

SCOMM

128:14

Alaska Oil and Gas Activities

Division of Oil and Gas
January 2002



Alaska Department of
**Natural
Resources**

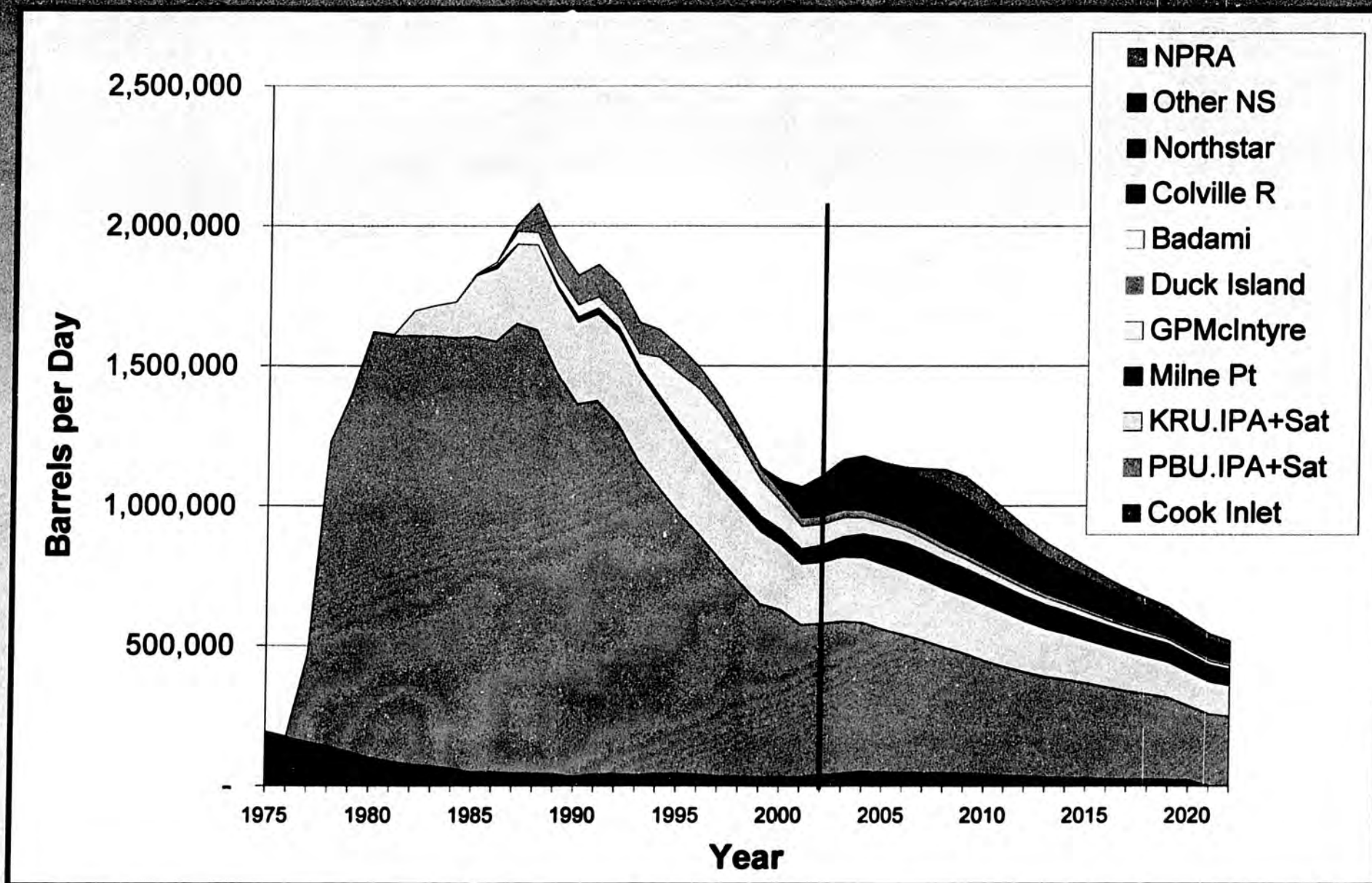
<http://www.dog.dnr.state.ak.us/oil/products/products.htm>

Alaska Reserves and Production

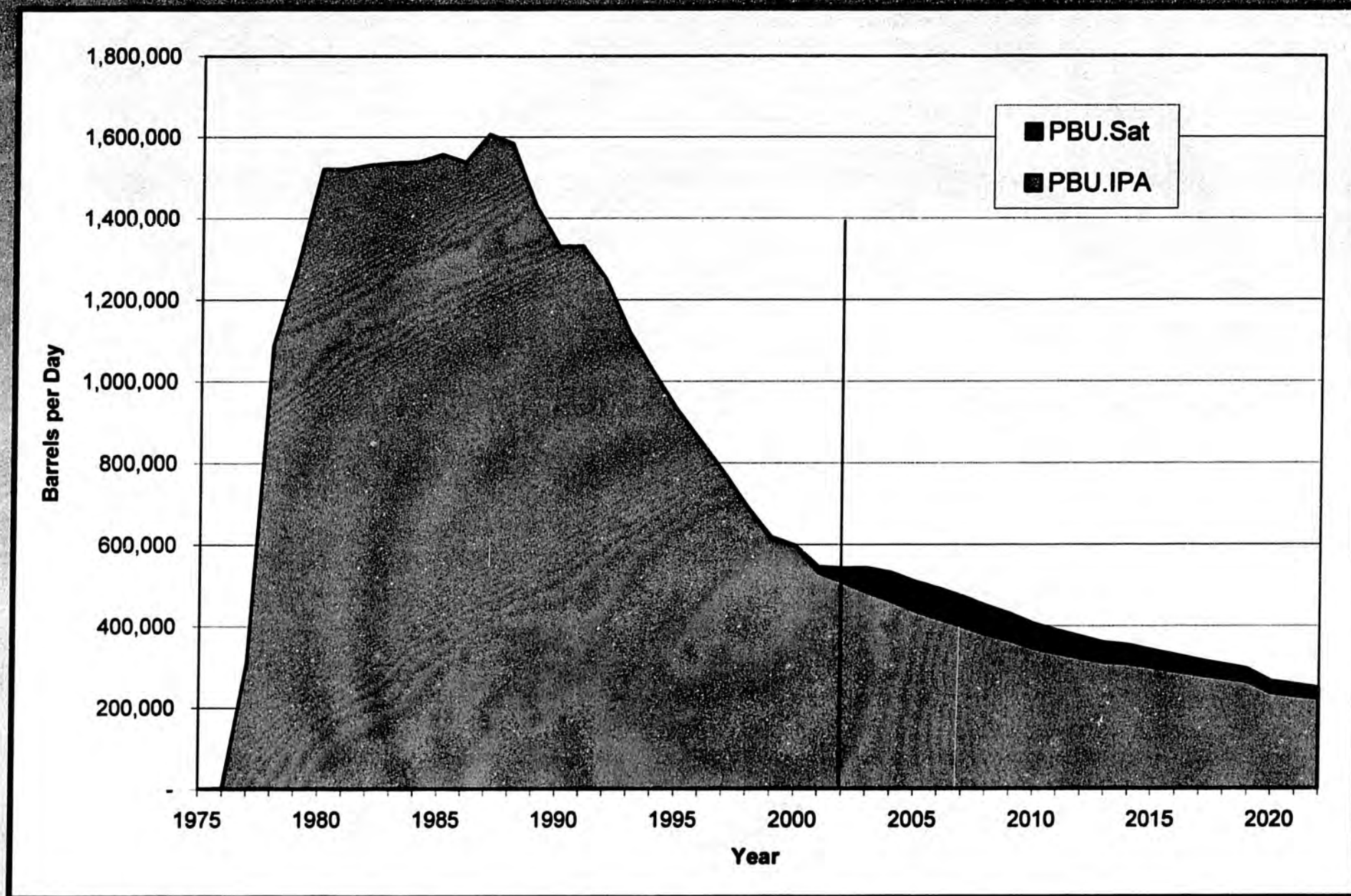
- **36% of total U.S. oil reserves.**
- 8.0 billion barrels of oil
- **17% of total U.S. gas reserves**
- 35 trillion cubic feet of gas
- **20% of total U.S. oil production**
- 1.04 million barrels of oil per day

Sources: Alaska data are from Department of Natural Resources, Division of Oil and Gas, 2001 Annual Report
U.S. data are from U.S. Crude Oil, Natural Gas, and NGL Reserves, 2000 Annual Report, U.S.D.O.E.-E.I.A.

1975 - 2020

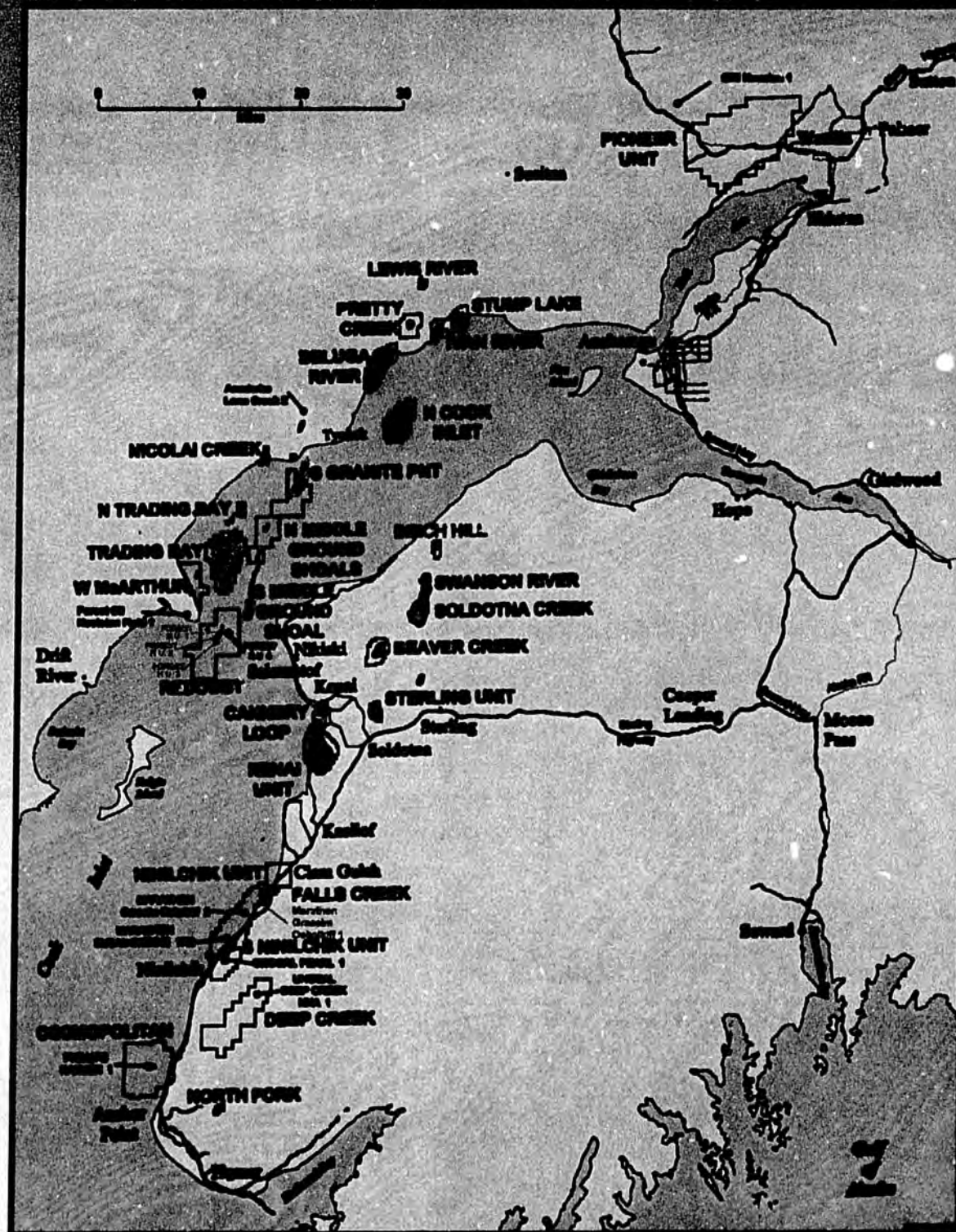
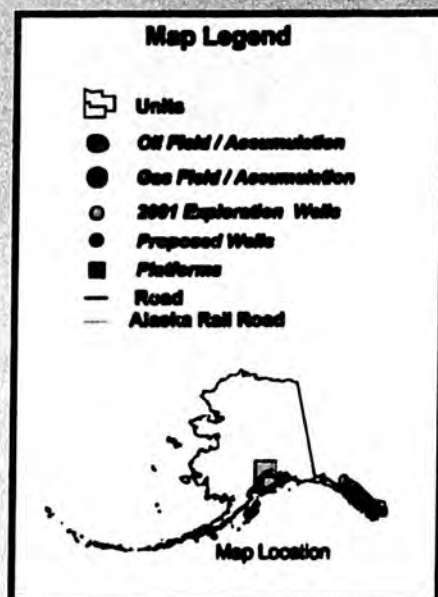


1975-2022

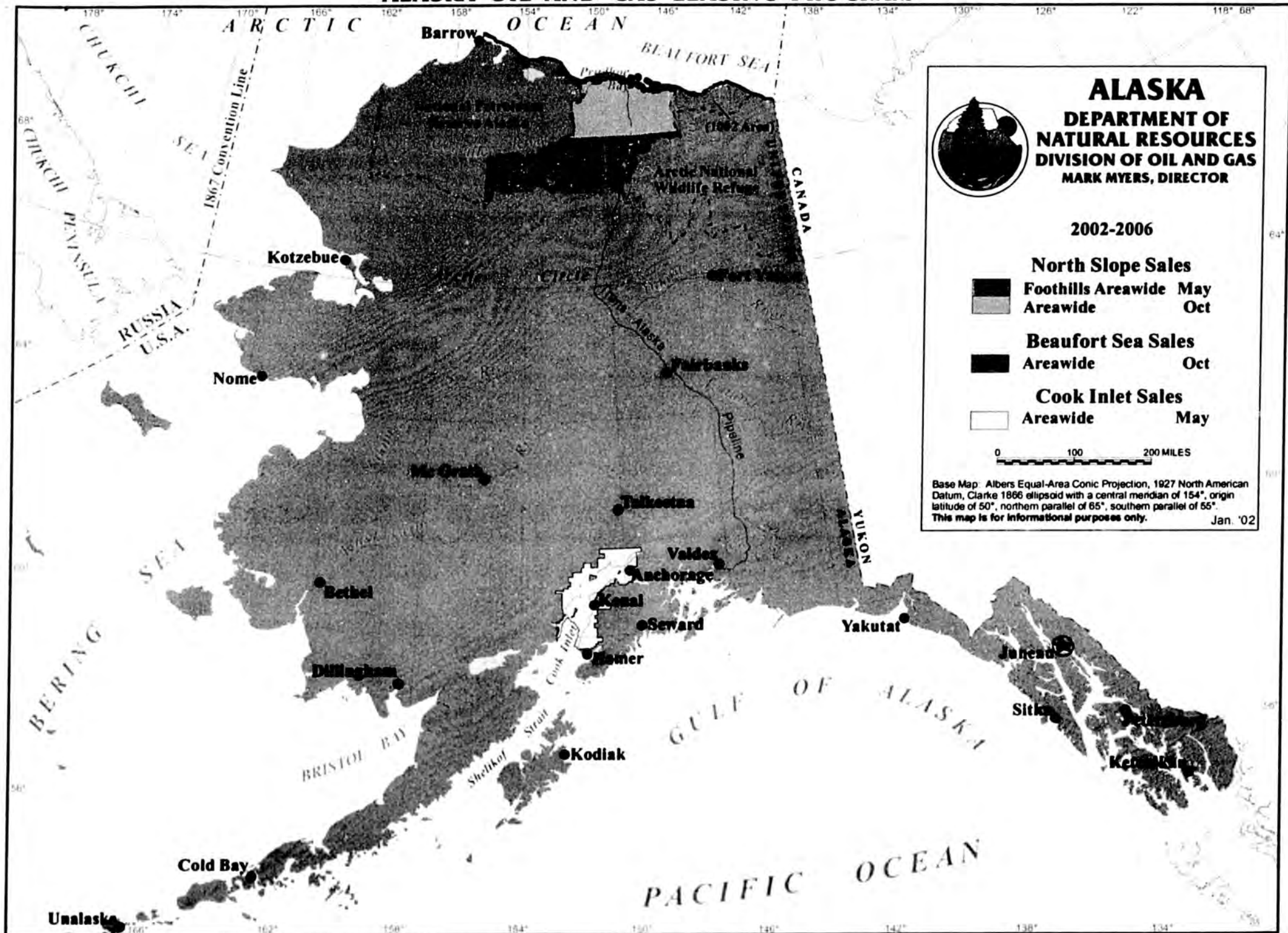


######

Cook Inlet Oil & Gas Activity January 2002

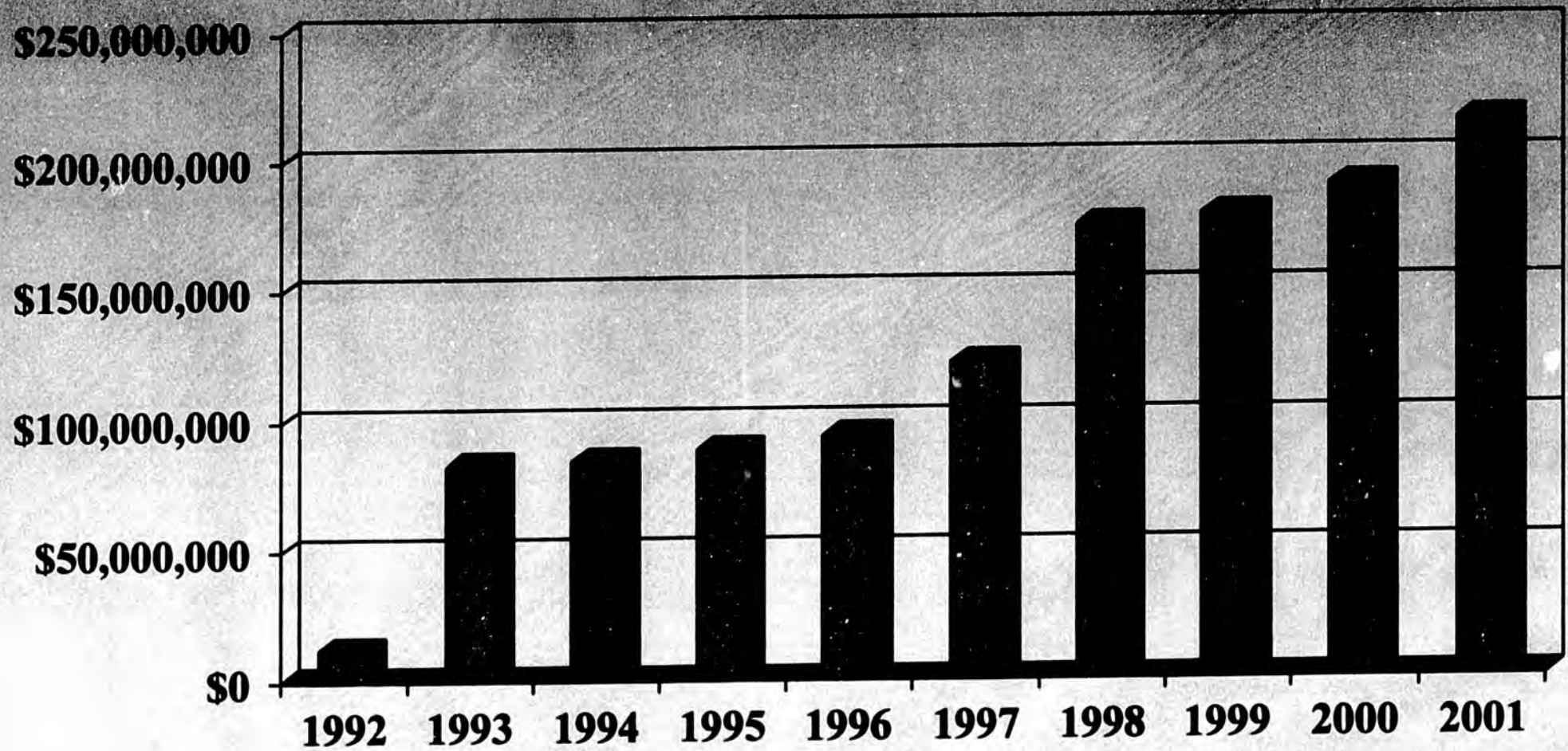


ALASKA OIL AND GAS LEASING PROGRAM



Visit our Website at "www.dog.dnr.state.ak.us/oil"

Cumulative Bonus Bids



2001 Area-wide Lease Sales

Total Acres Leased = 1.6 Million

Total Bonus Bids = \$24.5 Million

North Slope Foothills

- Area's First Lease Sale
- Largest State Sale Ever
- 8 Bidding Groups
- 978,560 Acres Leased
- \$10.7 Million in Bonus Bids

North Slope

- 16 Bidding Groups (Shell returns after 13 yrs)
- 469,760 Acres Leased
- \$7.4 Million in Bonus Bids

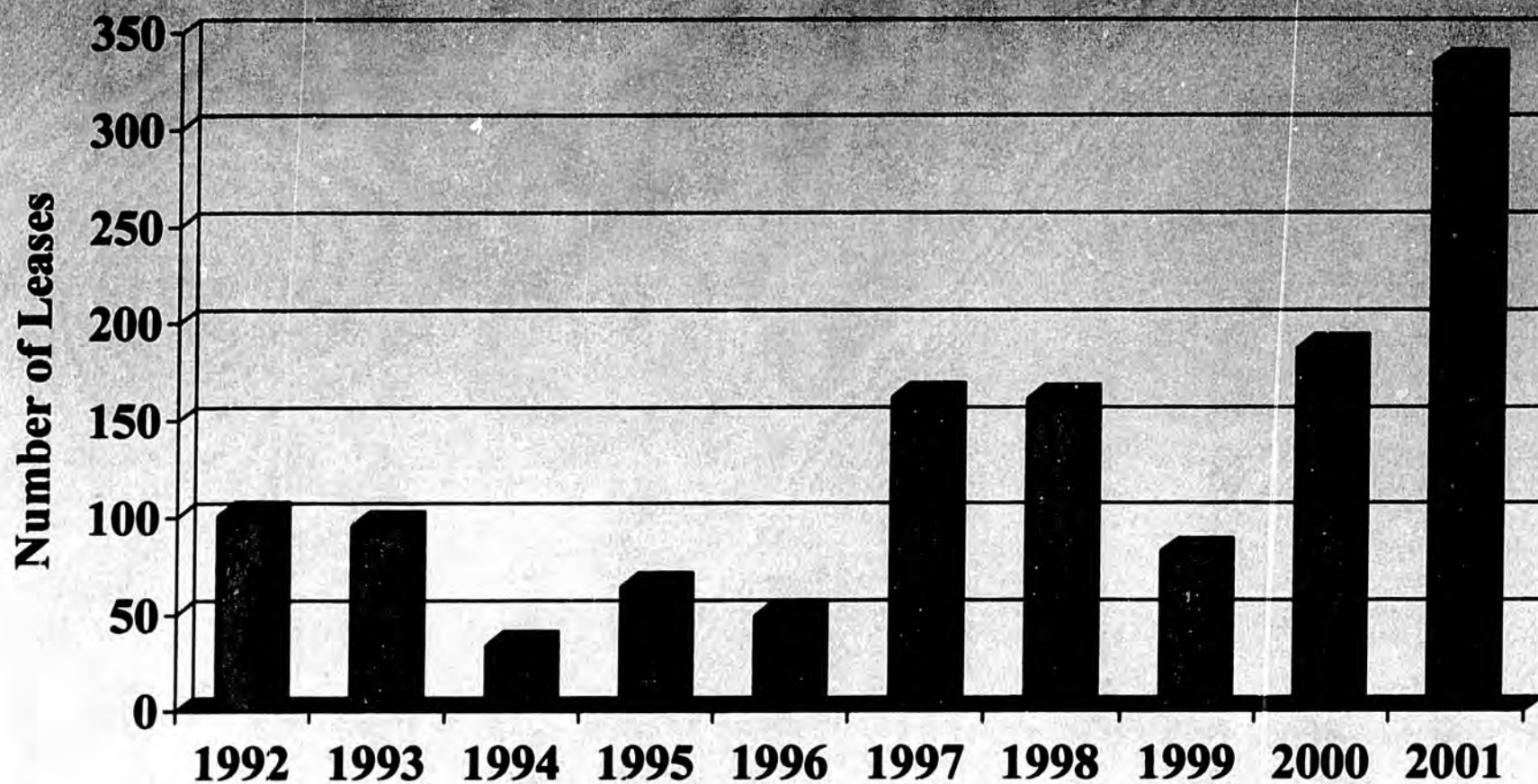
Cook Inlet*

- 6 Bidding Groups
 - 102,523 Acres Leased
 - \$928,085 in Bonus Bids
- (* Final Results)

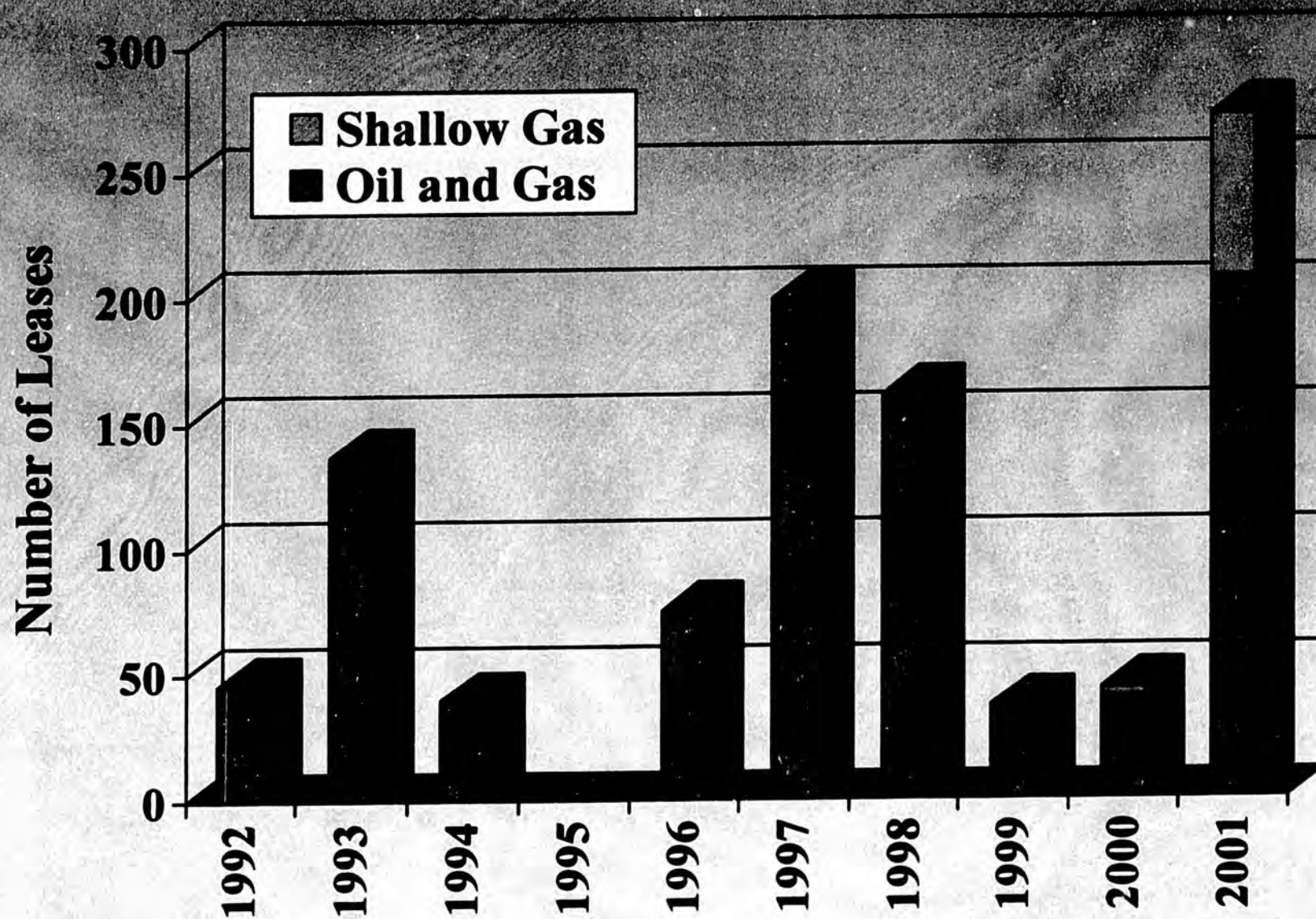
Beaufort Sea

- 7 Bidding Groups
- 60,800 Acres Leased
- \$5.4 Million in Bonus Bids

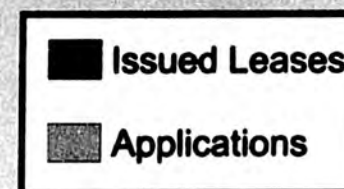
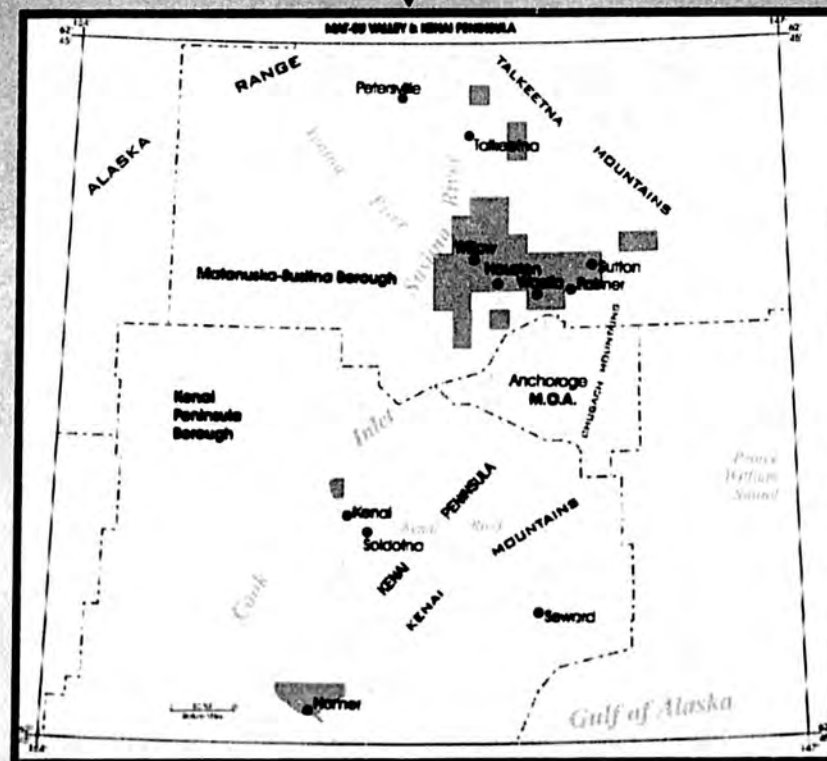
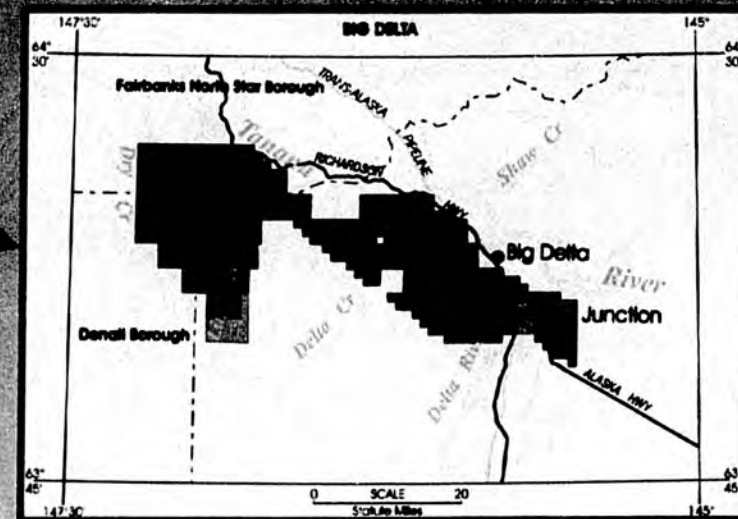
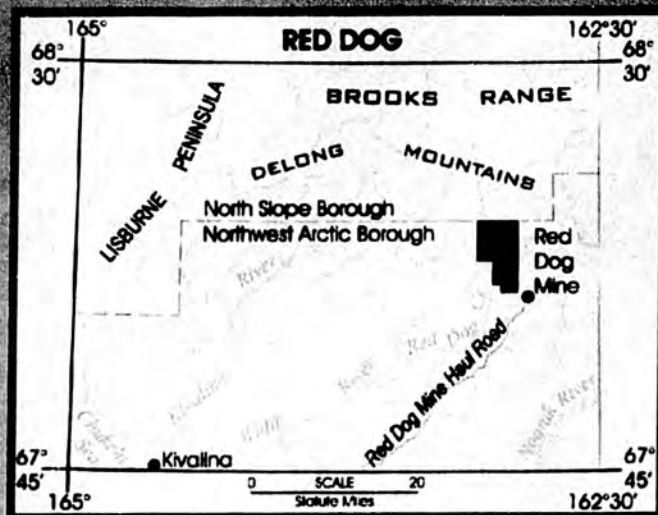
Oil and Gas Leases Sold

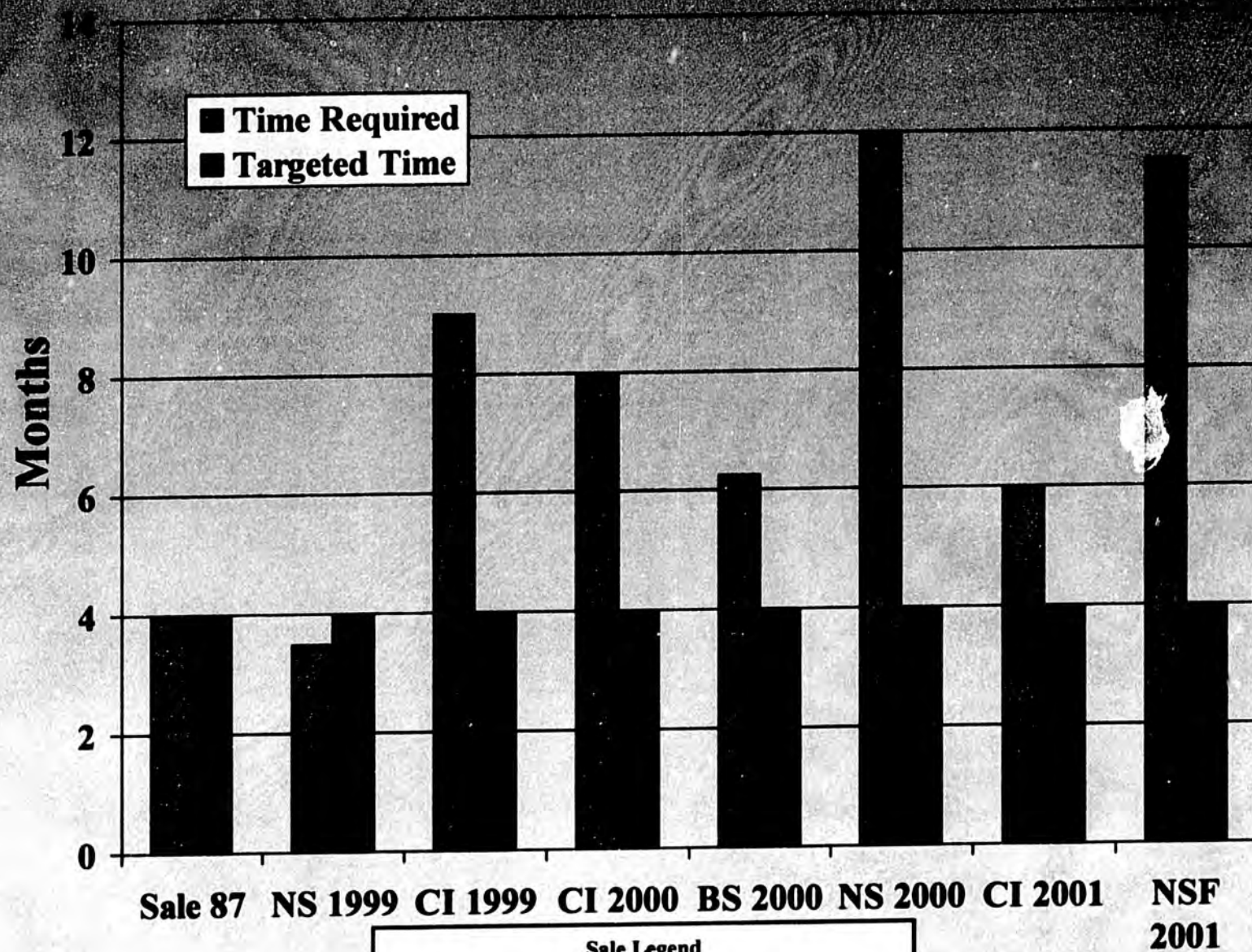


Leases Issued



SHALLOW SUBSURFACE GAS LEASING PROGRAM

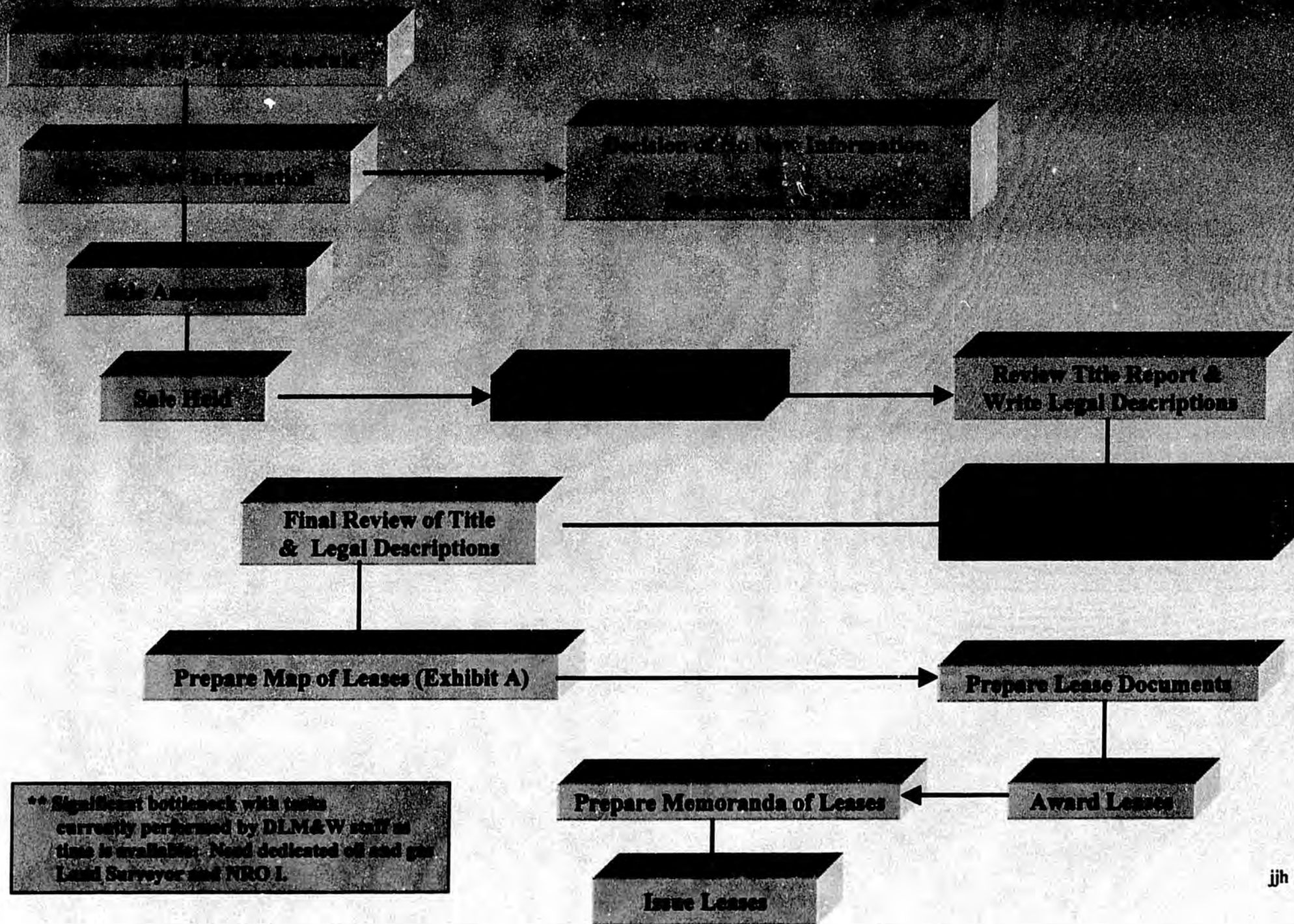




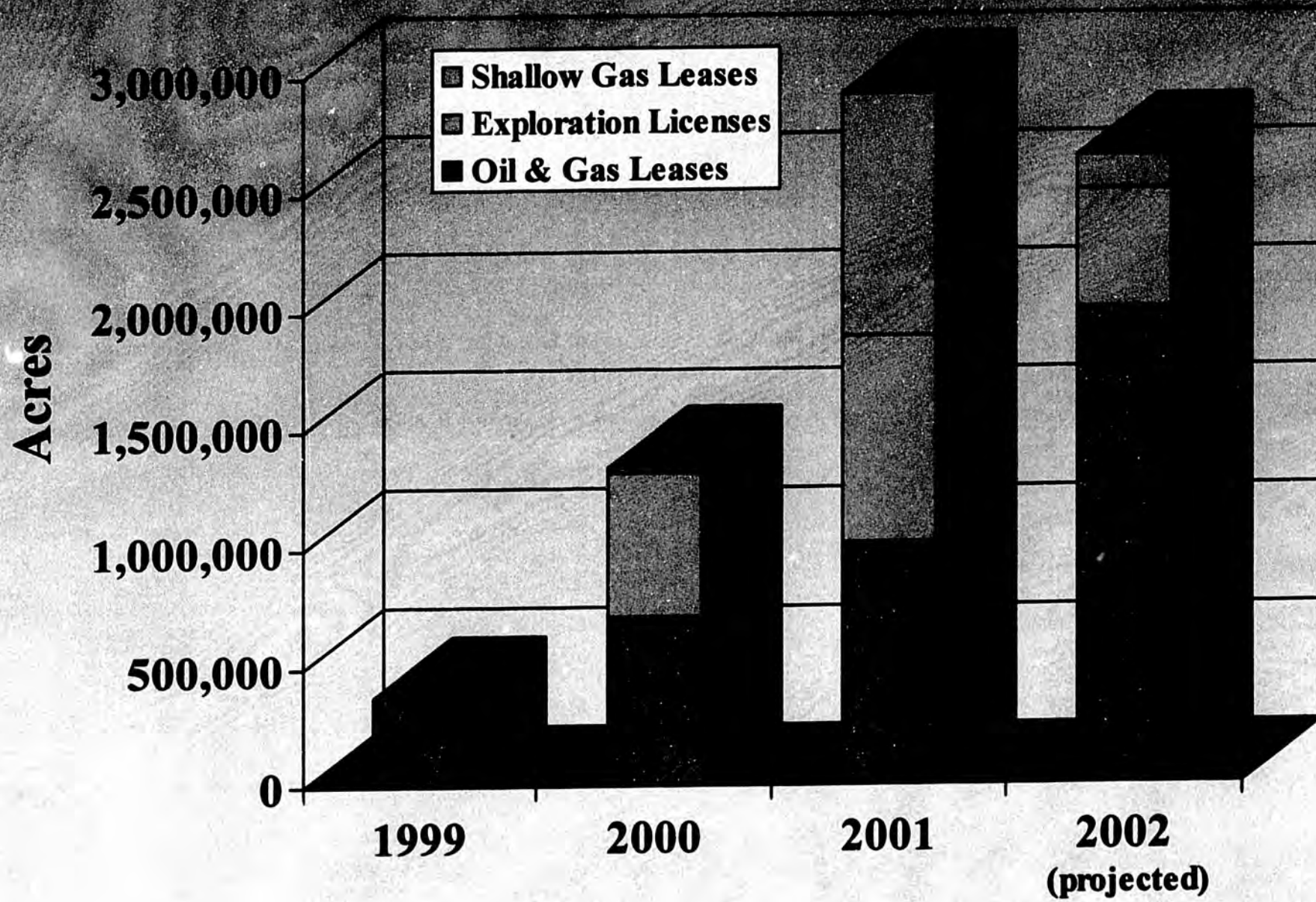
Sale Legend

BS - Beaufort Sea	CI - Cook Inlet
NS - North Slope	NSF - North Slope Foothills

(Projected)



Field Work



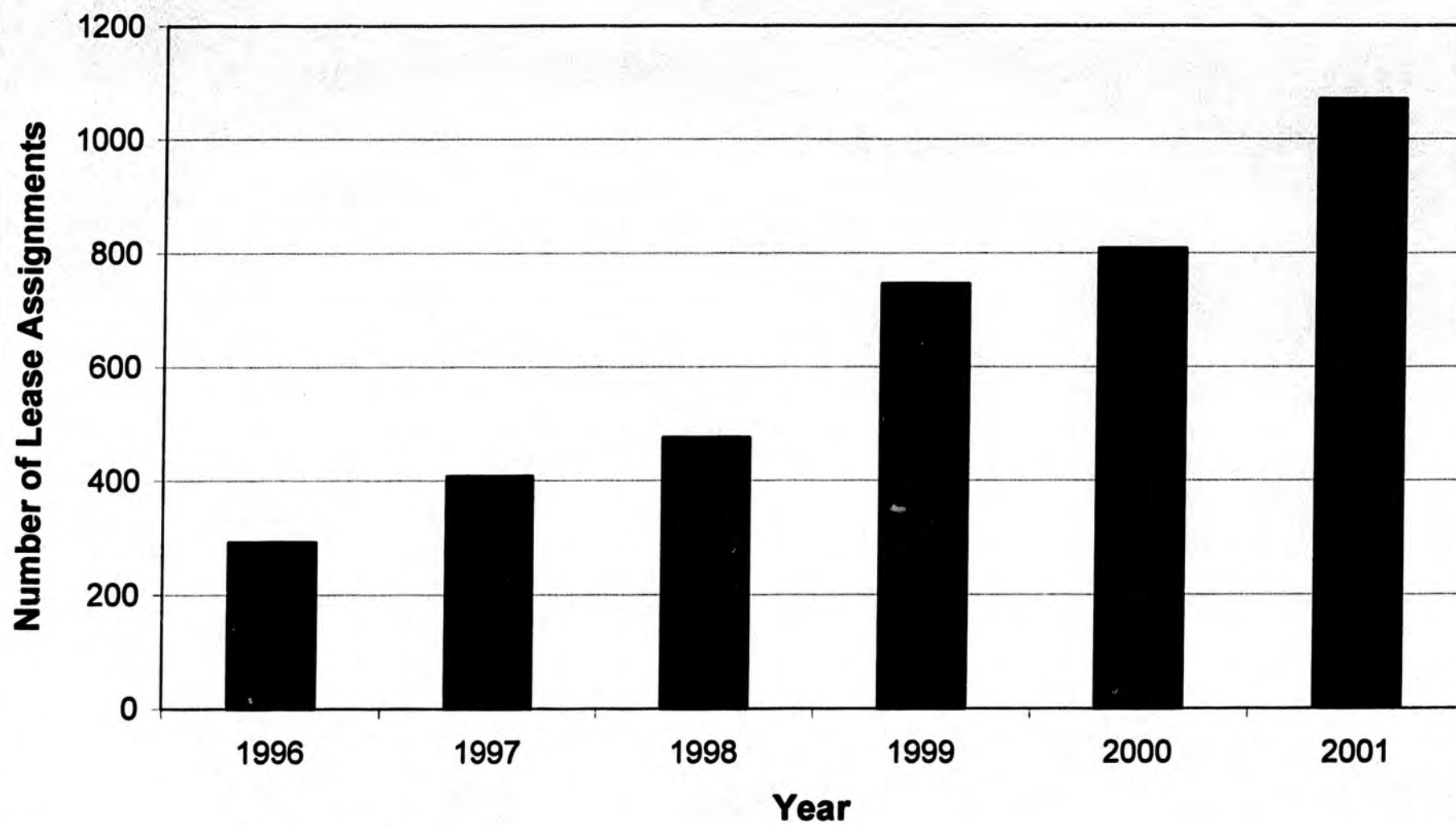
Shallow Gas Leases and Exploration Licenses Programs Drive Energy Increase Division Workload

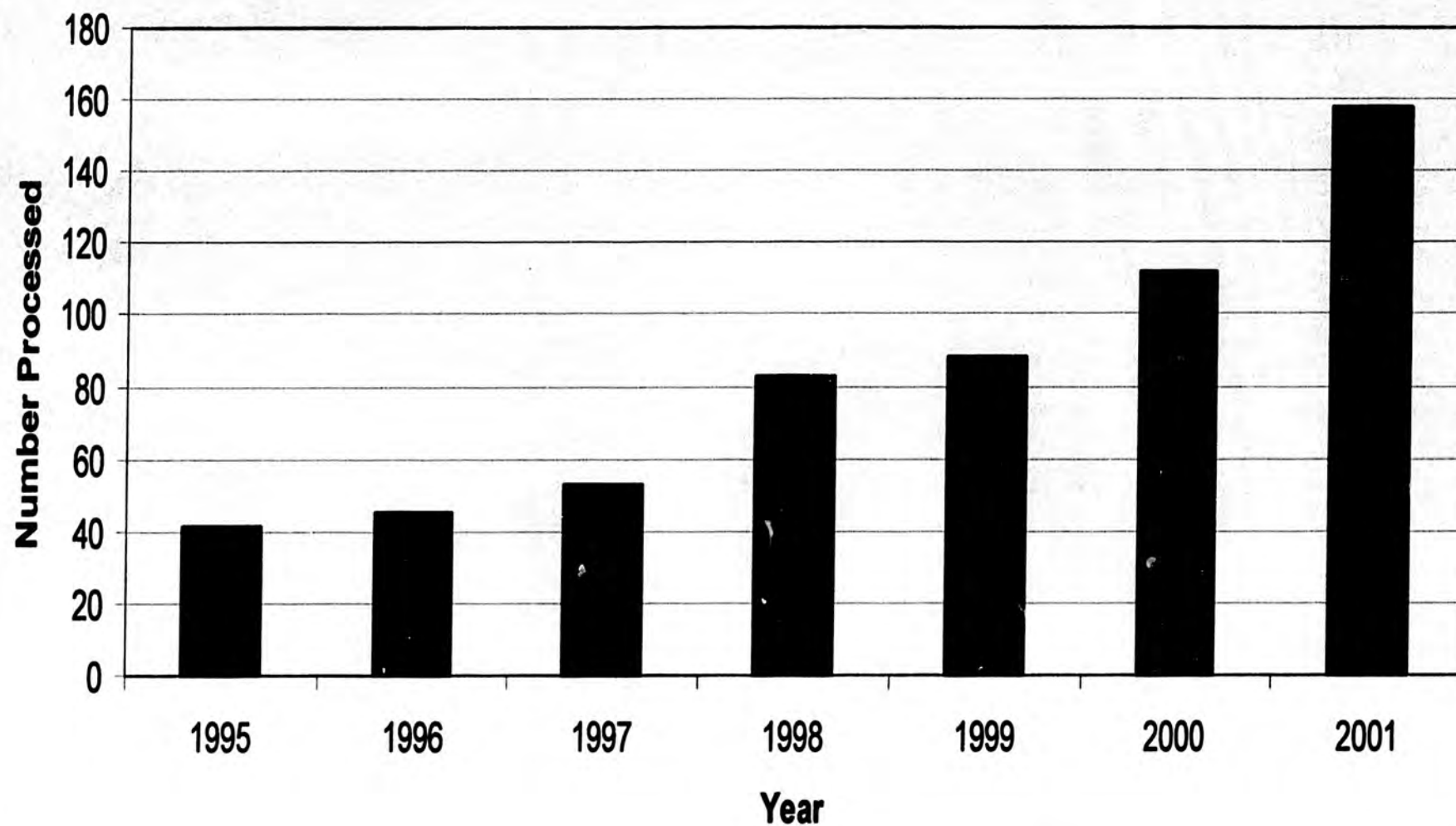
**2001 Title Work
2,922,880 Acres**

**Shallow Gas Leases
1,031,680 Acres**

**Oil and Gas Leases
1,017,600 Acres**

**Exploration Licenses
873,600 Acres**





Actions include Units and Participating Areas formed, expanded, contracted, and terminated;
Unit decisions appealed; Unit Plans of Exploration and Development reviewed and approved.

cdl 01/02

Lease/Unit Administrative Actions

Unit - Units are groups of leases; units are established to efficiently explore and develop the leases covering one or more potential hydrocarbon accumulations

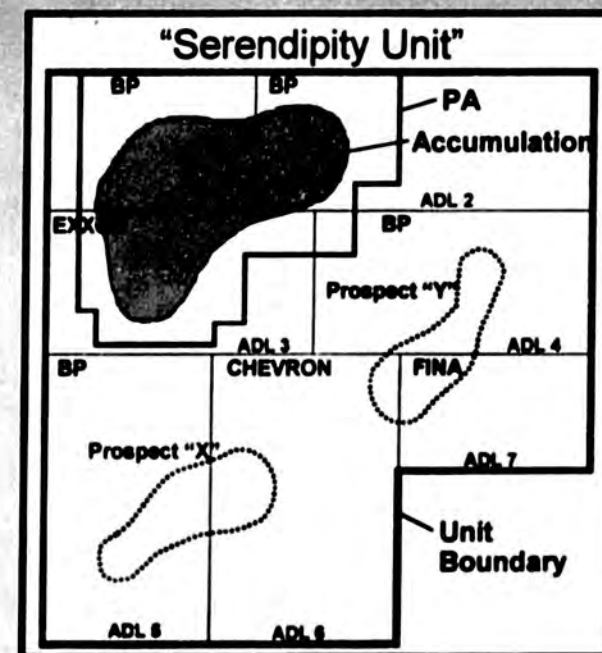
Participating Area (PA) - That portion of leases in a unit which cover a known or estimated accumulation and to which production is allocated via a unit agreement

Units Actions:

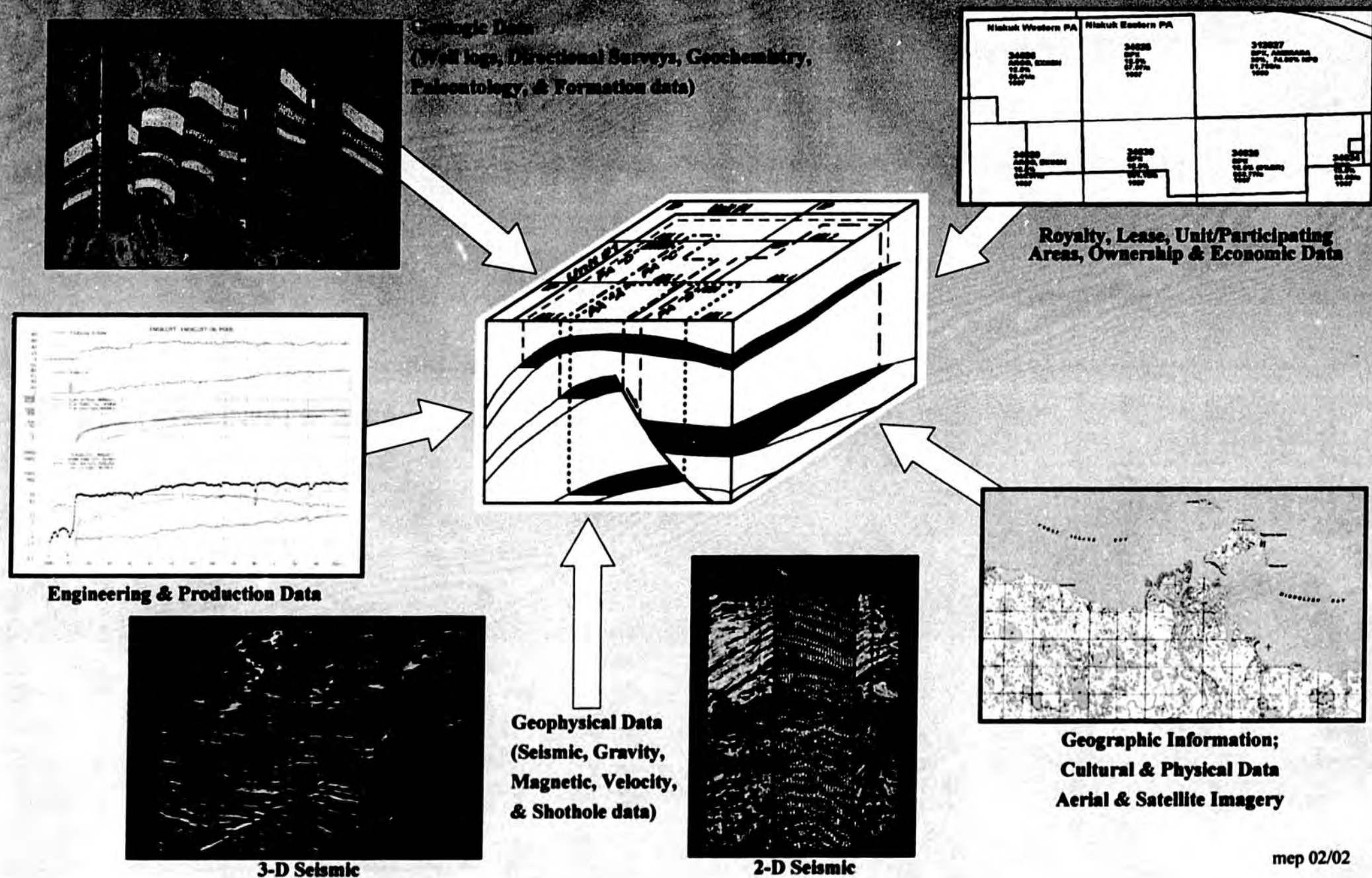
- Initial Formation
- Technical Evaluations - Reservoir Extent, Paying Quantities
- Negotiations - Unit Agreement
- Work Commitments
- Expansions
- Contractions
- Annual Plan of Exploration or Development

Participating Areas:

- Initial Formation
- Technical Evaluations - Commerciality
- Tract Allocation Factors
- Field Costs/Processing Costs
- Gas and Gas Liquids
- Fluid Commingling
- Facility Sharing
- Well Test Allocation
- Expansions
- Contractions
- Annual Plan of Development



create 3-D pictures of oil fields and royalty shares.



