say you certainly contacted a lot of people and have certainly had a broad exposure to views on this matter.

Finally, I would call your attention to an organization in the San Francisco bay area known as Environmental Management Services to Government. This organization is led by Dr. Stan Greenfield who was the first administrator for research in EPA.

I have had an opportunity to see their brochure and it seems to me that they have a good organization and can do good work. Most certainly I am not recommending this or selling him. It just occurred to me that you might be interested in writing to Dr. Stanley Greenfield, President, Systems Applications, Inc. 101 Lucas Valley Road, San Rafael, California 94903 to get their brochures and material. It is quite possible that the companies going in to Alaska should be asked to have some outside organizations such as this one to review their operation. I want to repeat, however, that I am not selling this organization, I am just aware of it.

Kindest personal regards,

Emil M. Mrak

MEMORANDUM State of Alaska

TO: John Katz
Commissioner
Department of Natural Resources

DATE: October 12, 1981

FILE NO:

TELEPHONE NO: 465-2700

Ed Orbeck

FROM: Edmund N. Orbeck
Commissioner
Department of Labor

SUBJECT: Review of Dow/Shell Group Alaska Petrochemical Industry Feasibility Study

The review on the Occupational Safety and Health issues has been completed. The basic findings and recommendations made in Raymond Jorgensen's initial response contained in the Petrochemical Industrial assessment for the State of Alaska by the interagency technical team remains the same. The basic issues of concern are adequately identified in that report.

Thank you for the opportunity to participate on the technical team.

MEMORANDUM State of Alaska

TO John W. Katz, Commissioner
Department of Natural Resources

DATE October 8, 1981

FILE NO

TELEPHONE NO

Ed Orbeck

FROM Edmund N. Orbeck, Commissioner
Department of Labor

SUBJECT Dow-Shell Petrochemical Assessment Update

The Alaska Department of Labor would like to reaffirm the general conclusions contained in our labor market impact report to the Petrochemical Technical Group. After a careful review of the Alaska Petrochemical Feasibility study prepared by the Dow-Shell Group and after discussions with Dow-Shell officials we can find no errors in our report or conflicts with data available from all sources. There are, however, some points that should be emphasized and one additional recommendation which would provide the necessary data for a detailed analysis of the employment impacts of petrochemical development.

Our report found that the construction phase of the project would require workers with skills available in Alaska but in greater numbers than are currently unemployed. The long term operations phase would require fewer workers but workers with many skills currently in short supply. Long term operations employment provides the opportunity for many jobs to be filled instate if appropriate training programs are established. The construction phase of the project, as described by the Dow-Shell group, would employ an average of 9,750 workers in the peak year. Based upon historical seasonal construction employment factors for Alaska the seasonal peak for the year would likely be 20 to 30 percent higher for direct construction labor placing a greater demand on the Alaska labor force than initially estimated.

The overall findings of the Dow-Shell Group report relating to community employment and population impacts cannot be disputed based upon currently available data. However, the estimates of nonlocal hiring and resulting population increases expected seem conservative in light of the estimated number of unemployed workers in the studied communities. A recommendation that should be considered, along with those already contained in our report, would be that the area that is chosen for the site should be surveyed to determine the actual labor force participation characteristics, skills of the currently unemployed workers and interest in employment of those not currently working. This would provide a relevant basis for determining, with a greater degree of accuracy, the employment, population and inmigration effects likely to occur. A localized survey might be sufficient but a broader survey to include the total labor market affected by the facility may be appropriate. The benefits associated with a larger number of job choices and the opportunities for skill upgrading could also be determined from such a survey.

In general, the Petrochemical Industry Assessment prepared by the Interagency Technical Team addresses most of the major concerns relating to petrochemical development. Further research will be required as the project comes closer to initiation. The Alaska Department of Labor will continue to monitor the progress of the project and provide support as necessary in review of issues relating to impacts on the Alaska labor force.

cc: John Post

CC/JH:bb

PHILIP E. KEOWN & ASSOCIATES, INC.
ENERGY PROCESSING CONSULTANTS
MEADOWS BUILDING, DALLAS, TEXAS 75206 (214) 361-1556

October 29, 1981

Honorable John W. Katz
Commissioner, Department of Natural Resources
State of Alaska
Pouch M
Juneau, Alaska 99811

Dear Mr. Katz:

The attached presents our evaluation of The Dow-Shell Group's "Report to the State of Alaska--Feasibility of a Petrochemical Industry".

In summary, our analyses indicate that based upon the investment and operating costs given by The Dow-Shell Group, their report does present a reasonable assessment of the economic feasibility of a petrochemical industry in Alaska.

Very truly yours,

Philip E. Keown

Philip E. Keown

PEK:kw
Attachments

EVALUATION OF THE DOW-SHELL GROUP

"REPORT TO THE STATE OF ALASKA-FEASIBILITY OF A PETROCHEMICAL INDUSTRY"

The overall purpose of this work has been to review the Dow-Shell Group (DSG) "Report to the State of Alaska--Feasibility of a Petrochemical Industry"; to update the economic evaluation computer model applicable to natural gas liquids and petrochemical facilities in Alaska based upon the DSG report; and to provide an independent assessment of the DSG report.

The time limit for this work and necessary restrictions of proprietary data have not allowed an extremely detailed assessment of the DSG study and report. However, we feel that based upon this scope of work, together with our previous related study, the following observations are warranted.

- Capital investments and ethane feedstock cost are the cost-related determinants of economic feasibility for NGL-based petrochemical production in Alaska.

- An economically viable NGL project is a necessity for (but does not insure) an acceptable petrochemical project.

- The price of crude oil is the basic determinant of NGL values; however, the future NGL-crude oil pricing will be affected by many new factors which complicate a reliable prediction of this relationship.

- The economic evaluation procedure--20% before tax return on investment--is not a sophisticated economic evaluation criteria. However, this method of presentation is considered appropriate because (1) any more sophisticated criteria would have required such a complex presentation as to have significantly reduced the audience for the report; (2) this general procedure is an often used economic viability criteria which does relate to the investment decision-making economic evaluation criteria; and (3) the results of the more sophisticated evaluation methods based upon the values developed from the 20% before tax return are consistent with reasonable economic viability criteria.

- Based upon the capital investments stated in their report and considering the magnitude of uncontrollable pricing and market factors, our evaluations indicate that the DSG analysis of feasibility is appropriate.

- Due to the very large capital investment requirements and the long permitting, engineering, and construction schedule, the business risks are indeed great. Consequently, a positive investment decision almost requires the critical cost factors must, at the time of such a decision, be at or near those values required for economic viability.

In the course of this work we have (1) reviewed the Dow-Shell Group report; (2) provided various state officials a preliminary assessment of the study and established goals for further evaluation; (3) met with members of the DSG to discuss the report and obtain additional information used to develop the economic evaluations; (4) adapted the available information for use in the economic evaluation model; and (5) developed independent economic evaluations based upon these data.

NGL Project

Based upon the stated capital investments and operating cost, our economic evaluation indicates the $947 MM/yr cost (1981 dollars) for the total NGL system would provide a real rate of return on investment (above inflation) of about 7% (see attachment I for comments on rate of return). The capital return component of the $947 MM is assumed to remain constant in nominal dollars throughout the project in this analysis. This actually results in a negative real growth rate in the total cost, e.g. in the tenth year the total cost is about $585 MM in constant 1981 dollars. This infers that with crude oil prices keeping pace with inflation and with NGL's priced at 100% BTU parity with crude oil, the potential revenue at Prudhoe Bay for NGL would be increased by about $360 MM (in constant 1981 dollars) in the tenth year of the project. Over a twenty-year period the potential revenue at Prudhoe Bay for NGL would be increased by the equivalent of about $340 MM per year in constant 1981 dollars. This overall method--20% before return--

does provide a relatively heavy front-end return on investment. It should be noted that the typical rate base return often utilized for regulated pipelines provides an even greater front-end return on investment.

Assuming that the return on investment portion of the total NGL cost were to keep pace with inflation, an initial total system cost of about $682 MM/yr would provide the same overall rate of return on investment (i.e. 7% real return). This would also infer that the revenue at Prudhoe Bay for NGL would be increased by $265 MM (1981 dollars) in the first and all subsequent years of the project. However, some of the basic operating parameters for these analyses have been stated optimistically. For example, at the base unit revenue for NGL, the rate of return on investment is reduced from 7.0% to 5.8% when considering the lower pipeline throughput, until the Phase II petrochemical project begins. Market conditions could prevent marketing of the total LPG stream. At an overall 90% throughput, the return on investment would be reduced to about 5.2% and at 80% throughput, the return would be reduced to about 3.2%.

Based upon the ever increasing investment estimates for ANGIS and the IAPS history, one must be concerned about the NGL pipeline investment. The DSG pipeline investment is about double that used in our previous work, which had been based upon escalation of the Pipeline Technologists report, which in turn was based upon their work for the El Paso proposed natural gas pipeline route. As a point of reference, a doubling of the NGL pipeline investment would increase the total cost for the NGL system from $942 MM/yr to about $1,466 MM/yr.

There are certainly factors which would indicate that NGL may be priced at greater than 100% BTU parity with crude oil. Due to past regulation of natural gas at less than oil parity, NGL has not experienced a significant cost-price squeeze. Deregulation of natural gas prices could be expected to result in an upward pressure on NGL prices. Although the non-US LPG ventures have been structured toward BTU parity between delivered crude oil and delivered LPG, these projects could probably undercut LPG prices significantly if such actions were perceived to be in their best interest. Therefore, there is also the possibility that LPG prices could be less than BTU parity with crude oil.

The recent elimination of restrictions on LPG exports will certainly have some positive effects on the LPG project, e.g. a broader market coupled with cost saving foreign flagship shipments. However, this is perceived as a potential two-edged sword in that a secure supply in some of the potential LPG export market countries could also produce a negative influence on the potential petrochemical demand for these same countries. This would require considerably more study before any firm assessment could be made of the net effect of LPG export upon the overall project viability.

Petrochemical Project

Based upon the stated capital investment and operating cost and our estimate of working capital, the $1,140 MM/yr cost (1981 dollars) would provide a real rate of return on investment of about 7.0%. When compared to a similar US Gulf Coast complex, the $400 MM differential would decrease in constant 1981 dollars over the years to about $225 MM in the tenth year, which would be equivalent to about a 5.6¢ per pound required ethane cost advantage. Over a twenty-year project period, the equivalent constant 1981 dollars differential would be about $233 MM/yr, or about 5.8¢ per pound required ethane price advantage.

As before, this evaluation method is equivalent to a negative real growth in the return on investment component. Assuming that the return on investment portion of the total petrochemical cost were to keep pace with inflation, an initial total cost of about $881 MM (1981 dollars) would provide the same overall rate of return on investment (i.e. 7% real return). The US Gulf Coast differential would be about $285 MM, or about a 7.1¢ per pound ethane cost advantage required in Alaska. However, market factors are almost certain to result in less than 100% production year after year. The return on investment, at the same contribution to return per unit of product, would be reduced to 5.8% at 95% operating rate, 4.6% at 90% operating rate, 3.0% at 85% operating rate, and 1.3% at 80% operating rate. At an 80% operating rate, the base contribution to return per unit of product would essentially have to keep pace with inflation to provide the 7.0% rate of return (see attachment II for additional information on operating rates).

Other factors not considered in these evaluations are the differences in timing of Phase I and Phase II facilities. Since the majority of the site costs are required for Phase I and there is a strong possibility that construction costs would increase at greater than inflation, the analysis procedure with Phase I and Phase II projects combined presents somewhat optimistic results. In addition there is no assurance that actual product prices would permit economic viability for the US Gulf Coast facilities used as a comparison basis in this study.

Overall Evaluation

Although the negative real growth rates for return on investment inherent in the analysis procedure used in the DSG report are questionable, we believe that consideration of other real factors results in essentially the same conclusion and that the DSG report is a reasonable presentation of economic feasibility.

It must be recognized that for such large capital requirements and with such a long permitting, engineering, and construction schedule, as well as future price and market uncertainties, a positive investment decision is indeed difficult. We are not aware of any available forecasting techniques or controls which would produce the results and assurance necessary for a positive investment decision at this time.

ATTACHMENT I

RATE OF RETURN

Part 1: Theoretical Analysis 1/

1.) The required real rate of return is made up of three components.

- Pure rate of return (no risk).
- Liquidity risk premimum.
- Business risk premimum.

2.) The capital requirements are essentially provided by two sources--debt and equity.

Capital Source	After Tax Return, % Pure Return	Risk Premiums Liquidity	Business	Real Return
Debt	2.0	1.5	0	3.5
Equity	2.0	1.5	4.0-8.0	7.5-11.5

3.) The composite real return is dependent upon the capital structure.

Equity	Composite Real Return
100%	7.5-11.5%
75%	6.5- 9.5%
50%	5.5- 7.5%
25%	4.5- 5.5%

1/ Based upon analysis by Dr. Larry J. Merville, Professor of Finance, The University of Texas at Dallas, in connection with our initial Alaska petrochemical study.

Part 2: Capital Structure

A recent Chemical & Engineering News survey showed that for a composite of fifteen major chemical companies (sales in excess of $1 billion annually) showed that equity provided 49-50% of the total capitalization of these firms in 1979 and 1980.

Part 3: Actual Return on Investment

We are not aware of any information on the real rate of return (as used in this analysis) actually experienced in the chemical industry. However, information is available on the net income as a percentage of total assets which is somewhat related to rate of return. These figures are for the same composite companies mentioned in Part 2.

Year	Net Income / Total Assets, %
1980	6.22
1979	7.10
1978	6.33
1977	6.26
1976	7.09
1975	6.92

Note: Due to the dynamic nature of these data, differences in book and tax depreciation, etc., these data are not directly relatable to real rate of return and are presented only as general information.

PHILIP E. KEOWN & ASSOCIATES

ATTACHMENT II

OPERATING RATE HISTORY FOR U.S. PETROCHEMICAL INDUSTRY

Operating Rate 1/
(Percentage of Nameplate Capacity)

		Product					
				Polyethylene			
Time Period	Ethylene	Styrene 2/	Vinyl Chloride 3/	Low-Density 4/	High-Density	Ammonia	Urea
1981 1st Qtr.	68	82	66	92	75	83	88
1980 3rd Qtr.	63	55	63	62	58	75	91
1st Qtr.	84	87	89	92	86	95	86
1979 3rd Qtr.	89	89	99	92	95	91	87
1st Qtr.	85	88	90	82	75	74	80
1978 3rd Qtr.	80	80	71	NA	NA	88	82
1st Qtr.	79	83	80	NA	NA	75	62
1977 3rd Qtr.	81	83	86	NA	NA	79	70
1st Qtr.	82	84	82	NA	NA	78	66
1976 1st Qtr.	84	84	84	NA	NA	88	66

1/ Source: Chemical & Engineering News, various issues.
2/ Major end-use for ethylbenzene.
3/ Major end-use for ethylene dichloride.
4/ Does not distinguish between conventional low-density polyethylene and new linear low-density polyethylene, which is experiencing phenomenal market acceptance and growth.

MEMORANDUM State of Alaska

TO: John Katz, Commissioner,
Department Of Natural Resources

Thru: Glenn Harrison, GH
Director, DMEM

DATE: October 12, 1981

FILE NO:

TELEPHONE NO: 276-2653

FROM: Sam Murray SM
Petroleum Economist, DMEM

SUBJECT: Dow-Shell Report

Please find attached DMEM's comments concerning the economic feasibility of petrochemical development in Alaska as outlined by the Dow Shell Group report of September 9, 1981.

CC: Kay Brown
Mary Halloran
Ed Phillips
Bill Van Dyke

02-001A(Rev.10/79)

The Economic Feasibility of Dow-Shell's Proposal for Petrochemical Development in Alaska

Introduction: The feasibility of petrochemical development in Alaska is a function of a variety of factors, many of which are interdependent and not subject to state influence. The uncertainties associated with many of the key facets of this question preclude a definative answer. As presented by Dow-Shell, the path to economical petrochemical development in Alaska entails a series of critical junctures, the combination of which, like a tumbler lock, leads to a myriad of possible outcomes. There are few combinations which unlock the door to efficient petrochemical development in Alaska. This is not to say that sound petrochemical development is unlikely, since favorable probabilities can be attached to certain junctures. In addition, each juncture or decision point will be critically evaluated by both state and industry; the outcome at each node will not be left to chance or approached in a random fashion. As a general conclusion, however, a "positive" confluence of circumstances will be necessary to insure a feasible outcome.

This paper assumes that the reader is familiar with the Dow-Shell report and previous petrochemical studies contracted by the state. An indepth overview of the industry is therefore replaced by a brief discussion of the economic factors governing petrochemical development which pertain to the issues to be raised. Finally, the approach presented by Dow-Shell (also referred to as the Dow-Shell Group (DSG)) will be examined. As a result of time and information constraints, the latter task will be held to a general discussion and incorporate simplifying assumptions. The outcome array and uncertainties mentioned above have forced Dow-Shell into a similar approach despite considerable expenditures. In summary, the following will highlight the major areas of concern regarding the economic development of this industry in Alaska.

The Petrochemical Industry: An Overview of Specific Economic Factors

The long capital life of a petrochemical plant serves as a strong incentive for firms to seek assured long term markets and feedstock supplies. Vertical integration has therefore become a hallmark of the chemical industry. Hydrocarbon producers tend to integrate forward in an effort to secure markets and provide outlets for their feedstocks, which include crude oil, gas and natural gas liquids (NGL's). The control which oil companies have over long term feedstock supplies eliminates much of the risk associated with a petrochemical complex. It is for the same reason that chemical firms often integrate backwards in an effort to secure insured feedstock supplies.

Assuming Alaska natural gas could be delivered to market, its ultimate use as a fuel or a petrochemical feedstock will depend on the price of natural gas relative to crude oil. Should the deregulation of natural gas lead to a comparatively high price in the lower 48, North Slope producers would not be inclined to remove high valve ethane from the Alaska-Canadian pipeline stream for the sake of a local, third party petrochemical industry. Conversely, a low natural gas price, brought about by either market conditions or pipeline regulation, would make producers more likely to sell gas liquids to Dow-Shell. The petrochemical industry, for its part, will seek the least expensive feedstock source and will choose between natural gas and petroleum based feedstocks accordingly. In general the physical availability of feedstocks does not seem to be a limiting factor to U.S. petrochemical production.

The petrochemical complex under consideration by Dow-Shell is fairly typical of most world-scale petrochemical complexes. As such, it is laid out like a large industrial park designed to expand in response to its anticipated market, technological change, an energy availability. Petrochemical plants can vary substantially in their capability, ranging from single product ethylene plants to a full product slate of primary, intermediate, and end use products.

The selection of a plant's product slate is often dictated by processing and transportation economics. In Alaska for instance, high processing costs suggest that no processing should occur in state and the feedstock should be shipped directly to a region of more acceptable costs. However this rule of thumb is outweighed by transportation considerations. The feedstock of interest to Dow-Shell is natural gas liquids. Natural gas liquids consist of ethane and the immediate group of heavier gases, (propane, butane, pentanes, and hexanes) in liquified form. Liquified petroleum gas (LPG) is NGL net of ethane. Ethane, when converted to ethylene, is an exceptionally versatile and desirable petrochemical feedstock. LPG is a less attractive feedstock. Although the various components of LPG can be cracked (broken down) into ethylene, cracking yields are relatively poor and produce a group of byproducts which have little current value. This factor, coupled with the fairly portable nature of LPG has led Dow-Shell to propose that LPG be shipped to the U.S. Gulf Coast as fuel/feedstock. Ethylene, on the other hand, requires extreme pressure and refrigeration to make it suitable for ocean transport. As a result, the ethylene would be effectively trapped in Alaska until it was converted into a slate of more managable primary petrochemicals. Thus, the petrochemical plant under consideration by Dow-Shell would manufacture a group of ethylene-based primary petrochemicals.

Because petrochemical complexes strive to achieve the lowest possible manufacturing cost, their product slates and system designs are carefully coordinated to optimize the use of chemical by-products, provide for waste disposal systems, and minimize power and fuel input. The Dow-Shell group, being composed of several large companies with established markets for their respective products, would organize their complex as a series of independently owned plants, holding infrastruture, power, and transportation facilities in common.

The energy requirements of a petrochemical complex are substantial. Of the total energy requirements of all U.S. manufacturing industries, chemicals account for more than one third. The industrys' substantial energy consumption is explained by the need for steam, process fuel, pumps, compressors, refrigeration, electricity, etc. Energy is probably the overriding factor of a petrochemical plants design. Heat generating processes, for instance, are usually placed strategically near heat absorbing processes. The availability of cheap electricity can also influence the location and design of a petrochemical complex.

Basic Economic Considerations

Before proceeding with the economics of the project the following concepts should be defined:

> fixed costs: The fixed costs of the contemplated project are essentially its construction costs with an imputed interest rate (or return on equity). These translate into a "fixed" periodic payment that does not vary with plant output.

variable costs: Variable costs are those costs which depend on the output of the plant. For our purposes labor, power, and feedstock costs would adequately define the variable costs of the project.

world scale petrochemical facility: A world scale petrochemical facility is one whose size is not constrained by feedstock supplies or market considerations. Being of optimal technical size, a world scale plant is able to achieve the lowest possible cost per unit of output. Under today's technology a world scale plant generally processes at least one billion pounds of feedstock per year.

Fundamental Considerations

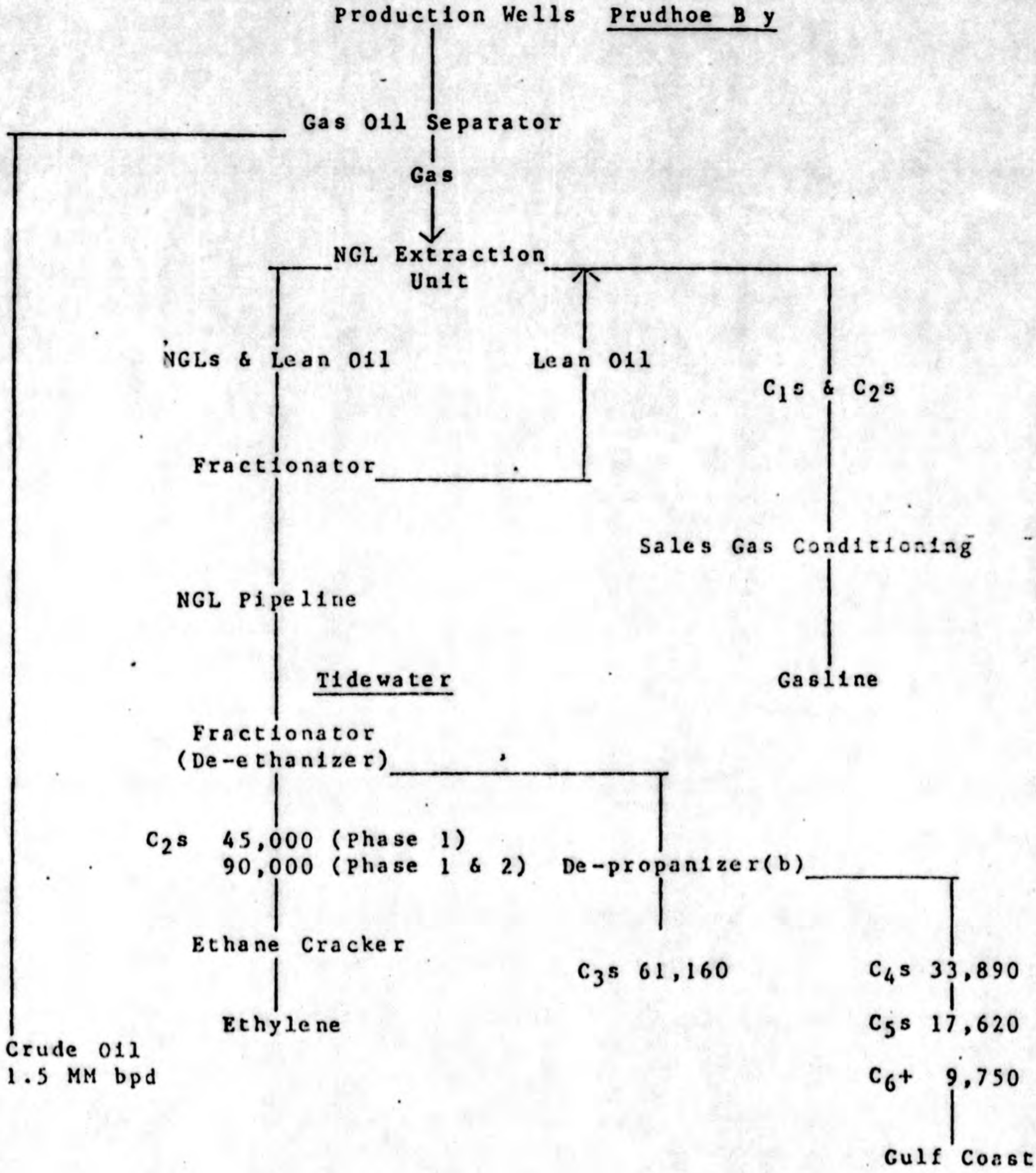
Transportation economics favor petrochemical development in Alaska. A petrochemical plant in Alaska would be well placed for the Pacific Rim markets. Consequently, an Alaskan plant would enjoy an advantage in market access over its competitors. The physically volatile nature of ethane implies that it should be processed in Alaska to enhance its mobility. This would be in keeping with the principle that can be observed in most Alaskan processing operations; the quest to reduce the weight, bulk, or perishability of any product whose transportations cost is otherwise prohibitive.

Construction costs disfavor petrochemical development in Alaska. As is well known to most Alaskans, in-state construction costs are often the prohibitive factor to development in Alaska. Dow-Shell estimates that the cost of building a petrochemical facility at tidewater in Alaska is 1.7 to 2.1 times greater than an equivalent U.S. Gulf Coast plant. The NGL extraction plant, NGL pipeline, and NGL fractionation plant require large capital outlays just to make feedstocks available at the complex. This raises a question as to whether or not ethane feedstock really is "cheap" in Alaska.

Fixed Costs are Sunk Costs. As a footnote it should be stated that although investors in a new plant expect revenues to cover total fixed and variable costs, once the plant is built fixed costs become sunk costs and do not affect operating decisions. Once established, a plant will operate at virtually full capacity provided its product sells for more than its feedstock and other variable costs, even if fixed costs cannot be covered. In general, any firm in this situation will stay in service so long as more money would be lost by shutting down than by continuing to operate.

"Figure 1"

DOW-SHELL GROUP PROPOSAL
DISPOSITION OF NORTH SLOPE GAS LIQUIDS (a)
(All figures in barrels per day)



(a) Source: The Dow Shell Group, Progress Report 8, July, 1981.
(b) Possible location for a De-propanizer.

Evaluation of Major Assumptions

Figure 1 is a simplified schematic diagram of the Dow-Shell project as presently envisioned. As can be seen, a petrochemical plant could coexist with TAPS and ANGTS. The petrochemical branch of the diagram, beginning at the NGL extraction unit, can be traced to two general product categories; ethylene and LPGs. As mentioned, the ethylene would be converted into a product slate of primary petrochemicals and the LPGs would be sold to the U.S. Gulf Coast. Figure 1 implies a host of favorable and often interelated assumptions which include but are not limited to the following:

1) North Slope producers will find it in their best interest to sell NGL's to Dow-Shell.

2) The costs of the gas liquids pipeline, and governmental regulations associated with this leg of the project will enable NGLs to be delivered to the plant at an acceptable price.

3) Dow-Shell has correctly estimated its on site capital construction costs, including the costs attendent to health, safety, and environmental regulations.

4) Dow-Shell will be able to secure adequate infrastructure facilities, and in its negotiations with the State, will not have to incur infrastructure costs that translate into unacceptable construction costs.

5) Dow-Shell will be able to secure sufficient quantities of suitably priced natural gas for its fuel and feedstock requirements.

6) There is a large enough market to absorb Dow-Shell's product slate at prices which cover all transportation costs, processing costs, and feedstock delivery costs and leave an adequate return on capital for all parties concerned.

7) Petrochemical developments in other low cost NGL regions will not seriously impinge upon Dow-Shell's target markets.

Numerous interelationships between the above assumptions can be found. The feedstock delivery cost and netback (net of transportation) product prices are two prime examples. Either of these variables, when sufficiently favorable, can render the project feasible and dictate the amount of cost variance that can be tolerated in assumptions 2 thru 5. Of the remaining assumptions, feedstock delivery costs will strongly influence assumption 1 and netback product prices are key elements of assumptions 6 and 7. By linking netback product prices to the BTU value of world oil prices, and allowing world oil prices to increase at the rate projected by the Department of Energy, Dow-Shell has effectively set the prices necessary to cover total estimated project costs. It follows that if DOE's projection and the foregoing set of assumptions is true a petrochemical development will be feasible in the time period specified by Dow-Shell.

A more detailed discussion of the first five assumptions, which are of particular interest to the State, is provided here.

1) North Slope producers will find it in their best interest to sell NGL's to Dow-Shell.

This is the most complex and nettlesome uncertainty of the project. The outcome rests upon the alternatives which producers face. The presence or absence of ANGTs is a key determinent of those alternatives as is the regulatory structure attendant to ANGTs. These variables imply 3 possible scenarios on the North Slope. These are: a) No ANGTS; b) ANGTS without natural gas regulation; c) ANGTS with natural gas regulation.

To understand the likely behavior of the producers under each of these scenarios we must briefly recount the transportation and physical aspects of North Slope gas. The gas composition of the Prudhoe Bay field is approximately 74 percent methane, 13 percent NGL, and 13 percent carbon dioxide. Based on a gas production stream of 2.7 billion standard cubic feet per day, the forecast level of production, the reservoir life is estimated at 27 years. The daily NGL component of such a volume and Dow-Shell's proposed recovery rate is given by category in Table 1.

(Table 1)

Summary of Natural Gas Liquids Extraction Plant in Barrels Per Day

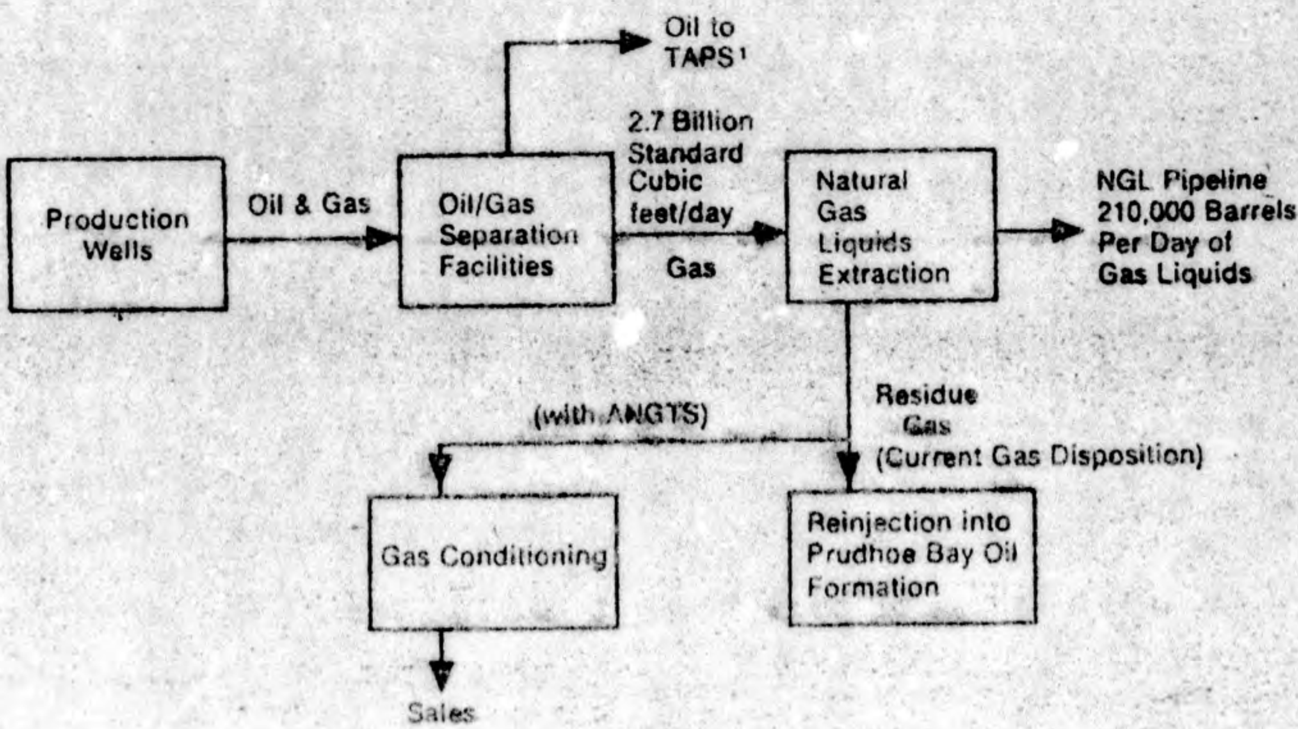
NGL Components	Entering Feed Gas Composition[1]	Phase 1 Initial Recovery[1]	Phase 2 Final Recovery[1]
Ethane (C_2H_6)	110,000	45,000	90,000
Propane (C_3H_8)	61,000	61,000	61,000
Butanes (C_4H_{10})	34,000	34,000	34,000
Pentanes (C_5H_{10}) and higher	28,000	25,000	25,000
Total	233,000	165,000	210,000

[1]Based on 2.7 billion standard cubic feet per day of entering gas

The high NGL recovery rate planned by DSG is a result of cost per unit considerations for (liquids line) transportation and the requirements of world-scale processing. Presently, oil and gas flowing from production wells are separated, with the oil entering TAPS and most of the gas reinjected back into the reservoir. Gas not reinjected is processed to meet most field fuel requirements. Should ANGTS be constructed, the raw gas producers now reinject would be separated from the NGLs and sent to a gas conditioning plant. To be compatable with ANGTS, carbon dioxide (CO_2) must be removed from the gas stream by further conditioning. The Dow-Shell Group may participate in the NGL extraction phase. Figure 2 schematically illustrates each phase leading to gas conditioning and ANGST.

Figure 2

Proposed Natural Gas Liquids Extraction Schematic



Two related issues will be mentioned before moving on to the three aforementioned scenarios. These are the extent of carbon dioxide removal and the composition of the raw gas stream over time. ANGTS could tolerate a gas stream with a CO_2 content of up to 3% whereas the conditioning plant could bring the CO_2 content to as low as 1%. A lower level of CO_2 removal would hold down the costs of the conditioning plant but may be problmatic for ANGTS maintanence. The converse holds true for maximum CO_2 removal. Since this aspect of gas conditioning is not seen as a major cost factor and does not affect the CO_2 content of the previously removed NGLs, it need not be considered. The same conclusion is drawn from the fact that the gas stream will become "leaner" over time. For physical reasons that will not be covered here, the gas stream is expected to grow leaner in the sense that the proportion of denser high BTU gases (butanes and pentanes plus) will decline. Considering the ample quantities available and prospects for additional North Slope discoveries, Dow-Shell has not expressed concern.

a) <u>ANGTS is not constructed:</u> If ANGTS is not constructed North Slope producers would have fewer alternatives for their raw gas. They could reinject, expand field fuel consumption of gas, or even co-mingle all the heavier gases and as much as half the available butanes with crude oil for shipment thru TAPS. The latter two options would entail some degree of NGL extraction, as would sales to the Dow-Shell Group.

It will be instructive now to explain some of the rudiments of NGL extraction. Just as liquids can be converted to vapor by heat and low pressure, gas vapors can be liquified by the application of pressure and refrigeration. The amount of pressure and refrigeration needed to bring a gas to liquid phase depends on the gas. A relatively heavy gas, such as butane and heavier groups, can be held in liquid phase under modest pressure as a disposable butane lighter demonstrates. The lightest of the hydrocarbon gases, methane, must be subjected to extreme pressure and temperature reduction to liquify. The composition of the Prudhoe Bay raw gas stream is such that heavier gases will be the first to liquify (drop out) in the extraction process. Progressively intense refrigeration and pressurization would force ethane and finally methane to drop out.

The foregoing discussion suggests that the degree of liquids extraction depends on sales to the Dow-Shell Group. For instance under this scenario, if producers chose not to sell to Dow-Shell but wish to exhaust alternatives to reinjection, they could utilize TAPS by extracting some propane and all heavier gases. Some portion of the remaining raw gas might also be conditioned to meet expanding field use. Conversion of methane to methonal for shipment down TAPS has also been proposed. These options are limited since TAPS capacity to carry NGLs will decline with the flow of oil, and gas is used to handle most present field fuel requirements. Should producers consider that approach superior to total reinjection, the prospective benefits of such an arrangement would establish the floor price which the Dow-Shell Group would have to bid against.

Without ANGTS, sales to a petrochemical plant is the most promising outlet for North Slope gas liquids. With Dow-Shell collecting nearly all gases save methane, producers could reinject, convert to methonal, or meet their field needs. Since some degree of NGL extraction would occur under either event, the Dow-Shell Group argues that their arrangement is more efficient. Dow-Shell maybe willing to participate in the costs of its selected extraction process. The division of cost and management responsibilities depend greatly on producer preferences and price negotiations. The producers, for their part, would likely seek to control all North Slope operations and would surely demand a price and level of participation which exceeds all costs incurred to accomodate Dow-Shell. These would include any inconveniences encountered in handling field requirements, the functional and speculative value of forgone reinjection gas, the net value of shipping NGLs down TAPS, and possibly the merits of methonal conversion.

b) <u>ANGST without natural gas regulation.</u>

The presence of an unregulated ANGST would pose a competitive hurdle for DSG. Physically, ANGTS is capable of transporting methane, ethane, and some propane. Although methane reserves are sufficient to run ANGST at full capacity over its lifetime, the BTU value (and thus the price) of ethane and propane is greater. Without sales to Dow-Shell, the producers would likely pack ANGTS with all the high BTU gas it could carry. However the mechanics of raw gas conditioning is such that this option is hampered.

To date, the preferred gas conditioning process on the North Slope appears to be the one recommended by Parsons Company. The process chosen by Parsons, however, results in a waste gas that contains about half the ethane that enters the plant. Thus the producers would ship a methane-ethane-propane mixture down ANGTS and be left with an ethane rich CO_2 gas. This waste gas, when spiked with propane (or possibly butane) would be suitable for field use. For the balance of the NGLs, producers could exercise the same options outlined in the without ANCST scenario.

To accomodate Dow-Shell, producers would have to condition primarily methane and forego the additional revenue which would otherwise accrue by a "richer" gas stream. In addition, any waste gas resulting from this arrangement would not be acceptable for field needs. Consequently, sales to DSG would be less attractive with the presence of ANGTS. Dow-Shell would find itself in heightened competition for Prudhoe Bay NGLs.

c) ANGTS with natural gas regulation.

If ethane and other NGLs are extracted before they enter an interstate natural gas pipeline, they are not subject to ceiling prices under the Natural Gas Policy Act. However, if ethane or other NGLs were co-mingled with methane destined for the Lower 48, federal law might treat them as "natural gas in interstate commerce" and subject to price regulation. This would dampen the producers incentive to spike the methane stream with higher BTU gases. Natural gas regulation would diminish the options available to producers and make them more disposed to negotiate with Dow-Shell.

In summary the outcome of assumption 1 hinges on a variety of indeterminent factors which the State is powerless to resolve. Until the disposition of ANGTS is known, producers cannot fully appraise their alternatives and they will be inclined to hedge their bets.

2) The costs of the gas liquids pipeline, and governmental regulations associated with this leg of the project will enable NGLs to be delivered to the plant at an acceptable price.

DSG has emphasized that they are not in the NGL extraction or transportation business. Consequently, they prefer that the ownership and management of those operations be left to other parties. Dow-Shell logically views the costs of NGL extraction and transportation as being imputed in the price of the NGLs which enter their plant. Although DSG is very cognizant of their markets, competition, product transportation costs, and on-site development, they appear to have a tariff mentality toward all activites upstream of the plant itself. Although such an approach is not inappropriate from Dow-Shell's perspective, the state should carefully scrutinize the costs of a gas liquids pipeline.

Dow Chemical assumed study responsibility for the northern half of the liquids line extending from Prudhoe Bay to Fox; Alaska Interstate Company studied the segment from Fox to tidewater. Assisting in the study were Williams Brothers Engineering Company for Dow Chemical and Delta Engineering Corporation, in cooperation with Brown and Root, for Alaska Interstate Company. Capital and operating cost estimates were made for a liquids line leading to each of the six selected sites. These costs dictate the NGL delivery cost for each site. Key assumptions concerning easements, environmental considerations, engineering specifications, etc. have been briefly outlined in the DSG report. The state does not presently have the expertise to throughly evaluate Dow-Shell's assumptions; but for the reasons enumerated above, it is appropriate for the state to be more concerned about this segment of the project than (say) events downstream of the plant. The major uncertainty is cost which is in turn influenced by regulation, financing, and the timing of other projects.

It is commonplace for projects of this magnitude to greatly exceed their original cost estimate. In 1975 for instance, when TAPS construction was already underway, the Alyeska Pipeline Service Company estimated a peak construction work force of 14 thousand. By 1976, however, Alyeska reported 26,770 persons employed. Cost overuns for the TAPS project are well documented and only the quadrupling of world oil prices saved TAPS from financial disaster. In hindsight, TAPS sponsors were well advised to insist upon government loan guarantees.

If construction of other large capital projects, such as Susitna, ANGTS or new North Slope oil and gas development were to occur at the same time a liquids line was being built, the economic boom could surpass that of TAPS construction in 1974-6. In that case, cost overuns would be phenomenal and this timing consideration could easily postpone the project.

Regulation for environmental and financing/pricing purposes can also have a strong effect on pipeline costs. A regulatory framework addressing the environmental concerns of pipeline construction has yet to crystalize. Dow-Shell states that all environmental stipulations will be followed during both construction and operation of the liquids line. The question becomes "at what cost?" Be it by more stringent engineering specifications, rerouting, or operations constraints, regulations nearly always translate to additional costs from the firms perspective. Consequently, Dow-Shell cannot make definitive estimates for either plant or pipeline construction costs until this matter is clarified.

The DSG report makes little mention of federal pipeline regulation. While the NGL liquids line would be entirely in-state, the federal government could conceivably assert authority over the pipeline. This might be done by interpreting LPG shipments to the U.S. Gulf Coast as inter-state commerce. The affect of such an interpretation is again manifest by cost. Without going into detail, it is safe to assume that the problems entailed by federal regulation are similar to those facing ANGTS. That is, some set of restrictions governing the pricing and financing practices of the project sponsers.

Finally, the issue of financing may become an inhibiting factor. Like TAPS, the construction of a gas liquids line involves a great deal of risk which financing sources are traditionally adverse to. To date, only the Alaska Interstate Company has expressed interest in constructing the pipeline. Moreover, that interest is restricted to the southern leg of the project. Who then will build the northern half of the line? The only certain statements that can be made is: a) that party will seek a substantial return for their risk; b) they may seek some form of loan guarantee or; c) they may seek both. The jest of the above paragraph is that the financing scheme envisioned by Dow-Shell, with pipeline owners holding a 10% equity position, is optimistic in light of the risks. Aside from the obvious concerns raised by these financing questions, it should be noted that the State has an uncomfortably high profile as a prospective equity participant/loan guarantor.

3) Dow-Shell has correctly estimated its on-site capital construction costs, including the costs attendant to health, safety, and environmental regulations.

