

ALASKA DEPARTMENT OF REVENUE

548 SCOM116: JOINT SPEC. COMM. ROYALTY OIL & GAS 1977-78

December 31, 1970

STATE OF ALASKA

BEFORE THE ALASKA PUBLIC UTILITIES COMMISSION

In the Matter of the Certification
of UNION OIL COMPANY OF CALIFORNIA
and MARATHON OIL COMPANY }

U-70-73

ORDER NO. 1

ORDER GRANTING TEMPORARY EXEMPTION

On December 18, 1970, the Commission received a request on behalf of the above-named parties for exemption from the certification provisions of AS 42.05.221, which provides:

"Sec. 42.05.221. Certificates required. (a) No public utility may operate and receive compensation for providing a commodity or service after January 1, 1971 without first having obtained from the commission under this chapter a certificate declaring that public convenience and necessity require or will require the service"

In the opinion of the Commission, the request poses problems sufficiently similar to those presented in Commission Cause No. U-70-85 to warrant the same approach utilized in Order No. 1 in that docket (copy attached).

FINDINGS

THE COMMISSION FINDS, good cause exists for temporarily exempting Union Oil Company of California and Marathon Oil Company from complying with AS 42.05.221 pending final decision on the request for exemption pursuant to AS 42.05.711(d).

U-70-73
DEC 31 1970

93

AGO 570682

ORDER

THE COMMISSION ORDERS:

1. Upon the request of the parties named in the caption of this proceeding for exemption from complying with AS 42.05.221, said parties are temporarily exempted from complying with AS 42.05.221 pending final decision on the issues raised pursuant to AS 42.05.711(d), upon the following condition:

That the parties must submit a complete application for a certificate of public convenience and necessity (Commission Form PU 101) on or before February 1, 1971.

2. Failure to comply with the condition specified in Paragraph (1) shall result, without necessity of further order, in termination of the temporary exemption.

3. The applications shall be accompanied, either individually or collectively, by whatever additional argument or information may be necessary to complete the presentations of the parties in support of the request for exemption. Factual matters contained in the request for exemption, if not also provided in the applications, shall be verified by persons having personal knowledge of such factual matters.

4. Pending final disposition of the request for exemption, Union Oil Company and Marathon Oil Company shall not enter into any new contracts for the sale of natural gas without affording the Commission a prior opportunity of at least thirty (30) days in which to review each said contract. Any such contracts entered into without prior submission to the Commission shall be null and void.

5. The Commission shall schedule such further proceedings, including public notice and hearing (consolidated or separate) as it deems warranted.

By Direction of the Commission:

DATED at Anchorage, Alaska this 31st day of December, 1970.

ALASKA PUBLIC UTILITIES COMMISSION

Don Hall

Don Hall
Executive Director

September 28, 1971

BEFORE THE ALASKA PUBLIC UTILITIES COMMISSION

in the Matter of the Application)
of UNION OIL COMPANY OF CALIFORNIA)
and MARATHON OIL COMPANY for)
Exemption of its Kenai-Nikiski)
Natural Gas Pipeline from Regula-)
tion Pursuant to AS 42.05.711(d))

U-70-73

ORDER NO. 2

ORDER DISMISSING APPLICATION FOR CERTIFICATE
AND GRANTING PARTIAL EXEMPTION FROM THE
PROVISIONS OF AS 42.05

The UNION OIL COMPANY OF CALIFORNIA (UNION) and MARATHON OIL COMPANY (MARATHON) each own fifty percent of the Kenai-Nikiski Pipeline (Pipeline) located in Section 21, T7N, R12W of the Seward Meridian. On December 18, 1970 Union and Marathon (herein after referred to as "Applicants") jointly filed an application with the Commission under AS 42.05.711(d) for exemption of the pipeline from all provisions of the Alaska Public Utilities Commission Act, and rules and regulations promulgated thereunder, except those pertaining to safety standards.

The above application indicates that approximately 160,000 - 170,000 Mcf of gas were being transported daily through the pipeline. Of that total, it appears that about 900 Mcf per day are delivered through a portion of the pipeline to the City of Kenai for use in its municipal gas distribution system.

On December 31, 1970, the Commission entered its Order No. 1 in this proceeding which granted the Applicants

temporary exemption from compliance with AS 42.05.221 pending final decision of the issues in this matter on the condition that a complete application for a certificate of public convenience and necessity would be filed by the Applicants on or before February 1, 1971. The order further provided that no new agreements for the sale of natural gas would be entered into without first affording the Commission an opportunity of at least thirty (30) days in which to review each proposed contract.

Union and Marathon, on January 29, 1971, each filed a separate application for a certificate of public convenience and necessity to operate a natural gas transmission pipeline, but continued to urge consideration of their previous request for partial exemption in preference to their application for a certificate.

Subsequent to the Applicants' filing for an exemption, but prior to the application being noticed to the public, the Alaska Public Service Corporation (APSC) requested an opportunity to intervene and to oppose the granting of such exemption because of the disclosure in the application that it was proposing to sell gas from the Pipeline to Chugach Electric Association, Inc. On January 29, 1971, the request to intervene and to oppose the granting of an exemption was withdrawn by the APSC. However, in a letter to the Commission, dated August 30, 1971, the President of APSC informed the Commission that the reason it did not object to the exemption of Applicants was "... because we believed the Commission would not allow the invasion of our Service Area during the course of such exemption."

gas distribution utility
Subsidiary
of APC

via APC?

AGO 570686

The aforementioned applications were noticed to the public and all known interested parties on March 6, 1971. No opposition to, or support for, the application was received in response to the public notice.

It is the position of the Applicants that, except for safety considerations, the provisions of AS 42.05 are not applicable to the type of operations performed or contemplated by the Pipeline. Clearly in contrast, the Applicants do transmit and sell natural gas to the City of Kenai, which in turn sells it to Wildwood Air Force Station and to Kenai Utility Service Corporation for resale to its individual commercial and residential customers. A natural gas utility as defined in AS 42.05.701(2) (D) includes any corporation or company furnishing, by transmission or distribution, natural gas to the Alaska public for compensation. This definition, viewed by itself, might lead to the assumption that since the individual commercial and residential consumers are not being served directly by the Applicants, the Applicants are not a public utility. AS 42.05.701(5), however, provides that the "public" or "general public" includes any utility purchasing or paying for the transmission of natural gas which is resold to ten or more customers; thus the City of Kenai and the Kenai Utility Service Corporation are the "public" in addition to being utilities. Sale of natural gas to the City of Kenai (the public), by statutory definition, make the Applicants a public utility.

It is apparent to the Commission that the primary purpose and use of the Pipeline is to provide natural gas to the Applicants' affiliated industrial manufacturing interests

and to other related gas and oil production activities. The Commission understands the reluctance of the Applicants to submit all of their pipeline operations to regulation as a public utility, particularly in view of the extremely small percentage of the total pipeline capacity dedicated to public utility service. On the other hand, the Commission must recognize its obligation to protect the interests of all ultimate utility customers who depend on the Applicants for the gas they use regardless of the fact that their usage is only a minuscule part of the gas transmitted by the Pipeline. The Commission must be assured that once utility service has been offered to the public, it will continue to be offered for a reasonable period at rates which are just and fair. Further, the Commission must be in a position to ascertain periodically that rates being charged to the utilities are consistent with those being charged to other users of the Pipeline and that the rates of return for sales to utilities are not excessive. Finally, the Commission should have a current knowledge of the quantity of gas the Applicants are prepared to deliver for public utility usage and the time periods over which such deliveries can be made.

AS 42.05.711(d) provides that the Commission, on finding that no legitimate public interest would be served, may exempt a utility from all or any portion of the Act. It would appear that the majority of Applicants' pipeline activities can properly be exempted from regulation, provided sufficient safeguards are retained to guarantee that the rate payers using the natural gas supplied by the Pipeline

will receive adequate regulatory protection. Safety matters, for which no exemption has been requested, should continue to be regulated by the Commission in accordance with the authority delegated to it through the Federal Government's Natural Gas Pipeline Safety Act of 1968, as amended.

FINDINGS

THE COMMISSION FINDS:

1. Union Oil Company of California and Marathon Oil Company, to the extent of their ownership, control and operation of the Kenai-Nikiski Pipeline, are a public utility as defined by AS 42.05.701(2) (D) and AS 42.05.701(5) (B).

2. Union Oil Company of California and Marathon Oil Company, in their ownership, control and operation of the Kenai-Nikiski Pipeline, should be exempted from the provisions of AS 42.05 except as it relates to or affects:

- A. The terms, conditions or pricing of natural gas sales to public utilities;
- B. The quality of service rendered to public utilities as customers;
- C. The safety of operations of the pipeline and its related facilities and appurtenances.

3. No legitimate public interest will be served by regulating any of the operations of Union Oil Company of California and Marathon Oil Company except to the extent indicated in Finding No. 2 above.

ORDER

THE COMMISSION ORDERS:

1. Order No. 1 in this proceeding is hereby
rescinded:-

2. The application of Union Oil Company of California and Marathon Oil Company for a certificate of public convenience and necessity to furnish natural gas transmission service is dismissed without prejudice.

3. Subject to the conditions of this Order, the application of Union Oil Company of California and Marathon Oil Company, as owners and operators of the Kenai-Nikiski Pipeline, for an exemption from the provisions of AS 42.05 is granted in part. The Commission retains jurisdiction to the extent that Union Oil Company of California and Marathon Oil Company, as owners and operators of the Kenai-Nikiski Pipeline shall:

a) File with the Commission within thirty (30) days of the effective date of this Order, copies of all contracts, agreements, or arrangements for the sale or delivery of natural gas in effect on the effective date of this Order.

b) File with the Commission within thirty (30) days after execution, a copy of any new contract, agreement, or arrangement or any modification, alteration or extension of an existing contract, agreement, or arrangement for the sale or delivery of natural gas.

c) Obtain prior written approval of the Commission before placing in effect any new contract, agreement, or arrangement or any

Does this
not apply
to APC
contract?

modification, alteration or extension
of an existing contract, agreement, or
arrangement for the sale of natural
gas to an utility certificated by the
Commission.

applicability
to APC
"extension"?

- d) Make available to the Commission, its employees, agents, and consultants for inspection and examination, at all reasonable times, the accounts, books, records, maps, inventories, appraisals, valuations, and/or other reports and documents of the pipeline operation which may be required to evaluate the justice, fairness and reasonableness of its contracts, agreements, and arrangements for the sale of natural gas to certificated public utilities, and to determine the quality of service being rendered.

Applicable to
APC!

- e) Comply with all State, Federal and Commission rules, regulations, orders, or procedures relating to natural gas pipeline safety.

4. The Commission retains jurisdiction to investigate all complaints filed by any certificated public utility to which the sale or delivery of natural gas is being made and to exercise all provisions of AS 42.05 in the resolution of such complaints.

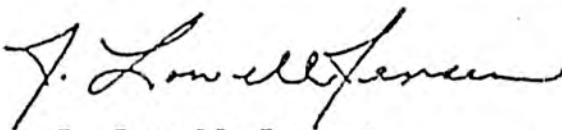
AGO 570691

5. The exemption granted herein is subject to modification or revocation after thirty (30) days notice to the Union Oil Company of California and the Marathon Oil Company, including an opportunity to be heard if requested by the parties in writing.

By Direction of the Commission (Commissioner Zerbetz, dissenting, filed a Dissenting Statement appended hereto):

DATED at Anchorage, Alaska this 28th day of September, 1971.

ALASKA PUBLIC UTILITIES COMMISSION



J. Lowell Jensen
Deputy Director

STATE OF ALASKA

BEFORE THE ALASKA PUBLIC UTILITIES COMMISSION

In the Matter of the Application)
of UNION OIL COMPANY OF CALIFORNIA)
and MARATHON OIL COMPANY for)
Exemption of its Kenai-Nikiski)
Natural Gas Pipeline from Regula-)
tion Pursuant to AS 42.05.711(d))

U-70-73

ORDER NO. 2

ORDER DISMISSING APPLICATION FOR CERTIFICATE
AND GRANTING PARTIAL EXEMPTION FROM THE
PROVISIONS OF AS 42.05
(DISSENT OF COMMISSIONER GOREN J. ZERBETZ)

I cannot agree with the decision of the majority which would allow Union Oil Company of California and Marathon Oil Company jointly to operate as a public utility without a certificate of public convenience and necessity in violation of AS 42.05.701(5). The majority opinion admits that applicant is a utility subject to certification but chooses to exempt it for various reasons including apparently the relatively small percentage of the operation which would be considered to be in public use. The size of the utility operation should not be used as a measure of determining the Commission's primary mission to protect the public. Furthermore, this particular operation represents the entire gas supply of the principal cities on the Kenai Peninsula and to the Wildwood Air Force Station.

Applicant contends that customers other than the City of Kenai are affiliated interests and that service to these affiliates would not place applicant in a public utility category. It is worthy of note that the other customers are not in the same ownership entity and though there

*APC not included!
Yet they had
a contract
as of 1967?*

are less than 10 of this type of customer their existence as separate entities strengthens my moral conviction that applicant should be treated as a public utility.

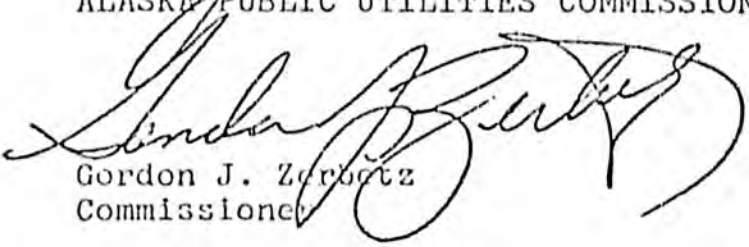
Also worthy of note is applicant's disclosure of an attempt to provide services in an area that has already been certificated to another gas utility. Granting of a certificate to one utility and granting an exemption to another for an operation in the same service area cannot but lead to regulatory difficulties in the future.

The majority decision would retain safety responsibility for this gas pipeline in spite of exemption. The creation of this special utility category could necessitate special handling of general safety orders which would add an unnecessary element of confusion to the Commission's regulatory procedures.

Final and timely consideration should also include the environmental aspect of this exemption. At a time when the Commission is involved in a vigorous program to balance essential utility services with ecological considerations, the jurisdiction of the Commission should be extended to the fullest extent allowed by the existing statutes.

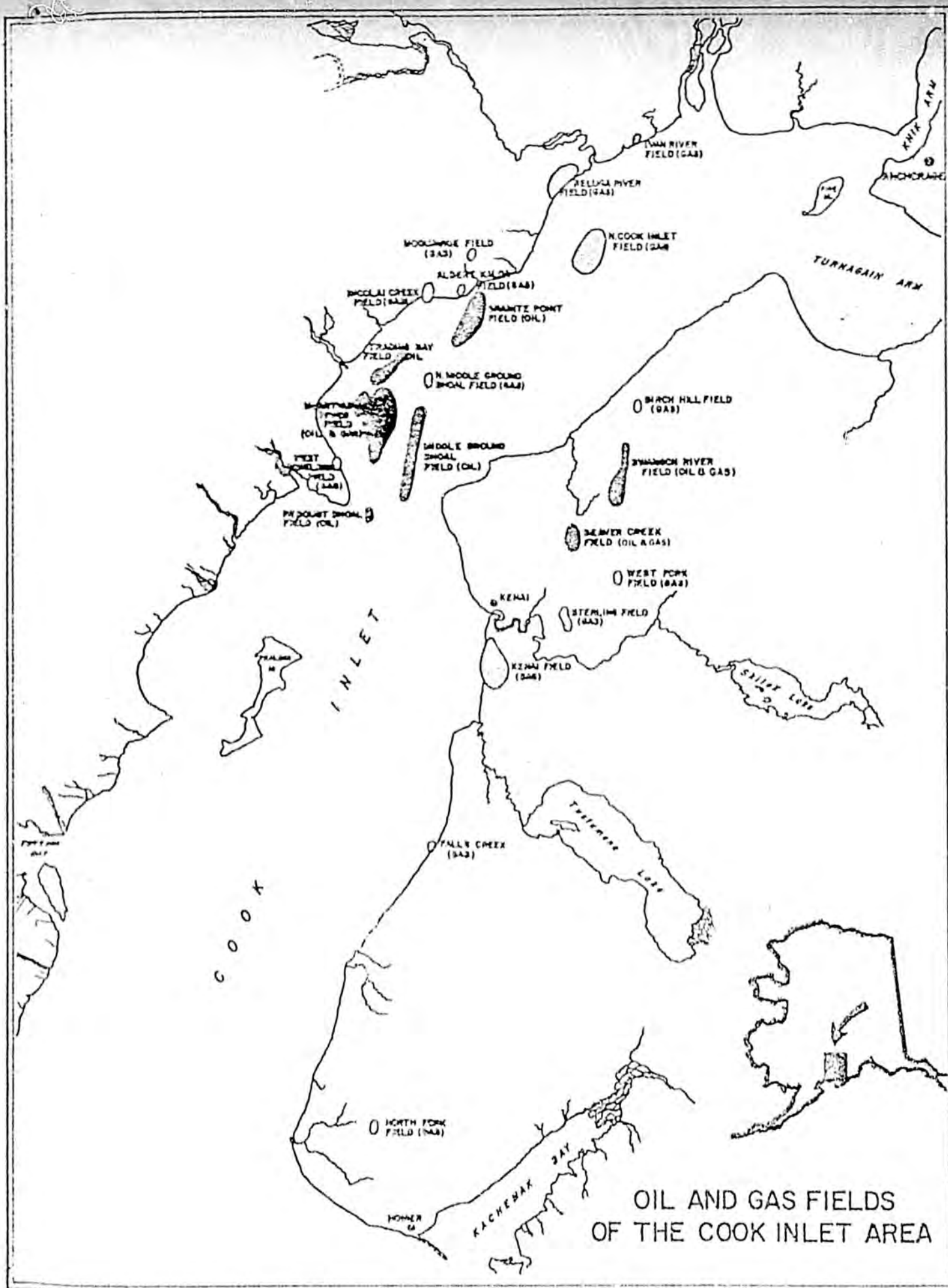
WITTED at Anchorage, Alaska this 28th day of September, 1971.