Gas Cap Mechanisms

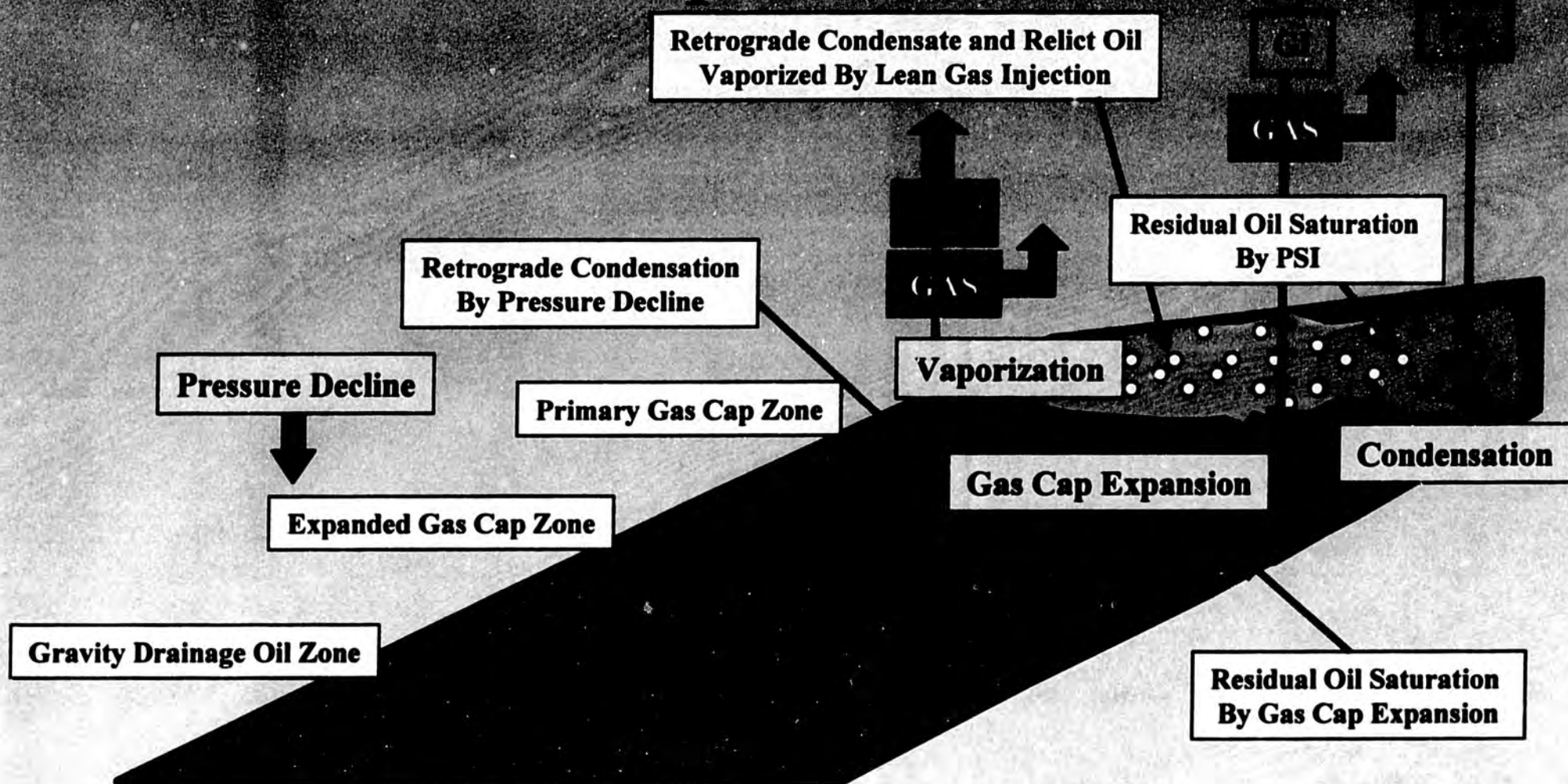


Figure 4

PBU Mechanisms

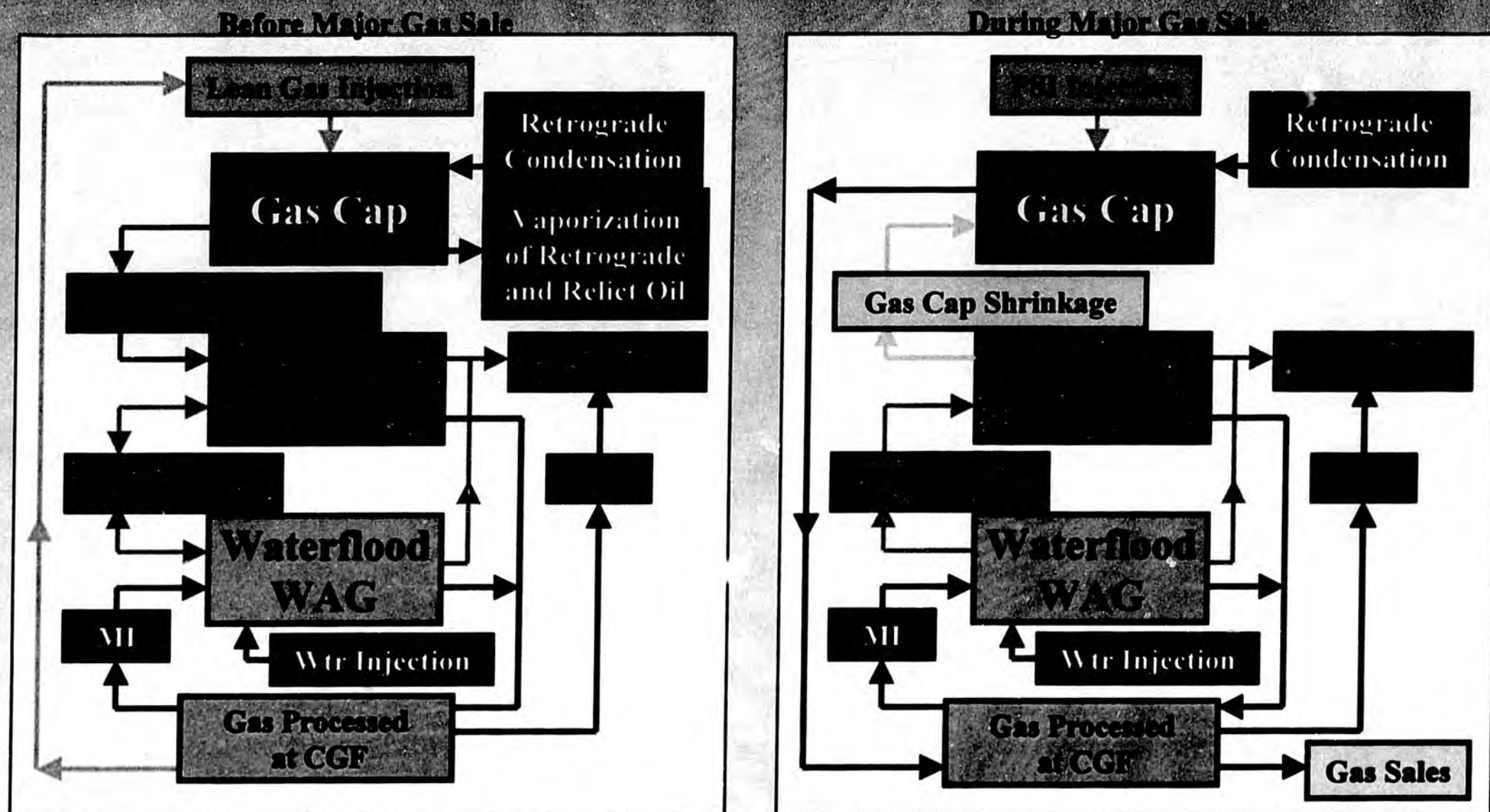
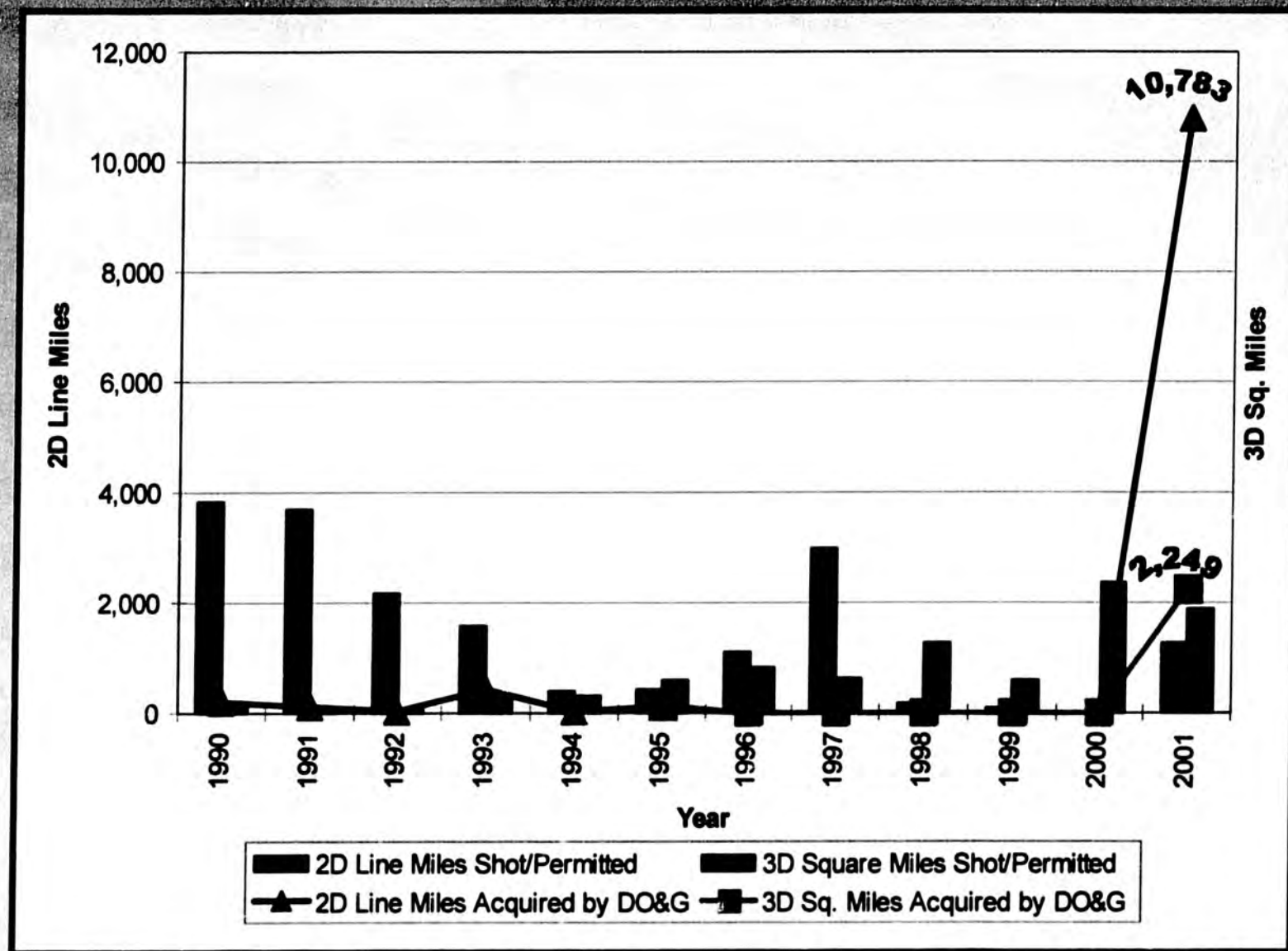


Figure 10

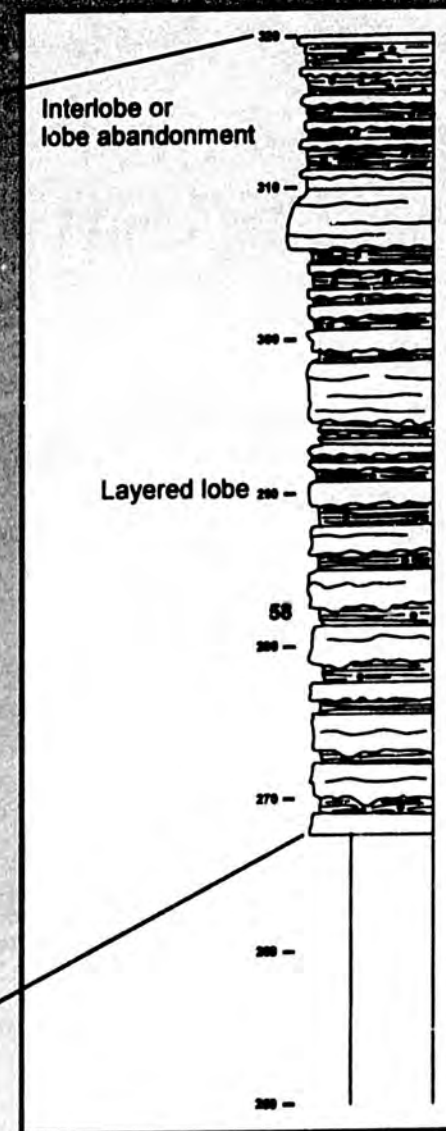
Seismic Data Status 1990 - 2001



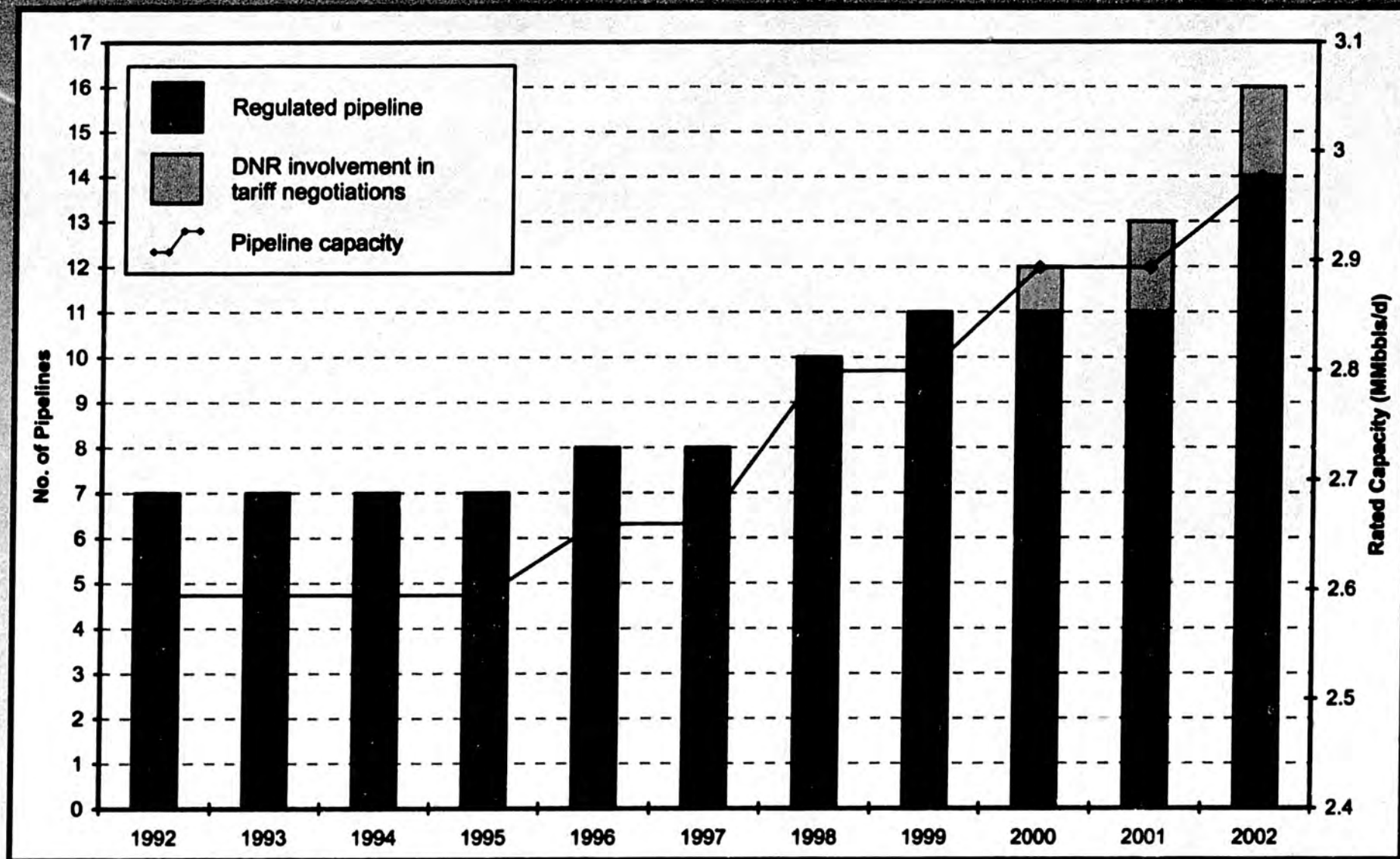
jrc 01/02



Modified from Phillips Alaska

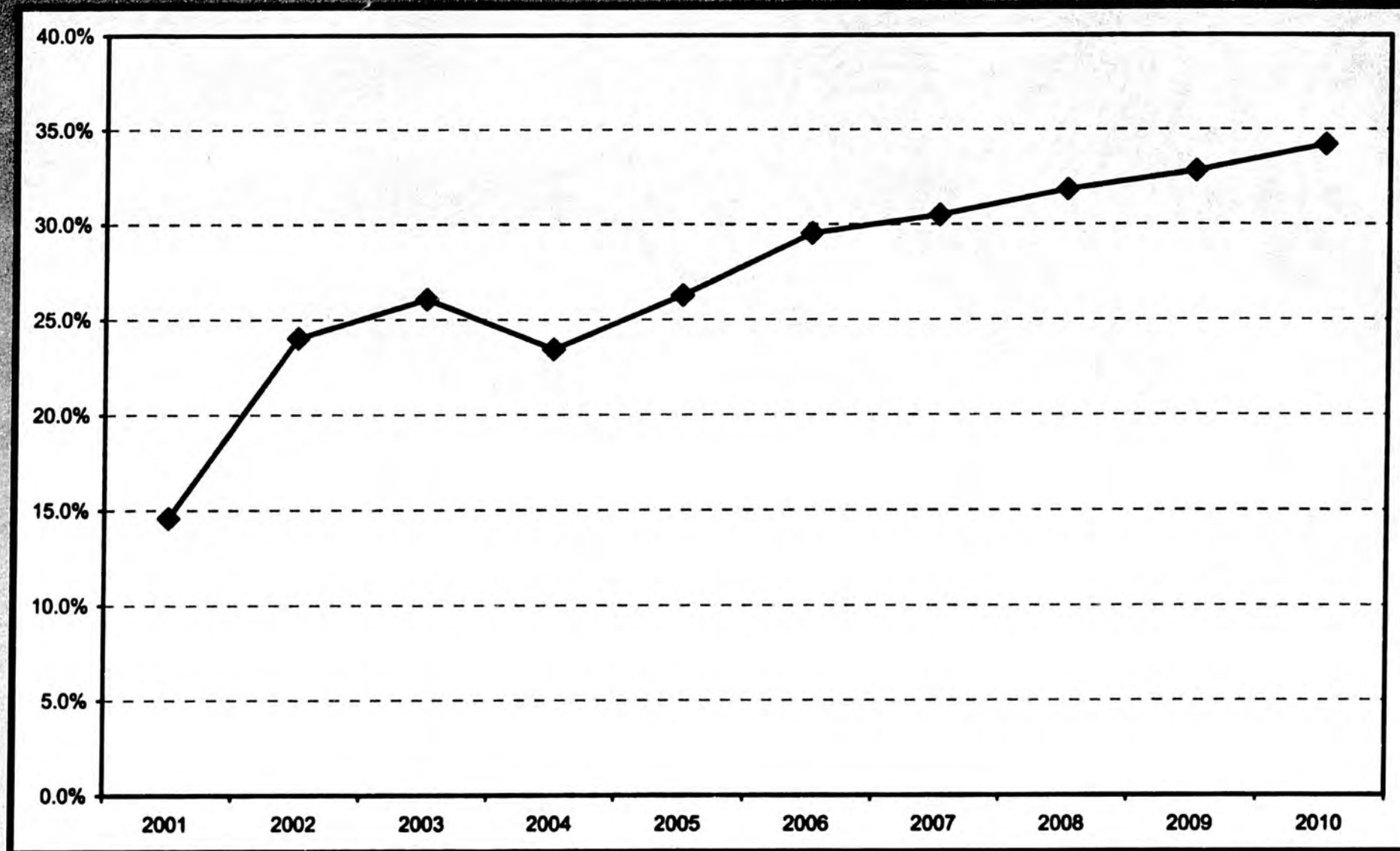


Torok Formation-Chandler River Section



Source: Division of Oil and Gas, January 2002

krb 1/02



Source: DOR, Revenue Sources Book, Fall 2001

krb 1/02



ANWR 1002 Area Wells, Discoveries, & Seismic Data



Reaching Bottom Line

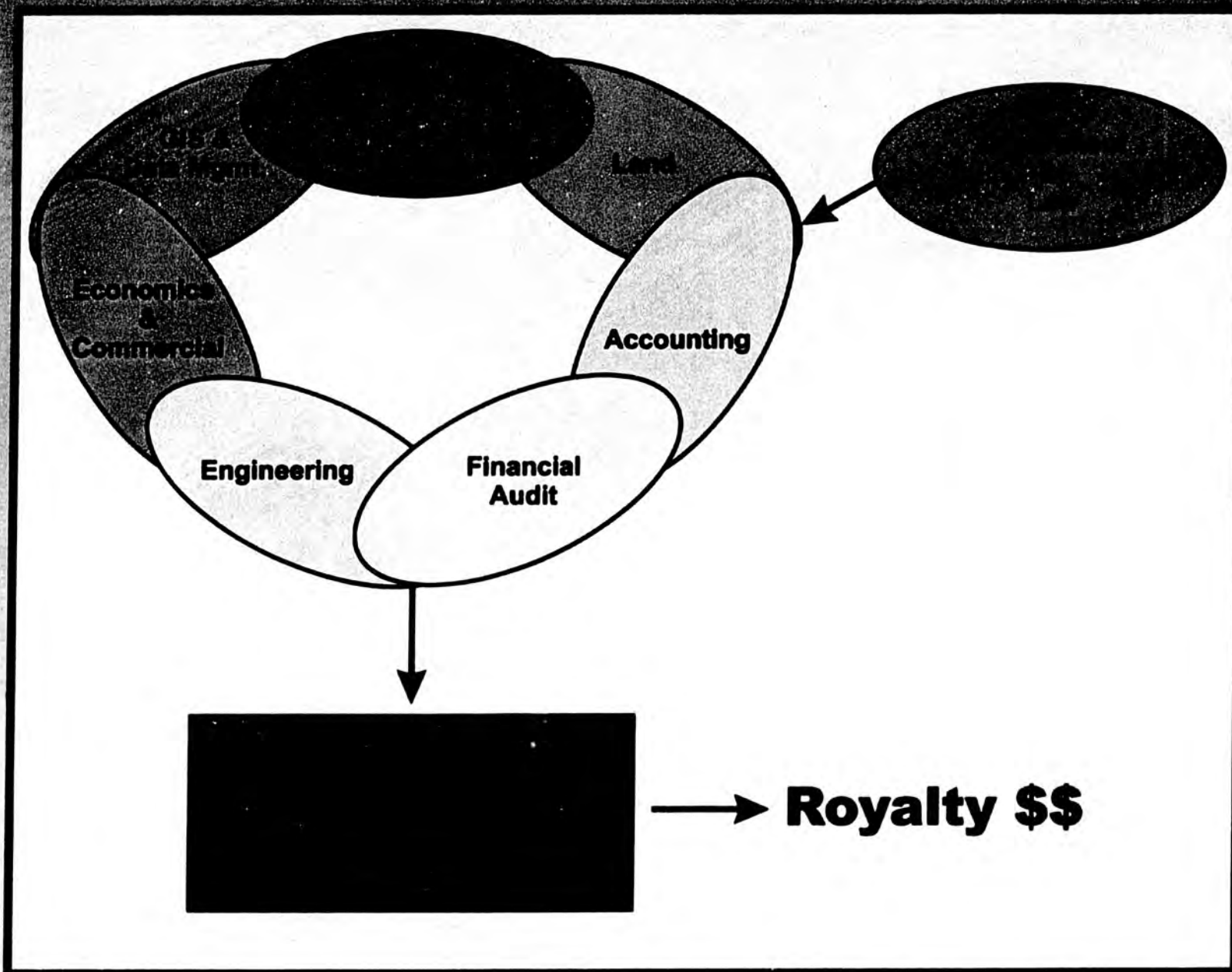
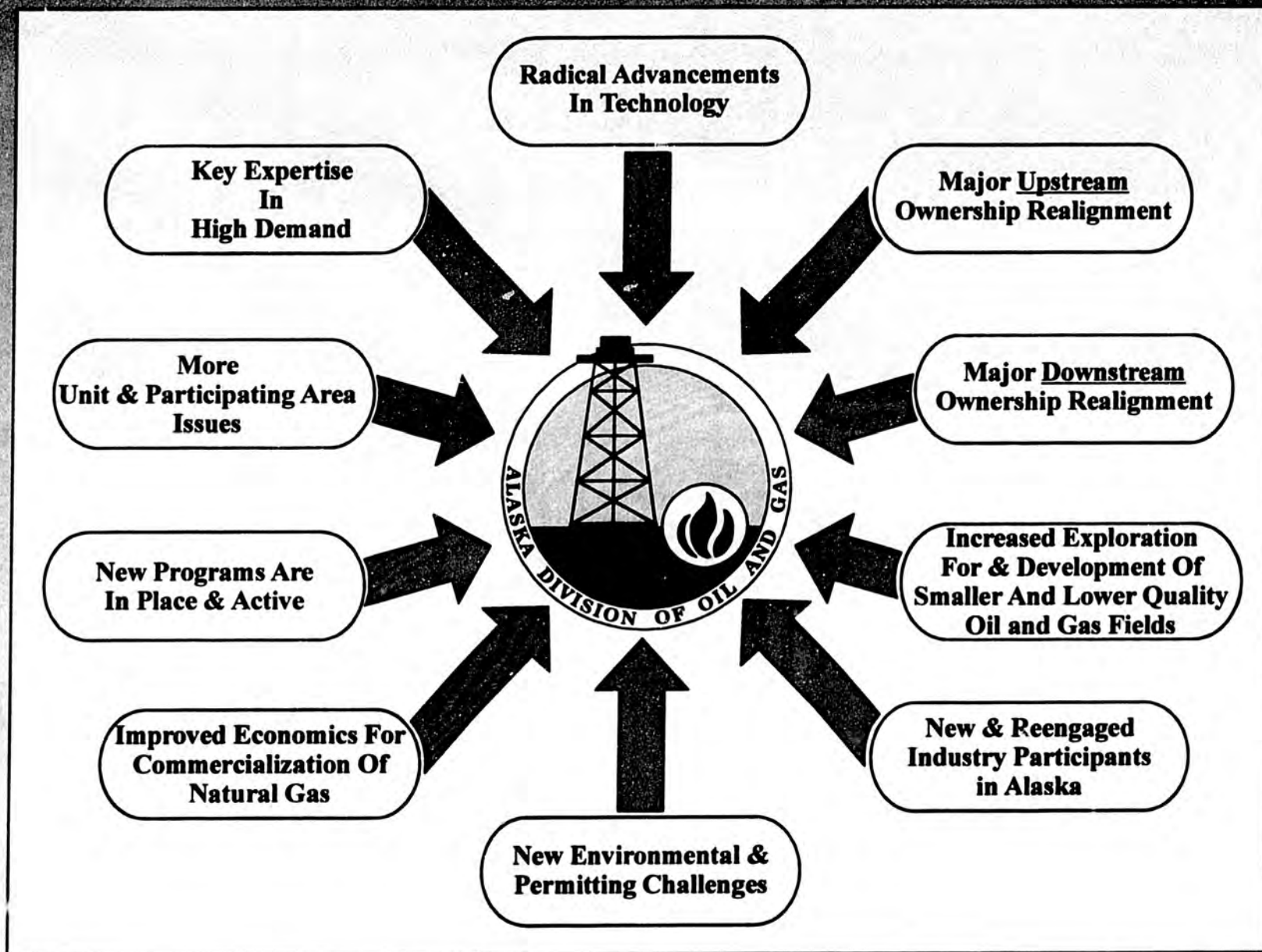
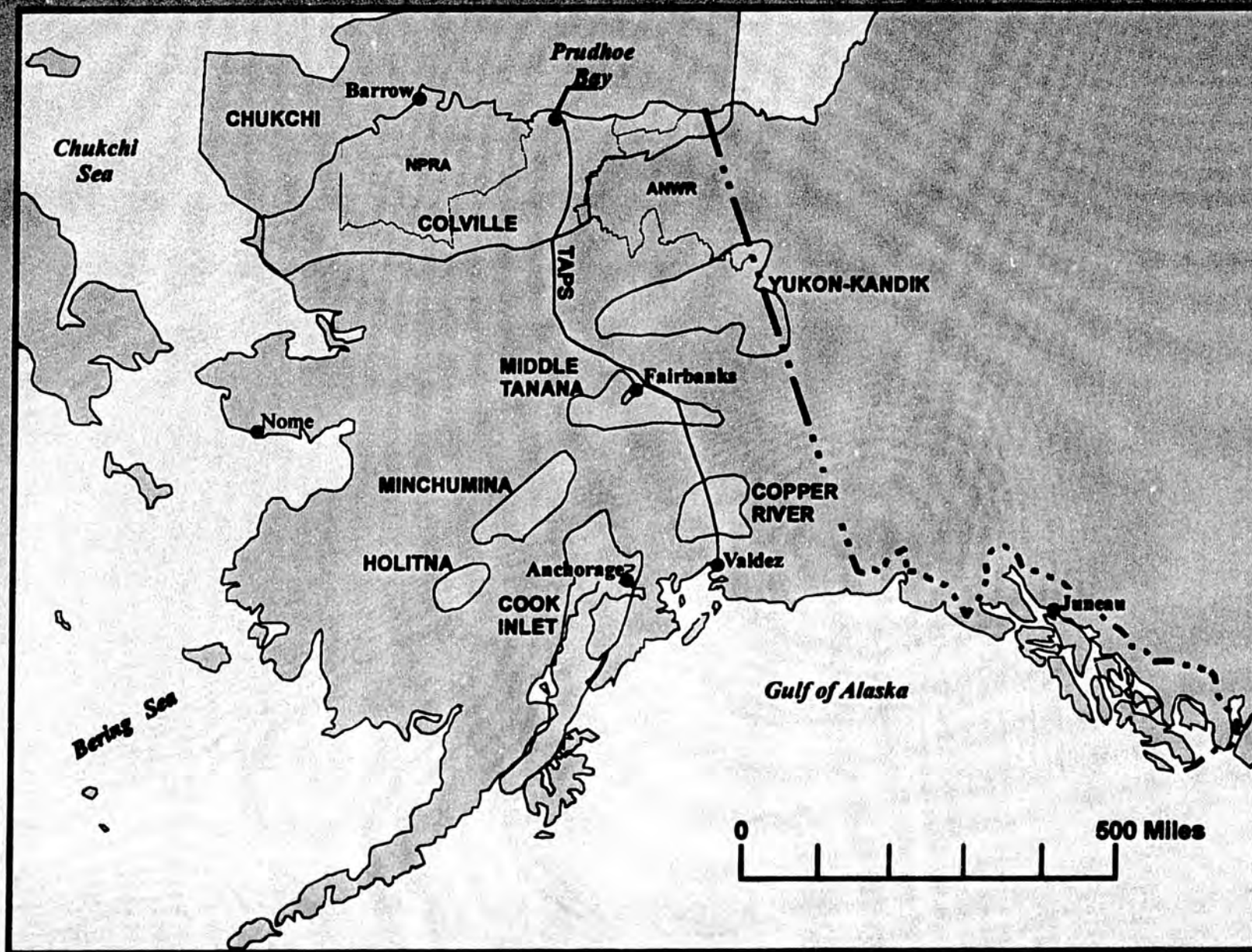


FIGURE 1: CHALLENGES OF THE DIVISION OF OIL AND GAS





Alaska Royalty-In-Kind Gas Sale

Division of Oil and Gas
January 2002



Alaska Department of
**Natural
Resources**

THE STATE'S ROYALTY SHARE

- **Is a percentage of production**
- **Usually is 12.5% of production, but may be 16 2/3% or 20% of production**
- **May be taken “in-value” or “in-kind”**
 - **When taken “in-value” the gas is left with the producer, who sells 100% of the gas, then pays the state 12.5% of the net proceeds from the sale of 100% of the gas, or the market value of the gas, whichever is higher**
 - **When taken “in-kind” the state physically takes 12.5% of the gas in the field and sells it itself**

**THE STATE MAY TAKE IT'S ROYALTY SHARE OF GAS
EITHER IN-KIND OR IN-VALUE**

The State's right to take gas either in-kind or in value:

- **Is a term of the lease agreement**
- **Allows switching between in-kind and in-value on six month's notice**
- **Is the same for oil and gas**
- **Has been part of the State's lease form for more than 40 years**

**THE STATE'S RIGHT TO TAKE IN-KIND, AND TO SWITCH
BETWEEN IN-KIND AND IN-VALUE, IS VALUABLE**

- **If the reported proceeds on royalty in-value appear low, the state can test the market by offering gas for sale in-kind**
- **If in-state producers are unwilling to sell to in-state purchasers (who may also be competitors of the producers), the state can supply in-state purchasers**
- **The state may be able to command a premium for its gas if it is willing to sell on terms different from the industry standard**

WHY CONSIDER A ROYALTY-IN-KIND SALE NOW?

- **2001 Legislative resolution**
- **Open season requires long-term commitments for pipeline capacity**
- **Governor's policy council**
- **Expressions of interest**

PROCEDURES FOR ROYALTY-IN-KIND SALE

To Date:

First DNR Finding	October 2001
First Royalty Board Hearing	November 2001
First Public Comment Period	Oct – Nov 2001
Second DNR Finding*	December 2001
Request for Proposals*	December 2001

Remaining:

Submission of Proposals	January 31, 2002
Public Opening of Proposals	February 1, 2002
Negotiations Based on Proposals	February 2002
Second Public Comment Period	March 2002
Second Royalty Board Hearing	March 2002
Third DNR Finding	March 2002
Submission of Proposed Contract(s)	
to Legislature for Approval/Disapproval	April 1, 2002
2002 Legislative Session Adjourns	May 14, 2002

* Available on the web at dog.dnr.state.ak.us

** Remaining dates are subject to change, except date 2002 legislature adjourns

IMPACT OF ROYALTY-IN-KIND SALE ON GASLINE

Three Scenarios:

Case #1: No RIK Sale

***Example:* 15 year nominations required in initial open season
No RIK gas sales during first 15 years of gasline's operation**

Case #2: RIK Sale For Same Duration As Nominations In Initial Open Season

***Example:* 15 year nominations required in initial open season
15 year RIK gas sales contract, no early cancellation rights**

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

***Example:* 15 year nominations required in initial open season
5 year RIK gas sales contract, commencing at gasline start-up**

IMPACT ON INITIAL PIPELINE SIZING

RIK Sale May Result In Bigger Pipeline

Case #1: No RIK Sale

Example:

PBU + PTU Equity Gas	3.50 bcfd
PBU + PTU Royalty Share (nominated by PBU + PTU lessees)	<u>.50 bcfd</u>
Total Pipeline Capacity	4.00 bcfd

Case #2: RIK Sale For Same Duration As Nominations In Initial Open Season

Example:

PBU + PTU Equity Gas	3.50 bcfd
PBU + PTU Royalty Share (nominated by RIK buyer)	.35 bcfd
PBU + PTU Royalty Share (nominated by PBU + PTU lessees)	<u>.15 bcfd</u>
Total Pipeline Capacity	4.00 bcfd

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

Example:

PBU + PTU Equity Gas	3.50 bcfd
PBU + PTU Royalty Share (nominated by RIK buyer)	.35 bcfd
PBU + PTU Royalty Share (nominated by PBU + PTU lessees)	<u>.50 bcfd</u>
Total Pipeline Capacity	4.35 bcfd

IMPACT ON GAS PIPELINE COMPANY

Full Pipeline Capacity Paid For At All Times

Case #1: No RIK Sale

4.00 bcf/d Pipeline Capacity Nominated

4.00 bcf/d Pipeline Capacity Paid For

Case #2: RIK Sale For Same Duration As Nominations In Initial Open Season

4.00 bcf/d Pipeline Capacity Nominated

4.00 bcf/d Pipeline Capacity Paid For

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

4.35 bcf/d Pipeline Capacity Nominated

4.35 bcf/d Pipeline Capacity Paid For

IMPACT ON PBU + PTU OIL & GAS PRODUCERS

May Affect, Positively or Negatively:

- **Pipeline Tariff,**
- **Date of Monetization of Stranded Gas Reserves, and**
- **Level of Usage of Gas Treatment Plant (GTP)**

Case #1: No RIK Sale

Gains: Fixed usage level of Gas Treatment Plant

Losses: Smaller pipeline may mean higher per unit tariff
No acceleration of monetization of stranded gas reserves

Case #2: RIK Sale For Same Duration As Nominations In Initial Open Season

Gains: Fixed usage level of Gas Treatment Plant

Losses: Smaller pipeline may mean higher per unit tariff
No acceleration of monetization of stranded gas reserves

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

Gains: Larger pipeline may mean lower per unit tariff
Acceleration of monetization of stranded gas reserves

Losses: Usage of Gas Treatment Plant may vary between 4.00 and 4.35 bcfd

IMPACT ON PBU + PTU PRODUCERS

(Continued)

Producers Can Mitigate Impact on Level of Usage of Gas Treatment Plant

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

Gains: Larger pipeline may mean lower per unit tariff
 Acceleration of monetization of stranded gas reserves

Losses: Usage of Gas Treatment Plant may vary between 4.00 and 4.35 bcfd

Solutions: Leave .35 bcfd (8%) of GTP capacity idle after 5 years

 Sell .35 bcfd GTP capacity to RIK purchaser

 Expand pipeline capacity .35 bcfd (or more)

 Negotiate for better solution

IMPACT ON PBU + PTU PRODUCERS

(Continued)

Are PBU + PTU Producers Unfairly Disadvantaged?

- **State's right to take in-kind or in-value exists under all leases**
- **State's right to switch between in-kind and in-value exists under all leases**
- **A decision to sell royalty gas from PBU + PTU now does not preclude future RIK sales from the same units or other leases or units**
- **Future sources of royalty gas may be equally "disadvantaged"**

PIPELINE CAPACITY

Initial:	4.5 bcfd	
Optimization:	4.6 – 4.7 bcfd	(+.1 - .2 bcfd)
Expansion through Compression:	5.6 bcfd	(+1.0 bcfd)
Further Expansions:	full length looping future technology	

OBSTACLES TO FUTURE EXPANSIONS

- **Arguably, FERC cannot compel expansion, even where economic**
- **Party or parties must have additional 1+ bcfd gas for expansion**
 - **Party with less than 1 bcfd gas powerless on timing of expansion**
 - **Currently appears PBU/PTU Producers will control timing of expansion**

Current Hydrocarbon Flow

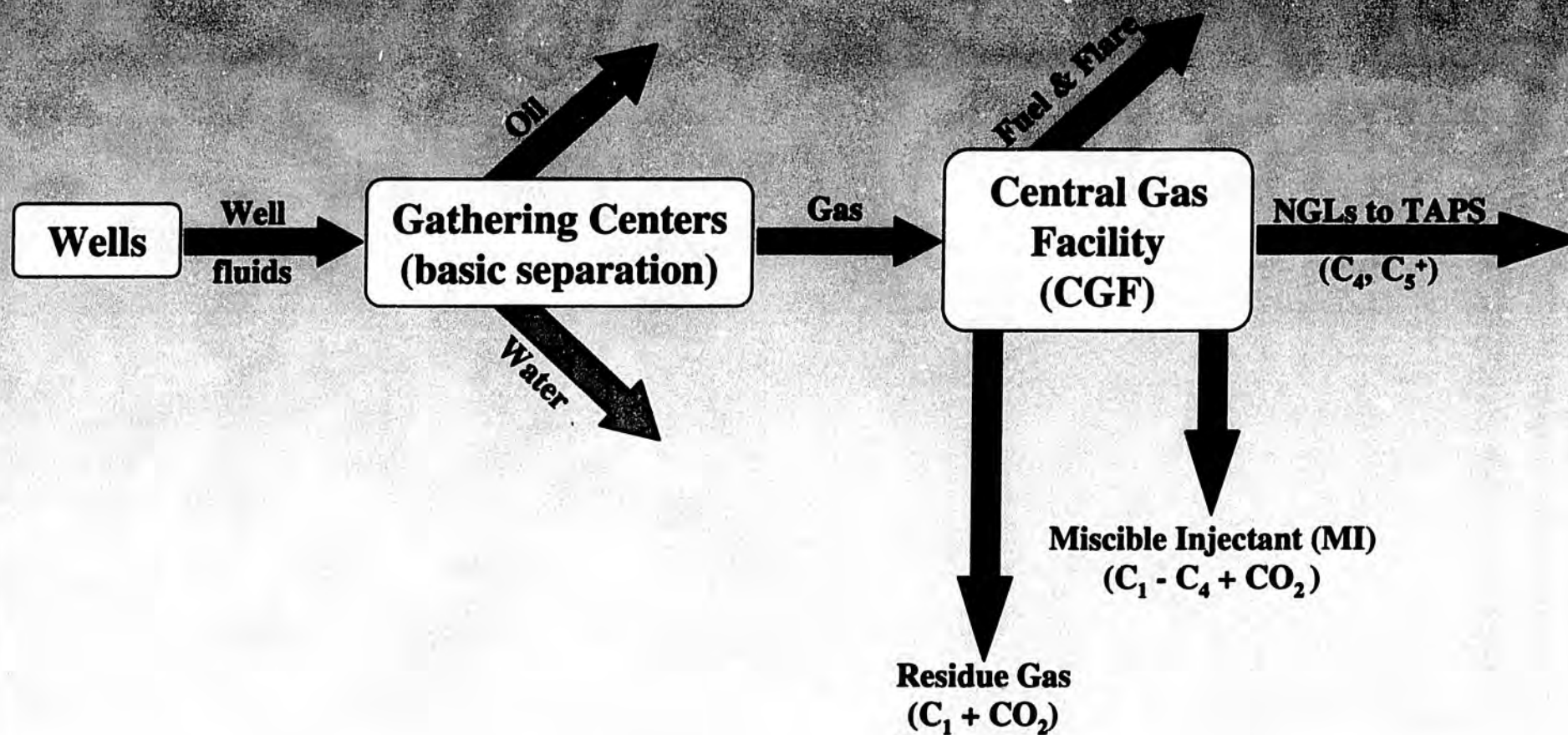


Figure 1

Current Hydrocarbon Flow - Volumes

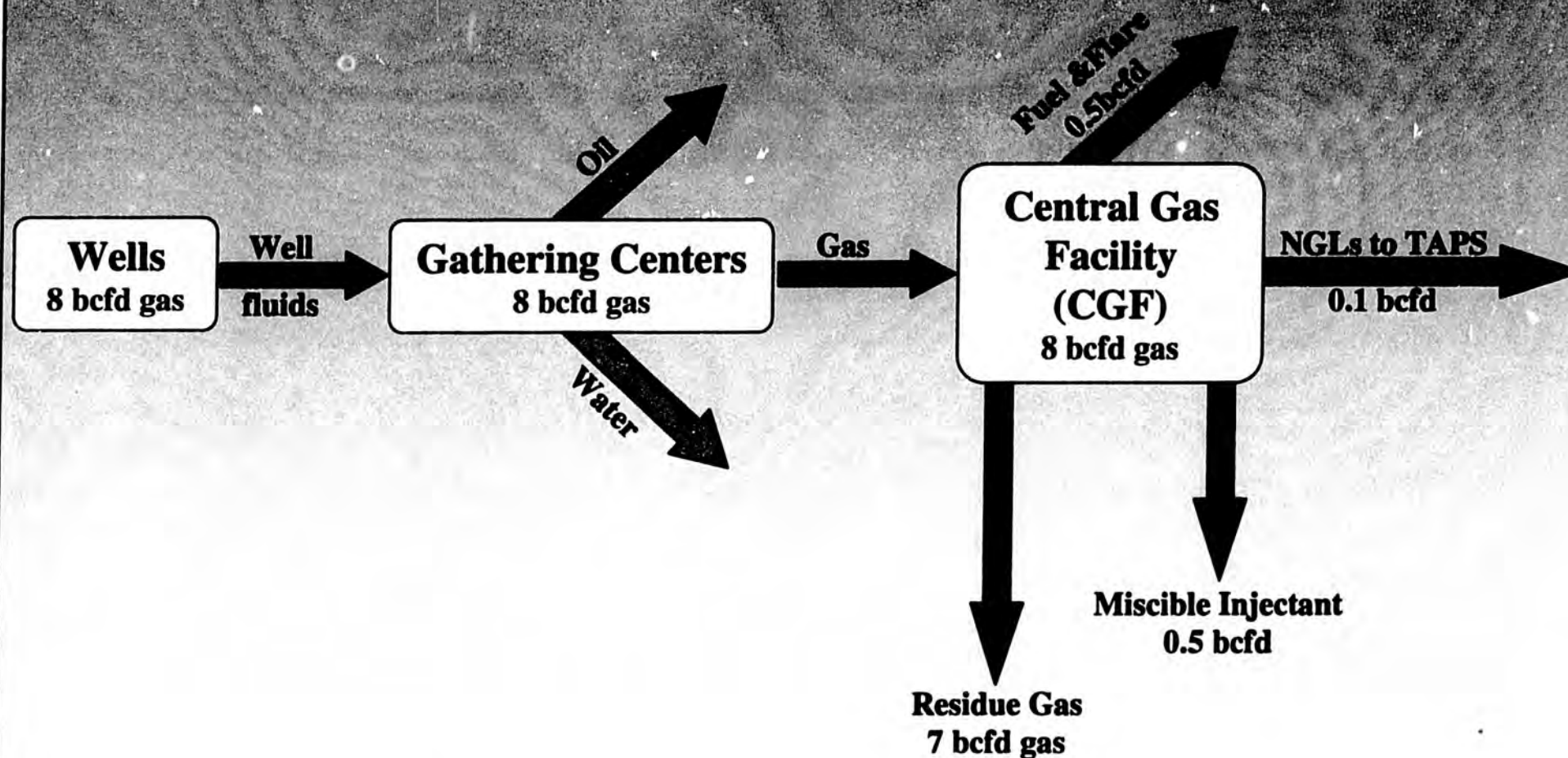


Figure 2

Future Hydrocarbon Flow

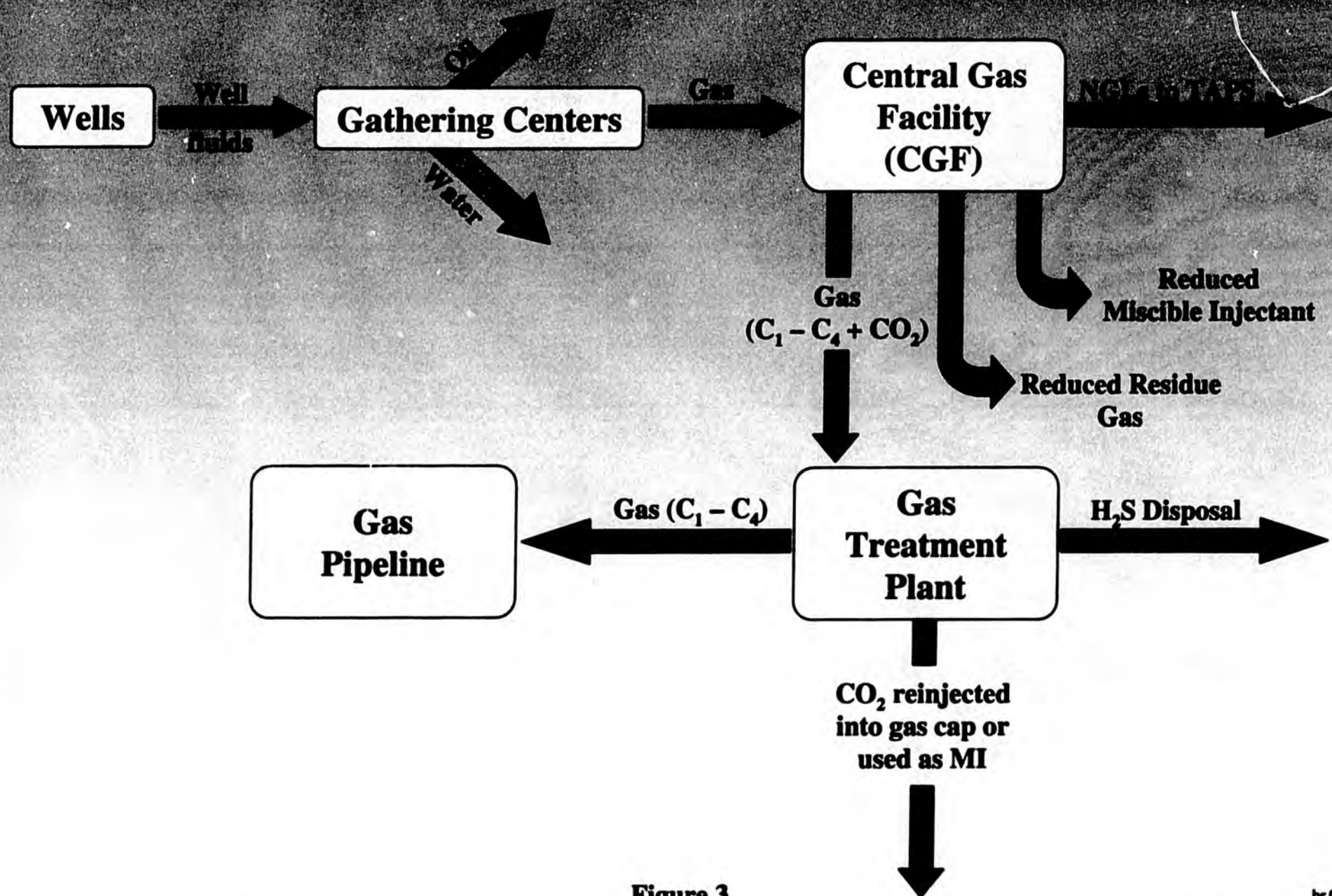
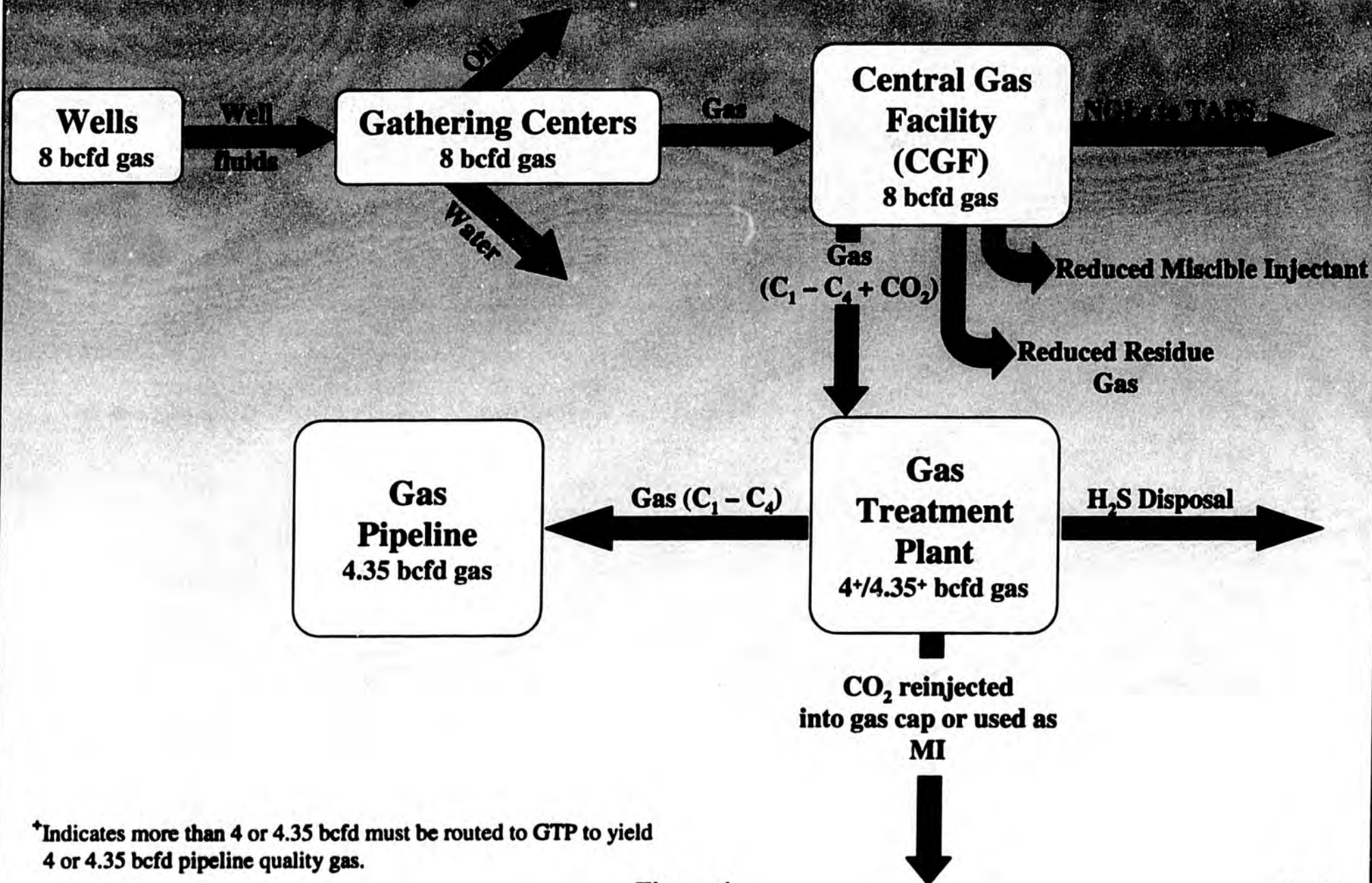


Figure 3

Future Hydrocarbon Flow - Volumes



*Indicates more than 4 or 4.35 bcfd must be routed to GTP to yield 4 or 4.35 bcfd pipeline quality gas.