The discussion relating to pipeline construction costs can generally be applied to plant construction costs. Given that Dow-Shell is intimately familiar with their construction requirements, and would be placing substantial capital at risk, their figures probably represent the most authoritative estimate available. Again, a delineation of the state's health, safety, and environmental regulations is imperative to establishing final costs. Moreover, even the most informed cost projection cannot escape the hazards of the Alaskan construction environment. Fortunately the state need not be overly concerned with DSG's construction costs. Once begun, the complex is almost certain to be completed despite overuns. Even if Dow-Shell were to suffer the fate of the sunk cost principle, the state would reap all the benefits anticipated.

4) Dow-Shell will be able to secure adequate infrastructure facilities, and in its negotiations with the State, will not have to incur infrastructure costs that translate into unacceptable construction costs.

This paper will not attempt a cost-benefit analysis of prospective state infrastructure costs. That task will be left to those who have intimate knowledge of State tax laws and community development. It is clear however that infrastructure costs must be defined before the state can begin rational deliberations.

Dow-Shell states that their calculations have been done on the basis that the state will not provide financial assistance in the funding of the project, except in "the normal areas of infrastructure ownership and financing". The DSG study anticipates a total project cost of nine to ten billion 1981 dollars, depending on the site. The level of world oil prices that Dow-Shell requires for feasibility would yield a 20% before tax rate of return on capital with a 15% rate of return applied to state capital expeditures. This implies that Dow-Shell would, over time, reimburse the state's outlays through taxes and user fees provided those outlays have been assessed accurately. Any miscalculations in this area will not change Dow-Shell's prospective revenues or their ability to reimburse the state.

The state will need to know: a) what costs Dow-Shell has calibrated at a 15% rate of return; b) the portion of those costs the state would finance. State decision makers should also bear in mind that Dow-Shell will not likely pay for infrastructure cost differentials from site to site and they are inherently more interested in appraising their own costs vis-a-vis state costs. Dow-Shell's analysis suggests that some fraction of the projects revenue is earmarked for payments toward infrastructure servcies. Those payments in turn form the states infrastructure budget which when exceeded, constitutes a subsidy.

5) Dow-Shell will be able to secure sufficient quantities of suitably priced natural gas for its fuel and feedstock requirements.

The plant under consideration by Dow-Shell would use feedstock hydrocarbons and byproducts for most of its internal needs. But despite the high energy value of its NGL feedstock, the complex would have a net energy requirement, in the form of electricity, of 75MW in the first phase of operation. The additional products planned for phase two would consume prodigious amounts of electricity, raising overall demand to 245MW. This compares to an average consumption of 600MW by the Municipality of Anchorage. The Dow-Shell group has determined that a combined cycle gas turbine co-generation system is optimal under most conditions. The details of this system as well as the others considered are covered in the energy section of Dow-Shell's report. For this analysis it is sufficient to say that the Dow-Shell Group would seek natural gas (methane) as fuel.

Project sponsors expect to purchase natural gas at $3 to $4/MCF. The source or wellhead price of the gas is unclear. For any of the tidewater sites an obvious source is Cook Inlet. The cost of delivery would vary considerably from site to site. With ANGTS, for example, gas would be available in Fairbanks at a minor delivery cost. The volume of gas involved is estimated at about 18.3 bcf. annually. The state will need to investigate the impact of such withdrawals from prospective reserve sources and possibly look into delivery costs for each site. The views of gas producers concerning Dow-Shell's price expectations would be useful. It should also be mentioned that DSG will seek feedstock methane during phase 2 of the project for their ammonia/urea operations.

Conclusions

As for assumptions 6 and 7, it is doubtful that state inquiries into world markets and competition would be very instructive. The petrochemical industry's expertise in this area, coupled with the tremendous risks that they would incur by such a project, effectively precludes the need for second guesses by the state. There is one area, however, in which the state's interests may be directly affected. The DSG study indicates that processes involving high ethane/low energy consumption are well suited for Alaska, but some of the products slated for phase 2 do not meet this description. The study further states that maximum production of the most favorable products is constrained by market considerations. Should Dow-Shell encounter unexpected methane/electricity costs, they may choose to drop certain items from their product slate and bypass Alaska by shipping out feedstocks earmarked for those items. Even the high cost of shipping ethylene (the first ethane derivitive) may be preferred to processing energy intensive chemicals in Alaska. In the extreme, all NGLs might be shipped out with virtually no processing in Alaska save the conversion of ethane in ethylene. Given that this possibility is mentioned in the DSG report, the state should examine the economic viability and consequences of that option.

To recap the issue of economic feasibility, the state should recognize that:

1) North Slope producers will not necessarily find it in their best interests to sell to Dow-Shell.

2) Until a regulatory structure is established all cost estimates should be considered highly tentative. Particular caution should be taken with cost estimates made by parties whose welfare is not directly linked to those estimates.

3) Any cost/financing difficulties arising outside of Dow-Shell's jurisdiction (e.g. the pipeline or state infrastructure) could end up at the state's doorstep.

4) It is not clear that Dow-Shell will commit itself to the degree of in-state processing presently contemplated.

The concerns enumerated in this paper suggest that the DSG report represents the most optimistic confluence of events. Even if world oil prices attain their expected level, the potential for "slippage" in some other area remains high. While the long term fundamentals for in-state petrochemical processing are good, one should not attach a high probability to sound development in the coming decade.

MEMORANDUM State of Alaska

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF FOREST, LAND AND WATER MANAGEMENT

TO: JOHN KATZ
Commissioner

DATE: October 14, 1981

FILE NO:

DICK LEFEBVRE, Deputy Director

TELEPHONE NO: 276-2653

FROM: DEAN N. BROWN, Chief
Water Management Section

SUBJECT: State Review of Dow/Shell Feasibility Study

Attached is a detailed response to Mary Halloran's memo of 9/27/81. The following is a brief summary of water resource concerns for each proposed Dow/Shell tidewater site:

Fire Island: Surface water unavailable. Insufficient groundwater information however data available shows salt water intrusion problem in existing well and suggests insufficient quantities available on island. Impact of water demand on Anchorage system would be extensive, doubling present capacity, enlarging treatment plant, building one larger and one new pipeline. The timing to incorporate changes is good since Anchorage is presently locating a new water source for development to be at either Eagle River or Eklutna.

Pt. MacKenzie: Surface water unavailable. Insufficient groundwater information, but two exploratory wells show water levels fluctuate with tides in Cook Inlet which raises serious concerns of salt water intrusion potential into aquifer with prolonged pumping.

Seward: Surface water insufficient year-round for project. Again insufficient groundwater information. Smaller glacially formed aquifers such as this is usually are of discontinuous and limited extent hydrologically and geologically. Depending on well location consideration should be given to creating salt water intrusion into aquifer during winter months.

Kenai: This is already an existing groundwater mining problem from industrial usage, which has lowered lake levels and affected domestic wells. Situation is believed to be mitigated, however Union Chemical had one well fail last month and is having to redrill it to reestablish water supply. Extensive aquifer testing needed before further large water uses permitted. Definite problem area. Surface water unavailable on site, but Kenai River could be source requiring tertiary water treatment facility and pipeline. Long term solution needed in Kenai with Borough, industry and State.

Valdez: Surface water insufficient. Groundwater source more than adequate for project if wells located based on ALPETCO drilling data results.

In all cases, the water cooling method proposed by Dow/Shell is the most resourse wasteful and other (more costly) alternatives such as air cooling are recommended by Water Management.

Additionally, you may wish to review page 7 of the attached document for potential State or Borough financial impact considerations.

cc: Dow/Shell Special Projects File

Question 1: Statement of the known water resources at each of the proposed tidewater sites.

I. FIRE ISLAND

1. No surface water is available on the island for this magnitude project.
2. Insufficient ground water anticipated. There is a water well on the island which has been monitored by U.S.G.S. The water was used for a small military outpost on the island, but when the well was pumped for a long period of time salt water entered the well.
3. Water from the municipality of Anchorage water and sewer system could be used. The present capacity is 20 MGD and would require doubling the system to meet the demands of the Petrochemical project.

Little information is available on Fire Island groundwater resources. Well pumping report located in the U.S.G.S. Water Resources System.

II. POINT MACKENZIE

1. No surface water is available at the site which could meet industrial demands.
2. Ground water is available, whether or not sufficient supply exists is not determined. Two test wells on the site, strong indication of potential salt water intrusion with prolonged pumping from these sources. The water level in the wells does fluctuate with the tides.
3. Sea water is available but would require a desalinization plant, and extreme tidal fluctuation and sedimentation would make this a poor site.

One technical report for two wells on the site by DGGS.

III. SEWARD

1. Surface water from Fourth of July Creek, a glacial stream may not be sufficient for requirements and does decrease flow substantially during winter months. Additional data is needed. The water will require treatment to remove silt and rock flour.
2. There is insufficient data to determine if the ground water from this valley would be an adequate supply. Similar glacial deposits frequently form discontinuous aquifers of limited hydrologic and geologic extent.
3. Sea water is available but would require a desalinization plant.

A report on water resources by U.S.G.S. and Quadra. There is very little information on groundwater resources at this site.

IV. KENAI

1. Groundwater is available in this area but present industrial usage has strongly impacted domestic users near existing wells. The site is in an industrially developed area. Tesoro - Alaskan Refinery, Phillips Petroleum Kenai Plant, Standard Oil of California are using ground water sources. Union Chemical Company is a major ground water user. Industrial ground water use is 4.2 MGD and domestic use is 0.35 MGD. Extensive aquifer testing is recommended prior to further industrial develoment from groundwater sources.
2. Surface water from the Kenai River would be able to supply 25 MGD for this project but tertiary pretreatment will be required before the water meets industrial standards.
3. Sea water useage would require a desalinization plant.

The Kenai area has been the subject of several technical reports since 1968. U.S.G.S. and DGGS have been monitoring groundwater supply for several years. A computer groundwater model has been developed by U.S.G.S. It is considered a water problem area by Water Management.

V. VALDEZ

1. Ground water: there has been a series of shallow test wells drilled on the ALPETCO Plant site and pump tests have been conducted on two deep wells. There should be adequate groundwater for this project.

2. Surface water: This source will not deliver the necessary quantities of water all year or the quality desired.

The area has been studied for industrial water use by ALPETCO. Department files have the pump test data and well logs.

Question 2: Review of Dow/Shell's potential usage, identifying the potential impacts of the project on water resources at each site.

At all sites, the amount of potential water use could be significantly decreased by use of other cooling methods.

Fire Island: Development of water from wells on site, if possible, is likely to cause salt water intrusion. Water from the Municipality of Anchorage would require doubling present capacity of Municipal system. Eagle River water via pipeline would require pretreatment to remove silt and glacier flour. Desalinization of sea water is expensive and tidal fluctuation and sediment load would not make this an ideal site.

Point MacKenzie: Pumping at present plant needs could possibly cause salt water intrusion. Impact of plant on amount of water available for urban development is undetermined. Surface water from the Susitna River may be an acceptable alternate but pipeline impact, need for treatment, and possible fisheries impact would need to be studied.

Seward: Impact is indeterminant due to groundwater data needs, however it could impact the industrial park development area the city is considering as well as fresh water needs for the port facility being considered.

Kenai: Ground water at this site is being used by other industries in the area. The lake levels in the Kenai area have been shown to fluctuate because of pumping from existing wells and further development of this magnitude is anticipated to effect domestic wells in the area.

Valdez: The impact of 25 MGD withdrawal from this location would not negatively impact the aquifer or other users. Bedrock ridges are known to extend under the site and wells would need to be located in the deepest part of the valley to avoid problems.

Question 3: Identification of major studies needed or additional information needed by the State in order to make decisions regarding water allocation.

Fire Island: Need exploration wells to determine amount of groundwater available on the island. Need study to determine effect and cost of using Anchorage water system as a source of water, including costs of a pipeline from Eagle River and one to Fire Island. Long range effect of this quantity of usage on the Municipal water reserves and demand should be determined.

Point MacKenzie: Need more test wells, pump tests, and peizometer installation to determine the amount of ground water available on the site. Hydrologic study of the ground and surface water potential in this area of the Susitna River Valley should examine aquifer extent, capacity, potential for salt water intrusion, effect of tidal fluctuations on aquifer and wells, and potential of using Rivers.

Seward: Need test wells and pump tests to develop aquifer information for this location. Stream gaging of Fourth of July Creek needed to determine minimum and maximum flows, duration, and recharge effect on aquifer.

Kenai: Additional drilling, pump tests and observation wells are needed on the actual site to determine possible effect on existing domestic wells, lake levels, existing industrial water withdrawals (Union Chemical's last well has gone dry and they are having to redrill now) and possible salt water intrusion. Feasibility of developing a water source from the Kenai River should be reexamined from the aspects of water treatment necessary, cost of treatment plant and pipelines, location, in-stream flows and affect on canneries located on the river (navigability).

Valdez: May need to determine availability of groundwater at the specific proposed well sites on the Dow/Shell site location. Water data generally sufficient for the location from ALPETCO studies. Should have an on-going monitoring program in existing wells on site.

Question 4: Recommendations, if any, for future action by the State or Dow/Shell or the local communities re water availability.

Dow/Shell - at all sites: develop cost, feasibility, and quantities needed for using a more conservative method of water use for cooling, such as air cooling. Prepare list of alternative options.

develop list of anticipated ancillary industries with related water usages.

Fire Island

Local - Municipality of Anchorage is presently developing a comprehensive water development plan which needs to consider impact of extension of a system to the island. Determine the cost of increasing water treatment plant capacity for use on the island.

Dow/Shell - cost of water from Eagle River via pipeline to the island. Cost of a desalinization plant on the island.

Point MacKenzie

Borough - develop a groundwater resource assessment program consisting of well drilling, pump testing, aquifer definition. Gather data on the effects that continuous pumping will have on the fresh water - salt water interface. Assess groundwater needs for projected urban-industrial-agricultural development and plan water development for the area.

Dow/Shell - develop cost of other water source options such as off-site wells, Susitna River, etc. including pipeline costs.

Seward

City - determine if water resources in this area can supply all their planned development and a petrochemical industry. Develop an information base of available ground and surface water for industrial development.

Kenai

State - reestablish funding for update of U.S.G.S. groundwater modeling system, undertake joint DGGS/USGS drilling program on-site to monitor water usage in this location, work with city and industry to develop a plan for water control.

City and Borough - Assess the impact that promotion of increased industrial development will have on existing water usages and determine a course of action for securing funding for a water source to meet present expansion and future needs.

Valdez

City - initiate groundwater monitoring of existing ALPETCO wells in this area.

Additional specific concerns that should be considered and may affect feasibility and cost of project:

1. Water pipeline construction funding -

   Possible pipeline construction for water has been mentioned for Pt. MacKenzie, Fire Island, and Kenai. In conversations, the question of funding has been nebulous with at least one indication that the State or Boroughs would be expected to fund and build one. and Dow/Shell would pay a water user charge commensurate with that charged domestic water users, but not any capital charges. Costs, alternative options, and impact on public, state, Borough should be evaluated.

2. Development of increased or new water supplies affecting existing municipal systems.

   Expansion of the Anchorage system due to population increases has necessitated the studies underway to identify and develop new water sources affecting Eagle River and possible Eklutna. Impact of the Dow/Shell project would be substantial, affecting quantities of water needed, treatment plant expansion, pipeline capacity increase to Anchorage and new pipeline possible to supply site. At Kenai existing industrial uses affect groundwater adversely in local areas. If Kenai continues to attract industries a new water supply system and source will need to be located, financed and developed. Again, funding, cost to be borne by a petrochemical plant, and effect on existing water supply reserves should be examined as well as Dow/Shell's implied position of not becoming involved in problems of construction, expansion or development of water supply that would serve other users.

3. Water conservation methods should be utilized by any petrochemical plant.

   Alternate cooling methods which will not use or minimize use of water are utilized in many areas, but are more expensive which would affect ultimate feasibility.

4. At some point the cost and feasibility of desalinization, which would be further impacted by sediment load in waters, should be investigated for the Kenai area. Water resources will continue to become an increased deterent to industrial development.

STATE of ALASKA

MEMORANDUM

TO: John W. Katz
Commissioner
Department of Natural Resources

DATE: October 7, 1981

FILE NO:

TELEPHONE NO: 465-4347

FROM: William R. Nix
Commissioner *by Sydne*
Department of Public Safety

SUBJECT: State Agencies' Recommendations & Policy Development; Petrochemical Technical Team

It is the recommendation of the Division of Fire Prevention that all six Fire Prevention Recommendations (copy attached) should be initiated during the next one to three years.

Reference Item #1. Planning must focus on both the fire protection needs of the petrochemical complex and the surrounding community, with decisions being made by the local government as to the level of desired fire protection (degree of acceptable risk).

The Feasibility Study is less than clear in its definition of responsibilities for response to emergencies at the complex. On one hand the report portrays an in-house fire protection capability, and later suggests that major fires or natural disasters would trigger the call-up of the community's emergency services. The report expresses reservations with the Pt. Mackenzie site in that there is considerable distance between the site and the community's emergency services.

In reference to the required plan checks of the complex design, the division has requested two additional staff positions (a fire protection engineer and a secretary/typist) plus contractual monies for technical reviews to meet the impact of the natural gas pipeline construction. It would be logical to carry these over for the subsequent NGL line and complex construction. Of key concern are the design features for which there are no regulations. It would be short-sighted to regulate the construction of the complex in only those aspects for which we now have regulations.

The division proposes to assess the risk to the safety of the population by verifying the stated safety record of the petrochemical industry in general and by specific companies through the National Safety Council. Additional data gathered by the National Fire Incident Reporting System, the National Fire Protection Association, and other sources will be examined. Research and data about known physical characteristics of materials will also be checked.

Substantial effort must also be directed to the transportation aspects of the project, both input (NGL) and output (Products) of the complex. There is insufficient information on the expected behavior of hazardous materials in emergencies for pre-planning and tactical decision making.

The report expresses a high safety record for the petrochemical industry, however, this is not specifically defined. The array of potential variables which affect the decision making process at a hazardous materials incident cannot be reduced to one simplistic answer. Therefore, the industry and communities must prepare for the catastrophic as well as the routine incidents.

Attachment

DEPARTMENT OF PUBLIC SAFETY

Fire Prevention

1. Need fire protection planning which involves both industry and public services where available, and also security measures planning.

2. Establish clearcut definition of responsibilities among the industry, state and local governments concerning fire protection systems.

3. Encourage Dow/Shell to examine the potential of the State's regional fire training centers, backed by the Department of Education's Fire Service Training Program.

4. Anticipate requests for grants or loans to finance local government fire protection equipment, apparatus and stations.

5. Investigate the appropriateness of a waiver of the local building code enforcement program in those communities which have both a local code and the state code plan requirement to avoid regulatory redundancy.

6. Consider the following statutory deficiencies:
(a) Certain aspects of the petrochemical facilities may be of such a scale that no nationally known recognized codes or standards may be written to meet the scope of the project. Should the State Fire Marshall develop independent codes or accept industry standards?
(b) If the plants are constructed in a political subdivision that does not exercise any building regulations, there will be no check on the structural integrity of buildings, such as the structures' ability to resist wind, snow or earthquake loading (as no state agency provides such a check).
(c) Consider establishment of followup field inspections of facilities whose plans have been reviewed by the Division of Fire Prevention.

MEMORANDUM

State of Alaska
Department of Revenue

TO: John W. Katz
Commissioner
Department of Natural Resources

DATE: November 2, 1981

FILE NO:

TELEPHONE NO:

FROM: Joseph K. Donohue
Deputy Commissioner, Taxation

SUBJECT: Dow-Shell Petrochemical Industry Feasibility Study

The attached memorandum outlines the possible state and local revenue impacts to be considered relative to a petrochemical operation like that envisioned by Dow-Shell. I believe, as the memorandum indicates, that major contractual, financial, and locational decisions on the part of prospective participants to the project must be made before the state can commence quantitatively assessing such impacts.

The attached memorandum does, however, discuss the primary areas impacting the state in terms of revenue.

MEMORANDUM

State of Alaska

Department of Revenue

TO: Vince Wright
Chief of Research

DATE: October 15, 1981

FILE NO:

TELEPHONE NO:

FROM: John Larson
Economist

SUBJECT: Review of Dow-Shell Petrochemical Industry Feasibility Study - Potential Impacts on State and Local Government Revenues

The purpose of this memo is to examine the potential effects of the Dow-Shell proposed projects on state and local government revenues. The discussion of revenue impacts at the state level will deal with the sale of the state's royalty share of natural gas liquids (NGL), the corporate income tax, the oil and gas property tax and other potential state government revenues. At the local level property taxes, sales taxes and other local government revenues will be discussed. An attempt will be made to identify areas where there is a need for additional information or clarification due to uncertainty about future events relative to the projects. An overall governmental fiscal impact analysis of the projects would involve also examining potential state and local government expenditures and means of finance for infrastructure, regulation and services relative to the projects and their induced activity. This is however beyond the scope of this memo and probably not possible given the level of information and uncertainties contained in the Dow Shell study.

The sale of the state's royalty share of Prudhoe Bay Natural Gas Liquids (NGL) to this project would represent one source of revenue at the state government level. The amount the state would receive for its NGL would be subject to negotiation but in no case would it be lower than the amount received had the state taken its royalty share of these NGL's in value from the producers rather than in kind and sold to this project. The advantage of this project depends on what alternative markets and means of transportation exist for Prudhoe Bay natural gas and NGL's. That is will the Alaska Natural Gas Transportation System (ANGTS) pipeline ultimately be built providing a market for these NGL's.

The Dow Shell project is really two separate projects. The first project would be a NGL extraction and transportation project where, given certain market conditions, producers at Prudhoe Bay would find it advantageous to extract NGL from natural gas at Prudhoe Bay, ship the NGL into its two major components Liquid Petroleum Gas (LPG) and ethane and then ship the LPG to market via cryogenic LPG tankers. The second project which depends upon the first for its feasibility would be the construction of ethane based petrochemical derivative plants probably at a tidewater site using the ethane from the LNG project as a feed stock. In addition to favorable market conditions and cost factors, the feasibility of the petrochemical project would depend on the availability of ethane from the NGL project.

Whether the producers eventually find a NGL project in their best interest will depend on what alternatives exist for marketing those NGL's. If ANGTS is not built, there will be no means to market the NGL and thus it will have no value to the producers unless they find an alternative means of bringing it to market such as a NGL project. This also means that the state's royalty share of these NGL will have no value unless alternatives are developed. If, however, ANGTS is built then the relative advantage to the producers and the state of this project, at least insofar as additional value for NGL's is concerned, will be reduced.

Corporate income tax levied on the income project sponsors derive from participation in the LNG or petrochemical projects and on the additional corporate activity and income induced as a result of these projects would represent another potential source of state government revenue.

The amount of corporate income tax the state would collect from direct participants in these projects would depend upon the financial structure of the project. That is, which corporations would own an interest in what portions of the projects and how would they be financed?

The corporate income tax would be collected under provisions of AS 43.20, the Alaska Net Income Tax Act as modified during the 1981 legislative session by SB 524 and HB 460. Under AS 43.20 corporations are separated into two types, "those doing business in the state which derive income from the production or pipeline transportation of crude oil or natural gas in the state," and those which do not. Oil is further defined as "crude petroleum oil and other hydrocarbons regardless of API gravity which are produced in liquid form, including the liquid hydrocarbons sometimes known as distillate or condensate which are recovered from gas other than at a gas processing plant," this would appear to include NGL's. The determination of income and apportionment factors for each type of corporation is different. Corporations which fall under the oil and gas provisions determine their Alaska taxable income by starting with their federal taxable income making certain adjustments and multiplying by an apportionment factor which is the average of the ratio of their Alaska divided by their worldwide property, extraction and sales. Corporations which are considered non oil and gas determine their Alaska taxable income by starting with their federal taxable income, making different adjustments and multiplying by an apportionment factor which includes property, payroll and sales ratios. Both types of corporations are subject to the same tax rates on their Alaska taxable income in determining their tax liability. A major difference aside from the use of an extraction factor in place of a sales factor for oil and gas corporations, is that oil and gas corporations may only use methods of depreciation in effect as of June 30, 1981, in computing their adjusted federal taxable income to be apportioned. This means that these corporations will not be able to take advantage of recently enacted federal tax legislation allowing for greatly accelerated cost recovery (depreciation) in computing their Alaska tax liability. Non oil and gas corporations on the other hand would be allowed to use the new depreciation methods in computing their tax liability under AS 43.20.

It appears from the Dow Shell study that various portions of the projects would be owned and operated by different types of corporations and those would be subject to different provisions of the corporate income tax. For example, if the Prudhoe Bay producers, ARCO, EXXON and SOHIO, owned and operated the NGL portion of the project, the income derived from that project would probably be taxed under the provisions of AS 43.20 as they apply to oil and gas production and transportation corporations. If the chemical corporations Dow and Shell owned and operated the petrochemical portion of the project, they would probably pay tax under the non oil and gas provisions of AS 43.20.

Due to uncertainty about future product and financial market conditions as well as potential participants in these projects the Dow Shell study does not specify the exact financial structure or amounts of income to be derived from the various portions of the project. It is thus not possible to determine at this time, with potential development so far in the future, the amount the state would collect under the corporate income tax from these projects.

Another source of revenue at the state level would be the tax collected under AS 43.56, the Oil and Gas Exploration, Production and Pipeline Transportation Property Tax. Under the provisions of AS 43.56, an "annual tax of 20 mills (2 percent) is levied on the full and true value of taxable property." Taxable property is further defined as "real and tangible personal property used or committed by contract or other agreement for use within this state primarily in the exploration for, production of or pipeline transportation of gas or unrefined oil (except for property used solely for the retail distribution or liquifaction of natural gas) or in the operation or maintenance of facilities used in the exploration for, production of . . . ." Unrefined oil includes "crude petroleum and other hydrocarbons regardless of gravity which are produced at the well head in liquid form and the liquid hydrocarbons known as distillate or condensate recovered or extracted from gas . . . ," which would seem to include NGL.

Based on the above definitions, it appear that the NGL portion of the project which would include an extraction plant, a NGL pipeline, a fractionation plant and an LPG terminal facility would be subject to the property tax under AS 43.56 since they are used in the production of and pipeline transportation of NGL. It is questionable whether the petrochemical derivative plants which would use the ethane from the LNG project as feedstock would be subject to the property tax. This is an area which would require additional legal clarification.

It should also be noted that under the provisions of AS 43.56 and AS 29.53 Municipal Assessment and Taxation, municipalities may also levy property taxes against property which is taxable by the state under AS 43.56 subject to certain limitations. The tax paid to a municipality is credited against the state tax and thus would reduce state tax revenue. Limitations on municipalities' property taxing power relate to population, existing tax base and rates and whether the tax is to pay for bond debt service. Since a definite site or sites for these projects has not been selected, it is not possible to determine the amount of municipal property tax which could be collected on project property. Due to uncertainty about the project and the interaction between state and municipal property taxes, it is not possible to determine the amount the state would collect under AS 43.56.

There are a number of other sources of revenue at the state level which would conceivably increase as a result of increased direct and induced employment and business activity resulting from these projects. These revenues would be certain gross receipt and sales and use type taxes as well as business and non business license and permit revenues and facilities and service-related charges. These revenues make up a very small portion of total revenues at the state level and the impact of these projects would not be very significant. Since Alaska no longer has an individual income tax, employment and payrolls resulting from the projects would not generate much revenue at the state level.

At the local level, property taxes on the facilities associated with these projects would probably represent the most significant source of addition of revenue. In addition to facilities used directly in the projects, support facilities and residential houseing induced by the project could also be taxed at the local level. Municipalites are given the power to levy property taxes under the provisions of AS 29.53. There are, however, limits as to the amounts they may collect through the property tax determined by the population of the municipality and various per capita limits. There are also maximum rate limitations. These limits, however, do not apply to "taxes levied to pay or secure payment of bond principal or interest" regardless of whether the bonds are in danger of default for boroughs and first class cities and only to avoid default on payment of principal and interest on bonds for second class cities. Thus, if a municipality which is a borough or firt class city sold bonds to finance infrastructure for these proposed projects, they could levy property taxes without limit if necessary to repay the bonds whereas a second class city could only levy unlimited property taxes if the bonds were in danger of default.

To determine the amount of additional local property tax that would result from these projects, it would be necessary to know the population of the municipality where they would be located, the type of municipality, the amount of tax base already subject to property taxes and the use to which the taxes would be put. Since no definite site has been selected, this is not possible at this time.

Sales taxes would be another possible source of revenue at the local government level. Municipalities are given the power to levy property taxes under AS 29.53 subject to the limitation that the rate may not exceed six percent. Also, if the municipality levies a property tax on property which is subject to the state oil and gas property tax AS 43.56 that property tax is in place of any sales taxes associated with that property.

Thus a municipality could not levy both a sales and property tax on activity associated with facilities which would be subject to the state property tax, which in the case of these projects would most likely include at least the LNG project facilities. Sales taxes could be levied on induced economic activity and sales. Again more specific information is needed to make any quantitative estimate of the amounts which would be collected.

Various license and permit fees at the local level would be an additional but minor source of revenue resulting from these proposed projects.

In conclusion, there is a potential for significant additional revenues at both the state and local level to result from these projects. Additional specific information as outlined above will be required before any quantitative estimates can be made. It is likely, in light of all the uncertainties which surround these projects in terms of timing, economic feasibility and financiing that this information will not be available for some time.

MEMORANDUM

State of Alaska

Department of Transportation & Public Facilities

TO: John W. Katz
Commissioner
Dept. of Natural Resources

DATE: November 2, 1981

FILE NO:

TELEPHONE NO: 465-3900

FROM: John Bates
Deputy Commissioner
Planning and Programming
DOT/PF

SUBJECT: Dow/Shell Petrochemical - Final Report

I have had my staff review the Dow/Shell final feasibility study. We found it to be a very professional product and have only two specific comments to offer on the report.

I would like to emphasize that certain segments of the proposed transportation facilities should not be considered as appropriate for public financing. Even though the report refers to significant infrastructure requirements and indirectly suggests that these facilities are a public responsibility, our traditional definition of "infrastructure" includes only those facilities that are developed to serve the general public and are open to all on an equal basis. It's obvious that improvements such as the liquids docks, and possibly others, will not fall within that definition.

We have also reviewed the cost estimates of transportation facilities that were transmitted to Mary Halloran earlier this year. We feel that the estimates are still valid and need no revision.

Given that the State is considering the option of acquiring the Alaska Railroad, it is reasonable to assume a greater responsiveness might exist with respect to those development scenarios involving use of the rail system. This situation should be particularly true in the case of any needed expansion of that system. Without attempting to estimate the levels of proposed traffic that would potentially be generated by the project, out recent assessments indicate a under-utilization of the capacity of the existing physical plant. Moreover, those same assessements have indicated a potential for a large increase in that capacity with a modest amount of investment.

Please be assured that DOT/PF will continue to participate in the assessment of industry proposals. If there is any further information that I can furnish, Please let me know.

Attachment

ESTIMATE OF COSTS - TRANSPORTATION ELEMENTS

DOW/SHELL PETROCHEMICAL DEVELOPMENT

KENAI

Dock Facilities	Order of Magnitude Cost Millions of Dollars
1. Dry Cargo Dock	20-25
2. Liquids Dock	175-250
3. Barge Dock	40-60
4. Bulk Material Dock	40-60
Highway & Industrial Access	
1. Spur highway Wildwood to Nikiski (5 miles)	5-10
2. Main Site access (1/2 mile)	1-2
TOTAL TRANSPORTATION ELEMENTS, KENAI	281- 407

PT MACKENZIE

Dock Facilities	
1. Liquids Dock	200-250
2. Barge Dock	50-75
3. Bulk Material Dock	50-75
Railroads	
1. Railroad from Houston	50-75
Highway & Industrial Access*	
1. Pt. Mackenzie Highway (20 miles)	10-15
2. Causeway to Anchorage	500-750
3. Access road to dock	5-10
TOTAL TRANSPORTATION ELEMENTS, PT. MACKENZIE	865-1,250

FIRE ISLAND

Dock Facilities	
1. Liquids Dock	75-150
2. Bulk Material Dock	50-75
Railroad	
1. Rail via causeway (12 miles)	15-20

*$5.5 million for Knik Arm Crossing in FCCSHB 50

Highways & Industrial Access

1. Causeway	300-500
2. Highway connecting with Seward Hwy (12 miles)	10-15
3. Access on Fire Island	5-10

TOTAL TRANSPORTATION ELEMENTS, FIRE ISLAND - 455-770

VALDEZ

Dock Facilities

1. Liquids Dock	100-200
2. RR Barge Dock	25-50
3. Container Barge Dock	25-50
4. Bulk Material Dock	25-50

Railroad

1. Dock to plant site	5-10

Highways & Industrial Access

1. Access to road to Alpetco site (1 1/2 miles)	1-2
2. Municipal Dock to site	1-2

TOTAL TRANSPORTATION ELEMENTS, VALDEZ - 182-364

SEWARD

Dock Facilities

1. Liquids Dock	75-100
2. RR Dock	25-50
3. Dry Cargo Dock	25-50
4. Bulk Material Dock	25-50

Railroad

1. RR Dock to plant site	10-15

Highway & Industrial Access*

1. Nash Road Extension (6 miles)	2-5
2. Seward Highway Upgrade	50-75

TOTAL TRANSPORTATION ELEMENTS, SEWARD - 212-345

*Currently authorized projects for FY '81 include $15.8 million for Seward Highway upgrade and $3.0 million for Nash Road - 4th of July Creek improvements.

BONANZA CREEK ALTERNATE

Railroad	
1. Spur to site (9 1/2 Miles)	15-25
Highway and Insdustrial Access	
1. Access from Parks Highway (2 miles)	1-2
TOTAL TRANSPORTATION ELEMENTS, BONANZA CREEK ALT.	16-27

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT

SEP 26 1980

Alaskan Northwest Natural Gas)
Transportation Company) Docket No. CP80-435

INTERIM REPORT TO THE COMMISSION

BY THE ALASKAN DELEGATE

AND THE DIRECTOR, AUDIT AND COST ANALYSIS,

OFFICE OF THE FEDERAL INSPECTOR

In its order of August 1, 1980 in the above captioned proceeding, the Commission directed the Alaskan Delegate, assisted by the OFI Division Director, to commence a series of technical conferences on the project sponsors' cost estimate for the Alaska segment of the ANGTS and related incentive rate of return (IROR) issues. The order inter alia offered the parties an opportunity to file comments on procedures for the conferences, and directed the Delegate to consider those comments with the parties at the first conference.

The first round of conferences was held on September 3 and 4, 1980, and dealt mainly with procedural issues. Prior to the conferences, procedural comments were received from the project sponsors and the Commission's trial staff. The comments, and the discussion that ensued, focussed primarily on the scheduling and location of the conferences, transcription of the conferences, and procedures for exchanging information. These matters were discussed at length in the morning session of September 3 and the afternoon session of September 4; the results of those discussions are summarized below.

Cost Estimate Formats

The afternoon session of September 3 was scheduled to consider cost estimate formats. That session was very brief in that no party indicated any disagreement with the cost estimate formats previously submitted by the project sponsors. We expect the sponsors' formats to be agreed to by the parties at next week's conference.

IROR Methodology Issues

The conferences opened with (and later returned to) a discussion of the concern expressed by the Commission in its August 1, 1980 order (at page 10), namely that:

> The Commission's orders establishing the IROR mechanism contemplated that all such [design] issues would have been resolved prior to the filing of the CCSE.

The design issues identified in the conferences as having some potential for resolution on a basis other than that contemplated by Alaskan Northwest's July 1 filing were:

1. Separation distance between the ANGTS and the Trans-Alaska (oil) Pipeline System (TAPS);

2. The possiblity of utilizing a tunnel of approximately two and one-half miles in length to bypass the most difficult portion of the Atigun Pass in the Brooks Mountain Range in northern Alaska;

3. Burial of the pipeline in a shallow or embankment mode, rather than in a trench; and

4. Access roads and work pads constructed of snow, with increased emphasis on winter construction, as opposed to access roads and work pads made of gravel, with emphasis on summer and "shoulder" months for the construction period.

The first of these issues, the separation or alignment question, was left open to some degree by Congress and the President in selecting the approved transportation system. 1/ On this basis, the Commission in its orders in Docket No. RM78-12 expressed its intention to consider establishing the Certification Cost Estimate (CCE, or occasionally referred to as the Certification Cost and Schedule Estimate, or CCSE) upon appropriate resolution of this issue. 2/ The issue has now been resolved by the Department of the Interior (DOI), on a basis slightly different from that on which the July 1 filing was based. DOI's proposed right-of-way grant allows for the possibility, upon completion of considerable further study, of authorizing the alignment originally proposed by Alaskan Northwest, 3/ but Alaskan Northwest suggested in our conferences that they would likely accept DOI's

---

1/ The nature and route of the approved system was specified in Section 2 of the Decision and Report to Congress on the Alaskan Natural Gas Transportation System (Executive Office of President, Energy Policy and Planning, September 1977). Approved by Joint Resolution of Congress, the Decision has the legal force and effect of a Federal statute. The Decision states (at page 7):

> From Prudhoe Bay to Delta Junction, Alcan expects to construct its line approximately eighty feet from the Alyeska oil pipeline. As proposed by Alcan, construction will be carried out by extending the existing Alyeska work pads. However, Alyeska advised that the Alyeska and Alcan lines must be separated by 100 to 200 feet where blasting to build the pipeline trench would occur (approximately 350 miles of pipeline length). Additional studies will determine the minimum distance between the Alyeska oil pipeline and the Alcan line that is necessary to permit safe construction and operation.

2/ See, e.g., Order No. 17-A, "Order Confirming the Incentive Rate of Return Mechanism and Denying Petition for Reconsideration and Classification," Docket No. RM78-12 (issued January 17, 1979).

3/ The proposed grant with its terms is contained in a letter, dated August 20, 1980, from Guy R. Martin, Assistant Secretary for Land and Water Resources, Department of the Interior, to Mr. John McMillian, Chairman of the Board of Directors for Alaskan Northwest Natural Gas Transportation Company, the sponsor of the Alaska segment. As mentioned later in this interim report, we have asked that this letter with its attachments be filed and served on the parties to this proceeding.

preferred routing. Accordingly, we believe it is appropriate to try to develop a recommended CCE value based on the revised alignment.

With respect to the other issues identified in our initial conferences, Alaskan Northwest characterized the burial mode and access road/work pad issues as ones for which the July 1 filing contained their preferred resolution, but for which agencies of the Federal Government, principally the Federal Inspector and various of his advisory bodies, had requested that alternatives be explored. Alaskan Northwest reported that the alternatives are being explored in good faith, but that Alaskan Northwest believes in the superiority of the preferred alternatives contained in the July 1 filing, and expects those alternatives to be selected when consideration is complete. On the other hand, the tunnel alternative for passage over the Brooks Range is being evaluated as a potentially preferable alternative to the use of Atigun Pass.

The Commission's Alaskan Delegate 4/ and the Commission itself 5/ have stated that the ANGTS approved by the President and the Congress is the system described in the Alcan filing submitted to the Federal Power Commission in March of 1977. 6/ It would seem, then, that the Commission's Order Nos. 31 and 31-B would have been written in the contemplation that it was basically that system (save for the separation issue as discussed above) which was to be constructed and for which the IROR mechanism as adopted by the Commission was to apply.

4/ See, e.g., "Report of the Alaskan Delegate on the System Design Inquiry" (especially at page 51), attached to "Notice of Delegate Report and Order Inviting Comments," issued by the Commission in Docket No. CP78-123, et al., on May 17, 1979.

5/ See, e.g., "Notice of Proposed Rulemaking and Statement of Policy," Docket No. RM79-19 (issued February 2, 1979) at page 7, and Order No. 45 (issued in that proceeding on August 24, 1979) at page 5 (rehearing pending).

6/ "Alcan Pipeline Project 48-inch Alternative Proposal," Docket No. RM77-6, filed on March 8, 1977.

Section 9 of the Alaska Natural Gas Transportation Act (ANGTA) limits changes to the approved system to those which would not

> . . . compel a change in the basic nature and general route of the approved transportation system or . . . . otherwise prevent or impair in any significant respect the expeditious construction and initial operation of such transportation system.

The question which arises for exploration in our proceeding is whether all changes such as would meet this test, including presumably any of the additional three mentioned above if ordered by the Government, 7/ are within the contemplation of Order Nos. 31 and 31-B.

Alaskan Northwest's proposal is to treat all such changes as "design changes" as allowed for by the Commission in Orders Nos. 31 and 31-B. As postulated in the Commission's August 1, 1980 order (at page 10), we think an alternative value of the CCE is appropriate for the new resolution of the separation issue, because of the referenced language regarding the separation issue in Order Nos. 17 and 17-A. In this proceeding, we will attempt to determine whether additional alternative values of the CCE are appropriate for alternative resolutions of other outstanding design issues, and, as requested, will address development of guidelines to govern the design change process envisioned by the Commission's orders.

With respect to procedure, it seems apparent that Alaskan Northwest's July filing is based on the same design concepts as the March 1977 filing, although those design concepts have been greatly refined since that time through expenditure of considerable time

---

7/ Condition No. I.5. at page 29 of the Decision requires that the project sponsors develop a final design, design cost estimate, and construction schedule for submission to and approval by the Federal Inspector prior to the initiation of construction. At that stage, the Inspector could order changes as a condition of his approval.

The Commission provided a discussion of its understanding of the design change problem as part of its change in scope discussion at pages 120-138 of Order No. 31 (issued June 8, 1979).

and effort. Alaskan Northwest suggests, and we concur, that the July 1 filing is an appropriate base from which to begin development of CCE and Center Point (CP) values for the Alaska segment. The cost consequences of any alternative resolutions of outstanding design issues would be developed by Alaskan Northwest as variations off of the basic cost information presented in that filing, and could best be evaluated by the Commission and the parties as variations from that base. Detailed evaluation of the basic estimate could thus be a step in evaluating estimated costs of any alternatives, even if our report to you ends up recommending CCE values for alternative designs.

Another aspect of the Commission's concern in this area was also addressed during our conferences. We raised the question of whether the recent agreement between the project sponsors and the North Slope producers on a cooperative study for design and engineering of the pipeline and conditioning plant would not result in some further changes to the design of the pipeline beyond those currently being studied. We were assured that that agreement did not contemplate such further changes. We requested that the agreement be filed and served on all parties to this proceeding, and that a statement on behalf of the parties to that agreement be filed and served on all parties to provide some idea of the agenda and timetable for the design review being conducted pursuant to that agreement.

As regards further proceedings on the IROR methodology issue, we agreed on the following additional steps:

1. In addition to filing and serving the cooperative study agreement, we asked that the sponsors file and serve the communication from DOI regarding the right-of-way grant.

2. We have developed a working paper on IROR concepts which is being circulated as an attachment to this report.

3. The Federal Inspector's report requested by the Commission to identify the major outstanding design issues from his perspective is expected to be submitted by the end of September. At approximately the same time, the project sponsors will submit the above-mentioned statement from the producer-sponsor study group, plus any further thoughts they may have with respect to (a) other outstanding major design issues, and (b) a more complete statement of their views regarding how such changes should be handled for purposes of the IROR mechanism.

4. At the same time, any other party may also submit its own comments on design issues, including any design changes that such party wishes to propose for consideration. (In this regard, Exxon, ARCO and Sohio took the position that the design should include the conditioning and processing facilities required to prepare the gas for pipeline entry.) Reports and comments on design issues, as submitted by the project sponsors and the parties, should also address the IROR implications of those issues.

5. The project sponsors expect to file by October 15 appropriate revisions to their proposed CCE to account for the changed separation from the oil pipeline. They indicated that they expect to have information available on the cost consequences of other design alternatives by the end of October.