ALASKA PUBLIC UTILITIES COMMISSION

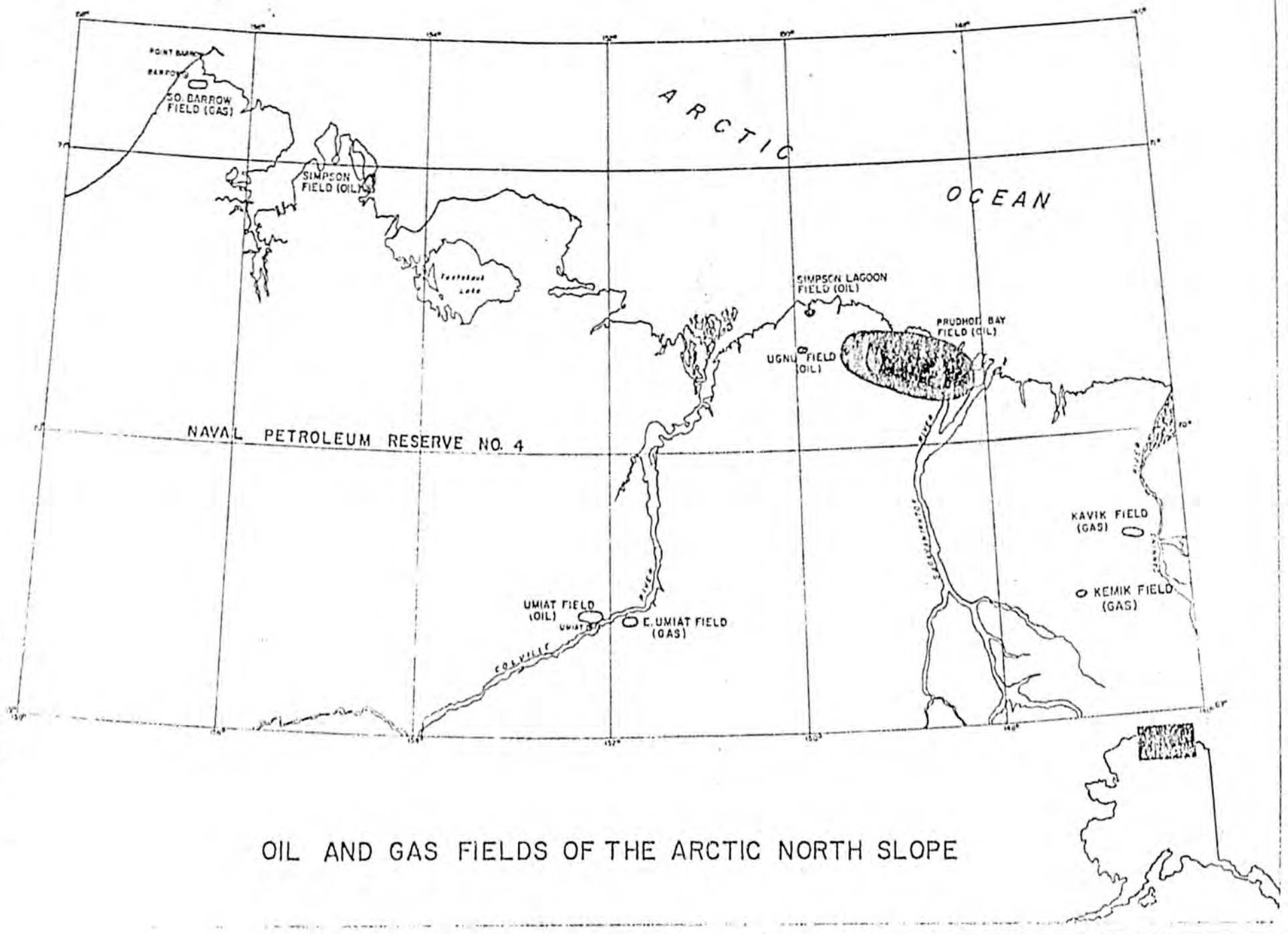

Gordon J. Zerbetz
Commissioner

What's who
that?

COOK INLET
OIL + GAS
FIELDS



AGO 570697



OIL AND GAS FIELDS OF THE ARCTIC NORTH SLOPE

BEAVER CREEK GAS FIELD

Operator: Marathon

Other Participants: Union Oil

Discovered: 1967

Production started: 1973

Number of wells (as of 2/75): 1 producer, 0 shut-in

Current producing rate (2/75): 7,249 MCF/month, 259 MCF/day

Estimated remaining reserves: 400,000 MMCF

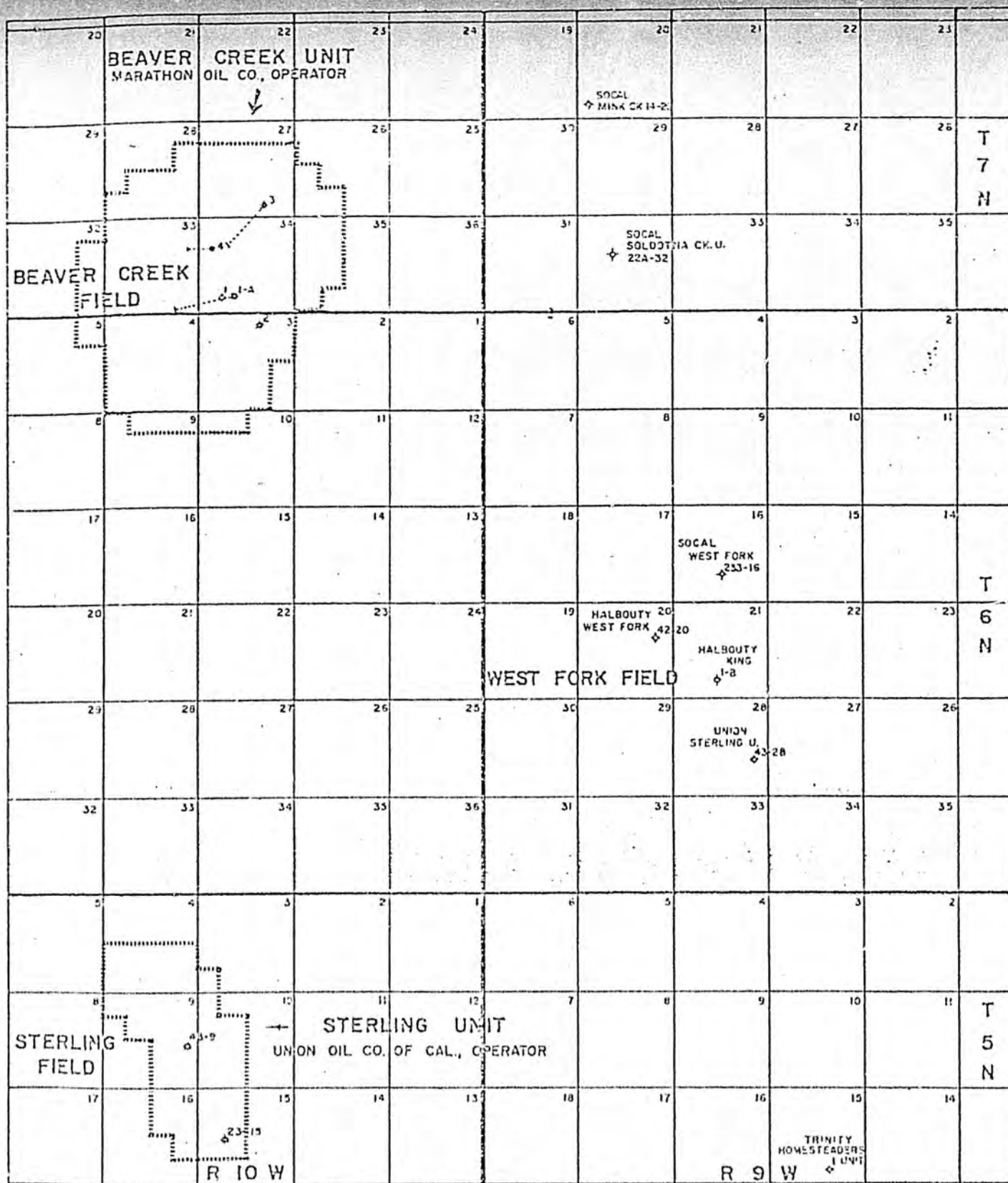
Gas utilization: Gas lift gas

State royalty interest: 0

General onshore location: Eastside Cook Inlet, see attached map.

Comments:

This field is a probable source of gas for the proposed Pacific Lighting LNG project near Kenai.



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

BEAVER CREEK, STERLING AND
WEST FORK FIELDS

AGO 570699

SCALE: 0 4,000' 8,000' 12,000'

APRIL 1, 1974

BELUGA RIVER GAS FIELD

Operator: Socal

Other participants: Shell and Arco

Discovered: 1962

Production started: 1968

Number of wells (as of 2/75): 1 producing, 4 shut-in

Current producing rate (2/75): 507,126 MCF/month, 18,112 MCF/day

Estimated remaining reserves: 700,00 MMCF

Gas utilization: Chugach Electric Assoc.

X Current wellhead value: \$0.163/MCF, escalates 1¢/MCF every 5 years

State royalty interest: 7.9862%

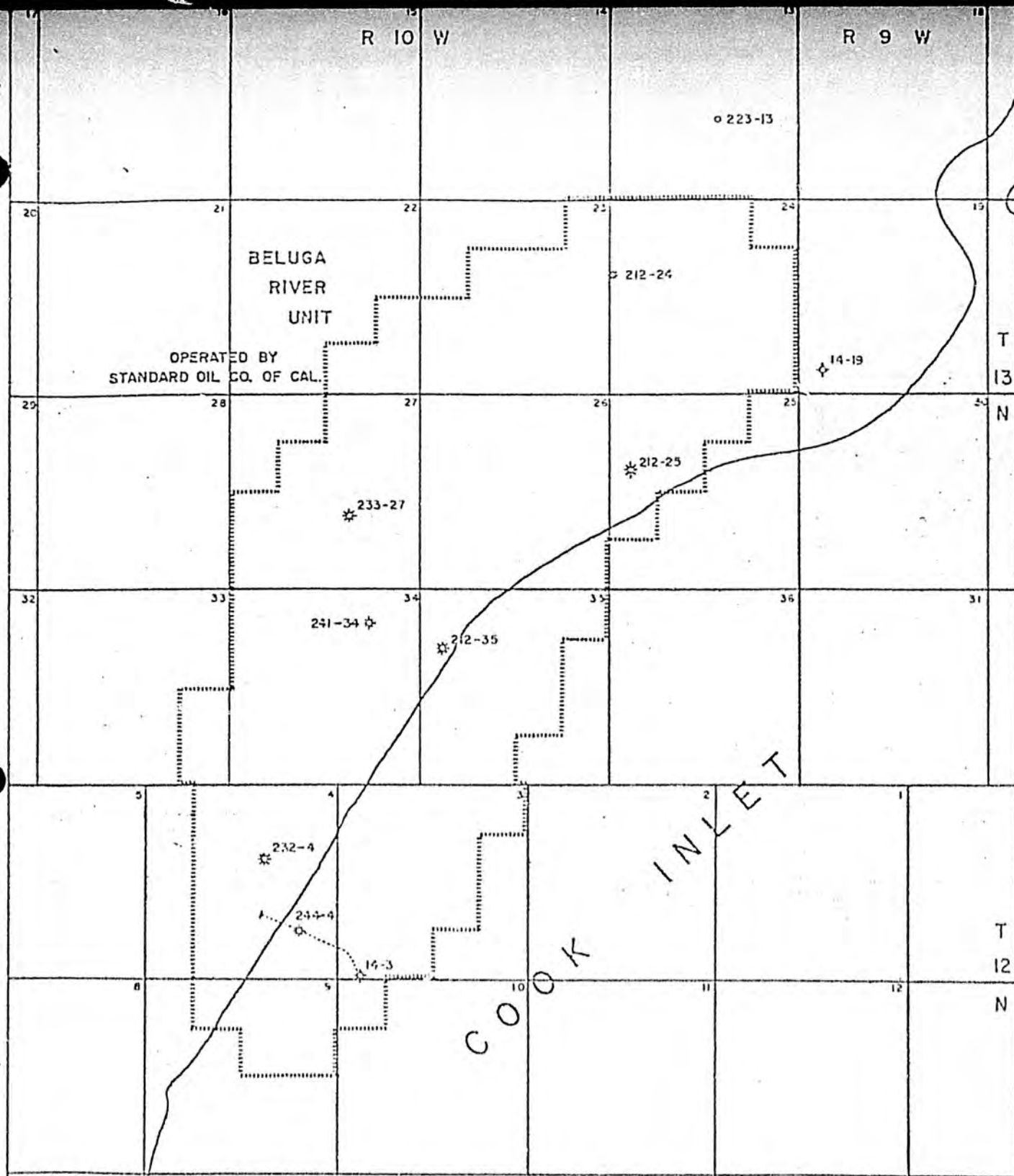
Gas sales (1974): 15,182 MCF/D

Possible inkind royalty rate: 1318 MCF/D

General onshore location - Westside Cook Inlet, see attached map.

Comments:

A 6% annual increase in gas production is predicted for this field. Future gas sales are an extrapolation of the past trend which reflects a continuing population and industry growth in the area.



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

BELUGA RIVER GAS FIELD

SCALE: 0 1,000' 2,000' 3,000' 4,000'

AGD 570701

NORTH COOK INLET GAS FIELD

Operator: Phillips Pet. Co.