Figure 4



Alaska Gas Producers Pipeline Team
601 W. 5th Ave. Suite 500
Anchorage, Alaska 99501
1 (907) 770-8000

January 15, 2002

Mr. Pat Pourchot
Commissioner
Alaska Department of Natural Resources
400 Willoughby Avenue, 5th Floor
Juneau, AK 99801

Re: North Slope Royalty Gas Sale Solicitation
Request for Reconsideration of Best Interest Finding

Dear Commissioner Pourchot:

The undersigned represent BP Exploration (Alaska) Inc., ExxonMobil Production Company, a division of Exxon Mobil Corporation, and Phillips Alaska, Inc. Please consider this letter as our request for your reconsideration of the Final Finding and Determination for a Solicitation for Offers to Purchase Alaska North Slope Royalty Gas, dated December 26, 2001 (the "BIF").

As you know, our three companies, and our affiliates, have expended in excess of \$100 million evaluating the feasibility of commercializing the ANS gas resources through the construction of a gas pipeline from the Alaska North Slope to markets in Canada and the "lower 48" states of the United States. To date, we have been unable to identify an economic project. We welcome State of Alaska actions that increase the prospects for project sanction. In that regard, we note that the BIF acknowledges that a gas pipeline project is "by no means certain."¹ We agree, and thus urge the State to focus its efforts on supporting the federal enabling legislation proposed by our companies, advancing discussion of terms and conditions that would enhance certainty in the state's fiscal regime, and other actions that would increase the prospects for an economic project. In contrast, we believe the Department of Natural Resources' solicitation for offers to purchase royalty in kind gas as currently structured is both premature and damaging to the prospects for project sanction.

The BIF states that the RIK solicitation schedule is driven by a desire to accommodate potential buyers who "are motivated to purchase RIK gas at this time in order to be able to nominate capacity on the gas pipeline during an 'open season,' which is currently expected to occur in 2002."² Contrary to this assertion, we do not foresee that we will

bp



ExxonMobil



conduct an open season in 2002. Moreover, we have consistently said that we would not proceed with a project that is not supported by the State of Alaska.

The BIF is based on the premise that the proposed sale of royalty gas would "possibly stimulate an earlier commercialization of ANS gas."³ We disagree. To the contrary, the proposed sale increases the risks for the parties with proven resources, who will ultimately underpin the costs of the pipeline construction. This increase in risk further burdens a project that has yet to be shown to be economic. Moreover, it is unreasonable to assume, as the BIF does, that the pipeline will be overbuilt on the basis of nominations backstopped by RIK gas. The project is being designed to optimize pipeline construction and field development (albeit with expansion potential in mind). Any overbuilding for RIK volumes would be inherently suboptimal.

Finally, the BIF asserts that "[t]he producers acknowledge that the FERC cannot compel a pipeline owner to expand capacity. It is presumed that competitive market forces will provide the necessary incentives."⁴ No precedent is cited in support of this assertion.

In fact, the Federal Energy Regulatory Commission (FERC) asserts that it can compel pipeline expansions in appropriate circumstances.⁵ FERC has implied they would apply the same principles they have applied in interconnection situations, and that would suggest expansion if

1. The party seeking the expansion is willing to bear the costs of construction,
2. The expansion can be accomplished in compliance with the pipeline's technical requirements,
3. The expansion and resulting transportation does not diminish service to the pipeline's existing customers,
4. The expansion does not cause the pipeline to be in violation of any applicable environmental or safety laws or requirements, and
5. The expansion does not cause the pipeline to be in violation of its right of way agreements or any other contractual obligations.⁶

We would be happy to meet with the State and the FERC to discuss these issues to assure a common understanding of these issues.

In conclusion, we believe that FERC regulatory authority will insure that future expansions of transportation capacity for North Slope gas are based solely on market forces. By contrast, the RIK "backstop" mechanism under consideration by the Department of Natural Resources is contrary to the modern FERC market-based principles, since it would burden the initial project with a reservation of capacity for as-yet unproven, and thus currently uneconomic, gas resources.

Mr. Pat Pourchot
January 15, 2002
Page -3-

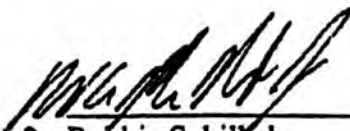
We request that you exercise your authority to cancel the solicitation. Alternatively, we request that you delay the solicitation until at least December 2002.

Please mail any notice or decision concerning the appeal to:

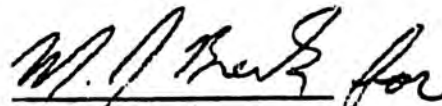
John S. Carr, Esq.,
Managing Counsel
Alaska Gas Producers Pipeline Team
601 W. 5th Ave., Ste. 500
Anchorage, AK 99501
Carris@bp.com
(907) 770-8036 (p)
(907) 770-8009 (fax)

We appreciate your reconsideration of this important matter. While we do not request a formal hearing, we would be pleased to meet with you to address our conviction that the state's proposed sale will have a negative impact on the prospects for the construction of a gas pipeline and our belief that there is, in any event, no need to rush the timing of the solicitation.

Sincerely,


for Robbie Schilhab

Ken Konrad


Joe Marushack

cc: Mark Myers

Mr. Pat Pourchot
January 15, 2002
Page -3-

We request that you exercise your authority to cancel the solicitation. Alternatively, we request that you delay the solicitation until at least December 2002.

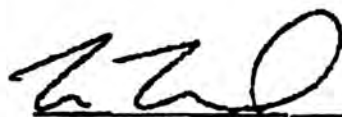
Please mail any notice or decision concerning the appeal to:

John S. Carr, Esq.,
Managing Counsel
Alaska Gas Producers Pipeline Team
601 W. 5th Ave., Ste. 500
Anchorage, AK 99501
Carr@bp.com
(907) 770-8036 (p)
(907) 770-8009 (fax)

We appreciate your reconsideration of this important matter. While we do not request a formal hearing, we would be pleased to meet with you to address our conviction that the state's proposed sale will have a negative impact on the prospects for the construction of a gas pipeline and our belief that there is, in any event, no need to rush the timing of the solicitation.

Sincerely,

Robbie Schilhab



Ken Konrad



Joe Marushack

cc: Mark Myers

Mr. Pat Pourchot
January 15, 2002
Page 4

¹ BIF at Section I.B.

² BIF at Section I.B.

³ BIF at Section IV.A.

⁴ BIF at Appendix B-8.

⁵ In Order No. 637, 65 Fed. Reg. 10,157 (Feb. 25, 2000), the FERC provided a lengthy commentary on the changing gas pipeline market and the associated regulatory changes. The FERC defined its regulatory objective as to "promote competitive and efficient markets, while mitigating market power and preventing undue discrimination...." 65 Fed. Reg. at 10168. Consistent with these objectives, the FERC stated:

[B]ecause of the possibility of affiliate abuse, the Commission will be particularly sensitive to complaints that pipelines, on which affiliates hold large amounts of transportation capacity, are refusing to undertake construction projects when demand for construction exists. In cases where such concerns are established, the Commission would need to take remedial measures. Depending on the circumstances, such remedies could include: requiring pipelines to put in taps to reduce capacity bottlenecks; requiring pipelines to build additional capacity when requested by customers willing to pay the costs of construction; limiting the rates at which the affiliate can release capacity; limiting the amount of capacity the affiliate can hold; or prohibiting the affiliate from holding capacity on its related pipeline.

Order No. 637, id. at 10186 Emphasis added).]

⁶ Panhandle Eastern Pipeline Co., 79 FERC P61,016 (1997), ANR Pipeline Company v. Transcontinental Gas Pipe Line Corp., 91 FERC P61,066, 2000 FERC LEXIS 823 (2000)



Remember what happened...



adn.com

Anchorage Daily News

North Slope gas opened to bidders

ROYALTY: State hopes to spark interest and test the market.

By Paula Dobbyn

Anchorage Daily News

(Published: December 27, 2001)

In a bid to stimulate exploration and test the market, the state is offering to sell North Slope natural gas directly to buyers for the first time. Bids can be made through the end of next month through the Alaska Department of Natural Resources.

As owner of the land, the state collects a percentage of oil and gas produced from state leases. Typically the state collects cash from the producers instead of actually finding buyers for the gas. State officials also sometimes take this "royalty" oil or gas and sell it directly to the highest bidder.

On the North Slope, the state has never taken that step before with its gas. But a natural gas policy advisory group appointed by the governor recommended such a move in November.

The state's option to sell its royalty gas directly must be retained, the advisory group said. Sales of royalty gas to companies other than producers will foster competition, leading to greater values and more benefits to residents, it said.

Although the state will be taking bids, it might not go through with the sales. Much will depend on the prices offered and to what extent the bidders' plans for the gas would benefit Alaska residents, said Mark Myers, director of the state Division of Oil and Gas.

Huge amounts of North Slope natural gas are produced now, but most is injected back underground to help produce more oil and because there's no way to get it to market; a little is used to power the oil fields or becomes liquid during production and then is put in the trans-Alaska oil pipeline.

The main North Slope companies are considering whether to pursue a multibillion-dollar gas pipeline project. If that happens, the state as landowner would get the fourth largest share of production, behind Exxon, Phillips and BP.

The state has received numerous inquiries about royalty gas from exploration and gas trading companies that want to see the pipeline built, said Kevin Banks, state petroleum market analyst.

To get the financing needed to make the pipeline a reality, the companies must show lenders signed contracts with gas suppliers to demonstrate that enough gas will flow through the line. Giving exploration companies the option of purchasing royalty gas puts them on more solid financial ground because if they don't find enough gas on their own, they have the option of buying it from the state, said Banks and other industry watchers.

"It removes some of the risk about getting gas into the pipeline," Myers said.

Spokesmen for BP Exploration (Alaska) Inc. and Phillips Alaska Inc. declined to comment.

"It's just good business sense," said Frank Brown, an oil and gas consultant and former senior vice president at Arco Alaska Inc.

"What the state needs to do is to preserve its option. Rather than depending on the big oil companies to market their gas for them, they need to preserve their options," said Brown, who co-chaired the governor's natural gas advisory group.

Reporter Paula Dobbyn can be reached at pdobbyn@adn.com or 907 257-4317.

Close Window

Copyright © 2001 **The Anchorage Daily News** (www.adn.com)



Alaska Gas Producers Pipeline Team
601 W. 5th Ave. Suite 500
Anchorage, Alaska 99501
1 (907) 770-8000

January 15, 2002

Mr. Pat Pourchot
Commissioner
Alaska Department of Natural Resources
400 Willoughby Avenue, 5th Floor
Juneau, AK 99801

Re: North Slope Royalty Gas Sale Solicitation
Request for Reconsideration of Best Interest Finding

Dear Commissioner Pourchot:

The undersigned represent BP Exploration (Alaska) Inc., ExxonMobil Production Company, a division of Exxon Mobil Corporation, and Phillips Alaska, Inc. Please consider this letter as our request for your reconsideration of the Final Finding and Determination for a Solicitation for Offers to Purchase Alaska North Slope Royalty Gas, dated December 26, 2001 (the "BIF").

As you know, our three companies, and our affiliates, have expended in excess of \$100 million evaluating the feasibility of commercializing the ANS gas resources through the construction of a gas pipeline from the Alaska North Slope to markets in Canada and the "lower 48" states of the United States. To date, we have been unable to identify an economic project. We welcome State of Alaska actions that increase the prospects for project sanction. In that regard, we note that the BIF acknowledges that a gas pipeline project is "by no means certain."¹ We agree, and thus urge the State to focus its efforts on supporting the federal enabling legislation proposed by our companies, advancing discussion of terms and conditions that would enhance certainty in the state's fiscal regime, and other actions that would increase the prospects for an economic project. In contrast, we believe the Department of Natural Resources' solicitation for offers to purchase royalty in kind gas as currently structured is both premature and damaging to the prospects for project sanction.

The BIF states that the RIK solicitation schedule is driven by a desire to accommodate potential buyers who "are motivated to purchase RIK gas at this time in order to be able to nominate capacity on the gas pipeline during an 'open season,' which is currently expected to occur in 2002."² Contrary to this assertion, we do not foresee that we will



ExxonMobil



conduct an open season in 2002. Moreover, we have consistently said that we would not proceed with a project that is not supported by the State of Alaska.

The BIF is based on the premise that the proposed sale of royalty gas would "possibly stimulate an earlier commercialization of ANS gas."³ We disagree. To the contrary, the proposed sale increases the risks for the parties with proven resources, who will ultimately underpin the costs of the pipeline construction. This increase in risk further burdens a project that has yet to be shown to be economic. Moreover, it is unreasonable to assume, as the BIF does, that the pipeline will be overbuilt on the basis of nominations backstopped by RIK gas. The project is being designed to optimize pipeline construction and field development (albeit with expansion potential in mind). Any overbuilding for RIK volumes would be inherently suboptimal.

Finally, the BIF asserts that "[t]he producers acknowledge that the FERC cannot compel a pipeline owner to expand capacity. It is presumed that competitive market forces will provide the necessary incentives."⁴ No precedent is cited in support of this assertion.

In fact, the Federal Energy Regulatory Commission (FERC) asserts that it can compel pipeline expansions in appropriate circumstances.⁵ FERC has implied they would apply the same principles they have applied in interconnection situations, and that would suggest expansion if

1. The party seeking the expansion is willing to bear the costs of construction,
2. The expansion can be accomplished in compliance with the pipeline's technical requirements,
3. The expansion and resulting transportation does not diminish service to the pipeline's existing customers,
4. The expansion does not cause the pipeline to be in violation of any applicable environmental or safety laws or requirements, and
5. The expansion does not cause the pipeline to be in violation of its right of way agreements or any other contractual obligations.⁶

We would be happy to meet with the State and the FERC to discuss these issues to as...are a common understanding of these issues.

In conclusion, we believe that FERC regulatory authority will insure that future expansions of transportation capacity for North Slope gas are based solely on market forces. By contrast, the RIK "backstop" mechanism under consideration by the Department of Natural Resources is contrary to the modern FERC market-based principles, since it would burden the initial project with a reservation of capacity for as-yet unproven, and thus currently uneconomic, gas resources.

Mr. Pat Pourchot
January 15, 2002
Page -3-

We request that you exercise your authority to cancel the solicitation. Alternatively, we request that you delay the solicitation until at least December 2002.

Please mail any notice or decision concerning the appeal to:

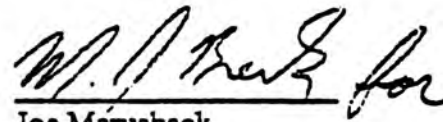
John S. Carr, Esq.,
Managing Counsel
Alaska Gas Producers Pipeline Team
601 W. 5th Ave., Ste. 500
Anchorage, AK 99501
Carris@bp.com
(907) 770-8036 (p)
(907) 770-8009 (fax)

We appreciate your reconsideration of this important matter. While we do not request a formal hearing, we would be pleased to meet with you to address our conviction that the state's proposed sale will have a negative impact on the prospects for the construction of a gas pipeline and our belief that there is, in any event, no need to rush the timing of the solicitation.

Sincerely,


for Robbie Schilhab

Ken Konrad


Joe Marushack

cc: Mark Myers

Mr. Pat Pouchot
January 15, 2002
Page -3-

We request that you exercise your authority to cancel the solicitation. Alternatively, we request that you delay the solicitation until at least December 2002.

Please mail any notice or decision concerning the appeal to:

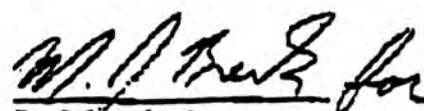
John S. Carr, Esq.,
Managing Counsel
Alaska Gas Producers Pipeline Team
601 W. 5th Ave., Ste. 500
Anchorage, AK 99501
Carrs@bp.com
(907) 770-8036 (p)
(907) 770-8009 (fax)

We appreciate your reconsideration of this important matter. While we do not request a formal hearing, we would be pleased to meet with you to address our conviction that the state's proposed sale will have a negative impact on the prospects for the construction of a gas pipeline and our belief that there is, in any event, no need to rush the timing of the solicitation.

Sincerely,

Robbie Schilhab


Ken Konrad


Joe Marushack

cc: Mark Myers

¹ BIF at Section I.B.

² BIF at Section I.B.

³ BIF at Section IV.A.

⁴ BIF at Appendix B-8.

⁵ In Order No. 637, 65 Fed. Reg. 10,157 (Feb. 25, 2000), the FERC provided a lengthy commentary on the changing gas pipeline market and the associated regulatory changes. The FERC defined its regulatory objective as to "promote competitive and efficient markets, while mitigating market power and preventing undue discrimination...." 65 Fed. Reg. at 10168. Consistent with these objectives, the FERC stated:

[B]ecause of the possibility of affiliate abuse, the Commission will be particularly sensitive to complaints that pipelines, on which affiliates hold large amounts of transportation capacity, are refusing to undertake construction projects when demand for construction exists. In cases where such concerns are established, the Commission would need to take remedial measures. Depending on the circumstances, such remedies could include: requiring pipelines to put in taps to reduce capacity bottlenecks; requiring pipelines to build additional capacity when requested by customers willing to pay the costs of construction; limiting the rates at which the affiliate can release capacity; limiting the amount of capacity the affiliate can hold; or prohibiting the affiliate from holding capacity on its related pipeline.

Order No. 637, *id.* at 10186 (Emphasis added).]

⁶ *Panhandle Eastern Pipeline Co.*, 79 FERC P61,016 (1997), *ANR Pipeline Company v. Transcontinental Gas Pipe Line Corp.*, 91 FERC P61,066, 2000 FERC LEXIS 823 (2000)

Subject: Re: House Oil & Gas

Date: Mon, 14 Jan 2002 16:06:09 -0900

From: "Ken Thompson" <ken@pacrimldr.com>

To: "Linda Hay" <Linda_Hay@Legis.state.ak.us>

Linda, I strongly support the State selling part - not all - of its royalty gas "in kind" versus "in value". This was a key recommendation from my "In-state Gas Use Committee" of the Natural Gas Policy Council. Selling part of the royalty gas to a high bidder creates more natural gas marketing competition. There are other pluses also. Importantly, the State would only sell to a third party if the netback natural gas price exceeded at least the average of the netback prices being received by the producers, so value of the RIK gas would be maximized.

Linda, I have attached excerpts from my committee's recommendations and conclusions from the Natural Gas Policy Council that highlights my and our committee's views. As Representative Ogan reviews what the State considers, any deal should meet the recommendations in the attachments.

Linda, importantly, I did review the DNR-DOG final "solicitation for RIK gas bid" letter that went out to potential bidders. I agreed with that overall and believe it is the best course of action. I did, however, have one major difference of opinion: the DNR is putting up for bid 70% of the State's RIK gas share. At this time, I personally would put up for bid only 50% of the State's RIK gas share to ensure we have enough gas for in-state markets and in-state use in the event the Cook Inlet deliverability falls more quickly than we forecast. If Cook Inlet gas deliverability forecasts are accurate, additional RIK gas could be sold to a third party at that time.

Additionally, I don't think we should sell all the RIK to one bidder, but perhaps to the top two bidders...to create competition even among those third parties and to keep good companies other than the producers interested in marketing Alaska's natural gas.

This note and the attachment really summarizes my views. If you or Representative Ogan have questions, please e-mail me or give me a call at 907-770-1600. I also can testify to the House Oil and Gas Resources Committee if needed. Ken

----- Original Message -----

From: "Linda Hay" <Linda_Hay@Legis.state.ak.us>

To: <ken@pacrimldr.com>

Sent: Monday, January 14, 2002 2:00 PM

Subject: House Oil & Gas

> Ken. Rep. Ogan has asked me to contact you and get your thoughts on the
> administration's decision to sell "royalty gas". We have scheduled a
> hearing for Thursday, January 17th, from 10 - noon. We will begin with
> an overview by the the Division of Oil & Gas on what has transpired
> since adjournment and then begin a discussion regarding the royalty gas
> sale issue. We are interested in your thoughts on this decision. Look
> forward to talking to you and perhaps seeing you here in Juneau in the
> near future.

> Linda Hay
> O & G Committee Aide
> 465-2283 (direct line)
>
>

EXCERPTS FROM NATURAL GAS POLICY COUNCIL REPORT
KEN THOMPSON'S "IN-STATE GAS USE COMMITTEE"
RECOMMENDATIONS, CONCLUSIONS REGARDING RIK GAS SHARE

Goal: Assess the costs or benefits of the state taking its royalty share "in kind" for facilitation of in-state access and use.

Recommendation:

The State should retain its right to take its royalty share of gas on the North Slope "in kind" or "in value". This flexibility creates competition to maximize wellhead value for the State by either the producers or other firms such as energy trading companies interested in marketing the State's share of gas. The producers have requested a long-term commitment by the state and are asking the State to decide up front to take either "in-kind" or "in-value". The council feels the flexibility to switch on six months notice is very important, creates marketing competition, and will ultimately maximize resource value. The State should not negotiate away its right to take its royalty share of gas "in-value" or "in-kind".

Recommendation:

The state could maximize the value of its natural gas royalty resource with a mixed portfolio of "in-value" and "in-kind" sales, with in-kind royalty marketed by energy trading companies such as Duke Energy, Enron, Williams Energy or major companies like them. The state should put its royalty "in-kind" gas out for bid and seek bids from multiple parties for contract terms and price. Such contracts should ask for a "floor price" equal to or exceeding the average netback wellhead price achieved by the three major producers or from "in value" sales as "insurance" that the energy trading companies are working in their marketing to beat the producers gas sales realization.

Recommendation:

When there are out-of-state sales using an energy trading company, the energy trading company will reserve the capacity and the liability associated with that capacity, and that liability will not fall back on the state.

Recommendation:

The State may choose to direct market some portion of its gas to in-state consumers using State staff, but it is recommended that sales to customers in outside markets be handled by professional energy trading firms, considering the complexity of and rapid change in those markets. This would also allow those firms to absorb the risk of nominating pipeline capacity and buying hedging instruments to lessen risk on pricing of contracts.

Recommendation:

By keeping some portion of its royalty share of natural gas "in-kind", the State may be able to make some contract deals with consumers in-state at more favorable terms than the producers, as the State might realize added dollar benefits through jobs and corporate taxation of value-added processing such as natural gas liquids processing, petrochemical manufacturing, power generation, etc. that may not otherwise be economically viable to entrepreneurs within the State. However, there should not be a subsidy in sales of royalty-in-kind gas. The state should receive a netback price for royalty gas equal to or greater than the market-based "netback value" of gas on the North Slope.

Recommendation:

To the extent practical, the State of Alaska should enforce its "higher of" clauses on natural gas royalty as this could add value and ensure producers work hard in their marketing to obtain the best value in their sales of natural gas. When the State elects to take any share of its royalty gas "in value", existing lease terms and statutes allow the State to receive royalty payments and production taxes on the "higher of" actual proceeds or market value. Other states, as well as the U.S. Minerals Management Service, are aggressive in ensuring all producers pay this "higher of" price for royalty and relevant taxes and receives such payments from the same producers that produce on the North Slope.

Recommendation:

Because of the complexities of the natural gas industry and the differences with the oil industry, the State should form a Natural Gas Services Group with people experienced in the natural gas industry, shipping, marketing, and trading so that the State becomes even more sophisticated in understanding deals and transactions that are often involved in the natural gas business. The group would provide an oversight function on sales of royalty gas out-of-state, but could also negotiate and manage in-state sales much like the Division of Oil and Gas now manages sales of royalty oil.

Recommendation:

For more cost effective development of in-state gas infrastructure resulting in more economical transportation of state royalty gas within the State, the State should encourage entities to examine the port authority concept of tax advantaged financing for a gas "hub", spur lines, and other distribution facilities.

Conclusions:

* Current North Slope oil and gas leases, and state statutes, allow state royalty production share to be taken "in kind", i.e. physically take the oil or gas and market the products itself or arrange for other parties to purchase the gas at market

value contracts; or to take "in value", i.e. allow the producers to sell the products and pay the State their realized value of wellhead price after deduction of certain transportation costs. The state has the option to switch between taking its royalty share "in-kind" and "in-value" every six months. Current state law requires any "in-kind" sales, however, to obtain values equal to or higher than "in-value" sales.

* The current North Slope producers have complied with the "in kind" or "in value" lease terms and statutes in other states and on federal offshore leases for decades and have instituted internal procedures that allow them to process the selection of "in kind" or "in value" promptly. Other states and the federal government also have internal processes for administering the switch between "in kind" or "in value" as does the State of Alaska for its royalty share of oil. The producers' arguments that Alaska must decide up front on "in kind" or "in value" to ease marketing and sales administration or to bring more certainty to gas transportation or marketing are not valid considering the same producers' decades of experience administering such programs for transportation and marketing elsewhere successfully.

* The natural gas industry in the U.S. is very sophisticated in gas trading and marketing. There are energy trading companies which may be able to market the state's royalty gas for a higher netback price than would be paid by the producers if the gas were taken in-value. If so, the state's leases include a "higher of" clause which means producers would have to pay royalties and taxes on the higher of their actual netback wellhead price or the actual netback wellhead price of an energy trader. This, in a way, creates competition and options to achieve the best possible wellhead netback value.

* In testimony from the General Land Office of Texas, the committee learned that Texas has similar "higher-of" clauses in their state leases that they enforce. In 2000, enforcement of the "higher-of" clauses, with producers paying royalties and taxes on the highest actual netback wellhead price achieved on various leases, resulted in additional revenues of \$17 million. Alaska's royalty gas sales will be ten times higher than Texas' volume of royalty gas sales.

* Alaska may achieve higher prices on some of its royalty gas by allowing energy trading companies to market the State's "in kind" share. The State of Texas takes 53 percent of its royalty gas in-kind and 47 percent in value, and claims to achieve higher prices on much of its royalty-in-kind sales by achieving better negotiated pipeline tariffs, higher customer prices, or integration for power generation.

* However, the flexibility in taking royalty-in-kind is important for other reasons as well as price. First, royalty sales will allow the state to periodically test the market, to assess whether it is getting fair market prices from producers. Second,

allowing energy trading companies to market royalty gas will create more competition by their accessing different customers than the producers and broadening the market exposure of Alaska's natural gas.

* While Texas is able to market its royalty gas with a small staff of state employees, Alaska should "outsource" its sales of royalty gas to the Lower 48 or other outside markets through an experienced gas trading firm. Because large volumes of Alaska royalty gas may be marketed in several of the Lower 48 gas markets or outside markets initially, a thorough understanding of and experience in those markets will be required.

* On the other hand, it may be more appropriate that the state negotiate directly for sales within Alaska of in-kind royalty gas as is now done with royalty oil, because of the better understanding of local conditions. A section within a new Natural Gas Services Group could perform this function.

* The concept of a public authority owning a segment of a natural gas pipeline within Alaska may present significant benefits for transportation of state royalty gas to in-state users. The tax advantage of a public authority, for example, would allow a lower tariff for transporting gas within the State, and resulting savings could help generate more business activity by providing natural gas at lower prices to consumers. The netback price, however, should remain at market values.

**Williams [NYSE: WMB]
Alaska North Slope Royalty Gas
January 31, 2002**

Alaska North Slope Royalty Gas Offer

Williams is pleased to participate in the State of Alaska's Solicitation for Offers issued Dec. 26, 2001, for the Alaska North Slope Royalty Gas. It is Williams' standard practice to submit all such responses under confidential terms and conditions. Therefore, the specific terms and conditions included in Williams' response submitted to the State of Alaska on Jan. 31 will not be able to disclose at this time.

Williams has a long history of working with the State of Alaska through contractual agreements to purchase the state's Royalty Crude.

Williams in Alaska

Williams operates the state's largest refinery at North Pole, processing 215,000 barrels per day of Alaska North Slope crude into 70,000 barrels of products (primarily jet fuel) per day. Williams also operates terminal facilities in Anchorage and Fairbanks and 29 convenience stores in the State.

Williams spent nearly \$1 billion for goods and services in Alaska during 2001, primarily for crude oil supply. Williams has more than 500 employees in Alaska with an annual payroll in excess of \$20 million. Williams is a large customer of the state-owned Alaska Railroad. And, Williams is a major contributor with dollars and manpower for a wide range of charitable groups.

About Williams

Williams, through its subsidiaries, connects businesses to energy, delivering innovative, reliable products and services. Williams information is available at www.williams.com.

Offer

To Purchase Alaska North Slope Royalty Gas

By

Alaska Power & Telephone Company

January 25, 2002

1. Qualification to Offer was submitted to Department of Natural Resources, Division of Oil and Gas on January 7, 2002. A copy of that submission is attached.
2. We hereby commit to a cash bonus of \$1.00 per Mcf per day.
3. We hereby agree to a Maximum Quantity of 1600 Mcf per day.
4. We hereby agree to pay at a "minimum" the base price as established in Article 3.3.1 of the sample contract.
5. Attached is a white paper that discusses the economic benefits of converting the power plant to use natural gas as its primary fuel and also building a small natural gas distribution system. Both the power system and the natural gas system would be located in Tok, Alaska. This paper indicates significant economic benefit to our existing electric customers as well as our proposed future natural gas customers.

Alaska Power & Telephone Company

By 

Its President

ANADARKO/AEC
OFFER FOR ROYALTY GAS SUMMARY
January 31, 2002

1. Cash Payment: \$350,000.
2. Option Payment: \$2 million up-front and an additional \$2 million at each 5 year term renewal.
3. Price Premium: \$0.02 per MMBtu first 5 years, with \$0.02 per MMBtu increases at each 5-year term renewal.
4. Reservation Fee: Equal to one percent (1.0%) of the sum of the Base Price and the then applicable Price Premium, subject to a cap equal to the then effective Price Premium.
5. Exploration Work Commitment: A minimum \$50 million expenditure for exploration and development in the gas-prone Brooks Range foothills ("Foothills") for 2002-2007.
6. Preference for Local Hire: The Purchasers agree to a local hire preference.
7. Training Obligation: In the event of a commercial Foothills gas discovery, the Purchasers agree to an annual training obligation of not less than \$25,000 per annum commencing the year of commercial discovery declaration and for a period of not less than ten (10) years.
8. Preference for In-State Gas Processing: The Purchasers agree to give preference to in-State processing of both the purchased State ANS Royalty Gas and any gas discovered in the Purchasers' Foothills exploration efforts. Such in-State processing must afford the Purchasers equivalent terms and conditions that they could otherwise receive for out-of-state processing.
9. In-State Usage Reservation: The State is afforded an in-State gas use preference to the extent the Purchasers' 70% call would exceed 350 MMcfd.
10. Call Option: APC and AEC granted right to call for all or a portion of State's royalty gas up to 70% of State's ANS royalty gas (Estimated at 350 MMcfd).
11. Quantity: Up to 70% of State's ANS royalty gas at APC's/AEC's election (Estimated at 350 MMcfd).
12. Employment & Economic Impact Related to the Exploration Work Commitment: Anchorage based Northern Economics has prepared a study quantifying these two benefits with respect to our Exploration Work Commitments under both an "Exploration Only Scenario" and a "Successful Development Scenario". The Exploration Only Scenario yields total in-State economic value of \$40 million and creates an annual average of 180 new jobs. The Successful Development Scenario yields total in-State economic benefits of \$6.4 billion and creates an annual average 560 - 3,300 new jobs, depending upon the operations mode (exploration, development, or production).
13. Offer Value Per Mcf: The Purchasers' Offer yields a value of \$0.09 per Mcf and \$10.06 per Mcf, in the Exploration Only and the Successful Development Scenarios, respectively. These values were computed based upon a purchase quantity of 639 Bcf during the Primary Term of five (5) years.

14. Term: Call option for primary term of 5 years ending at 5th anniversary of Pipeline being placed in full, normal service. APC and AEC have the option to extend the term for additional 5-year intervals with additional Option Payments and escalations in the Price Premium. Term cannot be extended beyond the term of the transportation contracts secured for such gas.
15. Early Termination Provision: Either Party may terminate early if (i) the Royalty Board and Legislature have not approved the definitive Agreement by August 31, 2002; (ii) no Pipeline open season has occurred by March 31, 2005; or (iii) the Pipeline is not in service or State Royalty Gas has not been delivered by July 31, 2012.
16. Point of Delivery: To be negotiated between the State and the Purchasers.
17. Firm Transportation Service Release: If APC/AEC are unsuccessful in securing firm transportation on the Pipeline in quantities equal to or greater than the volume necessary to achieve an economic gas development, APC/AEC may terminate the Agreement without further obligation.
18. Separate Agreements: Anadarko and AEC will enter into separate Agreements with the State for one-half of the option volume rights and one-half the obligations. Initial Agreements shall be equivalent, but administration and application shall be separate and independent.

**Testimony of Ken Konrad, Sr Vice President BP Exploration (Alaska) Inc.
to**

**House Oil and Gas Committee Hearing on
State Royalty In Kind Gas Sale Proposal**

February 5, 2002

Good Morning. My name is Ken Konrad. I am Vice President for BP's Alaska Gas business. Thanks for inviting me to speak here today regarding the State's proposed Royalty in Kind gas sale.

I'd like to begin by saying that BP supports the State's right to take gas in kind. We also fully support exploring for new sources of gas that could be produced into a gas pipeline. Furthermore, we support gas pipeline capacity expansion on open, fair and reasonable terms.

BP, and our major partners, are in the process of completing a major feasibility and engineering study on a possible gas pipeline. A central premise in that study is designing a pipeline system that can be easily expanded - and we have been successful in achieving a design that has higher expansion capability at lower cost than any other proposal we have seen. Efficient pipeline expansion can benefit both existing producers and explorers.

We understand the State's desire to see development of additional gas beyond the existing known resource. Indeed, the feasibility study we have undertaken this year assumes that additional gas will be found beyond the 35 TCF of currently identified gas. We currently assume at least 50 TCF of total gas will be needed during the life of a project.

Separately, BP is working on a major study with the DOE and the University of Alaska - Fairbanks to study possible ways to produce the enormous gas hydrate resource known to exist in and around existing north slope fields - this resource alone has been estimated at nearly 50 TCF. This is long term possibility with many technical challenges but is indicative of our active support for new sources of gas supply.

We support the States right to take gas in kind. This is clearly a choice the State should make on its own. Our sole request is that the State do so in a predictable manner that is consistent with how a contract carry gas pipeline will operate.

So we fully support the State's ability to take in kind, we fully support pipeline expansion on fair and reasonable terms and we fully support finding new sources of gas supply.

We do however have concerns over the proposed State sale of RIK gas as currently structured and also with respect to timing. We have openly discussed our concerns with the DNR over the past several months.

The State has frequently indicated that this proposed RIK sale is being driven by the perception that the Alaska Gas Producers Pipeline Team may hold an "open season" for

pipeline capacity in early 2002. We do not foresee any possibility of holding an open season during 2002.

As we have stated previously, for a gas pipeline to attract investment, there must first be an economic project. To reduce project risks, there must also be a predictable and viable government framework in place to support investment. Both federal regulatory legislation and clarity around State tax and royalty are important pieces of this government framework. Neither of these vital ingredients are currently in place.

According to DNR, the State's proposed RIK gas sale is being pursued to provide a free capacity access option to explorers without currently proven gas resources. The idea being that explorers could use the state's RIK gas to backstop their own bids for firm transport capacity on a new build line and then release the RIK gas back to the state should they find their own reserves.

The ability of RIK purchasers to return gas to the state on relatively short notice places a significant additional burden on our overall project economics by increasing the uncertainty on the amount of equity gas the major producers would be able to ship - i.e. uncertain cash flow. This burden on a sub-economic project is a clear step in the wrong direction.

For example, if a pipeline is designed to transport 4bcfd (just an example) and the State took 1/8th of this gas in kind - 500 mmcf/d - an RIK purchaser could use its purchased gas as a backstop for making a long term firm transportation commitment on a gas line. The balance of the FT commitments to get the line built would be made by the known resource owners. Should an RIK purchaser discover its own gas resources, it could cancel its purchase contract with the state and substitute its own gas into its Firm Transportation commitment. The State's gas would then revert back to the known resource owners in the form of RIV gas thus reducing by 500mmcf/d the amount of their own gas that the resource owners could export via their own fixed-volume of FT commitment. This reduction in cash flow is against firm financial commitments that have already been made.

The State's RIK proposal clearly seeks to transfer benefits from long term investors to new participants without transferring the risk associated with the massive investment that will be required to make any gas pipeline a reality. Such subsidies at the expense of those who will ultimately underwrite any new build pipeline are both unfair and, more importantly, reduce the chances of developing an economically viable project.

There is no access to a pipeline that never gets built.

BP supports the State's right to take gas in kind. We support pipeline expansion on fair and reasonable terms. We support vibrant exploration for gas. We believe FERC will ensure fair and open access to any gas pipeline.

However, we cannot support the State's proposed RIK sale as it is currently structured. We are deeply concerned that efforts to fix a problem that doesn't exist with economically

burdensome solutions cannot be in the best interest of the State, especially if those solutions could cause a gas pipeline project not to proceed at all.

Thank you

**Phillips Petroleum Company Testimony
House Oil and Gas Committee Hearing
Tuesday, February 5, 2002**

Good Morning, Mr. Chairman, members of the committee. My name is Michael Hurley and I represent Phillips Alaska. Simply stated, we believe the department's proposed royalty in kind sale of North Slope gas, as currently envisioned, further burdens an already economically challenged project.

Let me begin by saying that we understand the State's goal to ensure third party access to a gas pipeline. We understand that goal, and the State's desire to increase the value of their unleased acreage. As the state's most active explorer, Phillips has a keen interest in ensuring expandability and access in a new gas pipeline. We do not, however, believe that the department's RIK backstop proposal is the most appropriate way to address these goals.

Let me walk you through a simple example of the potential impacts of the department's proposal.

[example on next page]

This example demonstrates the department's RIK backstop sale proposal results in decreased revenues to us, and increases the level of uncertainty in the project. We have a hard time envisioning how to move forward on the project with this situation unchallenged.

In closing, we share the state's desire for equitable pipeline access. We are committed to fair and open access to any gas pipeline in which we participate, consistent with the regulatory requirements and direction of the Federal Energy Regulatory Commission. They have a regulatory structure in place which requires open, non-discriminatory access for both initial and expansion volumes. And we believe their regulatory oversight will ensure, as it does throughout the US, that all potential shippers are treated fairly and that economic burdens are distributed equitably.

We encourage you to look carefully, as you consider this proposal, at the impacts it has on the economics of the other potential shippers, who's long term shipping commitments will underpin the financing of the project.

Mr. Chairman, thank you for this opportunity to explain our position on this proposal. I'd be happy to try to answer any questions you might have.

Royalty in Kind Backstop Sale Example

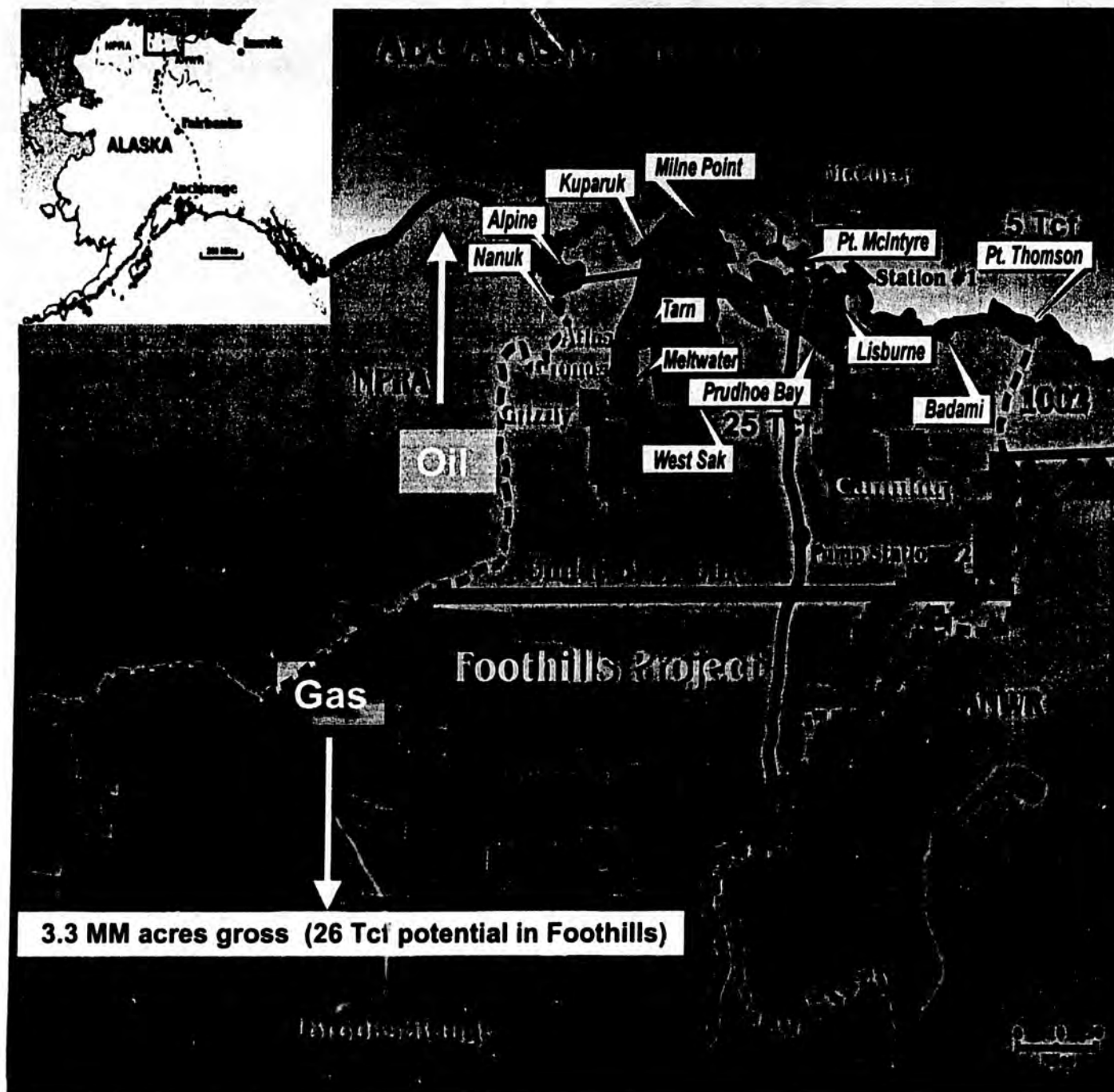
Total System in MMCFD	4,000
Royalty at 12.5 %	500
RIK Sale at 70%	350

<u>During RIK Sale</u>		<u>After Termination</u>
3,500	Producer Equity Gas	3,194
150	Royalty in Value	456
3,650	Producer Shipped Gas	3,650
350	Others Shipped Gas	350
4,000	Prudhoe Bay Gas	3,650
0	Other Non-Prudhoe Gas	350

Royalty In Kind (RIK) Sale

House Special Committee on Oil & Gas

Alan Sharp
AEC Marketing (USA) Inc.
February 5, 2002



Alaska* Players

Proven Reserves (Tcf)

• BP	9
• Exxon	10
• Phillips	9
• Chevron	2
• Other	< 1
	30

Other

- AEC
- Anadarko
- "others"

* North Slope Players; volumes include State royalty volumes

Why RIK in 'best interest' for State

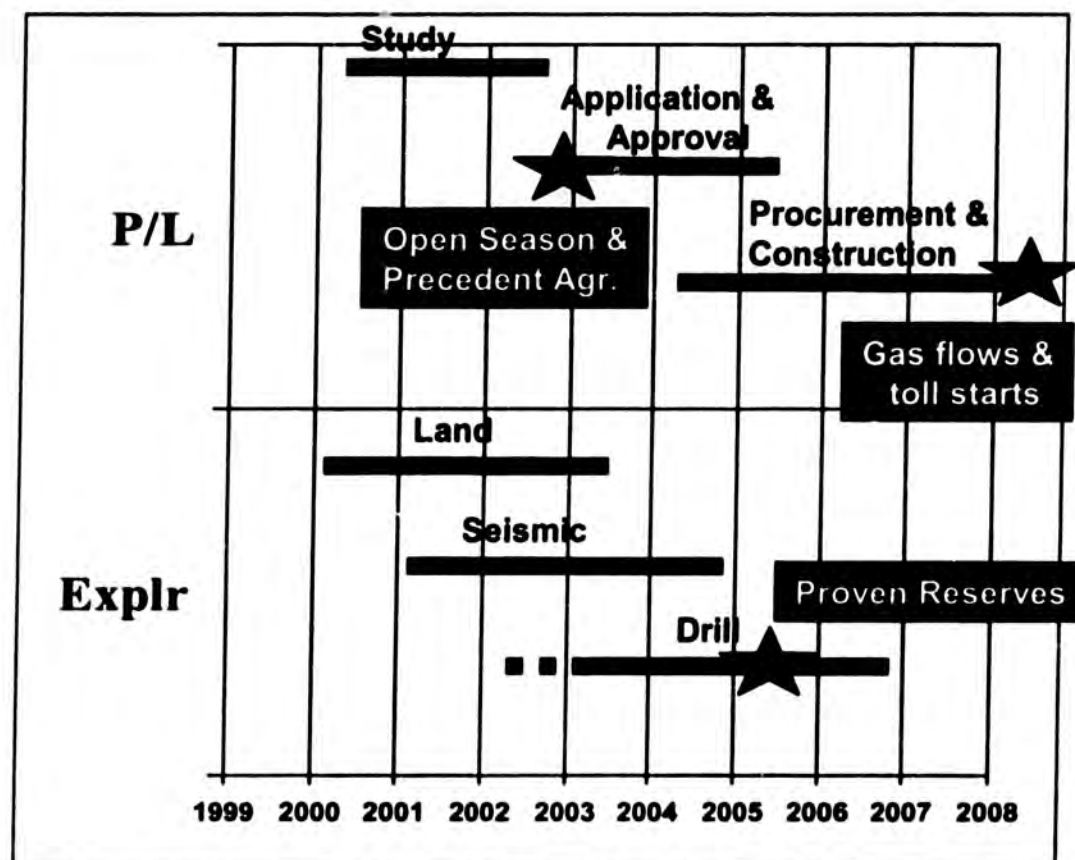
- No risk - leveraging gas volumes of tomorrow to support exploration projects of today
- Maximizes State's royalty value
- More players => more competition => more jobs => more revenue
- Elevates State to significant stakeholder in Pipeline and inclusion on the Pipeline negotiations
- Exploration dollars & jobs today (otherwise in 20 years)

Why do we need RIK now

- RIK sale requires at least 5 months
- Legislative approval required (Jan-May)
- No AGPPT open season commitments
- Explorer Open Season recommendations
 - on or later than June 2003
 - 6 months advance notice
 - disclosure of tariff (terms & conditions)
 - access, expansion, & tolls
 - reasonable expansion capacity increments

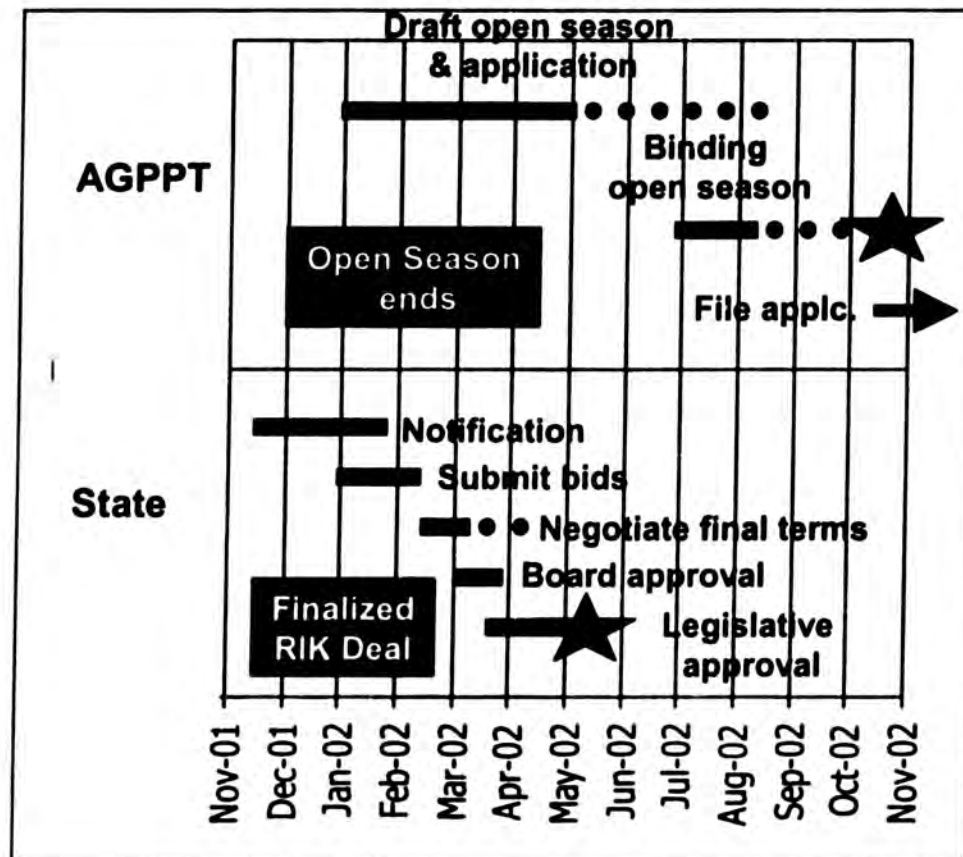
*may not be in
producer's power*

Explorers' Pipeline Decision Timeline



- 2002 Binding Open-season
- 2005 Earliest proven reserves
- 2008 Earliest pipeline ready
- Explorers' will not have proven gas reserves prior to the open-season (2002?)