Several parties (including, in particular, the trial staff) expressed reluctance to consider the IROR issues until after the parameters of the outstanding design issues had been clarified in the conferences. On the other hand, we felt that it was important to begin exploration of IROR questions early in the conferences, as application of the IROR mechanism is an important element of the context in which the Commission and the parties consider the sponsors' cost estimate filings. The compromise that we struck was to begin exploration of the IROR topics in a special conference in the week of October 6, 1980, then return to it at the end of the conferences.

Schedule of Future Conferences

Williams Brothers Engineering Company, the consultants recently retained by OFI, indicated a need to spend several days at the offices of the sponsors' project management contractor in California meeting with the project sponsors to familiarize themselves with the organization and methodology of the sponsors' filing. Those informational sessions were held on September 16-18. All parties were invited to participate. No decisions were reached at these sessions, and no transcript was prepared. The Alaskan Delegate and the OFI Division Director did not attend these sessions.

Further technical conferences will commence in the last week of September. We originally announced our intention to hold the conferences on alternate weeks pursuant to the following schedule:

September 30

October 14

October 28

November 11

November 25

However, inasmuch as several of these weeks involve Federal holidays our present intention is to reevaluate the schedule through discussion with the parties at the September 30 conference.

Each conference will commence on a Tuesday, and will continue for as many days as the parties consider useful and appropriate, but will terminate no later than the Friday of the week in which it commenced. The Alaskan Delegate or the OFI Division Director will preside at each of these conferences, and a limited transcript will be kept (as discussed below).

The first conference will be held in California. The location of the ensuing conferences will be determined at a later date, taking into consideration the subject matter to be discussed.

The following subjects will be taken up at the conferences, in this order:

1. Estimate format
2. Pipeline
3. Compressor and metering facilities
4. O & M facilities
5. Temporary facilities and services
6. Communications and supervisory systems
7. Project directorate
8. Potential design changes and P/L adjustments
9. Center Point and contingency and finance charges

The first conference will start off dealing with all subject areas to determine, to the extent possible, general areas on which there is substantial agreement or disagreement. The conference will then concentrate on subjects no. 1 and no. 2 above. At the conclusion of each conference, the parties will determine the scope and agenda of the next scheduled conference.

The conferences will continue until we and/or the parties conclude that they are no longer productive. We have tentatively scheduled them through the end of November, anticipating that they can usefully continue at least that long. At about that time, we will advise the Commission regarding our expected schedule for any further proceedings.

In addition, as mentioned above, a conference will be held in Washington on October 7, to consider design issues and their IROR implications.

The Delegate will issue a notice of each conference, identifying the date, place and subject matter of the conference. A copy of the notice announcing the September 30 and October 7 conferences is also attached to this report.

Transcripts

The project sponsors and the trial staff recommended that no transcripts be kept of the conferences, contending that the discussions would be faster, freer and more productive without them. Alaska, Exxon, and ARCO, on the other hand, recommended that verbatim transcripts be kept, contending that they would be needed to accurately record the results of the conferences as well as to keep all parties fully informed. After lengthy discussion, the Delegate established a compromise procedure designed to balance and accommodate all of these legitimate concerns to the extent feasible.

A court reporter will be present at all of the technical conferences (i.e. except for the pre-conference informational sessions during the week of September 16). All agreements by the parties present at the conference will be transcribed. When the parties disagree, but have discussed a subject at sufficient length to crystallize the nature of their disagreement with some degree of precision, their respective positions will be transcribed. In addition, the transcript will include a summary of the topics discussed, and a description of the agenda for the next conference. The transcript will also include a description of all informal exchanges of information between a party and a decisional person (generally, Williams Brothers personnel) that have occurred prior to the conference and subsequent to the last such transcription (see discussion below). Parties present at the conference may also include in the transcript any other procedural or substantive matter that is reasonably pertinent to the proceeding. Within these general parameters, the conferences will make very liberal use of "off the record" discussions, including simultaneous meetings in smaller groups, and free flowing consideration of thoughts, ideas and questions as they occur.

After careful consideration of the views expressed by the parties, it is our conclusion that this procedure will satisfy the legitimate needs of the parties (and of the OFI and the Commission) for an accurate record of the progress of the conferences and the conclusions reached (including conclusions in the nature of sharpened, articulated disagreements), without inhibiting the free flow of discussion. Parties who wish to be informed of the processes by which these positions and conclusions are reached will in any event have full opportunity to participate directly in the conferences themselves. In reaching this conclusion, we also note that the conferences are not formal evidentiary hearings, and that there will be no testimony under oath or cross-examination of witnesses. The purpose of the conferences is to assist the Alaskan Delegate and the OFI Division Director in the preparation of their report to the Commission by organizing the information and clarifying the issues; all parties will have ample opportunity to file comments and reply comments on the report itself.

In this regard, several parties inquired as to whether the conferences would be deemed part of the Commission's "record" of the proceeding. It is our conclusion (and we so stated) that the record of the conferences would be part of that "record" in the sense that they constitute preliminary, informal consideration of the subject matter designed to culminate in the issuance of a formal notice inviting comments and reply comments.

Finally, in the course of discussion of the transcript procedure, one party referred us to the following sentences on page 9 of the Commission's August 1, 1980 order:

> Stipulations and other agreements are encouraged, and will be included in the final report to the Commission. Unanimous agreement amoung the participants at a conference shall be deemed to constitute unanimous agreement among the parties. Objections to stipulations must be supported by substantial rationale.

It is our understanding (and we so stated) that the Commission's intent was to maintain steady progress at the conferences by precluding parties at a later conference from re-opening agreements and stipulations reached at earlier conferences. As we understand it, however, the above quoted passage was not intended to preclude the Alaskan Delegate and the OFI Division Director from exercising their independent judgment in the preparation of their report in the event that they reach a conclusion different from one stipulated or agreed upon by the parties. (In such event, the report would set forth the agreement or stipulation, and state why the Delegate and Division Director disagree with it.) Similarly, it is our understanding that the Commission did not intend to preclude any party (whether or not it participates in the technical conferences) from raising any issue in its comments and reply comments on the Delegate and Division Director's report to the Commission, regardless of any stipulations and agreements upon which the report may have been premised.

<u>Exchanges of Information</u>

The delegate first noted the August 15, 1980 comments from the Commission's trial staff, dealing, in large part, with the area of discovery. The Delegate pointed out that the technical conferences were intended to deal with the CCE, CP and related IROR matters only. To the extent that trial staff or other parties seek information that is to be dealt with in the final FERC certification proceeding (e.g., information relating to the financing plan or the marketability of Alaskan gas) or that relates to matters which are the responsibility of the OFI (e.g., the project sponsors' management plan), they must rely on methods of access available to them through means other than the technical conferences. The parties should deal directly with each other in obtaining access to documents and other information. The Delegate or the Division Director will rule on the production of documents directly relevant to this proceeding when the parties cannot reach agreement among themselves.

Williams Brothers, OFI's consultant assisting the Alaskan Delegate and the OFI Division Director in the preparation of their report, indicated a continuing need to obtain information informally from the project sponsors on their cost estimate. Similarly, the trial staff and their consultants indicated an occasional need to consult with Williams Brothers on questions of common interest. Both the project sponsors and the trial staff indicated that their respective rights would not be prejudiced by such private oral communications between conferences provided that the communications were fully disclosed at the next conference. No other party objected to this procedure, and all parties who expressed an opinion agreed that this procedure would expedite the conferences by enabling all participants (including Williams Brothers) to be better prepared for them.

Accordingly, any party may communicate privately with William Brothers personnel between conferences (or prior to the first conference). At the next conference subsequent to such communication, the contents of the communication will be disclosed and will be recorded in the transcript. Williams Brothers will maintain a log of all such communications, which will be reproduced as part of the transcript (or, if it is voluminous, will be circulated separately by the Delegate to all parties on the restricted service list).

The trial staff also indicated a possible need to obtain oral information from OFI on occasion. In such event, the OFI Division Director will record and report on the communication. Similarly, in the event of a need for communication between any party and

James McCullough, the Alaskan Delegate's IROR consultant, Mr. McCullough will record the communication and disclose it at the next conference.

In the event that information is communicated in written form between a party and either the Delegate, OFI or Williams Brothers, the sender of the written communication will serve copies of it on all parties on the restricted service list. If the information is voluminous and appears to be of limited interest, the party communicating it may circulate instead a short description of the material and an offer to provide copies to any parties indicating a desire for such.

The Alaskan Delegate will establish a public file in his office containing all of the transcripts and other materials generated by the conferences. The trial staff will ensure that the Commission's central filing system contains the same material, under Docket No. CP80-435.

John B. Adger, Jr.
Alaskan Delegate

J. Richard Berman
Director, Audit and Cost
Analysis, Office of the
Federal Inspector

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Alaska Northwest Natural Gas Transportation Company | Docket No. CP80-435

Notice of Technical Conferences

(September 23, 1980)

Notice is hereby given of the resumption of the series of technical conferences convened to consider for rate of return purposes the materials filed by the sponsors of the Alaska segment of the Alaska Natural Gas Transportation System in this docket on July 1, 1980. These conferences are being held pursuant to the Commission's order issued in this proceeding on August 1, 1980.

Two additional conferences are being scheduled at this time. The first will attempt an inventory of contested issues in all topic areas addressed by the July 1 filing, then focus on a discussion of any issues with regard to (1) the sponsors' cost estimate format, and (2) the pipeline construction component of the total cost estimate. The conference will also reconsider certain aspects of the conference schedule discussed previously. This conference will take place at the Fluor Corporation headquaters at 3333 Michaelson Drive, Irvine, California, and will begin at 1:00 p.m. on Tuesday, September 30, 1980, and continue until adjourned, in any event no later than Friday, October 3, 1980. The precise location of the conference will be posted at Fluor's headquarters on the day of the conference, and can be obtained in advance by calling Frieda Whiteside at (714) 975-6032.

The next succeeding conference will be held at the Commission's offices in Washington, D.C., beginning at 10:00 a.m. on Tuesday, October 7, 1980. This conference will consider a report from the Office of the Federal Inspector on major outstanding design issues, certain additional submissions regarding potential design changes from the project sponsors, and any further submissions from any other parties, in beginning to address the issue of the treatment of major design changes under the incentive rate of return (IROR) mechanism prescribed for the ANGTS by the Commission, and to address the development of guidelines to govern the design change process called for by that same IROR mechanism. That conference will also continue until adjourned, in any event no later than Friday, October 10. The precise location of this conference at the Commission's offices will be posted on the day of the conference, on the second floor bulletin board at 825 North Capitol Street, Washington, D.C. Further information about this conference can be obtained from Miss Jeanne Barrie at (202) 357-8900.

In accordance with the agreement reached at the conference of September 3-4, 1980, summary transcripts will be prepared for both the Washington and Irvine conferences. Information about obtaining copies of those summary transcripts is available from Miss Jeanne Barrie at (202) 357-8900.

John B. Adger, Jr.
Alaskan Delegate

WORK PAPER WP-1

THE FERC REGULATORY FRAMEWORK OF THE CENTER POINT OF THE IROR MECHANISM

James D. McCullough
September 22, 1980

Prepared for
"Comparative Cost Analysis for the Alaskan Segment, ANGTS Task"
Federal Energy Regulatory Commission
Contract DE-AC39-80RC-10477

TABLE OF CONTENTS

The FERC Regulatory Framework of the Center Point of the IROR Mechanism

I. Introduction

The purpose of this brief paper is to compile FERC's published regulatory comments on the Center Point established for the Incentive Rate of Return Mechanism (IROR) - its definition and scope. Of particular interest are the types of events contributing to cost uncertainty which are to be included in - and excluded from - the Center Point. A separate paper will explore the technical statistical aspects of the Center Point (CP).

II. Center Point Definitions

> (a) "Center Point -- The value of the Cost Performance Ratio which would be achieved at the expected or most likely level of construction costs for the pipeline. The difference between the Center Point and 1.0 is a measure of the likely or expected level of cost overruns from the Projected Capital Costs of the project."[1]

> (b) "Cost Performance Ratio -- The ratio of deflated Actual Capital Costs to Projected Capital Costs. This ratio is used to measure the performance of the project sponsors in achieving the budgeted cost of construction and reducing cost overruns."[1]

The ratio is adjusted for inflation and for design and other scope changes.

---

[1]Federal Energy Regulatory Commission, Order No. 17, "Order Attaching Incentive Rate of Return Conditions to Certificates of Public Convenience and Necessity," Docket No. RM 78-12, December 1, 1978, pg. 20.

(c) "Deflated Actual Capital Costs ... the sum of direct construction costs actually incurred in the construction of the pipeline after conversion into base-year prices ... plus a Finance Charge calculated from the Real Rate of Return ..."[1] The Finance Charge is based on the Real Rate of Return (set at 5 percent).

(d) "Projected Capital Costs ... the sum of direct construction costs included in the Certification Cost and Schedule Estimate approved by the Commission pursuant to Condition 7, ... and after any adjustments for Changes in Scope ... or resulting from design changes prior to the Final Design ... plus a Finance Charge calculated from the Real Rate of Return."[1]

Design Changes and Scope Changes will be discussed below.

III. Center Point Relationship by Formula to IROR Schedule

a. Definitions

1. "Incentive Rate of Return (IROR) -- The rate of return on equity that shall be decreased as the Cost Performance Ratio is increased in order to provide an incentive for project sponsors to keep construction costs as low as possible. This rate of return is referred to as a variable rate of return in the President's Decision."[2]
2. "Incentive Rate of Return Schedule -- A table or formula establishing a value of the Incentive Rate of Return for each value of the Cost Performance Ratio."[2]

b. Center Point Relationship to Center Point

"One of the Cost Performance Ratios must be chosen as the starting point for constructing the IROR schedule. Once that point has been assigned a rate of return, and the marginal rate has been chosen, the entire schedule can be determined.

---

[1]FERC, Order No. 31, "Order Setting Values for Incentive Rate of Return, Establishing Inflation Adjustment and Change in Scope Procedures, and Determining Applicable Tariff Provisions," Docket No. RM 78-12, June 8, 1979, pages 241-242.

[2]Order 17, op. cit., pages 20-21.

The Center Point is that Cost Performance Ratio which is associated with the Center Rate of Return. Ratios above the Center Point will yield rates of return below the Center Rate. Ratios below the Center Point will be rewarded as underruns, with rates of return greater than the Center Rate.

In order for the Center Rate to be perceived by investors as adequate compensation for risk, it should be the rate of return that they can realistically expect their investment to yield. As a result, the Center Point should be set at the most likely Cost Performance Ratio. Then, if the final costs are at the expected levels, the Center Rate will be earned."[1,2]

c. Formulas to Relate Center Point to IROR and to Determine Center Point

The IROR formulas established for Northern Border and Northwest Alaskan (NWA) are:

"The Incentive Rate of Return shall be set equal to [(17.5)(CP) + 8 (A - CP)]/A for the Alaska segment and [(15)(CP) + 8 (A - CP)]/A for the Northern Border segment, where A is the Cost Performance Ratio and CP is the Center Point."[3]

Formulas for the establishment of the Center Point were set forth in Order 31 as follows:

"Based upon the findings of the President's Decision, the Center Point (CP) for the Alaska segment shall be calculated from the following formula:

---

[1]FERC, "Revised Notice of Proposed Rulemaking," Docket No. RM 78-12, September 15, 1978, page 14.

[2]The IROR will be earned on equity capital in accordance with Condition 16, "Cost of Service Calculations," of Order 31, page 250. A one-time adjustment to the rate base will be made, per Condition 17 (page 251) to permit an "Operation Phase Rate" of 14 percent to be earned on that adjusted amount, per Condition 13 (page 249). The rate base for debt capital funds will include the actual cost of borrowing funds used during construction (AFUDC). The Commission assumed a 25 percent equity capitalization and a 75 percent debt capitalization in determining the Real Rate of 5 percent (see Order 31, page 38).

[3]Order 31, op. cit., page 249.

Center Point = [1.3 x (March 1977 Cost Estimate + Finance Charge)]/[Certification Cost Estimate + Finance Charge]

where the March 1977 Cost Estimate is in base-year prices.

The Center Point for the Northern Border segment will be calculated from the following formula:

Center Point = [1.1 x March 1977 Cost Estimate + Finance Charge)]/[Certification Cost Estimate + Finance Charge]

where the March 1977 Cost Estimate is in base-year prices."[1]

The Commission gave the sponsors the option to elect to not use the formula provided that:

"If the project sponsors believe that a major change in the basic nature of the project from that assumed in the Decision has occurred, and thus, the above procedure [the formula] for setting the Center Point is no longer applicable, then the sponsors, as part of their respective submissions of certification cost estimate, must at a minimum present evidence to the Commission on the following subjects:

(1) The nature of the changes in the project from that assumed at the time of the Decision.....

(2) The value or benefit to the Nation and gas consumers of construction of this project in light of the revised cost estimates.....

(3) The cost increases or cost overruns above the Certification Estimates that may reasonably be expected to occur....."[2]

---

[1]Ibid, page 247.

[2]Ibid, pages 52-53

Northern Border elected to follow the formula, and the Commission determined that their Center Point is 1.0758.[1] The Northern Border IROR schedule is shown on Figure 1.

> "The Commission, in Order 31, gave the project sponsors two choices or options as to how the Center Point would be determined. The first option was to utilize a formula based upon a comparison of the Certification Cost and Schedule Estimate and the estimates in the President's Decision. In its Motion for Rehearing, Alaskan Northwest objects to this formula approach. Under the second option, the project sponsors could request a Center Point without reference to the formula as part of the Certification Cost and Schedule Estimate submission if a major change had occurred in the project, including likely overruns, that exceeded the estimates in the Decision.
>
> Alaskan Northwest's motion states that '...it now appears very clear that a reasonable cost estimate for the Alaska Segment of the project will exceed the March 1977 cost estimate by more than 30 percent.' The Commission interprets this statement to mean that a major change in the Alaskan segment of the project has occurred since the President's Decision, and thus that Alaskan Northwest has rejected the option of setting the Center Point using a formula approach. Consequently, the Commission will not require that the formula approach be used for the Alaskan segment."[2]

IV. Minimum Value of Center Point

Upon petition by NWA, the Commission ruled that:

> "...the Center Point will not be set at a value less than one. However, the Commission will carefully review the Certification Estimate to determine if if is based upon normal or probable conditions and assumptions, and is an otherwise reasonable estimate, and will adjust the estimate if necessary before approval is granted."[3]

---

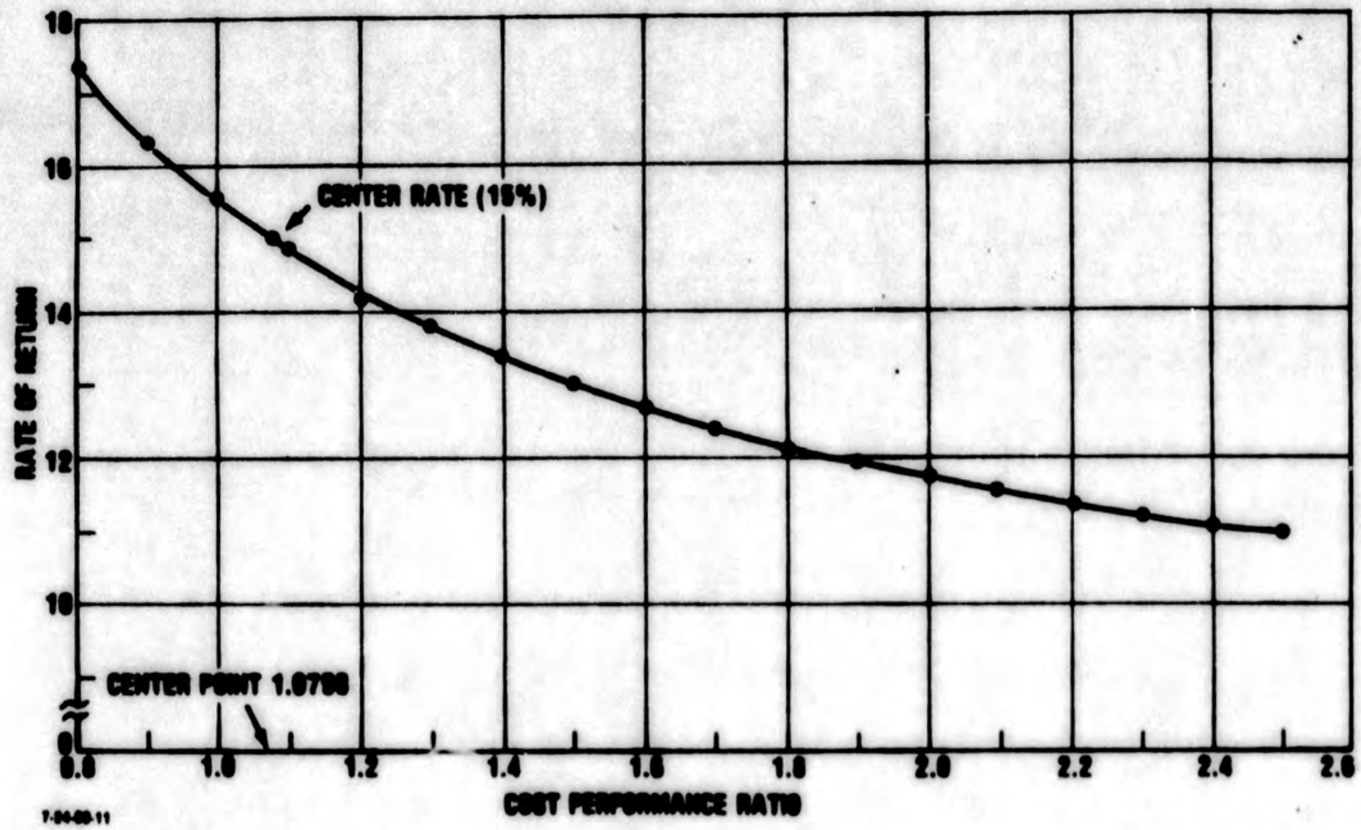
[1] FERC - *Findings and Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Importation of Natural Gas*, Docket Nos. CP78-123, et. al., April 28, 1980, page 103.

[2] FERC, *Order No. 31-B On Rehearing* - Docket No. RM 78-12, September 6, 1979, page 4.

[3] Ibid, page 5.

Figure 1

NORTHERN BORDER IROR SCHEDULE AS DETERMINED BY COMMISSION ORDER OF APRIL 28, 1980



V. Events to be Included in or Excluded From the Center Point

a. Abnormal Events to be Excluded from the CCE.

"The Commission expects that the Certification Estimates will only include costs resulting from normal conditions to be expected during construction. Abnormal or unlikely events that could increase costs will be analyzed as part of the sponsors' submission concerning potential cost overruns from the Certification Estimate."[1]

b. **Categories of Abnormal Events**

The Commission further clarified the categories of abnormal events in its Order to Northern Border.[2]

> "The Commission has previously dealt with the relationship between normal contingencies and the Center Point of the IROR schedule in its orders defining the IROR mechanism.[119/] In those orders, the Commission has distinguished among Change in Scope events, abnormal events and the conventional approach to estimation. These references may be categorized into three sets of "events" as concerns the Center Point:
>
> (1) Abnormal or unlikely events of such importance and consequence that the Commission has designated them as "Change in Scope" events.[120/] The cost consequences of these events are to be excluded from the cost estimates submitted for use in determining the Center Point. The project sponsors will be permitted to increase the Projected Capital Costs, which serve as the target for assessing cost and schedule control performance, by the estimated costs of Change in Scope Events as approved by the Federal Inspector.
>
> ---
>
> [119] See, especially, Order No. 31-B at pages 6-7.
>
> [120] See Condition 10, Order No. 31-B at page 73.

---

[1]Order 31, op cit., page 54.

[2]NB Order of April 28, 1980 op. cit., pages 96-97.

(2) Normal or likely events of a routine nature but of an unknown (but not significant) cost impact, such as are normally included in pipeline construction cost estimates as contingency or management reserve at rates, for example, of 5-7 percent. The cost consequences of these "anticipated unknown" events are to be included as contingencies in estimates submitted for use in determining the Center Point.

(3) Abnormal or unexpected events that could substantially increase costs but which are not included in the list of Change In Scope events. Examples of such events are 100 year storms, major fires and floods. The cost consequences of these "unanticipated unknown" events are to excluded from the normal contingency allowance discussed above, but because these events are not Change In Scope events they are covered only by the Center Point mechanism itself."

VI. Change in Scope Events

The estimated costs of events qualifying as Change-In-Scope Events are to excluded from the Center Point determination. Order 31-B defined these as:[1]

"Such Change in Scope events shall be limited to:

(1) declared or undeclared war, including civil war or a formally declared blockade,

(2) any emergency or major disaster which either (a) is determined, by the President of the United States, pursuant to the Disaster Relief Act of 1974, Pub. L. 93-288, 88 Stat. 143 (as it may be amended) to have occurred in the United States or its territories or possessions, or (b) is determined by the Federal Inspector (i) to have occurred outside the United States or its territories and possessions and (ii) to be of such consequence that, had it occurred in the United States, it is reasonably probable that it would be determined to constitute an emergency or major disaster pursuant to clause (a) above,

---

[1]Order 31-B, op. cit., pages 74-75.

(4) major changes in pipeline routing or capacity ordered by Federal or State Governments for the Alaska Natural Gas Transportation System from that approved by the Federal Inspector in the Final Design of the pipeline, and

(5) delay in the issuance of a government permit or certificate necessary for completion of the pipeline system, when such delay (a) occurs subsequent to approval of the Final Design, (b) occurs through no fault of the project sponsors and (c) causes significant cost increases."

VII. Normal Contingencies

NWA expanded upon the Commission's definition of normal contingencies in its Certification Cost Estimate submission:[1]

> "In-scope estimating uncertainty was carefully defined to separate its impact on project costs from the impact of unexpected events, design changes, and changes in scope. In-scope estimating uncertainty was explicitly defined as the variation in project costs and schedules resulting from:
>
> - Accuracy of material quantity estimates.
> - Accuracy of material price estimates.
> - Human productivity assumptions.
> - Equipment reliability assumptions.
> - Engineering/design development.
> - Accuracy of scheduled durations.
> - Accuracy of bid specifications based on current project definitions."

VIII. Design Changes Prior to Final Design Approval

It should be noted that neither the Certification Estimate nor the Center Point should include an allowance for design changes made prior to approval of the Final Design. Condition 9 of Order 31 permits the Projected Capital Cost baseline to be modified by the addition of the estimated costs of design

[1]NWA submitted an estimate for normal contingencies of 12.0 percent of Direct Capital Costs exclusive of Finance Changes, Volume XXXIII, "Normal Contingency, Contingency Methodology and Breakdown, WP-14," July 1, 1980, page 7.

changes incorporated into the Final Design approved by the Federal Inspector.[1] Thus, there is no need to allow for this in the Certification Estimate or Center Point. However, minor Design Changes due to pipeline rerouting subsequent to the Final Design approval, but prior to actual construction, are to be included. See item IX(2) below.

Further, the Projected Capital Costs may not be reduced for design changes that reduce costs.[2] This is to provide sponsors an incentive to propose design changes that reduce the ultimate costs to consumers. The Commission ruled that changes in design which reduce capital costs at the expense of increased operating and maintenance costs will not be allowed.

The Commission further clarified this ruling in a lengthy footnote to the Northern Border Order:[3]

> "The Commission takes this opportunity to clarify one aspect of Order No. 31-B, regarding revisions to the Projected Capital Costs target for the IROR mechanism. At pages 41 and 42 of Order No. 31-B, the Commission expressed a willingness to accept Northern Border's proposal that Projected Capital Costs should not be reduced for design changes that reduce costs. It has occurred to us that, in theory at least, abuses could arise in the following two types of situations:
>
> (1) Project sponsors were aware of cost-saving design changes at the time of consideration of the CCSE, but postponed them until after CCSE approval in order to retain a high CCSE and thus improve their expected cost performance ratio, and consequently their IROR; or
>
> (2) Certain optional assumptions (of which the project sponsors had knowledge at the time of preparation of the CCSE), such as alternate (cheaper) sources or (lesser) specifications for materials or equipment, were omitted in preparing the CCSE for the purpose of increasing its value, only to be changed once the CCSE had been approved.

---

[1]Order 31, op. cit., pages 244-245.

[2]Order 31-B, op. cit., pages 41-42.

[3]Northern Border Order of April 28, 1980, op. cit., pages 100-101.

The Commission still believes that Northern Border's basic suggestion is valid. To eliminate any potential for abuse, the Commission states that neither of the two above described situations were intended to result in design changes without adjustment in Projected Capital Costs. Orders No. 31 and No. 31-B were premised on the following assumptions:

(1) Project sponsors did not know about cost-saving design changes at the time of preparation of the CCSE if such design changes are to be approved without lowering Projected Capital Costs; and

(2) If optional assumptions were made in preparation of the CCSE, cost-saving design changes will continue to utilize those same assumptions unless the assumption made was the correct one at the time of preparation of the CCSE but had since become inappropriate.

The Commission's intention in accepting Northern Border's suggestion was exactly the reason that led Northern Border to propose it, namely, to give the project sponsors an incentive to propose design changes that reduce costs. The Commission recognized that implementing such an intention will be difficult, and will inevitably depend on the exercise of administrative judgment. The Commission intends that the Federal Inspector will be the one to exercise such judgment as he sees fit, and the Commission believes that it has structured the IROR mechanism in a manner which fully authorizes him to do so."

IX. Commission Comments on Abnormal Events not Covered by Change in Scope Rules

The Commission, in Orders 31 and 31-B, commented upon various abnormal events which are not covered by Change In Scope rules and hence, are covered only by the Center Point.

(1) Exclusion From "Wars":

"As [illegible] "wars," 'we do not include riots, insurrections, actions of public enemy, and civil or military disturbances or other interferences' either because such events are clearly of lesser magnitude than 'war' or because they are inherently vague and ambiguous in meaning."[1]

---

[1]Order 31-B, op. cit., page 33.

(2) Design Changes:

"In this instance, the adjective 'major' is essential to the basic structure of the Change in Scope mechanism. Any change in the capacity of the pipeline would probably constitute, on its face, a 'major' change, but that is not true of changes in the route. It is likely that, subsequent to approval of the Final Design but prior to the actual laying of the pipe into the ground, there may well be numerous minor deviations in the precise routing of the pipe - deviations made to accommodate particular terrain conditions as they are encountered. That process is inherent in pipeline construction, and the project sponsors can and should plan for it in their cost estimates."[1]

(3) Abnormal Weather, Fires, Floods, "Acts of God":

"The project sponsors should evaluate weather problems realistically (including a factor for delays caused by abnormal weather) when preparing their Certification Cost Estimate (including the Center Point). Then, when abnormal weather occurs, the efforts of all concerned can be focused exclusively on coping with it.

Similarly, fires, floods, landslides and other "acts of God," as well as "terrorism, sabotage, riots, and civil disturbances, and embargos, strikes, work stoppages and slowdowns" are all risks that the project sponsors can evaluate in advance, in the sense of considering a reasonable cost factor for some level of unanticipated and undesirable events that may occur during the course of the project."[2]

---

[1]Ibid, page 39.

[2]Order 31, op. cit., page 128.

(4) Delays Due to Non-Completion of Other Segments:

"The IROR mechanism fully protects the project sponsors from one other form of delay that could otherwise have a potentially serious impact on the rate of return. The project sponsors or investors in any one segment, Alaskan or Northern Border, of the pipeline will not be responsible for cost increases resulting from construction delays in the other segments, or from a delay in the initiation of gas production at Prudhoe Bay. This is accomplished by defining the Actual Capital Cost for a segment as those costs incurred up to the point that that segment is capable of rendering service, even though other segments are not yet capable of delivery from Prudhoe Bay. In other words (for IROR purposes only), AFUDC will cease to be added to the Actual Capital Costs for a segment when that segment is complete and ready to begin transporting gas even if, for whatever reason, it is not actually transporting gas. (AFUDC will, of course, continue to accrue for rate base purposes.)"[1]

(5) Field Conditions and Right-of-Way:

"With respect to field condidions there is an economic trade-off. Field conditions can be ascertained in advance through sampling and other scientific techniques. On the other hand, there comes a point at which the cost of elaborate advance ascertainment would exceed the cost of coping with whatever unexpected conditions may eventually be encountered. The project sponsors are in the best position to strike the proper balance between incurring the cost of totally comprehensive ascertainment in advance versus coping later with unacticipated conditions that had not been fully ascertained. The project sponsors should be the ones to make the judgement, to estimate their costs accordingly, and to bear the responsibility for whatever unanticipated conditions they eventually encounter. Similarly, right-of-way acquisiton is a problem that the project sponsors can and should evaluate when preparing their Certification Cost Estimate (including the Center Point.)"[2]

---

[1]Ibid, page 133.

[2]Ibid, pages 128-129.

X Recap of Key Points Related to the Alaska Segment

The Center Point is the Cost Performance Ratio which is associated with the Center Rate of Return. The value of the Center Point is the expected or most likely level of the actual construction costs of the pipeline. The difference between the Center Point and 1.0 is a measure of the expected level of cost overruns from the Projected Capital Costs (PCC) of the project. For the Alaska Segment, the Center Point will be established by review of NWA's Center Point justification paper and not by a formula.

The PCC's initial value is that of the approved Certification Cost Estimate. The PCC may be increased (but not decreased) by the cost of design changes approved by the Federal Inspector prior to the approval of the final design and construction go-ahead. Subsequently, the PCC may be increased by the cost of Change-In-Scope Events as approved by the Federal Inspector.

The abnormal events excluded from coverage by the Center Point are 1) design changes, 2) scope changes, 3) those events covered by the normal contingency allowance (in-scope estimating uncertainty). The abnormal events covered by the Center Point include weather (such as 100 year storms, landslides, major fires and floods), riots, insurrections, terrorism, sabotage, actions of a public enemy, civil disturbances, design changes made subsequent to the Federal Inspector's approval of the Final Design (but prior to the actual laying of the pipe), embargos, strikes, work stoppages and slowdowns.

The IROR will be earned on equity capital and AFUDC earned on borrowed capital. A 25 percent equity capitalization and a 75 percent debt capitalization is assumed.

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Georgiana Sheldon, Acting Chairman;
Matthew Holden, Jr., George R. Hall
and J. David Hughes.

Northwest Alaskan Pipeline Company) Docket No. CP78-123, et al.

Northern Border Pipeline Company) Docket No. CP78-124

Pacific Gas Transmission Company) Docket No. CP79-60

ORDER PROPOSING CONDITIONS TO CERTIFICATES

(Issued December 19, 1980)

The Commission is proposing the adoption of a condition to be appended to the final certificates of public convenience and necessity (for construction and operation of the Alaska Natural Gas Transportation System) issued by the Commission to Pacific Gas Transmission Company (PGT) and Northern Border Pipeline Company (Northern Border) in its orders of January 11 and April 28, 1980 in Docket No. CP78-123, et al., 1/ as well as to the conditional certificates issued December 16, 1977 in the same docket.

In light of the limited number, nature and scope of the proposed conditions, as well as the statutory mandate of Section 9 of the Alaska Natural Gas Transportation Act (ANGTA), 15 U.S.C. §719g, that certification of the Alaska Natural Gas Transportation System (ANGTS) be expedited, the Commission has decided to use notice and comment procedures to consider the condition. In addition to other applicable law, this order is issued pursuant to Section 7(e) of the Natural Gas Act, 15 U.S.C. §717f(e), Section 9 of the ANGTA, the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System (Decision), 2/ Paragraph 7 of the Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline, and Section 402(a) of the Department of Energy Organization Act, 42 U.S.C. §7172(a).

A. Background

The ANGTS is designed to transport natural gas from the North Slope of Alaska to the lower 48 states. The pipeline will be

---

1/ 10 FERC ¶61,032 and 11 FERC ¶61,088.

2/ Executive Office of the President, Energy Policy and Planning, September 1977.

DC-B-67

constructed through Canada, and will separate into two legs (Western and Eastern) just north of Calgary, Alberta. The Western Leg will enter the United States near Kingsgate, British Columbia and terminate at Antioch, California. The Eastern leg will enter the United States near Monchy, Saskatchewan and terminate at Dwight, Illinois.

The April 28, 1980 3/ order authorized Northern Border to "pre-build" a portion of the Eastern Leg of the ANGTS, consisting of 809 miles of 42-inch pipeline from Monchy to Ventura, Iowa. The January 11, 1980 order 4/ authorized, inter alia, the early construction of a portion of the ANGTS by PGT, consisting of 160.5 miles of the Western Leg from the point of importation near Kingsgate, British Columbia to Stanfield, Oregon.

The Commission has found that the ANGTS is not a purely domestic project, but is an international project undertaken jointly by the U.S. and Canada. 5/ The Agreement between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline (the Agreement on Principles) was signed by representatives of the two governments on September 20, 1977 (TIAS 9030). It was then incorporated into the Decision (at pages 47-83); inasmuch as the Decision was approved by a Joint Resolution of the Congress (on November 8, 1977), the Agreement on Principles, as a part of the Decision, has the legal force and effect of a federal statute.

3/ 11 FERC ¶61,088. The April 28 order became effective June 20, 1980 when the Commission issued its Order Granting Applications for Rehearing in Part, in the above-referenced docket. 11 FERC ¶61,302.

4/ The January 11 order became effective June 13, 1980 when the Commission issued its "Supplemental Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Importation of Natural Gas, and Order on Rehearing," in the above-referenced docket.

5/ "Supplemental Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Importation of Natural Gas, and Order on Rehearing," Northwest Alaskan Pipeline Company, Docket No. CP78-123, et al., June 13, 1980, 11 FERC ¶61,279, mimeo at p. 45.

The Agreement on Principles states, in Paragraph 7(a), that "having regard to the objectives of this Agreement each Government will endeavor to ensure that the supply of goods and services to the Pipeline project will be on generally competitive terms." In weighing competitiveness, the elements to be considered include price, reliability, servicing capacity and delivery schedules. Paragraph 8 of the Agreement provides for consultation between senior officials of the two governments on the implementation of principles relating to the construction and operation of the pipeline.

The responsible U.S. 6/ and Canadian officials have been discussing methods of implementing Paragraph 7 of the Agreement on Principles. The result is a reciprocal arrangement between the United States and Canada on a procedure to govern the procurement of certain designated items by the pipeline companies before contracts are awarded. That agreement betwe n the two governments is embodied in a formal exchange of diplomatic notes, signed June 10, 1980, and is effective subject only to the necessary regulatory action in each country.

By a letter dated August 4, 1980, the Federal Inspector has forwarded to the Chairman of the Commission an official copy of the diplomatic notes. A copy of the letter, including the diplomatic notes, is attached to this order for reference. In his letter, the Inspector requests the Commission to implement the notes by attaching appropriate conditions to the project sponsors' certificates.

In this regard, the exchange of notes provides that the agreed procurement procedures are subject to approval through regulatory processes of the two countries. Within the U.S., such approval is defined in terms of amending the project sponsors' certificates:

> "In fulfillment of this agreement, the United States agrees to adopt the procurement procedures contained in the Annex to this note. It is understood that the procedures in the Annex are subject to regulatory approval in the United States, specifically the amendment of the conditional certificates of the Alaskan Northwest Natural Gas Transportation Company, of the Pacific Gas Transmission

---

6/ The responsible U.S. Official is the Office of the Federal Inspector (OFI). The OFI was created by Reorganization Plan No. 1 of 1979, which became effective July 1, 1979, pursuant to Executive Order 12142 of June 21, 1979, 44 F.R. 36927 (June 25, 1979).

Company, and of the Northern Border Pipeline Company by the Federal Energy Regulatory Commission of the United States. It is further understood that Canada will also adopt the procurement procedures contained in the Annex to this notice, and bring them into force with Canadian regulatory process."

Thus, attaching the proposed condition to the certificates would complete the process envisioned in the exchange of notes, thereby implementing the executive agreement set forth in the notes.

B. Proposed Condition

The text of the agreement set forth in the diplomatic notes is self-explanatory, and is the product of extensive deliberations and negotiations by the two governments. Accordingly, the Commission is reluctant to attempt to recast that language into detailed conditions of the style and form generally used in drafting certificate conditions. Instead, the Commission proposes to attach to the certificates a shorter and more generalized condition that simply requires the certificate holders to comply with all requirements in the agreement that are applicable to them, and to co-operate fully with the Federal Inspector in his interpretation and implementation of the agreement.

C. Comment Procedures

The Commission invites the parties of record in Docket Nos. CP78-123, et al., to submit written data, views, comments and other information concerning the matters set forth in this order. An original and 14 conformed copies should be filed by January 16, 1981, with service of copies on all parties. Parties of record may also file reply comments, pursuant to the same procedure, by February 6, 1981. Comments and reply comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D. C. 20426, and should reference Docket Nos. CP78-123, et al. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D. C., during regular business hours.

The Commission orders:

(A) Parties of record in Docket No. CP78-123, et al., may submit comments and reply comments on the condition that the Commission proposes to append to the certificates of public convenience and necessity issued (for construction and operation of the ANGTS) by the Commission to the ANGTS project sponsors in the Commission's orders of January 11 and April 28, 1980, as well as to the conditional certificates of public convenience and necessity issued December 16, 1977 in that docket, as described more fully above. The proposed condition is set forth in an attachment to this order. Comments may be filed on or before January 16, 1981, and reply comments may be filed on or before February 6, 1981. Copies of all comments and reply comments should be served on all parties of record in Docket Nos. CP78-123, et al.

(B) Copies of this order shall be served on all parties in Docket No. CP78-123, et al.

By the Commission.
(S E A L)

Kenneth F. Plumb

Kenneth F. Plumb,
Secretary.

APPENDIX

PROPOSED CONDITION

The certificate holder shall comply with all of the requirements imposed on ANGTS project sponsors by the executive agreement set forth in the exchange of diplomatic notes between the United States and Canada, dated June 10, 1980, as those requirements are set forth in the "Procedures Governing the Procurement in Canada and the United States of America of Certain Designated Items for the Alaska Highway Gas Pipeline" adopted in said agreement. The certificate holder shall co-operate fully with the Federal Inspector in his interpretation and implementation of the agreement.

Docket No. CP78-123, et al.

THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM
ROOM 2413. POST OFFICE BUILDING
1200 PENNSYLVANIA AVENUE
WASHINGTON D C 20044

August 4, 1980

Honorable Charles B. Curtis
Chairman, Federal Energy
Regulatory Commission
825 N. Capitol Street, N.E.
Room 9000 Washington, D.C. 20426

Dear Chairman Curtis:

I have attached a copy of formal diplomatic notes, exchanged between the United States and Canada on June 10, 1980. This exchange of notes effectuates reciprocal procedures governing the procurement in Canada and the United States of designated items for the Alaska Highway Gas Pipeline, the U.S. portions of which represent the Alaska Natural Gas Transportation System. These procedures, by their terms, are to be administered by my office and the Northern Pipeline Agency.

Of particular interest to the Federal Energy Regulatory Commission is the following aspect of the U.S. diplomatic notes:

> It is understood that the procedures in the Annex are subject to regulatory approval in the United States, specifically the amendment of the conditional certificates of the Alaskan Northwest Natural Gas Transportation Company, of the Pacific Gas Transmission Company, and of the Northern Border Pipeline Company by the Federal Energy Regulatory Commission of the United States.

In this regard the Office of the Federal Inspector, as the administering agency in the U.S., is requesting that the Commission incorporate these reciprocal procedures as conditions to the aforementioned conditional certificates issued by the Commission on December 16, 1977, in Docket Nos. CP78-123, et al. In this manner these officially established and currently effective procurement review procedures may be administered by this agency also through Section 102(d) of Reorganization Plan No. 1 of 1979.

Thank you for your assistance in this manner.