Other participants: None

Discovered: 1962

Production started: 1969

Number of wells (as of 2/75): 7 producing, 1 shut-in

Current producing rate (2/75): 4,194,850 MCF/month, 149,816 MCF/day

Estimated remaining reserves: 1,500,00 MMCF

Gas utilization: LNG Plant

X Current wellhead value: \$0.3305/MCF

State royalty interest: 12.5%

Gas sales (1974): 120,797 MCF/D gross

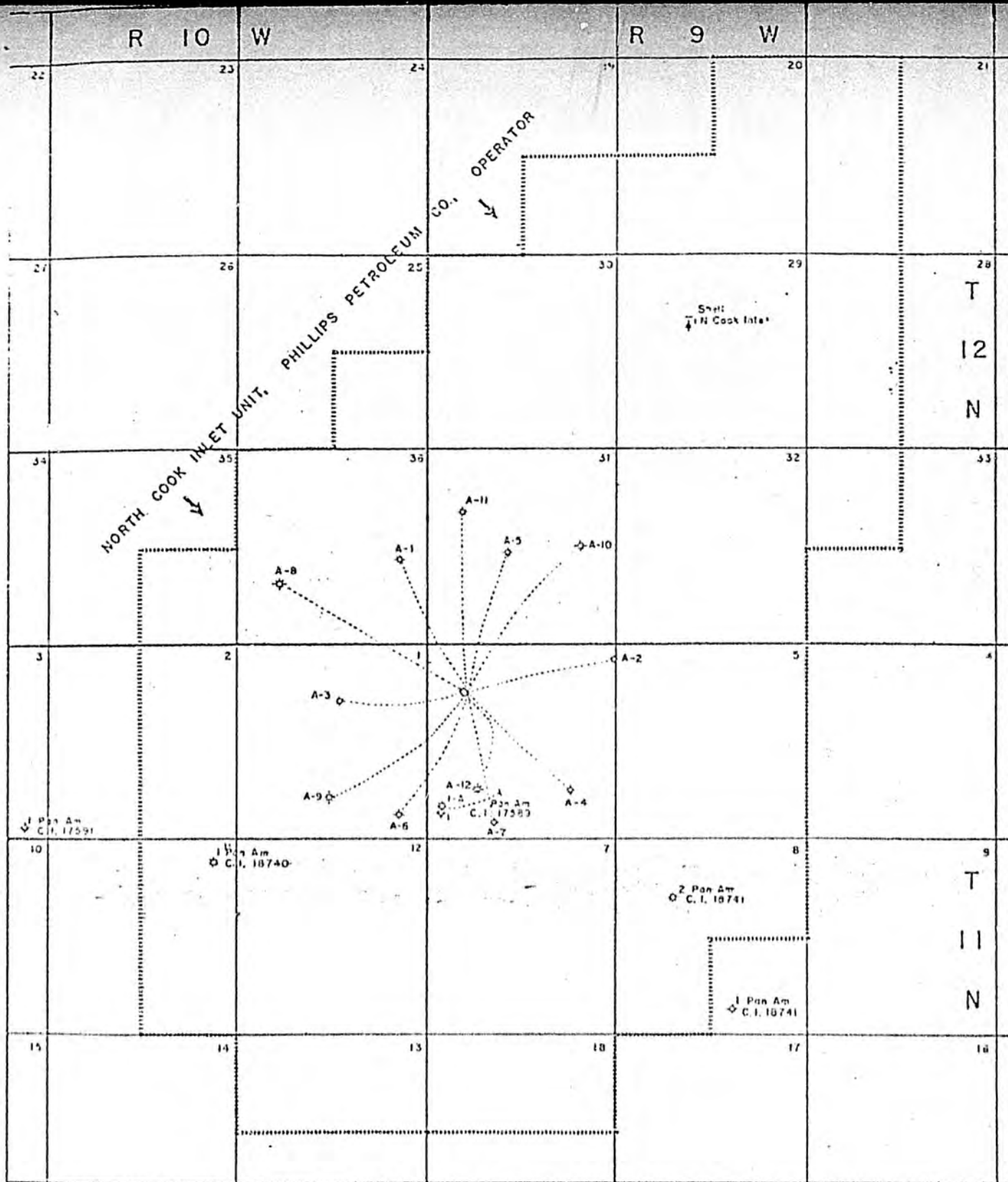
Possible inkind royalty: 17,257 MCF/D

General onshore location: Nikiski, eastside Cook Inlet

Comments:

This Phillips Petroleum Company operated unit delivers a fixed volume of gas for LNG manufacture and sale to Japan. The wellhead value has been increased by contract renegotiation with the Japanese from 10.45¢/MCF to 15.31¢/MCF on 3/12/74, to 28.78¢/MCF on 10/1/74, and to 33.05¢/MCF on 1/1/75. A contract with a new purchaser, NW Natural Gas Co. of Oregon, has been negotiated and is now in the courts. This new sale amounting to 28 MMCF/D should start in mid 1976 at a current Kenai dock price of 80¢/MCF with a 2¢/MCF/yr escalation. With escalation and plant costs it is estimated that the mid 1976 wellhead value for the new sale will be 43¢/MCF.

Kenai Field
7.17 million cf/day (average)
Cyclic supply
min 4.95 mil cf/day
max 9.25 " "
based on 1976 production



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

NORTH COOK INLET FIELD

SCALE: 0 2,000' 4,000' 6,000'

APRIL 1, 1974

KENAI GAS FIELD

Operator: Union Oil

Other participants: Arco, Marathon, Socal

Discovered: 1959

Production started: 1961

Number of wells (as of 2/75): 19 producing, 0 shut-in

Current producing rate (2/75): 6,324,540 MCF/month, 225,876 MCF/day

Estimated remaining reserves: 2,400,000 MMCF

Gas utilization (major): Collier Carbon and Chemical Plant (19%), LNG Plant (30%), Swanson River Oil Field Repressurization (19%), Anchorage and Kenai Residential and Commercial Consumers (32%).

X Current wellhead value: Collier Carbon = \$0.17/MCF, escalates 1¢/MCF every 5 years.
Phillips LNG Plant = \$0.38/MCF
Swanson River Rental = \$0.16/MCF
Anchorage Natural Gas PL. = \$0.22/MCF, escalates 2¢/MCF every 5 years. Special deliverability charge of 19.5¢/MCF minimum will be added to 22¢/MCF base charge starting 7/1/75.

State royalty interest: Shallow 3.6164% ----- Deep 1.1407%

Gas sales (1974): 187,474 MCF/D gross

Possible inkind royalty: 6,196 MCF/D

General onshore location - Eastside Cook Inlet, see attached map.

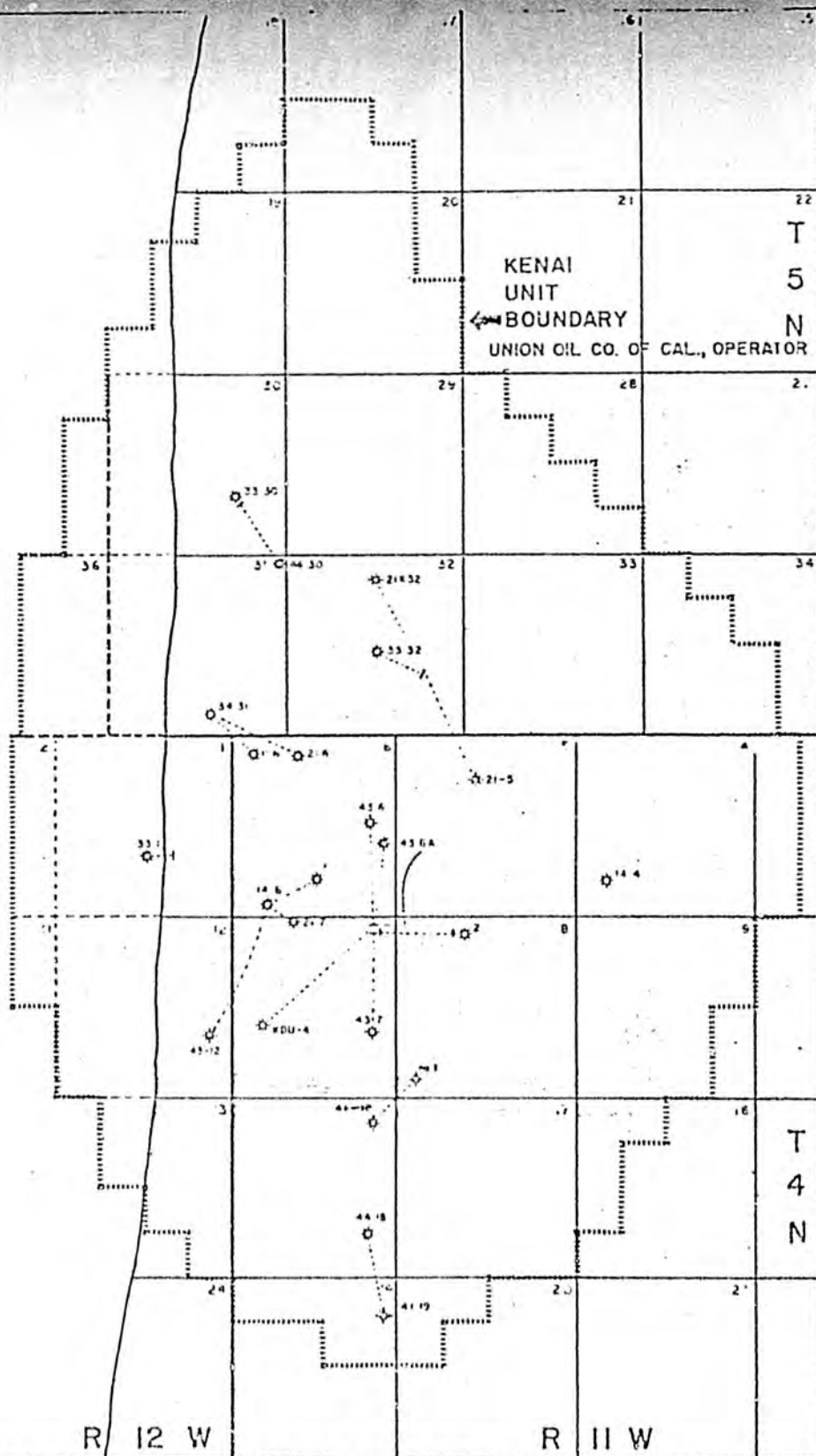
Comments:

Gas sales are predicted to steadily increase even though west side casinghead gas partially displaces Kenai dry gas. Previously flared wet gas from Cook Inlet oil fields became available to the market in October 1972 upon completion of pipeline and compression facilities, to displace dry gas purchased by Collier Chemical Plant and Phillips LNG Plant, and dry gas purchased for injection into the Swanson River Oil Field pressure maintenance project. Gas production is about 84% from Sterling (shallow) pools and 14% from the Tyonek (deep) pool. The federal government has the major royalty interest.

Kenai gas sales to Collier are predicted to increase 2% as the wet gas supply declines until mid 1977, when a planned plant expansion will add 65 MMCF/D.

capacity making a total from Kenai of about 100 MMCF/D. The LNG plant demand should be static until mid 1976 when a new contract, now in the courts, will add 12 MMCF/D in sales to NW Natural Gas Co. in Oregon making total Kenai gas purchases 62 MMCF/D. Alaska Pipeline is predicted to continue its 8% annual increase due to population growth and expansion of the domestic gas systems in Anchorage. Use of Kenai gas on a rental basis for injection in the Swanson River Oil Field reservoir pressurization project is estimated to decline at 15%. In summary, Kenai gas sales are predicted to increase at 5% annually to a mid 1977 average of 214 MMCF/D, when Collier plant expansion will increase sales to 276 MMCF/D; thereafter, total sales should increase at 4% annually.

COOK INLET



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

KENAI FIELD

AGO 570706

SCALE 0 1/2 1 1 1/2 miles

MCARTHUR RIVER GAS FIELD

Operator: Arco, Marathon and Union

Other participants: Amoco, Phillips, Skelly and Socal

Discovered: 1968

Production started: 1969

Number of wells (as of 2/75): 5 producing, 0 shut-in

Current producing rate (2/75): 624,846 MCF/month; 22,316 MCF/day

Estimated remaining reserves: 800,000 MMCF

Gas utilization: Used to run equipment on platforms. No sales

State royalty interest: 12.5%

General onshore location: Nikiski, eastside Cook Inlet, see attached map.

Comments:

This field is a probable source of gas for the proposed Pacific Lighting LNG project near Kenai. Gas pipelines from the McArthur River Field platforms to the westside shore facility and from there across Cook Inlet to Nikiski are installed and are being used to ship casinghead gas to market. These same pipelines are available for the dry gas.

NICOLAI CREEK GAS FIELD

Operator: Texaco

Other participants: Superior Oil

Discovered: 1966

Production started: 1968

Number of wells (as of 2/75): 1 producing, 2 shut-in

Current producing rate (2/75): 597 MCF/month, 21 MCF/day

Estimated remaining reserves: 50,000 MMCF

Gas utilization: Fuel for production and transmission equipment for
Granite Point Field

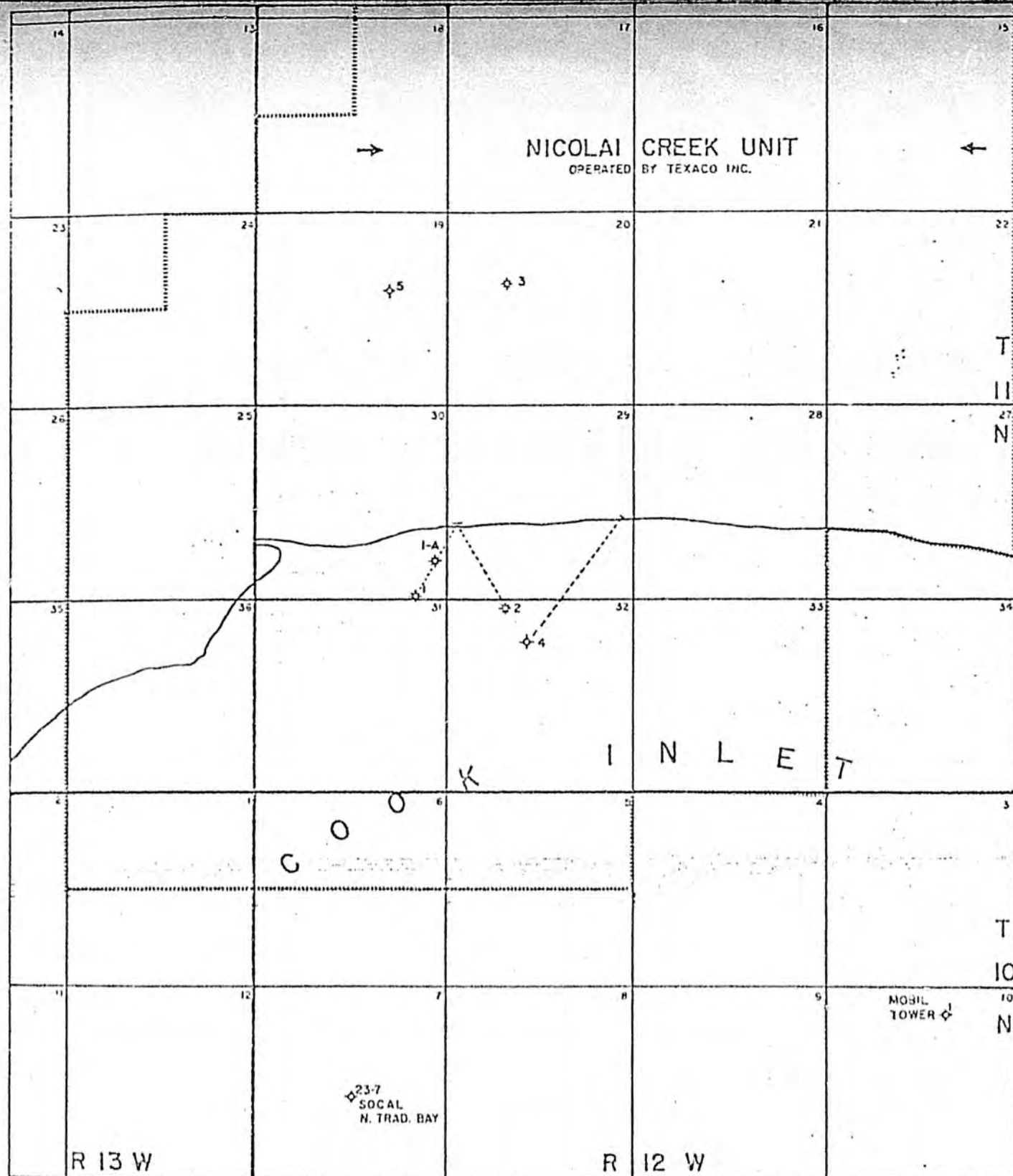
X Current wellhead value: \$0.151/MCF

State royalty interest: 12.5%, 5% on non-producing lease

Gas sales (1974): 26 MCF/D gross

Possible inkind royalty: 4 MCF/D

General location - Westside Cook Inlet, see attached map.



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

AGO 570710

NICOLAI CREEK FIELD

SCALE: 2,000' 0' 2,000' 4,000' 8,000'

APRIL 1, 1974

STERLING GAS FIELD

Operator: Union Oil Co.