State's RIK Decision Timeline



- Example timelines
- RIK sale requires ~5 months
- Legislative approval sets timeframe for sale (Jan-May)
- Open Season originally Q1 2002
- AGPPT does not 'foresee' an open season in 2002
- **Must execute the RIK agreement before a binding open-season occurs**

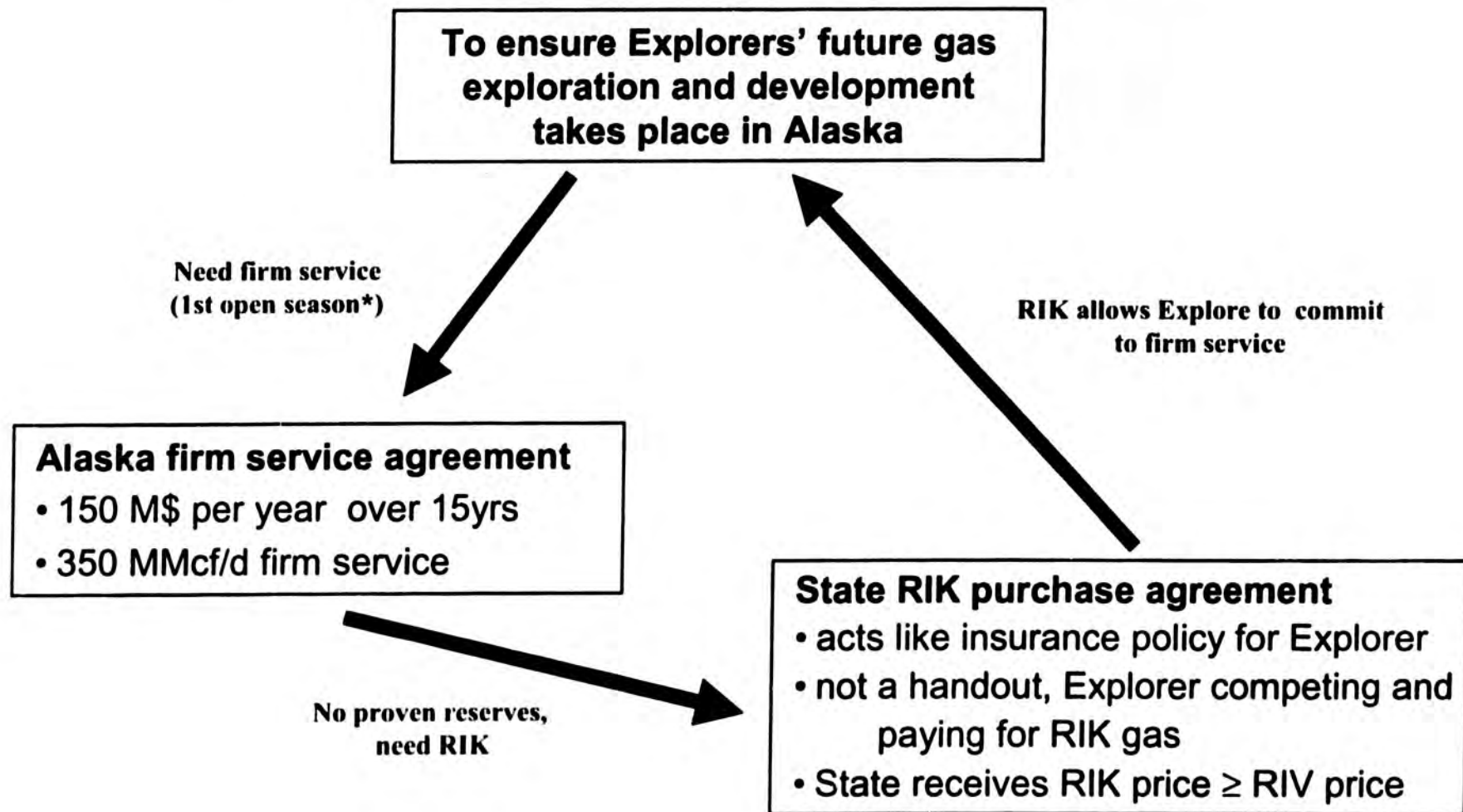
How can FERC* help

- Can not force a pipeline expansion**
- Open seasons are encouraged but not required
- Open seasons are not regulated (complaints basis)
- Open seasons held significantly before the application
 - helps determine design and size of pipeline required for application
- We do not agree with AGPPT, that FERC has the power to enforce pipeline access and expansion
 - why not write the access and expansion terms and conditions in to the proposed Federal Enabling Legislation ✱

* FERC points from July 17, 2001 Joint Pipeline Committee testimony by Robert Cupina - FERC Director of Energy Projects

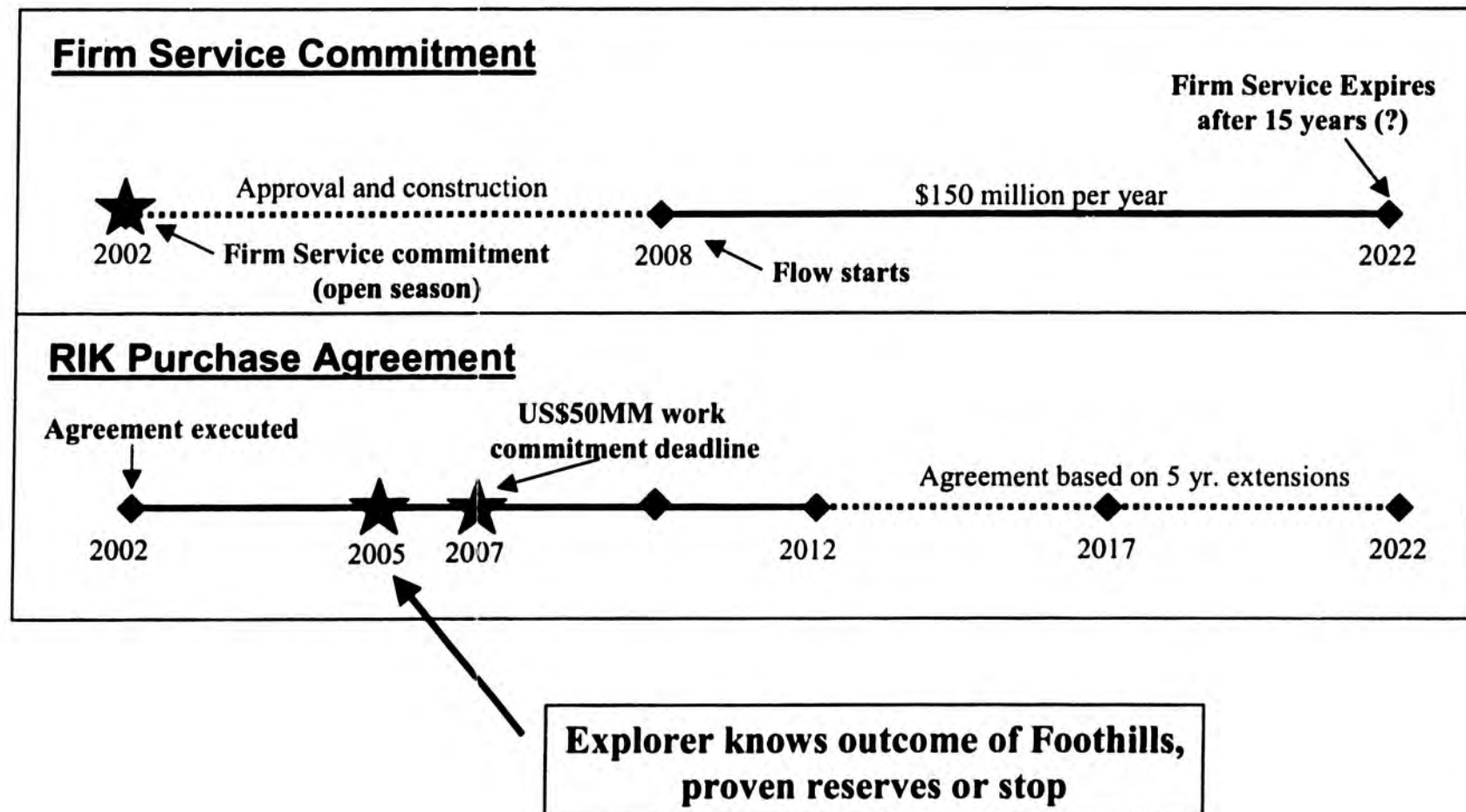
** Section 7 of the Natural Gas Act, Panhandle Eastern Pipe Line Co. v. FERC, 204 F.2d 675 (3rd Cir. 1953)

Why does the Explorer need RIK

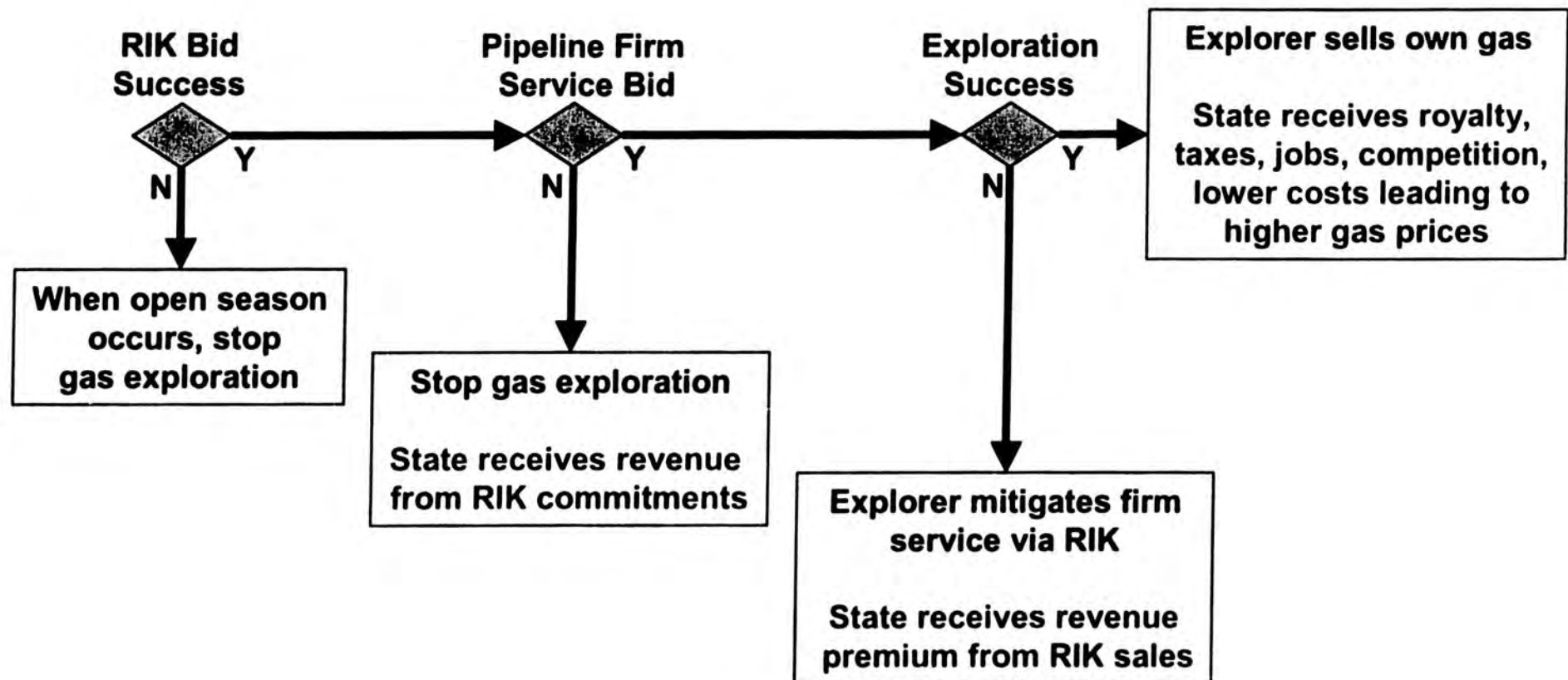


* Pipeline full for over 20 years; expansion can not be relied upon to make investment

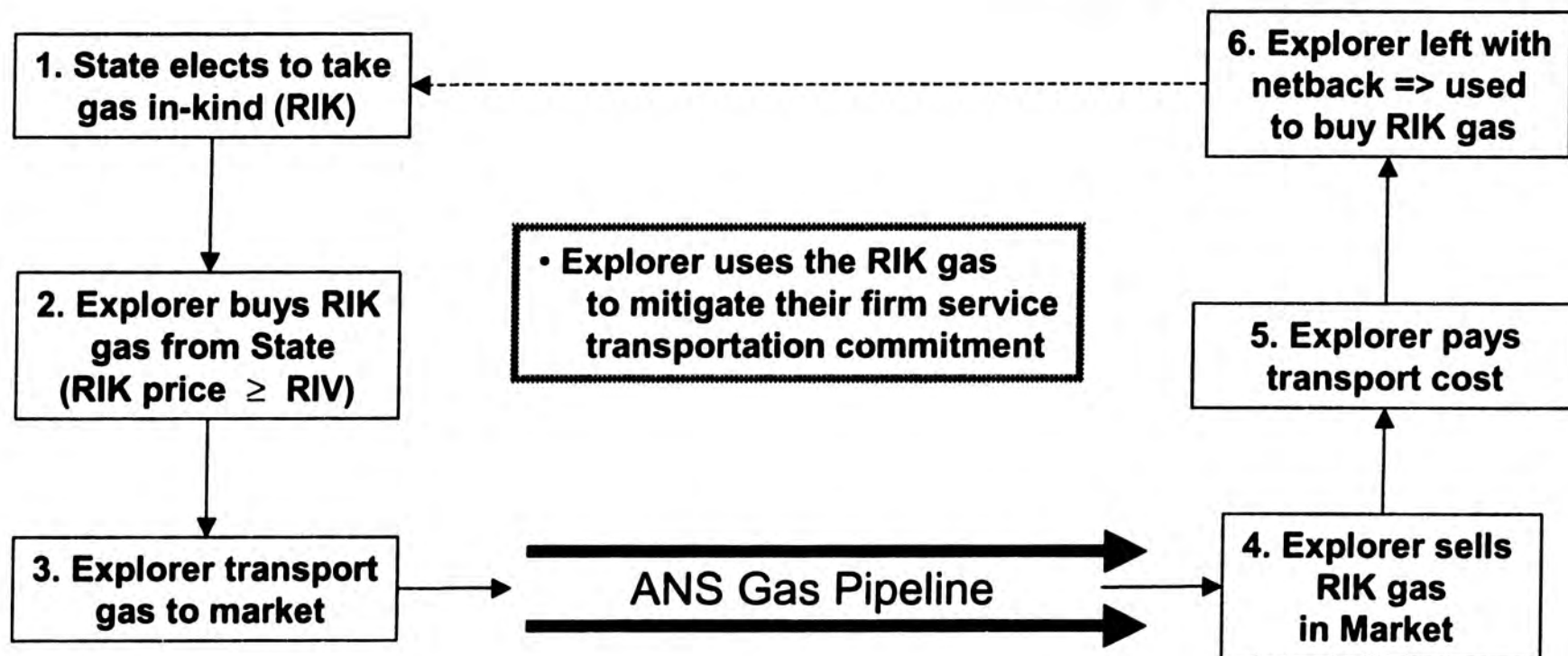
Firm Service & RIK Sale Timeline



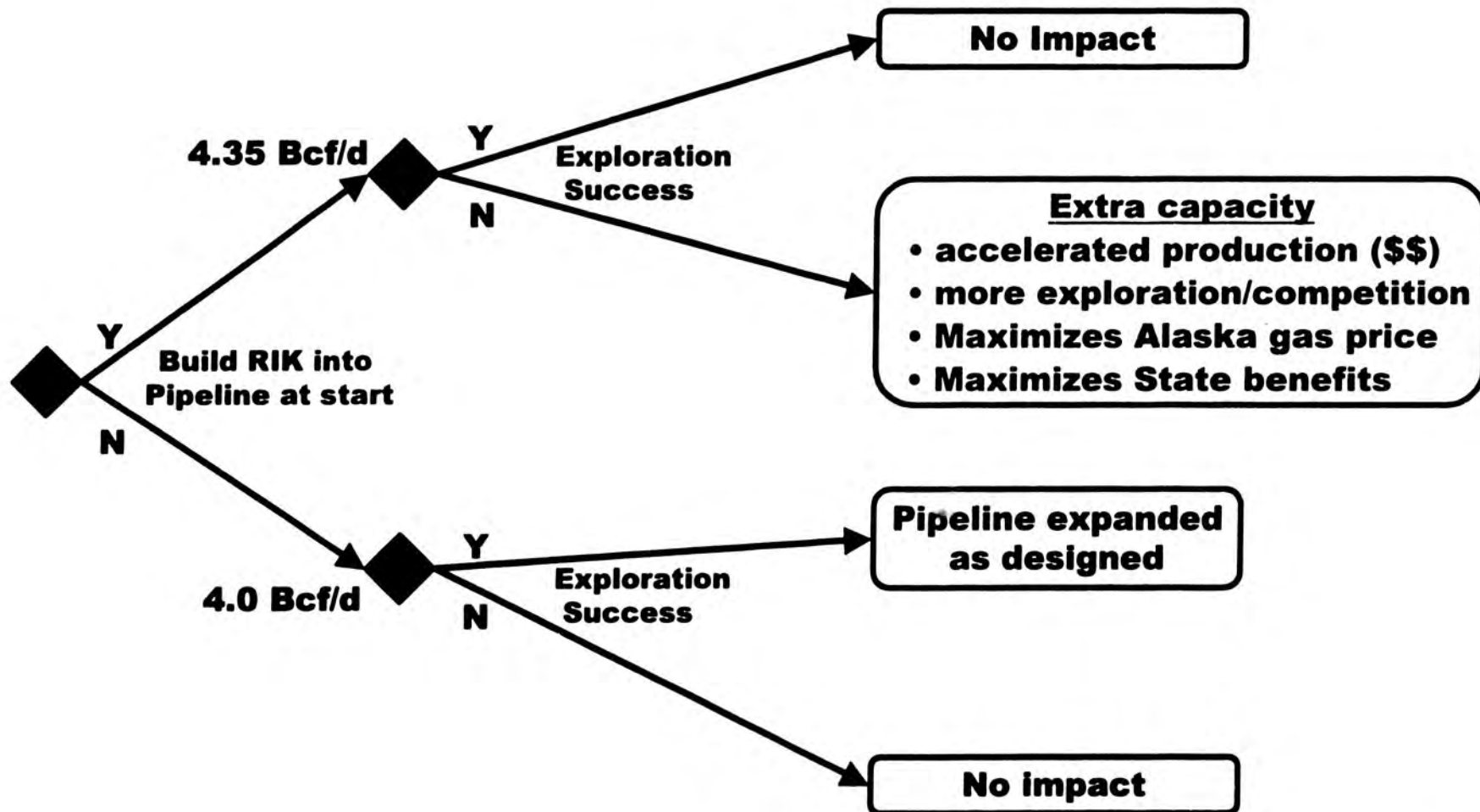
Explorers' Foothills Gas Decision Tree



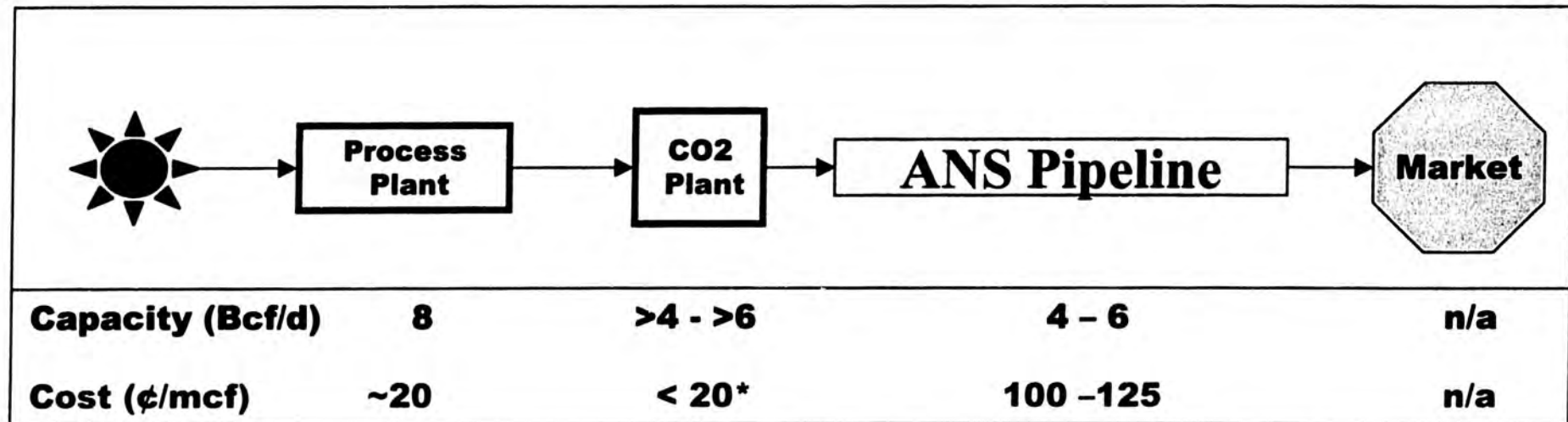
How does Explorer use RIK



Does RIK Impact AGPPT or Pipeline (Decision Tree)



Does RIK Impact AGPPT or Pipeline (Producer Gas Supply Cost Chain)



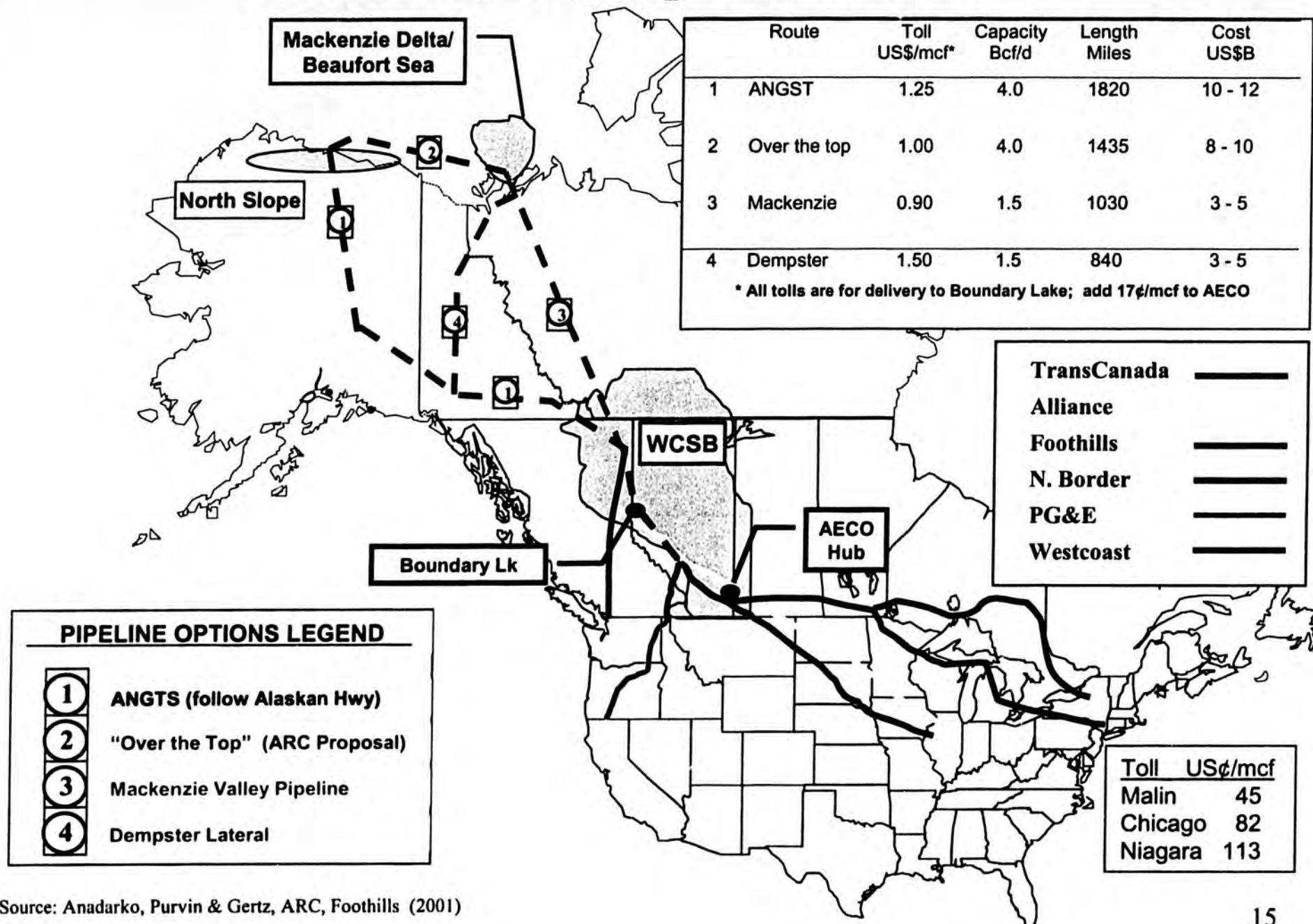
- **AGPPT would over design the CO2 plant (pipeline 5 – 6 times the cost)**
- **Annual down time for field and pipelines ~5% (non-coincidental)**
- **RIK volume 8% of pipeline capacity => net impact 3%**
- **Cost impact of 3% is less than 5 ¢/mcf**
- **Can AGPPT forecast their costs and prices this accurately ?**

* Cost assumed ≤ full process plant cost

Conclusion

- RIK is in the 'best interest' for the State and the Explorer
- RIK provides no risk to the State (guaranteed price $\geq$ RIV)
- RIK allows the State to influence the pipeline project
- RIK creates competition and higher gas prices for ANS gas
- RIK creates jobs for Alaskans
- RIK ensures exploration continues today

Northern Gas Pipeline Routes



Source: Anadarko, Purvin & Gertz, ARC, Foothills (2001)

Royalty In Kind (RIK) Sale

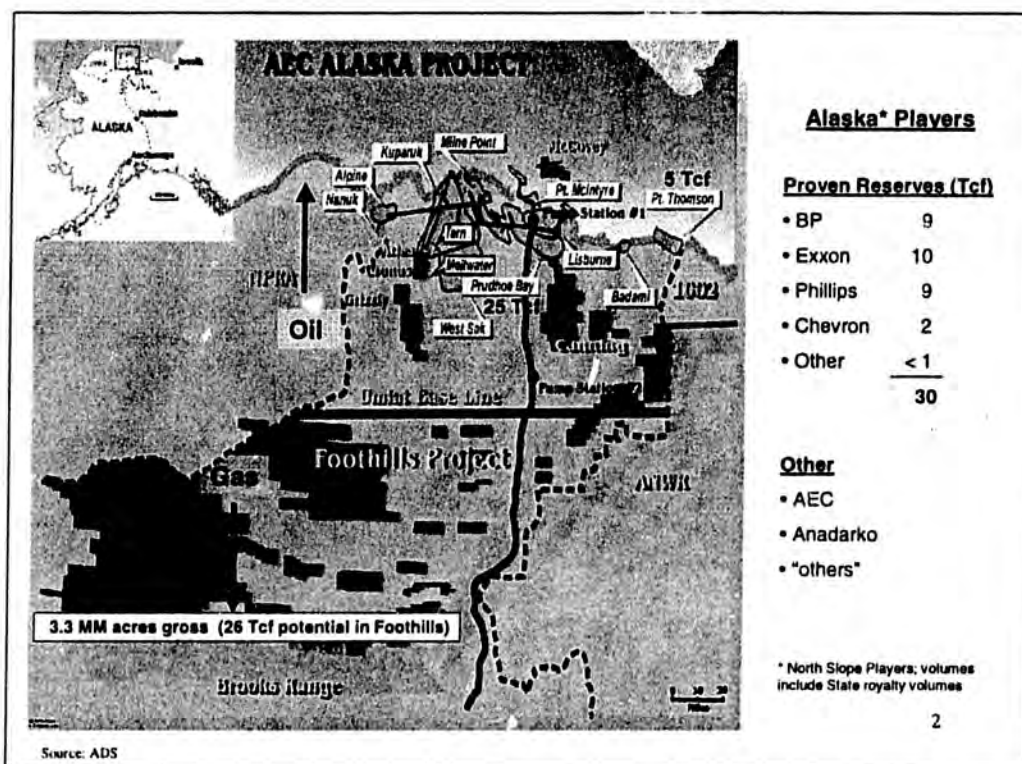
House Special Committee on Oil & Gas

Alan Sharp

AEC Marketing (USA) Inc.

February 5, 2002

S:\Data\Northern Gas\Alaska\RIK agr\RIK Testimony Feb5.ppt



1. Majority of proven gas reserves controlled by three companies, who form the AGPPT
2. Only small area has been explored (for oil – barrow arch); Exploring in area that would not otherwise be explored for over 20yrs (100Tcf potential of gas on ANS)

Others – PetroCanda, Unocal, Chevron, Burlington

- **30 Tcf at 4Bcf/d => 20yrs** AEC locked out of Alaska if not in 1st open season
- **ASRC** - Arctic Slope Regional Corporation is who some of our lands are leased from (right to earn)
- **NPRA** - National Petroleum Reserve of Alaska - held for future energy use for US
- **#1002** small area of ANWR that may be opened by Bush, no infrastructure, on coastal plain
- **ANWR** - Arctic National Wildlife Refuge - protected wildlife park area
- **TAPS** - TransAlaska Pipeline System - existing oil line to Valdez
- above Umiat Base Line Oil (coastal plain), below Gas (foothills)
 - ~30 Tcf onshore proven, (94 Tcf potential, mainly onshore, economic)
- **McCovey, Canning, & Grizzly** world class oil plays; could all have significant solution gas and potentially gas caps

Why RIK in 'best interest' for State

- No risk - leveraging gas volumes of tomorrow to support exploration projects of today
- Maximizes State's royalty value
- More players => more competition => more jobs => more revenue
- Elevates State to significant stakeholder in Pipeline and inclusion on the Pipeline negotiations
- Exploration dollars & jobs today (otherwise in 20 years)

3

1. Yes, RIK is in States best interest
2. Maximizes the State's gas value at no risk (royalty, tax, jobs, lease sales, EOR)

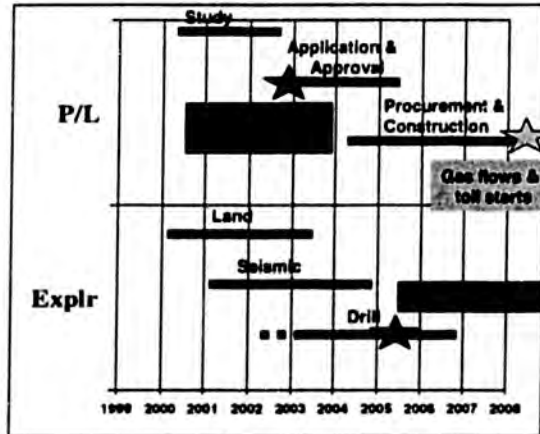
Why do we need RIK now

- RIK sale requires at least 5 months
- Legislative approval required (Jan-May)
- No AGPPT open season commitments
- Explorer Open Season recommendations
 - on or later than June 2003
 - 6 months advance notice
 - disclosure of tariff (terms & conditions)
 - access, expansion, & tolls
 - reasonable expansion capacity increments

4

1. Timing is critical for RIK to work – must do now or lose opportunity
2. Open season can be used to exclude other parties (explorers)
3. Require written agreement with AGPPT & pipelines to delay RIK (not likely)

Explorers' Pipeline Decision Timeline

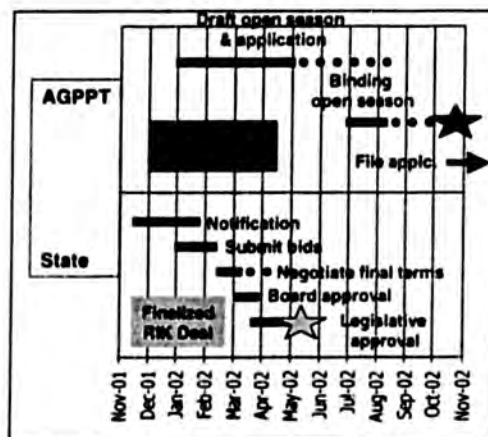


- 2002 Binding Open-season
- 2005 Earliest proven reserves
- 2008 Earliest pipeline ready
- Explorers' will not have proven gas reserves prior to the open-season (2002?)

5

1. Explorers will not have proven reserves prior to an open season
 2. Explorers need your assistance (RIK, legislative protection) – AEC/Anadarko furthest along paying for and competing for your support – not asking for a handout
- Gas pipeline support and timeline are likely to accelerate due to the terrorist attacks - national security. House has already passed the energy bill.
 - OTT from Alaska will only have 4 Bcf/d capacity; Mackenzie down will be 5 Bcf/d. No room for Explorers' (AEC) gas on either side.
 - Exploration issues for the Foothills gas
 - extended flaring
 - successfully obtaining firm service (at min economic rate)
 - lease access (gravel pads and roads)

State's RIK Decision Timeline



- Example timelines
- RIK sale requires ~5 months
- Legislative approval sets timeframe for sale (Jan-May)
- Open Season originally Q1 2002
- AGPPT does not 'foresee' an open season in 2002
- **Must execute the RIK agreement before a binding open-season occurs**

6

1. **MUST** do RIK now or lose opportunity
 2. AGPPT has made no firm commitment; could be P/L company or other initiating open season
- We are on the critical path. If the State realizes this, we hope they will help expedite the process.
 - The binding open season could be later in Q1 2002. When we are in Alaska, we hear Jan/02 is what AGPPT has told the State. AGPPT is telling explorers late Q1. If it is later, we can make the RIK deadline.
 - Note the RIK purchase is a competitive bid process.

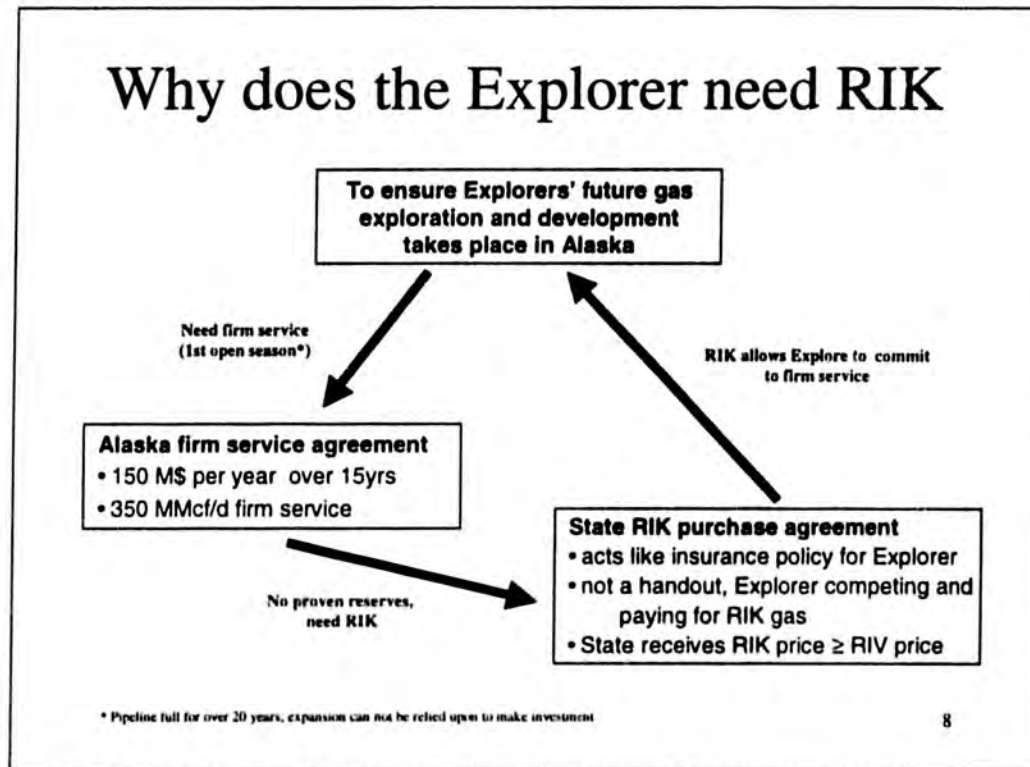
How can FERC* help

- Can not force a pipeline expansion**
- Open seasons are encouraged but not required
- Open seasons are not regulated (complaints basis)
- Open seasons held significantly before the application
 - helps determine design and size of pipeline required for application
- We do not agree with AGPPT, that FERC has the power to enforce pipeline access and expansion
 - why not write the access and expansion terms and conditions in to the proposed Federal Enabling Legislation

* FERC points from July 17, 2001 Joint Pipeline Committee testimony by Robert Cupina - FERC Director of Energy Projects
** Section 7 of the Natural Gas Act, *Panhandle Eastern Pipe Line Co. v. FERC*, 204 F.2d 675 (3rd Cir. 1953)

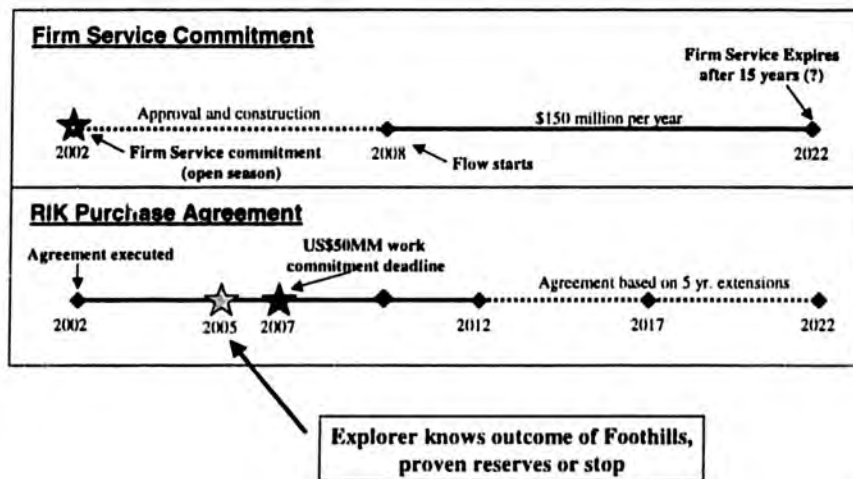
1. No, FERC can not force an expansion – legal precedent
2. If AGPPT believes it already exists, let's write it in to their Federal Enabling Legislation

Why does the Explorer need RIK



1. Explorer can not take risk on firm service without proven reserves – AGPPT think economics tight without exploration risk and cost
2. RIK acts like an insurance policy for the Explorer (firm service risk)
 - 2.0 B\$ over 15yrs, ~150 M\$/yr
 - 3.2 B\$ over 25yrs, ~150 M\$/yr

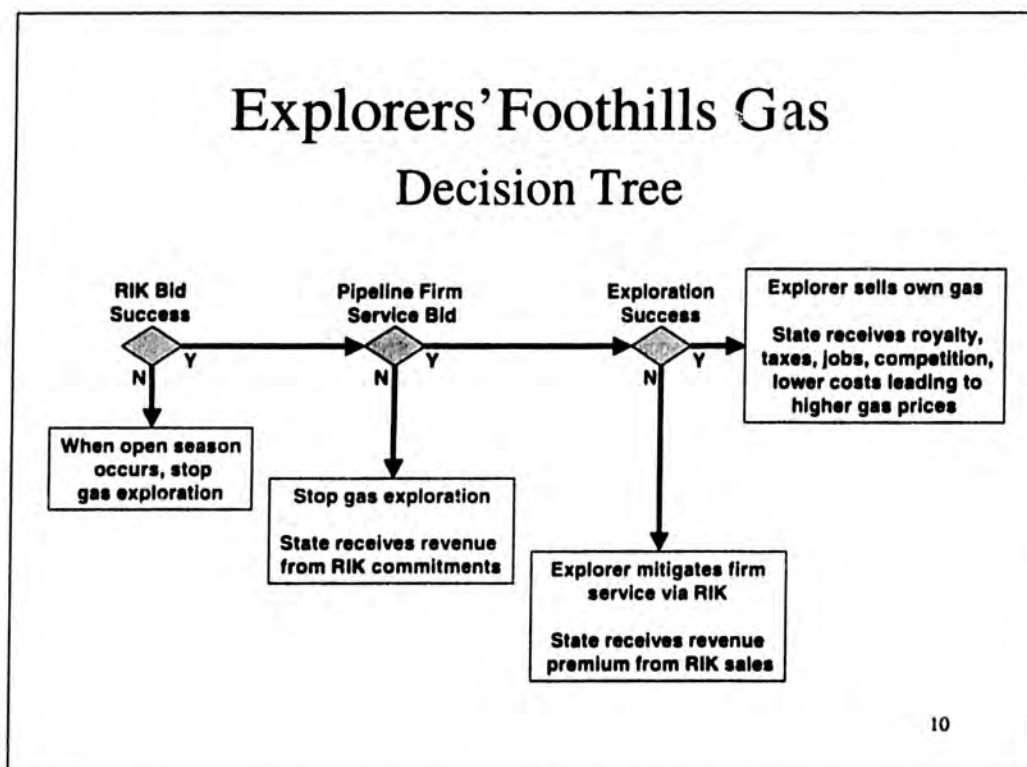
Firm Service & RIK Sale Timeline



9

1. Explorers will know by 2005 (before the P/L flows) if Foothills exploration successful
 2. Need RIK to participate in open season
- Top of the chart shows the firm service timeline. We estimated the term to be 15yrs. It could be longer (e.g., 25yrs) to create barriers to entry.
 - Notice the pipeline's earliest start date is 2008. The firm service term starts from this start date.
 - Also note that we will have proven gas or made the exit decision prior to the actual pipeline start-up date.
 - The option agreement will commence right away and terminate 5yrs after gas starts to flow on the pipeline, if the purchase has not been extended.

Explorers' Foothills Gas Decision Tree

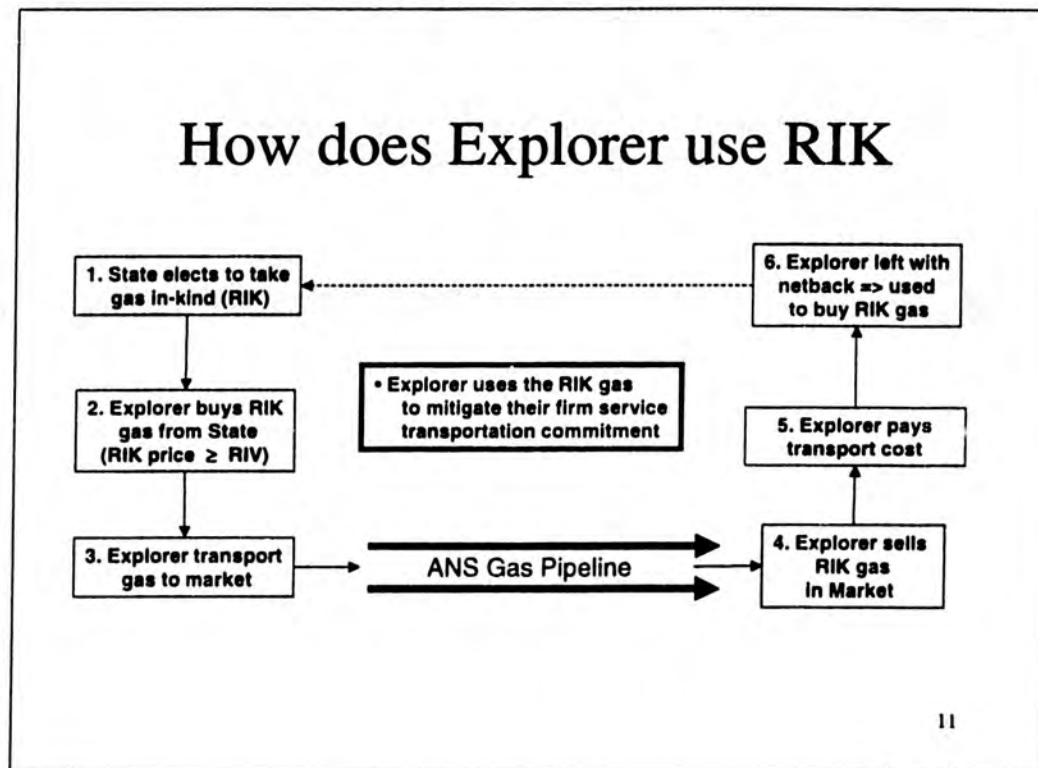


1. State receives benefit in all cases - no risk to State (win/win for all)
2. Foothills gas exploration will otherwise not occur for over 20yrs

Firm Service

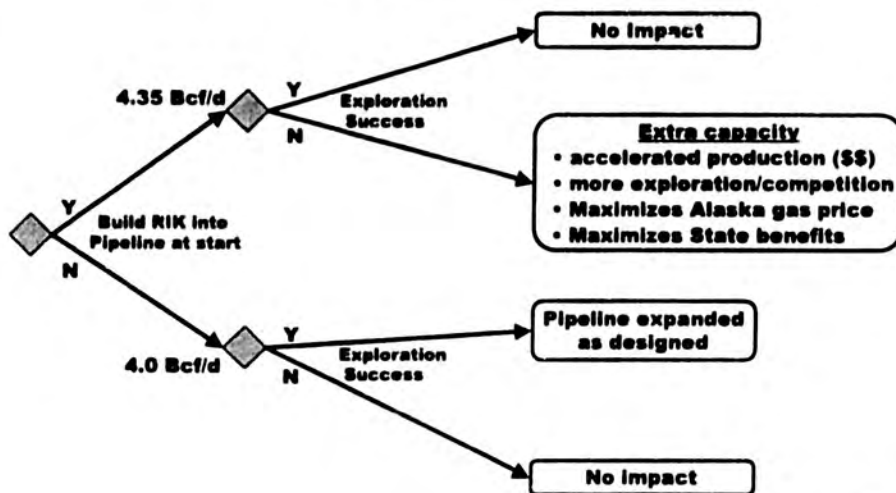
200MMcf/d @ 1\$US/Mcf	73M\$/yr	1.8B\$US over 25yrs
175MMcf/d @ 1\$US/Mcf	64M\$/yr	1.6B\$US over 25yrs

How does Explorer use RIK



1. Explorer uses the RIK to mitigate the firm service risk (get firm service in 1st open season)
2. Chart shows how Explorer uses RIK as an 'insurance policy'

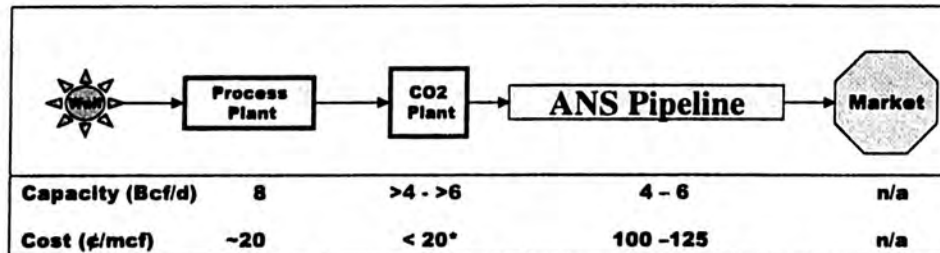
Does RIK Impact AGPPT or Pipeline (Decision Tree)



12

1. Shows AGPPT not impacted (creates competition, limits control)
2. State gets huge benefit building RIK in to pipeline at very start

Does RIK Impact AGPPT or Pipeline (Producer Gas Supply Cost Chain)



- AGPPT would over design the CO2 plant (pipeline 5 - 6 times the cost)
- Annual down time for field and pipelines ~5% (non-coincidental)
- RIK volume 8% of pipeline capacity => net impact 3%
- Cost impact of 3% is less than 5 \$/mcf
- Can AGPPT forecast their costs and prices this accurately ?

* Cost assumed ≤ full process plant cost

13

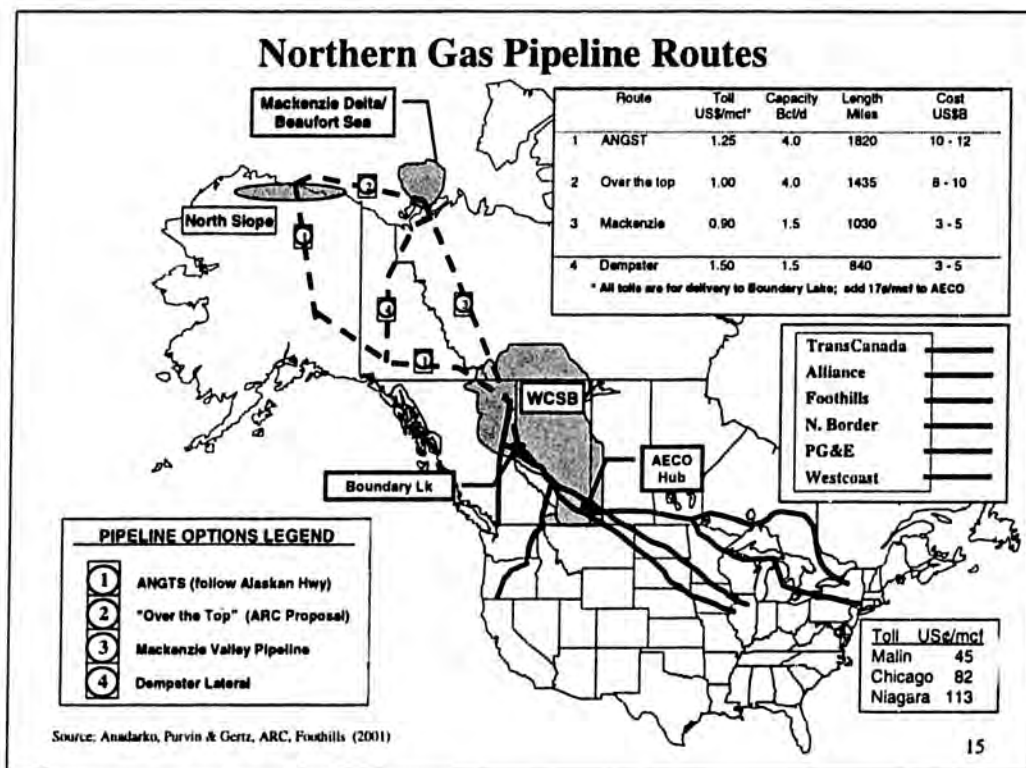
1. Shows that AGPPT impact insignificant relative to the other pipeline project risks/costs
2. Have AGPPT show us their economics (accuracy ??)

Conclusion

- RIK is in the 'best interest' for the State and the Explorer
- RIK provides no risk to the State (guaranteed price $\geq$ RIV)
- RIK allows the State to influence the pipeline project
- RIK creates competition and higher gas prices for ANS gas
- RIK creates jobs for Alaskans
- RIK ensures exploration continues today

14

1. RIK is in the best interest of the State, State has no risk
2. AGPPT is not impacted – RIK insignificant relative to their other risks/costs
3. We are offering the State more than a bid, we are offering the State to share in our vision – to create a competitive, multi-player natural gas industry in Alaska – RIK is the first step towards this vision.



- Mackenzie < 6 Tcf proven onshore; most of the reserves are offshore in the Beaufort Sea; total potential 64 Tcf, 20 onshore, 44 offshore (mostly uneconomic)
 - Alaska is mostly onshore 30 Tcf proven, potential 94 Tcf (economic)
 - 26 Tcf in the Foothills; of which more than half is considered to be on AEC & adjacent open State lands
 - Alta 270 Tcf - 86 Tcf produced, 49 Tcf proven, 135 Potential
 - BC 50 Tcf - 13 Tcf produced, 10 Tcf proven, 27 Potential
 - Players
 - Governments (Municipal, State, Provincial, & Federal)
 - Producers (mainly super independents)
 - Pipeline companies
 - Marketers
 - Environmental groups
 - First Nation bands
 - Service industries (direct, indirect)
 - Others (e.g., GTL, LNG)
1. **ANGTS** (Alaska Northern Gas Transportation System) which follows the Alaska Highway.
 2. **Over the top** - from Prudhoe Bay to Mackenzie via the Beaufort Sea, then approximately follows the Mackenzie Valley Pipeline
 3. **Mackenzie Valley** - standalone pipeline for the Delta; small capacity proposed
 4. **Dempster lateral** is a hold over from the Berger Commission - this pipeline would only be built if ANGTS is built first, stranding the Mackenzie reserves until 2010-2012 (assumes Market can not handle more gas and reserves are still small <6 Tcf).

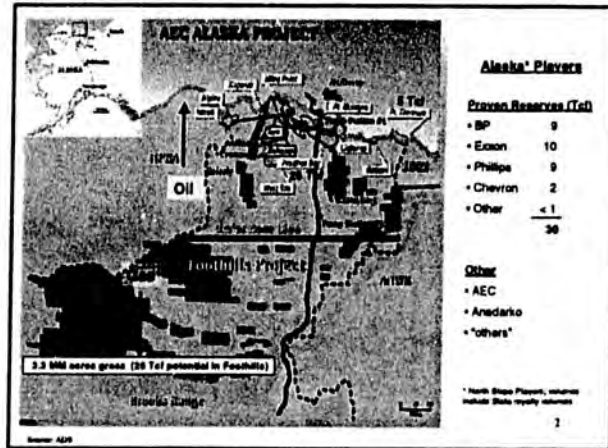
Will the WCSB 'potential' reserves be economic (i.e., small pools) vs the North?

Royalty In Kind (RIK) Sale

House Special Committee on Oil & Gas

Alan Sharp
AEC Marketing (USA) Inc.
February 5, 2002

\\charlotte\home\Carl\Alaska\RIK\agppt\Summary Ppt1.ppt



Why RIK in 'best interest' for State

- No risk - leveraging gas volumes of tomorrow to support exploration projects of today
- Maximizes State's royalty value
- More players => more competition => more jobs => more revenue
- Elevates State to significant stakeholder in Pipeline and inclusion on the Pipeline negotiations
- Exploration dollars & jobs today (otherwise in 20 years)

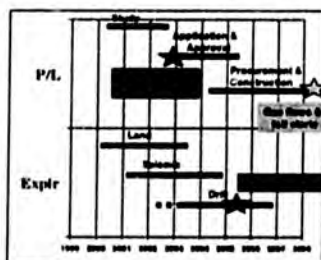
3

Why do we need RIK now

- RIK sale requires at least 5 months
- Legislative approval required (Jan-May)
- No AGPPT open season commitments
- Explorer Open Season recommendations
 - on or later than June 2003
 - 6 months advance notice
 - disclosure of tariff (terms & conditions)
 - access, expansion, & tolls
 - reasonable expansion capacity increments

4

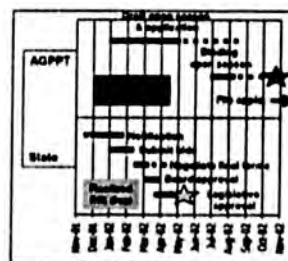
Explorers' Pipeline Decision Timeline



- 2002 Binding Open-season
- 2005 Earliest proven reserves
- 2008 Earliest pipeline ready
- Explorers' will not have proven gas reserves prior to the open-season (2002?)

5

State's RIK Decision Timeline



- Example timelines
- RIK sale requires ~5 months
- Legislative approval sets timeframe for sale (Jan-May)
- Open Season originally Q1 2002
- AGPPT does not foresee an open season in 2002
- Must execute the RIK agreement before a binding open-season occurs

6

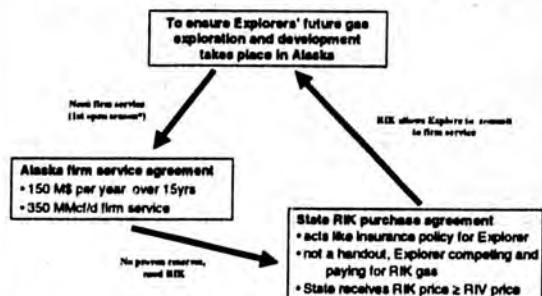
How can FERC* help

- Can not force a pipeline expansion**
- Open seasons are encouraged but not required
- Open seasons are not regulated (complaints basis)
- Open seasons held significantly before the application
 - helps determine design and size of pipeline required for application
- We do not agree with AGPPT, that FERC has the power to enforce pipeline access and expansion
 - why not write the access and expansion terms and conditions in to the proposed Federal Enabling Legislation

* FERC process from July 17, 2001 Joint Pipeline Commission testimony by Robert Chappin - FERC Director of Energy Projects
 ** Section 7 of the Natural Gas Act, Public Law 86-417, 49 USC, 3017.34 (19) (1952)

7

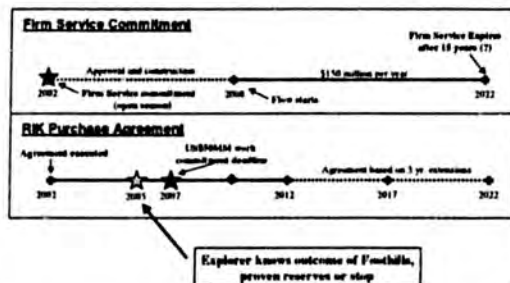
Why does the Explorer need RIK



* Pipeline bid not over 20 years, exploration cost can be added upon an early termination

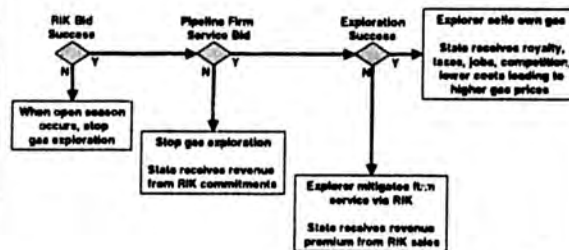
8

Firm Service & RIK Sale Timeline



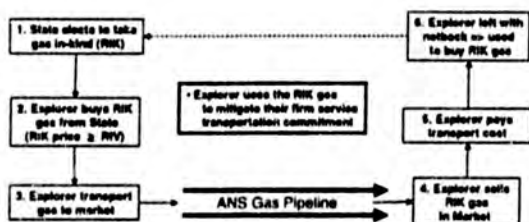
9

Explorers' Foothills Gas Decision Tree



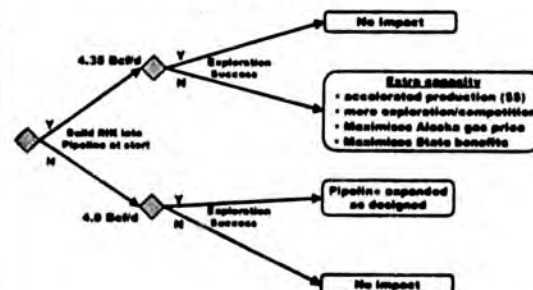
10

How does Explorer use RIK



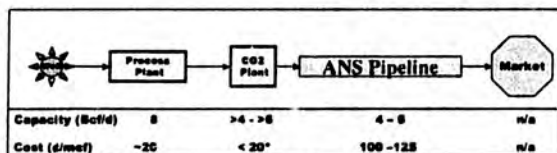
11

Does RIK Impact AGPPT or Pipeline (Decision Tree)



12

Does RIK Impact AGPPT or Pipeline (Producer Gas Supply Cost Chain)



- AGPPT would over design the CO2 plant (pipeline 8 - 5 times the cost)
- Annual down time for field and pipelines ~5% (non-coincidental)
- RIK volume 5% of pipeline capacity => not impact 3%
- Cost impact of 3% is less than \$/mcf
- Can AGPPT forecast their costs and prices this accurately?