Sincerely yours,

John T. Rhett
Federal Inspector

cc: John Adger
FERC
Michael Lucy
State Department
Darrell MacKay
Northwest Alaskan
Philip Reynolds
PGT
Carl Schulz
Northern Border
Trish Lortie
Canadian Embassy
Barry Yates
Northern Pipeline Agency

THE FOLLOWING DOCUMENT(S) MAY NOT FILM LEGIBLY BECAUSE OF POOR QUALITY OF THE ORIGINAL.

Enclosure 1

Docket No. CP78-123, et al.

Canadian Embassy — Ambassade du Canada

No. 226 — 20 June, 1980

Sir,

I have the honour to refer to your Note of today's date concerning procurement procedures designed to implement the provisions of the Agreement between Canada and the United States of America on Principles Applicable to a Northern Natural Gas Pipeline, signed at Ottawa on September 20, 1977.

I have the honour to inform you that these proposals are acceptable to the Government of Canada, and to confirm that your Excellency's Note, together with the attached statement on Procedures Governing the Procurement in Canada and the United States of America of Certain Designated Items for the Alaska Highway Gas Pipeline, and this reply, which is equally authentic in English and French, shall constitute an agreement between our two governments which shall enter into force on the date of this reply.

Accept, Sir, the renewed assurances of my highest consideration.

The Secretary of State
Washington, D.C.

Docket No. CP78-123, et al.

DEPARTMENT OF STATE
WASHINGTON

June 10, 1980

Excellency:

I have the honor to refer to Paragraph 7 of the Agreement between Canada and the United States on the Principles Applicable to a Northern Natural Gas Pipeline (Pipeline Agreement) and the recent discussions between representatives of the Government of the United States of America and representatives of the Government of Canada regarding procedures to ensure procurement on a generally competitive basis for the Alaskan Natural Gas Transportation System.

As a result of these discussions, the Government of the United States agrees to enter into an agreement with the Government of Canada permitting the mutual and reciprocal implementation of procedures governing the purchase of specified items for the Alaskan Natural Gas Transportation System.

In fulfillment of this agreement, the United States agrees to adopt the procurement procedures contained in the Annex to this note. It is understood that the procedures in the Annex are subject to regulatory approval in the United States, specifically the amendment of the conditional certificates of the Alaskan Northwest Natural Ga[illegible]

His Excellency

Peter Towe,

Ambassador of Canada.

Transportation Company, of the Pacific Gas Transmission Company, and of the Northern Border Pipeline Company by the Federal Energy Regulatory Commission of the United States. It is further understood that Canada will also adopt the procurement procedures contained in the Annex to this note, and bring them into force with Canadian regulatory process.

In the event of disputes regarding implementation of the procurement procedure in the United States of America or in Canada, either country may request consultations in accordance with paragraphs 7 (b) and 8 of the Pipeline Agreement.

If the foregoing is acceptable to the Government of Canada, this note and its Annex, together with your note in reply, shall constitute an agreement between the two Governments with effect from the date of your reply.

Accept, Excellency, the renewed assurances of my highest consideration.

For the Secretary of State:

Enclosure:

Annex: Procurement Procedures for the Alaskan Natural Gas Transportation System

PROCEDURES GOVERNING THE PROCUREMENT IN CANADA AND THE UNITED STATES OF AMERICA OF CERTAIN DESIGNATED ITEMS FOR THE ALASKA HIGHWAY GAS PIPELINE

Introduction

The Agreement between Canada and the United States of America on Principles Applicable to a Northern Natural Gas Pipeline, which was signed in Ottawa on September 20, 1977, states in its preamble that one of the principal objectives of the project is to "maximize related industrial benefits of each country." It further states in Clause 7(a) that "having regard to the objectives of this Agreement, each Government will endeavor to ensure that the supply of goods and services to the Pipeline will be on generally competitive terms." The same clause stipulates that the elements to be taken into account in weighing competitiveness will include price, reliability, servicing capacity and delivery schedules. Clauses 7(b) and 8 provide for coordination and consultation between the two governments with respect to the achievement of the objectives of the Agreement with respect to procurement

In order to implement these principles, the Governments of Canada and the United States of America agree that the following procedures with respect to the procurement of certain designated items of supply for the Alaska Highway Gas Pipeline will be adopted on a reciprocal basis by the appropriate regulatory authority in each country, namely, the Northern Pipeline Agency in Canada (NPA) and the Office of the Federal Inspector in the United States (OFI).

1. Qualification of Bidders

The project companies in each country will submit a list of qualified bidders they propose to invite to tender on any of the items designated in Schedule I to the appropriate domestic regulatory authority, which will expeditiously convey copies of any such lists to the regulatory authority of the other country both directly and through normal diplomatic channels. The regulatory authority of the other country will have 14 calendar days following its receipt in which to review the bidders' list and to propose to its counterpart the addition of any firm or firms which it considers should also be invited to tender. If any such modification is proposed, it is to be communicated to the originating project sponsor by the responsible regulatory authority in that country. Should the project sponsor not be prepared to accept the additional bidder or bidders proposed by the regulatory authority of the other country, the reasons for its position shall be communicated to that authority by the responsible domestic authority.

The project sponsors may, but are not required to, place advertisements inviting interested suppliers to prequalify as bidders for particular supplies. In the event that such advertisements are decided on for designated items, they shall be placed in appropriate trade journals or other publications in both Canada and the United States.

2. Technical Specifications and Tendering Documents

Prior to the actual solicitation of bids on designated items listed in Schedule I, the project sponsors in each country will submit technical specifications and tendering documents to the appropriate domestic regulatory authority, which will first expeditiously review the solicitation information for possibly restrictive language that would prohibit open competition and then expeditiously convey copies of such information on a confidential basis to the regulatory authority of the other country both directly and through normal diplomatic channels. The regulatory authority of the other country will have 14 calendar days following its receipt to review such information and to submit any proposed modifications in the technical specifications or tender document to the responsible regulatory authority, which in turn will communicate such representations to the originating project sponsor. Should the project sponsor not be prepared to accept the modification of the technical specifications or tender document proposed by the regulatory authority of the other country, the reasons for its position shall be communicated to that authority by the responsible domestic authority.

3. Recommended Decisions to Purchase or Negotiate

Following the receipt and evaluation of bids on designated items listed in Schedule I, the project sponsor will submit its conclusions in a report satisfactory to the domestic regulatory authority with respect to the purchase of supply, or of entering into negotiation with one or more firms for the purpose of reaching contract agreement, to the responsible domestic regulatory authority. After expeditiously reviewing these submissions for general competitiveness, the domestic regulatory authority shall prepare and submit to the regulatory authority of the other country a meaningful summary of the report and of its conclusions. Such information shall include an outline of the factors which were taken into account by the project sponsor in arriving at its conclusions, and, in cases where consideration of industrial benefit were involved, demonstrate that they came within the framework of general competitiveness.

while maintaining the confidentiality of proprietory commercial information, including the tender prices of individual bidders, such summaries should be designed to make possible an assessment of the extent to which the proposed procurement conforms with the stated objectives of the Canada-United States Agreement. In cases where bids submitted by either Canadian or United States firm on tenders called by sponsoring companies in the other country have been rejected or accepted only in part, the conclusions of the project sponsor and the reasons for them as outlined in the project sponsor's report will be communicated by the responsible domestic regulatory authority to the regulator authority of the other country as part of the meaningful summary.

In the event the regulatory authority in the other country wishes to raise questions with respect to the conclusions or the summary containing the factors which led to those conclusions, or wishes to initiate formal consultations as provided for under Clause 7(b) of the Canada-United States Agreement on Principles, it will be required to provide notification to the responsible domestic regulatory authority within a period of 14 calendar days.

Should consultations as provided for under the Agreement be invoked with respect to any aspect of the procurement process, it is recognized by the Governments of both Canada and the United States that they should proceed expeditiously so as to avoid causing any undue delay in the timely completion of the project.

4. Award of Contract

Although no specific requirement for consultation should be necessary at this time in view of the extensive provisions at earlier stages, a short delay may be required to advise the other country's regulatory authority of any significant changes that resulted during negotiations with the selected vendor(s).

Schedule 1

Designated Items

1. Line Pipe - Main Line Pipe 36 inches and over.

2. Gas Turbine/Compressor Packages.

3. Valves - 20 inches interior diameter and over (both block valves and station valves).

4. Pipe Fittings - 20 inches interior diameter and over.

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of:	)	
	)	Docket No. CP80-435
Alaskan Northwest Natural	)	
Gas Transportation Company	)	

ANSWER OF NORTHWEST ALASKAN PIPELINE COMPANY TO COMMISSION STAFF MOTION TO COMPEL

Pursuant to Section 1.12(c) of the Commission's Regulations, Northwest Alaskan Pipeline Company herewith files its answer to the motion of the Commission staff seeking to compel a reply, in writing, to staff interrogatories directed to Northwest Alaskan on October 21, 1980 and November 6, 1980. Staff asserts that Northwest Alaskan has not responded to the interrogatories.

Staff is in error. The questions posed in the interrogatories relevant to the matters before the Commission for decision -- resolution of the outstanding IROR matters, including approval of a CCE and center point -- have been answered either in writing or at the technical conferences authorized by the Commission's August 1, 1980 order in Docket No. CP80-435. 1/

The August 1, 1980 order established a special procedure to address the issues presented by the July 1st filing. The focus of this procedure was a series of technical conferences, and the process agreed on was to hold informational discussions off-the-record with a summary of these exchanges provided for the record by the presiding officer. The questions posed by the October 21, 1980 set of interrogatories were asked by the staff during the technical conferences and answered by Northwest Alaskan at that time. An examination by staff of its notes on the informal discussions and a review of the conference transcripts will provide staff with the information it seeks.

1/ Staff states in footnote 1 of its motion that it has served an additional set of interrogatories (December 5, 1980) and that the "time for response has not yet elapsed." Upon review of these particular interrogatories, Northwest Alaskan notes that these interrogatories as well were discussed at the technical conferences which the Alaskan Delegate commenced on September 3 and concluded on November 20, 1980.

The remaining questions posed by staff in the two sets of interrogatories go beyond the "limited purview of the subproceeding" as staff itself recognizes. Staff Motion at 1. As noted in its July 1, 1980 filing, Alaskan Northwest has not yet filed its financing plan and related economic materials. In its August 1, 1980 order the Commission "defer[red] such matters to a final certification proceeding which will be initiated upon submission of the financing plan." August 1 Order at 4-5 (footnote omitted). Since staff's unanswered questions relate to these types of concerns, Northwest Alaskan is unable to reply to questions that pertain to matters that are not part of the filed application. Northwest Alaskan will respond to the remaining questions at such time as it is able and when the questions posed correspond to the issues before the Commission.

Staff has filed a motion to compel replies to questions that Northwest Alaskan has already answered. Staff has received the information relevant to the certificate matters now pending before the Commission for decision. Therefore, since the relevant interrogatories have been answered, and the remaining questions are not ripe for Commission determination, the staff motion to compel should be denied.

Respectfully submitted,

William J. Grealis

Akin, Gump, Hauer & Feld
1333 New Hampshire Avenue, N.W.
Suite 400
Washington, D.C. 20036

Attorney for Northwest Alaskan
Pipeline Company

VERIFICATION

DISTRICT OF COLUMBIA) ss.

WILLIAM J. GREALIS being duly sworn, on oath, says that he is an attorney for Northwest Alaskan Pipeline Company; that he has read the foregoing Answer of Northwest Alaskan Pipeline Company to Commission Staff Motion to Compel and he is familiar with the contents theroef; that as an attorney, he has executed the same for and on behalf of said Company with full power and authority to do so; and that the matters set forth therein are true to the best of his information, knowledge and belief.

William J. Grealis

SUBSCRIBED AND SWORN TO before me this 29th day of December, 1980.

Sheila Lowenstein
Notary Public

My Commission Expires:

My Commission Expires April 30, 1984

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties of record in Docket No. CP80-435 in accordance with the requirements of §1.17 of the Rules of Practice and Procedure.

Dated at Washington, D.C. this 29th day of December, 1980.

William J. Grealis

NORTHWEST ALASKAN PIPELINE COMPANY

1120 20th Street, N.W.
Suite S-700
Washington, D.C. 20036
(202) 872-0280

REA-80-1091

December 15, 1980

Mr. John B. Adger, Jr.
Alaskan Delegate to the
Federal Energy Regulatory Commission

Mr. Richard Berman
Director, Office of Cost
and Audit Analysis
Office of the Federal Inspector

Re: Alaskan Northwest Natural Gas Transportation Company
Docket No. CP80-435

Gentlemen:

On October 7, 1980, at Alaskan Northwest Natural Gas Transportation Company ("Alaskan Northwest") technical conference, the Office of the Federal Inspector ("OFI") presented two documents addressed to John Adger, Alaskan Delegate, wherein the subject matter was the Outstanding Design Issues Related to Alaskan Leg. The two documents reflected a total of twenty-five (25) issues.

The OFI stated in the documents as well as orally that the design issues were the type of issues which Alaskan Northwest should consider during the detailed final design process.

Enclosed, pursuant to your request, is a copy of the Alaskan Northwest response to the detailed final design issues raised for consideration by the OFI.

If you have any questions regarding the enclosed material, please contact me.

Very truly yours,

NORTHWEST ALASKAN PIPELINE COMPANY

Cuba Wadlington, Jr.

Cuba Wadlington, Jr.
Director, Regulatory Affairs

Enclosure
cc: Restricted Service List Docket No. CP80-435
RDM Index

RESPONSES TO OFI SUMMARY REPORT ON MAJOR OUTSTANDING DESIGN ISSUES OCTOBER 1980

1. Design Criteria

We agree that definitive criteria for design of the gas pipeline are required wherever the alignment is adjacent to existing facilities. Criteria for the preliminary design are contained in the FERC filing and have been used as the starting point for the development of definitive criteria, which is now underway. These definitive criteria are required for all portions of the route.

2. 1980 Field Program

Field Programs, detailed procedures and concepts are developed primarily to support the design effort. They are important to the resolution of technical issues, particularly the frost heave testing, and the results will be applied to final design. The 1980 programs are almost completed as of this writing and the results are being utilized in design. The 1981 Field Programs are in the planning stage and the schedule for output from these tasks are being blended with the design schedule to make certain that the data acquisition is timely for final design.

3. Frost Heave Design

The criteria used to classify the existence and degree of frost heave potential and reported in the FERC filing documents, were on a preliminary basis. Work is continuing in this area - in the lab, in the field and in the office. The criteria are being confirmed so that a high degree of confidence can be placed in the definition of the extent of frost heave potential.

4. Steady-state Thermohydraulic Simulation

The steady-state thermohydraulic simulation program has been upgraded by coupling it with a geothermal program so that heat transfer in the soil can be calculated on a broader base. Also the input is improved as new data is received. As changes are made, the cost implications are evaluated and will be incorporated into the final design estimate.

5. Ditch Design and Stability

We agree that the number of miles of each ditch design type may conceivably change. Detail design is underway at the present time. One purpose of this detail design effort is to "fine tune" the location of the different ditch types and assess the impacts on materials quantities and costs. Both plus and minus differences are anticipated with minimal net effect on the final cost.

6. Pipe Selection Criteria

The mainline pipe materials were discussed in the FERC Conferences and are recorded in Transcript Volume from October 23, 1980 pages 18 to 26.

7. Workpad Design

The separation distance of 200 feet between the gas pipeline and TAPS has been incorporated into the Reroute Filing submitted to the Alaskan Delegate in October 1980. The impact on the design of the pad and the changes in the quantities of materials are in this same filing. A thermal workpad is more costly than a structural workpad ($437,000 per mile vs. $150,000 per mile) and therefore the structural pad was selected for design. The criteria for the workpad, both north and south of the Brooks Range will be reviewed during the detail design phase.

8. Major River Crossings

We agree that major rivers require special designs. The field programs to collect data on these streams is 90 percent completed, and data is already being used by the design engineers. The design of the crossings and the protective structures is underway and will be completed during final design.

9. Minor Stream Crossings

Minor stream crossings are being analyzed in the detail design phase to assess the probabilities for the formation of frost bulbs around the pipe. If a set of conditions is found that would result in the blockage of a stream, design alternatives will be utilized to avoid this situation. These alternatives include deeper burial and overhead structures

10. Thaw Settlement

Criteria for limiting thaw settlement during the dormant period have been developed and ditch configurations have been designed to control the thaw during this period. Type II A ditch will utilize a layer of insulation 1-1/2 to 3-1/2 inches thick in the ditch to control thaw. It also is a shallow ditch with a berm over the top of the pipe. It will be used on the North Slope to minimize disturbance of permafrost. Type II B ditch will utilize a 5-inch layer of insulation in the ditch in permafrost areas south of the Brooks Range where the active layer is deeper than on the North Slope.

11. Special Construction Sites

Designs for special sites are being developed in the detail design phase. The Atigun Tunnel is under study. Two boreholes have been completed along the trace of the primary site for this tunnel and several additional boreholes are scheduled to be drilled in 1981. The present design contemplates installing the pipeline over Atigun Pass. The estimated cost of a section of the system is $43.7 million dollars in 1980 dollars. It is considered feasible to continue with this plan and meet necessary safety requirements. However, the tunnel will be thoroughly studied as a possible alternative to provide additional reliability at an acceptable cost.

The Yukon River Bridge is designed to accommodate at least one more pipeline. Negotiations are currently in progress with Aleyska and the State to utilize this bridge for the natural gas pipeline. Considerations which will be balanced are design, security, cost, and any potential delay arising from possible litigation. The alternative is a separate bridge.

12. Temporary Facilities

The renovation or replacement of the existing sewage treatment plants at the TAPS camps is under study in detail.

13. Winter Construction

The utilization of snow and ice materials for workpads and access roads has been analyzed and was discussed at the FERC Conferences (Transcript Volume from November 18, 1980.)

14. Compressor Stations

All aspects of the compressor station design are being given further considerations in the detail design phase including pressure relief, emergency blow downs, foundations, and valving. The cost effectiveness of the design will be analyzed during this phase also.

15. Communication System

The possible utilization of portions of existing communications systems is being considered in the detail design phase.

16. Proximity to the TAPS

The filing of a reroute with the Alaskan Delegate in October, 1980 implemented the 200-foot separation from TAPS. There are about 5 miles (in total) of the route that require a variance from this 200-foot requirement because the gas pipeline crosses TAPS or the terrain restricts the space available for the gas pipeline. These areas do require special attention and they have been discussed with TAPS. The detail design will reflect design to resolve any concerns.

17. Proximity to the Fuel Gas Line

The workpad has been designed to protect the fuel gas line from damage during construction. Blasting criteria have been discussed with TAPS and that issue has been resolved.

18. Location of Metering/Compressor Station

Combining the metering station at the Yukon border with the compressor station in that area raises the following problems:

a. This is the custody transfer meter from NWA to Foothills and should take place as near the border as possible in order to properly establish responsibility for any lost or unaccounted for gas volumes. While it may not be possible to locate it exactly on the border because of soils conditions and access problems, the further west this station is moved, the more difficult it is to establish proper volumeter control and responsibility.

b. Seven compressor stations are scheduled to be constructed initially. Compressor Station No. 15 (MP 685) will be the closest to the Yukon border initially. When Compressor Station No. 16 is constructed at MP 731 in the future, the meter station must be moved if it is initially located at No. 15.

Costs will not necessarily be reduced by locating the meter station at a compressor station. Site work must be studied in detail before the cost impact can be determined and the cost of one set of pig traps would be more than offset by the moving of the station from No. 15 to No. 16 in the future.

19. Cross Flow of Groundwater

The pipeline is designed to accommodate the passage of water across it. Surface water will be controlled by drainage structures. The passage of sub-surface water is being analyzed on a site specific basis to assess the probabilities for the formation of aufeis or ice dams. Where the indications are that the consequences will adversely impact adjacent structures or the environment, mitigative designs will be utilized such as deeper burial, sub-surface drainage structures or overhead structures for pipeline crossings of smaller streams.

20. **Impact of Conditioning Plant Design on the Entire System**

The processing and conditioning plant design is being coordinated with the pipeline system design. The most critical variables are pressure, temperature, gas quality and equipment reliability. The pressure and temperature are defined. Studies are in progress to assure that the plant and compression equipment on the pipeline are properly matched to provide appropriate reliability to meet service contractual requirements.

The gas quality is resolved with the exception of the permissible carbon dioxide content. The highest acceptable limit is approximately 3 percent without incurring undue corrosion risks and economic penalties. The lowest reasonable design level is about 1 percent. Therefore, studies are evaluating the optimum level between 1 and 3 percent.

21. Valve Spacing

Valve spacing cannot be increased because of the requirements of the Federal Code (49 CFR 182).

22. Additional Compressor Station Design Issues

The utilization of exhaust heat has been studied and maximized. In order to utilize the energy in the exhaust heat, an intermediate process would be necessary to convert it to a driving force for the refrigeration system. This would not be cost effective.

The use of the larger, more fuel efficient turbines create problems such as foundation requirements that make it more cost effective to use the lighter aircraft derivative drivers.

ORGANIZATIONAL AND SCHEDULE RELATED ISSUES

1. Construction Management

During construction, multiple levels of the PMC organization with NWA oversight at these levels are necessary in order to have timely response to construction problems. Decision making about problems will be placed as close to the actual work as possible. This involves both PMC and NWA personnel. If a certain problem cannot be solved at a given level because of its size or complexity, and requires action at the next higher level, both PMC and NWA need representation there also so that time is not lost passing the problem through the entire organization.

2. Construction Schedules

The schedule for construction in ice rich soils has been planned for shoulder months and is shown on the March Charts along with the scheduling for the other construction. The limited time window for this activity has been taken into account. The construction across fish streams has also been scheduled in similar detail.

3. QA/QC Authorities

The QA/QC organization does not establish or modify specifications. They review specifications prepared by technical experts in each discipline, assess the quality requirements and recommend changes to the originator to clarify or simplify inspection requirements.

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT

0/g

APR 29 1982

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

MINERALS AND ENERGY MANAGEMENT

555 CORDOVA STREET
POUCH 7-005
ANCHORAGE, ALASKA 99510
(907) 276-2653

Phone: 276-2653

April 22, 1982

-NOTICE-
FINAL DECISION AND FINDING UNDER AS 38.05.035(a)(14)
REGARDING PROPOSED OIL AND GAS LEASE SALE 37
Middle Tanana and Copper River Basins

The Department of Natural Resources, Division of Minerals and Energy Management (DMEM), gives formal notice under AS 38.05.345(a)(3) of its intention to make a final decision under AS 38.05.035(a)(14) regarding the sale of oil and gas leases in proposed Competitive Oil and Gas Lease Sale 37 (Middle Tanana and Copper River Basins). Before the sale may be held, the Director of the Division of Minerals and Energy Management must make a written final decision that the sale is in the best interest of the state. This decision, issued pursuant to AS 38.05.035(a)(14), will set out the facts and applicable law upon which the Director bases her determination that the sale of oil and gas leases in proposed sale 37 will or will not best serve the interests of the state. This final decision is expected to be available to the public in June, 1982.

A preliminary analysis of the potential effects of proposed sale 37 and the means by which they may be mitigated is now available at DMEM, 555 Cordova Street, Anchorage, Alaska. Copies of the analysis may be obtained by writing to DMEM at Pouch 7-005, Anchorage, Alaska, 99510. The public is invited to comment on any aspect of the sale including any proposed term or condition. Comments must be received at DMEM by May 21, 1982 in order to be considered in the final decision of whether or not to hold this sale. A preliminary tract map of the area also is available at DMEM. The social, economic, and environmental analysis (SEEA) of Sale 37 will be available on May 3, 1982 at DMEM.

Proposed sale 37 includes an area of approximately 861,000 acres. The sale is divided into two areas: the Middle Tanana Basin, including about 632,000 acres in the Nenana area; and the Copper River Basin, which includes about 228,000 acres west of Glennallen in the Lake Louise area.

The Tanana portion of the sale contains 156 proposed tracts. Communities near the Tanana tracts include the first class city of Nenana, the second class city of Anderson, the villages of Minto, Manley, Tanana, and the Clear military reservation. Access to the area is provided via the Parks Highway, the Alaska Railroad, and several "winter" roads.

The Copper River portion of Sale 37 contains 61 tracts. Eureka and Glennallen are near the sale area. Road access to the area is available from the Glenn Highway and the Lake Louise Road.

If a decision is made that the proposed sale is in the best interest of the state, an "Information to Bidders" packet will be sent to all persons on the DMEM mailing list in June, 1982. If a decision is made to hold the sale, it is tentatively scheduled to occur at the Travelers Inn in Fairbanks on August 24, 1982 in accordance with AS 38.05.180. If you want to place your name on the DMEM mailing list, contact DMEM at (907) 276-2653, extension 4247.

Kay Brown

Kay Brown
Director

STATE OF ALASKA

SALE 37
Middle Tanana Basin
and Copper River Basin

PRELIMINARY TRACT LEGAL DESCRIPTIONS

April 22, 1982

TRACT 37-001

T. 2 S., R. 7 W., FAIRBANKS MERIDIAN

Section 1, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, [illegible] acres;
Section 2, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 646.00 acres;
Section 11, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres;
Section 12, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 644.00 acres.

This Tract contains [illegible] acres more or less.

TRACT 37-002

T. 2 S., R. 7 W., FAIRBANKS MERIDIAN

Section 3, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 646.00 acres;
Section 4, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 643.00 acres;
Section 9, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed Apr'l 1982, 640.00 acres;
Section 10, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres.

This Tract contains 2569.00 acres more or less.

TRACT 37-003

T. 2 S., R. 7 W., FAIRBANKS MERIDIAN

Section 5, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 642.00 acres;
Section 6, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 605.00 acres;
Section 7, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 606.00 acres;
Section 8, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres.

This Tract contains 2493.00 acres more or less.

TRACT 37-004

T. 2 S., R. 7 W., FAIRBANKS MERIDIAN

Section 17, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres;
Section 18, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 608.00 acres;
Section 19, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 612.00 acres;
Section 20, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres.

This Tract contains 2500.00 acres more or less.

TRACT 37-005

T. 2 S., R. 7 W., FAIRBANKS MERIDIAN

Section 15, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres;
Section 16, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres;
Section 21, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres;
Section 22, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres.

This Tract contains 2560.00 acres more or less.

TRACT 37-006

T. 2 S., R. 7 W., FAIRBANKS MERIDIAN

Section 13, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 643.00 acres;
Section 14, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres;
Section 23, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres;
Section 24, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 642.00 acres.

TRACT 37-007

T. 2 S., R. 7 W., FAIRBANKS MERIDIAN

Section 25, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 641.00 acres;
Section 26, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres;
Section 35, All, 640.00 acres;
Section 36, All, 640.00 acres.

This Tract contains [illegible] acres more or less.

TRACT 37-008

T. 2 S., R. 7 W., FAIRBANKS MERIDIAN

Section 27, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres;
Section 28, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres;
Section 33, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres;
Section 34, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres.

This Tract contains 2560.00 acres more or less.

TRACT 37-009

T. 2 S., R. 7 W., FAIRBANKS MERIDIAN

Section 29, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres;
Section 30, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 615.00 acres;
Section 31, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 619.00 acres;
Section 32, All, as shown on State of Alaska Supplemental Township plat of Tract "A" proposed April 1982, 640.00 acres.

This Tract contains 2514.00 acres more or less.

TRACT 37-010

T. 2 S., R. 8 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres.

This Tract contains 1920.00 acres more or less.

TRACT 37-011

T. 2 S., R. 8 W., FAIRBANKS MERIDIAN

Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This Tract contains 1920.00 acres more or less.

TRACT 37-012

T. 3 S., R. 5 W., FAIRBANKS MERIDIAN

Section 23, All, 640.00 acres.

This Tract contains 640.00 acres more or less.

TRACT 37-013

T. 3 S., R. 7 W., FAIRBANKS MERIDIAN

Section 1, All, 639.92 acres;
Section 2, All, 639.96 acres;
Section 3, All, 640.04 acres;
Section 10, N1/2, E1/2SE1/4, SW1/4SE1/4, S1/2NW1/4SE1/4, NE1/4NW1/4SE1/4, S1/2NW1/4NW1/4SE1/4, 475.00 acres;
Section 11, All, 640.00 acres;
Section 12, All, 640.00 acres.

TRACT 37-014

T. 3 S., R. 7 W., FAIRBANKS MERIDIAN

Section 4, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 629.80 acres;
Section 5, All, as shown on Supplemental Cadastral Survey plat 68-1 Nenana Recording District, 640.82 acres;
Section 6, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 621.00 acres;
Section 7, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 621.00 acres;
Section 8, All, as shown on Supplemental Cadastral Survey plat 68-1 Nenana Recording District, 641.36 acres;
Section 9, N1/2, 320.00 acres.

This tract contains 3463.10 acres more or less.

TRACT 37-015

T. 3 S., R. 7 W., FAIRBANKS MERIDIAN

Section 16, All, 640.00 acres;
Section 17, N1/2, N1/2 S1/2, SE1/4SE1/4, 520.00 acres;
Section 18, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 622.00 acres;
Section 20, SE1/4, S1/2NE1/4, NE1/4NE1/4, SW1/4NW1/4NE1/4, SE1/4NE1/4NW1/4, NW1/4NW1/4NE1/4, S1/2NW1/4NE1/4, E1/2SW1/4NW1/4, SW1/4NE1/4NW1/4, SE1/4NW1/4, S1/2NE1/4NW1/4, NE1/4NE1/4NW1/4, 430.00 acres;
Section 21, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres.

This tract contains 2852.00 acres more or less.

TRACT 37-016

T. 3 S., R. 7 W., FAIRBANKS MERIDIAN

Section 13, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 14, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 15, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 22, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 23, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 24, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-017

T. 3 S., R. 7 W., FAIRBANKS MERIDIAN

Section 25, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 26, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 27, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 34, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 35, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 36, All, as shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-018

T. 3 S., R. 7 W., FAIRBANKS MERIDIAN

Section 28, As shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 29, As shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 30, As shown on Supplemental Cadastral Survey plat 68-1 Nenana Recording District, 623.15 acres;
Section 31, As shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 626.00 acres;
Section 32, As shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres;
Section 33, As shown on State of Alaska Supplemental Township plat of Tracts "A & B" prepared April 1982, 640.00 acres.

This tract contains 3809.15 acres more or less.

TRACT 37-019

T. 4 S., R. 8 W., FAIRBANKS MERIDIAN

Section 33, All, 640.00 acres.

This tract contains 640.00 acres more or less.

TRACT 37-020

T. 1 S., R. 9 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, excluding the unnamed lake contiguous with U.S. Survey 4442C, 639.00 acres;
Section 27, Protracted, All, excluding U.S. Survey 4442 C and the unnamed lake contiguous with U.S. 4442C, 380.00 acres;
Section 35, Protracted, All, excluding the unnamed lake contiguous with U.S. Survey 4442C, 345.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 4564.00 acres more or less.

TRACT 37-021

T. 1 S., R. 9 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 598.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 600.00 acres;
Section 31, Protracted, All, 602.00 acres;
Section 32, Protracted, All, 640.00 acres.

This tract contains 5000.00 acres more or less.

TRACT 37-022

T. 1 S., R. 10 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-023

T. 1 S., R. 10 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 598.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 600.00 acres;
Section 31, Protracted, All, 602.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 5640.00 acres more or less.

TRACT 37-024

T. 2 S., R. 9 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-025

T. 2 S., R. 9 W., FAIRBANKS MERIDIAN

Section 3, Protracted, All, 640.00 acres;
Section 4, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-026

T. 2 S., R. 9 W., FAIRBANKS MERIDIAN

Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 594.00 acres;
Section 7, Protracted, All, 607.00 acres;
Section 8, Protracted, All, 640.00 acres.

This tract contains 2481.00 acres more or less.

TRACT 37-027

T. 2 S., R. 9 W., FAIRBANKS MERIDIAN

Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 609.00 acres;
Section 19, Protracted, All, 611.00 acres;
Section 20, Protracted, All, 640.00 acres.

This tract contains 2500.00 acres or less.

TRACT 37-028

T. 2 S., R. 9 W., FAIRBANKS MERIDIAN

Section 15, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-029

T. 2 S., R. 9 W., FAIRBANKS MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-030

T. 2 S., R. 10 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-031

T. 2 S., R. 10 W., FAIRBANKS MERIDIAN

Section 3, Protracted, All, 640.00 acres;
Section 4, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-032

T. 2 S., R. 10 W., FAIRBANKS MERIDIAN

Section 5, Protracted, All 640.00 acres;
Section 6, Protracted, All 594.00 acres;
Section 7, Protracted, All 607.00 acres;
Section 8, Protracted, All 640.00 acres.

This tract contains 2481.00 acres more or less.

TRACT 37-033

T. 2 S., R. 10 W., FAIRBANKS MERIDIAN

Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 609.00 acres;
Section 19, Protracted, All, 611.00 acres;
Section 20, Protracted, All, 640.00 acres.

This tract contains 2500.00 acres more or less.

TRACT 37-034

T. 2 S., R. 10 W., FAIRBANKS MERIDIAN

Section 15, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-035

T. 2 S., R. 10 W., FAIRBANKS MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-036

T. 2 S., R. 10 W., FAIRBANKS MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-037

T. 2 S., R. 10 W., FAIRBANKS MERIDIAN

Section 27, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-038

T. 2 S., R. 10 W., FAIRBANKS MERIDIAN

Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 613.00 acres;
Section 31, Protracted, All, 615.00 acres;
Section 32, Protracted, All, 640.00 acres.

This tract contains 2508.00 acres more or less.

TRACT 37-039

T. 2 S., R. 11 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;

TRACT 37-040

T. 2 S., R. 11 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 611.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres.

This tract contains 1891.00 acres more or less.

TRACT 37-041

T. 2 S., R. 11 W., FAIRBANKS MERIDIAN

Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 613.00 acres;
Section 31, Protracted, All, 615.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 3788.00 acres more or less.

TRACT 37-042

T. 2 S., R. 11 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-043

T. 3 S., R. 10 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-044

T. 3 S., R. 10 W., FAIRBANKS MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 617.00 acres;
Section 7, Protracted, All, 619.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 621.00 acres.

This tract contains 5697.00 acres more or less.

TRACT 37-045

T. 3 S., R. 10 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 623.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 625.00 acres;
Section 31, Protracted, All, 627.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 5715.00 acres more or less.

TRACT 37-046

T. 3 S., R. 10 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-047

T. 3 S., R. 11 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-048

T. 3 S., R. 11 W., FAIRBANKS MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 617.00 acres;
Section 7, Protracted, All, 619.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres.

This tract contains 3796.00 acres more or less.

TRACT 37-049

T. 3 S., R. 11 W., FAIRBANKS MERIDIAN

Section 17, protracted, All, 640.00 acres;
Section 18, protracted, All, 621.00 acres;
Section 19, protracted, All, 623.00 acres;
Section 20, protracted, All, 640.00 acres.

This tract contains 2524.00 acres more or less.

TRACT 37-050

T. 3 S., R. 11 W., FAIRBANKS MERIDIAN

Section 15, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-051

T. 3 S., R. 11 W., FAIRBANKS MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-052

T. 3 S., R. 11 W., FAIRBANKS MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-033

T. 3 S., R. 11 W., FAIRBANKS MERIDIAN

Section 27, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-034

T. 3 S., R. 11 W., FAIRBANKS MERIDIAN

Section 29, Protracted, All 640.00 acres;
Section 30, Protracted, All 625.00 acres;
Section 31, Protracted, All 627.00 acres;
Section 32, Protracted, All 640.00 acres.

This tract contains 2532.00 acres more or less.

TRACT 37-035

T. 3 S., R. 12 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-036

T. 3 S., R. 12 W., FAIRBANKS MERIDIAN

Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-037

T. 3 S., R. 12 W., FAIRBANKS MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-038

T. 3 S., R. 12 W., FAIRBANKS MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-039

T. 3 S., R. 12 W., FAIRBANKS MERIDIAN

Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 31, Protracted, All, 627.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 3187.00 acres more or less.

TRACT 37-080

T. 4 S., R. 9 W., FAIRBANKS MERIDIAN

Section 1, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 641.00 acres;
Section 2, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 3, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 10, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 11, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 12, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 641.00 acres;
Section 13, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 14, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 15, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres.

This tract contains 5762.00 acres more or less.

TRACT 37-081

T. 4 S., R. 9 W., FAIRBANKS MERIDIAN

Section 4, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 5, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 6, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 629.00 acres;
Section 7, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 631.00 acres;
Section 8, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 9, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 16, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 17, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 18, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 634.00 acres.

This tract contains 5734.00 acres more or less.

TRACT 37-082

T. 4 S., R. 9 W., FAIRBANKS MERIDIAN

Section 19, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 638.00 acres;
Section 20, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 21, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 28, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 29, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 30, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 641.00 acres;
Section 31, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 644.00 acres;
Section 32, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 33, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres.

This tract contains 5763.00 acres more or less.

TRACT 37-083

T. 4 S., R. 9 W., FAIRBANKS MERIDIAN

Section 22, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 23, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 24, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 25, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 26, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 27, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 34, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 35, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres;
Section 36, All, as shown on State of Alaska Supplemental Township plat, prepared April 1982, 640.00 acres.

TRACT 37-064

T. 4 S., R. 10 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-065

T. 4 S., R. 10 W., FAIRBANKS MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 629.00 acres;
Section 7, Protracted, All, 631.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 633.00 acres.

This tract contains 5733.00 acres more or less.

TRACT 37-066

T. 4 S., R. 10 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 633.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 637.00 acres;
Section 31, Protracted, All, 639.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 5751.00 acres more or less.

TRACT 37-067

T. 4 S., R. 10 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-068

T. 4 S., R. 11 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-069

T. 4 S., R. 11 W., FAIRBANKS MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 629.00 acres;
Section 7, Protracted, All, 631.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;

TRACT 37-070

T. 4 S., R. 11 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 633.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 637.00 acres;
Section 31, Protracted, All, 639.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 5751.00 acres more or less.

TRACT 37-071

T. 4 S., R. 11 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-072

T. 4 S., R. 12 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-073

T. 4 S., R. 12 W., FAIRBANKS MERIDIAN

Section 3, Protracted, All, 640.00 acres;
Section 4, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-074

T. 4 S., R. 12 W., FAIRBANKS MERIDIAN

Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 629.00 acres;
Section 7, Protracted, All, 631.00 acres;
Section 8, Protracted, All, 640.00 acres.

This tract contains 2540.00 acres more or less.

TRACT 37-075

T. 4 S., R. 12 W., FAIRBANKS MERIDIAN

Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 633.00 acres;
Section 19, Protracted, All, 633.00 acres;
Section 20, Protracted, All, 640.00 acres.

This tract contains 2546.00 acres more or less.

TRACT 37-076

T. 4 S., R. 12 W., FAIRBANKS MERIDIAN

Section 15, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres.

TRACT 37-077

T. 4 S., R. 12 W., FAIRBANKS MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-078

T. 4 S., R. 12 W., FAIRBANKS MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-079

T. 4 S., R. 12 W., FAIRBANKS MERIDIAN

Section 27, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-080

T. 4 S., R. 12 W., FAIRBANKS MERIDIAN

Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 637.00 acres;
Section 31, Protracted, All, 639.00 acres;
Section 32, Protracted, All, 640.00 acres.

This tract contains 2556.00 acres more or less.

TRACT 37-081

T. 4 S., R. 13 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 1280.00 acres more or less.

TRACT 37-082

T. 4 S., R. 13 W., FAIRBANKS MERIDIAN

Section 15, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres.

This tract contains 1280.00 acres more or less.

TRACT 37-083

T. 4 S., R. 13 W., FAIRBANKS MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-084

T. 4 S., R. 13 W., FAIRBANKS MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-085

T. 5 S., R. 8 W., FAIRBANKS MERIDIAN

Section 33, All, 640.00 acres.

This tract contains 640.00 acres more or less.

TRACT 37-086

T. 5 S., R. 9 W., FAIRBANKS MERIDIAN

Section 1, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 2, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 646.00 acres;
Section 3, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 643.00 acres;
Section 10, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres.

This tract contains 2572.00 acres more or less.

TRACT 37-087

T. 5 S., R. 9 W., FAIRBANKS MERIDIAN

Section 4, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 642.00 acres;
Section 5, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 641.00 acres;
Section 6, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 616.00 acres;
Section 7, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 618.00 acres;
Section 8, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 9, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres.

This tract contains 3797.00 acres more or less.

TRACT 37-088

T. 5 S., R. 9 W., FAIRBANKS MERIDIAN

Section 16, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 17, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 18, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 620.00 acres;
Section 19, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 622.00 acres;
Section 20, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 21, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres.

This tract contains 3802.00 acres more or less.

TRACT 37-089

T. 5 S., R. 9 W., FAIRBANKS MERIDIAN

Section 13, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 14, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 15, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 22, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 23, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 24, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-090

T. 5 S., R. 9 W., FAIRBANKS MERIDIAN

Section 25, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 26, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 27, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 34, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 35, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 36, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-091

T. 5 S., R. 9 W., FAIRBANKS MERIDIAN

Section 29, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 30, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 623.00 acres.

This tract contains 1263.00 acres more or less.

TRACT 37-092

T. 5 S., R. 10 W., FAIRBANKS MERIDIAN

Section 1, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 2, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 11, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 12, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 13, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 14, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-093

T. 5 S., R. 10 W., FAIRBANKS MERIDIAN

Section 3, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 4, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 9, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 10, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 15, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 16, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-094

T. 5 S., R. 10 W., FAIRBANKS MERIDIAN

Section 5, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 6, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 393.00 acres;
Section 7, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 395.00 acres;
Section 8, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 17, N1/2, as shown on Supplemental Cadastral Survey plat 81-12 Nenana Recording District, 320.00 acres;
Section 18, N1/2, as shown on Supplemental Cadastral Survey plat 81-12 Nenana Recording District, 298.00 acres.

This tract contains 3086.00 acres more or less.

TRACT 37-095

T. 5 S., R. 10 W., FAIRBANKS MERIDIAN

Section 17, S1/2, as shown on Supplemental Cadastral Survey plat 81-12 Nenana Recording District, 320.00 acres;
Section 18, S1/2, as shown on Supplemental Cadastral Survey plat 81-12 Nenana Recording District, 299.00 acres;
Section 19, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 399.00 acres;
Section 20, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 29, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 30, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 401.00 acres;
Section 31, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 403.00 acres;
Section 32, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres.

This tract contains 4342.00 acres more or less.

TRACT 37-096

T. 5 S., R. 10 W., FAIRBANKS MERIDIAN

Section 21, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 22, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 27, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 28, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 33, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 34, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-097

T. 5 S., R. 10 W., FAIRBANKS MERIDIAN

Section 23, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 24, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 25, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 26, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 35, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres;
Section 36, All, as shown on State of Alaska Supplemental Township plat prepared April, 1982, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-098

T. 5 S., R. 11 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-099

T. 5 S., R. 11 W., FAIRBANKS MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 393.00 acres;
Section 7, Protracted, All, 395.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 597.00 acres.

This tract contains [illegible] acres more or less.

TRACT 37-100

T. 5 S., R. 11 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 599.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 601.00 acres;
Section 31, Protracted, All, 603.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This Tract contains 5643.00 acres more or less.

TRACT 37-101

T. 5 S., R. 11 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This Tract contains 5760.00 acres more or less.

TRACT 37-102

T. 5 S., R. 12 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres.

This Tract contains 5760.00 acres more or less.

TRACT 37-103

T. 5 S., R. 12 W., FAIRBANKS MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 593.00 acres;
Section 7, Protracted, All, 595.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 597.00 acres.

This Tract contains 5625.00 acres more or less.