Other participants: Marathon

Discovered: 1961

Production started: 1962

Number of wells (as of 2/75): 1 producing, 0 shut-in

Current producing rate (2/75): 3,810 MCF/month, 136 MCF/day

Estimated remaining reserves: 200,000 MMCF

Gas utilization: Heat greenhouse

X Current wellhead value: \$0.25/MCF

State royalty interest: 2.7224%

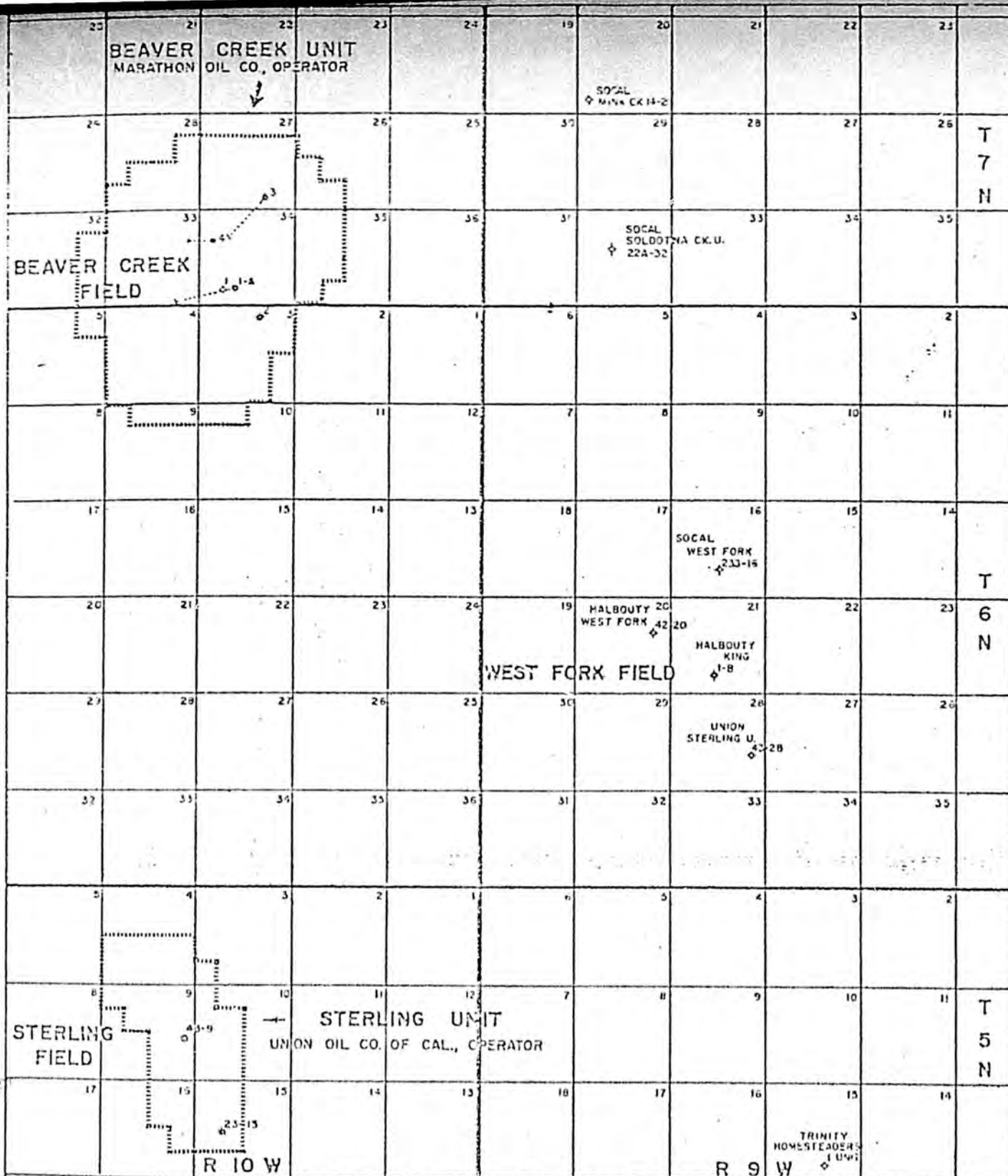
Gas sales (1974): 88 MCF/D

Possible inkind royalty: 2 MCF/D

General onshore location: Kenai, eastside Cook Inlet, see attached map.

Comments:

Available producing capacity is much greater than current sales, as shown in 1972 when gas was purchased by Consolidated Utilities to generate domestic electricity. All Sterling gas is now sold to heat a large greenhouse where vegetables are grown commercially.



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

BEAVER CREEK, STERLING AND
WEST FORK FIELDS AGO 570712

SCALE 4,000' 0 4,000' 8,000' 12,000'

APRIL 1, 1974

ALBERT KALOA GAS FIELD

Operator: Amoco

Other participants: Arco, Phillips and Skelly

Discovered: 1968

Production started: Field shut-in since discovery

Number of wells (as of 2/75): 1 shut-in well

Current producing rate (2/75): No production

Estimated remaining reserves: Not known

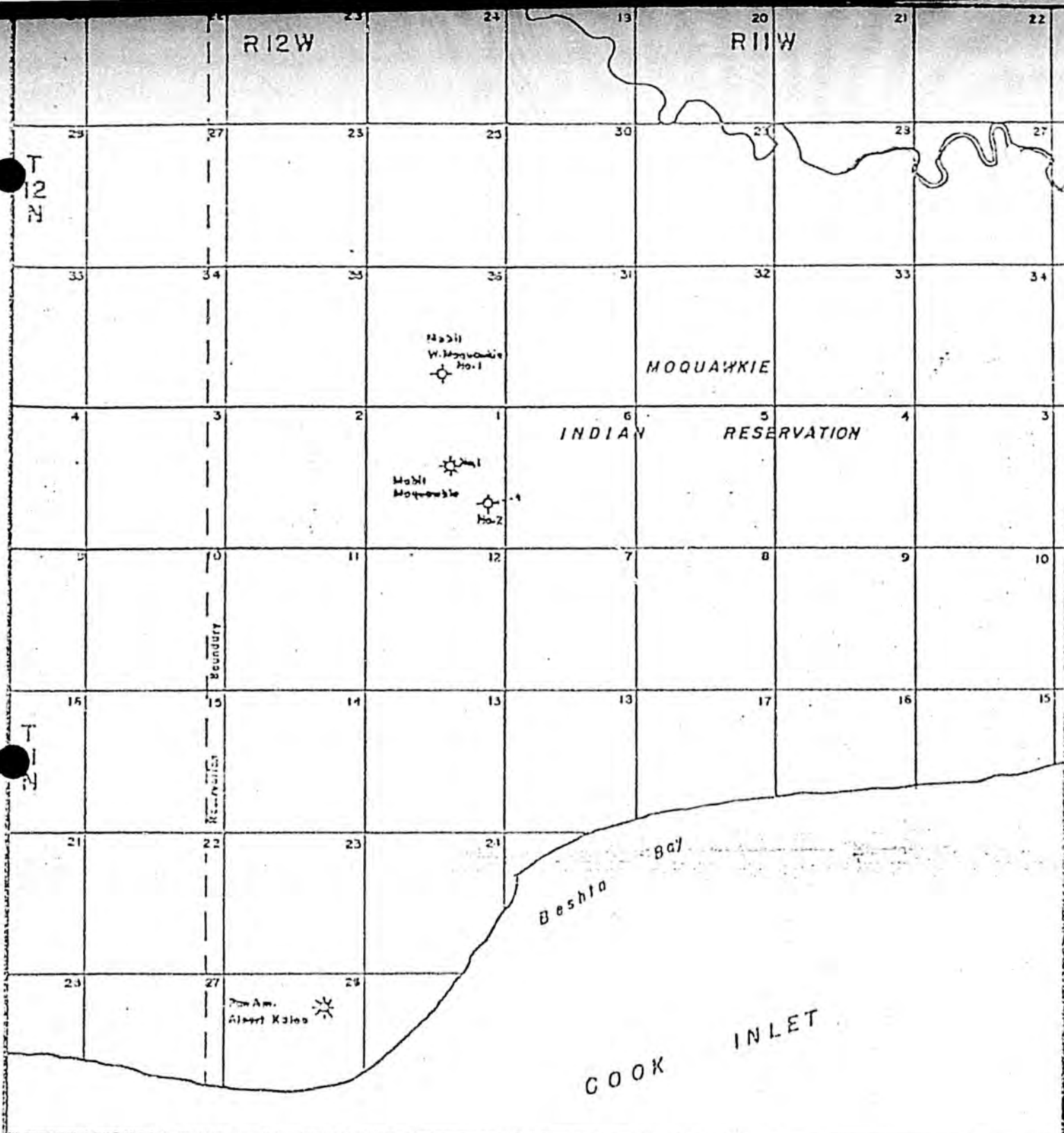
Gas utilization: No production

State royalty interest: 0

General onshore location: Westside Cook Inlet, see attached map.

Comments:

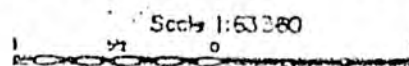
This field has no pipeline connection but is close to the submarine pipeline to eastside Cook Inlet.



STATE OF ALASKA
 DEPARTMENT OF NATURAL RESOURCES
 DIVISION OF OIL AND GAS
 ANCHORAGE, ALASKA

AGO 570714

ALBERT KOLOA and MOQUAWKIE FIELDS



APRIL 1, 1974

BIRCH HILL GAS FIELD

Operator: Socal

Other participants: Arco, Union and Marathon

Discovered: 1965

Production started: Field shut-in since discovery

Number of wells (as of 2/75): 1 well shut-in

Current producing rate (2/75): No production

Estimated remaining reserves: 20,000 MMCF

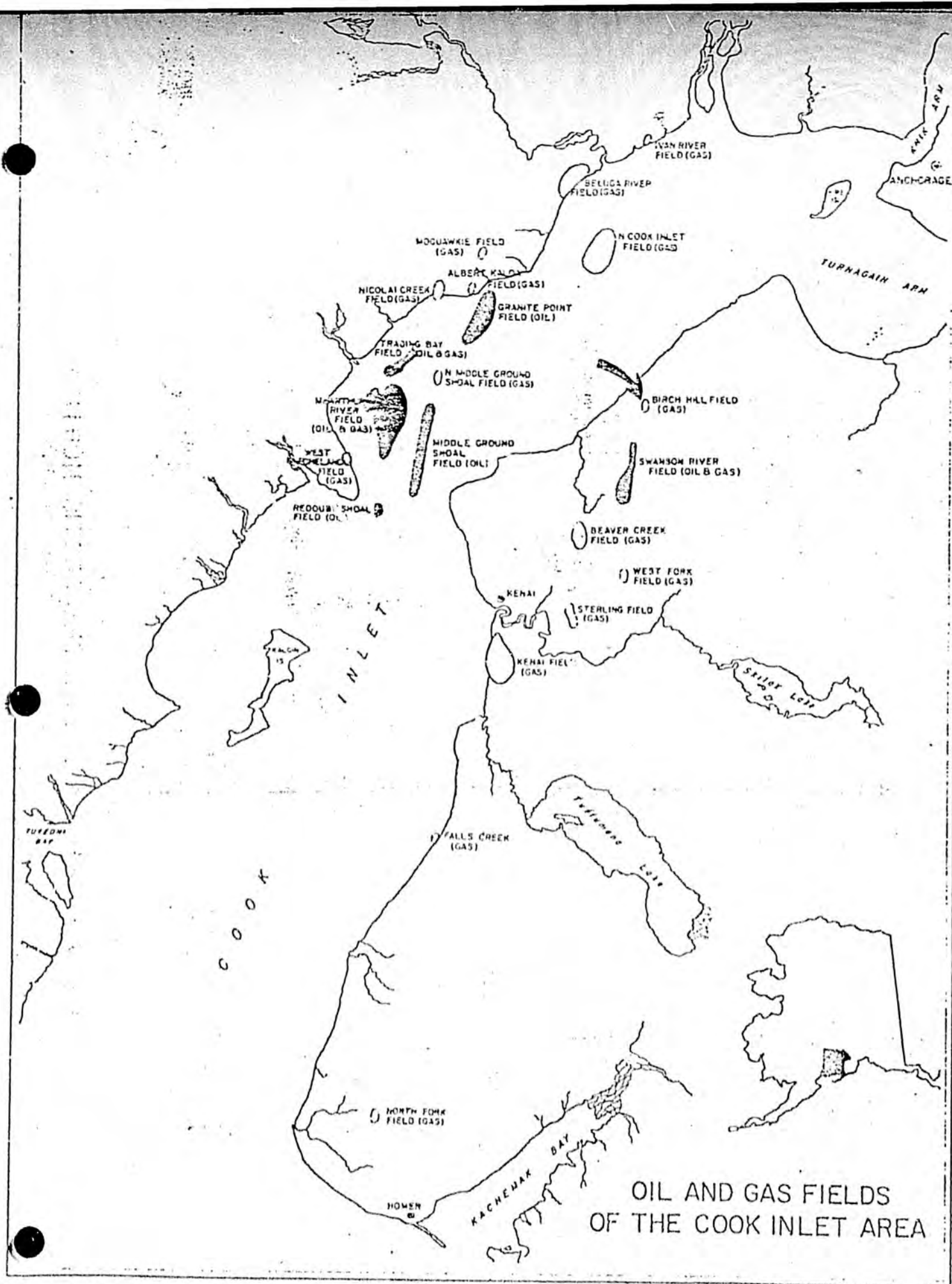
Gas utilization: No production

State royalty interest: 0

General onshore location: Eastside Cook Inlet, see attached map.

Comments:

This semi-remote field is four miles north of Swanson River Oil and Gas Fields. The closest possible pipeline would be the 16" line from Kenai Field which transports rental gas for Swanson River Field reservoir pressure maintenance.



IVAN RIVER GAS FIELD

Operator: Socal

Other participants: Arco

Discovered: 1966

Production started: Field shut-in since discovery

Number of wells (as of 2/75): 1 shut-in well

Current producing rate (2/75): No production

Estimated remaining reserves: 5,000 MMCF

Gas utilization: No production

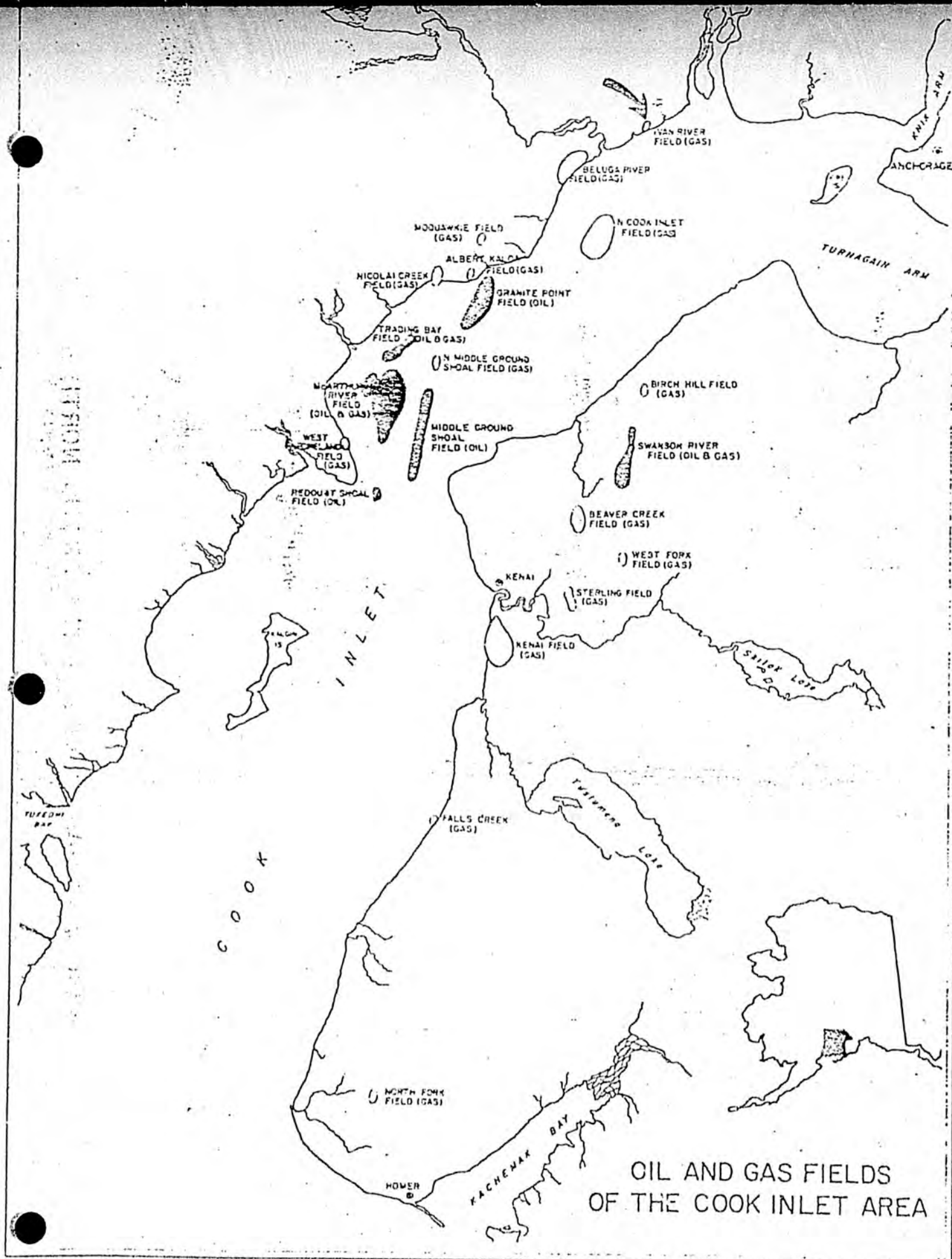
Misc.: One dry hole drilled within a mile

State royalty interest: 12.5%

General onshore location: Westside Cook Inlet, see attached map.