* Cost estimated by AGPPT process plant cost

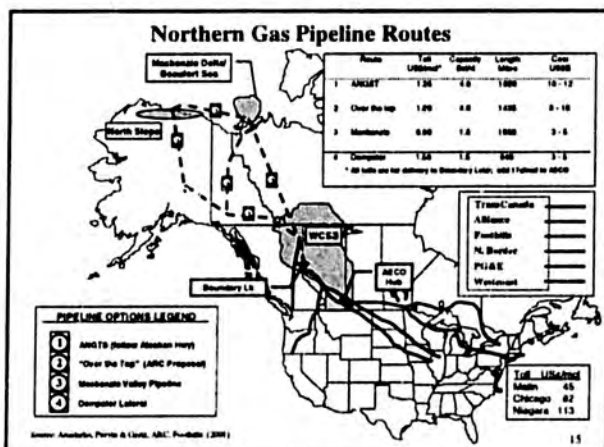
13

Conclusion

- RIK is in the 'best interest' for the State and the Explorer
- RIK provides no risk to the State (guaranteed price $\geq$ RIV)
- RIK allows the State to influence the pipeline project
- RIK creates competition and higher gas prices for ANS gas
- RIK creates jobs for Alaskans
- RIK ensures exploration continues today

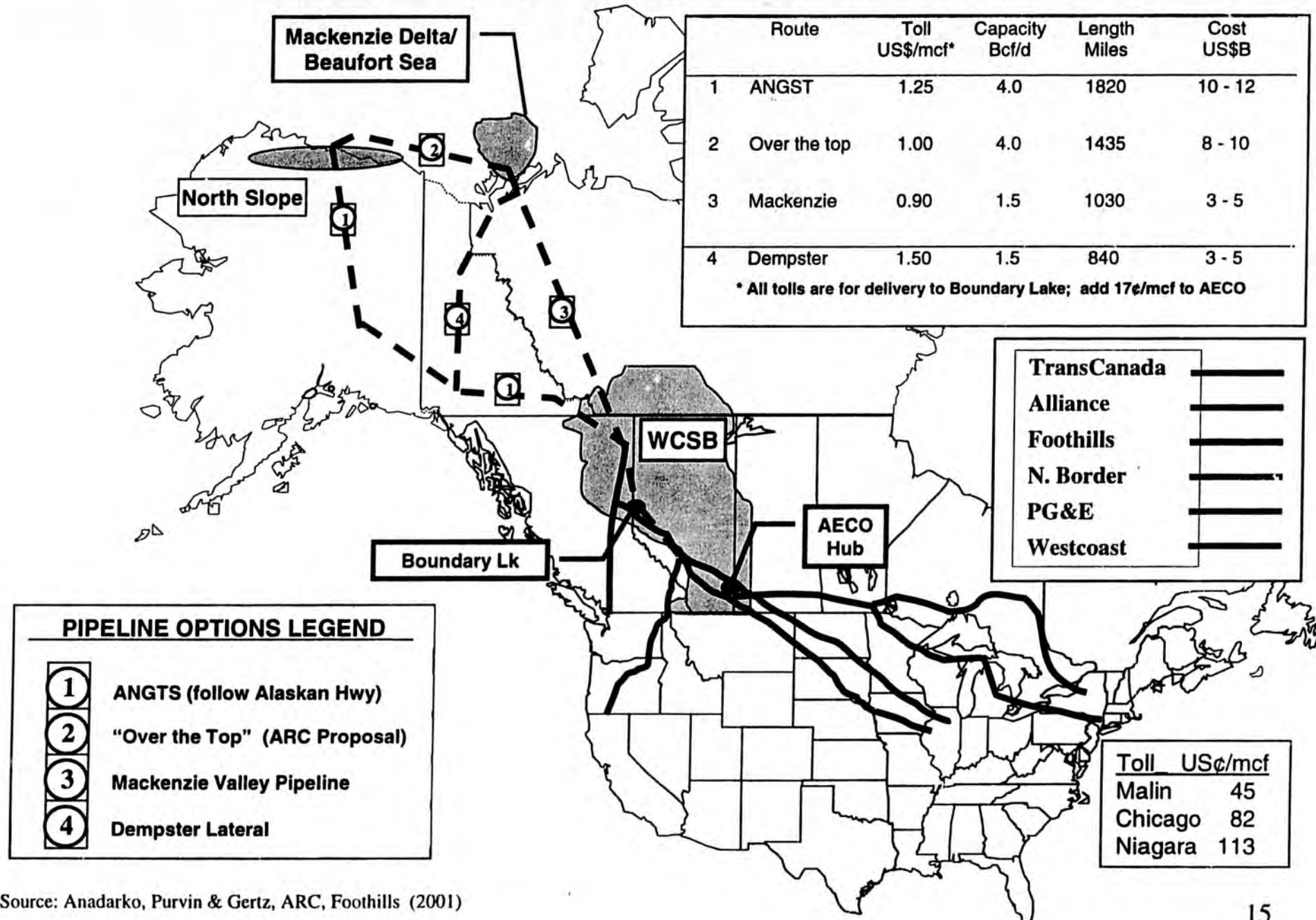
14

Northern Gas Pipeline Routes



15

Northern Gas Pipeline Routes



Source: Anadarko, Purvin & Gertz, ARC, Foothills (2001)

Royalty-In-Kind Gas Sale

Division of Oil and Gas
February 5, 2002



Alaska Department of
**Natural
Resources**

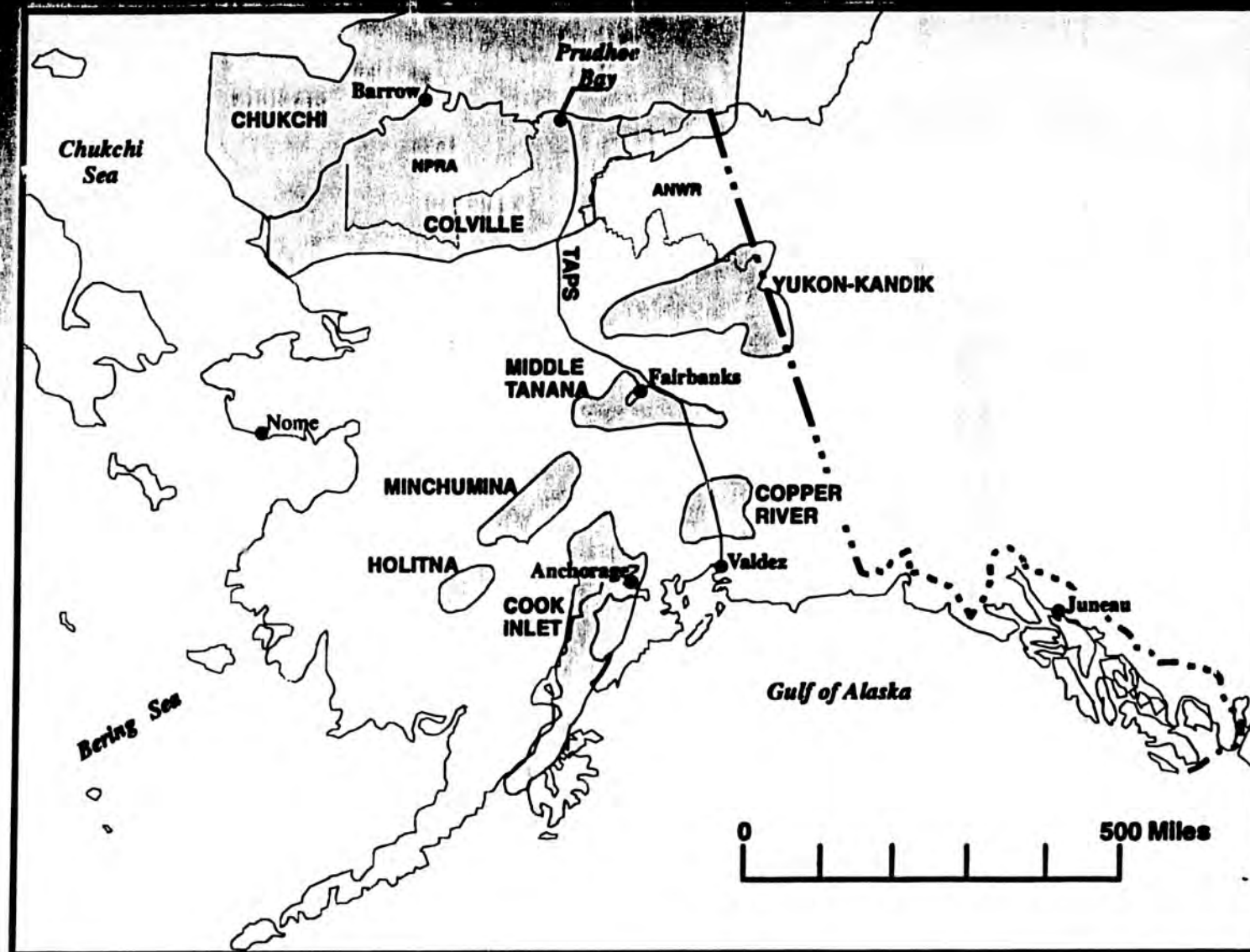


Figure A

Known Hydrate Accumulations

Prudhoe Bay, Alaska

42 TCF (Collett, 1993)

Cirque - Tarn, Alaska

60 TCF (Collett, 1993)

Figure B

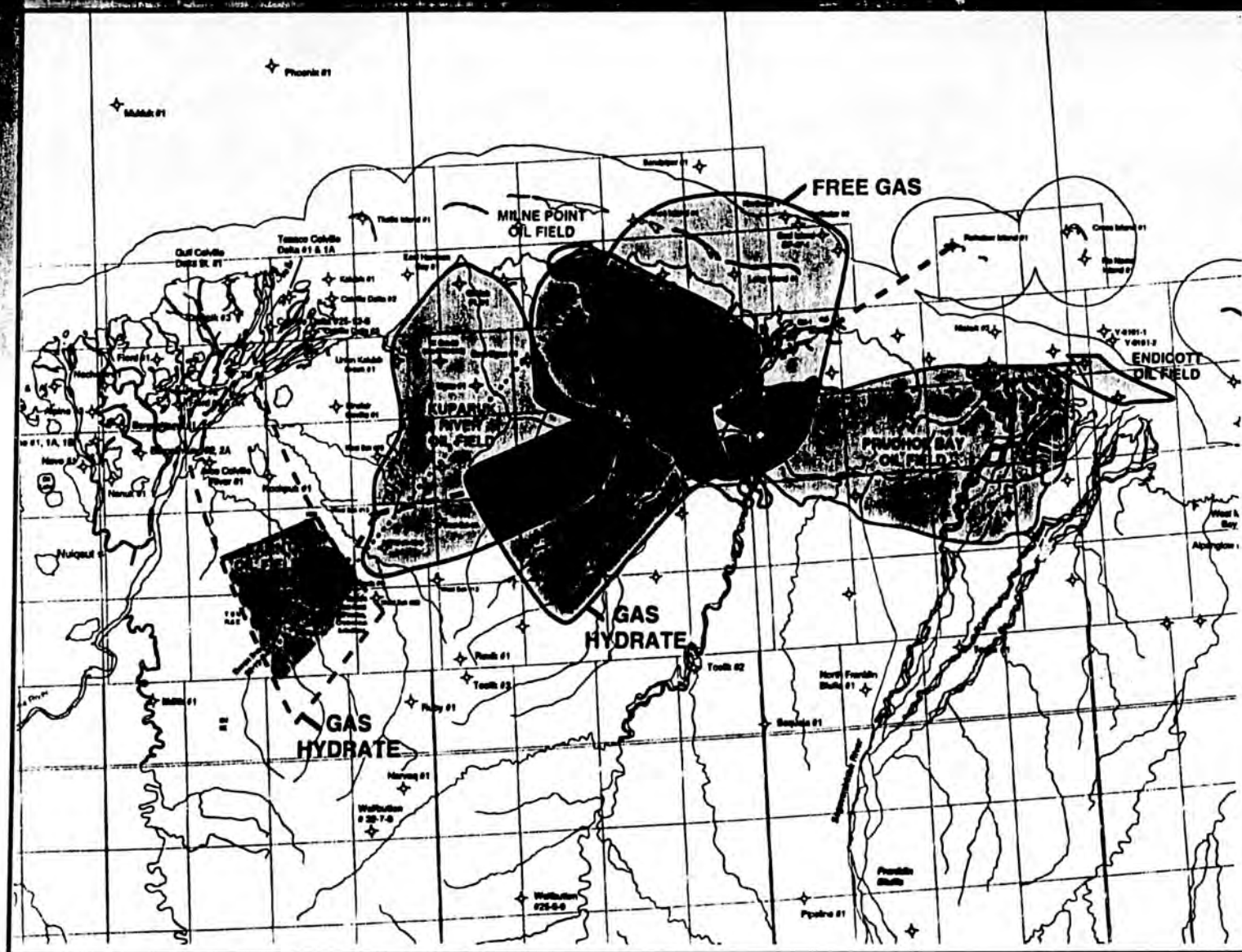


Figure C

T.S. Collett, USGS 10/4/01

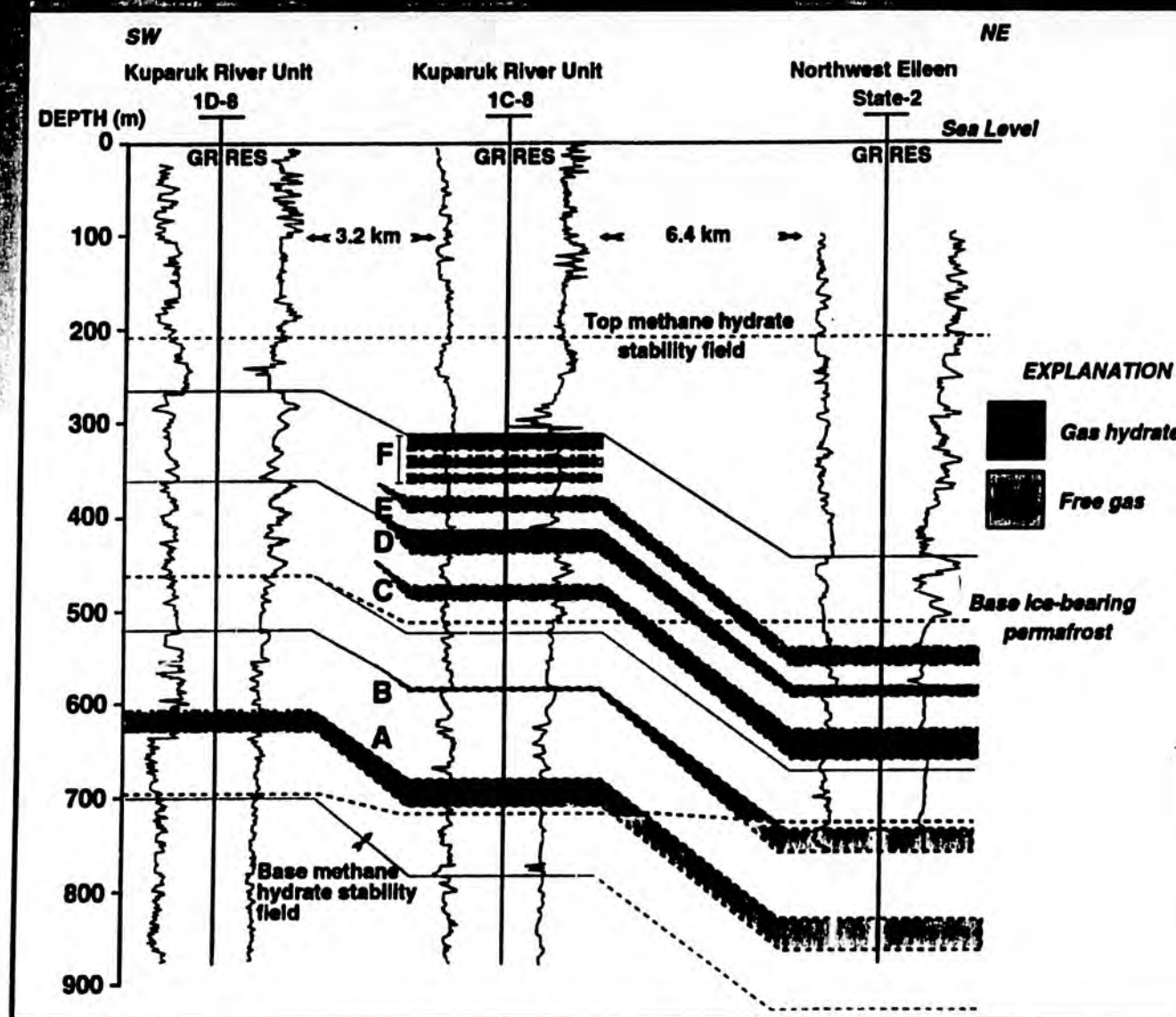
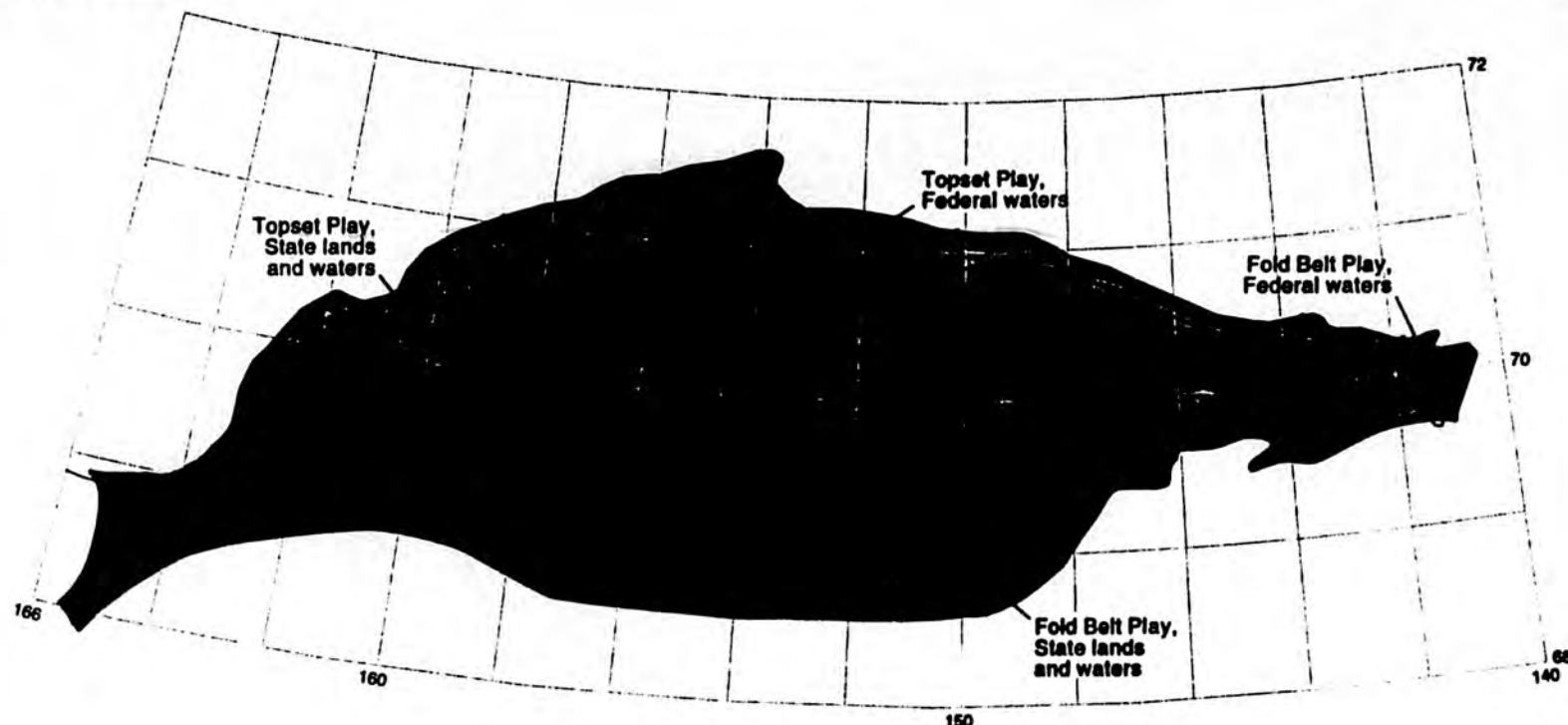


Figure D

T.S. Collett, USGS 10/4/01

U.S. DEPARTMENT OF THE INTERIOR
U.S. GEOLOGICAL SURVEY

DIGITAL DATA SERIES 30
PLATE 23



0 50 100 150 200 250 KILOMETERS
0 50 100 150 200 250 MILES

EXPLANATION

- | | | | |
|---|----------------------------|---|---|
|  | Topset gas-hydrate play |  | Gas hydrate stability zone thickness contours—in meters |
|  | Fold Belt gas-hydrate play |  | Coast line |
|  | Gas-hydrate play boundary | | |

This map is preliminary and has not been reviewed for compliance with USGS standards. Any mention of product names does not imply endorsement of those products. Political and geographic boundaries are provided for reference purposes only and are not intended to represent boundaries for legal descriptions.

MAP OF THE ALASKA TOPSET AND FOLD BELT GAS HYDRATE PLAYS

T. S. Collett, D. L. Barnett, W. R. Beeman, Compilers
1994

Albers Equal Area Projection
1st standard parallel: 55 00' 00" N
2nd standard parallel: 65 00' 00" N
Central meridian: 150 00' 00" W
Latitude of origin: 50 00' 00" N

Figure E

T.S. Collett, USGS 10/4/01

- Is a percentage of production
- Usually is 12.5% of production; but may be $16\frac{2}{3}\%$ or 20% of production
- May be taken "in-value" or "in-kind"
 - When taken "in-value" the gas is left with the producer, who sells 100% of the gas, then pays the state 12.5% of the net proceeds from the sale of 100% of the gas, or the market value of the gas, whichever is higher
 - When taken "in-kind" the state physically takes 12.5% of the gas in the field and sells it itself

Either In-Kind or In-Value

The State's right to take gas either in-kind or in value:

- **Is a term of the lease agreement**
- **Allows switching between in-kind and in-value on six month's notice**
- **Is the same for oil and gas**
- **Has been part of the State's lease form for more than 40 years**

Between In-Kind And In-Value Is Valuable

- **If the reported proceeds on royalty in-value appear low, the state can test the market by offering gas for sale in-kind**
- **If in-state producers are unwilling to sell to in-state purchasers (who may also be competitors of the producers), the state can supply in-state purchasers**
- **The state may be able to command a premium for its gas if it is willing to sell on terms different from the industry standard**

- Open season requires long-term commitments to pipeline capacity
- State's ability to sell royalty-in-kind gas effectively limited by access to pipeline capacity; and access is established through the open season
 - If the state does not conduct a sale now - prior to the initial open season - it may not be able to sell gas in-kind for decades or until the pipeline is expanded
 - Competition for the gas exists now, but will be reduced as pipeline capacity is restricted when open season closes
- Governor's policy council recommended a mix of royalty-in-kind and royalty-in-value dispositions
- Expressions of interest by multiple potential buyers, including Williams, Anadarko, Alberta Energy Company, BP, and Netricity; proposals actually received from Alaska Power & Telephone, Anadarko/AEC, Chevron, and Williams

First DNR Finding
First Royalty Board Hearing
First Public Comment Period
Second DNR Finding*
Request for Proposals
Submission of Proposals
Public Opening of Proposals

November 2001
November 2001
October - November 2001
December 2001
December 2001
January 31, 2002
February 1, 2002

Remaining:

Evaluation of Proposals
Negotiations Based on Proposals
Second Public Comment Period
Second Royalty Board Hearing
Third DNR Finding
Submission of Proposed Contract(s)
to Legislature for Approval/Disapproval
2002 Legislative Session Adjourns

February 2002
February 2002
March 2002
March 2002
March 2002
April 1, 2002
May 14, 2002

*Available on the web at dog.dnr.state.ak.us

**Remaining dates are subject to change, except date 2002 legislature adjourns

- **Price:**
 - **Base Price = royalty-in-value amount**
 - **Premium:** May be offered by potential purchaser
 - **Fixed Bonus:** \$1 for every 1 mcf of daily purchases
 - **Special Commitments:** May be offered by potential purchaser
- **Duration:**
 - **Up to the length of commitment required by those participating in an initial open season for pipeline capacity**
- **Point of Delivery:**
 - **At the same point and at the same time as the state takes delivery from the producers**
- **Notice Period for Reducing Volumes Taken**
 - **While state contractually required to give producers just 6 months notice, sale terms give purchaser an incentive to provide 2 years notice**

- **Impact on Pipeline Sizing**
- **Impact on Pipeline Company**
- **Impact on Prudhoe Bay Unit (PBU) and Point Thomson Unit (PTU) Producers**
- **Impact on Oil & Gas Explorers, In-State Industry, Utilities, and Alaska Consumers**

Three Scenarios:

Case #1: No RIK Sale

Example: 15 year nominations required in initial open season
No RIK gas sales during first 15 years of gasline's operation

Case #2: RIK Sale For Same Duration As Nominations In Initial Open Season

Example: 15 year nominations required in initial open season
15 year RIK gas sales contract, no early cancellation rights

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

Example: 15 year nominations required in initial open season
5 year RIK gas sales contract, commencing at gasline start-up

Impact On Initial Pipeline Capacity

RIK Sale For Same Duration As Nominations In Initial Open Season

Case #1: No RIK Sale

Example:

PBU + PTU Equity Gas	3.50 bcfd
PBU + PTU Royalty Share (nominated by PBU + PTU lessees)	.50 bcfd
Total Pipeline Capacity	4.00 bcfd

Case #2: RIK Sale For Same Duration As Nominations In Initial Open Season

Example:

PBU + PTU Equity Gas	3.50 bcfd
PBU + PTU Royalty Share (nominated by RIK buyer)	.35 bcfd
PBU + PTU Royalty Share (nominated by PBU + PTU lessees)	.15 bcfd
Total Pipeline Capacity	4.00 bcfd

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

Example:

PBU + PTU Equity Gas	3.50 bcfd
PBU + PTU Royalty Share (nominated by RIK buyer)	.35 bcfd
PBU + PTU Royalty Share (nominated by PBU + PTU lessees)	.50 bcfd
Total Pipeline Capacity	4.35 bcfd

Impact on Gas Pipeline Capacity

Will Pipeline Capacity Be Sufficient To Meet Demand?

Case #1: No RIK Sale

4.00 bcfd Pipeline Capacity Nominated

4.00 bcfd Pipeline Capacity Paid For

Case #2: RIK Sale For Same Duration As Nominations In Initial Open Season

4.00 bcfd Pipeline Capacity Nominated

4.00 bcfd Pipeline Capacity Paid For

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

4.35 bcfd Pipeline Capacity Nominated

4.35 bcfd Pipeline Capacity Paid For

Impact On PRICE & QUANTITY OF GAS

May Affect, Positively or Negatively:

- Pipeline Tariff,
- Date of Monetization of Stranded Gas Reserves, and
- Level of Usage of Gas Treatment Plant (GTP)

Case #1: No RIK Sale

Gains: Fixed usage level of Gas Treatment Plant
Losses: Smaller pipeline may mean higher per unit tariff
No acceleration of monetization of stranded gas reserves

Case #2: RIK Sale For Same Duration As Nominations In Initial Open Season

Gains: Fixed usage level of Gas Treatment Plant
Losses: Smaller pipeline may mean higher per unit tariff
No acceleration of monetization of stranded gas reserves

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

Gains: Larger pipeline may mean lower per unit tariff
Acceleration of monetization of stranded gas reserves
Losses: Usage of Gas Treatment Plant may vary between 4.00 and 4.35 bcfd

Producers Can Mitigate Impact on Level of Usage of Gas Treatment Plant

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

Gains: Larger pipeline may mean lower per unit tariff
Acceleration of monetization of stranded gas reserves

Losses: Usage of Gas Treatment Plant may vary between 4.00 and 4.35 bcfd

Solutions: Leave .35 bcfd (8%) of GTP capacity idle after 5 years
Sell .35 bcfd GTP capacity to RIK purchaser or other producers
Expand pipeline capacity .35 bcfd (or more)
Negotiate for better solution

Anadarko[®]



AEC MARKETING (USA) INC.



AEC OIL & GAS (USA) INC.



Offer to Purchase Alaska North Slope Royalty Gas

January 31, 2002

OFFER FOR ROYALTY GAS SUMMARY

January 31, 2002

1. Cash Payment: \$350,000.
2. Option Payment: \$2 million up-front and an additional \$2 million at each 5 year term renewal.
3. Price Premium: \$0.02 per MMBtu first 5 years, with \$0.02 per MMBtu increases at each 5-year term renewal.
4. Reservation Fee: Equal to one percent (1.0%) of the sum of the Base Price and the then applicable Price Premium, subject to a cap equal to the then effective Price Premium.
5. Exploration Work Commitment: A minimum \$50 million expenditure for exploration and development in the gas-prone Brooks Range foothills ("Foothills") for 2002-2007.
6. Preference for Local Hire: The Purchasers agree to a local hire preference.
7. Training Obligation: In the even of a commercial Foothills gas discovery, the Purchasers agree to an annual training obligation of not less than \$25,000 per annum commencing the year of commercial discovery declaration and for a period of not less than ten (10) years.
8. Preference for In-State Gas Processing: The Purchasers agree to give preference to in-State processing of both the purchased State ANS Royalty Gas and any gas discovered in the Purchasers' Foothills exploration efforts. Such in-State processing must afford the Purchasers equivalent terms and conditions that they could otherwise receive for out-of-state processing.
9. In-State Usage Reservation: The State is afforded an in-State gas use preference to the extent the Purchasers' 70% call would exceed 350 MMcfd.
10. Call Option: APC and AEC granted right to call for all or a portion of State's royalty gas up to 70% of State's ANS royalty gas (Estimated at 350 MMcfd).
11. Quantity: Up to 70% of State's ANS royalty gas at APC's/AEC's election (Estimated at 350 MMcfd).
12. Employment & Economic Impact Related to the Exploration Work Commitment: Anchorage based Northern Economics has prepared a study quantifying these two benefits with respect to our Exploration Work Commitments under both an "Exploration Only Scenario" and a "Successful Development Scenario". The Exploration Only Scenario yields total in-State economic value of \$40 million and creates an annual average of 180 new jobs. The Successful Development Scenario yields total in-State economic benefits of \$6.4 billion and creates an annual average 560 – 3,300 new jobs, depending upon the operations mode (exploration, development, or production).
13. Offer Value Per Mcf: The Purchasers' Offer yields a value of \$0.09 per Mcf and \$10.06 per Mcf, in the Exploration Only and the Successful Development Scenarios, respectively. These values were computed based upon a purchase quantity of 639 Bcf during the Primary Term of five (5) years.

14. Term: Call option for primary term of 5 years ending at 5th anniversary of Pipeline being placed in full, normal service. APC and AEC have the option to extend the term for additional 5-year intervals with additional Option Payments and escalations in the Price Premium. Term cannot be extended beyond the term of the transportation contracts secured for such gas.
15. Early Termination Provision: Either Party may terminate early if (i) the Royalty Board and Legislature have not approved the definitive Agreement by August 31, 2002; (ii) no Pipeline open season has occurred by March 31, 2005; or (iii) the Pipeline is not in service or State Royalty Gas has not been delivered by July 31, 2012.
16. Point of Delivery: To be negotiated between the State and the Purchasers.
17. Firm Transportation Service Release: If APC/AEC are unsuccessful in securing firm transportation on the Pipeline in quantities equal to or greater than the volume necessary to achieve an economic gas development, APC/AEC may terminate the Agreement without further obligation.
18. Separate Agreements: Anadarko and AEC will enter into separate Agreements with the State for one-half of the option volume rights and one-half the obligations. Initial Agreements shall be equivalent, but administration and application shall be separate and independent.

OFFER FOR ROYALTY GAS

January 31, 2002

1. Executive Summary:

For the purposes of this offer ("Offer"), the State of Alaska shall be referred to as ("the State"). Anadarko Petroleum Corporation shall be referred to as ("Anadarko") and AEC Marketing (USA) Inc. shall be referred to as ("AEC"). Anadarko and AEC shall be collectively referred to as ("the Purchasers").

In consideration for the valuable benefits to be provided the State as set forth below, the Purchasers seek an option to purchase the State's royalty share of North Slope gas production ("ANS Royalty Gas"). The key elements of the Purchasers' Offer are listed below in this first section. The key elements and their conditions are further outlined in the subsequent sections.

Upon the Purchasers' Offer being successful, the Purchasers and the State shall negotiate a definitive agreement based on the terms outlined in this Offer.

(A) Offer Elements:

1. Minimum Cash Bonus: \$350,000. This Minimum Cash Bonus is based upon the assumption that 70% of the State's ANS Royalty Gas volumes will equal 350,000 Mcfd. If 70% of the State's ANS Royalty Gas is determined to be more than 350,000 Mcfd prior to the Pipeline open season, the Purchaser's agree to make a supplemental Minimum Cash Bonus payment to the State for the expected increase in available volumes beyond 350,000 Mcfd.
2. Base Price: The volume weighted average royalty in-value price for the State's ANS Royalty Gas left in-value as further defined in that certain Solicitation For Offers To Purchase Alaska North Slope Royalty Gas, dated December 26, 2001 ("Solicitation For Offers").
3. Price Premium: A Price Premium of \$0.02 per MMBtu for each MMBtu of ANS Royalty Gas purchased during the primary term of the definitive agreement entered into between the State and the Purchasers ("Agreement"). The Price Premium shall be increased by \$0.02 per MMBtu for each subsequent five (5) year renewal period. The "Price Premium" as used herein shall be a payment amount added to the Base Price as set forth above.
4. Option Price: The Purchasers shall make an option payment to the State in the aggregate amount of \$2 million for each five (5) year term as compensation for the option to purchase all or part of the quantities of the State's ANS Royalty Gas made available to the Purchasers under the terms of this Offer and the Agreement. An initial cash payment of \$2 million shall be paid upon

execution and legislative approval of the Agreement, with an additional \$2 million payable 30 days prior to the commencement of each subsequent five (5) year renewal period.

In addition to the Option Price, the Purchasers agree to a one percent (1.0%) Reservation Fee subject to a volume and price cap.

5. Special Commitments (In-State Investments):

(a) Exploration Work Commitment:

The Purchasers commit to an "Exploration Work Commitment" totaling \$50 million during the period January 1, 2002 through December 31, 2007.

A socioeconomic impact assessment of this Exploration Work Commitment was undertaken by the independent consulting firm Northern Economics, Inc. Northern Economics' full report is attached hereto as an addendum. In summary, the Exploration Work Commitment totaling \$50 million is projected to have an overall in-state benefit of \$40 million when the economic multiplier effect and State fiscal assessments are taken into consideration. In addition, the Exploration Work Commitment is projected to generate an annual average of 180 new in-State jobs during the exploration phase of the program.

Northern Economics has also made a socioeconomic impact assessment of the scenario whereby the Purchasers continue their exploration efforts beyond the Exploration Work Commitment and such efforts result in a commercial natural gas discovery. Under such a scenario, the \$50 million Exploration Work Commitment is projected to result in an overall benefit to the State of \$6.4 billion when the economic multiplier effect and State fiscal assessments are taken into consideration. In addition, under this commercial discovery scenario, the Exploration Work Commitment is projected to generate annual new in-State jobs of 560, 2,400, and 3,300 per year during the exploration, development, or production phases, respectively.

The \$50 million Exploration Work Commitment is a Special Commitment obligation. In the event the Purchasers fail to meet the \$50 million Exploration Work Commitment during the term and under terms of this Offer, then the Purchasers shall pay to the State, as liquidated damages, an amount equal to the shortfall of said work commitment.

(b) Preference for Local Hire:

The Purchasers also commit to a local hire preference to the extent that local available labor is competitive and is qualified to perform the functions of the positions required by the Purchasers in carrying out their operations. The Purchasers agree to utilize their reasonable efforts to include local hire preferences in all their contracts with subcontractors and other service

providers. In implementing this practice, the Purchasers' policies on purchasing, employment standards, environment, health and safety will be followed.

If the Exploration Work Commitment results in a commercial discovery, the Purchasers will undertake commitments to train local laborers to fill available positions in Alaska. Commencing the year following declaration of a commercial discovery, the Purchasers shall commit to not less than \$25,000 per annum for training of local labor and for a period of not less than ten (10) years. In the event the Purchasers fail to meet the \$25,000 training obligation in any applicable year during the term and under terms of this Offer, then the Purchasers shall pay to the State, as liquidated damages, an amount equal to the shortfall of said training obligation.

Following a commercial discovery, the Purchasers will need to increase staff in the Anchorage office to support development operations in the field. To date, the Purchasers have been non-operators in successful exploration programs along the Barrow Arch.

As Operator of a commercial Foothills gas discovery, the Purchasers' in-State manpower requirements will increase substantially across all disciplines, experience levels, and authority grades. In addition to substantial field staffing requirements, a Foothills gas discovery will require a much larger Anchorage and North Slope employment presence. Local hire would be our preferred alternative for achieving this increase in staffing levels.

(c) Preference for In-State Gas Processing (NGL Extraction & Petrochemical Manufacturing):

The Purchasers commit to a preference for in-State processing of the gas purchased hereunder, as well as for any gas discovered in conjunction with the Exploration Work Commitment hereunder, all as further described in Section 15 below.

Our estimates are that a gas processing plant constructed for the processing of 350 MMcfd would entail capital investments on the order of \$100 million and generate an estimated 70 permanent direct jobs, as well as 400 construction jobs. We have not estimated the total economic impact to the State in terms of indirect labor, induced labor, property taxes, income taxes, and the economic multiplier effect.

It is our understanding that if the State's Royalty Gas is left in-value, the lessees intend to perform NGL extraction operations outside the State, in either Western Canada or the Lower 48 States.

6. Incidental State Benefits: Securing the option to purchase the State's ANS Royalty Gas will ensure Anadarko's and AEC's continuing commitment to the exploration for natural gas within the State of Alaska, particularly in the

area known as the Foothills. As a result, of securing the option, Anadarko and AEC are also expected to aggressively participate in future State oil and gas lease sales. Ensuring the two most active and aggressive independents' participation in future State oil and gas lease sales will result in greater State receipts from such lease sales both in terms of dollars per acre bid, as well as the numbers of leases awarded. In addition, ensuring Anadarko's and AEC's continued participation in State lease sales will surely result in incremental exploration activities and potential hydrocarbon discoveries by our two companies.

(B) Total State Economic Benefit per Mcf¹:

<u>Offer Element</u>	<u>Exploration Only Scenario</u>	<u>Exploration Success</u>
Cash Bonus	\$350,000	\$350,000
Price Premium	\$12,775,000	\$12,775,000
Option Price	\$2,000,000	\$2,000,000
In-State Investments	<u>\$40,000,000</u>	<u>\$6,410,000,000</u>
Totals	<u>\$55,125,000</u>	<u>\$6,425,125,000</u>
Offer Value per Mcf	<u>\$0.09 per Mcf¹</u>	<u>\$10.06 per Mcf¹</u>
Alaskan Jobs Created	<u>180</u>	<u>560 - 3,300</u>

It is worth noting that the State benefits substantially under the terms of this Offer regardless of whether the Purchasers exercise their call on the State's ANS Royalty Gas or not. If on the one hand, the Purchasers fail in their exploration efforts, the State will realize expected benefits in excess of \$175 million (see attached Exhibit "B"). If, however, the Purchasers are successful in their Foothills natural gas exploration effort that is contingent on this RIK Offer, the total direct economic benefit to the State is projected to exceed \$6.4 billion (see Northern Economics' Economic Impact report attached hereto as Exhibit "D").

In consideration for the economic values set forth above, the Purchasers shall be granted a call on 70% of the State's ANS Royalty Gas for a primary term ending on the fifth (5th) anniversary of the date that an Alaskan North Slope natural gas pipeline serving the Lower 48 States ("ANS Gas Pipeline" or "Pipeline") is placed into full, normal service. The Purchasers' call on ANS Royalty Gas shall, at the Purchasers' election, be for all or any portion thereof, upon providing appropriate notices as set forth below.

¹ Based upon the assumption of 350,000 Mcfd of State ANS Royalty Gas for the five (5) year Primary Term. Total royalty volume assumed is 639 Bcf (638,750,000 Mcf).

2. Mutual Benefits Discussion:

This call on the State's royalty in-kind gas production is mutually beneficial to the State and the Purchasers. The State shall realize valuable consideration both up-front and when the ANS Royalty Gas is called upon. The up-front payments will likely precede the State's initial ANS Royalty Gas production by seven or eight years. Through the proposed royalty purchase price structure, the State shall realize at least a \$0.02 per MMBtu Price Premium above the weighted average price received by the State for other ANS Royalty Gas sold off the North Slope.

In addition, the State will enjoy the benefits derived by the Purchasers' continued natural gas exploration and development expenditures. The Purchasers hereby commit to spending not less than \$50 million on natural gas exploration within the Foothills region of the Brooks Range over the next six (6) years.

A single successful natural gas development is expected to require investments on the order of \$1.4 billion. Due to the economic multiplier effect, under a single economic gas development scenario, these combined natural gas exploration and development expenditures are expected to yield economic benefits to the State of Alaska in the range of \$6.4 billion, inclusive of royalty, severance, income, and property tax benefits. Several natural gas developments would obviously result in similar direct economic impacts to the State in multiples of the \$6.4 billion generated from a single natural gas development.

Absent this call on the State's ANS Royalty Gas it will be extremely onerous and probably prohibitively risky for the Purchasers to bid on pipeline capacity in an open season nomination process. Without assured access to the ANS Gas Pipeline, backstopped by the State's ANS Royalty gas, it would be imprudent for the Purchasers to continue natural gas exploration within the State as the Purchasers would likely have no access to markets for their gas.

Part of the economic benefit to the State of Alaska under this arrangement is the opportunity to realize the potentially multibillion dollar economic benefits associated with the Purchasers' continued exploration for natural gas in northern Alaska. If the Purchasers fail to achieve capacity on the ANS Gas Pipeline, the State will likely be left with three multinational oil companies dominating the Pipeline without meaningful competition. Without access to the Pipeline, exploration for ANS natural gas by all remaining exploration companies will likely come to a standstill.

Having the State's ANS Royalty Gas as a backstop and early proxy for the Purchasers' own production for a period of time will substantially reduce the risks associated with bidding on pipeline capacity in the open season. Assuming that the Purchasers secure a combined 350,000 Mcfd of pipeline capacity, we anticipate that the demand payment obligation associated with this firm transportation capacity will likely exceed \$150 million per annum. This demand charge is a monthly obligation, which must be paid regardless of how much, if any, gas is actually

transported by the Purchasers. Having access to the State's ANS Royalty Gas will help ensure that the Purchasers discover, develop, and produce sufficient natural gas quantities to fulfill their firm transportation capacity commitments.

To this point, both the State and the Purchasers, despite numerous attempts to actively engage the Pipeline sponsors, have been largely shut-out of the Pipeline discussions in any meaningful way. Awarding ANS Royalty Gas to the Purchasers under the Solicitation For Offers elevates both the State and the Purchasers to legitimate, significant stakeholders in all facets of the proposed Pipeline. The Purchasers believe that award of ANS Royalty Gas to the Purchasers should facilitate the State's and the Purchasers' inclusion in future discussions and negotiations of the Pipeline project.

3. Effective Date:

This Offer shall become effective upon execution of a definitive agreement incorporating the terms and conditions contained herein and the subsequent approval of the Royalty Board and the Alaskan State Legislature.

The State recognizes that time is of the essence in securing the requisite approvals and completing the execution of the definitive agreement inasmuch as the Purchasers require this royalty in-kind purchase option in order to participate in the ANS Gas Pipeline open season. The State further recognizes that the Pipeline open season may occur as early as the first quarter of 2002.

4. Cash Consideration to be Paid:

The Purchasers shall pay the State a \$350,000 Minimum Cash Bonus commensurate with this Offer. This \$350,000 Minimum Cash Bonus is based upon the assumed award of 70% of the State's ANS Royalty Gas to the Purchasers equating to 350,000 Mcfd. If the awarded volume is an amount other than 350,000 Mcfd, the Minimum Cash Bonus shall be adjusted *pro rata* (e.g. 300,000 Mcfd = \$300,000 Minimum Cash Bonus).

This Minimum Cash Bonus is based upon the assumption that 70% of the State's ANS Royalty Gas volumes will equal 350,000 Mcfd. If 70% of the State's ANS Royalty Gas is determined to be more than 350,000 Mcfd prior to the Pipeline open season, the Purchaser's agree to make a supplemental Minimum Cash Bonus payment to the State for the expected increase in available volumes beyond 350,000 Mcfd.

The Purchasers shall also pay the State the Base Price for all State ANS Royalty Gas purchased pursuant to the terms of this Offer. The Base Price shall be computed in accordance with the definition of such term in the Solicitation For Offers and as further refined in the definitive agreement to be negotiated between

the State and the Purchasers. However, the Base Price shall be computed on a volume-weighted basis as to gas values received by the State for in-value sales in the same area and of similar composition. The Base Price shall not include any non-gas costs or adjustments. The intent of the Base Price is to reflect the weighted-average arms-length netback market price of the State's in-value gas sales made via the ANS Gas Pipeline. The Base Price under this Agreement shall not be higher than any royalty in-value base price used for any other royalty in-kind sales by the State.

The Purchasers shall also pay a Price Premium of \$0.02 per MMBtu for each MMBtu of ANS Royalty Gas purchased during the Primary Term of the Agreement. The Price Premium shall increase by \$0.02 per MMBtu during each subsequent five-(5) year term extension. The "Price Premium" as used herein shall be a payment amount added to the Base Price as set forth above.

A \$2 million cash Option Price payment shall also be paid upon execution of the Agreement and receipt of Legislative approval, plus an additional \$2 million cash Option Price payment prior to each subsequent five (5) year term extension. These Option Price payments are based upon the assumed award of 350,000 Mcfd of State ANS Royalty Gas to the Purchasers. If the awarded volume is an amount other than 350,000 Mcfd, the Option Price payments shall be adjusted *pro rata* (e.g. 280,000 Mcfd = \$1,600,000 Option Price payment).

In addition to the Option Price, the Purchasers agree to a monthly Reservation Fee equal to one percent (1.0%) of the sum of then effective Base Price plus the Price Premium, but not to exceed the then current Price Premium. The Reservation Fee shall be assessed on the difference between the volumes purchased for the month and the maximum ANS Royalty Gas volume available to the Purchasers for the month. The Purchasers, upon proper notices, shall be afforded the opportunity to reduce the maximum ANS Royalty Gas volume available by 50% and the ability to raise and/or restore such maximum volumes upon proper notice.

Lastly, the Purchasers agree to undertake the significant \$50 million Exploration Work Commitment set forth below.

5. Exploration Work Commitment:

The Purchasers commit to an "Exploration Work Commitment" of \$50 million during the period January 1, 2002 through December 31, 2007. This work commitment is contingent on the success of the Purchasers' efforts to secure sufficient firm transportation services on the ANS Gas Pipeline and an acceptable resolution of the lease access issues currently under discussion with the State.

The Exploration Work Commitment is for expenditures, exclusive of overhead charges and Anadarko and AEC internal manpower costs, for exploration costs incurred in the gas-prone Foothills of the Brooks Range. Exhibit "A" attached

hereto is a plat outlining the area considered as the Foothills of the Brooks Range for purposes of this Offer. This Exploration Work Commitment is a firm commitment by the Purchasers and should the Purchasers fail to satisfy the \$50 million Exploration Work Commitment by December 31, 2007 for any reason other than events of Force Majeure, the Purchasers shall make a cash payment to the State, as liquidated damages, for the full amount of any shortfall in expenditures relative to the \$50 million Exploration Work Commitment.

This \$50 million Exploration Work Commitment is an incremental exploration expenditure commitment for exploration in the gas-prone Foothills area. These exploration monies are dependent upon securing the right to purchase sufficient volumes of the State's ANS Royalty Gas. Without such rights to purchase sufficient volumes of the State's ANS Royalty Gas, the Purchasers' natural gas based exploration in the Foothills would be at substantial risk of discontinuation.

This \$50 million Exploration Work Commitment is also in addition to the substantial in-State investments that the Purchasers have undertaken and will continue to undertake for exploration and development in the oil-prone plays along the Barrow Arch and elsewhere in the State. For instance, Anadarko's North Slope campaign this winter includes shooting seismic in multiple locations, drilling our 100% Altamura No. 1 well in the NPR-A, and participating in an expected seven other exploratory wells. In total, Anadarko is participating in North Slope exploration operations this winter with expected expenditure levels of \$70 million, exclusive of exploration expenditures in the gas-prone Foothills region.

Over the next four years, Anadarko's in-State exploration and development expenditures, on a gross basis, are expected to be on the order of \$1.1 - \$1.6 billion.

In addition AEC plans to participate in three North Slope non-gas drilling prospects in 2002, subject to regulatory approval. AEC's share of the Exploration Work Commitment will be performed by AEC Oil & Gas (USA) Inc. or its successor in interest.

Although the Purchasers' projected exploration and development expenditures for the oil-prone Barrow Arch are cited above, we do not believe that exploration and development expenditures in oil-prone areas are germane to this RIK sales offer process.

6. Explanation of Call Rights:

The Purchasers shall have the right to call upon 70% of the State's ANS Royalty Gas for an initial five (5) year period ending on the fifth (5th) anniversary of the date that the ANS Gas Pipeline is placed into full, normal service. The Purchasers' call on the State's ANS Royalty Gas shall, at the Purchasers' election, be for all or any portion thereof, upon providing requisite prior notices to the State. As set forth in Section 13 below, for additional consideration, the Purchasers may elect to extend

the term of their call rights for additional five (5) year periods, but for no longer than the term of the underlying transportation contracts.

7. State's Obligation to Exercise its Royalty In-Kind Rights:

The State shall exercise its royalty in-kind rights pursuant to its leases for which ANS Royalty Gas is to be produced in the quantities equal to those called for by the Purchasers as set forth in Section 6 above and Sections 9 and 12 below. The State shall provide its lessees with the proper take in-kind notices and other requirements as set forth in the subject State leases.

8. Purchase Price Calculation:

During the Primary Term of the Agreement, for each MMBtu of the State's ANS Royalty Gas volume purchased pursuant to the Purchasers' call, payment shall be made in an amount equal to the Base Price, plus a \$0.02 per MMBtu Price Premium. If the Purchasers exercise their right to extend the term of the Agreement, for each five-(5) year term extension, the Price Premium shall be increased by \$0.02 per MMBtu.

The purchase payment calculation above shall be computed separately for AEC and Anadarko as the ANS Royalty Gas volumes purchased by each company may differ.

The pricing calculation shall be undertaken for each calendar month that the State's ANS Royalty Gas is purchased pursuant to the Purchasers' call option.

9. Contract Quantity:

The Purchasers shall have a call on 70% of the State's ANS Royalty Gas volumes during the term of this arrangement.

The Purchasers agree to negotiate with the State as to quantity provisions along the lines of the concepts set out in the Final Finding and Determination.

The Purchasers' nomination notice to the State shall provide the State with a breakout of the nominations between Anadarko's purchase quantity and AEC's purchase quantity. It is recognized herein that Anadarko's and AEC's nominations may not be equal.

10. Point of Delivery:

The definition of the Point of Delivery shall be negotiated between the State and the Purchasers. The State shall warrant clear title to the gas delivered at the Point of Delivery. The gas shall be free and clear of all encumbrances.

11. Firm Transportation Service:

The Purchasers shall secure and maintain firm transportation service on the ANS Gas Pipeline for the purchase and transportation of the ANS Royalty Gas volumes purchased hereunder. Transportation service levels to markets downstream of the southern terminus of the ANS Gas Pipeline shall be at the Purchasers' discretion.

The Purchasers' obligation to secure firm transportation service on the ANS Gas Pipeline is subject to the Purchasers' successfully bidding for capacity at the initial open season for the Pipeline. To the extent that the Purchasers are unable to secure firm transportation services for all of the State's ANS Royalty Gas volumes made available under this RIK sales process, the Purchasers agree to release the State from the call option contemplated hereunder as to the difference between the quantity of firm transportation secured and the full quantity of the State's ANS Royalty Gas volumes made available under this RIK offer process.

In addition, if the Purchasers are unable to secure a sufficient volume of firm transportation service on the ANS Gas Pipeline to achieve an economic threshold for their natural gas exploration and production initiatives, the Purchasers may terminate the Agreement upon written notice to the State. The Purchasers' termination rights pursuant to this clause must be exercised within 180 days of the awarding of firm transportation capacity on the Pipeline. Upon such termination, neither the State nor the Purchasers shall be liable to the other for any further obligations.

12. Source of Gas:

The Purchasers and the State recognize that different circumstances exist with respect to production related costs ("Field Costs") for the different fields from which the State receives ANS Royalty Gas. Under existing lease and settlement terms between the State and the lessees, the State currently bears such Field Costs as to certain leases if its ANS Royalty Gas is taken in-kind that the State would not have to bear if the ANS Royalty Gas were taken in-value rather than in-kind.

The State agrees to first source the volumes to be sold hereunder from those leases for which Field Costs are payable by the State regardless of whether such royalty volumes are taken in-kind or in-value. If, in order to meet the volumes nominated by the Purchasers hereunder, gas volumes must be taken from leases in which the State would have to bear Field Costs that would not be borne in the royalty in-value

mode ("High Cost Gas"), the State shall advise the Purchasers of the quantity and a good faith estimate of the Field Costs associated with such volumes. The Purchasers shall then have the right to adjust their purchase nominations to avoid or minimize the purchase of such High Cost Gas.

If, however, the Purchasers do elect to purchase such High Cost Gas, the Purchasers shall reimburse the State for the incremental Field Costs borne by the State relative to the costs, if any, the State would have borne had such gas been taken in-value.