TRACT 37-104

T. 5 S., R. 12 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 599.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 601.00 acres;
Section 31, Protracted, All, 603.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This Tract contains 5643.00 acres more or less.

TRACT 37-105

T. 5 S., R. 12 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This Tract contains 5760.00 acres more or less.

TRACT 37-106

T. 6 S., R. 10 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, excluding Native Allotment F024880,
600.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres.

This Tract contains 5680.00 acres more or less.

TRACT 37-107

T. 6 S., R. 10 W., FAIRBANKS MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 605.00 acres;
Section 7, Protracted, All, 607.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 609.00 acres.

This Tract contains 5661.00 acres more or less.

TRACT 37-108

T. 6 S., R. 10 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 611.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 613.00 acres;
Section 31, Protracted, All, 615.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This Tract contains 5679.00 acres more or less.

TRACT 37-109

T. 6 S., R. 10 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This Tract contains 5760.00 acres more or less.

TRACT 37-110

T. 6 S., R. 11 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-111

T. 6 S., R. 11 W., FAIRBANKS MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 605.00 acres;
Section 7, Protracted, All, 607.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 609.00 acres.

This tract contains 5661.00 acres more or less.

TRACT 37-112

T. 6 S., R. 11 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 611.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 613.00 acres;
Section 31, Protracted, All, 615.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 5679.00 acres more or less.

TRACT 37-113

T. 6 S., R. 11 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-114

T. 6 S., R. 12 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, All, as shown on Supplemental Cadastral Survey plat 81-130 Fairbanks Recording District, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-115

T. 6 S., R. 12 W., FAIRBANKS MERIDIAN

Section 3, All, as shown on Supplemental Cadastral Survey plat 81-130 Fairbanks Recording District, 640.00 acres;
Section 4, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-116

T. 6 S., R. 12 W., FAIRBANKS MERIDIAN

Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 605.00 acres;
Section 7, Protracted, All, 607.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 609.00 acres.

This tract contains 3741.00 acres more or less.

TRACT 37-117

T. 6 S., R. 12 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 611.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, All, as shown on Supplemental Cadastral Survey plat 81-132 Fairbanks Recording District, 640.00 acres;
Section 30, Protracted, All, 613.00 acres;
Section 31, All, as shown on Supplemental Cadastral Survey plat 81-132 Fairbanks Recording District, 615.00 acres;
Section 32, All, as shown on Supplemental Cadastral Survey plat 81-132 Fairbanks Recording District, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 5679.00 acres more or less.

TRACT 37-118

T. 6 S., R. 12 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-119

T. 7 S., R. 10 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-120

T. 7 S., R. 10 W., FAIRBANKS MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 617.00 acres;
Section 7, Protracted, All, 619.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 621.00 acres.

This tract contains 5697.00 acres more or less.

TRACT 37-121

T. 7 S., R. 10 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 623.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 625.00 acres;
Section 31, Protracted, All, 627.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 5715.00 acres more or less.

TRACT 37-122

T. 7 S., R. 10 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-123

T. 7 S., R. 11 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-124

T. 7 S., R. 11 W., FAIRBANKS MERIDIAN

Section 4,	Protracted, All, 640.00 acres;
Section 5,	Protracted, All, 640.00 acres;
Section 6,	Protracted, All, 617.00 acres;
Section 7,	Protracted, All, 619.00 acres;
Section 8,	Protracted, All, 640.00 acres;
Section 9,	Protracted, All, 640.00 acres;
Section 16,	Protracted, All, 640.00 acres;
Section 17,	Protracted, All, 640.00 acres;
Section 18,	Protracted, All, 621.00 acres.

This tract contains 5697.00 acres more or less.

TRACT 37-125

T. 7 S., R. 11 W., FAIRBANKS MERIDIAN

Section 19,	Protracted, All, 623.00 acres;
Section 20,	Protracted, All, 640.00 acres;
Section 21,	Protracted, All, 640.00 acres;
Section 28,	Protracted, All, 640.00 acres;
Section 29,	Protracted, All, 640.00 acres;
Section 30,	Protracted, All, 625.00 acres;
Section 31,	Protracted, All, 627.00 acres;
Section 32,	Protracted, All, 640.00 acres;
Section 33,	Protracted, All, 640.00 acres.

This tract contains 5715.00 acres more or less.

TRACT 37-126

T. 7 S., R. 11 W., FAIRBANKS MERIDIAN

Section 22,	Protracted, All, 640.00 acres;
Section 23,	Protracted, All, 640.00 acres;
Section 24,	Protracted, All, 640.00 acres;
Section 25,	Protracted, All, 640.00 acres;
Section 26,	Protracted, All, 640.00 acres;
Section 27,	Protracted, All, 640.00 acres;
Section 34,	Protracted, All, 640.00 acres;
Section 35,	Protracted, All, 640.00 acres;
Section 36,	Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-127

T. 7 S., R. 12 W., FAIRBANKS MERIDIAN

Section 1,	Protracted, All, 640.00 acres;
Section 2,	Protracted, All, 640.00 acres;
Section 3,	Protracted, All, 640.00 acres;
Section 10,	Protracted, All, 640.00 acres;
Section 11,	Protracted, All, 640.00 acres;
Section 12,	Protracted, All, 640.00 acres;
Section 13,	Protracted, All, 640.00 acres;
Section 14,	Protracted, All, 640.00 acres;
Section 15,	Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-128

T. 7 S., R. 12 W., FAIRBANKS MERIDIAN

Section 4,	Protracted, All, 640.00 acres;
Section 5,	Protracted, All, 640.00 acres;
Section 6,	Protracted, All, 617.00 acres;
Section 7,	Protracted, All, 619.00 acres;
Section 8,	Protracted, All, 640.00 acres;
Section 9,	Protracted, All, 640.00 acres;
Section 16,	Protracted, All, 640.00 acres;
Section 17,	Protracted, All, 640.00 acres;
Section 18,	Protracted, All, 621.00 acres.

This tract contains 5697.00 acres more or less.

TRACT 37-129

T. 7 S., R. 12 W., FAIRBANKS MERIDIAN

Section 19,	Protracted, All, 623.00 acres;
Section 20,	Protracted, All, 640.00 acres;
Section 21,	Protracted, All, 640.00 acres;
Section 28,	Protracted, All, 640.00 acres;
Section 29,	Protracted, All, 640.00 acres;
Section 30,	Protracted, All, 625.00 acres;
Section 31,	Protracted, All, 627.00 acres;
Section 32,	Protracted, All, 640.00 acres;
Section 33,	Protracted, All, 640.00 acres.

This tract contains 5715.00 acres more or less.

TRACT 37-130

T. 7 S., R. 12 W., FAIRBANKS MERIDIAN

Section 22,	Protracted, All, 640.00 acres;
Section 23,	Protracted, All, 640.00 acres;
Section 24,	Protracted, All, 640.00 acres;
Section 25,	Protracted, All, 640.00 acres;
Section 26,	Protracted, All, 640.00 acres;
Section 27,	Protracted, All, 640.00 acres;
Section 34,	Protracted, All, 640.00 acres;
Section 35,	Protracted, All, 640.00 acres;
Section 36,	Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-131

T. 8 S., R. 11 W., FAIRBANKS MERIDIAN

Section 1,	Protracted, All, 640.00 acres;
Section 2,	Protracted, All, 640.00 acres;
Section 3,	Protracted, All, 640.00 acres;
Section 10,	Protracted, All, 640.00 acres;
Section 11,	Protracted, All, 640.00 acres;
Section 12,	Protracted, All, 640.00 acres;
Section 13,	Protracted, All, 640.00 acres;
Section 14,	Protracted, All, 640.00 acres;
Section 15,	Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-132

T. 8 S., R. 11 W., FAIRBANKS MERIDIAN

Section 4,	Protracted, All, 640.00 acres;
Section 5,	Protracted, All, 640.00 acres;
Section 6,	Protracted, All, 629.00 acres;
Section 7,	Protracted, All, 631.00 acres;
Section 8,	Protracted, All, 640.00 acres;
Section 9,	Protracted, All, 640.00 acres;
Section 16,	Protracted, All, 640.00 acres;
Section 17,	Protracted, All, 640.00 acres;
Section 18,	Protracted, All, 633.00 acres.

This tract contains 5733.00 acres more or less.

TRACT 37-133

T. 8 S., R. 11 W., FAIRBANKS MERIDIAN

Section 19,	Protracted, All, 635.00 acres;
Section 20,	Protracted, All, 640.00 acres;
Section 21,	Protracted, All, 640.00 acres;
Section 28,	Protracted, All, 640.00 acres;
Section 29,	Protracted, All, 640.00 acres;
Section 30,	Protracted, All, 637.00 acres;
Section 31,	Protracted, All, 639.00 acres;
Section 32,	Protracted, All, 640.00 acres;
Section 33,	Protracted, All, 640.00 acres.

This tract contains 5751.00 acres more or less.

TRACT 37-134

T. 8 S., R. 11 W., FAIRBANKS MERIDIAN

Section 22,	Protracted, All, 640.00 acres;
Section 23,	Protracted, All, 640.00 acres;
Section 24,	Protracted, All, 640.00 acres;
Section 25,	Protracted, All, 640.00 acres;
Section 26,	Protracted, All, 640.00 acres;
Section 27,	Protracted, All, 640.00 acres;
Section 34,	Protracted, All, 640.00 acres;
Section 35,	Protracted, All, 640.00 acres;
Section 36,	Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-135

T. 8 S., R. 12 W., FAIRBANKS MERIDIAN

Section 1,	Protracted, All, 640.00 acres;
Section 2,	Protracted, All, 640.00 acres;
Section 3,	Protracted, All, 640.00 acres;
Section 10,	Protracted, All, 640.00 acres;
Section 11,	Protracted, All, 640.00 acres;
Section 12,	Protracted, All, 640.00 acres;
Section 13,	Protracted, All, 640.00 acres;
Section 14,	Protracted, All, 640.00 acres;
Section 15,	Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-136

T. 8 S., R. 12 W., FAIRBANKS MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 629.00 acres;
Section 7, Protracted, All, 631.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 633.00 acres.

This tract contains 5733.00 acres more or less.

TRACT 37-137

T. 8 S., R. 12 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 635.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 637.00 acres;
Section 31, Protracted, All, 639.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 5751.00 acres more or less.

TRACT 37-138

T. 8 S., R. 12 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-139

T. 5 S., R. 13 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-140

T. 5 S., R. 13 W., FAIRBANKS MERIDIAN

Section 3, Protracted, All, 640.00 acres;
Section 4, Protracted, E1/2, 320.00 acres;
Section 8, Protracted, SE1/4, 160.00 acres;
Section 9, Protracted, E1/2, SW1/4, 480.00 acres;
Section 10, Protracted, All, 640.00 acres.

This tract contains 2240.00 acres more or less.

TRACT 37-141

T. 5 S., R. 13 W., FAIRBANKS MERIDIAN

Section 15, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, E1/2, 320.00 acres;
Section 19, Protracted, S1/2, 300.00 acres;
Section 20, Protracted, E1/2, SW1/4, 480.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres.

This tract contains 3660.00 acres more or less.

TRACT 37-142

T. 5 S., R. 13 W., FAIRBANKS MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-143

T. 5 S., R. 13 W., FAIRBANKS MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-144

T. 5 S., R. 13 W., FAIRBANKS MERIDIAN

Section 27, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-145

T. 5 S., R. 13 W., FAIRBANKS MERIDIAN

Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 601.00 acres;
Section 31, Protracted, All, 603.00 acres;
Section 32, Protracted, All, 640.00 acres.

This tract contains 2484.00 acres more or less.

TRACT 37-146

T. 6 S., R. 13 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-147

T. 6 S., R. 13 W., FAIRBANKS MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 605.00 acres;
Section 7, Protracted, All, 607.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 609.00 acres.

This tract contains 5661.00 acres more or less.

TRACT 37-148

T. 6 S., R. 13 W., FAIRBANKS MERIDIAN

Section 19, Protracted, All, 611.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 613.00 acres;
Section 31, Protracted, All, 615.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 5679.00 acres more or less.

TRACT 37-149

T. 6 S., R. 13 W., FAIRBANKS MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-130

T. 7 S., R. 13 W., FAIRBANKS MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-131

T. 7 S., R. 13 W., FAIRBANKS MERIDIAN

Section 3, Protracted, All, 640.00 acres;
Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 617.00 acres;
Section 7, Protracted, All, 619.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres.

This tract contains 5076.00 acres more or less.

TRACT 37-132

T. 7 S., R. 13 W., FAIRBANKS MERIDIAN

Section 15, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 621.00 acres;
Section 19, Protracted, All, 623.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres.

This tract contains 5084.00 acres more or less.

TRACT 37-133

T. 7 S., R. 13 W., FAIRBANKS MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-134

T. 7 S., R. 13 W., FAIRBANKS MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-135

T. 7 S., R. 13 W., FAIRBANKS MERIDIAN

Section 27, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 625.00 acres;
Section 31, Protracted, All, 627.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres.

This tract contains 5092.00 acres more or less.

TRACT 37-136

T. 9 S., R. 8 W., FAIRBANKS MERIDIAN

Section 33, Protracted, All, 640.00 acres.

This Tract contains 640.00 acres more or less.

TRACT 37-157

T. 7 N., R. 6 W., COPPER RIVER MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This Tract contains 3840.00 acres more or less.

TRACT 37-158

T. 7 N., R. 6 W., COPPER RIVER MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, [illegible] acres;
Section 7, Protracted, All, 610.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres.

This Tract contains 3770.00 acres more or less.

TRACT 37-159

T. 7 N., R. 6 W., COPPER RIVER MERIDIAN

Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 612.00 acres;
Section 19, Protracted, All, 613.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres.

This Tract contains 3785.00 acres more or less.

TRACT 37-160

T. 7 N., R. 6 W., COPPER RIVER MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This Tract contains 3840.00 acres more or less.

TRACT 37-161

T. 7 N., R. 6 W., COPPER RIVER MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This Tract contains 3840.00 acres more or less.

TRACT 37-162

T. 7 N., R. 6 W., COPPER RIVER MERIDIAN

Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 615.00 acres;
Section 31, Protracted, All, 617.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This Tract contains 3792.00 acres more or less.

TRACT 37-163

T. 6 N., R. 6 W., COPPER RIVER MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This Tract contains 2560.00 acres more or less.

TRACT 37-164

T. 6 N., R. 6 W., COPPER RIVER MERIDIAN

Section 3, Protracted, All, 640.00 acres;
Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 619.00 acres;
Section 7, Protracted, All, [illegible] acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres.

This Tract contains [illegible] acres more or less.

TRACT 37-165

T. 6 N., R. 6 W., COPPER RIVER MERIDIAN

Section 15, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 623.00 acres;
Section 19, Protracted, All, 624.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres.

This Tract contains 5087.00 acres more or less.

TRACT 37-166

T. 6 N., R. 6 W., COPPER RIVER MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This Tract contains 2560.00 acres more or less.

TRACT 37-167

T. 6 N., R. 6 W., COPPER RIVER MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This Tract contains 2560.00 acres more or less.

TRACT 37-168

T. 6 N., R. 6 W., COPPER RIVER MERIDIAN

Section 27, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 626.00 acres;
Section 31, Protracted, All, 628.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres.

This Tract contains 5094.00 acres more or less.

TRACT 37-169

T. 5 N., R. 6 W., COPPER RIVER MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This Tract contains 3840.00 acres more or less.

TRACT 37-170

T. 5 N., R. 6 W., COPPER RIVER MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 638.00 acres;
Section 7, Protracted, All, 632.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres.

This Tract contains [illegible] acres more or less.

TRACT 37-171

T. 5 N., R. 6 W., COPPER RIVER MERIDIAN

Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 634.00 acres;
Section 19, Protracted, All, 635.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres.

This Tract contains 3829.00 acres more or less.

TRACT 37-172

T. 5 N., R. 6 W., COPPER RIVER MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This Tract contains 3840.00 acres more or less.

TRACT 37-173

T. 5 N., R. 6 W., COPPER RIVER MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This Tract contains 3840.00 acres more or less.

TRACT 37-174

T. 5 N., R. 6 W., COPPER RIVER MERIDIAN

Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 637.00 acres;
Section 31, Protracted, All, 639.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This Tract contains 3836.00 acres more or less.

TRACT 37-175

T. 5 N., R. 7 W., COPPER RIVER MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres.

This Tract contains 5760.00 acres more or less.

TRACT 37-176

T. 5 N., R. 7 W., COPPER RIVER MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 630.00 acres;
Section 7, Protracted, All, 632.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 634.00 acres.

This Tract contains 5736.00 acres more or less.

TRACT 37-177

T. 5 N., R. 7 W., COPPER RIVER MERIDIAN

Section 19, Protracted, All, 630.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 637.00 acres;
Section 31, Protracted, All, 639.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 5731.00 acres more or less.

TRACT 37-178

T. 5 N., R. 7 W., COPPER RIVER MERIDIAN

Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 5760.00 acres more or less.

TRACT 37-179

T. 5 N., R. 8 W., COPPER RIVER MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres;
Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-180

T. 5 N., R. 8 W., COPPER RIVER MERIDIAN

Section 3, Protracted, All, 640.00 acres;
Section 4, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-181

T. 5 N., R. 8 W., COPPER RIVER MERIDIAN

Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 630.00 acres;
Section 7, Protracted, All, 632.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 634.00 acres.

This tract contains 3816.00 acres more or less.

TRACT 37-182

T. 5 N., R. 8 W., COPPER RIVER MERIDIAN

Section 19, Protracted, All, 638.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 637.00 acres;
Section 31, Protracted, All, 639.00 acres;
Section 32, Protracted, All, 640.00 acres.

This tract contains 3831.00 acres more or less.

TRACT 37-183

T. 5 N., R. 8 W., COPPER RIVER MERIDIAN

Section 21, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-184

T. 5 N., R. 8 W., COPPER RIVER MERIDIAN

Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-185

T. 5 N., R. 9 W., COPPER RIVER MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted All, 640.00 acres;
Section 10, Protracte., All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-186

T. 5 N., R. 9 W., COPPER RIVER MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 630.00 acres;
Section 7, Protracted, All, 632.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres.

This tract contains 3832.00 acres more or less.

TRACT 37-187

T. 5 N., R. 9 W., COPPER RIVER MERIDIAN

Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 634.00 acres;
Section 19, Protracted, All, 639.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres.

This tract contains 3833.00 acres more or less.

TRACT 37-188

T. 5 N., R. 9 W., COPPER RIVER MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-189

T. 5 N., R. 9 W., COPPER RIVER MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-190

T. 5 N., R. 9 W., COPPER RIVER MERIDIAN

Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 637.00 acres;
Section 31, Protracted, All, 639.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 3836.00 acres more or less.

TRACT 37-191

T. 4 N., R. 7 W., COPPER RIVER MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-192

T. 4 N., R. 7 W., COPPER RIVER MERIDIAN

Section 3, Protracted, All, 640.00 acres;
Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 598.00 acres;
Section 7, Protracted, All, 599.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres.

This tract contains 5037.00 acres more or less.

TRACT 37-193

T. 4 N., R. 7 W., COPPER RIVER MERIDIAN

Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 601.00 acres;
Section 19, Protracted, All, 603.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres.

This tract contains 3764.00 acres more or less.

TRACT 37-194

T. 4 N., R. 7 W., COPPER RIVER MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, [illegible] acres;
Section 22, Protracted, All, [illegible] acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-195

T. 4 N., R. 7 W., COPPER RIVER MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-196

T. 4 N., R. 7 W., COPPER RIVER MERIDIAN

Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 605.00 acres;
Section 31, Protracted, All, 607.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 3772.00 acres more or less.

TRACT 37-197

T. 2 N., R. 8 W., COPPER RIVER MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-198

T. 2 N., R. 8 W., COPPER RIVER MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, excluding those portions of U.S.S. 3336, 3336A, 4824 and 5437 within Section 6, 585.38 acres;
Section 7, Protracted, All, 621.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres.

This tract contains 3766.38 acres more or less.

TRACT 37-199

T. 2 N., R. 8 W., COPPER RIVER MERIDIAN

Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 623.00 acres;
Section 19, Protracted, All, 625.00 acres;
Section 20, Protracted, All, 640.00 acres.

This tract contains 2528.00 acres more or less.

TRACT 37-200

T. 2 N., R. 8 W., COPPER RIVER MERIDIAN

Section 15, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-201

T. 2 N., R. 8 W., COPPER RIVER MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-202

T. 2 N., R. 8 W., COPPER RIVER MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-203

T. 2 N., R. 8 W., COPPER RIVER MERIDIAN

Section 27, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres.

This tract contains 2560.00 acres more or less.

TRACT 37-204

T. 2 N., R. 8 W., COPPER RIVER MERIDIAN

Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 626.00 acres;
Section 31, Protracted, All, 628.00 acres;
Section 32, Protracted, All, 640.00 acres.

This tract contains 2534.00 acres more or less.

TRACT 37-205

T. 4 N., R. 9 W., COPPER RIVER MERIDIAN

Section 1, Protracted, All, 640.00 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-206

T. 4 N., R. 9 W., COPPER RIVER MERIDIAN

Section 4, Protracted, All, 640.00 acres;
Section 5, Protracted, All, 640.00 acres;
Section 6, Protracted, All, 598.00 acres;
Section 7, Protracted, All, 599.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres.

This tract contains 3757.00 acres more or less.

TRACT 37-207

T. 4 N., R. 9 W., COPPER RIVER MERIDIAN

Section 16, Protracted, All, 640.00 acres;
Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 601.00 acres;
Section 19, Protracted, All, 603.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres.

This tract contains 3764.00 acres more or less.

TRACT 37-208

T. 4 N., R. 9 W., COPPER RIVER MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 15, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-209

T. 4 N., R. 9 W., COPPER RIVER MERIDIAN

Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-210

T. 4 N., R. 9 W., COPPER RIVER MERIDIAN

Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 609.00 acres;
Section 31, Protracted, All, 607.00 acres;
Section 32, Protracted, All, 640.00 acres;
Section 33, Protracted, All, 640.00 acres.

This tract contains 3772.00 acres more or less.

TRACT 37-211

T. 2 N., R. 9 W., COPPER RIVER MERIDIAN

Section 1, Protracted, All, excluding that portion of U.S.S. 3637 and 4824 within Section 1, 627.01 acres;
Section 2, Protracted, All, 640.00 acres;
Section 3, Protracted, All, 640.00 acres;
Section 10, Protracted, All, 640.00 acres;
Section 11, Protracted, All, 640.00 acres;
Section 12, Protracted, All, 640.00 acres.

This tract contains 3827.01 acres more or less.

TRACT 37-212

T. 2 N., R. 9 W., COPPER RIVER MERIDIAN

Section 4, Protracted, All, excluding U.S.S. 2919, 4062 Lots 1 and 3, and 3346, Lots 3, 4 and 5, and NW1/4NE1/4, 409.21 acres;
Section 5, Protracted, All, excluding E1/2NE1/4NE1/4, 620.00 acres;
Section 6, Protracted, All, excluding that portion of U.S.S. 3677 within Section 6, 605.15 acres;
Section 7, Protracted, All, 621.00 acres;
Section 8, Protracted, All, 640.00 acres;
Section 9, Protracted, All, 640.00 acres.

This tract contains 3535.36 acres more or less.

TRACT 37-213

T. 2 N., R. 9 W., COPPER RIVER MERIDIAN

Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 623.00 acres;
Section 19, Protracted, All, 625.00 acres;
Section 20, Protracted, All, 640.00 acres.

This tract contains 2528.00 acres more or less.

TRACT 37-214

T. 2 N., R. 9 W., COPPER RIVER MERIDIAN

Section 15, Protracted, All, 640.00 acres;
Section 16, Protracted, All, 640.00 acres;
Section 21, Protracted, All, 640.00 acres;
Section 22, Protracted, All, 640.00 acres;
Section 27, Protracted, E1/2, 320.00 acres.

This tract contains 2880.00 acres more or less.

TRACT 37-215

T. 2 N., R. 9 W., COPPER RIVER MERIDIAN

Section 13, Protracted, All, 640.00 acres;
Section 14, Protracted, All, 640.00 acres;
Section 23, Protracted, All, 640.00 acres;
Section 24, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres.

This tract contains 3840.00 acres more or less.

TRACT 37-216

T. 2 N., R. 9 W., COPPER RIVER MERIDIAN

Section 33, Protracted, S1/2, 320.00 acres;
Section 34, Protracted, All, 640.00 acres;
Section 35, Protracted, All, 640.00 acres;
Section 36, Protracted, All, 640.00 acres.

This tract contains 2240.00 acres more or less.

TRACT 37-217

T. 2 N., R. 9 W., COPPER RIVER MERIDIAN

Section 29, Protracted, All, 640.00 acres;
Section 30, Protracted, All, 626.00 acres;
Section 31, Protracted, All, 628.00 acres.

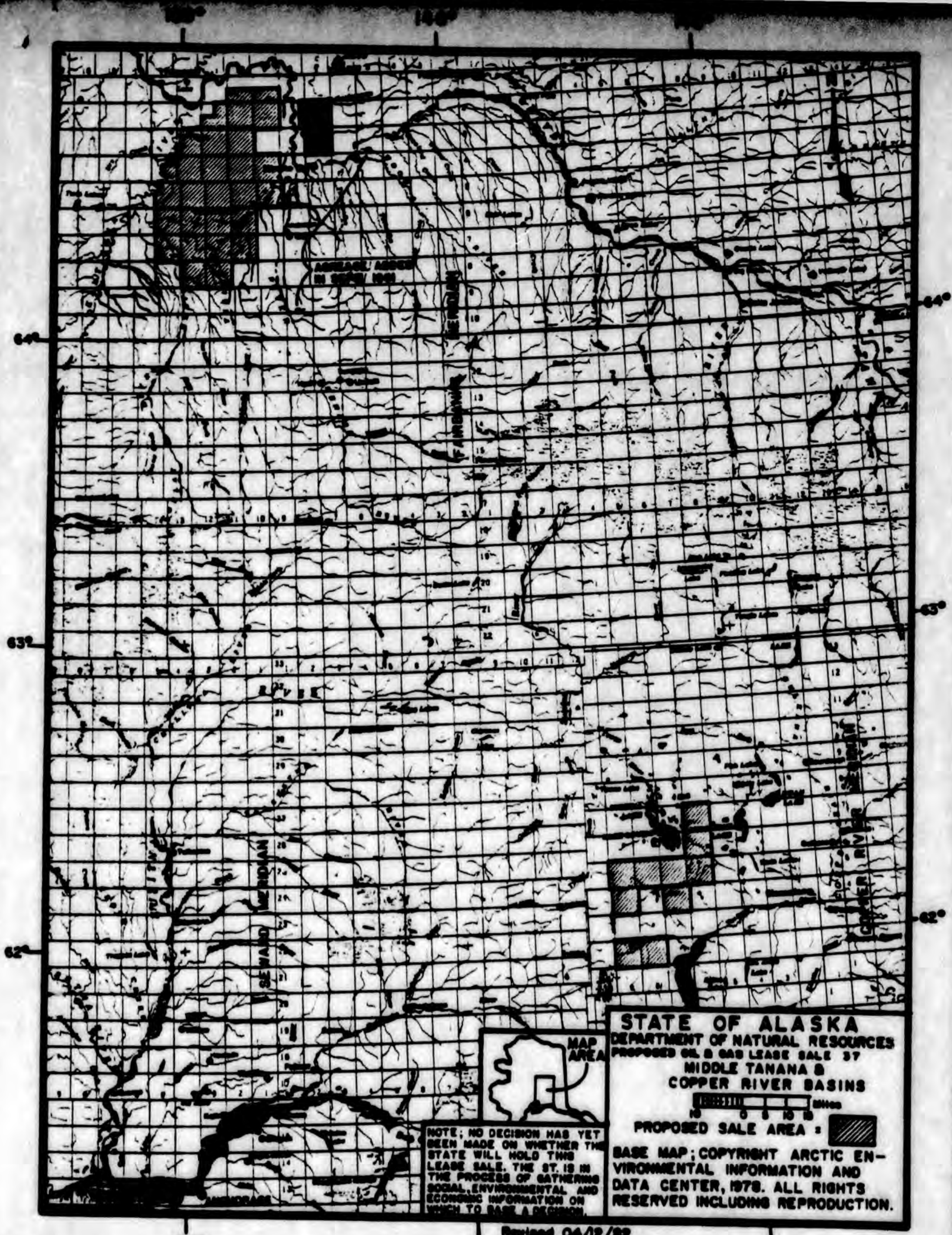
This tract contains 1894.00 acres more or less.

STATE OF ALASKA

SALE 37
Middle Tanana Basin
and Copper River Basin

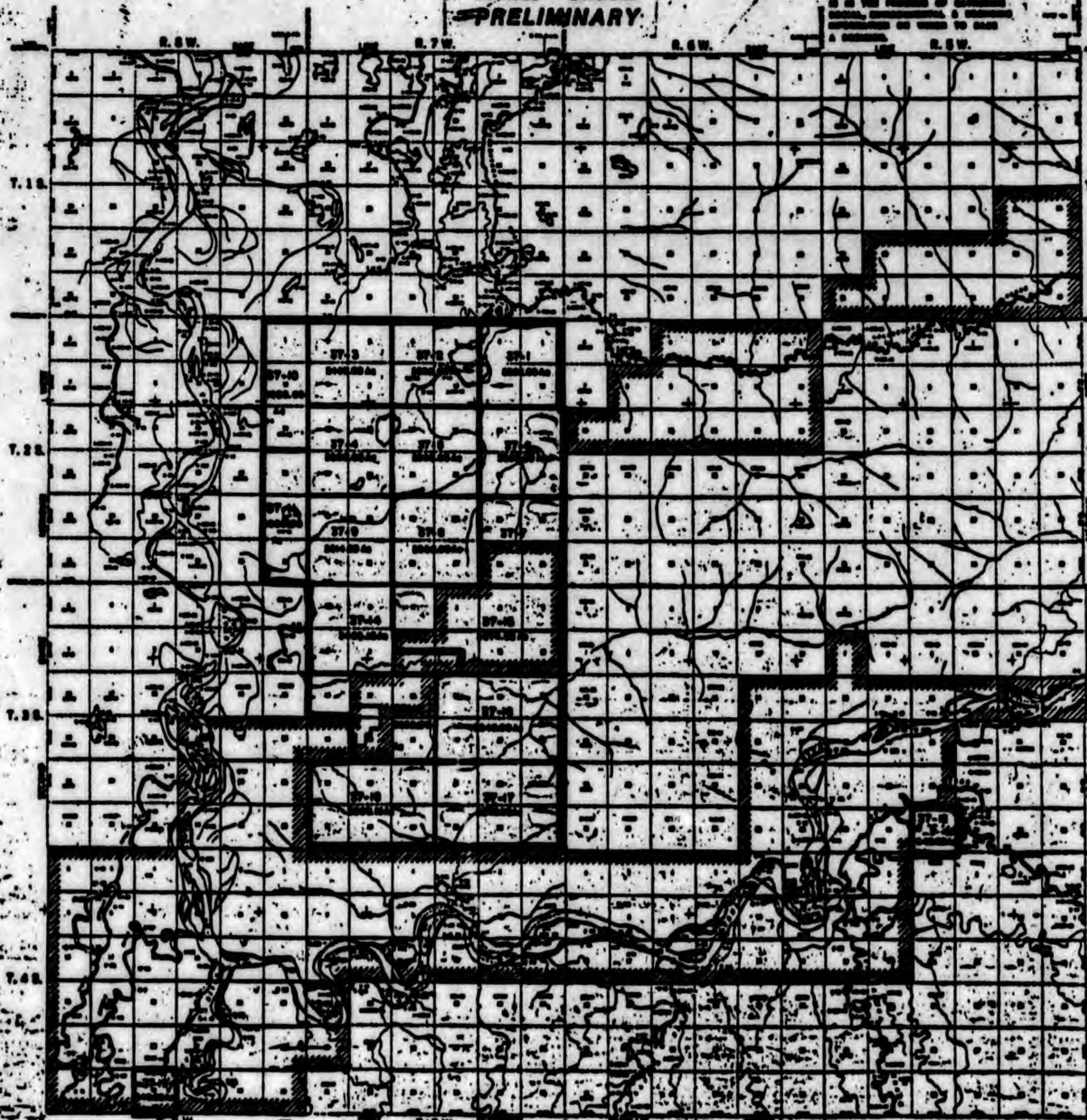
UNOFFICIAL TRACT MAPS

April 22, 1982



Revised 04/12/82 To Reflect A Reduction In Acreage.

TOWNSHIPS 1 TO 4 SOUTH, RANGES 5 TO 8 WEST, FAIRBANKS MERIDIAN, ALASKA
PROTRACTED (UNSURVEYED)
REVISED DIAGRAM
PRELIMINARY



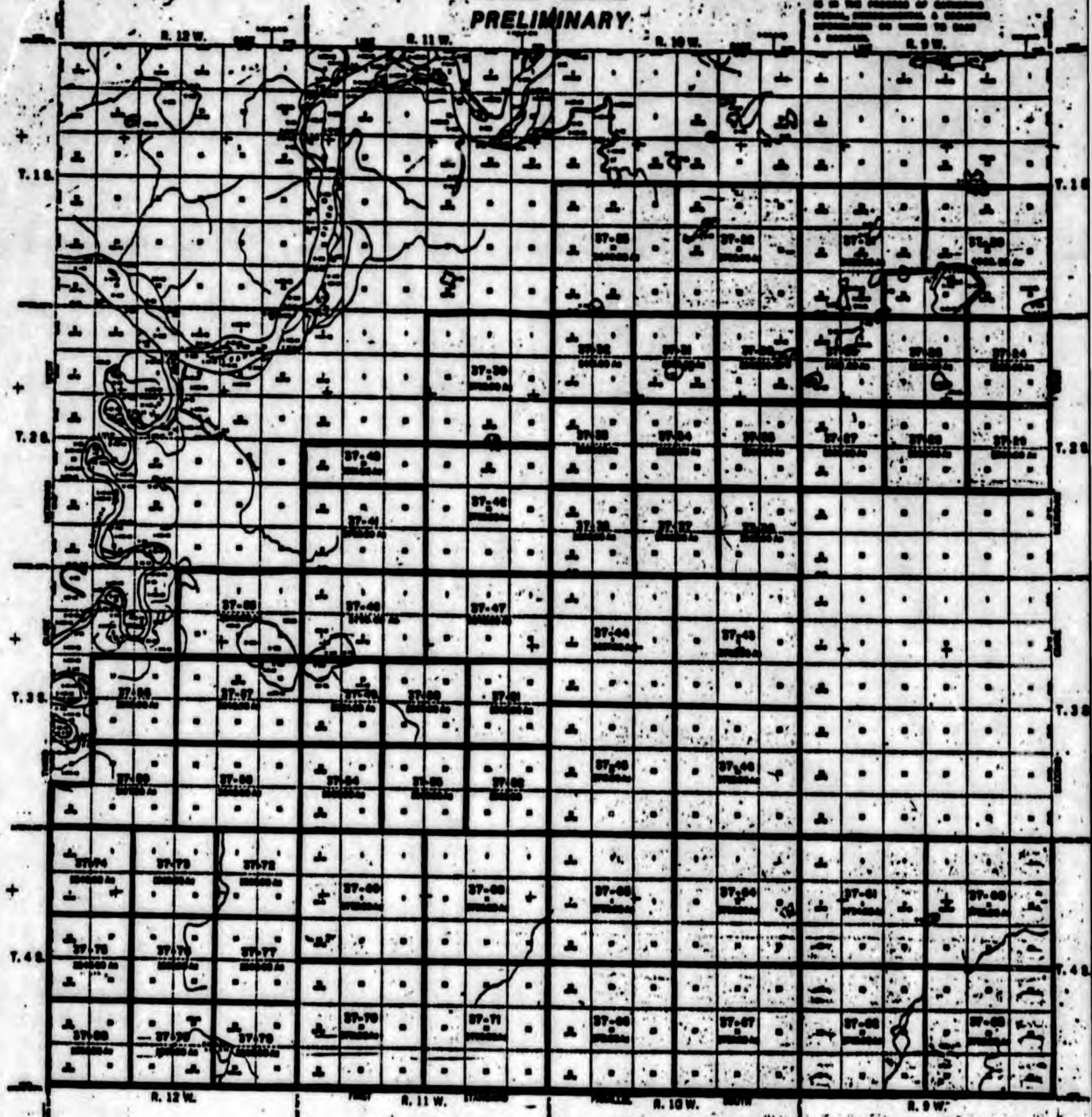
STATE OF ALASKA COMPETITIVE
OIL & GAS LEASE SALE 37

TOWNSHIPS 1 TO 4 SOUTH, RANGES 9 TO 12 WEST, FAIRBANKS MERIDIAN, ALASKA

PROTRACTED (UNSURVEYED)

REVISED DIAGRAM

PRELIMINARY



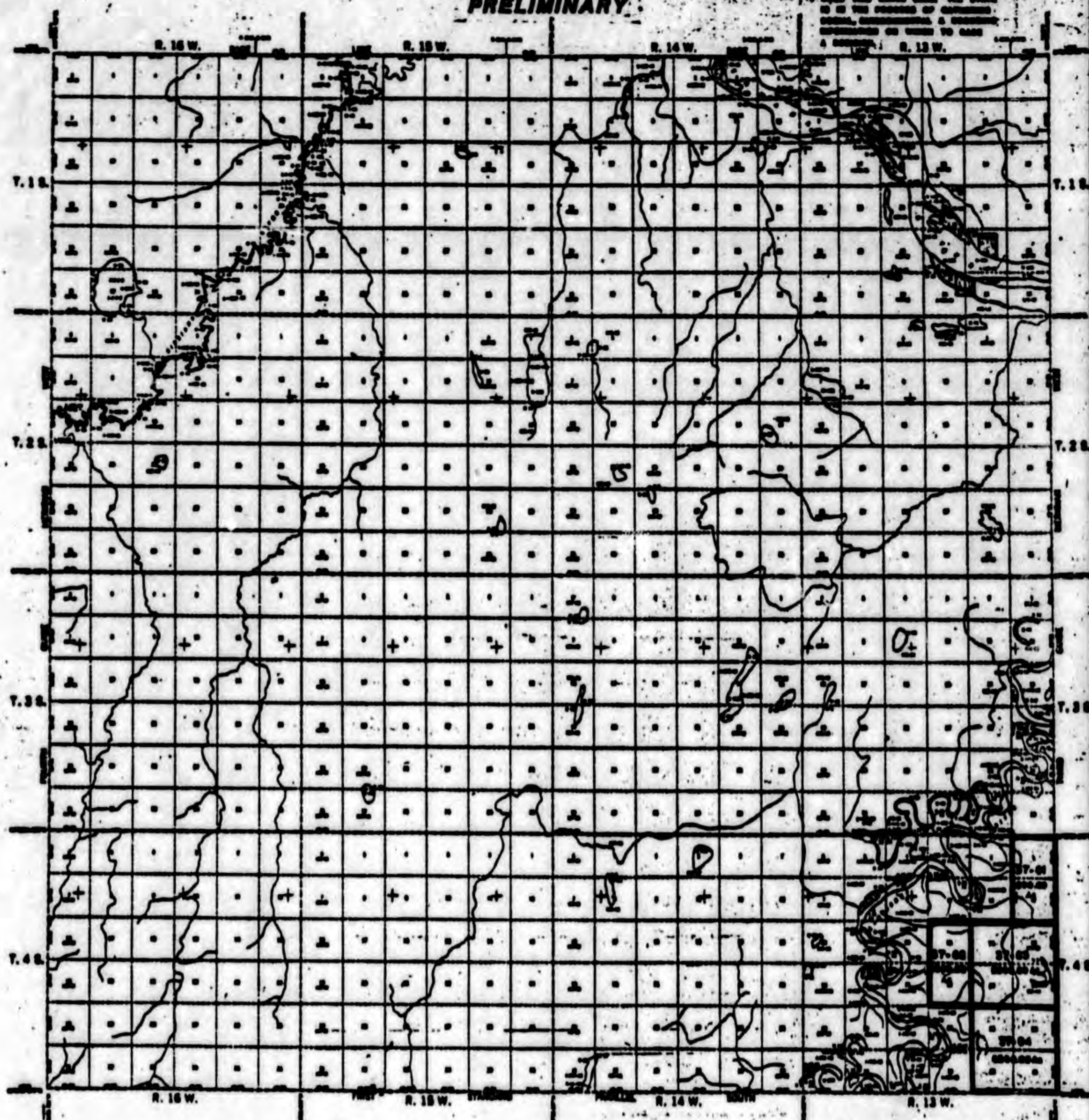
STATE OF ALASKA COMPETITIVE

OIL & GAS LEASE SALE 37

TOWNSHIPS 1 TO 4 SOUTH, RANGES 13 TO 16 WEST, FAIRBANKS MERIDIAN, ALASKA

PROTRACTED (UNSURVEYED)

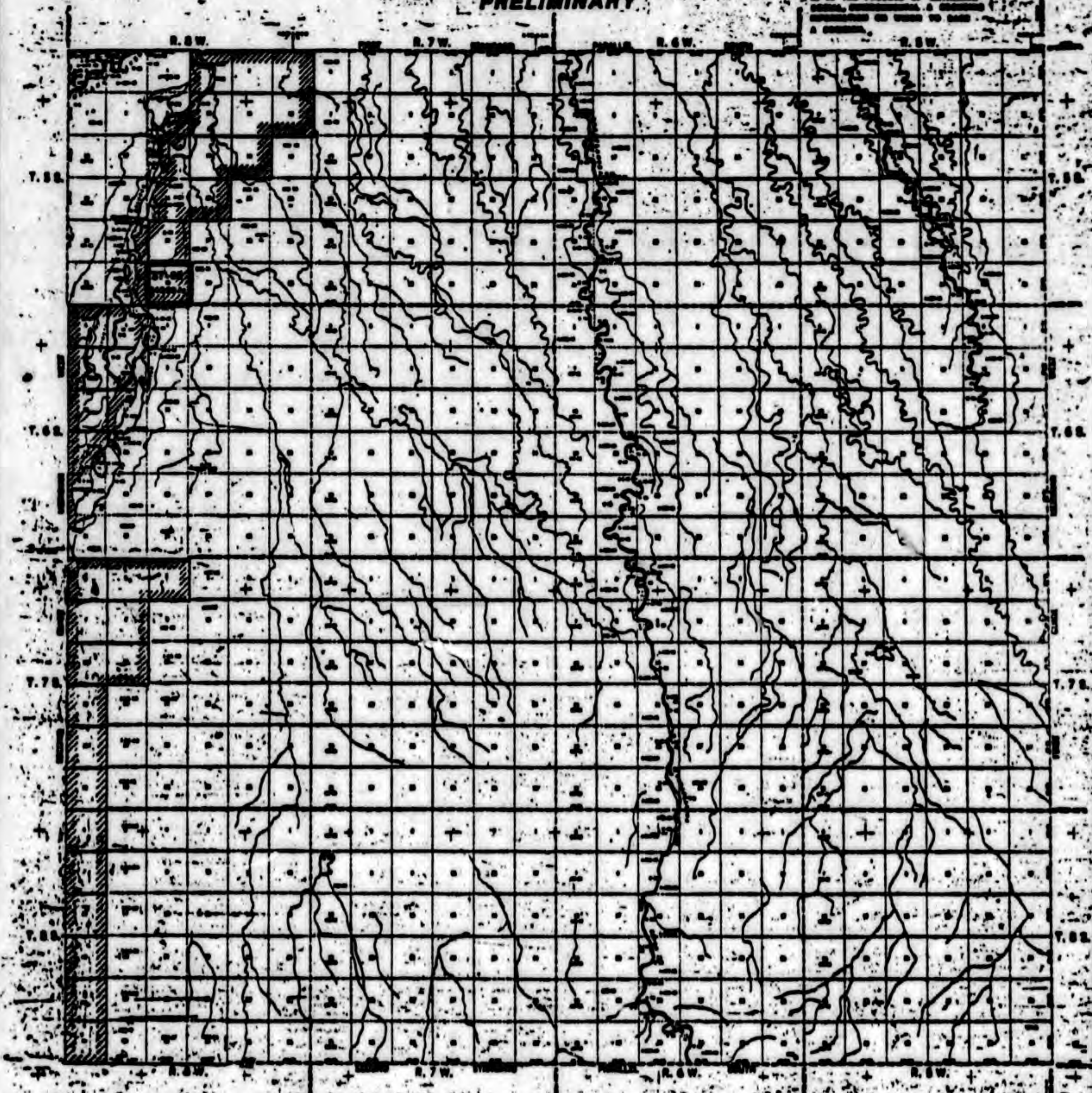
PRELIMINARY



STATE OF ALASKA COMPETITIVE OIL & GAS LEASE SALE 37

TOWNSHIPS 5 TO 8 SOUTH, RANGES 5 TO 8 WEST, FAIRBANKS MERIDIAN, ALASKA
PROTRACTED (UNSURVEYED)