Comments:

This field is located approximately nine miles northeast of Beluga Gas Field which fuels electric generators supplying electricity to Anchorage through a 138 KV transmission line which runs three miles northwest of Ivan River Field. No pipelines are close to this field.



OIL AND GAS FIELDS
OF THE COOK INLET AREA

NORTH FORK GAS FIELD

Operator: Socal

Other participants: Arco, Sun Oil Co.

Discovered: 1965

Production started: Field shut-in since discovery

Number of wells (as of 2/75): 1 shut-in well

Current producing rate (2/75): No production

Estimated remaining reserves: 20,000 MMCF

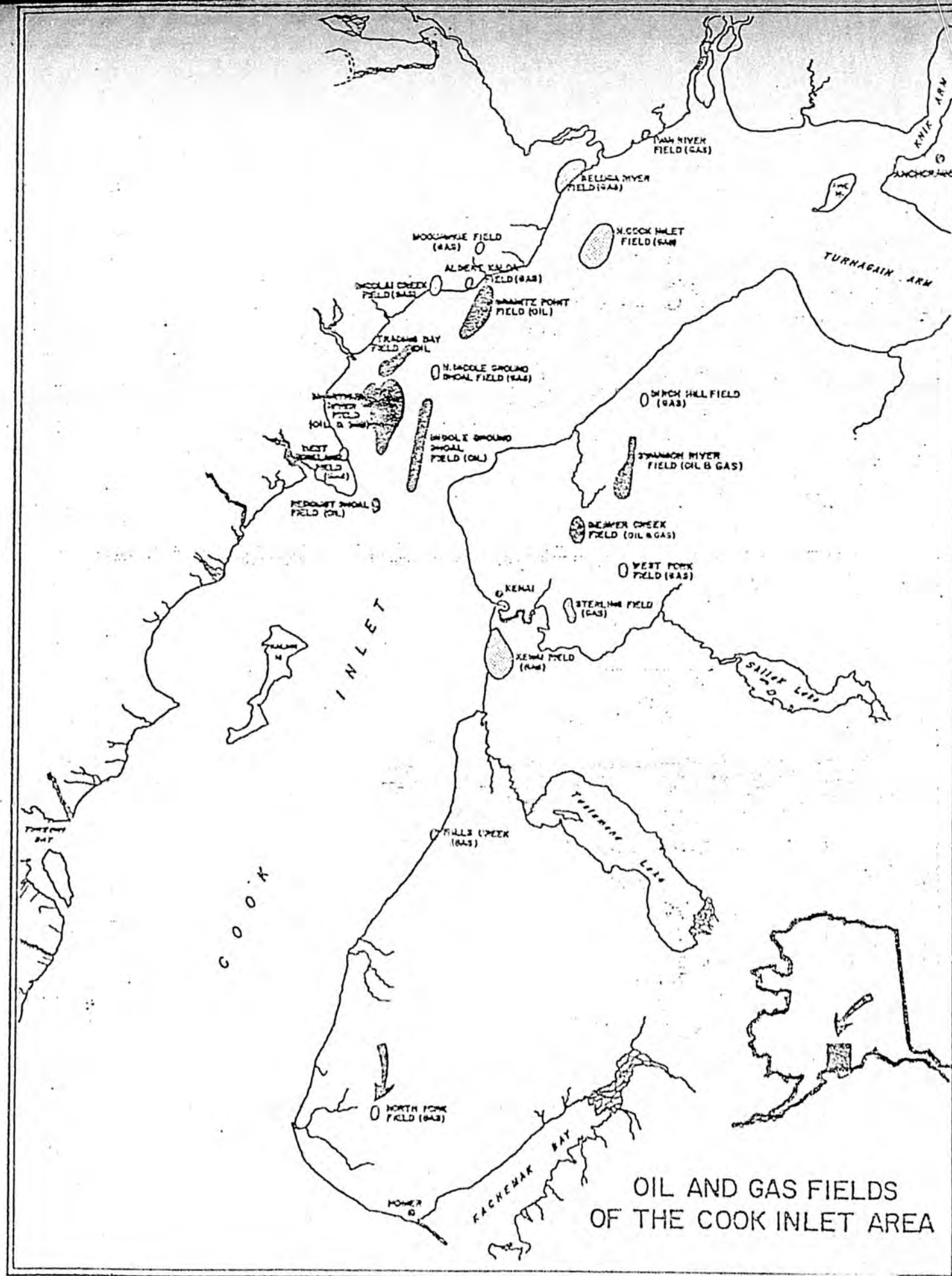
Gas utilization: No production

General onshore location: Eastside Cook Inlet, see attached map.

Comments:

This semi-remote field is not near any existing gas pipelines.

AGO 570719



SWANSON RIVER GAS FIELD

Operator: Socal

Other participants: Arco, Union and Marathon

Discovered: 1957

Production started: 1960

Number of wells (as of 2/75): 6 shut-in wells

Current producing rate (2/75): No production

Estimated remaining reserves: 300,000 MMCF

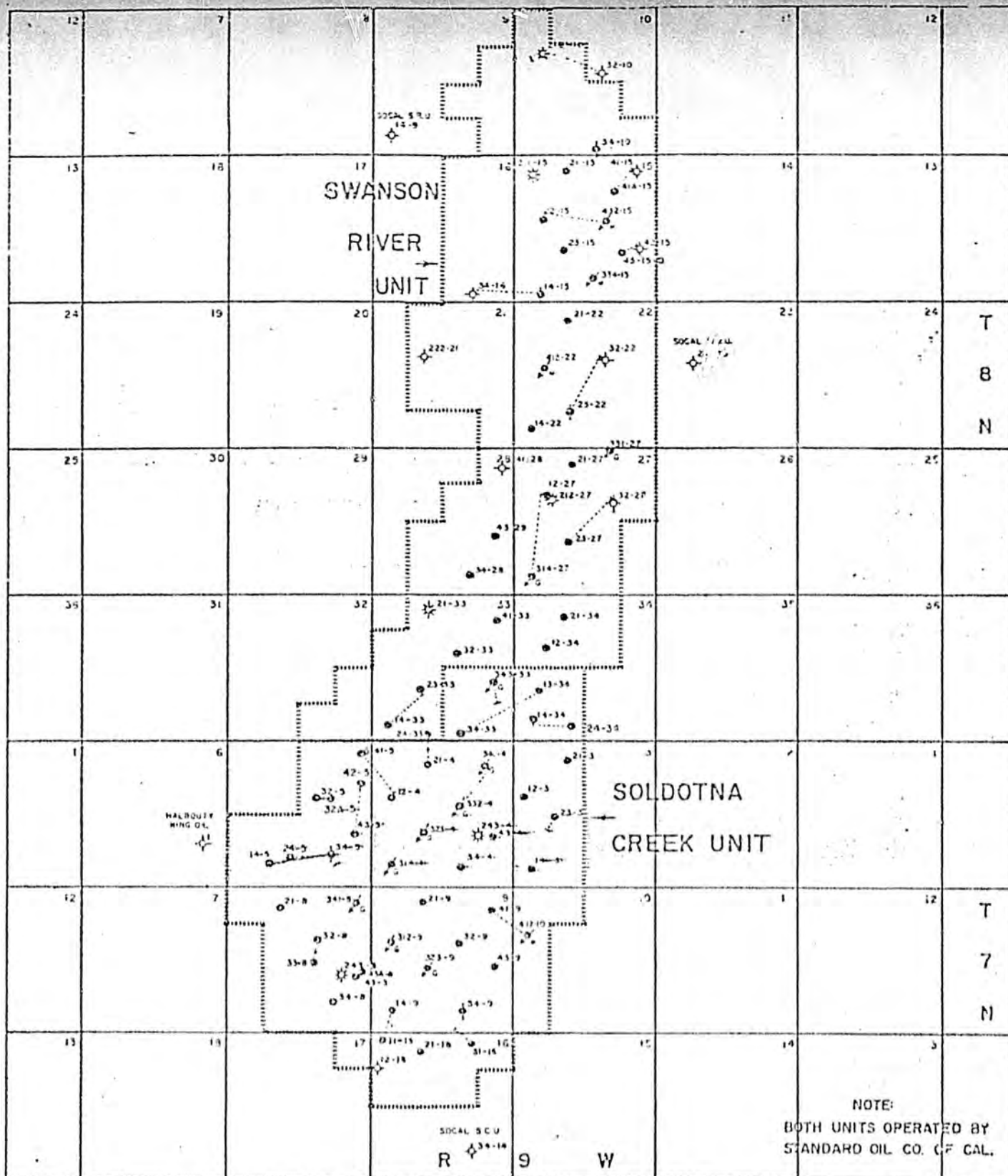
Gas utilization: Produced gas was injected into Swanson River Oil Field until 1967. The field has been shut-in since that time.

State royalty interest: 0

General onshore location: Eastside Cook Inlet, see attached map.

Comments:

This field has no gas pipeline connection but could feed the Kenai Field system through the rental gas pipeline if it became available.



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA
SWANSON RIVER FIELD

AGO 570722

SCALE: 1/2" = 1/2 mi 0 1/2" = 1 mi 1 1/2" = 1 1/2 mi

APRIL 1, 1973

WEST FORELAND GAS FIELD

Operator: Amoco

Other participants: Arco, Phillips and Skelly

Discovered: 1962

Production started: Field shut-in since discovery

Number of wells (as of 2/75): 1 shut-in well

Current producing rate (2/75): No production

Estimated remaining reserves: 120,000 MMCF

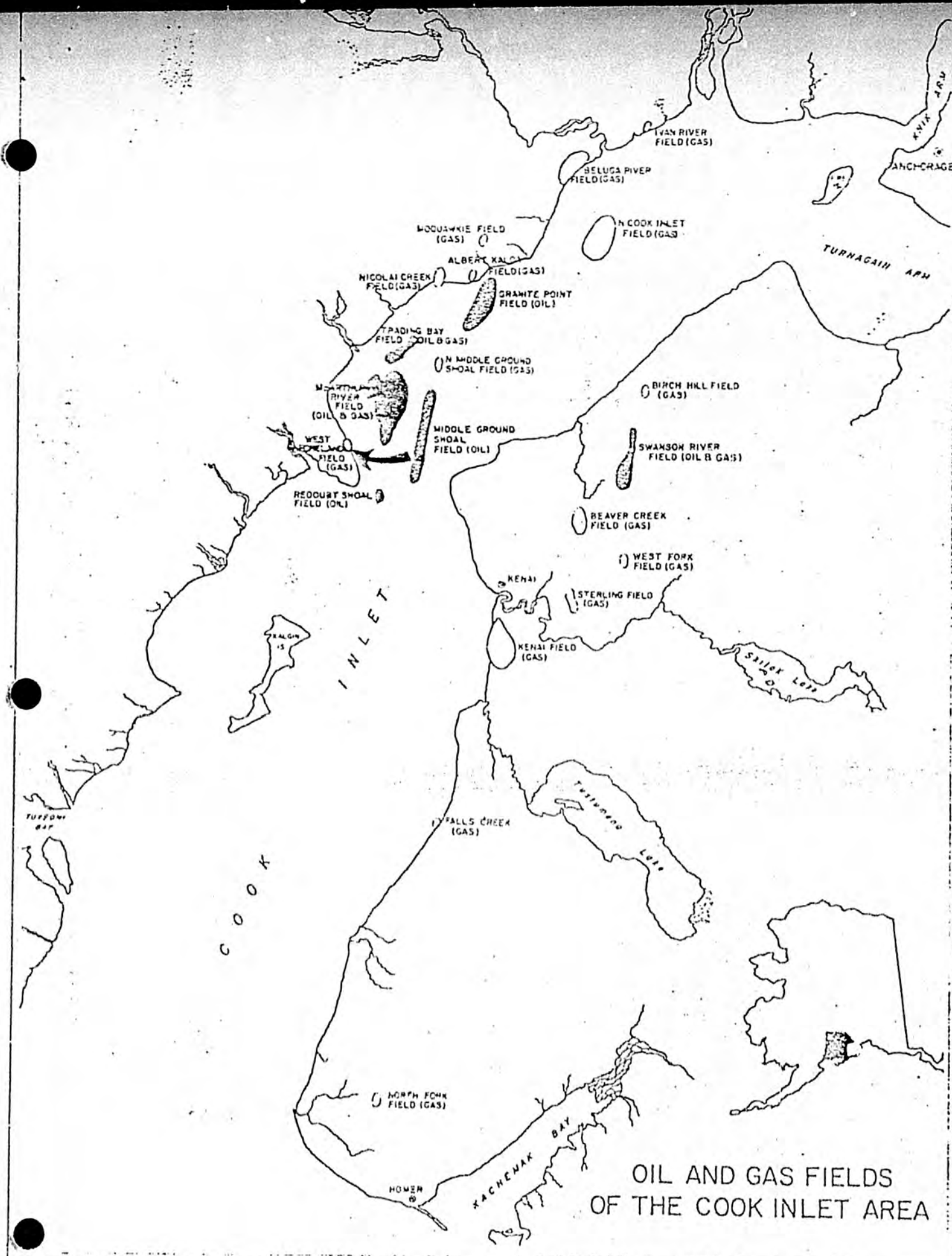
Gas Utilization: No production

State royalty interest: 0

General onshore location: Westside Cook Inlet, see attached map.

Comments:

Gas from this semi-remote field could possibly be connected by pipeline to the existing submarine gas pipeline and moved to Nikiski, eastside Cook Inlet.