In the event the State enters into ANS Royalty Gas sales agreements in addition to this sale, whereby the sale of High Cost Gas via a take in-kind election is unavoidable, the State shall allocate High Cost Gas *pro rata* between all ANS Royalty Gas purchasers so as to treat all purchasers equitably as to the allocation of such High Cost Gas sources. Again, the Purchasers shall have the right to individually adjust their purchase nominations to avoid or minimize the purchase of this High Cost Gas.

In recognition that the transportation commitment undertaken by the Purchasers for this ANS Royalty Gas purchase obligation is likely to be for a period of time in excess of 15 years, the Purchasers would like to include a call on future State ANS Royalty Gas volumes attributable to other North Slope fields (in addition to Prudhoe Bay and Point Thomson) to the extent such volumes are required in order to maintain an available volume of 350,000 Mcfd. Such a call on supplemental sources of the State's ANS Royalty Gas would still be restricted to the 70% limitation proposed by the State. This concept would seem equitable and consistent with the intent of the Final Finding and Determination. Therefore, the Purchases would like to preserve discussions of this concept during negotiation of the Agreement.

The Purchasers believe the above terms are consistent with the directive and intent given in the Final Finding and Determination. Nevertheless, if the State objects to the above concepts, the Purchasers are open to negotiating this provision.

13. Term:

The Purchasers' call on the State's ANS Royalty Gas volumes shall be for a term ending on the fifth (5th) anniversary of the date that the ANS Gas Pipeline is placed into full, normal service ("Primary Term"). Partial start-up, line-fill operations, and testing of the Pipeline shall not constitute full, normal service startup.

At the Purchasers' election, the Agreement may be extended for subsequent terms of five (5) years' duration commencing the first day following the end of the Primary Term and each applicable extension term. The Purchasers' shall provide the State formal written notice of their election to extend the term of the Agreement for such subsequent terms at least 14 months prior to the end of the then current

term. Term extensions shall require the payment of the Option Price payments, Price Premium escalations, and the Reservation Fee as set forth in Section 4 above.

In no event, however, shall the Purchasers have the right to extend the Agreement beyond the term of the underlying transportation agreements under which the State's ANS Royalty Gas is transported on the Pipeline.

14. Reservation of ANS Royalty Gas for In-State Use:

Provided the Purchasers are awarded the right to purchase up to 70% of the State's ANS Royalty Gas volumes and the available volumes exceed 350,000 Mcfd, the Purchasers agree to afford in-State usage a priority call on all available volumes exceeding 350,000 Mcfd that would otherwise be available to the Purchasers.

That is, if the State notifies the Purchasers that a priority in-State usage of its ANS Royalty Gas is required, the Purchasers agree to reduce their call on the State's ANS Royalty Gas for any quantities in excess of 350,000 Mcfd up to an amount equal to such in-State usage.

If such new in-State usage is for petrochemical manufacturing or NGL extraction, the Purchasers shall have the option, in lieu of releasing their call on such gas volumes, of entering into a gas processing arrangement with such petrochemical or NGL extraction plant (for appropriate consideration from the plant owners), such that the petrochemical and/or NGL extraction plant(s) receive their desired feedstock of NGLs, while allowing the Purchasers to retain title and possession of the residue gas attributable to the ANS Royalty Gas processed at such plant or plants.

In addition, to the extent that the Purchasers desire, such released in-State usage gas shall be transported on the Purchasers' transportation capacity on the Pipeline and the State shall reimburse the Purchasers for the actual costs of transporting such gas to the off take point on the Pipeline where such gas is consumed for in-State usage.

The intent of this provision is to afford the State flexibility to utilize its ANS Royalty Gas to encourage and facilitate new in-State gas consuming industries, while preserving the Purchasers the maximum reasonable call on the State's ANS Royalty Gas.

15. Natural Gas Liquids Processing:

Title to and processing rights related to natural gas liquids ("NGLs") contained in the stream of ANS Royalty Gas shall pass to the Purchasers at the Point of Delivery. Payments to the State relative to the value of extracting NGLs, if any, shall be in the form of the Base Price to be paid hereunder. That is, the weighted average royalty in-value price to be used as the Base Price is anticipated to reflect

any and all value associated with the processing of the State's ANS Royalty Gas sold in-value.

The Purchasers commit to a preference for in-State processing of the gas purchased hereunder, as well as for any gas discovered in conjunction with the Exploration Work Commitment hereunder. The Purchasers agree to negotiate in good faith with any third-party contemplating the construction of an in-State NGL extraction and/or petrochemical plant as to an acceptable gas processing agreement. Provided such in-State facility can provide the Purchasers with commercial terms and other relevant conditions that are at least equivalent to the Purchasers' other out-of-state processing alternatives, the Purchasers shall give the in-State option preference. Such preference shall also be subject to satisfaction of the Purchasers' policies on credit, environment, health and safety, and other relevant corporate policies.

Notwithstanding the above, should the Purchasers elect to install in-State gas processing and/or petrochemical facilities themselves, they shall not be under any obligation to enter into a processing agreement with any third-party in lieu of pursuing such investments themselves.

16. Re-Opener Clause:

Either Party may petition the other to re-open the terms of the Agreement in the event of a material change in the market conditions. Such change must be material and have a substantial adverse effect on the Party seeking re-opening of the terms and conditions of the Agreement. In the event of such a re-opener notice, the Parties shall meet and modify the Agreement so as to maintain the original intent and effect of the terms when the Agreement was first executed. The Parties shall be under a good faith obligation to reach mutual agreement of such modifications necessary to maintain the original intent and effect of the terms when the Agreement was first executed.

In the evaluation of whether a material change in market conditions has occurred and in the negotiation of modifications required, the Parties shall give weight to the terms and conditions of this Offer; the definitive agreement incorporating the terms of this Offer; and the Exhibit "C" attached hereto, entitled "Representations".

17. Early Termination Rights:

Either Party may terminate the Agreement if any of the following occur: (i) the Royalty Board and the Legislature have not approved the definitive Agreement by August 31, 2002; (ii) no Pipeline open season has occurred by March 31, 2005; or (iii) the ANS Gas Pipeline is not in service or State Royalty Gas has not been delivered by July 31, 2012.

In the event of an early termination under this provision, refunds, if any, shall be handled in accordance with Section 20 below. Any remaining outstanding non-cash Special Commitment obligations shall be waived in the event of (i), (ii), or (iii) above.

18. Gas Quality:

The gas sold and purchased hereunder shall, upon delivery at the Point(s) of Delivery, be of merchantable quality and in compliance with all of the ANS Gas Pipeline's quality specifications; including temperature, pressure, and CO₂ content. However, the Parties recognize that under certain circumstances the Point of Delivery may be such that the Purchasers will have to take custody of the gas prior to conditioning and potentially prior to other field services.

Under such circumstances, if requested by the Purchasers, the State shall assist the Purchasers in obtaining access to third-party conditioning and treating facilities and to help ensure access is obtained at on a nondiscriminatory basis and at fair and reasonable costs.

19. Field and Conditioning Costs:

The Purchasers shall reimburse the State or bear directly the field costs and conditioning costs attributable to those ANS Royalty Gas volumes purchased by the Purchasers for which the State would not have borne such costs had the gas been sold by the State in the royalty in-value mode.

The Parties recognize that under certain circumstances the Point(s) of Delivery may be such that the Purchasers will take custody of the gas prior to conditioning and potentially prior to other field services. In such cases where the Purchasers take custody of the Gas prior to the occurrence of such services and the Purchasers incur the costs of such services directly, the Purchases shall be entitled to deduct such costs from the remittances to the State for all such ANS Royalty Gas volumes that the State would have incurred such costs in the royalty in-value mode.

20. Offer Payment Refunds:

Per the Final Finding and Determination, if the Purchasers' Offer is not accepted by the State, the Minimum Cash Bonus will be refunded, without interest. Further, all bonus and other cash payments made by the Purchasers will be refunded, without interest, if any of the following occur: (i) the Royalty Board and the Legislature have not approved the definitive Agreement by August 31, 2002; (ii) no Pipeline open season has occurred by March 31, 2005; or (iii) the ANS Gas Pipeline is not in service or State Royalty Gas has not been delivered by July 31, 2012.

Any remaining outstanding non-cash Special Commitment obligations shall be waived by the State in the event of the occurrence of events described (i), (ii), or (iii) above.

21. Environmental Impact:

This Offer in and of itself should have no adverse environmental impact on the State. The Exploration Work Commitment will entail ingress and egress on and off of public and private lands. However, all operations will be conducted in compliance with State and Federal environmental laws and in close coordination with the appropriate State and Federal agencies having jurisdiction.

With respect to potential gas development operations, the Purchasers will incorporate industry "best practices" standards in order to minimize both the footprint as well as the overall environmental impacts. One of the Purchasers, Anadarko Petroleum Corporation, is a partner in the recently developed Alpine Field which serves as the Alaskan and the petroleum industry's current model for minimizing both field development footprints and efforts to mitigate and minimize overall environmental impacts as they relate to petroleum developments.

22. Social Impacts:

As set forth in the Northern Economics Study attached hereto as Exhibit "D", this Offer has the potential to provide the State with extraordinarily positive social impacts in terms of employment creation for both the State and the North Slope Borough. The financial contribution to both the State's general fund and permanent fund will provide incremental revenue sources to fund the State's overall social initiatives. In addition, if the Foothills exploration initiatives result in a commercial gas discovery, substantial property taxes accruing to the North Slope Borough will provide funding for the Borough to continue initiatives to provide both financial support and infrastructure development for the benefit of its citizens.

23. Separate Contracts:

Anadarko and AEC are submitting this Offer in combination seeking an equal share as to the call option for the State's ANS Royalty Gas volumes set out above and are each obligated to 50% of the consideration and obligations set out under this Offer as such relate to the Purchasers.

However, given the diverse exploration activities that Anadarko and AEC have undertaken within the State, Anadarko's and AEC's management and exercise of their respective call options and elections may differ. Therefore, we propose that the definitive agreement incorporating the terms and conditions of this Offer be

jointly negotiated, but that separate Agreements be executed between the State and Anadarko and between the State and AEC.

24. Other Terms and Conditions:

The definitive agreement contemplated herein shall include the above terms and conditions as well as the remaining terms and conditions typically contained in a natural gas purchase and sales contract, including but not limited to: indemnities, risk of loss, assignment, payment terms and conditions, Force Majeure, and governing law.

25. Indirect Benefits to the State:

Exercise of the Purchasers' call on the State's ANS Royalty Gas early in the five-year term of this arrangement could result in early expansion of the ANS Gas Pipeline. Assuming the Purchasers require most, if not all of the State's ANS Royalty Gas initially, all of the gas flowing through the pipeline will likely originate from the Prudhoe Bay Unit or a combination of the Prudhoe Bay and Point Thomson Units. This will result in added financial benefits to the State through the premiums paid for RIK gas. If the Purchasers ramp-up production from their own fields in the latter part of the five-year term of this arrangement, they will be backing out the State's ANS Royalty Gas from the Prudhoe Bay and Point Thomson Units. However, the RIK gas will be replaced with new gas production subject to severance, property, and corporate income taxes, as well as potential State royalties.

As the Purchasers reduce their State ANS Royalty Gas purchases, the State will notify the Prudhoe Bay and Point Thomson Unit working interest owners that the State is rescinding its royalty in-kind election and reverting to royalty in-value. The Prudhoe Bay and Point Thomson Unit working interest owners will be faced with debottlenecking the ANS Gas Pipeline, expanding the Pipeline, or curtailing their production. Confronted with potential curtailment, the Prudhoe Bay and Point Thomson Unit working interest owners will have direct economic incentive to debottleneck or expand the Pipeline.

Through use of the State's royalty in-kind and royalty in-value elections, the State can minimize the impact on the State's revenues if the Prudhoe Bay and/or Point Thomson Units' gas production becomes curtailed by virtue of the Purchasers' gas production volumes.

In order to maximize their cash flow and avoid curtailing gas production, the working interest owners in the Prudhoe Bay and/or Point Thomson Units would be motivated to ensure prompt pipeline debottlenecking or expansion.

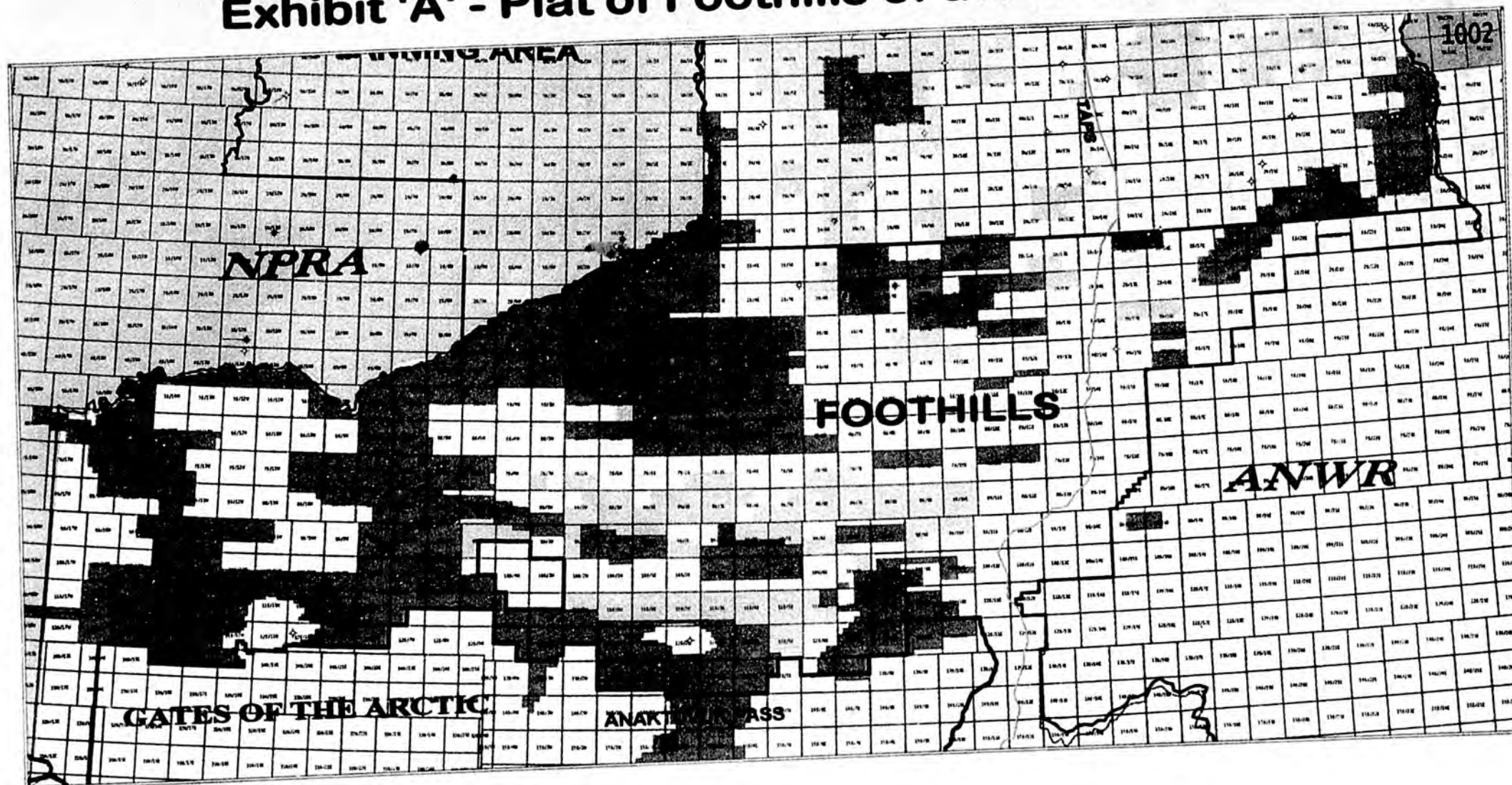
Under this scenario the State could actually realize an increase in royalties paid. If the Pipeline were to be promptly expanded and the State held all or part of the mineral rights underlying the Purchasers' new gas field, the State's royalty volume/value would increase by as much as 43,750 Mcfd (12.50% of 4.35 Bcfd verses 12.50% of 4.0 Bcfd). State severance taxes, property taxes, and corporate income taxes would also increase with the incremental 350,000 Mcfd of natural gas sales. In addition, if the Pipeline expansion required the installation of physical assets, such as compressor stations, the State would also realize increased property taxes from the pipeline expansion and increased State income taxes from the Pipeline related to the increased throughput.

26. Open to Negotiation:

The Purchasers believe the terms of this Offer accurately reflect the principles and intent of the Final Finding and Determination. The Purchasers also believe this Offer to be fair and reasonable to both the State and the Purchasers. If the State believes certain terms may not properly capture the principles in the Final finding and Determination, the Purchasers are prepared to negotiate mutually acceptable amendments to such terms.

Upon the Purchasers' Offer being successfully awarded, the State and the Purchasers shall negotiate a definitive agreement based upon the terms outlined in this Offer.

Exhibit 'A' - Plat of Foothills of the Brooks Range



- ☐ APC 100%
- ☒ APC PARTIAL
- ☒ ASRC
- ☐ INDUSTRY

Exhibit "B" – Economic Impact Without Exploration Success

Thousands of Dollars

<u>Offer Element</u>	<u>Years 1 – 5</u>	<u>6 –10</u>	<u>11 –15</u>	<u>16 –20</u>	<u>Total</u>
Cash Bonus	\$350	\$0	\$0	\$0	\$350
Option Payment	\$2,000	\$2,000	\$2,000	\$2,000	\$8,000
Price Premium	\$12,775	\$25,550	\$38,325	\$51,100	\$127,750
Special Commitments	<u>\$40,000</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$40,000</u>
Totals	<u>\$55,125</u>	<u>\$27,550</u>	<u>\$40,325</u>	<u>\$53,100</u>	<u>\$176,100</u>

Exhibit "C" – Representations

The intent of this Agreement is to assist the Purchasers in exploring for and developing non-associated natural gas in the Foothills of the Brooks Range region of northern Alaska. If successful, the State will benefit from new incremental proven and developed natural gas reserves, plus a more stable and higher State royalty revenue (i.e. lessening the State's dependence on oil revenue and its associated natural gas). Production and sales of non-associated natural gas would also allow the continued use of existing natural gas for enhanced oil recovery projects, thereby ensuring maximum oil recovery from existing oil reservoirs.

Through this Agreement, the State has provided the Purchasers an option to purchase ANS Royalty Gas in return for compensation and other socioeconomic benefits that will result if the Purchasers are successful in exploring for and developing non-associated natural gas.

The Purchasers will purchase the State's ANS Royalty Gas at a fair market value, plus the Price Premiums specified within this Agreement. The fair market value for ANS Royalty Gas will essentially be the netback gas price on the ANS Gas Pipeline for similar gas from the same supply area. The netback price is expected to reflect the royalty in-value prices realized for gas marketed on the ANS Gas Pipeline. The gas purchase price under this Agreement will yield the State a price in excess of the royalty in-value price that it could have otherwise received for its gas had the gas been sold in-value via the ANS Gas Pipeline. The royalty in-value price used as the Base Price under this Agreement shall not include any non-gas costs or adjustments.

The Purchasers are actively exploring for natural gas in the Foothills of the Brooks Range. However, the Purchasers will not have proven gas reserves by the end of 2002. The Alaska Gas Producer Pipeline Team ("AGPPT") has stated that an open season for nominating capacity on an ANS Gas Pipeline could occur as early as the first quarter of 2002. Therefore, bidding for firm capacity in the open season is extremely risky for the Purchasers from a financial exposure standpoint and is the primary reason for seeking this purchase option.

There are over 30 Tcf of proven gas reserves on the North Slope. Assuming a 4 Bcfd capacity pipeline, this pipeline would be full for nearly 20 years. Both the Purchasers and the State have a concern that if the Purchasers do not obtain firm transportation service in the initial open season, they may not be able to acquire capacity on the pipeline within a reasonable timeframe. Without some assurance concerning pipeline capacity, continued investment in new Alaska natural gas exploration is unlikely.

New natural gas exploration and this ANS Royalty Gas sale would help counter the dominant market position held by the relatively few major North Slope natural gas reserve holders. Three (3) companies own practically all of Alaska's proven North Slope natural gas reserves. These three companies have the power to influence:

- a. future exploration and development of new gas resources in Alaska, and
- b. the rates, terms and conditions of pipeline service, whether as owners of the proposed ANS Gas Pipeline or as the anchor-shippers.

The ANS Royalty Gas sales process takes time and requires legislative approval. Legislative approval is only available from January to May of any given year, restricting the timeframe that a royalty in-kind sale could be approved. Initiating the royalty in-kind process and finalizing the awarded sales contracts as soon as possible is critical for current and future natural gas exploration within Alaska.

At the ANS Gas Pipeline capacities currently contemplated, no new natural gas exploration is likely to occur within the State of Alaska for the next 20 years absent an arrangement along the lines of this Agreement. New entrants will not likely be able to obtain access to the Pipeline. As for the three dominant North Slope natural gas reserves holders, they will not need to explore for new incremental gas reserves for ten years or more after the start-up of the Pipeline. By providing ANS Royalty Gas to explorers like the Purchasers, the State can ensure exploration will continue to take place in areas that would otherwise remain unexplored for possibly decades to come.

Through this Agreement, the State is leveraging its royalty gas volumes of tomorrow to support natural gas exploration projects today and into the immediate future. The State has no risk under this arrangement, as the ANS Royalty Gas sales price agreed to herein is at a Price Premium to the State's alternative sales option (i.e. royalty in-value). If the Pipeline does not proceed, the State would have no obligation to deliver contracted future ANS Royalty Gas volumes under such circumstances and is afforded early termination rights under the Agreement.

Additional fundamental intents and representations are also contained in Section 2 (Mutual Benefits Discussion) above.

ECONOMIC IMPACTS OF ANADARKO EXPLORATION, DEVELOPMENT, AND PRODUCTION OF ALASKA NORTH SLOPE FOOTHILLS GAS OPERATIONS

Prepared for

**Anadarko Petroleum Corporation
AEC Oil and Gas (USA) Inc.**

January 2002

Prepared by

**NORTHERN
ECONOMICS**

INC.

880 H STREET, SUITE 210
ANCHORAGE, ALASKA 99501
907.274.5600
907.27.5601 FAX

PROFESSIONAL CONSULTING SERVICES IN APPLIED ECONOMIC ANALYSIS

President & Principal Economist: Patrick Burden
Economists: Leah Cuyno, Ph.D., Fred Wallace, Ph.D., Scott Miller
Associate Economists: Hart Hodges, Ph.D., John McCracken
Office Manager: Stephanie Cabaniss

Vice President & Senior Economist: Marcus L. Hartley
Policy Analyst: Nancy Mundy, Ph.D.
Analyst: Michael Fisher
Document Processor: Terri McCoy

880 H STREET, SUITE 210, ANCHORAGE, ALASKA 99501
TEL. 907.274.5600 FAX 907.274.5601
E-mail: norecon@norecon.com Internet: www.northerneconomics.com

**NORTHERN
ECONOMICS**

Contents

Section	Page
Abbreviations	vi
Executive Summary	1
1 Introduction	1-1
2 Natural Gas Development Scenario	2-1
2.1 Exploration	2-4
2.2 Development	2-5
2.3 Production	2-8
2.4 Alaska Revenue Estimates	2-10
3 Impacts on Employment	3-1
3.1 Employment Estimates	3-1
3.2 Methodology	3-4
4 Other Alaskan Economic Impacts	4-1
4.1 Labor Income	4-1
4.2 Value-Added Impacts	4-3
4.3 Impacts on the Alaska Permanent Fund	4-5
4.4 Benefits to Consumers from Lower Energy Costs in Fairbanks	4-5
5 References	5-1

Table	Page
Table ES-1. Anadarko/AEC Exploration, Development, and Production Expenditures for the Alaska North Slope Foothills Gas Project, 2001-2030	2
Table ES-2. Alaska North Slope Foothills Natural Gas Project Impacts for State of Alaska, 2001-2030	2
Table ES-3. Alaska North Slope Foothills Natural Gas Project Impacts for North Slope Borough, 2001-2030	2
Table ES-4. Total Revenue Estimates for the State of Alaska and the North Slope Borough, 2001-2030	3
Table 2-1. Alaska North Slope Foothills Natural Gas Exploration Costs	2-4
Table 2-2. Expenditure Pattern for Exploration of Remote Oil Fields by Category	2-4
Table 2-3. In-State Exploration Expenditures for Natural Gas Projects in the Alaska North Slope Foothills by Category, 2001-2030	2-5

<u>Table 2-4. Alaska North Slope Foothills Natural Gas Development Costs, 2001-2030</u>	<u>2-6</u>
<u>Table 2-5. Expenditure Pattern for Development of Remote Oil Fields</u>	<u>2-7</u>
<u>Table 2-6. In-State Development Expenditures for Natural Gas Projects in the Alaska North Slope Foothills by Category, 2005-2030</u>	<u>2-8</u>
<u>Table 2-7. Expenditure Pattern for Production of Remote Oil Field</u>	<u>2-9</u>
<u>Table 2-8. In-State Production Expenditures for Natural Gas Projects in the Alaska North Slope Foothills, 2011-2030</u>	<u>2-9</u>
<u>Table 2-9. Production, Wellhead Netback Price and Total Revenues, 2011-2030</u>	<u>2-10</u>
<u>Table 2-10. Revenue Estimates for the State of Alaska and the North Slope Borough, 2001-2030</u>	<u>2-13</u>
<u>Table 3-1. State of Alaska Employment Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills Gas Operations, 2001-2030</u>	<u>3-2</u>
<u>Table 3-2. North Slope Borough Employment Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills gas operations, 2001-2030</u>	<u>3-4</u>
<u>Table 4-1. State of Alaska Labor Income Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills Gas Operations, 2001-2030</u>	<u>4-2</u>
<u>Table 4-2. North Slope Borough Labor Income Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills Gas Operations, 2001-2030</u>	<u>4-3</u>
<u>Table 4-3. State of Alaska Value-added Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills Gas Operations, 2001-2030</u>	<u>4-3</u>
<u>Table 4-4. NSB Value-added Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills Gas Operations, 2001-2030</u>	<u>4-5</u>

Figure	Page
<u>Figure 2-1. Schedule of North Slope Foothills Natural Gas Project</u>	<u>2-3</u>
<u>Figure 2-2. Netback Wellhead Natural Gas Prices, 2011-2030</u>	<u>2-11</u>
<u>Figure 3-1. Annual Employment for the State of Alaska from Anadarko/AEC ANS Foothills Gas Project, 2001-2030</u>	<u>3-3</u>
<u>Figure 4-1. Annual Labor Income for the State of Alaska from the Anadarko/AEC ANS Foothills Gas Project, 2001-2030</u>	<u>4-2</u>
<u>Figure 4-2. Annual Value-added for the State of Alaska from the Anadarko/AEC ANS Foothills Gas Project</u>	<u>4-4</u>
<u>Figure 4-3. Amount of Fairbanks Power Generation Converting from Coal and Diesel to Natural Gas at Different Gas Prices</u>	<u>4-7</u>

Abbreviations

ANS	Alaska North Slope
ASRC	Arctic Slope Regional Corporation
Btu	British thermal unit
EIA	Energy Information Agency
I-O	input-output
Mcf	thousand cubic feet
MMcfd	million cubic feet daily
MIG	Minnesota IMPLAN Group
NSB	North Slope Borough
RIK	royalty in-kind gas
RIV	royalty in-value

Table ES-1. Anadarko/AEC Exploration, Development, and Production Expenditures for the Alaska North Slope Foothills Gas Project, 2001-2030

	2001 \$ (Millions)	
	Total Expenditures	In-State Expenditures
Exploration	175.0	135.4
Development	1,428.0	660.6
Production	1,144.0	870.8
Total	2,747	1,667

Source: Anadarko/AEC

The estimated total economic impact (in terms of increase in value-added or gross state product) to the State of Alaska for a single Anadarko/AEC ANS foothills gas development is \$6.4 billion, inclusive of the impact to the North Slope Borough. The estimated increase in value added to the North Slope Borough is \$637 million.

In terms of incremental employment, the Anadarko/AEC foothills program could potentially generate an average of 560, 2,400, and 3,300 full-time jobs during the exploration, development, and production phases, respectively. For the North Slope Borough, an average of 130 full-time equivalent jobs per year would be generated as a result of the project.

Table ES-2 presents total estimated employment, labor income, and value-added impacts for the State of Alaska from the ANS foothills natural gas project. Over the entire life of the project, an estimated 75,000 full-time jobs would be generated. Seventy-four percent (55,500 person years or full-time jobs) of this additional employment is attributed to government spending resulting from royalties, severance, and property taxes collected from the project. Total labor income was estimated at \$2.9 billion. Government expenditures contributed to the largest amount at \$1.8 billion.

Table ES-2. Alaska North Slope Foothills Natural Gas Project Impacts for State of Alaska, 2001-2030

	Exploration	Development	Production	Total
Employment (number of jobs)	2,561	12,059	60,128	74,748
Labor Income (millions of 2001 \$)	101	500	2,378	2,979
Value-added (millions of 2001 \$)	142	1,102	5,166	6,410

Table ES-3 presents total employment, labor income, and value-added impacts for the NSB from the project. The estimated additional NSB employment generated from the ANS foothills natural gas project is 3,900 full-time jobs. The estimated increase in value added to the North Slope Borough economy is about \$637 million.

Table ES-3. Alaska North Slope Foothills Natural Gas Project Impacts for North Slope Borough, 2001-2030

	Exploration	Development	Production	Total
Employment (number of jobs)	381	2,050	1,502	3,933
Labor Income (millions of 2001 \$)	13	77	66	156

Value-added (millions of 2001 \$)	62	391	184	637
-----------------------------------	----	-----	-----	-----

Table ES-4 presents the total estimated direct fiscal impacts of the project. The project generates additional gas royalties, severance, income and property taxes that accrue to State and local governments. Estimated total direct government revenue from the project is \$2.9 billion. The North Slope Borough is estimated to receive about \$496 million in property taxes associated with the project. These government revenues generate induced employment, labor income, and value-added impacts to the State and are also reflected in the State impacts in Table ES-2.

Table ES-4. Total Revenue Estimates for the State of Alaska and the North Slope Borough, 2001-2030

	2001 \$ (Millions)		Total
	Alaska	North Slope Borough	
Royalties	1,161	NA	1,161
Severance	697	NA	697
Property Tax	38	496	533
Corporate Income Tax	503	NA	503
Total	2,399	496	2,895

The proposed ANS foothills natural gas production will also affect the Permanent Fund receipts (25 percent of the gas lease rentals, and royalties accrue to the Fund). Over the life of the project, an estimated \$290 million of projected royalties and lease payments will flow to the Permanent Fund. Using an estimated 5.25 percent of the principal for dividend payouts, total estimated Permanent Fund dividend payout is \$135 million at the end of the project. The estimated indirect economic impacts from these annual payouts include 943 full-time jobs, \$33 million in labor income, and \$67 million in value-added.

In the event that no commercial quantities of gas are found, the impacts of the project would be limited to the direct and indirect effects of the exploration activities. In this case, about 2,500 jobs, \$100 million in labor income, and \$140 million in value-added will be generated from 2001-2006. These impacts will have been generated from the \$175 million investment in exploration activities.

With respect to Anadarko's \$50 million *Exploration Work Commitment*, under the exploration only scenario (with no resulting gas discovery and development) the total economic impact to the State of Alaska (in terms of change in gross state product or value-added) would be approximately \$40 million, most of which will be due to increase in labor income (\$30 million). The exploration only scenario could also potentially create about 180 new jobs per year (from 2001-2006). The economic impact to the North Slope Borough is relatively modest with a \$5 million increase in

value added, a total of 110 full-time jobs for the entire exploration phase, and \$3.7 million increase in labor income.

1 Introduction

In 1998, Anadarko Petroleum Corporation made an agreement with the Arctic Slope Regional Corporation regarding the exploration of 3 million acres of land located in the foothills of the Brooks Range. Later, AEC Oil and Gas (USA) Inc. (the U.S. subsidiary of Alberta Energy Co. Ltd.) and BP Exploration (Alaska) Inc. each acquired one-third interests in the exploration venture from Anadarko. In May of 2000, Anadarko Petroleum Corporation in partnership with AEC Oil & Gas (USA) Inc. were the high bidders for 36 of 43 tracts, covering 207,000 acres, located in the foothills of the Brooks Range of Alaska's North Slope (ANS). Anadarko also picked up gas potential acreage at the North Slope areawide sale in the Kavik area. The Foothills region, thought to contain large quantities of natural gas, stretches approximately 250 miles from the Colville River to the Canning River. Anadarko and AEC, in a six-year exploration program, began conducting seismic surveys in the foothills region during the winter of 2001. They intend to undertake their first exploratory drilling activity in the winter of 2002-2003 (Petroleum News Alaska, August 26, 2001).

One of the constraints Anadarko/AEC faces in developing future gas prospects is securing access to the proposed gas pipeline. Without access to the gas pipeline, monetizing exploration and development of new gas prospects would not be prudent. However, in committing to pipeline space, Anadarko/AEC could face a potential demand charge of \$150 to \$200 million a year for unused space. If Anadarko/AEC does not commit to pipeline space during the upcoming open season, they face the potential of delayed access to the pipeline for up to twenty years due to capacity limitations (Petroleum News Alaska, November 18, 2001). The daily capacity projected for the pipeline is 4 billion cubic feet and with 30 trillion cubic feet of proven reserves, the pipeline could be producing at capacity for 20 years (Petroleum News Alaska, November 18, 2001). One viable option for Anadarko/AEC is to purchase a share of the state's RIK gas to use as a backstop for nominating capacity on a gas line.

On December 26, 2001, the Department of Natural Resources Division of Oil and Gas issued the best interest finding and determination to offer to sell Alaska ANS royalty in-kind (RIK) gas in a competitive sale. Anadarko/AEC is pursuing a bid for the state's ANS RIK gas. The Division of Oil and Gas states that under most oil and gas leases on the ANS, the state has a right to one-eighth of total gas production as its royalty share. The state can choose to take its royalty share as RIK or in-value (RIV). With RIV, lessees market the royalty share of gas production, and then pay the state the cash value of the royalty gas. With RIK, the state takes possession of the royalty gas and sells it to its own buyers (Petroleum News Alaska, October, 29, 2001). The benefit to Anadarko/AEC from purchasing some of the state's RIK gas is being able to commit to pipeline space

because of their RIK share of state gas. This would allow Anadarko/AEC to mitigate the risk of paying demand charges while they developed their own gas.

In accordance with AS 38.05.183(e) and AS 38.06.070(a), the commissioner of the DNR will consider the economic and social impacts of the sale of ANS RIK gas to the state. In the case of Anadarko/AEC, the likely economic impacts to the state from RIK gas sales will be increased economic and social benefits. To quantify these economic impacts, Anadarko/AEC has retained Northern Economics, Inc. to determine the potential effects of their natural gas exploration, development, and production in Alaska. This report addresses the following economic and social impacts:

- Job creation (direct, indirect, and induced) from proposed natural gas exploration, development, and production
- Labor income (direct, indirect, and induced) from proposed natural gas exploration, development, and production
- Change in value-added (direct, indirect, and induced) from proposed natural gas exploration, development, and production
- Revenues to the State of Alaska and local governments resulting from royalties, severance, income and property tax payments (local government revenues are limited to property taxes in this report)
- Consumer benefits from lower energy costs (analysis for Fairbanks.)

Anadarko/AEC provided annual aggregated cost estimates for exploration, development, and production of ANS foothills gas. However, since exploration has only just begun in earnest in 2001, expenditures on future exploration, development, and production are based on perceptions of project feasibility, as affected by, but not limited to, marketing, geological, engineering, and budget constraints. Total expenditure projections for exploration, development, and production of ANS foothills gas were further disaggregated into expenditure categories in order to provide detailed data for the input-output (I-O) model.

I-O models from the Minnesota IMPLAN Group (MIG) of the State of Alaska and North Slope Borough were used to estimate employment, labor income, and change in gross state product that would result from the exploration, development, and production of ANS foothills gas projects. The I-O model shows how each dollar spent travels through the economy from the industry of the initial purchase to that industry's suppliers until it is dissipated by expenditures on products not available in Alaska. The induced impacts of government and household expenditures of tax revenue and wages and salaries earned from the project are also derived from the I-O analysis.

Estimates of state royalties, severance taxes, income taxes, and total property taxes were also developed.

Anadarko/AEC is exploring for natural gas reserves on both State lands and Arctic Slope Regional Corporation (ASRC) land. For the purpose of this study, the estimated impacts were derived as if the exploration, development and production occurred on State lands. The impacts associated with exploration and development of ASRC land would be similar, except for the Permanent Fund dividend pay-outs and the indirect effects of ASRC investments (which will be different from government spending impacts).

2 Natural Gas Development Scenario

This section presents preliminary information on exploration, development, and production expenditures, manpower requirements, and forecasts of production for the proposed natural gas project. Since project-related activities have not progressed to a stage where these items can be determined with any certainty, expenditures for goods and services and direct employment were estimated.

Anadarko/AEC provided estimated annual aggregated exploration, development, and production costs. The total annual exploration, development, and production costs were allocated into itemized expenditure categories for use in the I/O IMPLAN model. These annual expenditures include:

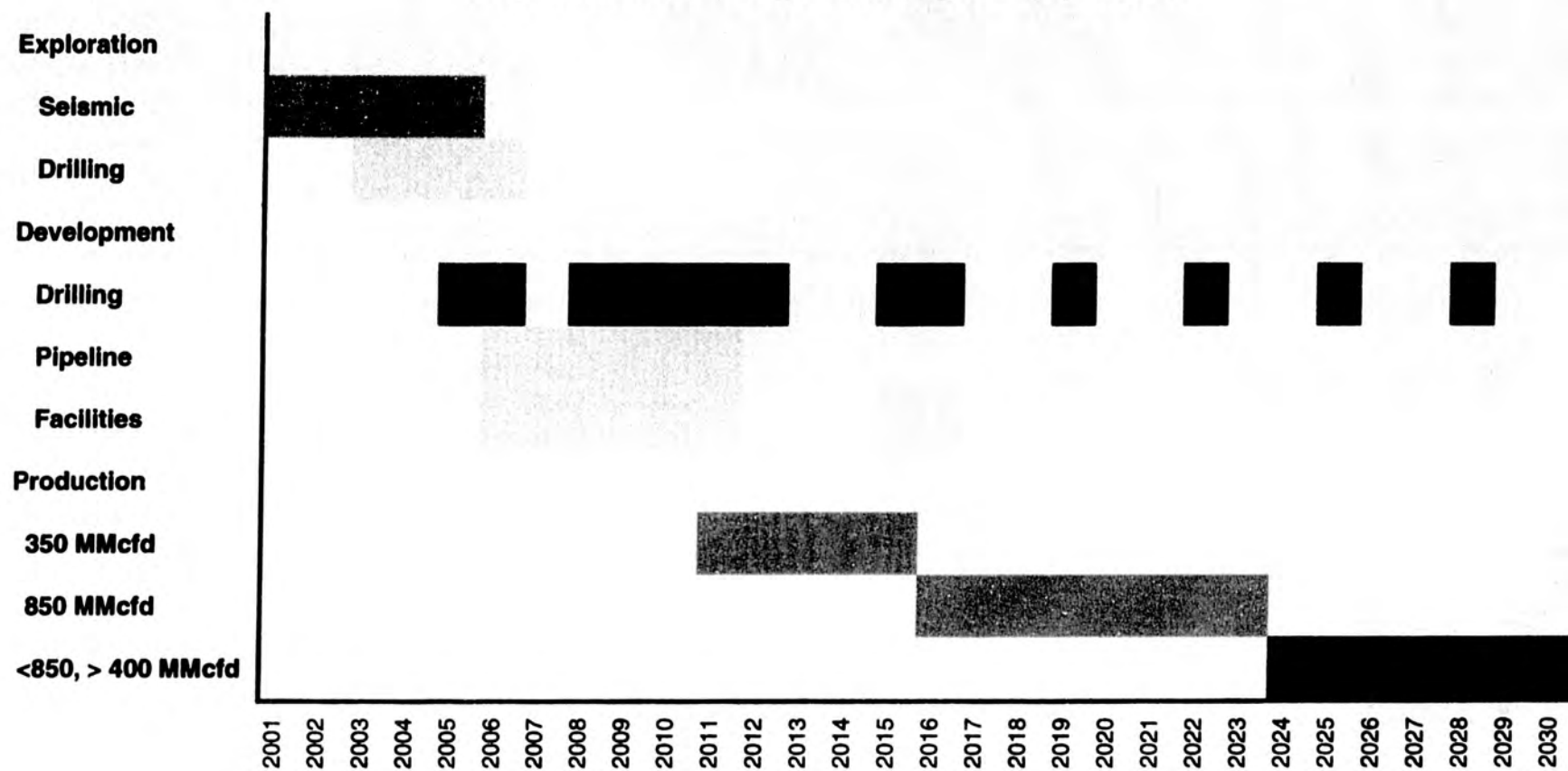
- Personnel
- Business services
- Equipment and supplies
- Construction activity
- Transportation
- Labor support
- Other

Allocation of Anadarko/AEC aggregated total costs for exploration, development, and production into categories were developed using estimated expenditure patterns designed from surveys of major North Slope operators and their prime contractors for three different oil and gas field scenarios: marginal field, enhanced oil recovery project, and remote field (Northern Economics, Inc., 1995). A marginal field was defined as located relatively near to existing North Slope development infrastructure, but not previously developed due to marginal field economics. An enhanced oil recovery project was defined as an increase in recoverable oil at a currently producing field. A remote field was defined as being at least 50 miles from existing infrastructure. For this study, the expenditure pattern associated with the remote field was applied because most Anadarko/AEC gas prospects are more than 50 miles from existing infrastructure.

Figure 2-1 presents a schedule of the ANS foothills natural gas project. Annual exploration activities include seismic and exploratory drilling starting in 2001 and ending in 2006. The development phase of the gas project is anticipated to start in 2005 and end in 2016, although additional drilling will continue periodically through 2028. Development activities include drilling, and pipeline and facilities construction. Production is projected to start in 2011 and end in 2030. Total annual projected gas production will be 350 MMcfd for the first five-years with an increase to 850 MMcfd for

the next 8 years. Beginning in 2024 production is likely to decline through the remaining life of the project.

Figure 2-1. Schedule of North Slope Foothills Natural Gas Project



2.1 Exploration

This section provides estimated expenditures for exploration by Anadarko/AEC in the ANS foothills (

Table 2-1). Exploration is the search for developable gas deposits and includes seismic investigation and exploratory drilling. Anadarko/AEC provided annual exploration costs from 2001-2006.

Table 2-1. Alaska North Slope Foothills Natural Gas Exploration Costs

Year	2001 \$ (Millions)			Wells
	Seismic	Drilling	Total	
2001	21.0	0.0	21.0	0
2002	27.0	0.0	27.0	0
2003	27.0	21.0	48.0	2
2004	18.0	21.0	39.0	2
2005	18.0	11.0	29.0	1
2006	0.0	11.0	11.0	1
Total	111.0	64.0	175.0	6

Source: Anadarko/AEC

In order to estimate expenditures by category based on Anadarko/AEC gas exploration activity, total annual exploration costs were multiplied by the percent of total expenditures for each expenditure category from the 1995 Alaska Oil and Gas Policy Council study (as presented in Table 2-2). The largest portion of projected exploration costs would be spent on business services (35 percent) and personnel (28 percent). In-state expenditures by category were then estimated using results from the same study also presented in Table 2-2. Of the total exploration expenditures, approximately 77 percent will likely be spent in Alaska. Estimated annual in-state expenditures for gas exploration in the foothills of the ANS are presented in Table 2-3. Exploration activities, which began during the winter of 2001, are projected to peak in 2003 at approximately \$37 million. Of the estimated \$135 million in total in-state expenditures, an estimated \$59 million will be spent on business services and \$42 million will be spent on personnel.

Table 2-2. Expenditure Pattern for Exploration of Remote Oil Fields by Category

Category	Percent of Total	Percent of Category Spent in Alaska	Percent of Total Spent in Alaska
Personnel	28.3	84.4	23.9
Business Services	34.6	98.2	34.0
Equipment and Supplies	23.3	51.4	11.9
Construction Activities	1.3	100.0	1.3
Transportation	5.7	88.9	5.0
Labor Support	1.3	100.0	1.3
Other	5.7	0.0	0.0
Total	100.0		77.4

Source: Socioeconomic Impacts of Changes in Alaska's Petroleum Royalty and Tax System, Northern Economics, Inc. December 1995.

Note: Expenditure patterns for remote oil field development are assumed to be equivalent to expenditures in remote gas fields.

¹ Includes Wages, Salaries, Benefits, and payroll taxes

² Includes Insurance, leases, lodging, office supplies

³ Includes Drilling hardware, fabricated metal products, trucks, heavy equipment, chemicals

⁴ Includes Gravel fill, construction subcontractors, equipment rental

⁵ Includes Waterborne transport, air cargo, trucking, railroad, communications, utilities

⁶ Includes Crew lodging units, food, medicines, crew air transportation

⁷ Profit, Depreciation, overhead, and other services

Table 2-3. In-State Exploration Expenditures for Natural Gas Projects in the Alaska North Slope Foothills by Category, 2001-2030

2001 \$ (Millions)							
Year	Personnel	Business Services	Equipment & Supplies	Construction Activities	Transportation	Labor Support	Total
2001	5.0	7.1	2.5	0.3	1.1	0.3	16.2
2002	6.5	9.2	3.2	0.3	1.4	0.3	20.9
2003	11.5	16.3	5.7	0.6	2.4	0.6	37.1
2004	9.3	13.3	4.7	0.5	2.0	0.5	30.2
2005	6.9	9.9	3.5	0.4	1.5	0.4	22.4
2006	2.6	3.7	1.3	0.1	0.6	0.1	8.5
Total	41.8	59.5	20.9	2.2	8.8	2.2	135.4

Source: Socioeconomic Impacts of Changes in Alaska's Petroleum Royalty and Tax System, Northern Economics, Inc., December 1995 and Anadarko/AEC.

2.2 Development

This section provides estimated expenditures for the development phase of the ANS foothills gas project. Development is the construction of the infrastructure that supports the production of deposits. This includes pipelines, treatment facilities, employment housing if needed, well sites and wells. The development phase is projected to start in 2005 and finish in 2016. Table 2-4 presents the development costs, which were provided by Anadarko/AEC. Development costs include drilling, pipeline construction, and facility construction. Drilling costs assume 42 wells at \$3.4 million per well and four delineation wells at \$8.8 million per well. During peak development, estimated expenditures will reach a high of about \$250 million annually from 2010 to 2011.

Table 2-4. Alaska North Slope Foothills Natural Gas Development Costs, 2001-2030

2001 \$ (Millions)									
Year	Drilling ¹ Tangibles	Drilling Intangibles	Pipeline ² Tangibles	Pipeline Intangibles	Facility ³ Tangibles	Facility Intangibles	Contingency ⁴	Unit Operator Cost ⁵	Total
2001	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2002	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	7.6	10.0	0.0	0.0	0.0	0.0	4.4	2.2	24.2
2006	7.6	10.0	2.9	11.6	14.3	57.0	25.8	12.9	142.2
2007	0.0	0.0	2.9	11.6	14.3	57.0	21.4	10.7	118.0
2008	5.6	8.0	4.3	17.4	21.5	86.0	35.7	17.9	196.4
2009	5.6	8.0	4.3	17.4	21.5	86.0	35.7	17.9	196.4
2010	5.6	8.0	7.2	29.0	27.0	107.3	46.0	23.0	253.1
2011	5.6	8.0	7.2	29.0	27.0	107.3	46.0	23.0	253.1
2012	5.6	8.0	0.0	0.0	0.0	0.0	3.4	1.7	18.7
2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2014	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	5.6	8.0	0.0	0.0	18.0	71.5	25.8	12.9	141.8
2016	5.6	8.0	0.0	0.0	0.0	0.0	3.4	1.7	18.7
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2019	5.6	8.0	0.0	0.0	0.0	0.0	3.4	1.7	18.7
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	5.6	8.0	0.0	0.0	0.0	0.0	3.4	1.7	18.7
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	5.6	8.0	0.0	0.0	0.0	0.0	3.4	1.7	18.7
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	2.8	4.0	0.0	0.0	0.0	0.0	1.7	0.9	9.4
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	74.0	104.0	29.0	116.0	143.6	572.0	259.6	129.8	1,428.0

Source: Anadarko/AEC

¹ Drilling costs assume 42 wells at \$3.4 million per well, and 4 delineation wells at \$8.8 million per well.² Pipeline costs consist of all costs associated with transmission line to connect with an Alaskan Highway natural gas pipeline.³ Facility costs include facility engineering, facility materials, module fabrication, module transportation, module installation, and field infrastructure.⁴ Contingency of 25% based on significant project unknowns in frontier area.⁵ Unit operator costs of 10% represents operator overhead associated with capital projects.

To estimate in-state expenditures by category for the development phase of the gas project, the same procedures used to estimate exploration expenditures were applied to total annual development costs. The estimated in-state development expenditure pattern is presented in Table 2-5. Estimated proportions of in-state purchases are also presented in Table 2-5. The largest development cost items in Alaska are projected to be personnel expenses (20 percent of the in-state development expenditures from 2005-2030) and equipment and supplies (12.6 percent). Of the total development expenditures, approximately 46.3 percent are estimated to be in-state purchases. Estimated annual expenditures for drilling, pipeline construction, and facility construction in Alaska are presented in Table 2-6.

Table 2-5. Expenditure Pattern for Development of Remote Oil Fields

Category	Percent of Total	Percent of Category Spent in Alaska	Percent of Total Spent in Alaska
Personnel	33.2	60.4	20.1
Business Services	6.9	58.9	4.1
Equipment and Supplies	43.7	28.9	12.6
Construction Activities	2.9	77.7	2.3
Transportation	5.4	51.8	2.8
Labor Support	1.8	100.0	1.8
Other	6.0	42.9	2.6
Total	100.0		46.3

Source: Socioeconomic Impacts of Changes in Alaska's Petroleum Royalty and Tax System, Northern Economics, Inc., December 1995

Note: Expenditure patterns for remote oil field development are assumed to be equivalent to expenditures in remote gas fields.

Table 2-6. In-State Development Expenditures for Natural Gas Projects in the Alaska North Slope Foothills by Category, 2005-2030

2001 \$ (Millions)								
Year	Personnel	Business Services	Equipment & Construction Supplies	Activities	Transportation	Labor Support	Other	Total
2005	4.9	1.0	3.1	0.5	0.7	0.4	0.6	11.2
2006	28.5	5.8	18.0	3.2	3.9	2.6	3.7	65.8
2007	23.7	4.8	14.9	2.7	3.3	2.2	3.1	54.6
2008	39.4	8.0	24.8	4.5	5.4	3.6	5.1	90.9
2009	39.4	8.0	24.8	4.5	5.4	3.6	5.1	90.9
2010	50.8	10.3	32.0	5.7	7.0	4.7	6.6	117.1
2011	50.8	10.3	32.0	5.7	7.0	4.7	6.6	117.1
2012	3.7	0.8	2.4	0.4	0.5	0.3	0.5	8.7
2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2014	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	28.4	5.8	17.9	3.2	3.9	2.6	3.7	65.6
2016	3.7	0.8	2.4	0.4	0.5	0.3	0.5	8.7
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2019	3.7	0.8	2.4	0.4	0.5	0.3	0.5	8.7
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	3.7	0.8	2.4	0.4	0.5	0.3	0.5	8.7
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	3.7	0.8	2.4	0.4	0.5	0.3	0.5	8.7
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	1.9	0.4	1.2	0.2	0.3	0.2	0.2	4.3
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	286.4	58.3	180.6	32.4	39.6	26.3	37.0	660.6

Source: Socioeconomic Impacts of Changes in Alaska's Petroleum Royalty and Tax System, Northern Economics, Inc., December 1995 and Anadarko/AEC.

2.3 Production

This section provides estimated expenditures for levels of natural gas production in the ANS foothills. Production is defined as extracting and processing gas from deposits to be sold to final customers. Anadarko/AEC provided annual projected production for ANS foothills gas and the related annual production costs from 2011-2030. Forty-two production wells are planned for the ANS foothills project. Total annual projected gas production will be 350 MMcfd for the first five-years followed by 850 MMcfd for the next 8 years through 2023. Gas production is projected to decline steadily after 2023 through the end of the project lifecycle. In 2030 production of 407 MMcfd is

projected. At 350 MMcfd, projected annual production costs are \$32 million, and at 850 MMcfd, costs are \$78 million.

Annual production costs were allocated into itemized categories (Table 2-7) following the same procedure used to estimate exploration and development expenditures by category. Approximately 76 percent of production expenditures will be spent in Alaska. Based on the expenditure pattern, approximately 61 percent of in-state production expenses will be spent on personnel. Estimated annual in-state expenditures for gas production in the ANS foothills are presented in Table 2-8.

Table 2-7. Expenditure Pattern for Production of Remote Oil Field

Category	Percent of Total	Percent of Category Spent in Alaska	Percent of Total Spent in Alaska
Personnel	68.4	89.5	61.2
Business Services	10.8	50.0	5.4
Equipment and Supplies	13.1	39.2	5.1
Construction Activities	0.0	0.0	0.0
Transportation	1.0	75.0	0.8
Labor Support	3.6	100.0	3.6
Other	3.1	0.0	0.0
Total	100.0	353.7	76.1

Socioeconomic Impacts of Changes in Alaska's Petroleum Royalty and Tax System, Northern Economics, Inc., December 1995

Table 2-8. In-State Production Expenditures for Natural Gas Projects in the Alaska North Slope Foothills, 2011-2030

Year	Personnel	Business Services	Equipment & Supplies	Transportation	Labor Support	Total
2011	19.5	1.7	1.6	0.2	1.1	24.3
2012	19.5	1.7	1.6	0.2	1.1	24.3
2013	19.5	1.7	1.6	0.2	1.1	24.3
2014	19.5	1.7	1.6	0.2	1.1	24.3
2015	19.5	1.7	1.6	0.2	1.1	24.3
2016	47.5	4.2	4.0	0.6	2.8	59.0
2017	47.5	4.2	4.0	0.6	2.8	59.0
2018	47.5	4.2	4.0	0.6	2.8	59.0
2019	47.5	4.2	4.0	0.6	2.8	59.0
2020	47.5	4.2	4.0	0.6	2.8	59.0
2021	47.5	4.2	4.0	0.6	2.8	59.0
2022	47.5	4.2	4.0	0.6	2.8	59.0
2023	47.5	4.2	4.0	0.6	2.8	59.0
2024	42.7	3.8	3.6	0.5	2.5	53.1
2025	38.4	3.4	3.2	0.5	2.3	47.8
2026	34.6	3.1	2.9	0.4	2.0	43.0
2027	31.1	2.7	2.6	0.4	1.8	38.7
2028	28.0	2.5	2.4	0.4	1.6	34.9
2029	25.2	2.2	2.1	0.3	1.5	31.4
2030	22.7	2.0	1.9	0.3	1.3	28.2

Total	700.2	61.8	58.8	8.8	41.2	870.8
--------------	--------------	-------------	-------------	------------	-------------	--------------

Source: Socioeconomic Impacts of Changes in Alaska's Petroleum Royalty and Tax System, Northern Economics, Inc., December 1995 and Anadarko/AEC Petroleum Inc.