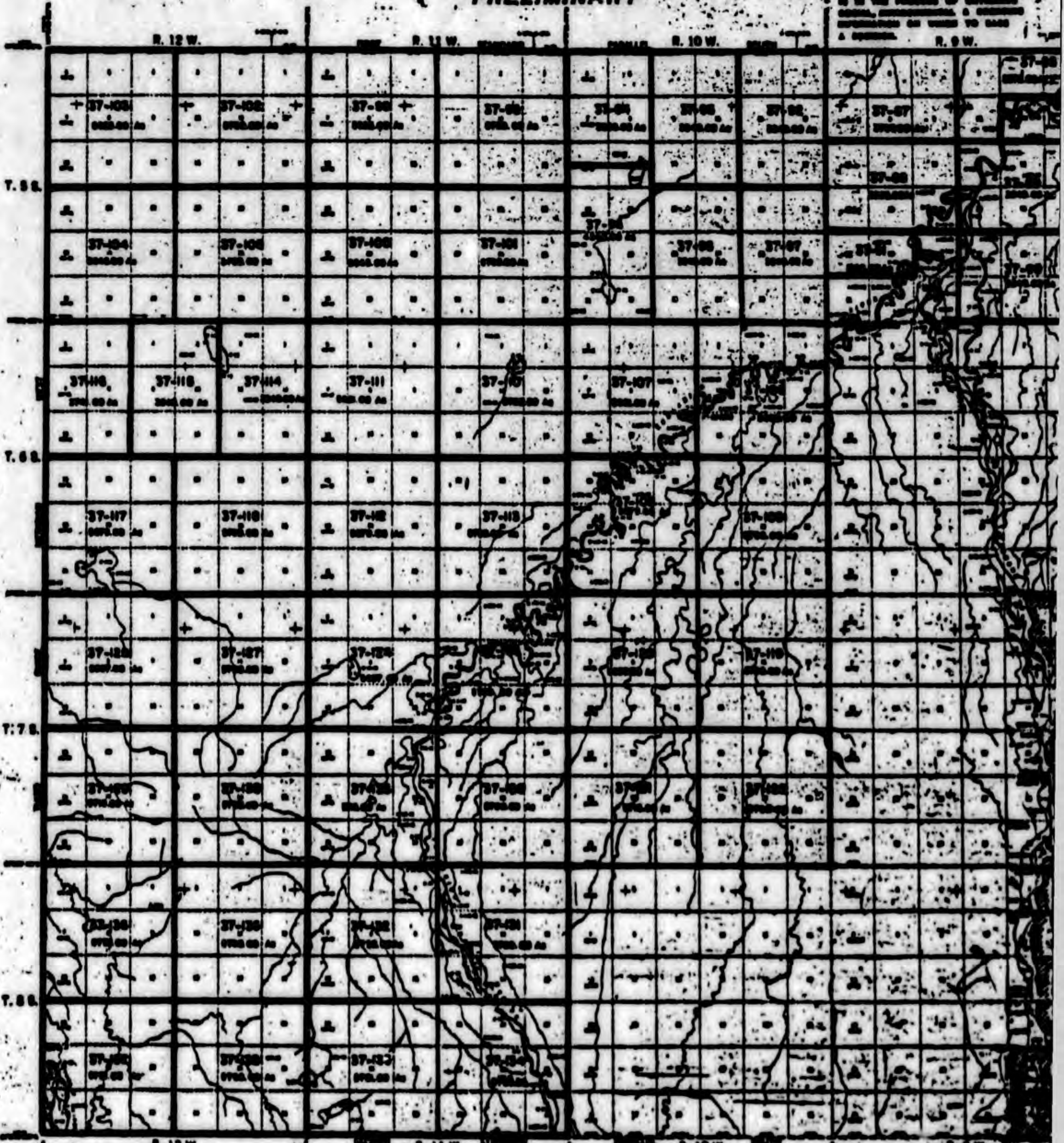
PRELIMINARY



STATE OF ALASKA COMPETITIVE
OIL & GAS LEASE SALE 37

TOWNSHIPS 5 TO 8 SOUTH, RANGES 9 TO 12 WEST, FAIRBANKS MERIDIAN, ALASKA
PROTRACTED (UNSURVEYED)

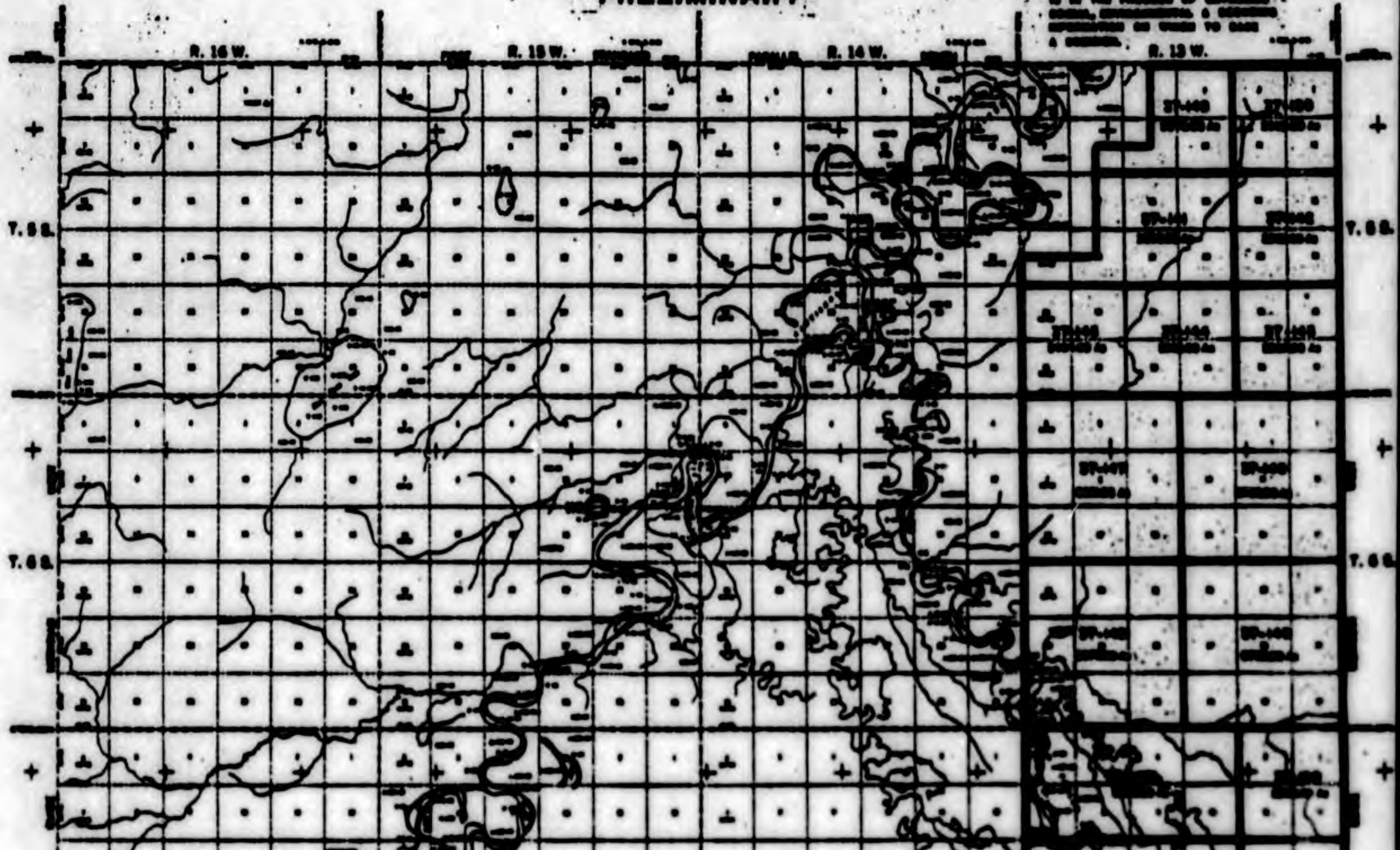
PRELIMINARY



STATE OF ALASKA COMPETITIVE
OIL & GAS LEASE SALE 37

TOWNSHIPS 5 TO 8 SOUTH, RANGES 13 TO 16 WEST, FAIRBANKS MERIDIAN, ALASKA
PROTRACTED (UNSURVEYED)

PRELIMINARY

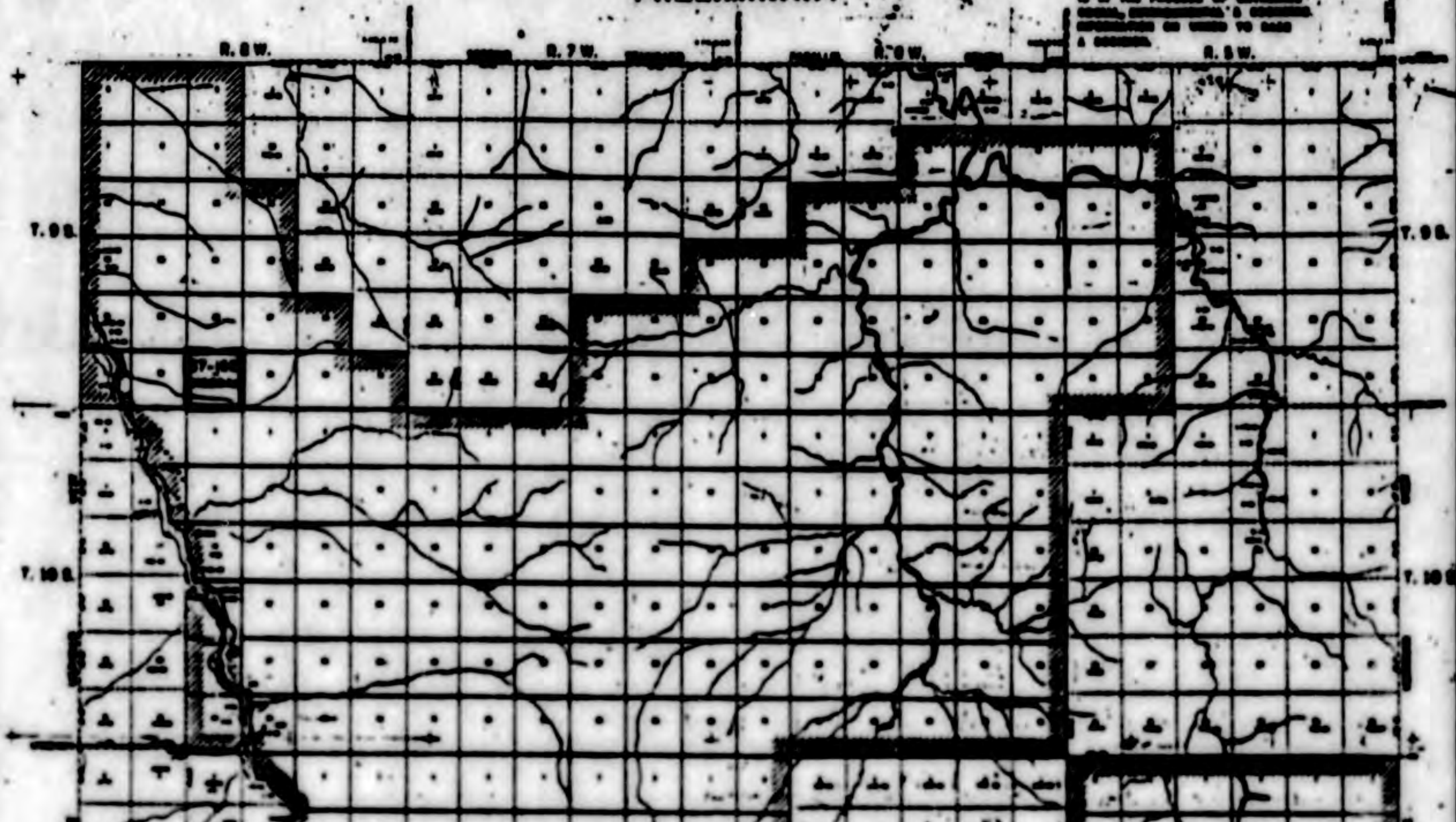


STATE OF ALASKA COMPETITIVE
OIL & GAS LEASE SALE 37

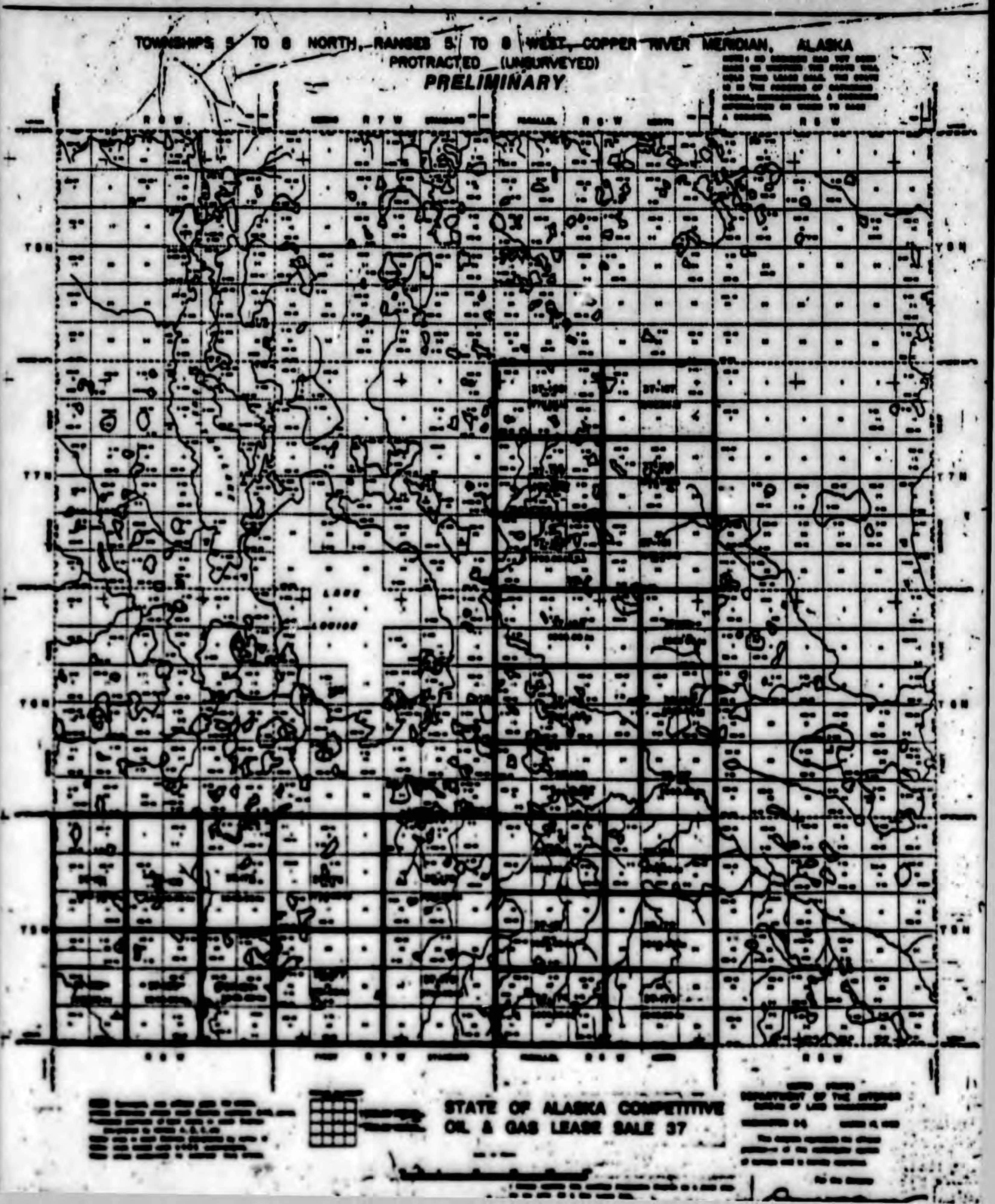
TOWNSHIPS 9 TO 12 SOUTH, RANGES 5 TO 8 WEST, FAIRBANKS MERIDIAN, ALASKA

PROTRACTED (UNSURVEYED)

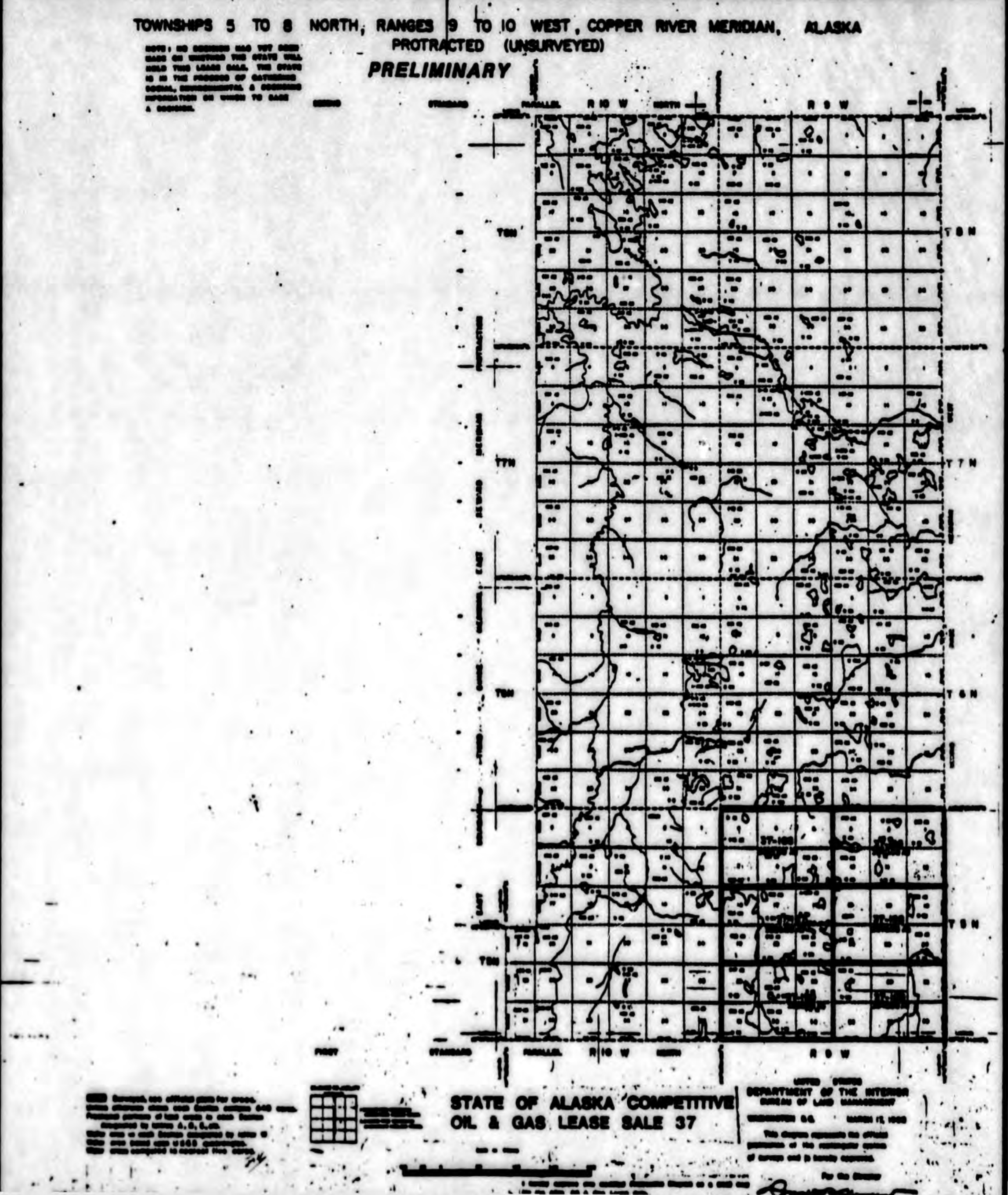
PRELIMINARY



STATE OF ALASKA COMPETITIVE OIL & GAS LEASE SALE 37



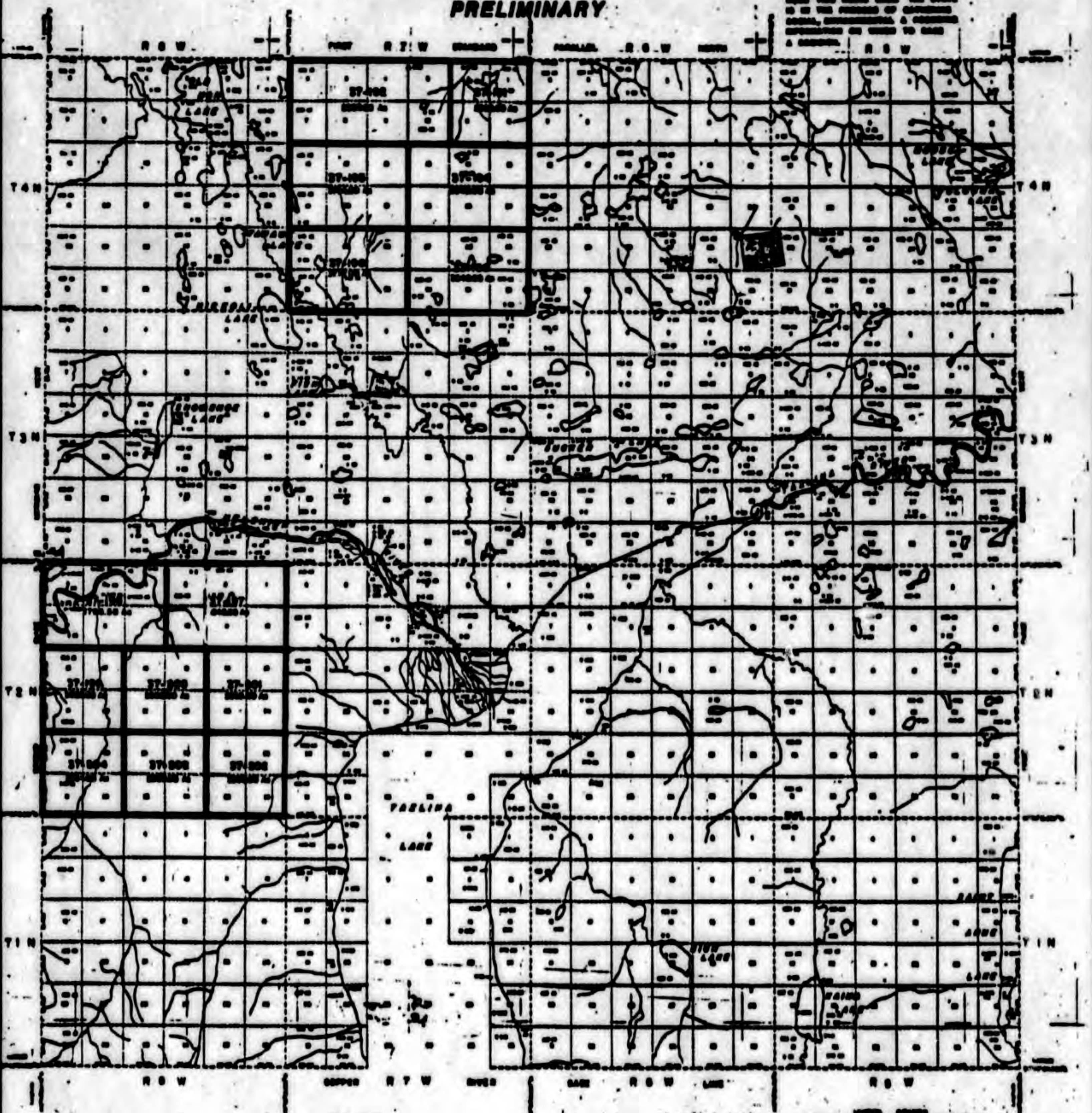
TOWNSHIPS 5 TO 8 NORTH, RANGES 5 TO 8 WEST, COPPER RIVER MERIDIAN, ALASKA
PROTRACTED (UNSURVEYED)
PRELIMINARY
R 8 W
R 7 W
R 6 W
R 5 W
T 8 N
T 7 N
T 6 N
T 5 N
STATE OF ALASKA COMPETITIVE
OIL & GAS LEASE SALE 37



TOWNSHIPS 5 TO 8 NORTH, RANGES 9 TO 10 WEST, COPPER RIVER MERIDIAN, ALASKA
PROTRACTED (UNSURVEYED)
PRELIMINARY
R 10 W
R 9 W
T 8 N
T 7 N
T 6 N
T 5 N
STATE OF ALASKA COMPETITIVE
OIL & GAS LEASE SALE 37
DEPARTMENT OF THE INTERIOR

TOWNSHIPS 1 TO 4 NORTH, RANGES 5 TO 8 WEST, COPPER RIVER MERIDIAN, ALASKA
PROTRACTED (UNSURVEYED)

PRELIMINARY



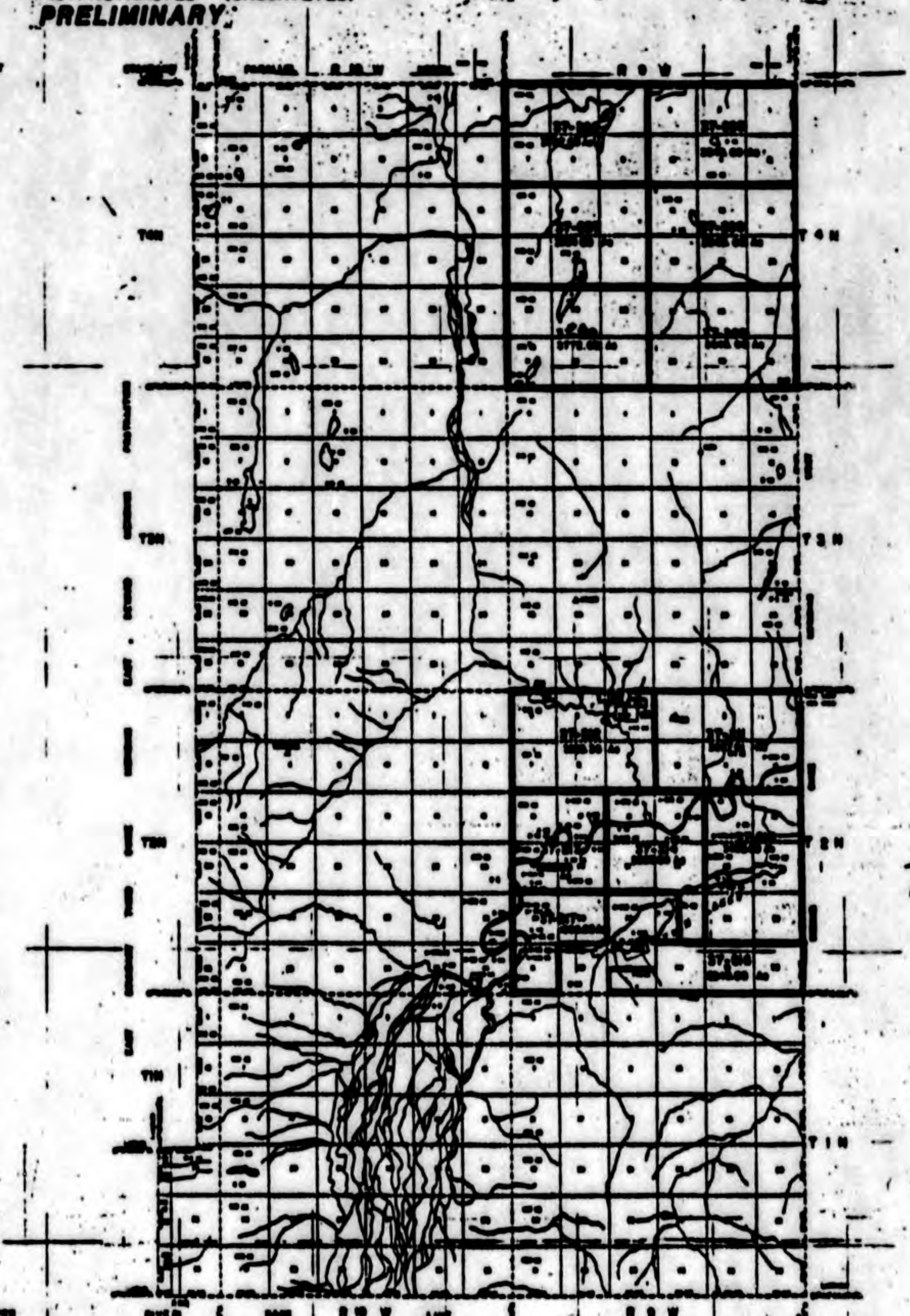
STATE OF ALASKA COMPETITIVE
OIL & GAS LEASE SALE 37

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

TOWNSHIPS 1 TO 4 NORTH, RANGES 9 TO 11 WEST, COPPER RIVER MERIDIAN, ALASKA

PROTRACTED (UNSURVEYED)

PRELIMINARY



STATE OF ALASKA COMPETITIVE OIL & GAS LEASE SALE 37

UNITED STATES DEPARTMENT OF THE INTERIOR BUREAU OF LAND MANAGEMENT

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

MINERALS AND ENERGY MANAGEMENT

555 CORDOVA STREET
POUCH 7-005
ANCHORAGE, ALASKA 99510
(907) 276-2653

Phone: 276-2653

April 22, 1982

-NOTICE-
FINAL DECISION AND FINDING UNDER AS 38.05.035(a)(14)
REGARDING PROPOSED OIL AND GAS LEASE SALE 37A
Chakok River

The Department of Natural Resources, Division of Minerals and Energy Management (DMEM), gives formal notice under AS 38.05.345(a)(3) of its intention to make a final decision under AS 38.05.035(a)(14) regarding the sale of an oil and gas lease in proposed Competitive Oil and Gas Lease Sale 37A. Before the sale may be held, the Director of the Division of Minerals and Energy Management must make a written final decision that the sale is in the best interest of the state. This decision, issued pursuant to AS 38.05.035(a)(14), will set out the facts and applicable law upon which the Director bases her determination that the sale of an oil and gas lease in proposed Sale 37A will or will not best serve the interests of the state. This final decision is expected to be available to the public in June, 1982.

A preliminary analysis of the potential effects of proposed sale 37A and the means by which they may be mitigated is now available at DMEM, 555 Cordova Street, Anchorage, Alaska. Copies of the analysis may be obtained by writing to DMEM at Pouch 7-005, Anchorage, Alaska, 99510. The public is invited to comment on any aspect of the sale including any proposed term or condition. Comments must be received at DMEM by May 21, 1982 in order to be considered in the final decision of whether or not to hold this sale. A preliminary tract map of the area also is available at DMEM.

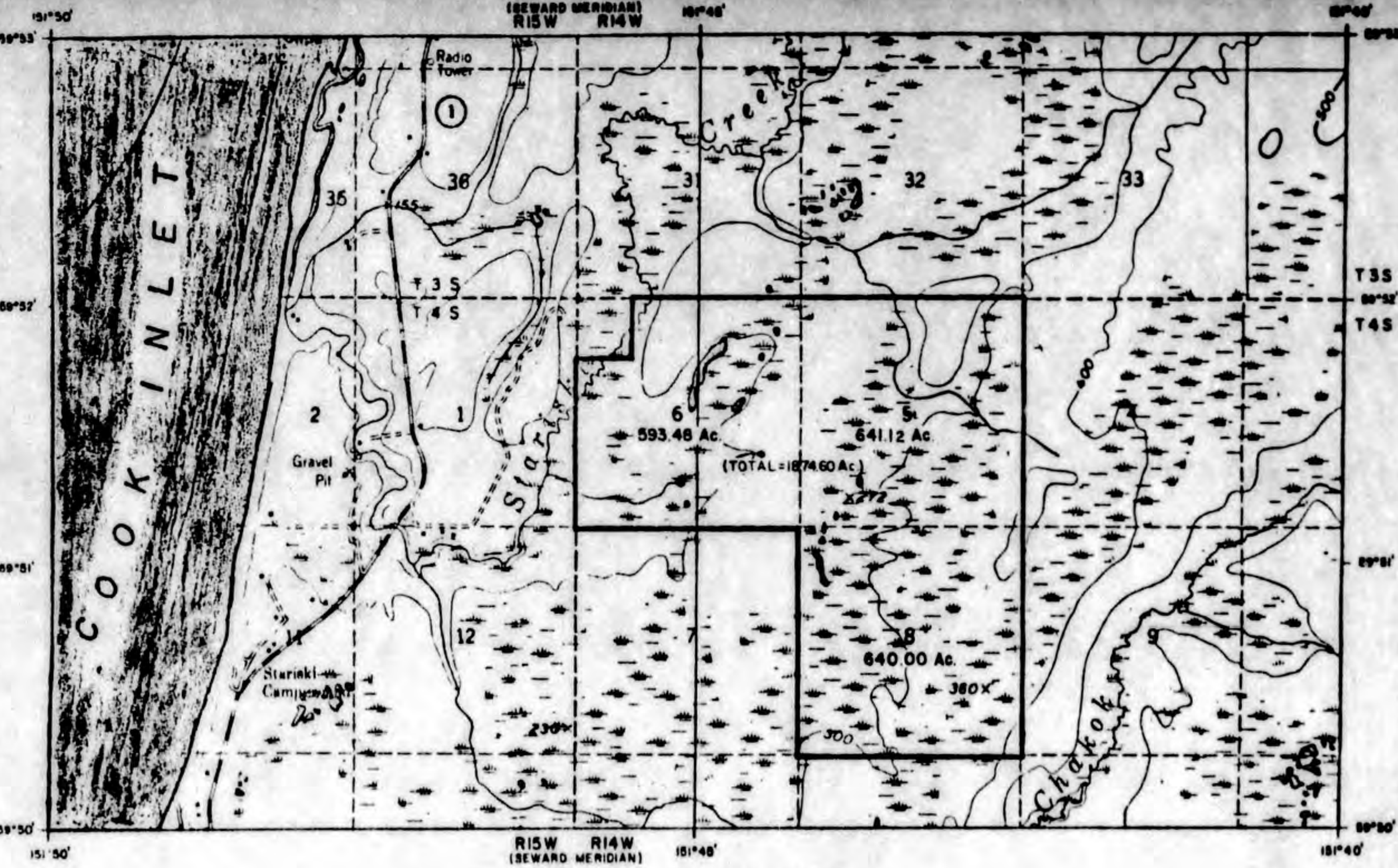
Proposed Sale 37A contains an area of approximately 1875 acres on the Kenai Peninsula. The sale area contains sections 5, 8, and most of section 6 in township 4 south, range 14 west, Seward Meridian. All of the acreage will be offered in one tract. The sale area is located within the Kenai Peninsula Borough, approximately five miles north of Anchor Point and about 15 miles north of Homer. The Sterling Highway is about one mile west of the tract.

The Chakok River sale is being offered as "exempt" acreage under the terms of AS 38.05.180(d)(1). This provision in the state oil and gas leasing statute allows the Commissioner of the Department of Natural Resources to issue oil and gas leases in an area that has not been included in the five-year leasing program if "the land to be leased was previously subject to a valid state or federal oil and gas lease." This entire tract was previously subject to state oil and gas lease ADL #53914, which was issued in June, 1971 and expired in May, 1981.

If a decision is made that the proposed sale is in the best interest of the state, an "Information to Bidders" packet will be sent to all persons on the DMEM mailing list in June, 1982. If the decision is made to hold the sale, it is tentatively scheduled to occur at the Travelers Inn in Fairbanks on August 24, 1982 in accordance with AS 38.05.180. If you want to place your name on the DMEM mailing list, contact DMEM at (907) 276-2653, extension 4247.

Kay Brown

Kay Brown
Director



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINERALS AND ENERGY MANAGEMENT
COMPETITIVE OIL AND GAS LEASE SALE 37A
CHAKOK RIVER
PRELIMINARY TRACT MAP

SCALE 1:48,000 1"=4,000 ft.

MILE 3/4 1/2 1/4 0

FEET 5000 4000 3000 2000 1000 0 FEET

DIRECTOR D.M.E.M., KAY BROWN — Kay Brown	DRAWN BY O.D.S.	CHECKED BY KMO
LEASING MANAGER, PAMELA ROGERS — Pamela Rogers	DATE APPROVED 4/14/82	

LEGEND

BASE MAP
U.S.G.S. SELDOVIA (D-5) QUADRANGLE 1:63,360 SERIES (TOPOGRAPHIC)
A PORTION OF SELDOVIA (D-5) HAS BEEN PHOTOGRAPHICALLY ENLARGED TO APPROXIMATELY 1:24,000 SCALE

CONTOUR INTERVAL 100 FEET

WATER DEPTH IN FEET

STERLING HIGHWAY

PROPOSED TRACT

NOTE: NO DECISION HAS YET BEEN MADE ON WHETHER THE STATE WILL HOLD THIS LEASE SALE. THE STATE IS IN THE PROCESS OF GATHERING SOCIAL, ENVIRONMENTAL & ECONOMIC INFORMATION ON WHICH TO BASE A DECISION.

April 22, 1982

STATE OF ALASKA

PRELIMINARY LEGAL DESCRIPTION

PROPOSED OIL AND GAS LEASE SALE 37A

TRACT 37A

T. 4 S., R. 14 W., Seward Meridian

Section 5,	All, 641.12 acres;
Section 6,	Lots 1, 2, 3, 5, 6, 7, S1/2NE1/4, SE1/4NW1/4, E1/2SW1/4, SE1/4, 593.48 acres;
Section 8,	All, 640 acres.

This Tract contains 1874.60 acres more or less.

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

MINERALS AND ENERGY MANAGEMENT

555 CORDOVA STREET
POUCH 7-005
ANCHORAGE, ALASKA 99510
(907) 276-2653

STATE OF ALASKA
SUPPLEMENTAL NOTICE
OIL & GAS LEASE SALE 36
APRIL 12, 1982

Under the Notice of Sale for competitive Oil and Gas Lease Sale 36 dated April 7, 1982, lessees are eligible for exploration incentive credits for the first exploratory well per tract. In addition to the provisions of that notice, Term of Sale No. 41, and laws and regulations governing exploration incentive credits, bidders are advised that the Commissioner will in all instances approve the assignment of credits earned in Sale 36.

Kay Brown

Kay Brown, Director
Division of Minerals and Energy Management

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

RHL

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Georgiana Sheldon, Acting Chairman; Matthew Holden, Jr., George R. Hall and J. David Hughes.

Alaskan Northwest Natural Gas Transportation Company) Docket No. CP78-123, et al.

ORDER TO SHOW CAUSE
(Issued December 15, 1980)

On February 2, 1979, Alaska Northwest Natural Gas Transporation Company (ANNGTC) filed an application for an order approving past expenditures and to establish procedures for continuing audit and approval of future expenditures and major commitments. Supplements to that application were filed on August 14, 1979 and July 16, 1980.

The President's Decision and Report to Congress on the Alaska Natural Gas Transportation System (Decision) contemplates contemporaneous auditing during the course of the project. Finance Condition 2, at page 37 of the Decision, provides in part that the project sponsors "shall . . . submit to the FPC for approval on a timely basis all components of construction work in progress." Section 9 of the Alaska Natural Gas Transportation Act of 1976 (ANGTA) (15 U.S.C. § 719g) mandates expedition.

On April 18, 1979, the Commission directed 1/ its Office of the Chief Accountant to audit expenditures incurred by the certificate holders of the Alaska Natural Gas Transportation

---

1/ Directive to the Office of the Chief Accountant, Administrative Order No. 4, 7 FERC _____ (1979).

System (ANGTS). 2/ The Commission directed the Chief Accountant to include in the reports his opinion as to whether "expenditures are properly assignable to the project and of a nature that would qualify the expenditures for eventual inclusion in the rate base, whether the accounting used by the sponsors meets the requirements of the Uniform System of Accounts and generally accepted accounting principles, and whether the project sponsors are in compliance with other accounting and reporting regulations and requirements of the Natural Gas Act, the Decision, and the certificate of public convenience and necessity." 3/

The Commission has, to date, received three audit reports from the Office of the Chief Accountant. 4/ The first report covers pre-partnership expenditures by five individual companies which later became partners in ANNGTC. Those expenditures include Allowance for Funds Used During Construction (AFUDC), expenses related to the preparation and presentation of applications for the construction certificate for the Alaskan pipeline, and expenses

---

2/ ANGTS was authorized by the ANGTA, 15 U.S.C. §§ 719-719o and the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System, (Executive Office of the President, Energy Policy and Planning, September 1977), as enacted into law by H. J. Res. 621, Pub. Law No. 95-166 (November 2, 1977). The Commission, by an order issued December 16, 1977 in this docket, issued conditional certificates of public convenience and necessity to construct and operate the ANGTS. Several competing companies, including the Northwest Alaskan Pipeline Company (the successor in interest to the Alcan Pipeline Company, whose proposed pipeline route was selected by the President in his Decision), formed a partnership to construct and operate the Alaska section of the ANGTS on February 1, 1978. That partnership is known as the Alaska Northwest Natural Gas Transportation Company (ANNGTC). Expenses incurred before the formation of the partnership are referred to as "pre-partnership expenditures."

3/ Administrative Order No. 4, at 3.

4/ The reports are each entitled "Report on the Results of Audit of Expenditures by the Alaskan Northwest Natural Gas Transportation Company . . ." and were submitted in August and October 1980.

made through membership or participation in the Gas Arctic/Northwest Study Group. 5/

The second report covers expenditures incurred by ANNGTC partners from February 1, 1978 through December 31, 1978, including AFUDC.

The third report covers expenditures, including AFUDC, incurred from January 1, 1979 through December 31, 1979 and charged to various gas plant accounts of the partnership. In both the second and third reports, a substantial part of the AFUDC claimed is related to pre-partnership and other expenditures at issue in the first report.

The audit reports are attached to this order for review by interested persons.

The Commission orders:

Within 60 days of the issuance of this order, any interested person shall show cause why the Commission should not adopt, for purposes of rate base determination pursuant to the Natural Gas Act, ANGTA, and the President's Decision, the data and opinions set forth in the three Reports on Results of Audit prepared by the Office of the Chief Accountant.

By the Commission.

(S E A L)

Kenneth F. Plumb,
Secretary.

5/ Also known as the Canadian Arctic Gas Study Limited (CAGSL).