WEST FORK GAS FIELD

Operator: Socal

Other participants: Arco, Belco Pet. Co., Pet Corp. of Texas, Halbouty Alaska

Discovered: 1960

Production started: Field shut-in since discovery

Number of wells (as of 2/75): 1 shut-in well

Current producing rate (2/75): No production

Estimated remaining reserves: 100,000 MMCF

Gas utilization: No production

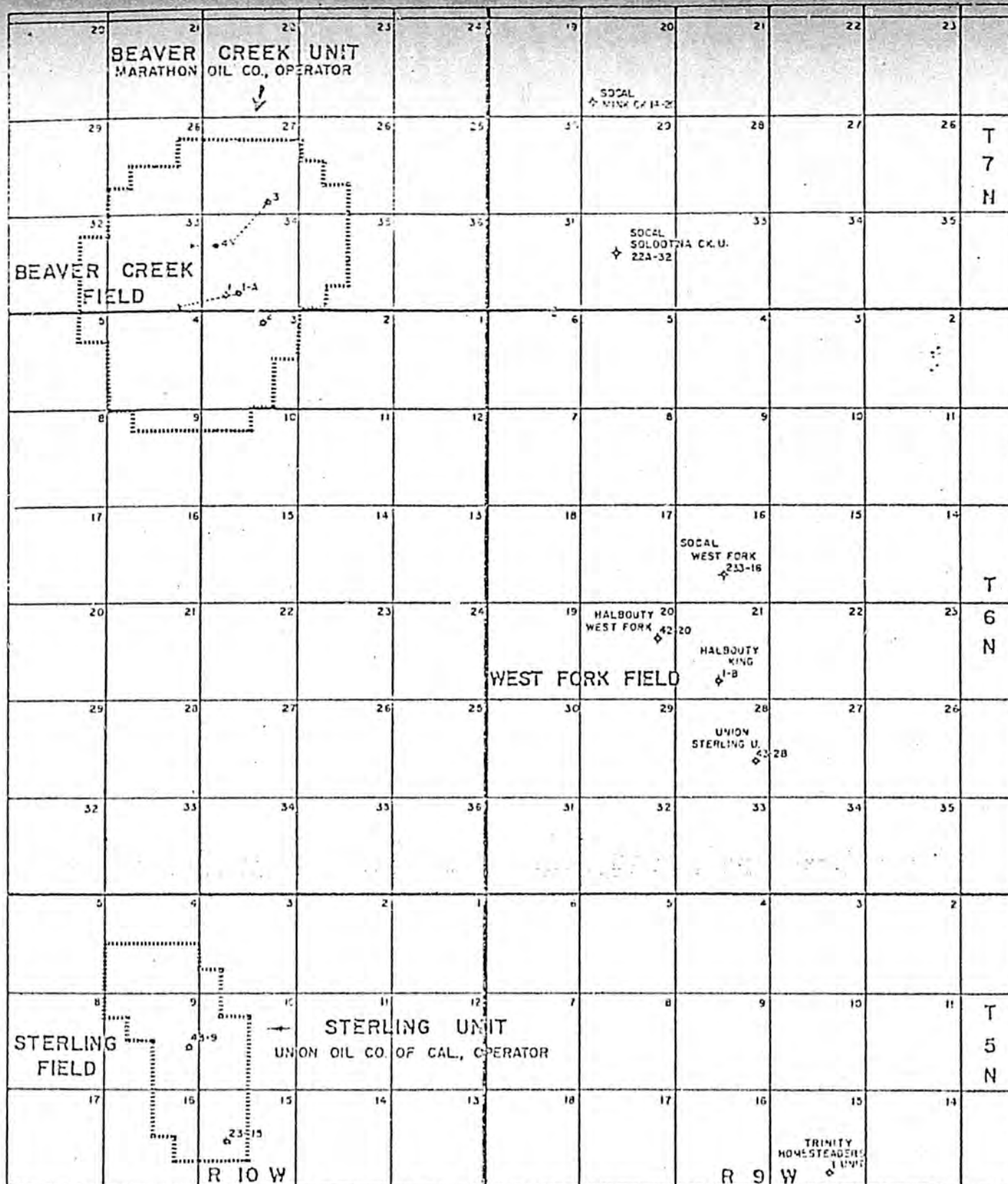
Misc.: This ultimately may be a one well field since three other wells drilled in this vicinity were dry holes.

State royalty interest: 0

General onshore location: Eastside Cook Inlet, see attached map.

Comments:

This semi-remote field is seven miles from the Sterling Gas Field pipeline.



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

BEAVER CREEK, STERLING AND
WEST FORK FIELDS

AGD 570726

SCALE: 4,000' 0 4,000' 8,000' 12,000'

APRIL 1, 1974

PRUDHOE BAY FIELD

Prudhoe Oil Pool

Proposed unit operators: Arco and BP

Other participants: ^{Exxon} Amerada, Getty, Hunt, Louisiana Land & Explor.,
Marathon, Mobil, Phillips, Placid, and Socal.

Discovered: 1967

Production started: 4/69, very small volumes for fuel requirements

Number of wells (as of 3/75): 2 producing, 97 shut-in

Current producing rate (2/75): Gas 225,165 MCF/month, 8042 MCF/day
oil (net) 46,209 bbl/month, 1650 B/D

Estimate of reserves by industry: Oil, approximately 9-1/2 billion bbls
Gas, approximately 26 trillion cu. ft.

Oil and gas utilization: Oil is run through topping plant to make arctic
diesel and naptha. Gas is used to generate
electrical power.

Current wellhead value: Gas, \$.30/MCF, oil \$2.07/BBL.

State royalty interest: 12-1/2%

Comments:

If the oil pipeline is completed on schedule, oil production could start from the Prudhoe Bay Oil Pool in July, 1977. The start of gas sales is more uncertain since the route for the gasline has not been selected yet. The earliest forecasted date for gas sales is 1980.

The following table shows the state royalty volumes of oil and gas from the Prudhoe Bay Oil Pool for a 5 year period on the following assumptions: (1) oil production begins in July, 1977 and will build up to a maximum rate of 1.7 million barrels per day at the end of the second year. (2) gas sales will begin in July, 1980 and will build up to a maximum rate of 2.6 billion cu. ft. per day in the second year.

Fiscal Year	<u>78</u>	<u>79</u>	<u>80</u>	<u>81</u>	<u>82</u>
Total oil production (million bbls.)	315	584	621	621	621
Total oil production (million barrels per day)	0.9	1.6	1.7	1.7	1.7
State royalty share (million bbls.)	39	73	78	78	78
State royalty share (million bbls. per day)	0.1	0.2	0.2	0.2	0.2
Total gas sales (billion cu.ft.)				708	967
Total gas sales (billion cu.ft. per day)				1.9	2.6
State's royalty share (billion cu.ft.)				88	121
State's royalty share (billion cu.ft. per day)				0.2	0.3

Lisburne Pool

The area and productivity of this pool have not been defined. Well information released to date has not been very encouraging. Arco recently tested their East Bay St. well in the Lisburne and reported a total rate from all intervals tested of only 1350 barrels of oil per day. Since this is a deep pool, approximately 11,000'; higher rates would probably be needed to be commercial. Further drilling will be required to determine if this pool has any significant reserves.

Kuparuk River Pool

Drilling on the west end of the Prudhoe Bay Field has indicated that the areal extent of the Kuparuk River Pool is larger than originally anticipated. Arco reported a test rate of 1030 barrels of oil per day from its West Sax #2 well. Since this is not a deep pool, approximately 6500', well rates as reported could be commercial. Additional drilling will be required to better define the area and productivity, indications are that this pool may have significant oil reserves.

OTHER NORTH SLOPE FIELDS

Oil

The Ugnu field and the Simpson Lagoon fields have 2 shut-in wells and one shut-in well respectively. These wells tested oil in the Kuparuk River sands. These fields could be just extensions of the Kuparuk River Pool of the Prudhoe Bay Field.

Gas

There are three small gas fields on the north slope, East Umiat with 2 shut-in wells, Kavik with 2 shut-in wells and Kemik with 1 shut-in well. The East Umiat and Kemik fields are on federal leases. The Kavik field is a unit on state leases. The unit size has been reduced and plans are to drill two additional wells for a total of four. This would complete the development of this small field.

Comments:

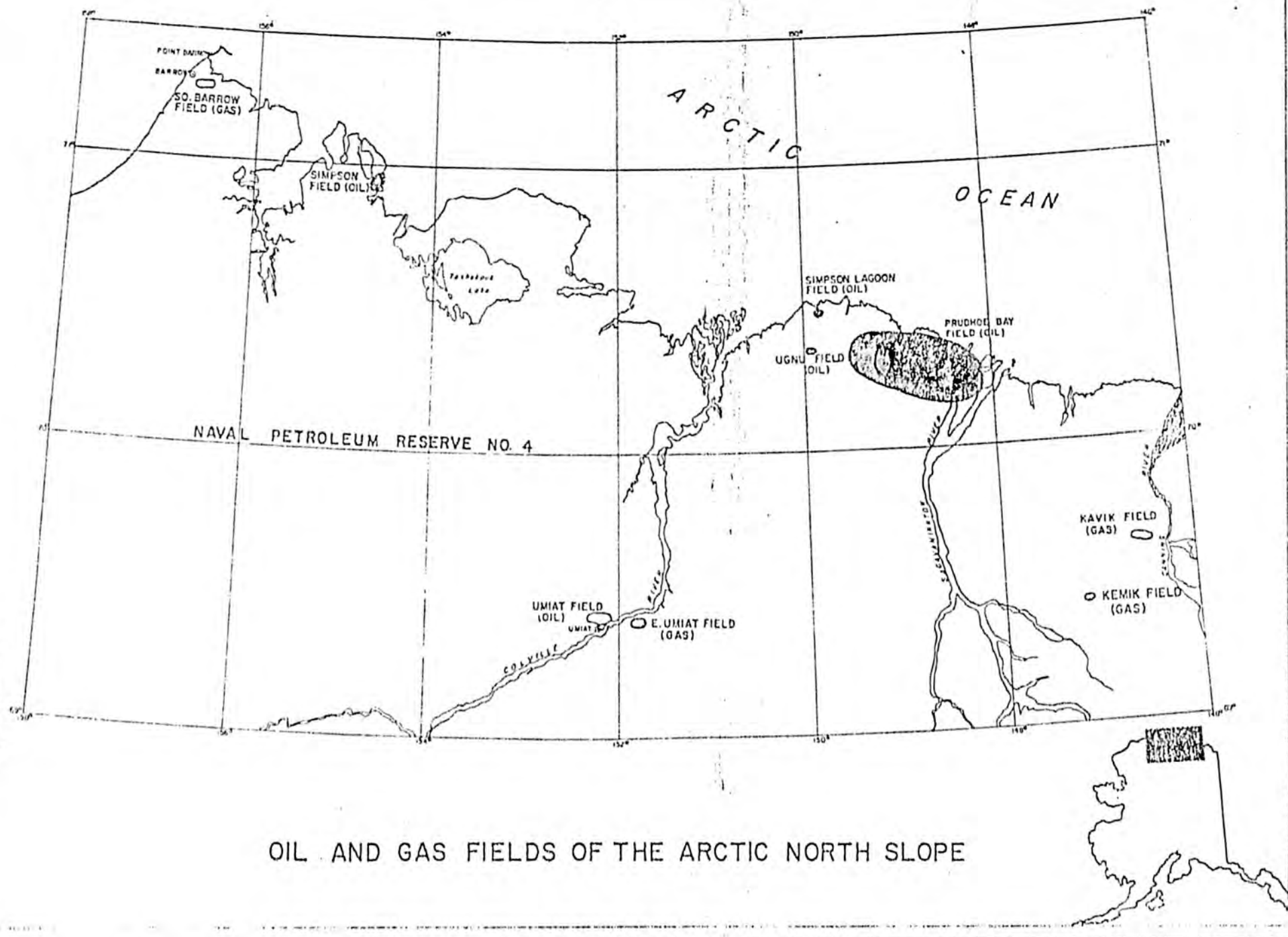
The oil and gas fields mentioned above as well as the Kuparuk River Pool and Lisburne Pool in the Prudhoe Bay field have not been adequately defined and tested to determine their potential. The following forecast is actually the additional production, besides that predicted for the Prudhoe Bay Oil Pool, that is needed to fill the oil and gas pipelines. It assumes that this production will come from the miscellaneous fields and pool described or from new discoveries.

Fiscal Year	<u>78</u>	<u>79</u>	<u>80</u>	<u>81</u>	<u>82</u>
Total oil production (million bbls.)			18	55	146
Total oil production (million bbls. per day)			.05	.15	.25
State royalty share (million bbls.)			2	7	18
State royalty share (million bbls. per day)			.006	.02	.03
Total gas sales (billion cu.ft.)				22	36
Total gas sales (billion cu.ft. per day)				.06	.10
State royalty share (billion cu.ft.)				3	5
State royalty share (billion cu.ft. per day)				.008	.012

TOTAL PRUDHOE BAY FIELD & OTHER NORTH SLOPE FIELDS

Fiscal Year	<u>78</u>	<u>79</u>	<u>80</u>	<u>81</u>	<u>82</u>
Total oil production (million bbls.)	315	584	639	675	712
Total oil production (million bbls. per day)	0.9	1.6	1.75	1.85	1.95
State royalty share (million bbls.)	39	73	80	84	89
State royalty share (million bbls. per day)	0.11	0.20	0.22	0.23	0.24
Total gas sales (billion cu.ft.)				730	1004
Total gas sales (billion cu.ft. per day)				2.0	2.75
State royalty share (billion cu.ft.)				91	126
State royalty share (billion cu.ft. per day)				0.25	0.34

AGD 570730



OIL AND GAS FIELDS OF THE ARCTIC NORTH SLOPE

SCOMM

#16:6

PIPELINE AND LNG TRANSPORTATION SYSTEMS
FOR
COOK INLET GAS

Pacific Gas and Electric Co
Southern California Gas Co
February 14, 1978

AGO 544928 +

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I. SUMMARY

The recent selection of the Alcan Highway Route for transportation of Alaskan North Slope gas has raised questions concerning the feasibility of moving Cook Inlet gas to the lower 48 states via pipeline across Central Alaska to the Alcan system. From this connection, Cook Inlet gas would flow south to Kingsgate, B.C. where connection would be made to the Pacific Gas Transmission Company (P.G.T.) portion of the Western Leg for transport to Malin, Oregon and then through Pacific Gas and Electric Company's system to Antioch, California. Several routes from the Cook Inlet area to a point of connection with this system were investigated in September, 1977, and cost estimates were prepared. A pipeline from Cook Inlet to Tok, on the Alcan Route, proved to be the most promising alternative.

On October 28, 1977, the FERC requested Pacific Alaska LNG Associates to provide a supplement to the "Alternatives to the Proposed Action" section of their environmental report. Specifically, FERC asked for information on possible pipeline route alternatives from Cook Inlet to the proposed Alcan Highway pipeline at Tok or Fairbanks.

This report summarizes estimated capital costs of these two alternatives and includes construction schedules and cost of service projections. All estimates are based on a 24" main line with an initial capacity of 431.4 million cubic feet per day. This volume is identical to that of the Pacific Alaska

filing. All costs are in July, 1977 dollars.

Energy balances for both alternatives have been estimated and are compared with the energy balance for the Pac Alaska LNG project. The following are the points of comparison:

	<u>Pac Alaska</u>	<u>Pipeline via Tok</u>	<u>Pipeline via Fairbanks</u>
Efficiency (%)	88.1	82.1	81.3
Capital (\$ MM)	1269	1154	1233
Cost of Delivered Gas (\$/MMBtu)			
Incremental:			
1st Year	3.63	4.03	4.29
Level Annual	3.42	3.45	3.66
Average:			
1st Year	4.06	4.64	5.06
Level Annual	3.72	3.85	4.16

II. DESCRIPTION OF ALTERNATES

Two cases are considered in this study (See Map - Exhibit A). Common to both are the Cook Inlet gathering systems, compressor stations at Beluga and Soldotna, 20" transmission lines from these stations to Palmer, and the Palmer compression station. From Palmer, Case I transports the gas in a 24" main line along Highway No.1 to a compressor station at Glennallen and then to Tok with a fifth station at Tok for delivery to the Alcan system. Case II provides for a 24" main line from Palmer generally following Highway No.3 with compressor stations at Curry, Lignite, and Fairbanks where connection to the Alcan line would be made.

Several assumptions have been necessary which undoubtedly will be changed by actual gas discoveries. These changes should have little effect on the capital cost and cost of service figures, however. For this initial study, the 431.4 million cubic feet per day capacity of the Pacific Alaska LNG project has been used as the basis for line and compressor sizing and cost of service calculations. Pacific Alaska's layout and cost estimates for gathering systems on both sides of Cook Inlet were also used with the exception that this pipeline plan provides for laterals on each side of the Inlet and eliminates the need for the 23-mile long underwater crossing required by the LNG project. Lacking firm data on location and deliverability of actual gas sources, it was further assumed that the two laterals would carry equal volumes of gas and that final design

changes in pipeline sizes and compression requirements would balance out in the final cost estimate.

Flow calculations for the two cases are detailed in Exhibits E-1 and E-2.

III. ENERGY BALANCES

Gas balances have been estimated for both pipeline alternatives as well as for the LNG project. Fuel usage from Cook Inlet to the points of delivery, Gosford, California for Pac Alaska and Antioch, California for the pipeline alternatives have been calculated and are detailed in Exhibits B-1, B-2, and B-3. The overall efficiency of the LNG project is about 6-7% higher than the pipeline alternatives' incremental efficiencies presented in the Exhibits. The pipeline alternatives' efficiencies are based on the incremental fuel necessary to transport the Cook Inlet gas when it is transported on top of Prudhoe Bay and Mackenzie Delta Gas.

IV. CAPITAL COSTS

Capital cost figures have been developed for Cook Inlet to Alcan and Western Leg segments of the proposed system using, wherever possible, firm quotations from suppliers and contractors. In this phase of the study, however, it has been necessary to make assumptions on construction methods and unit costs on some portions of the work. Where this has been done, the effort has been made to estimate costs on the conservative side. For example, total costs include refrigeration of the gas to 30°F and insulation of the entire pipeline. In final design, it may well be that this will prove redundant. Bases for the major cost items are:

Construction - Hood Corporation was retained to inspect and determine the feasibility of the proposed routes, and to prepare installation estimates and construction schedules. Exhibit F is a statement of their assessment of the project.