2.4 Alaska Revenue Estimates

This section provides estimated revenue projections for the state of Alaska from ANS foothills gas production. Since Anadarko/AEC gas operations are still in the exploration phase, wellhead netback¹ prices for Anadarko/AEC natural gas production are not known at this time. In order to estimate the wellhead netback price for Anadarko/AEC ANS foothills gas, delivered prices for gas to lower 48 industrial customers and transportation costs to the lower 48 were derived. Information was obtained from the Energy Information Agency (EIA) for forecasted delivered prices to industrial and electricity generator users from 2002 to 2020. The forecasted gas price used was an average of industrial and electricity generator prices. To estimate prices beyond EIA forecasts (2021-2030), a linear growth rate of slightly more than two percent² was used. Figure 2-2 presents wellhead prices based on EIA forecasted and extrapolated prices.

Estimated transportation costs for shipping Anadarko/AEC gas from ANS foothills to the lower 48 were \$2.09 per thousand cubic feet (Mcf) for the Southern route (Alaska Highway) and \$1.75 per Mcf for the Northern Canadian route (Alaska Gas Producers Pipeline Team, October 25, 2001). For this study, the transportation costs associated with the Southern route were used. Annual wellhead netback prices are presented in Table 2-9.

Table 2-9. Production, Wellhead Netback Price and Total Revenues, 2011-2030

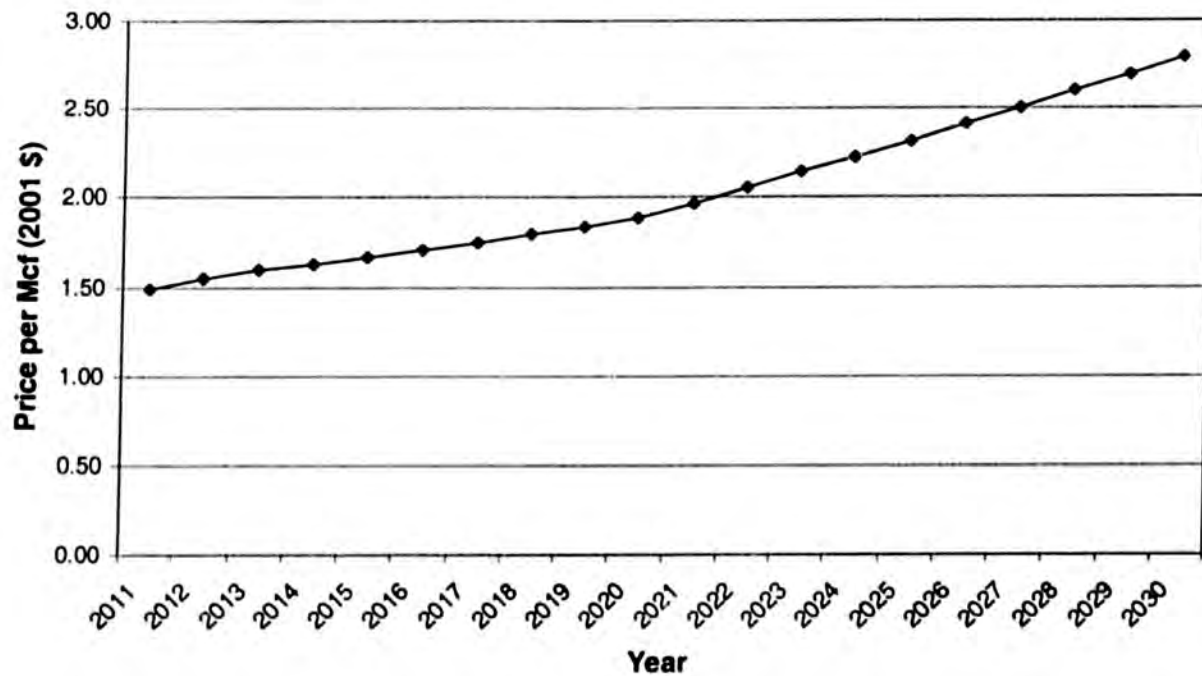
Year	Industrial (Mcf) from EIA	Electricity Generators (mcf) from EIA	Average (mcf)	Production (MMcfd) Provided by Anadarko	Wellhead Netback Price	Total Revenue (2001 \$ Millions)
2011	3.63	3.53	3.58	350.00	\$1.49	\$190.35
2012	3.68	3.59	3.64	350.00	\$1.55	\$197.37
2013	3.73	3.64	3.69	350.00	\$1.60	\$203.76
2014	3.75	3.68	3.72	350.00	\$1.63	\$207.59
2015	3.79	3.72	3.76	350.00	\$1.67	\$212.70
2016	3.82	3.76	3.79	850.00	\$1.70	\$527.43
2017	3.86	3.80	3.83	850.00	\$1.74	\$539.84
2018	3.91	3.85	3.88	850.00	\$1.79	\$555.35
2019	3.95	3.89	3.92	850.00	\$1.83	\$567.76
2020	4.01	3.94	3.98	850.00	\$1.89	\$584.82
2021	4.10	4.02	4.06	850.00	\$1.97	\$610.51

¹ Wellhead netback is the market price for natural gas, minus transportation, and related costs that are encountered after the gas is produced.

² This is an extrapolation of EIA forecasted prices from 2002 to 2020.

2022	4.19	4.10	4.14	850.00	\$2.05	\$636.73
2023	4.28	4.18	4.23	850.00	\$2.14	\$663.51
2024	4.37	4.27	4.32	765.00	\$2.23	\$621.75
2025	4.46	4.35	4.41	688.50	\$2.32	\$582.18
2026	4.56	4.44	4.50	619.65	\$2.41	\$544.72
2027	4.66	4.53	4.59	557.69	\$2.50	\$509.33
2028	4.76	4.62	4.69	501.92	\$2.60	\$475.92
2029	4.86	4.71	4.79	451.72	\$2.70	\$444.43
2030	4.96	4.81	4.89	406.55	\$2.80	\$414.78
Total				\$12,541.03		\$9,290.82

Figure 2-2. Nethack Wellhead Natural Gas Prices, 2011- 2030



Source: Energy Information Agency, Anadarko/AEC, Department of Revenue, and Alaska Gas Producers Pipeline Team

Total estimated royalties, severance, corporate income and property taxes from the ANS foothills gas project are presented in Table 2-10. State royalties and severance are based on estimated wellhead netback price (based upon EIA prices) for ANS foothills, annual gas production (provided by Anadarko/AEC), and the assumption used by the Alaska Department of Revenue that the state's share of gas production value is 20 percent (12.5 percent from royalty and 7.5 percent from severance tax) using wellhead netback price.

Estimates of property taxes were determined using a straight-line depreciation of annual land improvements associated with exploration, development, and production

activity for the gas project. Total property tax rate for oil and gas property is 2 percent of the assessed value, which is shared between the State of Alaska and any incorporated Borough in which the facilities are located. Property taxes levied by local governments are subtracted from the potential 20-mill property tax, with the state receiving the balance. The ANS foothills gas project is located within the NSB, with a reported year 2000 mill rate of 18.58 (Alaska Taxable, 2000). Estimated total NSB property tax collected is about \$495 million. The remaining proportion, \$37 million (1.42-mills) goes to the state. The annual corporate income tax payments were estimated using a tax rate of 9.4 percent of taxable income.

Table 2-10. Revenue Estimates for the State of Alaska and the North Slope Borough, 2001-2030

2001 \$ (Millions)						
Year	Royalties	Severance	Corporate Income Tax	Property Tax (Alaska)	Property Tax (North Slope Borough)	Total
2001				\$0.03	\$0.39	\$0.42
2002				\$0.07	\$0.88	\$0.95
2003				\$0.13	\$1.74	\$1.88
2004				\$0.18	\$2.41	\$2.59
2005				\$0.25	\$3.32	\$3.57
2006				\$0.46	\$6.05	\$6.50
2007				\$0.61	\$8.02	\$8.62
2008				\$0.86	\$11.36	\$12.22
2009				\$1.10	\$14.56	\$15.66
2010				\$1.41	\$18.65	\$20.07
2011	\$23.79	\$14.28	\$0.00	\$1.76	\$23.14	\$62.97
2012	\$24.67	\$14.80	\$8.32	\$1.75	\$23.03	\$72.58
2013	\$25.47	\$15.28	\$8.80	\$1.71	\$22.53	\$73.79
2014	\$25.95	\$15.57	\$9.09	\$1.67	\$22.00	\$74.28
2015	\$26.59	\$15.95	\$9.09	\$1.83	\$24.07	\$77.53
2016	\$65.93	\$39.56	\$28.34	\$1.86	\$24.53	\$160.22
2017	\$67.48	\$40.49	\$29.27	\$1.86	\$24.54	\$163.64
2018	\$69.42	\$41.65	\$30.44	\$1.85	\$24.46	\$167.82
2019	\$70.97	\$42.58	\$31.31	\$1.87	\$24.62	\$171.35
2020	\$73.10	\$43.86	\$32.59	\$1.84	\$24.32	\$175.72
2021	\$76.31	\$45.79	\$34.53	\$1.81	\$23.90	\$182.34
2022	\$79.59	\$47.75	\$36.42	\$1.80	\$23.71	\$189.27
2023	\$82.94	\$49.76	\$38.43	\$1.75	\$23.01	\$195.88
2024	\$77.72	\$46.63	\$36.04	\$1.67	\$22.02	\$184.08
2025	\$72.77	\$43.66	\$33.64	\$1.60	\$21.10	\$172.78
2026	\$68.09	\$40.85	\$31.38	\$1.48	\$19.54	\$161.35
2027	\$63.67	\$38.20	\$29.28	\$1.34	\$17.72	\$150.21
2028	\$59.49	\$35.69	\$27.10	\$1.20	\$15.83	\$139.31
2029	\$55.55	\$33.33	\$25.35	\$1.02	\$13.47	\$128.73
2030	\$51.85	\$31.11	\$23.69	\$0.82	\$10.85	\$118.32
Total	\$1,161.35	\$696.81	\$503.11	\$37.60	\$495.77	\$2,894.65

Source: NEI and Anadarko/AEC

3 Impacts on Employment

This section provides estimates of the number of jobs that would be created in Alaska and NSB during Anadarko/AEC gas exploration, development, and production activities in the ANS foothills. Estimates are presented for direct, indirect, and induced employment.

- Direct employment is the number of persons directly employed in exploration, development, and production as full-time employees. Examples of direct employment duties include seismic surveying, engineering, drilling, construction, owner-employed contract management and supervision, and logistics.
- Indirect employment is a measure of all inter-industry activity, including persons employed by industries that supply inputs directly to Anadarko/AEC gas development activity as well as those that indirectly support Anadarko/AEC by supplying inputs to suppliers. Indirect employment is the number of persons employed full-time in activities stimulated by inter-industry transactions that support Anadarko/AEC ANS foothills gas development.
- Induced employment is an estimate of all employment created by additional household and government spending from payments to labor and government revenues generated by Anadarko/AEC ANS foothills gas operations. Induced employment includes employment by suppliers of goods to the government and households as well as employment by other entities that support those suppliers. Government revenues include royalties, severance, income and property taxes.

3.1 Employment Estimates

Table 3-1 provides State of Alaska total estimates for direct, indirect, and induced employment, as defined above, for exploration, development, and production of Anadarko/AEC ANS foothills gas operations. The largest share of estimated employment will occur from government revenues received from royalties, severance, income and direct property taxes. Combined, these additional revenues would result in an estimated employment of over 55,000 additional jobs. Total employment generated from exploration, development, and production activity is estimated at 14,000 (direct and indirect impacts). The largest portion of these jobs would occur during the development and production phases of the gas project. Total estimated induced

employment of 4,800 full-time jobs could potentially be generated from household spending.

Figure 3-1 presents the annual Alaska employment from the ANS foothills gas project. During the first few years, employment remains low, but employment increases significantly after 2006. Employment peaks in 2011. During this period, infrastructure development is finishing at the same time production is slated to commence. Employment declines in the years immediately following 2011, but once again increases once production is at full capacity in 2016. In the subsequent years, employment gradually decreases.

Table 3-1. State of Alaska Employment Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills Gas Operations, 2001-2030

	Employment (person-years or FTE)			
	Exploration	Development	Production	Total
Direct	398	2,625	6,530	9,552
Indirect	1,020	2,866	964	4,850
Induced (household expenditures)	426	2,023	2,360	4,809
Induced (government expenditures)	717	4,545	50,274	55,537
Total	2,561	12,059	60,128	74,748

Source: Northern Economics, Inc. and Anadarko/AEC

Figure 3-1. Annual Employment for the State of Alaska from Anadarko/AEC ANS Foothills Gas Project, 2001-2030

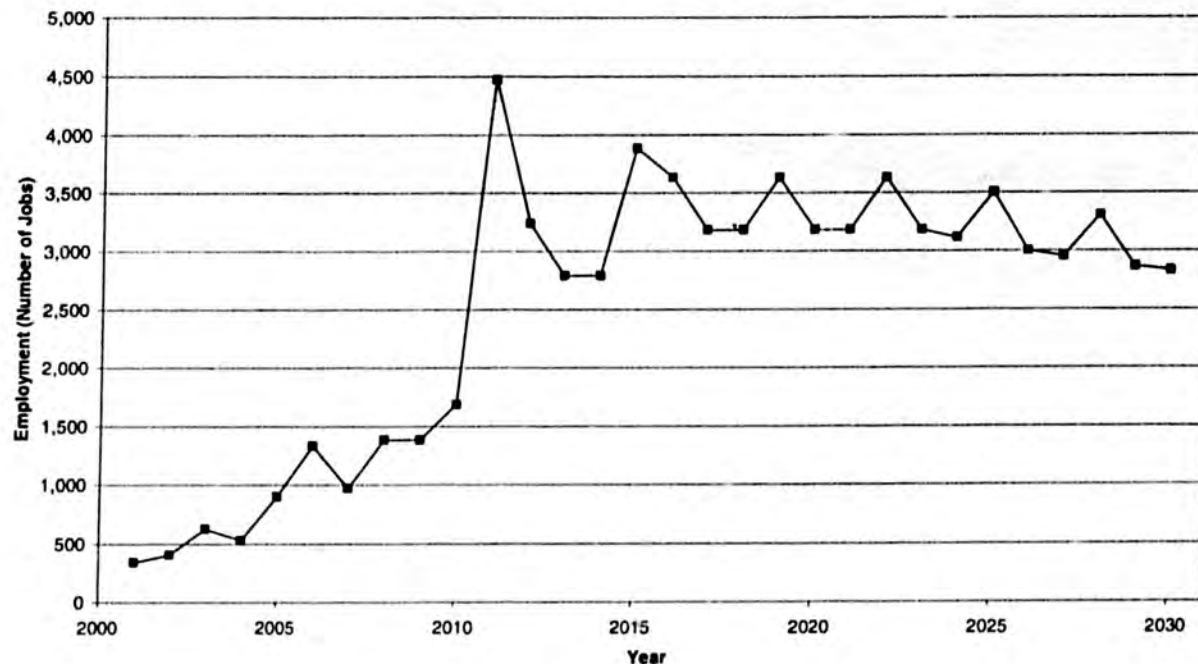


Table 3-2 provides NSB estimates for direct, indirect, and induced employment for exploration, development, and production of Anadarko/AEC ANS foothills gas operations. Like the state, the largest share of the impacts for the NSB is from expenditures of government revenues. The largest direct impact is from property taxes. Vital to NSB, the property taxes are used to fund government services, including education, and pay down debt. Over the life of the project, the NSB will have collected an estimated \$496 million in property taxes from the ANS foothills gas project. Total employment generated from the exploration, development, and production of the gas project would create about 4,000 jobs.

Table 3-2. North Slope Borough Employment Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills gas operations, 2001-2030

	Employment (number of jobs)			Total
	Exploration	Development	Production	
Direct	15	101	251	367
Indirect	72	110	37	219
Induced (household expenditures)	16	78	91	185
Induced (government expenditures)	277	1,761	1,123	3,162
Total	381	2,050	1,502	3,933

Source: Northern Economics, Inc. and Anadarko/AEC

3.2 Methodology

The employment estimates presented in Table 3-1 and 3-2 were derived using Anadarko/AEC projected annual exploration, development, and production costs and an I-O model of the State of Alaska available from the Minnesota IMPLAN Group.³ The I-O model examines relationships among Alaska businesses and between Alaska businesses and final consumers (households and government). When money is spent in the Alaska economy, it affects more than the initial recipient. As an example, when Anadarko/AEC develops a gas discovery, firms hired to manage the drilling operation are direct beneficiaries, but other supporting businesses are also beneficiaries, just not directly. The drilling firm buys supplies from other Alaska companies and hires workers to man the drilling rigs. The firms selling the supplies make additional purchases, as do the drill workers. This process of supplying the supplier continues until it dissipates because of out-of-state purchases, also called leakages. In the case of Alaska, a large share of purchases may be out-of-state. The impacts associated with these out-of-state purchases are not included in the estimates.

Expenditure patterns were derived from a study completed for the Alaska Oil and Gas Policy Council. The expenditure patterns were applied to the Alaska IMPLAN I-O model for exploration, development, and production (Northern Economics, Inc., 1995). These models were used to estimate the indirect and induced impacts from exploration, development, and production of the ANS foothills gas project. Direct impacts were generated from Anadarko/AEC projected cost estimates. Additional induced impacts were generated from expenditures by households from Anadarko/AEC wages and expenditures by the state and NSB governments from royalties, severance, income and property taxes associated with the gas project. Employment estimates generated from additions to the Alaska Permanent Fund Dividend program were also included.

³ An I-O model is used to estimate the impacts of spending by individual industries. The model shows how each dollar spent travels through the Alaska economy from the industry of the initial purchase to that industry's suppliers until it is dissipated by expenditures on products not available in Alaska.

Estimating the employment impacts of the ANS foothills gas project on the NSB involved two steps. First, estimates of employment related to the exploration, development, and production of the gas project were determined using a ratio of the total output for NSB to the total output for the State of Alaska (3.84 percent). The second step involved measuring the impacts from NSB government expenditures collected from ANS foothills gas related property taxes. The largest share of this revenue is used to pay for annual debt services and is not included in impacts. Using results from the 2000 Alaska Taxable, the research team over the life of the project assumed a constant 66 percent of annual property taxes from the gas project for debt services. The remaining proportion was used for operating budget and capital improvements.

4 Other Alaskan Economic Impacts

This section provides estimates of labor income and value-added that would likely occur in Alaska and NSB from exploration, development, and production of the ANS foothills gas project. Estimates include direct, indirect, and induced labor income and value-added. Labor income is the sum of wage and salary payments and proprietary income. Value-added is payments by industries made to individuals, interest, profits, and indirect taxes. At the state level, value-added is defined as the gross state product. Value-added is composed of four elements:

- Employee compensation
- Proprietor income
- Other property income
- Indirect business taxes

The impacts on the Alaska Permanent Fund are also provided in this section.

4.1 Labor Income

Employee compensation is wage and salary payments in addition to other employee benefits including health and life insurance, retirement payments, and any other non-cash compensation. Proprietary income is payments to self-employed individuals as income. Other property income is payments from interest, rents, royalties, dividends, and profits. Indirect business taxes are sales and excise taxes paid by businesses to government. These would include royalties, severance, and property taxes. Indirect business taxes would not include taxes on profits or income.

Table 4-1 provides estimates for direct, indirect, and induced labor income impacts for Alaska from exploration, development, and production of ANS foothill natural gas operation. Over the life of ANS foothills natural gas project, \$2.9 billion in labor income will be paid out to Alaska residents. Like employment, the expenditures of government revenues collected from ANS foothill natural gas project related taxes are estimated to generate the largest impact.

Royalty and severance tax revenue contribute the largest impact from expenditures of government revenues, contributing \$1.2 billion in labor income to the Alaska economy. The direct effects on labor income associated with exploration, development and production of ANS foothills natural gas were estimated at \$840 million.

Table 4-1. State of Alaska Labor Income Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills Gas Operations, 2001-2030

	Labor Income (Millions of 2001 \$)			
	Exploration	Development	Production	Total
Direct	35.0	230.9	574.5	840.4
Indirect	35.7	100.3	33.8	169.8
Induced (household expenditures)	14.9	70.8	82.6	168.3
Induced (government expenditures)	15.4	97.4	1,687.3	1,800.1
Total	101.0	499.5	2,378.1	2,978.6

Source: Northern Economics, Inc. and Anadarko/AEC

Figure 4-1 presents annual labor income from ANS foothill natural gas operation. During the initial decade of the natural gas project, labor income increases and peaks in 2011 as income outlays associated with infrastructure development and production coincide. After 2016, Anadarko/AEC anticipates full production and thus labor income impacts stabilize and decrease in the last five years of the project.

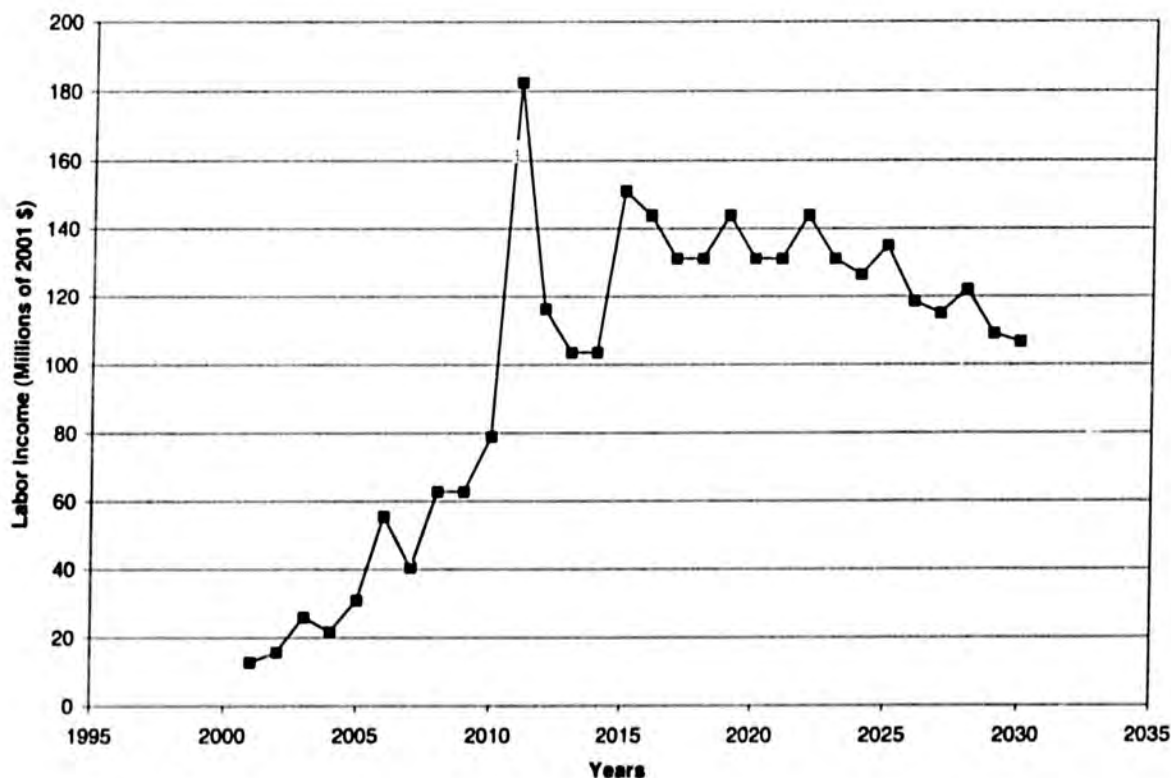
Figure 4-1. Annual Labor Income for the State of Alaska from the Anadarko/AEC ANS Foothills Gas Project, 2001-2030

Table 4-2 provides estimates of labor income impacts for NSB. Overall, the gas project is estimated to generate approximately \$156 million in labor income for NSB residents. The largest share of these impacts is expected to come from expenditures of NSB property taxes during the life of the project. Total labor income generated from these expenditures is estimated at about \$110 million. Impacts directly related to the exploration, development, and production of the gas project are estimated to amount to \$45 million (direct, indirect, and household induced).

Table 4-2. North Slope Borough Labor Income Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills Gas Operations, 2001-2030

	Labor Income (Millions of 2001 \$)			
	Exploration	Development	Production	Total
Direct	1.3	8.9	22.1	32.3
Indirect	1.4	3.9	1.3	6.5
Induced (household expenditures)	0.6	2.7	3.2	6.5
Induced (government expenditures)	9.7	61.6	39.3	110.7
Total	13.0	77.1	65.8	155.9

Source: Northern Economics, Inc. and Anadarko/AEC

4.2 Value-Added Impacts

Table 4-3 provides estimates for direct, indirect, and induced value-added impacts for Alaska from exploration, development, and production of ANS foothill natural gas operation. Over the life of ANS foothills natural gas project, the gas project will have generated an estimated \$6.4 billion in total value-added. On an annual basis, value-added averaged \$213 million or slightly greater than .9 percent of the gross state product using 1998 IMPLAN data. In 1998, the gross state product was \$23 billion (IMPLAN).

Direct expenditures by Anadarko/AEC generated an estimated total value-added of \$3.6 billion. Payments by Anadarko/AEC to the state for royalties, severance, income and property taxes were the reason for the high direct value-added value. Impacts generated from state government expenditures related to ANS foothill natural gas project were estimated at \$2.2 billion.

Table 4-3. State of Alaska Value-added Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills Gas Operations, 2001-2030

	Value Added (Millions of 2001 \$)			
	Exploration	Development	Production	Total
Direct	47.1	761.6	2,785.8	3,594.4

Indirect	62.3	165.2	58.9	286.4
Induced (household expenditures)	25.7	129.8	138.6	294.1
Induced (government expenditures)	7.1	45.0	2,182.8	2,235.0
Total	142.2	1,101.6	5,166.1	6,409.9

Source: Northern Economics, Inc. and Anadarko/AEC

Figure 4-2 depicts annual value-added impacts from the ANS foothills natural gas operation. Like Figures 3.1 and 4.1, value-added gradually increases over the first few years. After 2006, value-added from the gas project increases significantly. Value-added generated from the gas project peaks in 2011 during which infrastructure development is winding down and production is slated to start. After 2016, Anadarko/AEC anticipates being at full production, so value-added from the gas project is estimated to stabilize.

Figure 4-2. Annual Value-added for the State of Alaska from the Anadarko/AEC ANS Foothills Gas Project

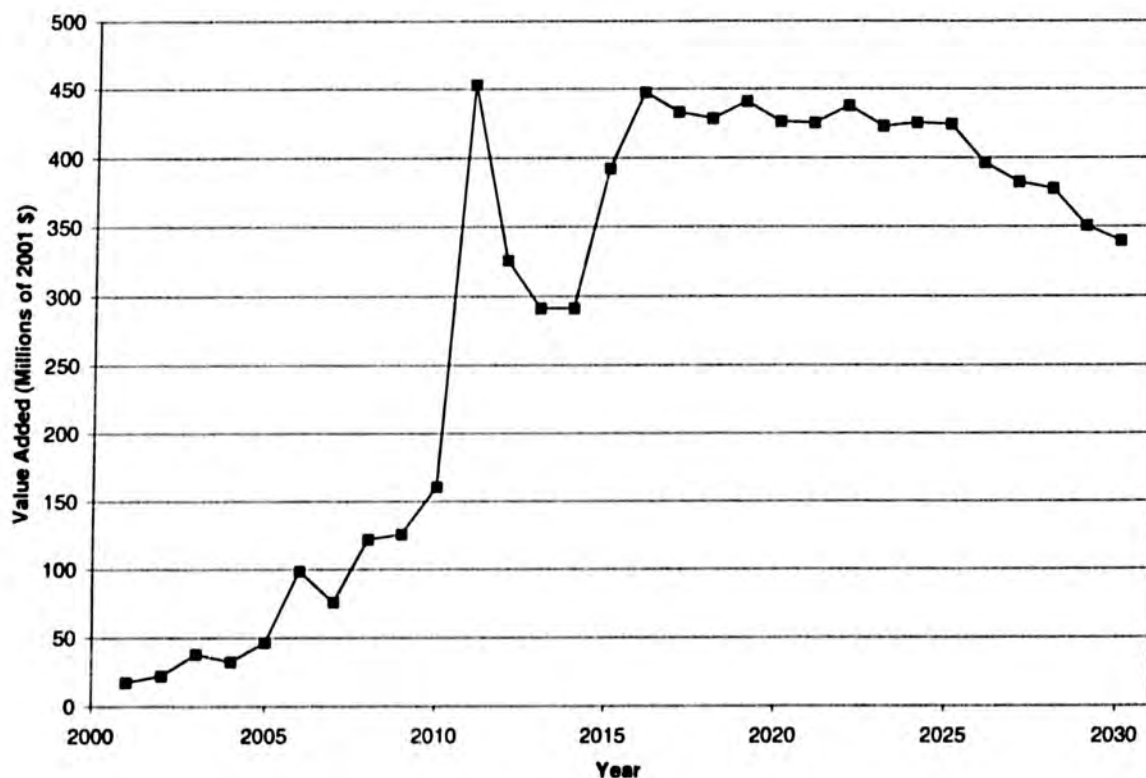


Table 4-4 presents NSB impact estimates for value-added from ANS foothill natural gas project. Direct expenditures by Anadarko/AEC contributed total value-added of \$471 million. Payments by Anadarko/AEC for property taxes were the reason for the large direct value-added impact. NSB revenue expenditures generated additional \$143 million in value-added.

Table 4-4. NSB Value-added Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills Gas Operations, 2001-2030

	Value Added (Millions of 2001 \$)			
	Exploration	Development	Production	Total
Direct	45.9	300	125.6	471.4
Indirect	2.5	6.3	2.3	11.1
Induced (household expenditures)	1.0	5.0	5.3	11.4
Induced (government expenditures)	12.6	79.7	50.8	143.1
Total	62.0	391.0	184.0	637.0

Source: Northern Economics, Inc. and Anadarko/AEC

4.3 Impacts on the Alaska Permanent Fund

The Permanent Fund was established through a Constitutional amendment approved by Alaska voters in 1976. The amendment set aside at least 25 percent of all mineral lease rentals, royalties, and royalty sales paid to the State to be deposited into a public savings account to be invested for the benefit of the current and all future generations of Alaskans. A Permanent Fund Dividend was first paid to eligible Alaska residents in 1982. In 1999, total Permanent Fund Dividend payout was \$987.3 million.

The proposed ANS foothills natural gas production will generate additional Permanent Fund receipts amounting to 25 percent of the gas lease rentals, royalties, and royalty sales paid to the State. Over the life of the natural gas project, an estimated \$290 million of projected royalty payments will flow to the Permanent Fund. Using an estimated 5.25 percent of the principal for dividend payouts, total estimated Permanent Fund dividend payout is \$135 million. The estimated economic impacts from these annual payouts are 950 full-time jobs, \$33 million in labor income, and \$67 million in value-added.

4.4 Benefits to Consumers from Lower Energy Costs in Fairbanks

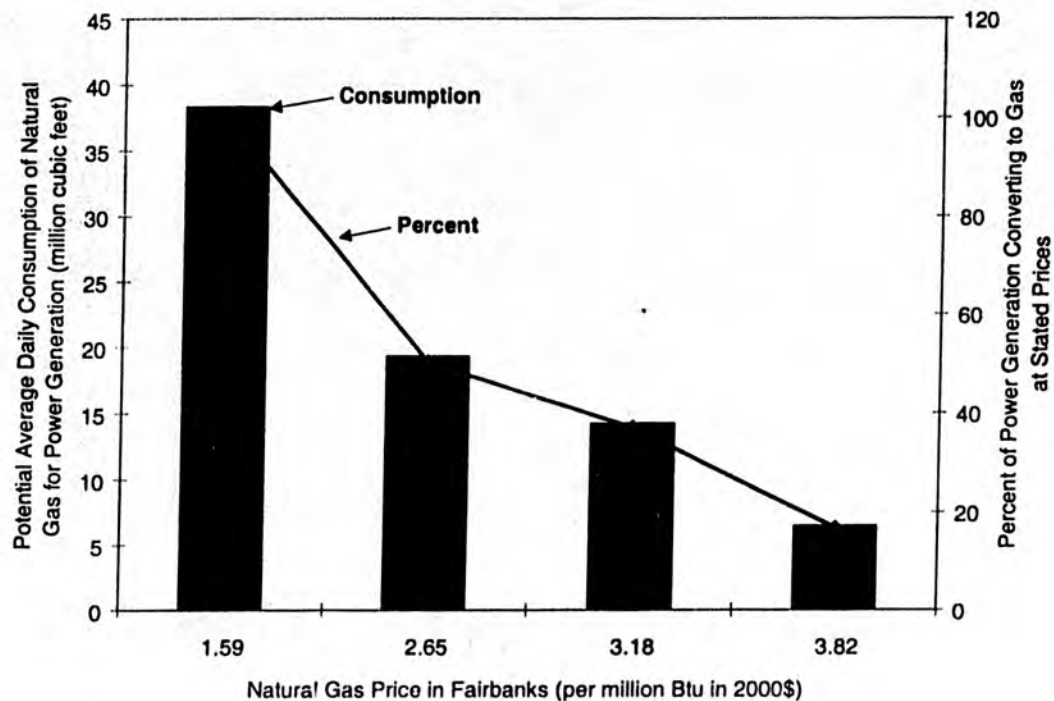
This section provides an analysis of the effects of the availability of natural gas on residential energy costs. The ANS gas project is expected to produce gas at a rate of 350 MMcfd from 2011-2015, 850 MMcfd from 2016-2030, and gradually declines to 407 MMcfd in 2030. This increase in natural gas production as a result of the ANS gas project, assuming a southern route gas pipeline is in operation, would represent an increase in the availability of natural gas for in-state consumption. Consequently, this may result in lower energy costs if the price of natural gas is low enough to allow for conversion of electric/heating generation from other sources to natural gas.

The community of Fairbanks is the largest community in interior Alaska. The Fairbanks North Star Borough has a recorded population of 82,840 residents. Hence, the area represents the largest potential demand for natural gas in the interior. This section looks at the possible benefits of lower energy costs to Fairbanks residents only.

Consumer benefits are realized only if the price of energy supplied by gas in comparison to the price of energy generated from other sources is lower. Utilities, businesses, and residents are not likely to convert to natural gas for their energy needs if it will cost them more to do so compared to costs from existing power generation systems. Electric energy in Fairbanks is mostly generated from a coal-fired power plant located in Healy, Alaska. In addition, an electric transmission line supplies access to low cost electricity generated by gas-fired turbines in southcentral Alaska. However, the transmission line can only support a portion of the Fairbanks electric demand. Heating demand in Fairbanks is met mostly with heating fuel refined in several local refineries. The refinery gate price for No. 2 heating fuel in August 2000 was about \$0.93 per gallon or \$6.70 per million British thermal unit (Btu).

A 1997 survey by the Alaska Department of Natural Resources (Zobrist 1997) indicates that power generators would be willing to pay only \$2.50 per million Btu (in 1997 dollars) to consider converting to natural gas. With a higher gas price there may not be enough incentive to switch to natural gas. Figure 4-3 shows the estimated daily natural gas usage for power generation at different prices. The gas price that would induce utilities to convert is relatively low because capital investments in existing coal-fired power plants are debt free and capital costs may increase substantially with conversion. Also, coal is relatively low in price for at least one major utility.

Figure 4-3. Amount of Fairbanks Power Generation Converting from Coal and Diesel to Natural Gas at Different Gas Prices



Source: Adapted from Zobrist, 1997.

A switch to ANS gas that would merely displace the existing uses of state resources may not offer significant net benefits to the state or regional economies, especially if it means eliminating jobs (at the coal-fired power plant). Subsidies to the power generators, in the form of grants to convert to gas-fired generating equipment and compensate for potential stranded assets, may be required for the power generators to switch fuels. Alternatively, subsidies could be employed to lower the price of natural gas sold to the power generators and other customers.

5 References

- Alaska Department of Community and Economic Development. *Alaska Taxable 2000. Municipal Taxation— Rates and Policies*. Volume XXXX, January, 2001.
- Alaska Gas Producers Pipeline Team (AGPPT). *Overview and Status*. Presented during the forum for the International Association of Energy Economists, Alaska Chapter. October 25, 2001. Anchorage, Alaska.
- Energy Information Administration (EIA), Department of Energy. *Natural Gas Prices, Margins, and Revenues*. www.eia.doe.gov
- Minnesota IMPLAN Group, Inc. IMPLAN Professional. Version 2. Social Accounting and Impact Analysis Software. 2nd Edition, June 2000.
- Northern Economics, Inc. *Socioeconomic Impacts of Changes in Alaska's Petroleum Royalty and Tax System*. Prepared for the Alaska Oil and Gas Policy Council. December, 1995.
- Northern Economics, Inc. *A Review of Cook Inlet Natural Gas Supply and Demand*. Prepared for the Anchorage Economic Development Corporation. 2001.
- Petroleum News Alaska. *Alberta Energy, Anadarko/AEC looking for space in gas pipeline*. Vol. 6, No. 17, Week of November 18, 2001,
- Petroleum News Alaska. *Anadarko/AEC to drill two NPR-A wells south of Moose's Tooth this winter; Brooks range foothills drilling possible in 2002-2003*. Week of August 26, 2001.
- Zobrist, Daniel H. Alaska Department of Natural Resources, Division of Oil and Gas. *The Potential In-State Demand for Alaska North Slope Gas*. Prepared for RIK/RIV Committee of the North Slope Gas Commercialization Team. October 1, 1997.

**Notice of Clarification
Regarding State of Alaska Solicitation for Offers to Purchase
Alaska North Slope Royalty Gas
dated December 26, 2001**

The purpose of this notice is to clarify and update the State of Alaska's Solicitation for Offers to Purchase North Slope Royalty Gas, dated December 26, 2001. This notice clarifies that the State's Solicitation for Offers is seeking proposals for consideration under the procedures set out in 11 AAC 03.030-11 AAC 03.070.

The State hereby notifies all prospective buyers that their proposals must be consistent with the terms of the Solicitation for Offers, as clarified herein, and the procedures set out in 11 AAC 03.030-11 AAC 03.070 and will be evaluated under the criteria set out in AS 38.05.183(e).

The deadline for submitting applications for qualification is extended. Prospective buyers should not submit their applications for qualification by January 17, 2002, but must include the applications with their proposals, which remain due on January 31, 2002. The State will open the proposals on February 1, 2002. Except as set out above, the dates and procedures in Sections 17 and 18 of the Solicitation for Offers no longer apply.

The State reserves the right, after the proposals are opened, to negotiate terms before it awards sale contracts. The Commissioner will evaluate the proposals under the criteria set out in AS 38.05.183(e) before announcing which proposals, if any, have been selected for further consideration. If, after further consideration, the Commissioner believes a disposition of RIK gas under 11 AAC 03.030-11 AAC 03.070 is in the best interests of the State, the Commissioner will make a preliminary determination to award a sale contract to the prospective buyer, or buyers, whose proposal reasonably offers the maximum benefits to the citizens of Alaska, as provided under 11 AAC 03.060.

The Commissioner will provide public notice of the preliminary determination under 11 AAC 03.020(c). After considering public comments, the Commissioner will make a final determination whether an award of a sale contract to the prospective buyer, or buyers, is in the best interests of the State, as provided under 11 AAC 03.030(b).

Questions may be directed to:

Kevin Banks
Division of Oil and Gas
550 West Seventh Avenue, Suite 800
Anchorage, Alaska 99501-3560
(907) 269-8781
e-mail: [kreb@dnr.state.ak.us](mailto:krb@dnr.state.ak.us)

Final
Finding and Determination
For a Solicitation for Offers to Purchase
Alaska North Slope Royalty Gas



550 West 7th Avenue, Suite 800
Anchorage, Alaska 99501-3510

December 26, 2001

I. INTRODUCTION AND BACKGROUND

The Commissioner of the State of Alaska Department of Natural Resources has determined that it is in the best interests of the State to solicit offers to purchase, in competitive sale, a portion of the State's royalty share of natural gas (Royalty Gas) that may be produced from Alaska's North Slope (ANS) upon completion of a natural gas pipeline. Because of the possibility of an "open season" in 2002 for nominating shipping space on a future gas pipeline, an offer to sell now responds to a commercial opportunity to improve the State's future royalty revenues from ANS natural gas and promote new private investment in the State.

On December 26, 2001 the department will issue a Solicitation for Offers to Purchase ANS Royalty Gas. Proposals offering to purchase Royalty Gas must be received by the Division of Oil and Gas no later than January 31, 2002. The department will open the offers at a public meeting on February 1, 2002, but the department will not determine which proposals will result in contract awards until it has evaluated all the proposals. The department intends begin negotiating royalty in-kind (RIK) gas sale contracts with successful proposers in February 2002. The solicitation and sale schedule is detailed in section D below.

On October 29, 2001, the department issued a "Preliminary Finding and Determination for a Competitive Sale of Alaska North Slope Royalty Gas" (Preliminary Finding) and solicited comments from the public.¹ During the comment period, the Alaska Oil and Gas Royalty Development Advisory Board (Royalty Board) convened a public meeting to discuss the merits of a sale and take public testimony. After review of the Royalty Board's and public's comments on the Preliminary Finding the commissioner has determined that a competitive sale of the State's royalty share of ANS gas at this time is in the State's best interest. The "Final Finding and Determination for a Solicitation for Offers to Purchase Alaska North Slope Royalty Gas" (Final Finding) documents the commissioner's determination.

The commissioner reserves the right to cancel or postpone the solicitation for offers and the competitive RIK sale at any time. After the RIK sale is conducted, the State will negotiate the final contract terms with successful buyers. No RIK gas sale contracts that result from the RIK sale will be effective until they are approved by the Legislature.

A. Background

Under the terms of most of its leases with North Slope oil and gas producers, the State has a right to one-eighth of the oil and gas production as its royalty share. Some leases provide for higher royalty rates. The leases, along with various unit agreements and royalty settlement agreements, grant the State the right to take its royalty share of oil and gas production in-kind (RIK) or in-value (RIV). When the State takes its royalty share as RIV, the lessees market the royalty share and pay the State the cash value received. When the State takes its royalty share as RIK, it takes possession of the oil and gas and sells it in the market.

Currently half of the royalty oil production at the Prudhoe Bay Unit (PBU) has been taken as RIK and sold to Williams Alaska Petroleum, Inc. for use in Williams' North Pole refinery. The

¹ Written public comments and the State's responses appear in Appendix A and B.

State has also sold other volumes of oil as RIK to various purchasers in the past. Current North Slope royalty gas production is less than 4,000 Mcf per day.² The State has elected to take its royalty share of gas in-value and the lessees have sold to ANS utilities and the Trans-Alaska Pipeline System (TAPS) as fuel.

B. Why have a competitive RIK gas sale now?

Successful development of the vast ANS natural gas resource has challenged the State and the oil producers since the Prudhoe Bay oil field was first discovered. In the last year the major ANS oil and gas producers have renewed attempts to evaluate the challenges of transporting ANS gas to market. Construction of an ANS gas pipeline is by no means certain. But if a new gas pipeline were built to deliver natural gas from the North Slope to markets in the U. S. Lower 48 or elsewhere, the State's royalty share could rise to 500,000 Mcf per day or more by the end of the decade.

There are several important reasons for the State to conduct an immediate ANS RIK gas sale. First, potential buyers are motivated to purchase RIK gas at this time in order to be able to nominate capacity on the gas pipeline during an "open season," which is currently expected to occur in 2002. An "open season" is an opportunity during the early stages of a proposed pipeline's design for potential owners to invite potential shippers to secure transportation capacity on the future pipeline. An open season nomination is a firm commitment by the shipper to fill the capacity it nominated when the pipeline is operational or to pay demand charges for the unused space. It is an important (and often required) step in the process of applying to the U.S. Federal Energy Regulatory Commission (FERC) and the Canadian National Energy Board (NEB) for the certificate of public convenience and necessity for a pipeline.

In recent months companies have expressed interest in securing a gas supply from the State as a precondition to their participation in an "open season" for a future Alaska gas pipeline. Companies have suggested using RIK gas for marketing in the Lower 48, for potential in-state petrochemical plants, and as a "back-stop" to gas production for North Slope lease holders. The State also received a proposal in December 2000 to buy gas to fuel a power plant for a large Internet data center on the North Slope.³ With a gas sale contract from the State in hand, these companies could reduce some of the risk involved in committing to pipeline space in the open season.

Second, the sale of RIK may contribute to earlier commercialization of ANS gas and the successful completion of a pipeline by bringing additional participants to the open season. Evidence of additional participants interested in purchasing and transporting Royalty Gas on an Alaska gas pipeline could influence the timing and design of the pipeline.

Third, as discussed further in the explanation of Royalty Gas sale contracts, the State will receive more royalty revenues by taking the gas in-kind and disposing of it through an RIK sale than it would receive if the royalty gas were left in-value and marketed for the State by the lessees.

² Mcf = one thousand cubic feet; Bcf = one billion cubic feet.

³ The Alaska Legislature passed a resolution directing the department to consider sale of RIK gas for this purpose. (22nd Legislature; SCS CSHCR 17)

Finally, the RIK gas sale may attract proposals from other in-state buyers who would use the gas on the North Slope or buyers who may wish to supply in-state utilities or industrial users along the pipeline route.⁴

The State cannot guarantee when or if the ANS RIK gas it is proposing to offer for sale now will ever be delivered. But the prospects for an ANS natural gas pipeline project and an upcoming "open season" for nominating transportation capacity on a future gas pipeline has presented the State with an opportunity now to offer a portion of its future Royalty Gas as RIK in a competitive sale for delivery when an Alaska gas pipeline is developed.

C. What happens next?

Since publication of the Preliminary Finding, the Division of Oil and Gas has met with the Alaska Natural Gas Pipeline Project Team (ANGPPT), a consortium of the three largest ANS oil and gas producers. The ANGPPT indicated that an open season would not occur in the first quarter 2002 as had been assumed at the time of the Preliminary Finding. For this reason the department has extended the time schedule for some steps listed in the Preliminary Finding. Because the 2002 Legislative session will end in May, however, any RIK gas sale contracts submitted to the Legislature have to be negotiated by the end of the first quarter 2002.

The next step in the process is publication of a Solicitation for Offers to Purchase RIK Gas. The Solicitation will specify certain conditions of the offering, including the quantity of gas offered for sale, the term of the sale contract, the point of delivery, the date that proposals are due, and qualifications to participate in the sale. It will request that potential purchasers to submit proposals that specify terms the purchaser would like to include in a final RIK gas sale contract with the State. The Solicitation for Offers will provide at least 30 days notice to potential purchasers and indicate where the various application documents may be obtained.

Because of the current uncertainty surrounding completion of a gas pipeline project and a potential completion date still many years off, detailed contract requirements that are normally found in an RIK gas sale contract have yet to be developed. The Solicitation will include a sample RIK gas supply sale contract that illustrates the type of contract the State expects to negotiate for the sale of its Royalty Gas ("*Sample Contract*"). The *Sample Contract* is intended to be illustrative only; it will not contain all the terms that will appear in the final contracts.⁵ The *Sample Contract* will specify certain standard contract terms that are generally included in the State's final contracts, such as payment, default, security, and warranty clauses. Other contract terms, such as the base price to be paid for the gas, quantity purchased, volume measurement, and the timing of gas deliveries, will be negotiated after proposals are opened.

Offers must be received by the Division of Oil and Gas by no later than January 31, 2002. The department will open and announce the offers at a public meeting on February 1, 2002. But the successful offers will not be announced until after the department has evaluated all the proposals

⁴ Other North Slope uses could conceivably include a gas-to-liquids plant, a small plant to make methanol for oil field operations, or enhanced oil recovery (EOR) projects in fields outside of the Prudhoe Bay Unit.

⁵ A copy of the *Sample Contract* is attached to this Final Finding in Appendix D.

offered. The department expects the offers to present a number of variable terms and conditions that the department will need to evaluate and recommend to the commissioner before they are awarded. The department intends to complete the evaluations and notify the potential buyers whether their offers have been accepted no later than February 2002. After the offers are accepted the department will begin negotiating RIK gas supply contracts with the buyers.

Upon written request of the potential purchaser, the commissioner will hold as confidential to the extent provided by AS 38.05.035(a)(9)(D), any cost, financial or other proprietary information contained in an offer. All offers will be made public when the department submits the RIK gas sale contract to the Royalty Board, except as otherwise provided by law.

If the commissioner rejects any offers received under the solicitation, the commissioner will notify the Royalty Board and document the reasons for the rejection. As provided in 11 AAC 03.210 and 11 AAC 03.230, potential purchasers whose offers were rejected may request a conference with the commissioner before any contracts are executed.

Finally, the negotiated RIK gas sale contracts will be submitted to the Royalty Board for review and approval at a public meeting. The contracts will then be forwarded to the Legislature for approval with the Royalty Board's recommendations.

D. Schedule for Offers and RIK Gas Sale

The table below summarizes the schedule for the State's RIK gas sale purchase solicitation. Under this schedule successful RIK gas purchasers should know by March 2002 whether the commissioner and the Royalty Board have approved their contracts.

Schedule for the 2002 Solicitation for Offers to Purchase ANS RIK Natural Gas Sale	
Publish Final Finding and Solicitation	December 26, 2001
Proposals due at Division of Oil and Gas	January 31, 2002
Public opening of RIK Proposals	February 1, 2002
<i>The following dates are tentative and may be delayed or cancelled</i>	
Award Successful RIK Proposals	February 15, 2002
Publish Notice of Royalty Board Hearing	February 15, 2002
Convene Royalty Board Hearing	March 1, 2002
Executed RIK gas sale contracts to Legislative for approval	March 15, 2002

II. DEVELOPING RIK GAS PURCHASE PROPOSALS

A. To be considered, proposals must meet the following Minimum Cash Bonus and Base Price conditions.

Minimum Cash Bonus: In order to participate in the competitive sale, potential buyer's offer must include a minimum cash bonus. The minimum cash bonus must equal \$1.00 per Mcf per day of Maximum Quantities the buyer proposes to purchase (see the *Sample Contract* at Article

3.1.1.). For example, if a potential buyer proposes to purchase 200,000 Mcf per day of the State's royalty gas, it must include a minimum \$200,000 cash bonus with its proposal. If the quantities of RIK gas the potential buyer proposes to purchase will vary from season to season during the life of the contract, the offer should include a cash bonus based on the period of greatest quantity.

The State will initially retain the minimum cash bonus submitted with the successful offers and refund the cash bonuses of the offers that are rejected. The minimum cash bonuses of the successful offers will be refunded, without interest, if the Royalty Board or Legislature has not approved the final contracts by August 31, 2002, or if an open season has not occurred by December 31, 2004, or if an ANS gas pipeline is not in service or royalty gas has not been delivered to the pipeline by July 31, 2012. (See discussion of Term below.)

Base Price: The potential purchaser must offer a base price. For the purposes of this competitive RIK sale "Base Price" is as defined in paragraph 3.3.1 in the *Sample Contract*. It will be the higher of a fixed dollar per-volume unit price or the volume-weighted average of the amounts paid by the lessees on royalty gas left in-value (RIV). (See 11 AAC 03.210 (c).)

The State will consider offers that include a different mechanism to calculate the Base Price so long as it satisfies the definition of Base Price as the volume-weighted average of the amounts paid by the lessees on royalty gas left in-value (RIV). If the State is not satisfied with a proposed Base Price mechanism, the State will detail an acceptable mechanism.

The mechanism for calculating the value of RIV is set out in the State's current leases, unit agreements and royalty settlement agreements. A majority of the gas-producing leases in the Prudhoe Bay Unit (PBU) and the Point Thomson (PTU) Unit are the State's Form DL-1 leases that contain the following RIV value terms.

ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts of gross production. (Form DL-1 lease at paragraph 15)

PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant. (Form DL-1 lease at paragraph 16)

In the event of a major gas sale, the lease language above, together with the provisions of unit agreements, royalty settlement agreements, or new settlement language, will define value for much of the RIV gas. Although the lease terms were disputed in the ANS Royalty Litigation, many issues were resolved as the litigation progressed. For example, the State agreed to pay field costs on PBU RIK gas. The State and the lessees in several royalty settlement agreements have also resolved the question of value with respect to RIV oil and natural gas liquids (NGLs). The royalty settlement agreements also define value for the current production of RIV gas.

The final determination of RIV value may take several years after the gas is delivered. For example, implementation of the lease terms to determine the value of RIV gas typically requires the State to audit the lessees for gas sale receipts and transportation cost deductions. The State then assesses the effect of terms, like those quoted above from the Form DL-1 leases that contain "higher-of" provisions to determine the final value for RIV gas. Additionally, retroactive changes in transportation or processing charges could result in changes to the RIK gas Base Price. Accordingly, the RIK gas buyer will have a contingent liability for upward adjustments in the RIK gas Base Price that may take several years to finally determine.

The RIK buyer is also subject to the possibility that the State and one or more lessees may settle an RIV obligation by invoking a different methodology than that specified in the leases. If the State and a lessee agree to define the method of valuing RIV differently than the leases currently specify, the Base Price of the RIK gas sale contract could be affected. It would still be calculated using the weighted-average of the amounts paid by the lessees on royalty gas in-value, but would use the newly agreed-upon values. This could result in application of different Base Price calculations and different timeframes for adjustments under the affected leases.

Price Premium: Potential Buyers may offer a Price Premium over the Base Price. A Base Price premium might be structured as a flat, per-unit addition to the Base Price, or a percentage of the Base Price added to the Base Price.

Option Price: An option price or fee could be offered for the ability to increase or decrease the quantity the buyer would purchase during the life of the RIK gas sale contract. The *Sample Contract* provides a mechanism for the buyer to reserve a quantity option. (See e.g. *Sample Contract* at Article 3.1.2- reduction, 3.4-reservation fee, and 9.4 termination fee.)

B. In addition to the required Minimum Cash Bonus and Base Price, an offer may propose Special Commitments.

Potential buyers may offer Special Commitments in addition to the minimum cash bonus and Base Price. A potential buyer is not required to propose a Special Commitment; however, Special Commitments may be given weight in the State's evaluation process. In order to be given weight in the evaluation process, the benefits to the State of special commitments must be quantifiable.

A Special Commitment could be a commitment to in-state processing, in-state use, in-state investment, in-state exploration, local hire, or anything else that a potential buyer offers to enhance its proposal. But, such commitments must be measurable and enforceable. Forecasts or

other reasonable statistical measures that indicate the in-state economic and social benefits they afford should be provided.

Among the in-state benefits the State will consider are the economic and social benefits of increased employment, increased household incomes, in-state construction, purchases of local and state goods and services, consumer benefits in the form of lower cost energy, local and state property taxes, corporate income taxes, and economic growth in related industrial sectors. (A listing of these considerations is found in AS 38.06.070.)

If a proposal includes in-state investments and asks the State to consider the benefits offered by Special Commitments, it should describe the Special Commitments to incorporate into the RIK gas sale contract as performance obligations. For example, if an offer proposes benefits from in-state investments it should include quantifiable performance standards. If an offer proposes benefits from in-state use of the RIK gas, it should provide a mechanism to assure that the gas purchased under the contract will be used in-state. It should also offer some restriction on the re-sale of the RIK gas beyond adjustments required for the efficient operation of the buyer's facilities.