REPORT ON RESULTS OF AUDIT OF EXPENDITURES BY PARTNERS OF THE ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY WHICH WERE INCURRED PRIOR TO THE FORMATION OF THE PARTNERSHIP ON FEBRUARY 1, 1978

(DOCKET NO. CP78-123, *et al.*)

August 1980
Division of Audits
Office of Chief Accountant
Federal Energy Regulatory Commission

REPORT ON RESULTS OF AUDIT OF EXPENDITURES BY PARTNERS OF THE ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY WHICH WERE INCURRED PRIOR TO THE FORMATION OF THE PARTNERSHIP ON FEBRUARY 1, 1978 (DOCKET NO. CP78-123, et al.)

INTRODUCTION

This is the first in a series of reports on the results of audits of expenditures related to the construction of the Alaska Natural Gas Transportation System (ANGTS)1/. The audits and reports are being made pursuant to the directions contained in Administrative Order No. 4, issued April 18, 1979.

This report conveys the results of the staff's initial audit of expenditures charged to the Alaskan section of the ANGTS. The initial audit covered expenditures incurred prior to the formation of the partnership (Alaskan Northwest Natural Gas Transportation Company (ANNGTC)) on February 1, 1978, for the construction and operation of the Alaskan section.

Amounts charged to the Alaskan section for pre-partnership expenditures totaled $57,415,070 2/.

1/ ANGTS was authorized by the Alaska Natural Gas Transportation Act of 1976 (ANGTA), 15 U.S.C. 719 et seq. and the President's Decision and Report to Congress on Alaska Natural Gas Transportation System, as enacted into law, H.J. Res. 621, Pub. L. No. 95-108 (November 2, 1977).

2/ See Exhibit No. 1.

SUMMARY

Prior to the formation of the partnership, for the purpose of construction and operation of the Alaskan section of the ANGTS under a Conditional Certificate of Public Convenience and Necessity issued by FERC on December 16, 1977 (Docket No. CP78-123, *et al.*), substantial sums were expended by the individual companies[3].

One partner, Northwest Alaskan Pipeline Company (Northwest) was the original applicant for the route and pipeline proposal ultimately selected and conditionally authorized in Docket No. CP78-123, *et al*. Northwest's claimed pre-partnership expenditures of $19,048,187 were related to the preparation and presentation of its application for the construction certificate for an Alaskan pipeline[4].

Four other partners, Pan Alaska Gas Company (Pan Alaska), Calaska Energy Company (Calaska), Pacific Interstate Transmission Company (Arctic) (Pacific), and Northern Arctic Gas Company (Northern), claimed pre-partnership expenditures totaling $38,366,883 which were made through their membership and/or participation in the Gas Arctic/Northwest Project Study Group, better known by its service organization name, Canadian Arctic Gas Study Limited (CAGSL)[4].

3/ In some instances the expenditures were actually made by affiliated or other companies. For clarity in presentation, this report attributes such expenditures to the current partner company.

4/ See Exhibit No. 1.

CAGSL sponsors unsuccessfully applied to FERC and the National Energy Board of Canada for certificates to construct a gas pipeline to transport Alaskan gas to the United States via a predominantly Canadian route.

With respect to the pre-partnership expenditures claimed by Northwest, the staff concludes that:

1. Expenditures of $15,190,609, including Allowance for Funds Used During Construction (AFUDC) of $965,272, are properly assignable to the Alaskan section of the ANGTS and are of a nature that would qualify for eventual inclusion in rate base.
2. Expenditures of $193,236, including AFUDC of $12,278 are not of a nature that would qualify for eventual inclusion in rate base, and should be disallowed.
3. Expenditures of $3,664,342, including AFUDC of $232,847 may not be properly assignable to the Alaskan section of the ANGTS for eventual inclusion in rate base. Requests to Northwest for additional information on these expenditures have not been answered. Therefore, staff proposes that these expenditures be disallowed without prejudice to Northwest's reclaiming them upon submission of appropriate supporting information.

With respect to the pre-partnership expenditures claimed by the four other partners, the staff concludes that:

1. None of the claimed expenditures, totaling $38,366,883, including AFUDC of $6,587,916, are properly assignable to the Alaskan section of the ANGTS and such expenditures should be disallowed.
2. Calaska claimed $1,300,277 in excess of its actual expenditures due to the method used to account for Canadian/United States dollar exchange differences. However, no separate adjustment for this item will be necessary if conclusion 1 above is sustained, since all claimed expenditures would be disallowed.
3. The parent companies of three of the partners, Pacific Lighting Service Company (Pacific Interstate Transmission Company (Arctic)), Panhandle Eastern Pipeline Company (Pan Alaska Gas Company), and Northern Natural Gas Company (Northern Arctic Gas Company) have already recovered significant portions of their pre-partnership expenditures via tariff charges to their existing customers. The staff is proposing that the claimed pre-partnership expenditures be disallowed to the extent that their parent companies had recovered such expenditures through January 31, 1979, and that any recoveries made after that date be credited against any of their remaining pre-partnership expenditures. However, no separate adjustments for this item will be necessary if conclusion 1 above is sustained, since all claimed CAGSL expenditures would be disallowed.

4. Pacific claimed $23,375 in excess of its actual expenditures due to its failure to reduce such expenditures by interest reimbursements received. However, no separate adjustment for this item will be necessary if conclusion 1 above is sustained, since all claimed expenditures would be disallowed.
5. The parent companies of Pan Alaska, Northern and Pacific have already claimed the pre-partnership CAGSL expenditures as tax deductions for Federal income tax purposes. The staff is proposing that the deferred taxes resulting from this procedure be recorded on ANNGTC's books to assure that the tax benefits are properly associated with the CAGSL expenditures in making AFUDC computations, computing Federal income tax allowances, and establishing rate base. This item becomes moot if conclusion 1 above is sustained, since all claimed CAGSL expenditures would be disallowed.
6. AFUDC amounts are incorrectly computed and will require downward adjustment in the event that any portion of the pre-partnership expenditures are ultimately allowed. However, no separate adjustment for this item will be necessary if conclusion 1 above is sustained, since all claimed expenditures would be disallowed.

The bases for the conclusions cited above are discussed in the text of this report.

SCOPE OF AUDIT

The audit covered claimed pre-partnership expenditures totaling $57,415,070, including AFUDC. Of these pre-partnership expenditures, $38,366,883, including AFUDC, is related to disbursements made by four companies for their shares of the costs incurred by Canadian Arctic Gas Study Limited (CAGSL). Therefore, it was necessary for the staff to examine the total costs incurred by CAGSL $154,849,479 (Canadian) to determine whether the partners' expenditures were properly assignable to the Alaskan section of the ANGTS.

The audit included an examination of the accounting and other records to the extent deemed necessary to determine whether:

1. The various financial statements and reports properly reflected the underlying records and documents,
2. The expenditures were adequately documented and supported,
3. The accounting for the expenditures met the requirements of the Uniform System of Accounts and generally accepted accounting principles, and
4. The expenditures were properly assignable to the Alaskan section of the ANGTS and were of a nature that would qualify for eventual inclusion in rate base.

RESULTS OF AUDIT

A. Northwest Alaskan Pipeline Company

Northwest claimed pre-partnership expenditures of $19,048,187, including $1,210,397 of AFUDC. The staff determined that

1. Expenditures of $15,190,609, including $965,272 of AFUDC, were made in the planning, researching, developing, formulating, testing and filing processes related to the successful application before the Commission to build the Alaskan section of the ANGTS. These expenditures were found to be properly assignable to ANNGTC, and of a nature that would qualify them for eventual inclusion in ANNGTC's rate base.

2. Expenditures of $193,236 including $12,278 of AFUDC are not of a nature that would qualify them for eventual inclusion in ANNGTC's rate base. These expenditures fall into the following categories:

a. Influencing Public Opinion

Expenditures of $115,406, including $7,333 of AFUDC relate to payments to various public relations firms for preparing and disseminating information about the Alcan Proposal and the two alternative proposals during the selection process. A review of the brochures, news ads and news articles resulting from these expenditures disclosed that they were intended and used to influence public opinion and the opinions of public officials during the selection process of the Alaskan Gas Project.

The Uniform System of Accounts requires that expenditures of this nature be recorded in Account 426.4, Expenditures for certain civic, political and related activities, a non-utility expense account.

b. <u>Lobbying Activities</u>

Expenditures of $57,888, including $3,678 of AFUDC relate to payments to two firms for lobbying services.

One firm performed services which involved legislative efforts to secure passage of the Natural Gas Policy Act of 1978. This emanated from President Carter's 1977 Energy Plan which proposed substantial changes to the Natural Gas Act. Northwest requested the firm to analyze the President's proposal and determine its impact on the Alaska Natural Gas Transportation System. After analysis of the President's proposal, the firm began contacting members of both the House and Senate and their staffs to inform them of the impact of gas pricing legislation on the Project. Position papers on the Project and letters to all Senators and Representatives were prepared and sent during the deliberations in both Houses on the pending legislation. The firm monitored all public sessions and met personally with conferees, and their staff on a regular basis through the 9-month conference. Numerous proposals and counter-proposals were offered by the conferees and this firm prepared position papers on the impact of the various proposals on the Project. Once the conferees agreed on a compromise bill, the firm again contacted members of both the House and Senate urging passage of the compromise bill. The compromise bill was ultimately passed and was signed into law in November of 1978.

The second firm focused its efforts on gaining Congressional radification of the President's Decision on the ANGTS.

The Uniform System of Accounts requires that expenditures of this nature be recorded in Account 426.4, Expenditures for certain civic, political and related activities, a non-utility expense account.

c. Celebration Costs

Expenditures of $18,874, including $1,199 of AFUDC, relate to payments for receptions held in Washington, D. C., Anchorage, Alaska, and Fairbanks, Alaska to celebrate President Carter's selection of the Alcan Project proposal to construct the Alaskan Natural Gas Pipeline.

The Commission, in various cases, has ruled that celebration-type expenditures are not properly expendable to the plant or operating expense accounts, but are of a nature that should be recorded in Account 426.5, Other deductions.

d. Donations

Expenditures of $1,068, including $68 of AFUDC, relate to a contribution to the Hubert Humphrey Institute of Public Affairs (University of Minnesota Foundation).

The Uniform System of Accounts requires that expenditures of this nature be recorded in Account 426.1, Donations, a non-utility expense account.

3. Expenditures of $3,664,342, including $232,847 of AFUDC, were not sufficiently supported to enable the staff to determine whether they are properly assignable to the Alaskan section of the ANGTS for eventual inclusion in rate base. Requests to Northwest for additional information on these expenditures have not resulted in responses which clearly document the nature and character of the items. These expenditures fall into two general categories:

a. Amounts paid to a number of law firms for services which appear to include political lobbying or public relations efforts designed to influence public opinion concerning the project and, as such, would not be allowable in plant accounts under the provisions of FERC's Uniform System of Accounts.

b. Amounts paid to a number of consultants where sufficiently competent evidential material (i.e. contracts, written agreements, vendor memoranda, etc.) either did not exist or were not made available. Therefore, there was no adequate basis upon which to evaluate the propriety of the assignment of the costs to the project, or their qualification for eventual inclusion in rate base.

The staff proposes that these expenditures be disallowed, without prejudice to Northwest's reclaiming them upon submission of appropriate supporting information.

B. Other Partners

The other four partners claimed pre-partnership expenditures totaling \$38,366,883, including AFUDC of \$6,587,916. All of these expenditures were related to their membership and/or participation in CAGSL.

1. Review of CAGSL's Expenditures

During its existence, CAGSL[5/] expended \$154,849,479 (Canadian) in the planning, researching, developing, formulating, testing and filing processes in an unsuccessful attempt to obtain the necessary

5/ See Exhibit No. 2 for background data on CAGSL.

Canadian and U. S. governmental certificates and permits required to construct and operate a primarily Canadian routed Natural Gas Transmission Line to transport Alaskan and Canadian Gas to the lower 48 states. The staff has determined that the amounts expended were properly authorized in accordance with CAGSL agreements, adequately documented and supported, and reasonably classified by cost categories. The cost categories and staff's determinations regarding possible future value to the Alaskan section of the ANGTS are as follows:

CAGSL Expenditures (Canadian Dollars)

Cost Categories-Direct	Possible Future Value or Usefulness	No Future Value	Total
Engineering and Construction Planning	$ 8,762,705	$ 57,057,095	$ 65,819,800
Environmental Studies and Research	3,988,16(	14,569,834	18,558,000
Sociological	763,138	3,554,362	4,317,500
Public Affairs	-	3,202,200	3,202,200
Gas Reserves and Market Studies	446,964	1,547,436	1,994,400
Reproduction of Hearing Material and Application	-	2,134,800	2,134,800
Environmental Impact Study	-	2,335,600	2,335,600
Termination Costs	-	1,267,100	1,267,100
Working Capital Included in Equalization at Merger 6/	-	243,600	243,600
Subtotal	13,960,973	85,912,027	99,873,000
Direct Cost Ratios	13.98%	86.02%	100%
Cost Categories-General (Allocated Using Direct Cost Ratios Shown Above)			
Finance, Accounting, Legal and Other Advisors	2,329,250	14,332,050	16,661,300
General and Administrative	4,361,187	26,834,713	31,195,900
Depreciation and Amortization	108,247	666,053	774,300
Costs through Aug. 31, 1977	20,759,657	127,744,843	148,504,500
Cash Calls Required from Sept. 1, 1977 through Jan. 31, 1978 7/	-	6,345,000	6,345,000
Totals at Jan. 31, 1978	$20,759,657	$134,089,843	$154,849,500
Total Allocation	13.41%	86.59%	100%

6/ The Working Capital Included in the Equalization at Merger was payable to the CAGSL participants.

7/ The expenditures incurred by CAGSL after August 31, 1977 and through January 31, 1978 were for termination payments related to activities after CAGSL's dissolution.

The $134,089,843 (Canadian) of CAGSL expenditures which are listed above as having no future value are not considered to be properly assignable to the Alaskan section of the ANGTS or of a nature that would qualify for inclusion in rate base because they have one or more of the following disqualifying features:

a. They have no specific direct provable relationship or future benefit to the approved Alaskan section of ANGTS. The type expenditures included in this category relate to specific design, location, siting, and other items unique to the unsuccessful route;

b. They are duplicative to other expenditures specifically related to the approved Alaskan section of the ANGTS. This classification includes all types of duplicative filing fees and related payments to the various U. S. and Alaskan governmental bodies;

c. Similar activities or task related expenditures have never been considered capitalizable items by the Commission in the past. Costs of this classification are related to political lobbying and public relations type of activities;

d. They specifically relate to Canadian:

(1) line design or layout,

(2) land or rights-of-way,

(3) gas supply,

(4) regulatory filings.

Application of the findings of our audit of CAGSL expenditures to the related American dollar amounts recorded in ANNGTC's books, exclusive of AFUDC amounts, gives the following results.

	CAGSL Costs Recorded on ANNGTC Books	No Future Value 8/	Possible Future Value 9/
Pre-partnership Expenditures	$31,778,967	$27,517,407	$4,261,560
Pan Alaskan Gas Company	$ 8,011,392	$ 6,937,064	1,074,328
Calaska Energy Company	7,783,286	6,739,547	1,043,739
Pacific Interstate Transmission Company (Arctic)	8,020,863	6,945,265	1,075,598
Northern Arctic Gas Company	7,963,426	6,895,531	1,067,895
	$31,778,967	$27,517,407	$4,261,560

8/ Based upon allocation of 86.59% developed above.
9/ Based upon allocation of 13.41% developed above.

While the audit indicated that $4,261,560 of pre-partnership expenditures may have possible future value to the approved Alaskan section of the ANGTS, no value at all has yet been demonstrated. Therefore, staff concludes that none of the $38,366,883 of pre-partnership expenditures associated with CAGSL activities ($31,778,967 of CAGSL costs plus $6,587,916 of AFUDC related thereto) and properly assignable to the Alaskan section of the ANGTS.10/

10/ ANNGTC's justifications for assigning CAGSL expenditures to the Alaskan section of the ANGTS are included in an application to FERC dated February 2, 1979. See Exhibit No. 4, page 5 to end.

2. Calaska Energy Company - Improper Method of Accounting for Canadian/United States Dollar Exchange Differences

Calaska was established in December 1978 as a wholly-owned subsidiary of Pacific Gas & Electric Company to participate in the ANNGTC partnership as of February 1, 1978.

In July of 1972, Pacific Gas & Electric Company (PG&E), Pacific Gas Transmission Company (PGT)(53% owned by PG&E), Montana Power Company and Alberta Natural Gas Company (a Canadian company 45% owned by PGT) joined the CAGSL as a group liable for one participant's share of CAGSL's expenditures.

Under the terms of the group's agreement, all payments to CAGSL were made in Canadian dollars by Alberta Natural Gas Company, without reimbursement by the other members of the group. The expectation was that CAGSL's proposal(s) would be successful and that Alberta Natural Gas Company would recover its net CAGSL expenditures by claiming them as part of the cost of the project(s) The agreement also provided that, in the event Alberta Natural Gas Company was unable to recover, it could require the other members of the group to reimburse it for its net CAGSL expenditures as follows:

Pacific Gas & Electric Company	55.65%
Pacific Gas Transmission Company	18.55%
Montana Power Company	7.25%
	81.45%

To the extent that the net CAGSL expenditures were irrecoverable by any members of the group, the ultimate loss would be borne in the same percentages shown above, with Alberta Natural Gas Company bearing the balance, 18.55%, of such loss.

In December 1978, Alberta Natural Gas Company determined that it could not recover any of its net CAGSL expenditures and called upon the other three members of the group to reimburse it for their agreed upon shares of such expenditures.

On December 31, 1978, but as of February 1, 1978, Calaska claimed, as pre-partnership expenditures on behalf of the group, all of Alberta Natural Gas Company's net CAGSL expenditures, including AFUDC through January 31, 1978[11/]. These expenditures totaled $9,689,376 (Canadian). At December 31, 1978 conversion rates, the American dollar equivalent was $8,156,517. However, instead of claiming that amount as pre-partnership expenditures, Calaska computed their claim on a hypothetical basis, using conversion rates that were in effect at the time each Canadian dollar payment was made by Alberta Natural Gas Company to CAGSL.

11/ Cash reimbursements by the group to Alberta Natural Gas Company also included AFUDC from February 1, 1978 to December 31, 1978, but these amounts were not claimed because Calaska will accrue AFUDC on the claimed expenditures commencing February 1, 1978.

As a result, Calaska claimed pre-partnership expenditures of $9,456,744, whereas the actual American dollar amount which would have been required at December 31, 1978 to repay Alberta Natural Gas Company for all of its net expenditures to CAGSL through January 31, 1978 was only $8,156,517, or $1,300,227 less.

While Calaska's pre-partnership expenditures are overstated by $1,300,227 because of the improper method used to account for Canadian/American dollar exchange differences, no separate adjustment for this item will be necessary if staff's position with respect to disallowance of all claimed CAGSL expenditures is sustained (see item 1 above).

3. <u>Pacific Interstate Transmission Company (Arctic) - Interest Reimbursements</u>

Pacific's claimed pre-partnership expenditures include AFUDC on payments made to CAGSL by an affiliated company. However, such expenditures were not reduced by $23,375 of interest reimbursements received by the affiliated company when various equalization payments were received as new companies joined the CAGSL group. Accordingly, Pacific's claimed pre-partnership expenditures are overstated by $23,375 and staff proposes that such amount be disallowed. No separate adjustment for this item will be necessary if staff's position with respect to disallowance of all claimed CAGSL expenditures is sustained (see item 1 above).

4. <u>Recovery of CASGL Expenditures Via Tariff Charges</u>

The parent companies of three of the partners have already recovered significant portions of the claimed CAGSL pre-partnership expenditures through tariff billings to existing customers. Additionally, two of the partners' parent companies have recovered the carrying costs associated with some of the CAGSL pre-partnership expenditures.

a. Northern Arctic Gas Company

As of June 30, 1979, Northern, through the rates charged by its parent, Northern Natural Gas Company, had recovered at least $2,333,261 of its pre-partnership CAGSL expenditures. These expenditures were allowed in determining Northern Natural Gas Company's cost of service as follows:

Docket No.	Amount
RP74-80	$ 243,840
RP75-89	243,840
RP77-56	577
R&D Tracker	1,845,004
	$2,333,261

In addition to the amounts shown above, $353,289 of expenditures relating to CAGSL regulatory costs, along with other regulatory costs, have been and are being amortized as charges to gas operating expenses. Therefore, there is a presumption that the $353,289 has been or will be recovered by Northern Natural Gas Company's tariff rates.

Northern's claimed pre-partnership CAGSL expenditures do not give recognition to the recoveries that have been made by its parent company.

Prior to October 31, 1976, all payments to CAGSL, less related accumulated deferred income taxes, were recognized in Northern Natural Gas Company's rate base and rates. Beginning November 1, 1976, only the amounts listed below were allowed in rate base:

Month	Net Amount Reflected in Rate Base
1976 - November	$1,772,277
December	898,562
1977 - January	1,037,081
February	1,151,974
March	1,261,157
April	1,321,863
May	1,429,392
June	1,515,412
July	1,623,665
August	1,798,420
September	1,835,996

While various portions of the CAGSL expenditures were included in rate base, and at least $2,333,261 has been recovered in cost of services through June 30, 1979, AFUDC was accrued and capitalized by Northern based on the total CAGSL expenditures without giving recognition to the rate treatment afforded part of these same expenditures. As a result, AFUDC related to the CAGSL pre-partnership expenditures is also overstated.

b. Pan Alaska Gas Company

As of June 30, 1979, Pan Alaska, through its parent, Panhandle Eastern Pipeline Company, had recovered $4,160,970 of its pre-partnership CAGSL expenditures. These expenditures were allowed in determining Panhandle Eastern Pipeline Company's cost of service as follows:

Year	Amount
1973	$ 685,727
1974	1,095,763
1975	1,778,005
1976	206,220
1977	206,220
1978	189,035
	$4,160,970

Pan Alaska's claimed pre-partnership CAGSL expenditures do not give recognition to the recoveries that have been made by its parent company.

In addition, Pan Alaska has computed AFUDC on the total CAGSL expenditures without giving recognition to the cost of service rate recoveries made by its parent company. As a result, AFUDC related to CAGSL pre-partnership expenditures is overstated.

c. Pacific Interstate Transmission Company (Arctic)

As of June 30, 1979, Pacific, through its affiliate, Pacific Lighting Service Company, had recovered $1,148,044 of its pre-partnership CAGSL expenditures. These amounts have been recovered since January 1, 1978 through rates established by the California Public Utilities Commission.

Pacific's claimed pre-partnership expenditures do not give recognition to recoveries that have been made by its affiliated company.

In addition, all of Pacific's claimed CAGSL expenditures have been allowed in rate base, on a net-of-tax basis, by the California Public Utilities Commission. However, Pacific has computed AFUDC on total CAGSL expenditures without giving recognition to the rate base treatment allowed its affiliated company for such expenditures. As a result, AFUDC related to CAGSL prepartnership expenditures is overstated.

The staff proposes that the claimed pre-partnership expenditures of Northern, Pan Alaska and Pacific be disallowed to the extent that their parent companies had recovered such expenditures through January 31, 1978, and that any recoveries made after that date be credited against any remaining pre-partnership expenditures.[12/] However, no separate adjustments for this item will be necessary if staff's position with respect to disallowance of all claimed CAGSL expenditures is sustained (see Item 1 above).

12/ By letter dated April 19, 1979, to the Secretary, FERC, the attorney for ANNGTC stated that a portion of the pre-partnership expenditures claimed by Northern and Pan Alaska had been recouped. The letter states that the then outstanding balance for Northern was $6,427,926 (a reduction of $3,159,864) and for Pan Alaska was $4,227,681 (a reduction of $5,427,447). The reduced claimed outstanding balances reflect the recoveries through tariff billing by the parent companies discussed on pages 21-23 and lower AFUDC claims resulting from the lower outstanding balances. The attorney for ANNGTC proposed that appropriate adjustments, to avoid over-recovery by Pan Alaska and its affiliates and by Northern and its affiliates, be made at such time as the ANNGTC tariff becomes effective, and revenues are generated thereby.

5. **Federal Income Tax Benefits Derived from CAGSL Expenditures Need to be Associated with Claimed CAGSL Pre-Partnership Expenditures**

The parent companies of Pan Alaska, Northern, and Pacific have already claimed the pre-partnership CAGSL expenditures as tax deductions for Federal income tax purposes, thereby reducing their tax liabilities for prior years.13/ This procedure will result in higher tax liabilities in future years (deferred taxes).

ANNGTC is a partnership and, as such, will not pay Federal income taxes. However, ANNGTC tariff rates will include allowances for Federal income taxes which will be paid by the individual companies or their parent companies. Such tax allowances should not include any amounts for the higher tax liabilities resulting from the parent companies' use of the tax benefits associated with costs capitalized as part of the ANNGTC project. Accordingly, to assure this result, staff believes that the tax benefits already realized by the parent companies (represented by deferred taxes) should be recorded on the books of ANNGTC.

In addition, the deferred taxes balances represent a reduction in the net cost of CAGSL expenditures. Staff believes that this reduction in cost should be reflected in ANNGTC's AFUDC computations during the construction period and in ANNGTC's rate base during the period of operations by reducing the base for such computations by the deferred tax balances relating to the CAGSL expenditures.

13/ IRS has consistently challenged these claimed tax deductions but the dispute has not yet been resolved.

Recommendations

The staff recommends that:

1. $15,190,609, including AFUDC of $965,272, of Northwest's pre-partnership expenditures be allowed as charges properly assignable to the ANNGTC project and be determined as qualified for eventual inclusion in the rate base of ANNGTC.

2. $193,236, including AFUDC of $12,278, of Northwest's pre-partnership expenditures be disallowed as costs qualified for eventual inclusion in the rate base of the ANNGTC.

3. $3,664,342, including AFUDC of $232,847, of Northwest's pre-partnership expenditures be disallowed as costs properly assignable to the ANNGTC project for eventual inclusion in rate base, without prejudice to Northwest's reclaiming them upon submission of appropriate supporting information.

4. All of the $38,366,833, including AFUDC of $6,587,916 relating to the CAGSL pre-partnership expenditures of Calaska, Northern, Pan Alaska and Pacific be disallowed as costs properly assignable to the ANNGTC project.

5. $1,300,227 of Calaska's claimed pre-partnership expenditures, relating to Canadian/United States dollar exchange differences, be disallowed. No separate adjustment for this item will be necessary if recommendation number 4 is adopted, since all claimed CAGSL expenditures would be disallowed.

6. $23,375 of Pacific's claimed pre-partnership expenditures, recovered by interest reimbursements received, be disallowed. No separate adjustment for this item will be necessary if recommendation number 4 is adopted, since all claimed CAGSL expenditures would be disallowed.

7. The claimed pre-partnership expenditures of Pacific, Pan Alaska and Northern be disallowed to the extent that their parent companies had recovered such expenditures through tariff charges to their customers through January 31, 1978. Any such recoveries by the parent companies after January 31, 1978, should be credited against any remaining pre-partnership expenditures. No separate adjustments for this item will be necessary if recommendation number 4 is adopted, since all claimed CAGSL expenditures would be disallowed.

8. The deferred taxes arising from Pan Alaska, Northern and Pacific's parent companies' use of CAGSL expenditures as deductions for Federal income tax purposes be recorded on ANNGTC's books.
This recommendation becomes moot if recommendation number 4 is adopted, since all claimed CAGSL expenditures would be disallowed.

9. All AFUDC amounts included as pre-partnership expenditures by Pacific, Pan Alaska, Northern and Calaska be recomputed and reduced to reflect the recommendations in this report.

This recommendation becomes moot if recommendation number 4 is adopted, since all claimed CAGSL expenditures would be disallowed.

Exhibit No. 1

Alaska Northwest Natural Gas Transportation Company
Pro Forma Balance Sheet
As of February 1, 1978
With Staff Adjustments Thereto

	Pro Forma Balance 2-1-78	Staff Adjustments	Adjusted Balance 2-1-78
Assets			
Plant in Service	$ 175,617	$ -	$ 175,617
Less: Accrued Depreciation	(1,671)	-	(1,671)
Net Plant in Service	173,946		173,946
Construction Work in Progress:			
Northwest Alaskan Pipeline Co. Expenditures	18,874,241	(3,857,578)A/	15,016,663B/
CAGSL Expenditures	38,366,883C/	(38,366,883)	-
Total CWIP	57,241,124	(42,224,461)	15,016,663
Total Assets	$57,415,070	$(42,224,461)	15,190,609
Partners' Equity			
Calaska Energy Company	$ 9,456,744	$(9,456,744)	$ -
Pacific Interstate Transmission Co. (Arctic)	9,667,221	(9,667,221)	-
Pan Alaska Gas Company	9,655,128	(9,655,128)	-
Northern Arctic Gas Co.	9,587,790	(9,587,790)	-
United Alaska Fuels Corp.	-	-	-
Subtotal	38,366,883C/	(38,366,883)	-
Northwest Alaskan Pipeline Co.	19,048,187	(3,857,578)A/	15,190,609B/
Total Partners' Equity	$57,415,070	$(42,224,461)	$15,190,609

A/ Includes $245,125 of AFUDC
B/ Includes $965,272 of AFUDC
C/ Includes $6,587,916 of AFUDC

BACKGROUND DATA

CANADIAN ARCTIC GAS STUDY GROUP LIMITED (CAGSL)

CAGSL, also known as the Gas Arctic/Northwest Project Study Group, was a consortium of United States and Canadian energy companies (see Exhibit 3 for a list of the members and their contributions) which attempted to obtain the necessary certificates and permits required of the Canadian and U. S. Governments to build a pipeline transversing Alaska and Canada.

The project had its beginning in 1967 when Trans Canada Pipelines Limited, Michigan Wisconsin Pipeline Company and Natural Gas Pipeline Company of America organized the Northwest Project Study Group (NPSG) to conduct engineering and feasibility studies for a natural gas pipeline system to transport natural gas from the Canadian Northwest Territories to gas markets in the United States. In June of 1969, the NPSG was expanded to include studies for a pipeline from Alaska and the Mackenzie Delta. The consortium membership was expanded to include Standard Oil Company of Ohio, Atlantic Richfield Company and Humble Oil & Refining Company (Exxon).

In 1969, Alberta Gas Trunk Line Company Limited, undertook studies which resulted in its sponsorship of the Gas Arctic Project (GAP). The initial proposal considered was the construction of a 1,550 mile pipeline from Prudhoe Bay, Alaska, to connect with Alberta Gas Trunk Line's facilities near Grande Prairie, Alberta. The other initial members of this group were Canadian National Railways, Columbia Gas Systems, Inc., Northern Natural Gas Company and Texas Eastern Transmission Corporation. Pacific Lighting Gas Development Company joined the group in 1971.

Studies for both projects were conducted independently until July of 1972. At that time, the GAP (with its six members) and the NPSG (with its six members) merged and became the Gas Arctic - Northwest Project Study Group, better known by its service corporation name of Canadian Arctic Gas Study Limited (CAGSL). At the time of the merger, four additional companies joined CAGSL; Canadian Pacific Investments, Gulf Oil Canada Limited, Imperial Oil Limited, and Shell Canada Limited. When this consolidation took place, NPSG had spent $11,481,944 (Canadian) while the GAP Group had spent $7,483,980 (Canadian). The combined expenditures of $18,965,924 (Canadian) became known as CAGSL pre-inception costs. Under the Joint Research and Feasibility Study Agreement of 1972, $1,185,370.25 (Canadian) of pre-inception costs were allocated to each of the sixteen members of the Group.

Additional members continued to join, each time causing a reallocation of the total contributions through the respective entry dates. The following companies joined CAGSL in late 1972 and early 1973 bringing the total participants to twenty-eight: Canada Development Corporation, Canadian Superior Oil Limited, Canadian Utilities Limited, Colorado Interstate Gas Company, Pampine Pipelines Limited, Sunoco Exploration and

Production Limited, Transcontinental Gas Pipe Line Corporation, Alberta Natural Gas Company, Consumers Gas Company, Panhandle Eastern Pipeline Company, Polaris Pipelines and Union Gas Limited.

CAGSL divided its corporate organization into four units: CAGSL, Alaskan Arctic Gas Study Company (AAGSC), Canadian Arctic Gas Pipeline Limited (CAGPL) and Alaskan Arctic Gas Pipeline Company (AAGPC).

CAGSL was responsible for completing the necessary research and general studies required to indicate project feasiblity and to cause to be prepared an application to the NEB and other Canadian government departments for a permit to construct and operate a pipeline in Canada. It managed the day-to-day activities of the total project and assured coordination between themselves and AAGSC. It provided service to AAGSC on an "as needed" basis.

AAGSC was responsible for carrying out the development activities of the project in Alaska. AAGSC prepared the required application for filing with state and federal authorities for authorization to build a pipeline in Alaska.

CAGPL was responsible for making application for Canadian governmental authorizations necessary for construction and operation of the pipeline in Canada. If the project had been successful, it would have constructed and operated the pipeline as a Canadian Inter-Provincial Pipeline Company.

AAGPC was responsible for making application to the U. S. and Alaskan Governments for authorizations necessary to construct and operate the pipeline in Alaska. If the project had been successful, it would have constructed and operated the pipeline section in Alaska.

On March 24, 1974, when the applications were filed with the Federal Power Commission and the Canadian National Energy Board (CNEB) for certificates and permits to build a pipeline through Alaska and Canada known as the Arctic Project, 27 participants remained in the Arctic project. Only Transcontinental Gas Pipe Line had withdrawn. Shortly thereafter, however, other members began to withdraw. The most significant was the withdrawal on September 16, 1974 of Alberta Gas Trunk Line Company Limited, the original sponsor of the Gas Arctic Project. By November 1975, when Atlantic Richfield withdrew, the CAGSL Group was down to fifteen participants, the number that remained for the duration of the project.

In the Spring of 1975, Alberta Gas Trunk Line joined with Westcoast Transmission Company Limited to prepare the Foothills Project. They developed the Foothills (Yukon) Project (sometimes called the "Alaska Highway Project") to move Alaskan gas reserves to the United States. This project was the successful applicant before the CNEB in July 1977 and now is an integral part of the Alaska Natural Gas Transportation System.

After the CNEB decision in July 1977, the CAGSL Group terminated active operation. By that time, $148,504,479 had been expended. Subsequent cash calls to cover the finalization payments of the group were $6,345,000 which brought CAGSL expenditures to $154,849,479 Canadian, the amount covered by this audit.

Exhibit No. 3

CAGSL PARTICIPANTS AND PAYMENTS (CANADIAN DOLLARS)

Participating Companies	Date Withdrawn	Contributions and Fees Through Jan. 31, 1978
Alberta Gas Trunk Line	09/16/74	$ 2,249,285
Atlanta Richfield Company	11/30/75	4,183,524
Canada Development Corporation	10/31/75	4,000,383
Canadian National Realties	05/31/74	2,004,713
Canadian Pacific Investments	02/28/75	2,657,282
Canadian Superior Oil Limited	07/31/75	3,448,043
Canadian Utilities Limited	05/31/75	3,100,655
Colorado Interstate Gas Company	10/15/74	2,317,357
Exxon Company, U.S.A.	02/28/75	2,657,282
Pembine Pipelines Ltd.	10/21/74	2,332,100
Standard Oil (Ohio)	09/30/74	2,282,035
Sunoco E & P Limited (Numac Oil & Gas)	04/30/75	2,908,625
Transcontinental Gas Pipe Line	12/07/73	1,613,072
Alberta Natural Gas Company	N/A	8,020,533
Columbia Gas Transmission Corporation	N/A	8,020,533
Consumers Gas Company	N/A	8,020,533
Gulf Oil Canada Limited	N/A	8,020,533
Imperial Oil Limited	N/A	8,020,533
Michigan Wisconsin Pipe Line	N/A	8,020,533
Natural Gas Pipeline Company	N/A	8,020,533
Northern Natural Gas Company	N/A	8,020,533
Pacific Lighting Gas Development Co.	N/A	8,020,533
Panhandle Eastern Pipeline Company	N/A	8,020,533
Polaris Pipelines (Northern & Central)	N/A	8,020,533
Shell Canada Limited	N/A	8,020,533
Texas Eastern Transmission Corporation	N/A	8,020,533
Trans Canada Pipelines Limited	N/A	8,020,533
Union Gas Limited	N/A	8,020,533
Gross Contributions and Fees		156,062,351
August 1977 Cash Call Overpayment		(1,212,872)
Net Contributions and Fees through January 31, 1978		$154,849,479

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Alaskan Northwest Natural Gas Transportation Company	)	Docket No. CP78-123, et al.

APPLICATION OF
ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY
FOR AN ORDER APPROVING PAST EXPENDITURES AND
TO ESTABLISH PROCEDURES FOR CONTINUING AUDIT AND
APPROVAL OF FUTURE EXPENDITURES AND
MAJOR COMMITMENTS

Alaskan Northwest Natural Gas Transportation Company (the Partnership), pursuant to the Alaska Natural Gas Transportation Act of 1976 (ANGTA), the Natural Gas Act, and the Commission's Order Vacating Prior Proceedings and Issuing Conditional Certificate of Public Convenience and Necessity issued December 16, 1977, hereby applies for an order approving, for inclusion in rate base, expenditures made prior to August 1, 1978 1/ for pre-construction activities necessary to place the Alaskan section of the Alaska Natural Gas Transportation System in service. These expenditures are reflected in the capital accounts of each Partner, Northwest Alaskan Pipeline Company (Northwest), Northern Arctic Gas Co. (Northern), Pan Alaskan Gas Company (Pan Alaskan), Calaska Energy Company (Calaska), 2/ Pacific Interstate Transmission Company (Arctic) [Pacific] and United Alaska Fuels Corporation (United). The Partnership also requests that the Commission establish procedures to review and approve, on a continuing basis at regular quarterly intervals, completed activities and both actual and conditionally committed expenditures necessary to place the Alaskan section of the Alaska Natural Gas Transportation System in service.

1/ Partnership expenditures from August 1, 1978 through December 31, 1978 will be submitted to the Commission for review and approval as soon as practicable.

2/ Calaska is successor to the interests of Natural Gas Corporation of California and the interests of Natural Gas Corporation of California were transferred to Calaska as of November 28, 1978.

In support thereof, the Partnership would show as follows:

I.

Background

The Commission initiated a new phase of the proceedings contemplated in ANGTA by its order dated December 16, 1977, issuing a Conditional Certificate of Public Convenience and Necessity as mandated by the Decision and Report to Congress on the Alaska Natural Gas Transportation System issued by the President of the United States on September 22, 1977, and approved by the Congress on November 22, 1977. 3/

Subsequently, on June 30, 1978, the Commission transferred the Conditional Certificate of Public Convenience and Necessity from Alcan Pipeline Company to the Partnership.

II.

Basis for Authorization Requested Herein

A. In the Decision and Report, the President provided that certain "general terms and conditions shall be appropriately incorporated into any certificate, right-of-way, lease, permit or authorization directed to be made by any Federal Officer or agency" (Section 5, page 26). Among such general terms and conditions is the requirement that the Partnership must "submit to the FPC (FERC) for approval on a timely basis all components of construction work in progress." (Finance Condition, page 37; emphasis added.) The order requested herein is necessary to implement this mandate.

B. In the Commission's order issued December 16, 1977, the Commission recognized that it would have either exclusive or coextensive jurisdiction over the President's terms and conditions concerning finance matters, which included the condition described above. Further, the Commission adopted the Partnership's suggestion that quarterly progress reports are appropriate. Thus, the Commission has already moved toward implementation of the above-cited requirement of the Decision and Report and has recognized that authorization of the type requested herein is appropriate.

3/ Pub. L. 95-158, 91 Stat. 1268.

C. In its Notice of Succession in Interest and Application for Transfer of Certificate of Public Convenience and Necessity filed April 19, 1978, the Partnership indicated that it "...stands ready to report to the Commission, or its Delegate, on all matters relating to the Alaskan Natural Gas Transportation System, and particularly the status of pre-construction planning, funds expended to date, budgeted and anticipated costs for the balance of 1978, financial planning, and system engineering and design. Such other information and reports as the Commission, or its Delegate, may desire will, to the extent of the Partnership's abilities, be furnished in such form and manner as the Commission, or its Delegate may direct. The Partnership requests the institution of a mechanism for review and approval of cost expenditures and budgets for the Project on a regular and recurring basis."

D. The General Partnership Agreement 4/ (the Agreement) envisions Commission review and approval of actual expenditures. The relevant provisions are found in Sections 4.1.1, 4.1.2, 4.1.3 and 4.1.4, which provide a procedure for determining the Qualified Expenditures 5/ of each Partner. Northwest's Qualified Expenditures are $19,163,000; those of Northern are $9,587,790; those of Pan Alaskan are $9,655,128; those of Calaska are $9,456,744; and those of Pacific are $9,667,221. 6/ All of these are expressly subject to review and approval by FERC.

In summary, there is ample basis in the Decision and Report and in prior Commission orders, as well as the Partnership Agreement, for the Commission to consider and grant this application.

4/ Reviewed by the Commission and approved in its Order issued June 30, 1978 (Docket No. CP78-123).

5/ Expenditures to acquire information, knowledge, studies, tests, computer programs or governmental authorizations by any Partner or corporate affiliate of a Partner, in the course of activities reasonably related to the selection of a transportation system for the delivery of Alaskan natural gas, if such expenditures were made by such Partner or corporate affiliate prior to January 31, 1978.

6/ The totals shown include an interest component on funds spent.

III.

Authorization Requested

A. The Partnership requests that the Commission review and verify (1) the expenditures made by each Partner incurred prior to the formation date of the Partnership which have been determined to be "Qualified Expenditures" and therefore appropriately included in the Partners' capital accounts; and (2) $15,174,000 in expenditures of the Partnership for the period of February 1, 1978, through July 31, 1978. The Partnership further requests that the Commission, by order, approve acceptance of all such expenditures for inclusion in rate base, subject only to "completion and commissioning of operation of the system," a necessary precondition specified on page 38 of the Decision. Exhibit Z-1 attached hereto shows in detail the amounts and purposes for which "Qualified Expenditures" were made by Northwest. Exhibit Z-2 attached hereto shows in detail the amounts and purposes for which "Qualified Expenditures" were made by Northern, Pan Alaskan, Calaska and Pacific. Exhibit Z-3 attached hereto shows in detail the amounts and purposes for which Partnership funds were expended from February 1, 1978 through July 31, 1978.

B. The Partnership also requests that the Commission institute procedures to audit and approve actual expenditures on a continuing quarterly basis throughout the pre-construction and construction periods of the project.

C. In addition to the audits and approvals of actual expenditures made, the Partnership also requests the Commission to include within the scope of its reviews, upon specific request of the Partnership, certain major financial commitments that are covered by an executed contract for which payment may be due at some future date subject to certain conditions having been met. 7/ In such cases, the Partnership requests that the Commission by order give provisional approval to the obligation or conditional expenditure, subject to later audit and approval by the Commission

7/ The project management contract, the project labor agreement, agreements for purchase or use of Alyeska camps and/or data, and the contracts for purchase of line pipe are expected to have sufficient impact on project costs to warrant advance regulatory review.

of actual expenditures made. No commitments of this nature are included in the period from February 1 through July 31, 1978.

The Partnership stands ready to make available its books and records at the convenience of the Commission to permit such reviews and field audits as may be required to issue the order requested herein.

IV.