Pipeline Materials - Price quotations were obtained by Southern California Gas Company's purchasing department from domestic suppliers for pipe, valves, and insulation. All pipe was quoted as double-jointed and wrapped, F.O.B., Seattle. Transportation to the job sites is included in the Hood estimate. Ten mile spacing of main line valves was used with three main valves at compressor stations and valves at both sides of the Turnagain Arm underwater crossing.

Gathering Systems - Costs developed by Pacific Alaska LNG Associates (Docket No. CP75-140, et al, Exhibit No. _____ MEF-12) were amended to eliminate the 23-mile Cook Inlet crossing. Pipeline systems on both sides of the inlet were retained with connection assumed to be made at compressor stations located at Beluga and Soldotna.

Capital cost estimates are itemized in Exhibits C-1 through C-5.

V. COST OF SERVICE

Cost of service figures have been developed for delivery of Cook Inlet gas to California using the following data:

- Cook Inlet to Alcan: Southern California Gas Company capital cost estimates, Exhibits C-1 and C-2.
- Alcan System:
to Kingsgate, B.C. Southern California Gas Company estimates based on Alcan Pipeline Company, March, 1977 FPC filing. Average cost of service for Prudhoe gas was used prorated on a mileage basis. Incremental cost of service for Prudhoe plus Cook Inlet gas based on PGandE estimates.
- P.G.T. System: P.G.T. estimates for 592 miles of
Kingsgate-Malin, 42" - 911 psig pipeline looping
Ore. with 4-14100 HP compression units. Incremental cost for Prudhoe plus Cook Inlet gas.
- PG&E System: PG&E estimate for 281.6 miles of
Malin-Antioch, CA. 42" - 911 psig pipeline looping with
2-14100 HP compression units. Incremental cost for Prudhoe plus Cook Inlet gas.

Other assumptions used in the calculations were:

	<u>Debt/Equity</u>	<u>Return on Equity</u>	<u>Debt Interest</u>
Pac Alaska	75/25	16%	10%
Cook Inlet to Alcan Pipelines	75/25	16%	10%
P.G.T.-Kingsgate to Malin	75/25	16%	10%
PGandE-Malin to Antioch	75/25	16%	10%

Cost of Services Estimates for both the first year of full delivery and on a level annual cost basis over the project life are tabulated in Exhibits D-1 through D-6.

VI. CONSTRUCTION

Project completion date is assumed to be first quarter 1983 to agree with estimated completion of the Alcan System. Actual construction time for either the Tok or Fairbanks alternate is estimated to be 18 months. Soil conditions are expected to limit construction of the gathering systems and Beluga and Soldotna laterals to the winter months. Work on the main lines from Palmer to Alcan is expected to be possible year-round. Thus, construction would start in the fall of 1981, and be completed in spring 1983 with two winter construction periods available for the Cook Inlet work. Hood Corporation has estimated that the work would be organized in the following manner:

	<u>Miles</u>	<u>Crew Size</u>	<u># of Spreads</u>	<u>Pipeline Inst. Time</u>	<u>Project Duration</u>
<u>East Side Cook Inlet</u>					
Soldotna-Turnagain Arm	60	190	1	5 mo.	7 mo.
Turnagain Arm Crossing	5	160	1	2 mo.	4 mo.
Turnagain Arm-Palmer	43	190	1	4 mo.	6 mo.
<u>West Side Cook Inlet</u>					
Beluga-Palmer	84	260	2	4 mo.	6 mo.
<u>Main Line</u>					
Palmer-Tok	267	750	3	6 mo.	8 mo.
or					
Palmer-Fairbanks	314	750	3	7 mo.	9 mo.
<u>Gathering Systems</u>					
Indefinite but based on previous estimates of laterals extending to Anchor Point and Drift River on the order of:					
East Side Cook Inlet	--	190	1	5 mo.	7 mo.
West Side Cook Inlet	--	260	1	7 mo.	9 mo.

Other conditions considered in the study are 100% x-ray of all welds and the use of existing power line and/or highway rights-of-way.

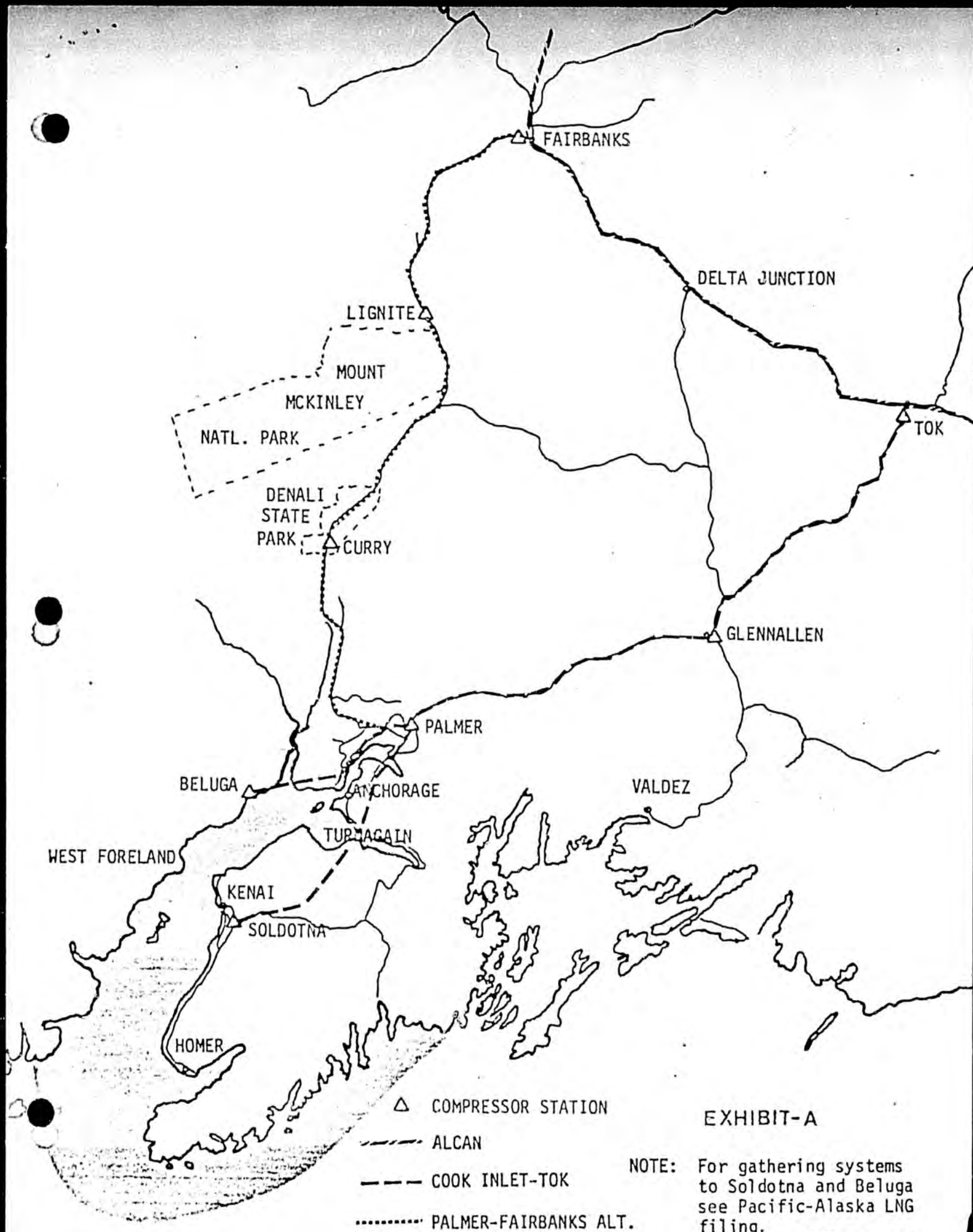


EXHIBIT-A

NOTE: For gathering systems to Soldotna and Beluga see Pacific-Alaska LNG filing.

PAC ALASKA

GAS BALANCE
(Millions of cubic feet per day) ⁽¹⁾

Cook Inlet Input		442.8
<u>Fuel</u>		
LNG Plant	39.3	
LNG Shipping ⁽²⁾	3.3	
LNG Terminal	<u>0.2</u>	
Total Fuel	42.8	
Delivery to Gosford		400
Pac Alaska Efficiency ⁽²⁾		90.3%

(1) All gas volumes adjusted to 1014 Btu/cf heating value.

(2) If Bunker "c" fuel oil consumption of 10.1 mmcf/d gas equivalent is included, efficiency is reduced to 88.1%.

Exhibit B-1

PIPELINE ALTERNATIVE VIA TOK

GAS BALANCE

(Million cubic feet per day) ⁽¹⁾

Cook Inlet Input		431.4
<u>Fuel</u> ⁽²⁾		
Cook Inlet to Tok	9.0	
Tok to Caroline	50.7	
Caroline to Kingsgate	2.5	
Kingsgate to Malin	10.8	
Malin to Antioch	<u>4.2</u>	
Total Fuel	77.2	
Delivery to Antioch		354.2
Pipeline Efficiency		82.1%

(1) All gas volumes adjusted to 1014 Btu/cf heating value.

(2) Incremental fuel to transport Cook Inlet gas in addition to Prudhoe (2.4 Bcf/d) and Delta (1.2 Bcf/d) gas.

PIPELINE ALTERNATIVE VIA FAIRBANKS

GAS BALANCE

(million cubic feet per day) ⁽¹⁾

Cook Inlet Input		431.4
<u>Fuel</u> ⁽²⁾		
Cook Inlet to Fairbanks	8.9	
Fairbanks to Tok	3.4	
Tok to Caroline	50.7	
Caroline to Kingsgate	2.5	
Kingsgate to Malin	10.8	
Malin to Antioch	<u>4.2</u>	
Total Fuel	80.5	
Delivery to Antioch		350.9
Pipeline Efficiency		81.3%

(1) All gas volumes adjusted to 1014 Btu/cf heating value.

(2) Incremental fuel to transport Cook Inlet gas in addition to Prudhoe (2.4 Bcf/d) and Delta (1.2 Bcf/d) gas.

COOK INLET TO TOK PIPELINE

CAPITAL COST ESTIMATE - 1977 \$
(Thousands of Dollars)

	<u>Materials</u>	<u>Construction</u>	<u>Total</u>
Pipeline	\$ 79,690	\$247,494	\$327,184
Valves, Fittings, Misc.	8,679	4,575	13,254
Insulation	39,816	19,340	59,156
Compression	28,000	12,750	40,750
Refrigeration	12,280	5,590	17,870
Anchors	820	1,640	2,460
Controls	6,515	13,030	19,545
X-Ray	--	8,845	8,845
	\$175,800	\$313,264	\$489,064
Sales Taxes	10,080	--	10,080
Total Pipeline Direct	<u>\$185,880</u>	<u>\$313,264</u>	<u>\$499,144</u>
		Right-of-Way	\$ 11,641
		R/W Restoration	9,300
		E.I.R	2,815
		Engineering	26,310
		Contingency	71,497
		Working Capital	588
		AFUDC	64,073
		Financing Fee	2,522
		Materials & Supplies	6,210
		Total Project	<u>\$694,100</u>

Exhibit C-1

AGO 544944

COOK INLET TO FAIRBANKS PIPELINE

CAPITAL COST ESTIMATE - 1977 \$

(Thousands of Dollars)

	<u>Materials</u>	<u>Construction</u>	<u>Total</u>
Pipeline	\$ 86,130	\$267,474	\$353,604
Valves, Fittings, Misc.	8,914	4,581	13,495
Insulation	44,331	21,274	65,605
Compression	28,000	12,750	40,750
Refrigeration	12,280	5,590	17,870
Anchors	820	1,640	2,460
Controls	6,515	14,350	20,865
X-Ray	--	9,832	9,832
	\$186,990	\$337,491	\$524,481
Sales Taxes	10,751	--	10,751
Total Pipeline Direct	<u>\$197,741</u>	<u>\$337,491</u>	<u>\$535,232</u>
		Right-of-Way	\$ 12,192
		R/W Restoration	10,220
		E.I.R.	3,061
		Engineering	28,115
		Contingency	76,910
		Working Capital	588
		AFUDC	68,721
		Financing Fee	2,704
		Materials & Supplies	6,657
		Total Project	<u>\$744,400</u>

Exhibit C-2

AGD 544945

PAC ALASKA LNG

CAPITAL INVESTMENT SUMMARY - 1977\$
(Millions of Dollars)

Pac Alaska LNG	<u>Phase I</u>	<u>Phase II</u>	<u>Total</u>
Gas Gathering	168	32	200
Liquefaction Plant	496	154	650
Ships	197	197	394
Terminal	<u>25</u>	<u>-</u>	<u>25</u>
Total	886	383	1269

PIPELINE ALTERNATIVE VIA TOK
CAPITAL INVESTMENT SUMMARY - 1977 \$
(MILLIONS OF DOLLARS)

	<u>Base⁽¹⁾ Design</u>	<u>Base Plus Cook</u>	<u>Cook Incremental</u>
Cook to Tok	0	694	694
Tok to Kingsgate	-	-	150
Kingsgate to Malin	367	590	223
Malin to Antioch	<u>205</u>	<u>292</u>	<u>87</u>
TOTAL ⁽²⁾	-	-	1154

- (1) Base Design is for a system to transport Prudhoe plus Mackenzie Delta Gas.
- (2) Modifications to existing natural gas system will be needed south of Antioch. Such modifications may add as much as an additional \$126 million (1977 \$) investment to the Cook Incremental.

PIPELINE ALTERNATIVE VIA FAIRBANKS

CAPITAL INVESTMENT SUMMARY - 1977 \$

(MILLIONS OF DOLLARS)

	<u>Base⁽¹⁾ Design</u>	<u>Base Plus Cook</u>	<u>Cook Incremental</u>
Cook to Fairbanks	0	744	744
Fairbanks to Kingsgate	-	-	179
Kingsgate to Malin	367	590	223
Malin to Antioch	<u>205</u>	<u>292</u>	<u>87</u>
TOTAL ⁽²⁾	-	-	1233

- (1) Base Design is for a system to transport Prudhoe plus Mackenzie Delta Gas.
- (2) Modifications to existing natural gas system will be needed south of Antioch. Such modifications may add as much as an additional \$126 million (1977 \$) investment to the Cook Incremental.

PAC ALASKA

INCREMENTAL COST OF GAS SUMMARY

(1977 \$/MMBTU)

Pac Alaska	1982 Phase I	1983 Phase I & II	Level Annual
Purchased Natural Gas	1.64	1.64	1.64
Gathering & Liquefaction Plant	2.25	1.29	1.18
Shipping	.61	.62	.52
Terminal (Incremental)	<u>.16</u>	<u>.08</u>	<u>.08</u>
Delivered Price of Gas (Incremental)	4.66	3.63	3.42
Price of Pac Indonesia at Incremental Cost	4.72	3.74	3.45

PAC ALASKA

COST OF GAS SUMMARY SUBSTITUTING AVERAGE TERMINAL
AND TERMINAL PIPELINE COSTS

(1977 \$/MMBTU)

	1982 Phase <u>I</u>	1983 Phase <u>I & II</u>	<u>Level Annual</u>
Pac Alaska			
Purchased Natural Gas (Incremental)	1.64	1.64	1.64
Gathering & Liquefaction Plant (Incremental)	2.25	1.29	1.18
Shipping (Incremental)	.61	.62	.52
Terminal (Average)	.93	.46	.34
Terminal Pipeline (Average)	<u>.08</u>	<u>.05</u>	<u>.04</u>
Delivered Price of Gas at Average Cost of California Facilities	5.51	4.06	3.72
Price of Pac Indonesia at Average Terminal Cost	4.04	3.36	3.25

PIPELINE ALTERNATIVE VIA TOK
INCREMENTAL COST OF GAS SUMMARY

(1977 \$/MMBTU)

	<u>1983</u>	<u>Level Annual</u>
Purchase of Natural Gas	1.80	1.80
Pipeline Segments		
Cook to Tok	1.28	.92
Tok to Kingsgate	.41	.33
Kingsgate to Malin	.39	.29
Malin to Antioch	<u>.15</u>	<u>.11</u>
TOTAL DELIVERED TO ANTIOCH ⁽¹⁾	4.03	3.45

- (1) Modification to existing natural gas system will be needed south of Antioch. Such modification may add as much as an additional 20¢ to 30¢ per million Btu (1977 \$).