Justification for the Authorizations Herein Requested

A. Qualified Expenditures

Prior to the formation of the Partnership, substantial funds were expended by the individual companies, or their affiliates, for reasonable and necessary expenditures related to the ultimate construction and operation of the Alaskan segment of the Alaskan Natural Gas Transportation System. Because the factual circumstances surrounding the expenditures made by Northwest differ from the factual background and circumstances relating to the expenditures by Northern, Pan Alaskan, Calaska, and Pacific; each category of pre-Partnership expenditures is treated separately:

1. Pre-Partnership Expenditures of Northwest. Northwest, through its predecessor company, Alcan Pipeline Company, was the original applicant for the route and pipeline proposal ultimately selected by the President and the Congress under the terms and conditions of the Alaska Natural Gas Transportation Act. The reasonable and necessary costs to Northwest of presenting to the Federal Power Commission, and later to the President and the Congress, the Alaska Highway Project through the date of formation of the Partnership, was $19,163,000, including interest. The details of these expenditures are set forth in Exhibit 5-1 and such expenditures were reasonably and prudently made as necessary to the preparation and presentation of Northwest's application for a certificate of public convenience and necessity, Northwest's presentation to the President and the Congress for selection of the Alaska Highway Project as the desired route, and selection of Northwest as the company to construct the Alaskan segment of the ANGTS. All of such expenditures are appropriate for inclusion in the capital account of Northwest as a Partner, and inclusion in the rate base of the Partnership pipeline project.

2. Pre-Partnership Expenditures of Others. Northern, Pan Alaskan, Calaska and Pacific made expenditures prior to the formation of the Partnership through their membership and participation in the Gas Arctic/Northwest Project Study Group (Gas Arctic). Gas Arctic was the result of a combination of two groups which had begun studies long before any other study group was formed, and before any of the subsequent applicants for a certificate of public convenience and necessity to transport Alaskan and Canadian gas to lower U.S. 48 markets made any indication that they would file an application. The total paid by participants in the Gas Arctic Study Group through January 31, 1978 was approximately $154.8 million. The costs were shared by as many as 26 participants, and after a number of participants had withdrawn, the group narrowed to 15 members. Each of these 15 members had paid in $8,020,533 (Canadian) through January 31, 1978.

Included in the expenditures of the Gas Arctic Group were the following major categories of costs:

Engineering & Construction Planning	$65.8 million
Environmental Studies and Research	18.6 million
Finance, Accounting, Legal and Other Advisors	16.7 million
General and Administrative	31.2 million
Sociological	4.3 million

The expenditures for the items listed above include basic research such as that done with respect to an Arctic ditcher, metallugical questions, cost effects, slope stability, the environmental impact on fish, mammals, birds and vegetation, and training programs which might be used in connection with the use of native labor in the project. In addition, substantial amounts were spent developing computer models to be used in engineering and financial analysis, and some of these are currently in use.

The knowledge and information developed by the Gas Arctic Study Group will be useful and of significant importance to the Alaska Highway Pipeline Project. The design and construction of the Alaska project will be materially aided by the basic research which was performed into environmental and engineering issues, and the development of computer analysis techniques which resulted from Study Group activities and expenditures. Relevant portions of the information, data, and computer programs developed will be, as a consequence of the Partnership's approval of the "Qualified Expenditures" of Northern, Pan Alaskan, Calaska and Pacific, available to the Partnership for its continuing use in development of the project.

It must be emphasized that the Arctic Gas Project and the Alaskan Highway Pipeline Project were considered as alternatives by governmental authorities at all levels of the decision-making process in both the United States and Canada prior to the time of the President's Decision and Report in September of 1977. If only a single applicant had proposed an Alaska Natural Gas Transportation System, that applicant would nonetheless have been legally compelled at substantial cost to develop and present information on alternative routes, and such costs would clearly have been includable in the rate base of the authorized project. The costs presented here by the Partners who were members of the Study Group were just as necessary to the decision-making process as the costs of the hypothetical single applicant, and should be afforded the same regulatory treatment.

In accord with the Partnership Agreement, the pre-formation expenditures of Northern, Pan Alaska, Calaska, and Pacific have been reviewed by the Board of Partners and a determination made with respect to whether such constituted "Qualified Expenditures." An extract from the Board of Partners' minutes relating to this is appended to this application as part of Exhibit Z-2.

The nation and U.S. gas consumers have benefited from the thorough analysis of transportation alternatives which the Partners' "Qualified Expenditures" made possible. The hearing process before the Federal Power Commission, and the subsequent Presidential selection of a route that is preferable from an environmental and economic standpoint, were materially advanced by the efforts of Northern, Pan Alaska, Calaska and Pacific. Therefore, it is appropriate that those companies who continue to participate in the development of this project to connect Alaskan natural gas be allowed to include those costs as part of the rate base of the Alaskan portion of the system. These costs, although significant in relation to the revenues and assets of each sponsoring company, will be less than one percent of the total investment in the Alaskan system.

The details of the pre-Partnership expenditures by Northern, Pan Alaska, Calaska, and Pacific are set forth in Exhibit S-2 appended hereto. The pre-Partnership expenditures of the four Partners named above were clearly reasonable and necessary to the Partnership pipeline project, and are properly includable in the capital accounts of each such Partner, and in the rate base of the Partnership pipeline project.

B. Partnership Expenditures

The six Partners who have funded the Partnership's pre-construction activities since the formation date of the Partnership have provided $21,769,000 in funds which were expended prior to August 1, 1978. 8/ The details concerning such Partnership expenditures are set forth in Exhibit S-3 appended hereto. All of such expenditures were reasonable and necessary to proper planning for, and design of, the Alaskan segment of the Alaska Natural Gas Transportation System, and securing all necessary governmental authorizations, permits, certificates, and rights-of-way. All of such expenditures are properly includable in the capital accounts of the respective partners, and properly includable in the rate base of the Partnership's pipeline project.

C. "Provisional Approvals"

With respect to the request for "provisional approval" of certain contractual obligations and conditional expenditures, we believe that the Commission has the authority to take such action, which would be entirely consistent with Sections 9(a) and (b) of ANGTA, and the provisions of the President's Decision calling upon the Partnership to "submit

---

8/ This total includes AFUDC but the Partnership does not seek, through this application, approval of the AFUDC rate inasmuch as the Commission has stated its intention to determine this issue in Docket No. RM78-12, Order No. 17-A, issued January 17, 1979. Expenditures, without AFUDC, through July 31, 1978, total $15,174,000.

to the FPC (FERC) for approval on a timely basis all components of construction work in progress." The spirit of the latter requirement reasonably can be construed to include certain major potential expenditures covered by an executed contract for future conditional payment. The Partnership does not in any way expect to seek provisional approval for all future expenditures. Rather, it would make such a request on a selective basis where it appears that such an approval would materially reduce uncertainty, and have a correspondingly salutatory effect on the Partnership's ability to obtain private financing. It is presently contemplated that such major cost items as the project management contract, the project labor agreement, contracts for line pipe, and contracts for the acquisition and/or use of Alyeska camps and data will be of sufficient magnitude and will have sufficient impact on project costs, to warrant advance regulatory review and approval.

V.

Argument

It is essential that the audit and approval process for determination that the expenditures of Alaska Natural Gas Transportation System reasonably and necessarily made be implemented on a current and continuing basis. The magnitude of ANGTS is such that delayed review and approval of expenditures will pose insurmountable administrative problems for the Commission and the sponsors. Periodic, and frequent, review and approval of expenditures will reduce the task to manageable proportions; uncertainty will be reduced; and potential problem areas can be promptly identified and necessary corrections made. The authorizations and procedures suggested here will materially enhance cost consciousness on the part of the government, the sponsors and all interested parties.

Further, it is important that the Commission create a positive regulatory environment in order to help assure realization of private financing of this major undertaking. Banks and other potential institutional lenders are carefully observing the regulatory climate surrounding the early stages of project implementation and a prompt, and favorable, consideration of this application will help reassure not only the sponsors themselves, but also potential lenders, that all that the government can possibly do to reduce uncertainty and support this critically important project is being done.

The sponsors of the Alaskan segment of the ANGTS have already exposed themselves to substantial risk by the advancement of pre-construction dollars in pursuit of a project still beset by major uncertainties and delays. Reassurance to the project sponsors that their faith in the regulatory process has not been misplaced is important at this juncture, particularly in view of the continuing uncertainties which surround the incentive rate of return procedures under consideration in Docket No. RM78-12.

One final reason exists for the Commission's prompt and affirmative action on this application: such action will serve as tangible evidence to those pipeline companies not presently members of the Partnership that their previous Gas Arctic expenditures may reasonably be considered as appropriate for inclusion in the Partnership's rate base if those companies, or any of them, decide on active participation in support of the project as a partner. The Partnership clearly needs a broader base of membership and equity support, and favorable early action on this application by the Commission would be a positive inducement to other prospective partners who have also expended substantial sums in the development and presentation of alternative systems for North Slope gas transportation to join the Partnership.

VI.

The names, titles and mailing addresses of the persons to whom all correspondence and communications concerning this application should be addressed are as follows:

Darrell B. MacKay
Vice President
Northwest Alaskan Pipeline Company
1801 K Street, N.W.
Suite 901
Washington, D. C. 20006

Jack D. Bachman, Esquire
General Counsel
Northwest Alaskan Pipeline Company
P. O. Box 1526
Salt Lake City, Utah 84110

Rush Moody, Jr., Esquire
Vinson & Elkins
1101 Connecticut Avenue, N.W.
Suite 900
Washington, D. C. 20036

WHEREFORE, the Partnership respectfully requests that the Commission issue an order pursuant to ANGTA, the Natural Gas Act, and the President's Decision, giving final approval to the expenditures described herein for ultimate inclusion in the rate base for the Alaskan section of the Alaska Natural Gas Transportation System. The Partnership further requests that the Commission establish procedures for continuing audit and approval of actual and conditionally committed expenditures.

Respectfully submitted,

Rush Moody, Jr.

Rush Moody, Jr.

Vinson & Elkins
1101 Connecticut Avenue, N.W.
Suite 900
Washington, D. C. 20036
(202) 862-6500

ATTORNEYS FOR
ALASKAN NORTHWEST NATURAL GAS
TRANSPORTATION COMPANY,
A PARTNERSHIP

VERIFICATION

THE DISTRICT OF COLUMBIA §

I, DARRELL B. MacKAY, being first duly sworn on his oath, deposes and says:

That he is Vice President of Northwest Alaskan Pipeline Company and is duly authorized to make this affidavit, that he has read the foregoing and is familiar with the contents thereof, and that the facts and allegations contained therein are true and correct to the best of his information, knowledge and belief.

Darrell B. MacKay
Darrell B. MacKay

Subscribed and sworn to before me this 2nd day of February, 1979.

Ann H. Pearlman
Notary Public

My Commission Expires:
MY COMMISSION EXPIRES JAN. 1, 1984

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding in accordance with the requirements of § 1.17 of the Rules of Practice and Procedure.

Dated at Washington, D.C. this 2nd day of February, 1979.

Rush Moody, Jr.

Rush Moody, Jr.

Exhibit E-1

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY
NORTHWEST ALASKAN PIPELINE COMPANY
QUALIFIED EXPENDITURES 1/

1.	FILING FEE	$1,671,000	
2.	OFFICE EQUIPMENT	144,000	
3.	TRANSPORTATION EQUIPMENT	30,000	$1 ,846,000
4.	COMPANY SERVICES		
	Salaries and Related Benefits	1,347,000	
	Employee Expenses	697,000	
	Office supplies	210,000	
	Equipment Use	1,631,000	
	Recruitment and Relocation	28,000	
	Rents	107,000	
	Other	.247,000	
			4,267,000
5.	OUTSIDE SERVICES		
	Legal	3,415,000	
	Executive	188,000	
	Finance	1,524,000	
	Regulatory, Environmental & Civic Affairs	96,000	
	Administration	99,000	
	Public Relations	89,000	
	Engineering	5,996,000	
	Other	153,000	
			11,560,000
6.	DEPARTMENT OF INTERIOR		165,000
	Sub-Total		17,838,000
7.	AFUDC 2/		1,325,000
	Total Qualified Expenditures Including AFUDC		$19,163,000

1/ Expenditures made prior to January 31, 1978.
2/ Includes only an interest component on funds spent.

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY
GAS ARCTIC/NORTHWEST PROJECT STUDY GROUP-NON ANNGTC PARTNERS
QUALIFIED EXPENDITURES 1/

		Partners			
	Total	Pan Alaska Gas Co.	Calaska Energy Co.	Pacific Interstate Trans. Co.	Northern Arctic Gas Co.
1. GENERAL & ADMINISTRATION					
Direct Operations	$ 5,275,777	$1,330,009	$1,292,140	$1,331,582	$1,322,046
Indirect Operations	1,126,398	283,962	275,877	284,297	282,262
	6,402,175	1,613,971	1,568,017	1,615,879	1,604,308
2. OUTSIDE SERVICES					
Legal	1,626,919	410,142	398,464	410,627	407,686
Executive	156,299	39,402	38,281	39,449	39,167
Finance	968,765	244,223	237,269	244,512	242,761
Regulatory, Environmental & Civic Affairs	5,711,181	1,439,774	1,398,779	1,441,475	1,431,153
Administration	501,939	126,537	122,935	126,687	125,780
Public Relations	657,171	165,671	160,954	165,867	164,679
Engineering	13,917,264	3,508,505	3,408,608	3,512,652	3,487,499
	23,539,538	5,934,254	5,765,290	5,941,269	5,898,725
3. TERMINATION AND CLOSE-OUT COST	1,562,191	393,824	382,611	394,290	391,466
4. GOVERNMENT AGENCIES	66,165	16,680	16,205	16,700	16,5[illegible]
5. OTHER COSTS	208,898	52,663	51,163	52,725	52,347
Sub-Total	31,778,967	8,011,392	7,783,286	8,020,863	7,963,426
6. AFUDC 2/	6,587,916	1,643,736	1,673,458	1,646,358	1,624,364
Total Qualified Expenditures Including AFUDC	$38,366,883	$9,655,128	$9,456,744	$9,667,221	$9,587,790

1/ Expenditures made prior to January 31, 1978.

2/ Includes only an interest component on funds spent.

Extract from the Minutes of a meeting of the Board of Partners, Alaskan Northwest Natural Gas Transportation Company, a Partnership, held November 28-29, 1978:

* * *

"(10) The Board of Partners next considered the qualified expenditures of the partners other than Northwest Alaskan. By letter dated November 15, 1978, a copy of which is appended, Calaska Energy Company requested that its capital account be credited with the total of $9,456,744 pursuant to Section 4 of the Partnership Agreement; a similar request, by letter dated November 16, 1978, a copy of which is appended to these minutes, was made on behalf of Pacific Interstate Transmission Company, with the requested capital account credit for that partner being $9,667,221. A similar request on behalf of Pan Alaskan Gas Company, by letters dated September 27 and November 27, 1978, copies of which are attached to these minutes, requested capital account credit for that partner of $9,655,128. A similar request on behalf of Northern Arctic Gas Company by letter dated November 27, 1978, a copy of which is appended to these minutes, requested capital account credit for that partner of $9,587,790.

"Prior to the meeting of November 28-29, those partners requesting capital account credit for qualified expenditures had submitted to all partners substantiation for the amounts claimed, and had further tendered in support of the request for capital accounts credit summary reports prepared by Arthur Andersen & Co. under dates of October 5, 1977 and November 10, 1978. Copies of these reports are appended to these minutes.

"The Board of Partners discussed fully and completely the nature of the expenditures made, the value to the Partnership of such expenditures, and the reasonableness and necessity of the amounts expended. It was noted that the prior expenditures by Calaska, Pan Alaskan, Pacific Interstate, and Northern Arctic encompassed basic research into environmental and engineering issues, and the development of computer analysis techniques which will be of material benefit to the Partnership's activities. It was further noted that the expenditures by Partners other than Northwest were made in conjunction with the study of an alternative route for the movement of Alaskan gas to the lower 48 states, and such expenditures, if not made by the Arctic gas participants, would have been required of the Partnership prior to final approval of the Alaskan Highway routing; the expenditures relating to an alternative route were of significant benefit to the governmental decision-making process in both the United States and Canada.

"Mr. McMillian made inquiry as to whether the materials developed as a result of the claimed qualified expenditures would be made available to the Partnership, and he was assured that Northwest and the Partnership would have the benefit of such.

"Mr. McMillian reported that Northwest had made a detailed study of the available Canadian Arctic gas design information, and had concluded that there were a number of items of information and data which would be of extreme value to the Partnership in its ongoing efforts; the results of Northwest's preliminary evaluation of the specific gas design information which should prove to be of value to the Partnership is set forth on the appended list denominated "List of Canadian Arctic Gas Design Information," and each item on this listing refers to specific data and/or information which the Partnership will review to insure that no duplication of expenditures for design and research occurs.

"On motion of Mr. McMillian, seconded by Mr. Smith, the Board of Partners unanimously approved the requests of Calaska, Pacific Interstate, Pan Alaskan and Northern Arctic for inclusion in the respective capital account of each such partner the qualified expenditures submitted on behalf of each such partner; in connection with this approval, it was the expressed determination of the Board of partners that the expenditures made by each of such partners was reasonable and necessary to the conduct of the business of the Partnership, that such expenditures were prudently incurred, and that the Partnership received full value, in an amount at least equal to the amounts credited to the capital accounts pursuant to the instant approval. The Board of Partners further determined that the expenditures claimed by each of the four partners named were expenditures to acquire information, knowledge, studies, tests, computer programs or governmental authorizations by one or more of such partners or corporate affiliates of such partners, in the course of activities reasonably related to the selection of a transportation system for the delivery of Alaskan natural gas, and that each such expenditure was made by such partner or corporate affiliate prior to the formation date of the Partnership."

Exhibit S-3

**ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY
ACTUAL EXPENDITURES FOR THE PERIOD
FEBRUARY 1, THROUGH JULY 31, 1978**

1.	OFFICE EQUIPMENT	$ 470,000	
2.	TRANSPORTATION EQUIPMENT	27,000	
			$ 497,000
3.	COMPANY SERVICES		
	Salaries and Related Benefits	2,158,000	
	Employee Expenses	345,000	
	Office Supplies	129,000	
	Equipment Use	887,000	
	Recruitment and Relocation	307,000	
	Rents	444,000	
	Other	315,000	
			4,585,000
4.	OUTSIDE SERVICES		
	Legal	1,459,000	
	Executive	253,000	
	Finance	996,000	
	Regulatory, Environmental & Civic Affairs	251,000	
	Administration	466,000	
	Public Relations	178,000	
	Engineering	5,902,000	
	Other	73,000	
			9,578,000
5.	GOVERNMENT AGENCIES		
	Federal Bureau of Land Management	471,000	
	State of Alaska:		
	Fish & Game	26,000	
	Office Pipeline Coordinator	17,000	
			514,000
	Sub-Total		15,174,000
6.	AFUDC		6,595,000
	Total Actual Expenditures Including AFUDC 1/		$21,769,000

1/ This total includes AFUDC but the Partnership does not seek, through this application, approval of the AFUDC rate inasmuch as the Commission has stated its intention to determine this issue in Docket No. RM78-12, Order No. 17-A, issued January 17, 1979.

REPORT ON

RESULTS OF AUDIT OF EXPENDITURES

BY THE

ALASKAN NORTHWEST NATURAL GAS

TRANSPORTATION COMPANY

WHICH WERE

INCURRED FROM

FEBRUARY 1, 1978 THROUGH DECEMBER 31, 1978

(DOCKET NO. CP78-123, et al.)

August 1980
Division of Audits
Office of Chief Accountant
Federal Energy Regulatory Commission

REPORT ON RESULTS OF AUDIT OF EXPENDITURES BY THE ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY WHICH WERE INCURRED FROM FEBRUARY 1, 1978 THROUGH DECEMBER 31, 1978 (DOCKET NO. CP78-123, *et al.*)

INTRODUCTION

This is the second in a series of reports on the results of audits of expenditures related to the construction of the Alaska Natural Gas Transportation System (ANGTS)[1/]. The audits and reports are being made pursuant to the directions contained in Administrative Order No. 4, issued April 18, 1979.

The first report conveyed the results of the staff's initial audit of expenditures charged to the Alaskan section of ANGTS. The initial audit covered expenditures incurred prior to the formation of the partnership (Alaskan Northwest Natural Gas Transportation Company (ANNGTC)) on February 1, 1978, for the construction and operation of the Alaskan section of ANGTS. Amounts charged to the Alaskan section for pre-partnership expenditures totaled $57,415,070, including Allowance for Funds Used During Construction (AFUDC) of $7,798,313.

1/ ANGTS was authorized by the Alaska Natural Gas Transportation Act of 1976 (ANGTA), 15 U.S.C. 719, *et seq.* and the President's *Decision and Report to Congress on the Alaska Natural Gas Transportation System*, as enacted into law, H.J. Res. 621, Pub. L. No. 95-108 (November 2, 1977).

In the first report, the staff recommended the disallowance of $42,224,461, including AFUDC of $6,833,041 of the total claimed pre-partnership expenditures of $57,415,070[2/].

This report conveys the results of the staff's audit of partnership expenditures charged to the Alaskan section of ANGTS for the period February 1, 1978 through December 31, 1978. Partnership expenditures charged to the gas plant accounts during this period totaled $44,918,798, including AFUDC of $13,988,691. The staff's findings and recommendations in this report do not cover the $13,988,691 of AFUDC claimed during the period. A large part of the AFUDC claimed is related to pre-partnership expenditures which are at issue in our first audit report. Upon disposition of the audit findings and recommendations in that report, AFUDC claimed for the period February 1, 1978 through December 31, 1978 will be recomputed and adjusted as appropriate.

SUMMARY

With respect to the partnership expenditures made during the period February 1, 1978 through December 31, 1978 ($30,930,107, exclusive of AFUDC), the staff concludes that:

1. Expenditures of $29,107,087 are properly assignable to the Alaskan section of ANGTS

2/ These proposed disallowances have been reflected in Exhibit No. 1.

and are of a nature that would qualify for eventual inclusion in rate base.

2. Expenditures of $652,294 are not of a nature that would qualify for eventual inclusion in rate base and, therefore, should be disallowed.

3. Expenditures of $1,170,726 may not be properly assignable to the project for eventual inclusion in rate base. Requests to ANNGTC for additional information on these expenditures have not been answered. Therefore, the staff proposes that these expenditures be disallowed without prejudice to ANNGTC's reclaiming them upon submission of appropriate supporting information.

4. Corrective action is needed to eliminate discrepancies between the accounting records and the financial statements.

SCOPE OF AUDIT

The audit covered claimed partnership expenditures charged to the gas plant accounts totaling $30,930,107, exclusive of AFUDC, for the period February 1, 1978 through December 31, 1978.

The audit included an examination of the accounting and other records to the extent deemed necessary to determine whether:

1. The various financial statements and reports properly reflected the underlying records and documents.

2. The expenditures were adequately documented and supported.

3. The accounting for the expenditures met the requirements of the Uniform System of Accounts and generally accepted accounting principles.

4. The expenditures were properly assignable to the Alaskan section of ANGTS and were of a nature that would qualify for eventual inclusion in rate base.

5. The other accounting and reporting regulations and requirements of the Natural Gas Act, the Decision and the Certificate of Public Convenience and Necessity were complied with.

6. The policies, procedures, and controls appear adequate to ensure the efficient and economic construction of the project.

RESULTS OF AUDIT

ANNGTC claimed partnership expenditures of $30,930,107, excluding AFUDC. With respect to these expenditures, the staff has determined that:

1. Expenditures of $29,107,087 were for engineering studies and plans, environmental studies, governmental fees, legal and consultant fees related to the preparation of an application for a Certificate of Public Convenience and Necessity to construct the Alaskan section of ANGTS. These expenditures are properly assignable to the Alaskan section of the ANGTS and are of a nature that would qualify for eventual inclusion in rate base.

2. Expenditures of $652,294 are not of a nature that would qualify for eventual inclusion in ANNGTC's rate base and should be disallowed. These expenditures fall into the following categories.

a. Lobbying Activities

Expenditures of $513,171 relate to payments made to various public relations firms, consultants and legal firms.

Three public relations firms were involved in a campaign to develop public and legislative support for a financial plan proposed by ANNGTC. This financial plan proposal provided for State of Alaska participation in the project through the issuance of $1 billion in tax-exempt revenue bonds or an equity interest in the project. Legislative action was needed for either proposal.

Three other firms lobbied on the Company's behalf regarding its proposed financial plans, the question of whether Alaskan gas should be incrementally costed, the wellhead prices of Prudhoe Bay gas, and proposed legislation affecting exploration of certain lands in Alaska.

- Another law firm performed services which involved legislative efforts to secure passage of the Natural Gas Policy Act of 1978. This emanated from President Carter's 1977 Energy Plan which proposed substantial changes to the Natural Gas Act. This firm analyzed the President's proposal and contacted members of the House and Senate and their staffs to inform them of, the impact of gas pricing legislation on the project. The firm was involved in urging the passage of the compromise bill which was ultimately signed into law in November 1978.

The Uniform System of Accounts requires that expenditures of this nature be recorded in Account 426.4, Expenditures for certain civic, political and related activities, a non-utility expense account.

b. <u>Public Relations</u>

Expenditures of $91,416 relate to payments made to three public relations firms. One firm, located in Washington, D. C., distributed information to the press, members of Congress and the public. A consultant was paid a retainer to provide technical expertise in developing and implementing film projects documenting construction activities. The third firm was an agency which monitored the media and handled liaison work in Canada.

The Commission, in various cases, has ruled that public relations-type expenditures are not properly assignable to the plant accounts, but are of a nature that should be recorded in Account 930.1, General advertising expenses.

c. Non-Project Expenditures

Expenditures of $21,208 represent payments made to a law firm which provided services to ANNGTC and Northwest Alaskan Pipeline Company (Northwest), the managing partner of ANNGTC. Charges for legal services for Northwest were erroneously recorded on the books of ANNGTC as a project construction expenditure.

The Uniform System of Accounts provides for the use of Account 143, Other accounts receivable, to correct this error.

d. Fishing Trip

Expenditures of $19,363 relate to payments for a chartered fishing trip and riverboat reception held subsequent to an ANNGTC partnership meeting in Fairbanks, Alaska.

The Uniform System of Accounts requires that expenditures of a nonoperating nature be recorded in Account 426.5, Other deductions, a non-utility expense account.

e. Country Club Dues

Expenditures of $5,221 relate to payments to various country clubs, luncheon and dinner clubs and athletic clubs for membership dues.

NARUC Interpretation No. 49 requires that club dues of this nature be recorded in Account 426.5, Other deductions, a non-utility expense account.

f. Donations

Expenditures of $1,915 relate to contributions made to the Anchorage Community YMCA, Alaska Foundation of Native Youths and the Iditarod Trail Committee, Inc.

The Uniform System of Accounts requires that expenditures of this nature be recorded in Account 426.1, Donations, a non-utility expense account.

3. Expenditures of $1,170,726 were not adequately supported; therefore, the staff was unable to determine whether they are properly assignable to the Alaskan section of the ANGTS for eventual inclusion in rate base. Requests to ANNGTC for additional information on these expenditures have not resulted in responses which clearly document the nature and character of the items. These items fall into two general categories:

   a. Amounts paid to a number of law firms for services which appear to include political lobbying efforts designed to influence public opinion concerning the project and, as such, would not be allowable in the plant accounts under the provisions of the Uniform System of Accounts.

b. Amounts paid to a number of consultants where sufficiently competent evidential material (i.e. contracts, written agreements, vendor memoranda, etc.) did not exist or were not made available. Therefore, there was no adequate basis upon which to evaluate the propriety of the assignment of the costs to the project or their qualification for eventual inclusion in rate base.

Therefore, the staff proposes that these expenditures be disallowed, without prejudice to ANNGTC's reclaiming them upon submission of appropriate supporting information.

4. Monthly financial statements prepared by ANNGTC reported and compared actual project expenditures with budgeted project expenditures. The accounting records supporting

these financial statements did not agree with the reported actual project expenditures in many instances and adequate reconciliations were not available. The scope of the staff's audit was expanded due to the differences noted and the staff was able to satisfy itself as to the validity of the expenditures by additional testing of transactions. However, the staff was not able to attest to the reasonableness of the recorded or reported classification of expenditures by work orders or cost elements. Some improvements were made by ANNGTC the spring of 1979. However, some control deficiencies remain which must be eliminated from the accounting system prior to active construction.

The Uniform System of Accounts requires that the accounting records be maintained in a manner that permits ready analysis by the prescribed accounts and preparation of financial statements directly from the accounting records. Further, since this project will be subject to the incentive rate of return (IROR) mechanism[3/], it is imperative that the actual construction costs be readily identifiable and verifiable.

3/ Pursuant to Order No. 31, Docket No. RM78-12, issued June 8, 1979.

Otherwise it will be difficult, if not impossible, to audit costs for compliance with the IROR mechanism and to issue timely audit reports.

RECOMMENDATIONS

The staff recommends that:

1. $29,107,087 of partnership expenditures be allowed as charges properly assignable to the ANNGTC project and be determined as qualified for eventual inclusion in the rate base of ANNGTC.

2. $652,294 of partnership expenditures be disallowed as costs qualified for eventual inclusion in the rate base of the ANNGTC.

3. $1,170,726 of partnership expenditures be disallowed as costs properly assignable to the ANNGTC project for eventual inclusion in rate base, without prejudice to ANNGTC's reclaiming them upon submission of appropriate supporting information.

4. Corrective action be taken to permit the preparation of financial statements directly from the accounting records. Until such corrective action is implemented, ANNGTC should prepare reconciliations of differences

between the recorded and reported actual expenditures. These reconciliations should list each reconciling amount, the source of original entry, and explain the reason for the reconciling item.

EXHIBIT

Alaskan Northwest Natural Gas Transportation Company
Adjusted Balance Sheet
As of February 1 and December 31, 1978
With Staff Adjustments Thereto

	Adjusted Balance 2-1-78 1/	Activity 2-1-78 Through 12-31-78	Staff Adjustments 3/	Adjusted Balance 12-31-78
Assets				
Plant in Service	$ 175,617	$ 411,530	$ -	$ 507,147
Less: Accrued Depreciation	(1,671)	(52,840) 2/	-	(54,519)
Construction Work in Progress	15,016,663	44,560,116	(1,023,020)	57,753,759
Total Gas Plant	15,190,609	44,918,798	(1,023,020)	58,286,387
Cash and Other Assets	-	10,607,476	-	10,607,476
Total Assets	$15,190,609	$55,526,274	$(1,023,020)	$68,893,863
Partners' Equity and Liabilities				
Partners' Contributions Paid In:				
Calaska Energy Co.	$ -	$ 5,675,000	-	$ 5,675,000
Pacific Interstate Trans. Co. (Arctic)	-	5,675,000	-	5,675,000
Pan Alaska Gas Company	-	5,675,000	-	5,675,000
Northern Arctic Gas Co.	-	5,675,000	-	5,675,000
United Alaska Fuels Corp.	-	5,675,000	-	5,675,000
Northwest Alaskan Pipeline Co.	15,190,609	5,675,000	-	20,865,609
Total Partners' Contributions	15,190,609	34,050,000	-	49,240,609
Partners' Equity:				
Retained Earnings	-	14,317,272	(1,023,020)	12,494,252
Total Partners' Equity	15,190,609	48,367,272	(1,023,020)	61,734,861
Accounts Payable and Other Liabilities	-	7,159,002	-	7,159,002
Total Partners' Equity and Liabilities	$15,190,609	$55,526,274	$(1,023,020)	$68,893,863

1/ This is the adjusted balance, as shown in the initial staff audit report on ANNGTC, after the proposed disallowance of $42,324,461 pre-partnership expenditures.

2/ Includes AFUDC of $13,988,691.

3/ Staff adjustments do not cover AFUDC for reasons explained in the introduction of this report.

REPORT ON

RESULTS OF AUDIT OF EXPENDITURES

BY THE

ALASKAN NORTHWEST NATURAL GAS

TRANSPORTATION COMPANY

WHICH WERE

INCURRED FROM

JANUARY 1, 1979 THROUGH DECEMBER 31, 1979

(DOCKET NO. CP78-123, et al.)

October 1980
Division of Audits
Office of Chief Accountant
Federal Energy Regulatory Commission

REPORT ON RESULTS OF AUDIT OF EXPENDITURES
BY THE ALASKAN NORTHWEST
NATURAL GAS TRANSPORTATION COMPANY WHICH
WERE INCURRED FROM JANUARY 1, 1979
THROUGH DECEMBER 31, 1979
(DOCKET NO. CP78-123, et al.)

INTRODUCTION

This is the third in a series of reports on the results of audits of expenditures related to the construction of the Alaska Natural Gas Transportation System (ANGTS).[1/] The audits and reports are being made pursuant to the directions contained in Administrative Order No. 4, issued April 18, 1979.

The first report conveyed the results of the staff's initial audit of expenditures charged to the Alaskan section of ANGTS. The initial audit covered expenditures incurred prior to the formation of the partnership (Alaskan Northwest Natural Gas Transportation Company (ANNGTC)) on February 1, 1978, for the construction and operation of the Alaskan section of ANGTS. Amounts charged to the Alaskan section for pre-partnership expenditures totaled $57,415,070 including Allowance for Funds Used During Construction (AFUDC) of $7,798,313.

The second report conveyed the results of the staff's audit of partnership expenditures charged to the Alaskan section of ANGTS for the period February 1, 1978 through December 31, 1978. Partnership expenditures charged to the gas plant accounts during this period totaled $44,918,798 including AFUDC of $13,988,691.

1/ ANGTS was authorized by the Alaska Natural Gas Transportation Act of 1976 (ANGTA), 15 U.S.C. 719 et seq. and the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System, as enacted into law, H. J. Res. 621, Pub. L. No. 95-108 (November 2, 1977).

In the first report, the staff recommended the disallowance of $42,224,461, including AFUDC of $6,833,041, of the total claimed pre-partnership expenditures of $57,415,070.[2/]

In the second report, the staff recommended the disallowance of $1,823,020 of the total claimed partnership expenditures.[2/] The staff's findings and recommendations in that report did not cover $13,988,691 of AFUDC capitalized during the period.

This report conveys the results of the staff's audit of partnership expenditures charged to the Alaskan section of ANGTS for the period January 1, 1979 through December 31, 1979. Partnership expenditures charged to the gas plant accounts during this period totaled $53,710,138, including AFUDC of $11,920,788. The staff's findings and recommendations in this report do not cover the $11,920,788 of AFUDC claimed during the period. A large part of the AFUDC claimed is related to pre-partnership and other expenditures which are at issue in our first two audit reports. Upon disposition of the audit findings and recommendations in these

2/ These proposed disallowances have been reflected on the Exhibit.

reports, AFUDC claimed for the period January 1, 1979 through December 31, 1979 will be recomputed and adjusted as appropriate.

SUMMARY.

With respect to the partnership expenditures made during the period January 1, 1979 through December 31, 1979 ($41,789,350 exclusive of AFUDC), the staff concludes that:

1. Expenditures of $40,794,243 are properly assignable to the Alaskan section of ANGTS and are of a nature that would qualify for eventual inclusion in rate base.

2. Expenditures of $349,691 are not of a nature that would qualify for inclusion in rate base and, therefore, should be disallowed.

3. Expenditures of $645,416 may not be properly assignable to the project for eventual inclusion in rate base. Requests to ANNGTC for additional information on these expenditures have not been answered. Therefore, the staff proposes that these expenditures be disallowed without prejudice to ANNGTC's reclaiming them upon submission of appropriate supporting information.

4. Corrective action needs to be implemented to eliminate discrepancies between the accounting records and the financial statements.

SCOPE OF AUDIT

The audit covered claimed partnership expenditures charged to the gas plant accounts totaling $41,789,350, exclusive of AFUDC, for the period January 1, 1979 through December 31, 1979.

The audit included an examination of the accounting and other records to the extent deemed necessary to determine whether:

1. The various financial statements and reports properly reflected the underlying records and documents.

2. The expenditures were adequately documented and supported.

3. The accounting for the expenditures met the requirements of the Uniform System of Accounts and generally accepted accounting principles.

4. The expenditures were properly assignable to the Alaskan section of ANGTS and were of a nature that would qualify for eventual inclusion in rate base.

5. The other accounting and reporting regulations and requirements of the Natural Gas Act, the Decision and the Certificate of Public Convenience and Necessity were complied with.

6. The policies, procedures, and controls appear adequate to ensure the efficient and economic construction of the project.

RESULTS OF AUDIT

ANNGTC claimed partnership expenditures of $41,789,350, excluding AFUDC. With respect to these expenditures, the staff has determined that:

1. Expenditures of $40,794,243 were for engineering studies and plans, environmental studies, governmental fees, legal and consultant fees related to the preparation of an application for a Certificate of Public Convenience and Necessity to construct the Alaskan section of ANGTS. These expenditures are properly assignable to the Alaskan section of ANGTS and are of a nature that would qualify for eventual inclusion in rate base.

2. Expenditures of $349,691 are not of a nature that would qualify for eventual inclusion in ANNGTC's rate base and should be disallowed. These expenditures fall into the following categories:

   a. Lobbying Activities

      Expenditures of $158,962 to three firms engaged in lobbying activities on behalf of ANNGTC regarding; D-2 legislation affecting lands in Alaska designated as a national reserve, an amendment to Section 103 of the Internal Revenue Code concerning the State of Alaska issuance of tax exempt bonds, and meetings with members of the U. S. Congress and members of the Alaskan legislature on various legislation affecting the project.

The Uniform System of Accounts requires that expenditures of this nature be recorded in Account 426.4, Expenditures for certain civic, political and related activities, a non-utility expense account.

b. Donations

Expenditures of $90,002 relate to contributions to the following organizations: Alaskans for the Gas Pipeline, Citizens for Management of Alaskan Lands, Inc., and Close-Up Foundation.

The Uniform System of Accounts requires that expenditures of this nature be recorded in Account 426.1, Donations, a non-utility expense account.

c. Public Relations

Expenditures of $74,572 to four public relations firms. One firm was located in Washington, D. C. and distributed information to the press, members of Congress and the public. Another firm provided media coverage in New York on the Alaskan gas pipeline. The third firm produced a film documenting progress on the gas pipeline. The fourth firm monitored the media and handled liason work in Canada.

The Commission in various cases has ruled that public relations type expenditures are not properly assignable to the plant accounts but are of a nature that should be recorded in Account 930.1, General advertising expenses, a utility expense account.

d. Photo Prints, Ski Lessons, and Fishing Arrangements

Expenditures of $14,450 relates to photo prints of the "Old Salmon Cannery", ski lessons and charter fishing arrangements which were provided to various Board of Partners representatives subsequent to their meetings in February, March and April of 1979.

The Uniform System of Accounts requires that expenditures of a nonoperating nature be recorded in Account 426.5, Other deductions, a non-utility expense account.

e. Country Club Dues

Expenditures of $8,047 to various country clubs, luncheon and dinner clubs and athletic clubs for membe ship dues.

NARUC Interpretation No. 49 requi s that club dues of this nature be recorded in Account 426.5, Other deductions, a non-utility expense account.

f. Gifts

Expenditures of $3,658 relate to gifts to satisfy the oriental business custom of exchanging gifts resulting from ANNGTC's business ties with Japan.

The Uniform System of Accounts requires that expenditures of a nonoperating nature be recorded in Account 426.5, Other deductions, a non-utility expense account.

3. Expenditures of $645,416 were not adequately supported; therefore, the staff was unable to determine whether they are properly assignable to the Alaskan section of ANGTS for eventual inclusion in rate base. Requests to ANNGTC for additional information on these expenditures have not resulted in responses which clearly document the nature and character of the items. These items fall into two general categories:

   a. Amounts paid to a number of law firms for services which appear to include political lobbying efforts designed to influence public opinion concerning the project and, as such, would not be allowable in the plant accounts under the provisions of the Uniform System of Accounts.

   b. Amounts paid to a number of consultants where sufficiently competent evidential material (i.e. contracts, written agreements, vendor memoranda, etc.) did not exist or were not made available. Therefore, there was no adequate basis upon which to evaluate the propriety of the assignment of the costs to the project or their qualification for eventual inclusion in rate base.

Therefore, the staff proposes that these expenditures be disallowed without prejudice to ANNGTC's reclaiming them upon submission of appropropriate supporting information.

4. Monthly financial statements prepared by ANNGTC reported and compared actual project expenditures with budgeted project expenditures. The accounting records supporting these financial statements did not agree with the reported actual project expenditures in many instances and adequate reconciliations were not available. Corrective action implemented by ANNGTC in 1979 were not fully successful in that the new procedures sometimes created a lag in recording a charge to the proper work order and resulted in further reporting discrepancies.

The Uniform System of Accounts requires the accounting records be maintained in a manner that permits ready analysis by the prescribed accounts and preparation of financial statements directly from the accounting records.

It is imperative on this project that the actual construction costs be readily identifiable and verifiable. Otherwise, it will be difficult, if not impossible, to audit costs and to issue timely audit reports.

RECOMMENDATIONS

The staff recommends that:

1. $40,794,243 of partnership expenditures be allowed as charges properly assignable to the ANNGTC project and be determined as qualified for eventual inclusion in the rate base of ANNGTC.

2. $349,691 of partnership expenditures be disallowed as costs qualified for eventual inclusion in the rate base of ANNGTC.

3. $645,416 of partnership expenditures be disallowed as costs properly assignable to the ANNGTC project for eventual inclusion in rate base, without prejudice to ANNGTC's reclaiming them upon submission of appropriate supporting information.

4. Corrective action be taken to permit the preparation of financial statements directly from the accounting records. Until such corrective action is implemented, ANNGTC should prepare reconciliations of differences between the recorded and reported actual expenditures. These reconciliations should list each reconciling amount, the source of original entry, and explain the reason for the reconciling item.

EXHIBIT

Alaskan Northwest Natural Gas Transportation Company
Adjusted Balance Sheet
As of January 1 and December 31, 1979
With Staff Adjustments Thereto

	Adjusted Balance 1-1-79 1/	Activity 1-1-79 Through 12-31-79	Staff Adjustments 3/	Adjusted Balance 12-31-79
Assets				
Plant in Service	$ 587,147	$ 381,453	$ -	$ 968,600
Less: Accum. Deprec. and Amort.	(54,519)	(103,823)	-	(158,342)
Construction Work in Progress	57,753,759	53,432,508 2/	(995,107)	110,191,160
Total Gas Plant	58,286,387	53,710,138	(995,107)	111,001,418
Cash and Other Assets	10,607,476	(5,137,625)	-	5,469,851
Total Assets	$68,893,863	$48,572,513	(995,107)	$116,471,269
Partners' Equity and Liabilities				
Partners' Constributions Paid in:				
Calaska Energy Co.	$ 5,675,000	$ 5,061,667	$ -	$ 10,736,667
Pacific Interstate Trans. Co. (Arctic)	5,675,000	5,061,667	-	10,736,667
Pan Alaska Gas Company	5,675,000	5,061,667	-	10,736,667
Northern Arctic Gas Co.	5,675,000	5,061,667	-	10,736,667
United Alaska Fuels Corp.	5,675,000	5,061,667	-	10,736,667
Northwest Alaskan Pipeline Co.	20,865,609	5,061,667	-	25,927,276
Total Partners' Contributions	49,240,609	30,370,002	-	79,610,611
Retained Earnings	12,494,252	12,301,507	(995,107)	23,800,652
Total Partners' Equity	61,734,861	42,671,509	(995,107)	103,411,263
Accounts Payable and Other Liabilities	7,159,002	5,901,004	-	13,060,006
Total Partners' Equity and Liabilities	$68,893,863	$48,572,513	(995,107)	$116,471,269

1/ This is the adjusted balance, as shown in the second staff audit report on ANNGTC, after the proposed disallowance of $42,224,461 pre-partnership expenditures and $1,823,020 partnership expenditures.

2/ Includes AFUDC of $11,920,788.

3/ Staff adjustments do not cover AFUDC for reasons explained in the introduction of this report.

GPO 879 290