PIPELINE ALTERNATIVE VIA TOK

COST OF GAS SUMMARY
SUBSTITUTING AVERAGE COST FOR
INCREMENTAL COST FOR TOK TO KINGSGATE

(1977 \$/MMBTU)

	<u>1983</u>	<u>Level Annual</u>
Purchase of Natural Gas	1.80	1.80
Pipeline Segments		
Cook to Tok	1.28	.92
Tok to Kingsgate ⁽¹⁾	1.02	.73
Kingsgate to Malin	.39	.29
Malin to Antioch	<u>.15</u>	<u>.11</u>
TOTAL DELIVERED TO ANTIOCH ⁽²⁾	4.64	3.85

- (1) Based on Alcan Pipeline Company, March, 1977 FPC filing. Redesign of Alcan system may reduce this average cost slightly.
- (2) Modification to existing natural gas system will be needed south of Antioch. Such modification may add as much as an additional 20¢ to 30¢ per million Btu (1977 \$).

PIPELINE ALTERNATIVE VIA FAIRBANKS

INCREMENTAL COST OF GAS SUMMARY

(1977 \$/MMBTU)

	<u>1983</u>	<u>Level Annual</u>
Purchase of Natural Gas	1.84	1.84
Pipeline Segments		
Cook to Fairbanks	1.41	1.01
Fairbanks to Kingsgate	.48	.39
Kingsgate to Malin	.40	.30
Malin to Antioch	<u>.16</u>	<u>.12</u>
TOTAL DELIVERED TO ANTIOCH ⁽¹⁾	4.29	3.66

- (1) Modification to existing natural gas system will be needed south of Antioch. Such modification may add as much as an additional 20¢ to 30¢ per million Btu (1977 \$).

PIPELINE ALTERNATIVE VIA FAIRBANKS

COST OF GAS SUMMARY
SUBSTITUTING AVERAGE COST FOR
INCREMENTAL COST FOR FAIRBANKS TO KINGSGATE
(1977 \$/MMBTU)

	<u>1983</u>	<u>Level Annual</u>
Purchase of Natural Gas	1.84	1.84
Pipeline Segments		
Cook to Fairbanks	1.41	1.01
Fairbanks to Kingsgate ⁽¹⁾	1.25	.89
Kingsgate to Malin	.40	.30
Malin to Antioch	<u>.16</u>	<u>.12</u>
TOTAL DELIVERED TO ANTIOCH ⁽²⁾	5.06	4.16

- (1) Based on Alcan Pipeline Company, March, 1977 FPC filing. Redesign of Alcan system may reduce this average cost slightly.
- (2) Modification to existing natural gas system will be needed south of Antioch. Such modification may add as much as an additional 20¢ to 30¢ per million Btu (1977 \$).

ASSUMPTIONS USED IN COST OF SERVICE
AND
CAPITAL COST COMPARISONS

Cook Inlet to Tok
Cook Inlet to Fairbanks

1. Construction costs, fuel usage, operating and maintenance estimated by Southern California Gas Company. AFUDC cost computed.
2. 75% debt at 10% interest and 25% equity at 16% return.
3. 20-year project life.
4. 2% property tax rate.
5. 52.89% composite federal and state income taxes.
6. Fuel included in cost of purchased gas.
7. Annual Btu volume based on delivered volume as shown in energy balance.
8. Used normalized method to compute cost of service.

Tok to Kingsgate
Fairbanks to Kingsgate

1. Based on cost of service figures from Exhibit 7-1, page 1 of 2 of Alcan's filing of March 1977 for 48" alternative.
2. Used 10% of Alcan's Alaskan cost of service for Tok alternate since distance from Tok to Yukon is approximately 75 miles or 10% of a total of 731 miles from Prudhoe to Yukon. Used 38% for Fairbanks costs since distance from Fairbanks is approximately 280 miles or 38% of a total distance of 731 miles.
3. Used 100% of the remaining cost of service figures excluding PGT and PG&E.
4. Increased cost of service figures by 30% for probable cost overruns per President Carter's Message to Congress.
5. Inflated cost of service derived above by an additional 8% compounded annually to obtain 1977 \$ from 1975 \$.
6. Fuel cost left at \$1.00/MMBTU per the Alcan Pipeline Company filing of March 1977 for 48" alternative.

(Continued)

Kingsgate to Malin

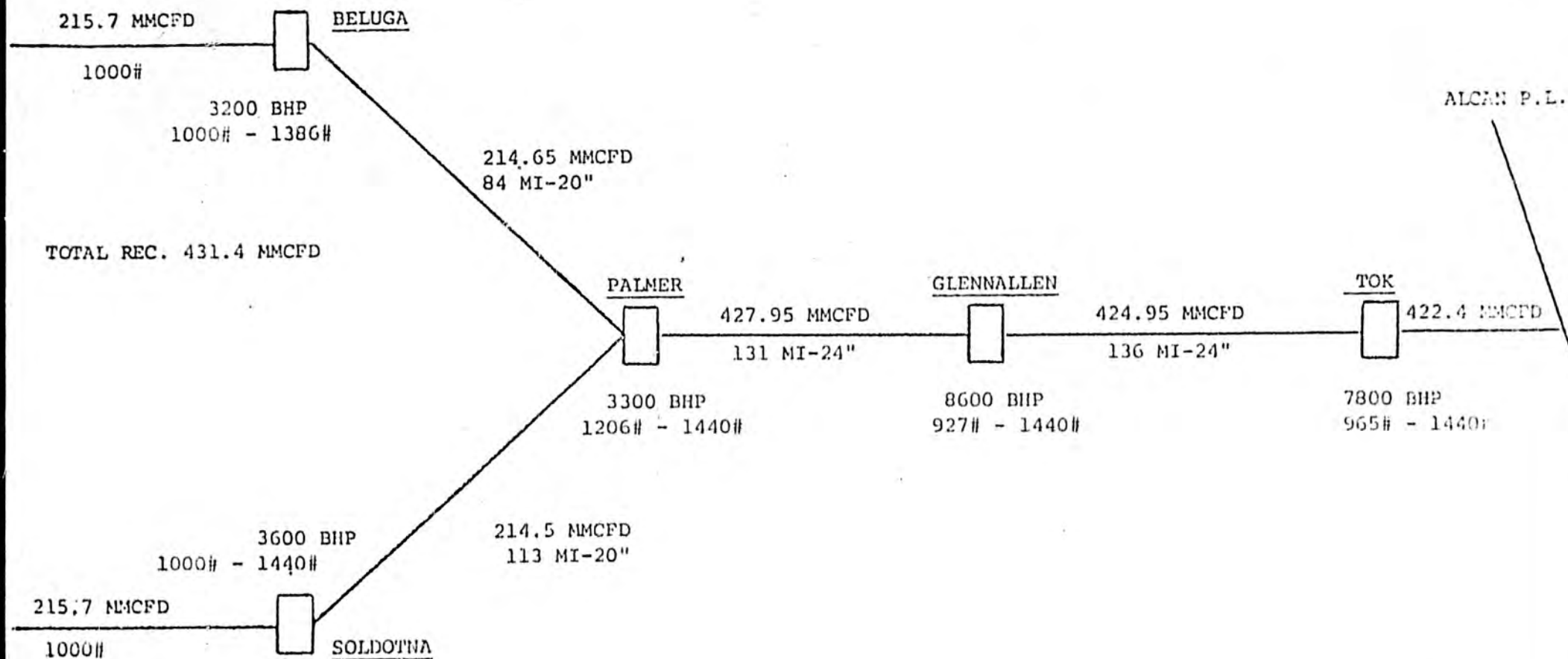
1. Construction costs, fuel usage, operating and maintenance and AFUDC from P.G.T.
2. 75% debt at 10% interest and 25% equity at 16% return.
3. 20-year project life.
4. 1.5% property tax rate.
5. 52% composite federal and state income taxes.
6. Fuel included in cost of purchased gas.
7. Annual BTU volume based on delivered volume as shown in energy balance.
8. Used normalized method to compute cost of service.

Malin to Antioch

1. Construction costs, fuel usage, operating and maintenance and AFUDC from PG&E.
2. 75% debt at 10% interest, 25% common equity at 16% return.
3. 20-year project life.
4. 1.75% property tax rate.
5. 52.68% composite federal and state income taxes.
6. Fuel included in cost of purchased gas.
7. Annual BTU volume based on delivered volume as shown in energy balance.

Purchase Natural Gas Costs

Purchase Natural Gas costs for both the LNG and Pipeline alternatives reflect the \$1.46/MMBtu field price assumed for both projects adjusted to reflect the respective overall system gas balance efficiency of each project.



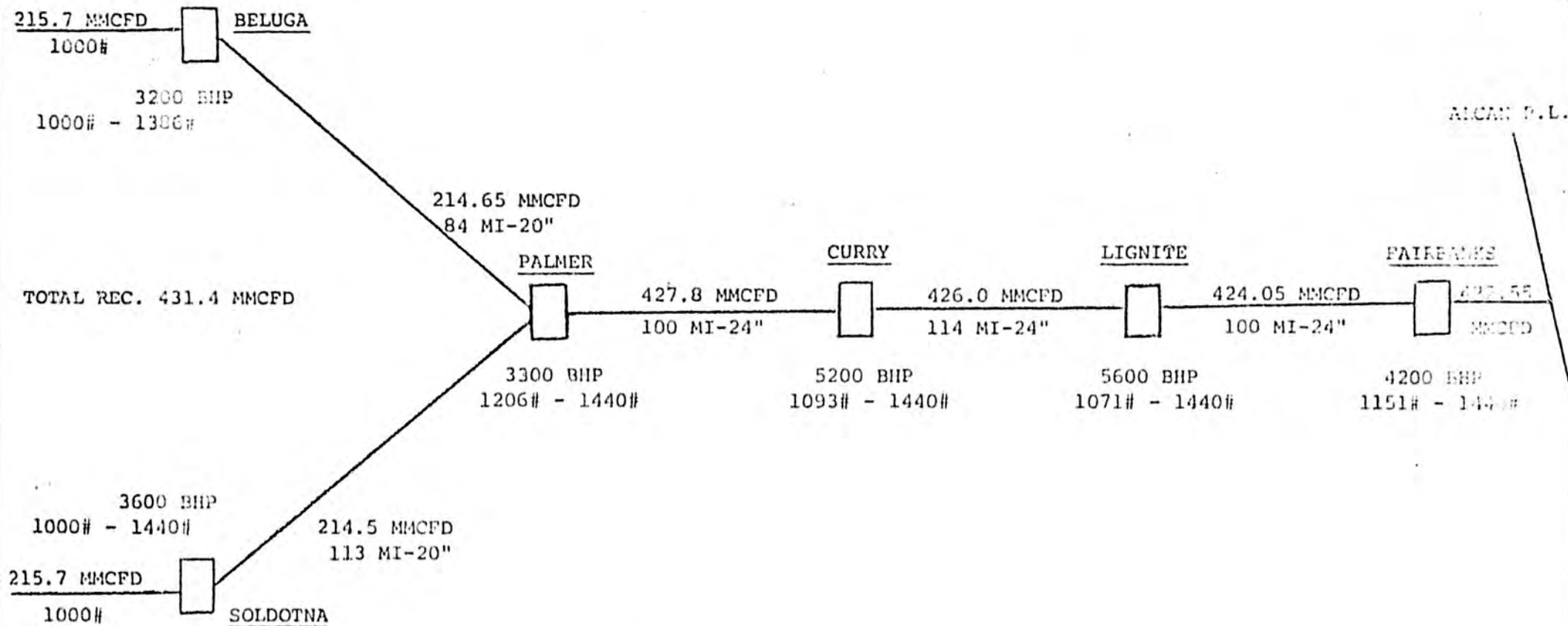
TOTAL REC. 431.4 MMCFD

PIPELINE: X-G5
1440# MAOP
CLASS I

t = 30°F
S.G. = 0.60
EFF. = 85%

EXHIBIT E-1

FLOW CALCULATIONS-COOK INLET TO TOK



PIPELINE: X-65
1440 MAOP
CLASS I

t = 30°F
S. G. = 0.60
EFF. = 85%

EXHIBIT E-2

FLOW CALCULATIONS-COOK INLET TO FAIRBANKS

AGD 544958

Southern California Gas Company
Alaska Gas Pipeline Study
Possible Route Selection and Description

In November of 1977, Hood Corporation was engaged by the Southern California Gas Company to examine possible gas pipeline routes from Anchor Point, Alaska on the east side of Cook Inlet and Drift River on the west side of Cook Inlet, north to Palmer and then on northerly to a possible tie-in point on the proposed Alcan Natural Gas Pipeline at either Fairbanks, Delta Junction or Tok Junction.

Six different cost of field construction alternates were prepared and submitted to the Gas Company utilizing various pipeline sizes and final tie-in points to the Alcan line. The proposed right-of-way for all cases studied was identical from Drift River and Anchor Point to Palmer. At Palmer the Fairbanks alternate would follow north along Highway 3 to Fairbanks while the Delta Junction and Tok Junction alternates would be routed easterly to Glennallen along Highway #1 and either follow Highway 4 northerly to Delta Junction or continue along Highway 1 to Tok Junction.

Route determination was accomplished by utilizing topographic maps of the Alaska topographic series prepared by the United States Department of the Interior Geological Survey. Topographic or physical features not shown or noted on the U.S.G.S. maps were confirmed by visual inspection while flying the proposed pipeline routes in a Bell Jet Ranger Helicopter.

A generalized description of the terrain to be encountered and existing rights-of-way on each leg of the proposed right-of-way is described below.

Drift River to Beluga (63 Miles)
(Kenai and Tyonek topographic sheets)

Beginning at the Drift River Marine Terminal follow existing Drift River pipeline right-of-way north to West Foreland and Beluga. This terrain is essentially flat, marshy ground and can only be worked as a winter time operation off of snow pads - all materials must be barged in from the east side of Cook Inlet and temporary construction camps set up along the right-of-way. Camp site facilities are available at Drift River, Trading Bay and Standard Oils' Beluga installation. Air strip facilities exist at Drift River, Trading Bay and Beluga. Due to existing pipeline right-of-way, minimal negative environmental effect anticipated from additional pipeline construction operations.

Beluga to Palmer (84 Miles)
(Tyonek and Anchorage topographic sheets)

From Beluga to Point McKinzie follow Chugach Electric transmission line right-of-way across the mouth of the Big Suisitna River Delta. Terrain flat, swampy marsh lands suitable only for winter construction operations. Existing electrical transmission line right-of-way suitable for pipeline construction purposes. All material must be barged across from east side of Cook Inlet, however, there appears to be an abundance of local trails and roads suitable for pipe and equipment hauling.

From Point McKenzie area follow transmission line right-of-way north of Knik Arm up the Matanuska River Valley to Palmer. The existing road system from Goose Lake to Wasilla to Palmer should minimize pipe hauling and stringing operations. Utilization of existing right-of-way should minimize environmental problems. Terrain is high elevation and contains less lakes and swamp conditions.

Anchor Point to Soldatna (57 Miles)
(Seldovia and Kenai topographic sheets)

From Anchor Point follow the existing power line rights-of-way

north along the Sterling Highway to Soldatna. Ample right-of-way for pipeline construction appears to be available with minimal environmental impact anticipated if existing right-of-way is utilized. Right-of-way terrain is cleared of timber with scattered brushy areas.

Kenai River crossing south of Soldatna should be scheduled to avoid Salmon run season.

Between Soldatna and Sterling go north to pick up the existing Anchorage Natural Gas Company right-of-way. This existing cleared pipeline right-of-way is an excellent route across the moose range and should have a very minimal environmental impact. This route avoids most of the major swampy areas and could be constructed in either summer or winter. This route continues to Burnt Island on the south side of Turnagain Arm.

Turnagain Arm Crossing (5 Miles)
(Seward and Anchorage topographic sheets)

This proposed crossing of the Turnagain Arm parallels the dual line crossing installed by Anchorage Natural Gas Company. The recommended crossing point is approximately 500' west of the existing lines from Burnt Island across to Potter on the Anchorage side of the arm. No environmental problems are anticipated in installing a parallel system to the existing lines. Lines should be buried across tidal mud flats.

Turnagain Arm to Palmer (48 Miles)
(Anchorage topographic sheets)

From Potter on the north side of Turnagain Arm it is recommended to follow the existing Anchorage Natural Gas line right-of-way along the foothills east of Anchorage, east of Campbell Air Strip and north to Fort Richardson and Eagle River. From Eagle River north to Palmer follow existing power line right-of-ways along the Glenn Highway across the Knik River, Matanuska River and on into Palmer.