Special Commitments and performance obligations will be subject to all contract remedies available to the State if a buyer fails to meet its performance terms. These may include cancellation of the sales contract, substitution of performance obligations, reduction in sales volumes, damages and other remedies available at law.

C. Proposals should address the following terms and conditions as specifically as possible.

Quantity: RIK proposals must specify the quantity of gas desired. The State's royalty share from the ANS leases is not a specified daily quantity, but rather a specified percentage of production. The State recognizes, however, that potential RIK purchasers who expect to participate in an open season will want to contract for a specified daily quantity of gas. For this reason, the State's draft *Sample Contract* assumes that royalty gas will be measured volumetrically in Mcfs, but for a final RIK gas sale contract it may need to be converted to percentage of production.

No Guarantee of Quantity: The State cannot guarantee a certain quantity of gas under an RIK gas sale contract supply. The State can deliver royalty gas only to the extent it receives royalty gas from the lessees. The quantity of royalty gas available to the State may vary and may be interrupted from time to time depending on a variety of factors, including the rate of production from the leases and unit. Furthermore, the State may be required to nominate royalty gas as a percentage of its total royalty gas, and not by quantity. Accordingly, prospective buyers must be willing to accept the risk of receiving more or less than the desired quantity at any given time.

The State will consider offers that request seasonal variations in quantity, but the proposal should include a schedule that predicts by month, year or season the quantity that will be required throughout the term of the contract. Potential purchasers should be aware that in order to vary the quantity of royalty the it takes in-kind under any lease, the State must provide several months' notice to the lessee depending on the terms of the lease, unit agreement, or settlement

agreement. For instance, the State must nominate RIK gas in the PBU at least six months before the production month in which the nomination will be effective.

The State and the successful purchaser will ultimately negotiate a Maximum Quantities term for the final RIK gas sale contract. (See e.g. *Sample Contract* at Article 3.1.1) A purchaser may also negotiate a provision to reduce the Maximum Quantities up to 50% with at least two years notice. (See e.g. *Sample Contract* at Article 3.) If a potential purchaser wishes to negotiate for terms that would permit terminating the contract or reducing the Maximum Quantities by more than 50 percent, it should include a proposal for the option. (See e.g. *Sample Contract* at Article 9.4 and the discussion of Option Price above.)

Six months before the production month in which the RIK gas will be delivered, the State will notify the PBU and PTU operators of the percent of royalty gas it nominates for the production month to tender to the buyer. The *Sample Contract*, Article 3, provides an illustration for the buyer to notify the State of its quantity nomination for RIK gas seven months before the production month. The buyer's nomination may not exceed the Maximum Quantities and a reservation fee will be required for the difference in quantity between the Maximum Quantities and the quantity of royalty gas actually purchased.

The *Sample Contract* specifies that the State will reserve 30 percent of its ANS royalty gas in-value. The State has an interest in keeping some of its royalty in-value for two reasons. First, it provides the base price measure used in determining RIK gas prices. Second, the State's interests are best served by retaining the option to sell some of its RIK gas in the future. For these reasons, the State will not sell 100 percent of its royalty gas, and offers should be for a lesser volume.

No Guarantee of Quantity: The State cannot guarantee a certain quantity of gas under an RIK gas sale contract supply. The State can deliver royalty gas only to the extent it receives royalty gas from the lessees. The quantity of royalty gas available to the State may vary and may be interrupted from time to time depending on a variety of factors, including the rate of production from the leases and units. Furthermore, the State may be required to nominate royalty gas as a percentage of its total royalty gas, and not by quantity. Accordingly, prospective buyers must be willing to accept the risk of receiving more or less than the desired quantity at any given time.

Term: RIK proposals must specify the time period of the sales contract. The delivery of RIK gas will not begin until gas is produced for the gas pipeline. Although the State would prefer a contract term that is relatively short, the State understands that the potential buyers may need RIK gas sale contract terms that matches the term of their pipeline transportation commitments. The state will negotiate a term based on the buyer's proposal.

The RIK gas sale contract will be terminated if the Royalty Board or Legislature has not approved the final contract by August 31, 2002, or if an open season does not occur By December 31, 2004, or if an ANS gas pipeline is not in service or royalty gas has not been delivered to the pipeline by July 31, 2012. The State selected these dates to balance the requirements of potential purchasers with the State's requirements to take advantage of alternative opportunities as soon as possible should the pipeline project be delayed.

It is important to note that, while the period of deliveries will be negotiated in the final contract, obligations to pay for price and volume adjustments may extend for months or years after the deliveries.

Source: In drafting the *Sample Contract*, the State assumed that RIK gas would likely come from the PBU and the presently undeveloped PTU and be delivered into an ANS gas pipeline. Estimated total production of gas is 2.5 Bcf per day from the PBU and 1.5 Bcf per day from the PTU, but could be substantially different. The state's royalty share of this production will be approximately 400 mmcf per day. The State cannot guarantee that RIK gas will be available from a specific unit or source.

Under the terms of the *Sample Contract* the State will deliver RIK gas first from the PBU and, if adequate volumes of royalty gas are not available from the PBU, then from the PTU. This allocation will be subject to the 30 percent reservation described above and a mechanism that prorates the volumes of RIK from each unit based on the buyer's monthly nomination. Under this proration each buyer of royalty gas will pay the same Base Price per Mcf calculated from the weighted-average royalty values for royalty in-value. However, the State reserves the right to supply the contract quantity of RIK gas from either or both PBU or PTU or other units, unless otherwise negotiated in the final RIK gas sale contract.

III. DISCUSSION OF SAMPLE CONTRACT TERMS

The final RIK sale contracts negotiated by the State will include contract terms similar to those found in a standard gas sale contract with certain terms to reflect the unique nature of the RIK sale. Because of the uncertainty of the future of a gas pipeline and the need to act quickly, the State reserves the right to negotiate all contract terms with the successful buyers. Below is a discussion of the type of terms the State expects to include in the final RIK gas sale contracts.

The final RIK gas sale contracts and the all commitments of the State and the buyers are contingent on the successful completion of an ANS gas pipeline by 2012.

A. Point of Delivery

The RIK gas sale contract will define the point(s) of delivery as the transfer point where the State receives its royalty gas in-kind from the lessees. Specific points of delivery are not yet known.

B. Field and Conditioning Costs

The RIK gas sale contract will require that the purchaser pay any and all field and conditioning costs chargeable against the State's royalty share of gas subject to the contract.

Field and conditioning costs may vary from lease-to-lease and unit-to-unit. Various lease, unit, and royalty settlement agreements address whether field and conditioning costs, or one or the other, may be charged against the State's royalty share of gas. The State's obligation to pay these costs may depend on whether the State takes its royalty share in kind or in value. In

addition, the RIK purchaser will be effectively bound by any future agreement between the State and lessees as to field and conditioning costs chargeable against the royalty gas sold.

This term is non-negotiable.

C. Payments

The State will bill the buyer each month using its best estimate of price and volume. The State will make adjustments in later months as information about price and volume becomes available.

This term is non-negotiable.

D. Security

The security provision is to protect the State's interests if the buyer defaults on payments, becomes unable to take all of the sale gas it specified under the RIK gas sale contract, or otherwise fails to meet its performance obligations. The State's risk exposure takes at least three forms. First, under the contract the State will bill the buyer for RIK gas the State supplied in the previous month. If the buyer defaults the State may not receive payment for the gas it already supplied. Second, there is the "de-nomination" risk. The State must provide at least six months notice to the lessees to de-nominate RIK and return it to RIV. During this six-month period the State may have to find other buyers for RIK gas the buyer cannot accept or pay for, or the State may have to pay the lessees to take the RIK gas back in-value. Third, if the contract includes Special Commitments, there is the risk that the buyer will fail to meet the commitments. Insofar as the State may have awarded a gas sale contract in part because of the benefits to the state provided by the Special Commitments, the State will regard the buyer's failure to perform those commitments as real damages to the State and may pursue damages in addition to the amount of the security.

The *Sample Contract* illustrates potentially acceptable forms of security: 1) an irrevocable stand-by letter of credit giving the State the right to draw on the letter of credit or present drafts to the issuer at any time through at least six months after the State's final delivery of gas; 2) a security contract between the buyer and a promisor for the direct benefit of the State; and 3) a provision for any special security arrangements offered by the buyer in its RIK proposal and negotiated with the State. Other forms of security may be determined by the commissioner to be adequate to secure the State. The commissioner may require additional security to protect the State's interests.

The requirement to provide security is non-negotiable; however, the security terms may be negotiated to some degree.

E. Default and Termination

The commissioner may suspend or terminate the State's obligations to sell RIK gas or reduce volumes if the buyer fails to do one or more of the following:

- The buyer fails to perform any of its obligations under the contract and fails to cure the non-performance or the non-performance continues for more than 30 days after the buyer has been notified by the State of the non-performance;
- The buyer fails to pay in full any sum of money owed under the contract within two business days after the State gives the buyer notice that payment is due and has not been paid;
- The buyer fails to provide written assurances satisfactory to the State of its intention to perform its obligations under this agreement and provide evidence or assurances of transportation arrangements;
- The buyer fails to comply with all terms of the RIK sale contract to secure payment;
- There is a substantial change in the buyer's financial condition, business operations, property, or ownership that may affect the buyer's ability to perform its obligations under the contract; or
- If any representation or warranty made by the buyer in accordance with the contract is found to have been materially false or incorrect when made.

The buyer is required to notify the State immediately if the buyer is insolvent or unable to pay any of its debt. This automatically terminates the State's obligations to deliver gas. If the buyer defaults, all monetary obligations are immediately due.

If the buyer defaults or the contract is terminated, the State may immediately give notice to the lessees "de-nominating" its RIK. However, the State must provide the lessees with six-months' notice of nomination. Consequently, the buyer may be obligated to continue to take the gas during the notice period if the State chooses not to assume physical possession of the gas, or is unable or unwilling to sell the gas in a distress situation.

If the buyer initiates termination of the contract, the State requires a minimum of six months and ten days written notice of early termination of the contract.

This term is non-negotiable.

F. Successors and Assigns

Neither party to the contract may assign or encumber the agreement without first obtaining the written consent of the other party.

This term is non-negotiable.

G. Interpretation of Terms and Conditions

The State will include a dispute resolution procedure in the RIK gas sale contract. It will permit either the State or the buyer to start the process by providing written notice of a disagreement or dispute to the other party. The State and the buyer are permitted to submit to the commissioner written arguments and evidence supporting their views of the dispute and a proposed resolution. The buyer must agree to be bound by the commissioner's resolution of the dispute if the resolution is reasonable and not arbitrary.

This term is non-negotiable.

G. Other Provisions

The sales contract will contain other standard provisions such as force majeure, buyer and seller warranties, metering, and balancing. To the extent permitted by law and as appropriate to the proposal, a provision for local hire may also be included. Finally, because any contract will be entered into many years before first gas deliveries, a provision will be included to allow a change in terms if necessary to better implement the original intent of the parties.

IV. ANALYSIS OF STATE BENEFITS

To determine whether a sale of the State's Royalty Gas at this time is in the State's best interest, the commissioner considered (1) the economic impacts of the proposed sale to the State; (2) the projected social impacts of the transaction; and (3) the projected positive and negative environmental effects related to the transaction.⁶

The State will always sell its royalty gas as it does royalty oil. When the State keeps its royalty in-value, it "sells" it to the lessees who, in turn, deliver into the market and pay the State the value. When the State sells its royalty in-kind, it becomes a participant in the market where the lessees sell their production. In both instances the State receives the value for its royalty.

Regardless of whether a buyer purchases ANS gas from the State or a producer, its availability may be an incentive to make in-state investments. For example, access to an assured supply of gas from the State might facilitate financing for the buyer or allow the buyer to commit to capacity on an ANS gas pipeline in an open season. By making its ANS royalty gas available at this time the State hopes to encourage such investments and, in so doing, contribute to diversity in the State economy.

At this stage it is not possible to know whom, if anyone, will be successful buyers, or what or where any facilities might be built as a result of a competitive RIK sale. In order to consider the impacts of the proposed sale, DNR contemplated four reasonable scenarios possible for RIK sales:

1. To a buyer who will deliver the gas to markets in the Lower 48;
2. To a facility on the North Slope;
3. To an industrial facility in Fairbanks or another Alaskan community along the pipeline route; and
4. To gas or electric utilities in Alaska.

Three of the scenarios contemplate in-state sales that would likely involve local construction and operation of facilities. These scenarios would have economic, social and environmental effects of their own. But incremental economic, social, and environmental effects, beyond royalty revenues and administrative effects, attributed solely to sale of RIK gas are, with few exceptions, unlikely. However, the RIK sale could accelerate the timing of potential economic benefits.

⁶ See AS 38.05.183(e) and AS 38.06.070(a).

A. Projected Economic Impacts

The RIK gas sale should generate greater royalty revenues and, possibly, stimulate an earlier commercialization of ANS gas. Consider the following scenarios:

Scenario 1: Sales of RIK gas to buyers who will deliver the gas to markets in the Lower 48. A Scenario 1 sale will generate economic benefits to the State in the increase in royalty revenue that results from RIK sales. About 70 percent of the additional royalty revenue will go to the State general fund. The extent of the economic effects will depend on the size of the RIK price premiums offered or cash bonuses received and the nature of their expenditure by the state

Suppose, for example, that current holders of undeveloped oil and gas leases on the North Slope are awarded RIK gas sale contracts and commit to capacity on the pipeline during an open season. These RIK purchasers have an additional incentive to step-up exploration and development of their own gas resources. They would hold reserved pipeline capacity to transport their own new gas production to market as they reduce their gas purchases under the RIK gas sale contract. The principle economic effect would be to accelerate the timing of new jobs in the exploration phase, increased personal incomes from wages, local purchases and contracting, and potentially new gas development. It could also contribute to more vigorous competition and higher bonus bids for oil and gas leases that the State will offer in ANS lease sales in the future.

The RIK sale may affect production of equity gas from the PBU and PTU. If new explorers buy RIK gas and lever the purchases into firm capacity nominations in the open season, the existing resource owners (as pipeline sponsors) could design a larger pipeline to meet throughput requirements. The existing resource owners might be encouraged to produce equity gas earlier and at higher rates because they can produce equity gas to meet their firm transportation commitment instead of shipping RIV gas.

Alternatively, if pipeline capacity is not increased, the existing resource owners may have to reduce their equity production if the new exploration is successful. If the new explorers who have bought RIK gas are successful in gas exploration and begin to produce gas from their newly developed leases, they would reduce their purchases of RIK gas. The RIV gas volumes from the PBU and PTU will increase and displace some equity gas of the existing resource owners. This situation could result in a decrease in the revenues for the existing resource owners and underutilization of the PBU and PTU conditioning plants and other lease investments.

However, existing resource owners have not provided estimates of the potential benefits of early higher rates of equity production and costs of potential future reductions of equity production or pipeline expansion.

Scenario 2: Sales of RIK gas to industrial users on the North Slope. The State's RIK gas will not be offered at a subsidized price and, if the market factors are favorable without a subsidy, other sources of ANS gas can be and have been induced to supply North Slope industrial users. Under

Scenario 2, the economic effects would result from increased royalty revenues of selling the State's royalty in-value.

Scenario 3: Sales to an industrial facility in Fairbanks or other Alaskan community along the pipeline route. The volume of RIK gas expected to be produced for the ANS gas pipeline will probably be insufficient to supply the NGLs needed for a petrochemical plant. Such a development would have to supplement any RIK gas purchase with gas supplied from other ANS producers.

A company's decision to move forward on such a project, like any investor's decision to move forward on a major industrial use of ANS gas, will result from an evaluation of the market fundamentals including gas supply prices, transportation logistics, and the demand for industrial products. As in Scenario 2, a Scenario-3 RIK gas sale to an industrial facility would produce increased royalty revenues to the State. The economic benefits of a petrochemical plant would go beyond royalty revenue receipts. They would include employment opportunities during construction and operation, personal incomes, property tax revenues, corporate income taxes, and the impact through value added through the manufacture of intermediate products such as polyethylene and propane. But these benefits value-added benefits would accrue to the project whether the gas supplying the plant comes from the State's RIK or from a gas producer.

Scenario 4: RIK gas sales for local utility gas and electric power generation. A study conducted by Econ One Research for the department has evaluated the economic feasibility of sales of ANS gas to electric or gas utilities in Alaska.⁷ (See Appendix C.) The pipeline designs promoted by various sponsors in recent months consist of high-pressure, dense-phase (i.e., containing NGLs) pipelines. Gas suitable for space heat or electric generation cannot be removed from the pipeline without lowering pipeline pressure and extracting the NGLs. These costs, combined with the acquisition, transportation, and distribution costs of delivering ANS gas to Alaska customers, suggest that in order to achieve sufficient economies of scale, utility gas supplies will be limited to only the largest concentrations of gas dispositions in Alaska.

If ANS gas can be supplied economically to local gas and power utilities, consumers may benefit from lower energy prices as compared to the price of alternatives energy supplies in the State. If utilities are able to acquire ANS gas for less than the cost of ANS gas in the Lower 48 then this could invite commercial and industrial gas-related investment in Alaska. Current in-state demand for gas in all uses is approximately 227 Bcf per year. Utility gas usage for residential and electric power generation account for about 29 percent of total in-state gas usage. The remainder includes commercial and industrial usage, including LNG exports, ammonia-urea manufacturing, and gas for TAPS pump stations and North Slope field operations. According to Econ One, potential in-state usage of gas could increase by 140 Bcf per year in 2020 due to baseline growth, expanded gas service, new industrial uses, and fuel switching for power generation. This estimate, however, is based on several assumptions:

⁷ Dismukes, David E. et al. 2001. Alaska Natural Gas In-State Demand Study. Prepared on behalf of the Alaska Department of Natural Resources by Econ One Research, Inc., Los Angeles, California and Acadian Consulting Group, Baton Rouge, Louisiana.

- Relative energy prices in the future are consistent with levels observed today;
- The state's regional economy exhibits continued gradual economic expansion at rates comparable with the past five years (about a half percent per year in real dollars);
- In-state access to ANS gas from a high-pressure, dense-phase gas pipeline from the North Slope to Canadian and Lower-48 destinations is not cost prohibitive.

The study concludes that the economics of supplying ANS gas for various in-state uses, including new industrial uses and expansions of current industrial uses, are favorable only if the throughput in a spur pipeline to Southcentral Alaska is high enough to generate needed economies of scale. In order to reach competitive levels of throughput, the spur pipeline would have to serve some of the existing customer base now served by gas reserves in the Cook Inlet Basin as well as potential growth from expanded gas service and new industry applications. Rising gas prices in the Southcentral region may encourage new exploration and development of gas resources in the Cook Inlet but may also jeopardize industrial consumption and LNG exports. Even with rising Southcentral gas prices, ANS gas may not be competitive when the tariff on a spur pipeline linking Fairbanks with Southcentral is added to the cost of ANS gas deliveries to a meter-station tap near Fairbanks.

Natural gas distribution in the City of Fairbanks began in 1998 with LNG imports from gas produced in the Cook Inlet Basin and shipped north by the truckload at delivered, burner-tip prices of about \$7.50 per Mcf in 2001. Total gas usage for residential space heating Fairbanks has increased to about 155 million cubic feet per year in 2001 (0.155 Bcf per year). Various estimates, including the Econ One study indicates that baseline growth plus expanded residential gas service to areas not yet connected in the interior region including Fairbanks could increase gas usage to 2-to-6 Bcf per year by 2020. Conversion of electrical generation for the military bases and the University of Alaska Fairbanks complex could double estimated gas usage by 2020. These estimates are included in the statewide forecast above and build on the same assumption that the cost of gas delivered to interior region applications, including furnace and generator system conversion to natural gas, would be competitive with other energy alternatives.

B. Projected Social Impacts

The analysis of social impacts is similar to the analysis of economic benefits. The proposed RIK sale itself will have no significant or reasonably foreseeable effects on land use, local schools, roads, or other state infrastructure. Social impacts that might occur as a result of RIK gas sales to in-state facilities include:

- Additional employment opportunities while the facilities or pipelines are being built.
- Long-term employment opportunities once the facilities or pipelines are operational.
- Utility gas or electric supplies to towns and villages in interior Alaska.
- An additional tax base to local governments from facilities built in an organized borough or town, such as the North Slope or Fairbanks North Star Boroughs.

C. Projected Environmental Impacts

The sale by itself will have no incremental environmental impact. However, it is conceivable that some environmental impacts could indirectly result from activities or projects developed by the successful buyers. But before a project may commence permits must be obtained and findings must be made. The permit and findings process imposes conditions on allowable impact of projects.

Permits: Depending on the project proposed and the exact location, a combination of permits could be required prior to construction.

DNR, Div. of Mining, Land, and Water Land Use Permit – This permit could be required if a proposed facility is located on state land or crosses state land.

DEC Air Quality control Permit to Operate – The federal Prevention of Significant Deterioration (PSD) program, which is administered by DEC, establishes threshold amounts for the release of byproducts into the atmosphere. Oil and gas exploration and production operations with emissions below predetermined threshold amounts must still comply with state regulations designed to control emissions at these lower levels (18 AAC 50). Activities that exceed predetermined PSD threshold amounts are subject to a more rigorous application and review process. Such activities include the operation of turbines and gas flares.

DEC Wastewater Disposal Permit – Domestic gray water must be disposed of properly at the surface and a permit is required under 18 AAC 72.

Corps of Engineers Wetlands Permit – If a facility is proposed for location in wetlands a permit will be required from the Corps of Engineers. Before a permit may be issued, the Corps will need to complete an environmental assessment and possibly an environmental impact statement under the National Environmental Policy Act.

Alaska Coastal Management Program (ACMP): Alaska has a coastal management program in accordance with the Federal Coastal Zone Management Act of 1972. Alaska's program sets out statewide standards that govern how various uses, activities, resources, and habitats are managed under the ACMP.⁸ It applies generally to lands along Alaska's coast and along some rivers. Parts of the North Slope Borough are within the coastal zone, while Fairbanks is not within coastal zone boundaries.

In addition, communities and boroughs may adopt local management plans. The North Slope Borough has adopted a local coastal management plan (NSBCMP) under the ACMP. Any proposed facilities, including pipelines, must be consistent with both the ACMP and the NSBCMP.

⁸ 6 AAC 80.040 – 150.

Zoning: Both the North Slope Borough and the Fairbanks North Star Borough have developed zoning ordinances.⁹ Any industrial development would be subject to local zoning.

To the extent that RIK gas is sold to in-state utilities and users might displace other fuels such as coal or fuel oil, there may be beneficial impacts on air and other resources.

V. ANALYSIS OF THE PROPOSED RIK GAS SALE

As demonstrated by the proposal and contract terms discussed above, taking a portion of the State's royalty gas in-kind and selling it by competitive sale is in the best interests of the State.

The competitive sale could enhance the State's economic interests through increased revenues without any measurable negative social or environmental impacts. The State will not award an RIK gas sale contract if the sale price is not at least equal to the amount the State would receive if it took its royalty in-value. The competitive process gives the State the opportunity to accept proposals that offer the greatest benefit to the State. And the State can impose contract conditions that protect the State's interest while affording the flexibility necessary to attract serious proposals.

The sale and contract terms do not preclude a purchaser from exporting the royalty gas from the State. At 4 bcf per day, total production of ANS gas exceeds by four-fold future potential in-state domestic and industrial usage. However, using the most optimistic gas demand forecast from the Econ One study and the most pessimistic Cook Inlet gas supply outlook, the State's royalty share by itself will not be sufficient to meet in-state requirements in 2020.¹⁰ Nevertheless, 30 percent of the ANS gas state royalty share reserved in this sale could satisfy baseline utility gas demand growth predicted in the Econ One study for residential and power generation usage. This level of demand will materialize only if ANS gas can be acquired, delivered, and distributed to customers throughout the Southcentral and Interior region at competitive prices.

In determining that the proposed sale is in the best interests of the State, the commissioner also considered the criteria of AS 38.06.070.

1. Revenue needs and fiscal condition of the State: The economic condition of the State is largely dependent on its royalty revenues from oil and gas sales. Supplementing the current royalty revenue sources grows more important each year as production declines in the larger fields on the North Slope. The State can be paid for its royalty gas either in-value by the lessees or in-kind through competitive sales such as the one proposed. Because contract award will depend, in part, on the price premium offered for the RIK gas supply and cash bonus offered for an option to buy RIK gas, revenues from the sale of RIK gas will exceed the in-value alternative.

⁹ The North Slope Borough's zoning ordinances are located under North Slope Borough Ordinances Title 19 and the Fairbanks zoning ordinances are located under Fairbanks Ordinances Title 18.

¹⁰ This shortfall assumes that demand will grow as a result of baseline economic growth, gas utility expansion in the Southcentral and Interior regions, an expansion of the ammonia-urea plant, a new petrochemical plant is built, and oil- and coal-fired power generation in the Interior is replaced by gas. It also assumes that relative prices for gas in remain unchanged and ANS gas is competitive to alternative energy sources.

If the Price Premium offered in this sale is \$0.05 per mcf and the volume sold under the contract is 200 mmcf per day, the State will receive an extra \$3.7 million per year for the RIK gas.

The sale may also enhance competition for oil and gas leases on State lands. As more companies with access to the pipeline compete for leases, bonus bids for these leases can be expected to be higher. The greater diversity of companies undertaking exploration and development on the North Slope and along the pipeline route may contribute to new royalty revenues for the State.

2. Local and regional requirements for petroleum products: In selling its RIK gas the State becomes another seller in the same market where the State's RIV gas is sold. Offering the State's gas at market prices should not adversely affect the market for ANS gas in the State.

3. Desirability of localized capital investment, increased payroll, and secondary development effects: Depending on the commitments that buyers are willing to make, the sale may yield new investments and other economic benefits in addition to the direct revenues to the State.

4. The social impacts of the sale: No incremental social impacts are projected as a result of the RIK gas sale.

5. Additional costs to state and local governments caused by the development related to the proposed sale: No impact is projected on state and local governments. Any gas sold through the proposed RIK sale would otherwise also have been produced and sold at a lower value as RIV gas. No additional construction projects are assured as a result of this sale.

6. Local and regional labor market: The proposed RIK sale, itself, will have no direct effect in state labor markets, but it might affect the timing of development. If projects that have been proposed for use of the State's RIK gas are developed, there will be a beneficial effect on labor markets through construction projects and operational needs.

7. Environmental effects: The RIK sale by itself will have no negative incremental environmental effect.

8. Impacts on existing private commercial enterprises and investment patterns: Local uses of ANS gas could compete with other higher-priced energy supplies. However, the wholesale and retail markets for local gas will have more affect than the proposed sale will on the price and availability of ANS gas for local consumers, commercial and industrial users, and power generators. If the State's RIK gas is sold at lower prices than alternative fuels, existing private enterprises may realize lower costs and output growth. Incremental economic benefits are not assured by an RIK gas sale.

VI. CONCLUSION

Based on the considerations discussed above, the Commissioner has determined that it is in the best interests of the State to solicit purchase offers at this time for a competitive sale of a portion

of the State's royalty share of natural gas that may be produced from Alaska's North Slope upon completion of a natural gas pipeline.

A person affected by this decision may request reconsideration in accordance with 11 AAC 02. Any reconsideration request must be received by **January 15, 2002** and may be mailed or delivered to Pat Pourchot, Commissioner, Department of Natural Resources, 550 W. 7th Ave, Suite 1400, Anchorage, Alaska 99501; faxed to 1-907-269-8918; or sent by electronic mail to dnr_appeals@dnr.state.ak.us. If reconsideration is not requested by the deadline, this decision goes into effect as a final order and decision on January 25, 2002.

Failure of the commissioner to act on a request for reconsideration within 30 days after issuance of this decision is a denial of reconsideration and is a final administrative order and decision for purposes of an appeal to Superior Court. The decision may be appealed to Superior Court within a further 30 days in accordance with the rules of the court, and to the extent permitted by applicable law. An eligible person must first request reconsideration of this decision in accordance with 11 AAC 02 before appealing this decision to Superior Court. A copy of 11 AAC 02 may be obtained from any regional information office of the Department of Natural Resources.

<Signed>
Pat Pourchot, Commissioner

December 26, 2001
Date

Appendix A: Comments on the Preliminary Finding

By the November 30, 2001 deadline for comments listed in the Preliminary Finding, the State had received letters from Ken Thompson, Anadarko Petroleum Corporation, Phillips Alaska, Inc. and BP Exploration (Alaska) Inc. AEC Marketing (USA), Inc. sent a letter and written testimony to the Royalty Board on November 9, 2001. AEC Marketing also sent a letter commenting on the Preliminary Finding received by the department after the November 30, 2001 deadline. Williams Energy Marketing and Trading sent comments on the Preliminary Finding in a letter dated December 6, 2001.

A public hearing was held November 13, 2001 before the Alaska Royalty Oil and Gas Development Advisory Board.

- Anadarko testified in favor of the sale.
- AEC Marketing also in favor of the sale and timing.



AEC MARKETING

3900, 421 - 7th Avenue S.W.
Calgary, Alberta, Canada T2P 4K9
Phone (403) 266-8111
Fax (403) 266-9746
www.aec.ca

November 9, 2001

Alaska Oil and Gas Royalty Development Advisory Board
c/o Alaska Division of Oil and Gas
550 W. 7th Ave., Suite 800
Anchorage, AK 99501

Attention: Mr. Kevin Banks
Petroleum Market Analyst

This letter is in support of the Preliminary Finding and Determination to Sell Alaska North Slope Royalty Gas in a Competitive Sale ("Preliminary Finding") issued on October 29, 2001. AEC strongly advocates the sale of royalty-in-kind gas and the timeline and process set forth within the Preliminary Finding.

We are confident the proposed royalty gas sale is in the State's best interest and that now is opportune time for the State to capture the maximum benefit from their royalty gas. We also believe initiating the royalty-in-kind process and finalizing the awarded gas sales contracts as soon as possible is critical for current and future gas exploration within Alaska.

Attached is AEC's testimony in support of the Preliminary Finding. If you have any questions, please contact Alan Sharp at (403) 261-2560.

Sincerely,

Alan Sharp
Director, Northern Business Development

Hand Delivered - mmc

Alaska Royalty Oil and Gas Development Advisory Board

Alaska North Slope Royalty Gas in a Competitive Sale

Atwood Building, Room 240 at 9:00am

November 13, 2001

Hearing: To discuss the merits and solicit public testimony on the proposed sale and the Preliminary Finding and Determination to Sell Alaska North Slope Royalty Gas in a Competitive Sale ("Preliminary Finding").

Witness: Mr. Alan Sharp, Advisor to AEC Marketing (USA) Inc.

Testimony: Good morning Mr. Chairman and members of the committee. My name is Alan Sharp. I am the Director of Northern Business Development for AEC Marketing and advisor to AEC Marketing (USA) Inc. ("AMUS"). AMUS is an indirect, wholly-owned subsidiary of Alberta Energy Company Ltd. ("AEC"). One of my key responsibilities is to advise AMUS on Alaska natural gas pipeline issues. Such issues include commercialization of Alaska natural gas, which entails access to a pipeline under fair and acceptable terms and conditions.

I would like to start by giving you a brief background on AEC. We are Canada's largest natural gas producer and one of North America's largest independent oil and gas producers. In 2001, our daily production is expected to exceed 370,000 barrels of oil equivalent. Our current daily sales gas production is approximately 1.5 Bcf/d (November 2001 estimate).

AEC is focused on *Growth, Value and Performance* as it builds a Super-Independent oil and gas company. This strategy capitalizes on the world-class assets and high-quality, long-life reserves that AEC has established in its three strong growth platforms - Western Canada, the U.S. Rockies and Ecuador. In 2000, the Company set a target to double production from existing assets within five years.

The Company is also looking to establish additional growth platforms through new venture exploration in Alaska, the Mackenzie Delta, the Gulf of Mexico, Australia, West Africa and Azerbaijan.

Midstream natural gas storage and pipelines assets comprise approximately 20 percent of the Company's asset base and provide a growing source of cash flow. Currently, AEC's enterprise value is approximately US\$9 billion.

In Alaska, AEC's U.S. subsidiary has over 1.1 million net acres in the Central Arctic region of the North Slope (i.e., Foothills of the Brooks Range). We have vast experience in the exploration, development, production and marketing of natural gas and have come to Alaska to explore for new non-associated gas reserves.

1. The first question I would like to address is why we need to establish a royalty gas sales arrangement now.

- The Alaska Gas Producer Pipeline Team ("AGPPT") has informed us that an open season for nominating capacity on an Alaska gas pipeline could occur as early as the first quarter of 2002.
- AEC's U.S. subsidiary and Anadarko are actively exploring in the Foothills of the Brooks Range, however, we will not have proven gas reserves by 2002. Therefore, nominating for firm capacity in the open season is extremely risky from a financial exposure standpoint.
- As you are aware, there are over 30 Tcf of proven gas reserves on the North Slope. Assuming a 4 Bcf/d capacity pipeline, this pipeline would be full for over 20 years. (Note that in the Oct. 2, 2001 testimony to the US Senate Committee on Energy and Natural Resources, Phillips AK Inc. indicated the pipeline would be full for over 30 years). We have a concern that if we do not obtain firm service in the first open season, we may never be able to acquire capacity on the pipeline. Without some assurance concerning pipeline capacity, continued investment in new Alaska gas exploration is unlikely.

- To reduce the risks of capacity nomination and to ensure continued exploration expenditures, Anadarko and AMUS are interested in purchasing state royalty gas to backstop, if needed, any potential nominations for capacity during an open season. We understand that a royalty sales process takes some time and requires legislative approval. We also understand legislative approval is only available from January to May of any given year, restricting the timeframe that a royalty-in-kind sale could be approved.
- We strongly support the State's Preliminary Finding and the timeline for royalty-in-kind gas sales within. Initiating the royalty-in-kind process and finalizing the awarded sales contracts as soon as possible is critical for current and future gas exploration within Alaska.

2. The second question is what benefits do we and the royalty gas sale offer the State.

- We believe that a sale of royalty gas is beneficial to both the state and to companies like ours who are interested in exploring in Alaska for new gas resources. This exploration is a benefit to the State of Alaska and is in addition to the cash bonuses and price premiums as described in the Preliminary Report.
- Our focus is on non-associated gas in the Foothills. If successful, the State will have new incremental proven and developed gas reserves, plus a more stable and higher State royalty revenue (By this, I mean lowering the State's dependence on oil revenue and its associated gas). Non-associated gas also allows the State to consider enhanced oil recovery projects while still maintaining a stable revenue stream.
- As mentioned earlier, the existing proven reserves in Alaska would likely fill a 4 Bcf/d pipeline for 20-30 years. If additional pipeline capacity were not added, this would likely mean no gas exploration in Alaska for 20 years, as new entrants would not be able to obtain access to the pipeline. As for the AGPPT, they would not need to explore for new incremental gas reserves for about 20 years. By providing royalty gas to explorers like us, the State can ensure exploration will continue to take place in areas that would otherwise remain unexplored.
- We believe the State should leverage its gas volumes of tomorrow to support gas exploration projects of today. The State has no risk, as this is a natural hedge. If the pipeline does not proceed, the State would have no obligation to deliver contracted future royalty gas volumes under those circumstances. The benefits are greater exploration and greater revenues, which is one reason why the Preliminary Finding is recommending the royalty gas sale.
- The more players (producers and explorers) on the North Slope, the more competition that will be created. More competition leads to lower costs and higher royalty revenues for the State.
- The royalty gas sale would help counter the dominant market position held by the AGPPT. AGPPT owns practically all of Alaska's proven gas reserves. Thus, they have the power to influence :
 - a. future exploration and development of new gas resources in Alaska, and
 - b. the rates, terms and conditions of pipeline service, whether as owners of the proposed Alaska gas pipeline or as anchor-shippers.
- More players likely means more jobs for Alaskans. The money we spend exploring and, if successful, developing the Foothills will have a positive multiplier effect on the economy.
- More players will likely contribute to the earlier commercialization of Alaska gas and the successful completion of the pipeline to Canadian and Lower 48 markets.
- We do not require all of the State's royalty gas. The remaining royalty gas could be used for future in-State use and for establishing a meaningful royalty-in-value price.
- AEC is Canada's largest gas producer. One of our core competencies is marketing natural gas in Canada and its interconnected Lower 48 markets. By teaming with AEC, the State will have one of Canada's best producer/marketers working with them. In 2000, AEC had the highest netback gas price compared to the top 23 Canadian producer/marketing companies.
- If our exploration efforts are successful, we will not need to purchase the State's royalty gas. The State will then be free to re-market the royalty gas to other parties, while receiving all the same benefits mentioned above.

3. The third question is do we have any specific comments on the terms laid out in the Preliminary Finding.

- Since the pipeline has not been built yet and actual gas sales will not occur for sometime in the future, we believe the State should leave as many terms and conditions open as possible for the Bidder. This will allow for maximum creativity and innovation. This should also maximize the potential value available to the State.
- We believe the proposed royalty gas sale is in the State's best interest and strongly support the Preliminary Finding. Now is opportune time for the State to capture the maximum benefit from its royalty gas.



2001 NOV 16 PM 3 19

November 12, 2001

Alaska Oil and Gas Royalty Development Advisory Board
c/o Alaska Division of Oil and Gas
550 W. 7th Ave, Suite 800
Anchorage, AK 99501
Attn: Mr. Kevin Banks

Dear Royalty Board:

This letter is being sent in support of the Preliminary Finding and Determination for a Competitive Sale of Alaska North Slope Royalty Gas ("Preliminary Finding") issued on October 29, 2001. Anadarko is a strong advocate of the State's efforts to solicit bids for the State's Royalty gas in accordance with the timeline set forth in the Preliminary Finding. The royalty in-kind ("RIK") bid process timing is critical to current, future, and continued natural gas exploration within the State of Alaska.

Securing access to the proposed natural gas pipeline from the North Slope is a necessity for the continued exploration for natural gas within the State of Alaska. We believe that the gas pipeline capacity will be fully subscribed at the outset. Therefore, failure to secure firm transportation now could result in Anadarko's prospective gas discoveries being stranded without any means to produce and sell the gas. However, without proven gas reserves it will be extremely risky for exploration companies, such as Anadarko, to commit to firm transportation services on the gas pipeline. Firm transportation services entail substantial monthly demand charges that must be paid regardless of whether or not the shipper tenders gas volumes to the pipeline. We anticipate that the demand charges associated with the minimum economic field size in the Foothills region will likely be on the order of \$180 million per annum.

A RIK bid process would allow an opportunity for an exploration company to purchase the State's royalty gas in conjunction with bidding for firm transportation on the future natural gas pipeline. The RIK bid process timing is critical inasmuch as the Alaska Gas Producers Pipeline Team ("AGPPT") that is studying the natural gas pipeline feasibility has publicly stated that an open season for securing capacity on the pipeline could occur in the first or second quarter of 2002.

Conducting this RIK bid process at this point in time capitalizes upon the substantial current interest in the State's royalty gas from a number of diverse industry players. Since firm capacity is expected to be required to market North Slope natural gas and given the expectation of an early 2002 open season, it is expected that now is the optimal time for the State to secure maximum value for its royalty gas. With numerous expressions of interest in the State's royalty gas, it is expected that the competition for the State's royalty gas will be substantial.

In addition, the RIK bid process creates an opportunity for the State to capture real economic value for its royalty gas volumes years before the State will actually have royalty gas volumes available to sell. The gas pipeline needed to market North Slope gas reserves is not likely to be constructed and placed in service until the 2008 - 2010 timeframe.

Given the Preliminary Finding's requirement for a minimum cash bonus and/or cash option payments, in all likelihood the State will realize some form of substantial compensation for its royalty gas volumes some seven (7) to nine (9) years in advance of production and sales. In addition, certain bid structures may entail commitments to in-state investments as outlined in the Preliminary Finding. Such investments would yield substantial economic benefits to the State in terms of incremental investments, increased tax revenue, new employment creation, and similar socioeconomic benefits.

Lastly, given the basic premise and mandate that any winning bid must yield the State a royalty price of not less than the price it would have otherwise received had it sold the gas as royalty in value ("RIV"), there appears to be absolutely no downside to this initiative by the Department of Natural Resources. By definition and structure of the Preliminary Finding, the State will be revenue neutral at worst, but is mostly likely to generate a substantial incremental value to the State along with acceleration of values and benefits vis-a-vis the RIV option. The economic benefits expected from this RIK bid process will accrue to the State in the form of increased State revenues, employment gains, and potential improvements in the standard of living for Alaskan residents.

Holding this bid process now is both appropriate and critical in terms of optimizing and capitalizing upon the opportunities and competitiveness for the State's royalty gas. A timely process will preserve the maximum number of options for the use of State royalty gas, it will help the State better understand the possible uses for its gas, and as has been described above, it is critical to current, future, and continued Alaska natural gas exploration. As a company keenly interested in bidding for the State's RIK gas we appreciate this opportunity to support the process and provide comments. We are confident that this arrangement will provide significant benefits to and be in the best interest of the State of Alaska.

Respectfully yours,

A handwritten signature in dark ink, appearing to read 'D. D. Anderson', with a long horizontal flourish extending to the right.

David D. Anderson
Manager, International Commercial Development

Kevin Banks

From: Ken Thompson [ken@pacrimldr.com]
Sent: Monday, November 19, 2001 2:26 PM
To: krb@dnr.state.ak.us
Cc: Mike Navarre; Ken Freeman; Bonnie Robson
Subject: My Public Comments re; RIK Sale

Thank you for allowing the public to comment on the "Preliminary Finding and Determination for a Competitive Sale of Alaska North Slope Royalty Gas". Below are my personal comments regarding the bidding and potential sale of the State's "royalty in kind" volumes of natural gas from the North Slope.

1) This process, the first of its kind for North Slope RIK gas in Alaska, is being accelerated primarily based on "speculation" that the major producers may hold an open season for nominations in the first quarter, 2002. I suggest a letter from the State be mailed immediately to the three major North Slope producers with a copy to FERC asking these three companies to let the State know by mid-December if an open season is indeed planned for the first quarter, 2002, or not. Also asking this of the new Foothills Pipeline consortium would be wise, in my opinion. While the producers may not tell the State, having documentation either way that the Producers were giving - or not giving - the State adequate real notice would be advantageous to have.

2) The current DNR commissioned study underway by Econ1 regarding the current and forecasted supply/demand for natural gas within the state should be completed and analyzed first before the step of "Publish Final Finding and Invitation to Bid". This may mean that the date of December 12 for the "Publish Final Finding" be delayed some. With analysis of the details in the Econ1 study, the state should assess what portion of the royalty gas must be held off the bid table, or bid but specified for instate use, before the "Final Finding" is mailed. While the "Preliminary Finding" says the state is allowed to keep gas for instate use and that the state will allow only a portion of RIK gas to be bid on, I think it is very important to be more exact. For example, for energy security within the state, it is my opinion that a volume of state RIK gas deliverability from the North Slope be held for replacement of the natural gas shortfall in residential and commercial use from the Cook Inlet. The State should not forecast exploration success in the Cook Inlet to replace this 2006-2008 gas deliverability shortfall which you're aware of, but should be able to fully supply the Anchorage and Cook Inlet increasing gas needs from the North Slope RIK gas or certainly plan to if needed. Considering this, the amount of RIK gas that can be bid on may be less than 250 MMCFD of the total 500 MMCFD if a gross sale is 4 BCFD.

2) For the reason mentioned above and to allow for flexibility for additional bidding packages of RIK gas, it may be wise in this "first pass" of bidding in January, 2002, that no more than 100-250 MMCFD be allowed in this initial bidding package. Bidding in smaller packages is also advantageous in that the State should not want a small gas explorer or producer on the North Slope interested in securing pipeline capacity to "corner" all the available RIK bid capacity or else other smaller explorers would be disadvantaged.

3) I would also suggest with future uncertainty in Cook Inlet gas supply post 2010 that the term of this first bid package be no more than 5 years for the 100-250 MMCFD.

4) If this effort proceeds to bidding and two or more acceptable bids are obtained, the State might choose to accept two bids instead of one to create more future competition for gas marketing, keeping various players interested and involved.

5) It would be advantageous for the State to specify in the "Final Finding" that a North Slope netback wellhead price be presented in a bid for certain volumes. If all bids are quoted as a Lower 48 hub price minus transportation, this still leaves speculation and uncertainty to the netback wellhead price as pipeline tariffs are not yet known. However, if a bidder would step out, take the lead and risk by bidding a netback wellhead price that is acceptable, this would be very significant for Alaska, in my opinion. Such an acceptable absolute price would cross for the first time in Alaska history the "reasonable price" stipulation in the North Slope leases, triggering Producers to also have to consider selling at this price or be in violation of lease terms. This could be

leveraging as these Producers make decisions next year to sell their gas or not.

6) It should be clear that the natural gas liquids in the RIK gas should be separately bid and sold separately based on liquids prices versus a BTU adjusted price.

Please feel free to reply by e-mail or to phone me at 770-1600 if you have questions of me regarding these comments. Thanks again for the chance to provide input.

Sincerely, Ken Thompson
(Past President of ARCO Alaska, Inc. (retired) and currently President, Pacific Rim Leadership Development, LLC)

11/20/2001

November 27, 2001

2001 NOV 28 AM 

Division of Oil and Gas
550 W. 7th Ave, Suite 800
Anchorage, AK 99501
Attn: Mr. Kevin Banks, Petroleum Market Analyst

Re: Preliminary Finding and Determination for a
Competitive Sale of Alaskan North Slope Royalty Gas

Dear Mr. Banks,

In accordance with the provisions of the captioned October 29, 2001 Preliminary Finding, Anadarko Petroleum Corporation submits the following comments for the State of Alaska Department of Natural Resources' and the Alaska Oil and Gas Royalty Board's consideration in the preparation of the "Final Finding" and the related "Invitation to Bid". We would also like to take this opportunity to reiterate our support for this royalty in-kind sales process as set forth in our letter of November 12, 2001 (copy attached).

Although not specified in our November 12 letter of support, we believe that the present is the optimal time for the State to hold this competitive royalty gas sale due in large part to the significant difference between oil pipeline access mechanics and natural gas pipeline access procedures.

Oil pipelines falling under Federal regulations operate as "common carriers" by which all parties seeking transportation are afforded access on a *pro rata* basis. However, natural gas pipelines covered by Federal jurisdiction function as "contract carriage" pipelines. Contract carriage pipelines contract out capacity to potential shippers for fixed terms. Shippers can secure capacity on a "firm" basis meaning such capacity is exclusively available to such shippers. If the pipeline contracts all of its effective capacity under "firm" arrangements, no capacity would be available to subsequent shippers seeking capacity.

We anticipate that the proposed Alaskan gas pipeline serving the North Slope will be fully subscribed with firm service shippers during the open season process. Once all of the pipeline's capacity is let as the firm service, the universe of practical potential State royalty gas purchasers will be fixed to the limited number of shippers successfully securing such firm transportation capacity.

Therefore, in order to ensure that the maximum number of parties compete for the State's royalty gas and thereby ensuring the most attractive bids, the State is correct in proceeding with this bid process before the pipeline open season. After the open season and probable allocation of all of the pipeline capacity on a firm basis, there will likely be fewer potential bidders for the State's royalty gas.

Our questions and comments related to the Preliminary Finding are as follows:

1. Quantity:

Section I. C. on page 4 of the Preliminary Finding indicates that the "Invitation to Bid" will specify the quantity of gas offered for sale. In order to retain the maximum creativity of the potential proposals in response to the Invitation to Bid, we suggest that the State not limit the quantity of royalty gas to be made available, at least not at this early stage of the process. It is further suggested that if any quantity limit is imposed, that such limit be set at the absolute highest volume reasonably acceptable to the State.

2. Term:

As with quantity above, we believe that leaving the term unspecified in the "Invitation to Bid" will allow for more creativity in the potential bids. However, Section II.C. in the Preliminary Finding lends some confusion as to the length of an acceptable term. Section II.C. references a preference for a relatively short term, yet indicates that a term commensurate with the term of the firm transportation may be acceptable. We believe that it would be mutually beneficial to provide greater guidance as to an acceptable term length in the Final Finding and the Invitation to Bid. However, we recommend that an absolute term maximum not be set out in the Invitation to Bid as it may reduce bid creativity.

3. Delivery Point:

Section II.C. in the Preliminary Finding indicates that the delivery point will be defined in the Invitation to Bid. Section III.A. of the Preliminary Finding indicates that there are a number of generic locations that could be established for the Point of Delivery. The selection of the Point of Delivery is a critical matter and it may be more appropriate to defer a final determination of the Point of Delivery until negotiation of the definitive gas purchase and sales agreement following bid award.

It is anticipated that the natural gas subject to this bid process will require conditioning for the extraction of diluents; specifically CO₂. As such, it may be better for the State to secure conditioning services for the royalty gas prior to delivery to the purchaser, as the State will likely have more leverage than the buyer in negotiating fair and reasonable conditioning fees.

4. **Proposed RIK Gas Supply Contract:**

Section I.C. indicates that an RIK gas supply contract will accompany the Invitation to Bid. We recommend that the Final Finding and Invitation to Bid clarify that the subject contract will be a basis for contract negotiations and not non-negotiable. Also, in an effort to shorten the fairly substantial time required to finalize this bid process, we would recommend that the subject contract be tendered to potential bidders as soon as practicable in order that constructive comments may be provided by potential bidders.

5. **Allocations of RIK Volumes:**

The next to last paragraph in Section I.C. leaves open the potential for multiple awards of RIK gas volumes. We would like to take this opportunity to observe that for a number of bidders, there is a minimum quantity of RIK gas required in order to satisfy the bidders' objectives for the RIK gas. For some bidders, such as ourselves, the minimum quantity is quite substantial. We would caution against the inclination to make multiple awards in an effort to appease numerous bidding parties at the risk of undermining the needs of legitimate bidders requiring large quantities to fulfill their needs.

Given our concern as to minimum volumetric thresholds, we request that the Final Finding and Invitation to Bid contain a provision that allows a successful bidder to withdraw its bid if it is awarded a quantity substantial less than the quantity bid for.

6. **Propose No Bidder-Initiated Contact After Bid Opening:**

Given the fact that the terms of all bids will be publicly announced at the "Bid Opening", we recommend that the Final Finding and Invitation to Bid expressly state that no bidder may initiate contact with the Division of Oil and Gas or the Alaska Oil and Gas Royalty Board after bids are revealed at the Bid Opening. We are concerned that absent such a pronouncement, there will be substantial temptation for bidders to enhance their bids based upon the information disclosed by competing bids revealed at the Bid Opening.

7. **Minimum Cash Bonus Bid:**

It is unclear whether this bonus is only assessed against the winning bidder, or whether this is a non-refundable payment due from all bidders as a prerequisite to bidding. This point should be clarified in the Final Finding and Invitation to Bid. Our preference would be that such payments would be refunded unless the bidding party is awarded RIK gas purchases.

8. Base Price Determination:

We suggest that the Final Finding and Invitation to Bid clarify that the RIK gas price paid will not be used in the determination of the RIV gas price. Per Section II.A. of the Preliminary Finding, the RIV gas price is computed based upon the higher of a number of valuation criterion, including the prices received by producers in the field.

By definition, the RIK price will be higher than the RIV price inasmuch as the RIK price will include a premium price added to the RIV Base Price. This creates a circular process wherein the RIK premium price could be factored into the RIV price thereby escalating the RIV and RIK prices without end.

This circular deficiency also arises if one or more of the dominant North Slope gas producers is awarded purchase of the State's RIK volumes. The Base Price for purposes of bidding for the RIK gas is the weighted average RIV price resulting from the sale of North Slope gas. The three largest North Slope gas producers hold over 90% of the proven gas reserves on the Slope. As such, their respective gas sales prices will be prominent in the determination of the RIV sourced Base Price. If one or more of the dominant North Slope gas producers is awarded RIK gas purchases, there could be incentive for that party to manipulate the RIV price in order to minimize the RIK Base Price.

9. Base Price Determination Intent:

Section II.A of the Preliminary Finding contains a discussion of the Base Price determination and in particular the "netback" nature of determining the RIV price. We believe that it would be mutually beneficial to incorporate such a discussion in the Final Finding as well. In fact, we believe that further clarification in the Final Finding, Invitation to Bid, and draft gas supply contract could serve to reduce ambiguity and potential dispute as to the intended determination of the RIV price.

Inasmuch as the RIV price represents the Base Price for RIK pricing, accurate understanding and application of the RIV price is of paramount importance. Any further explanation and/or language that could serve to reduce some of the uncertainty in the determination of the RIV price would serve all interested parties well.

10. Limitation on Base Price Redetermination:

Section II.A of the Preliminary Finding addresses the fact that the RIK Base Price may be subject to modification through audit and dispute resolution for years. In order to limit some of the risk associated with the uncertainty of and administration of the RIV Base Price, we request that the Department of Natural Resources and the Alaska Oil and Gas Royalty Board seriously consider adopting a reasonable statute of limitations for adjustment of the RIV price to be

used as the Base Price for RIK gas pricing. We would suggest a two-year audit cutoff and limit any adjustments beyond the two-year audit constraint to those adjustments arising out of resolution of audit claims which occurred within the two-year audit cycle.

11. In-State Investment Performance Obligations:

The last paragraph in Section II.B. of the Preliminary Finding outlines the potential remedies for the State in the event a bidder fails to carry out in-State investments contained within the bidder's RIK purchase proposal. Given the fact that in-State investments could be given material weighting in the evaluation of bids, we recommend that the Final Finding and Invitation to Bid documents adopt one or more of the more punitive recourses set out in the Preliminary finding.

In particular, there would not appear to be much downside risk to embellishing and/or renegeing on in-State investment elements of one's bid if the only consequence for failure to perform such investments was a cancellation of the sales contract, or a reduction in sales volumes.

12. Delivery Quantity:

Section II.C. of the Preliminary Finding states that the prospective buyer must be willing to accept the risk of receiving more or less than the desired quantity. We suggest that this concept be softened somewhat in the Final Finding and Invitation to Bid documents. In the event the State's RIK volumes exceed the expected volumes, the buyer may be operationally precluded from purchasing the excess volumes if such volumes exceed the buyer's firm transportation capacity and no interruptible transportation service is available on the pipeline at the time.

We would suggest that the Final Finding, Invitation to Bid, and draft gas supply contract address this situation such that the buyer would be under a best efforts obligation to purchase such excess volumes.

13. RIK Supply Source:

The last sentence of Section II.C. affords the State the right to supply the contract quantity of RIK gas from either or both the Prudhoe Bay Unit and the Point Thomson Unit. Given the potential differences between the handling of Field Costs between these units, such unlimited discretion could be materially detrimental to the buyer.

It is our understanding that the purchaser will have to bear Field Costs for some Point Thomson Unit volumes attributable to Form DL-1 leases. If we understand the issue correctly, if the State receives royalty in-value from the

subject Point Thomson leases, the State does not have to bear Field Costs. If, however, the State takes its royalty volumes attributable to these leases in-kind, the State must bear the associated Field Costs.

We would suggest that unless and until such time as the State's total RIK volumes reach a volumetric level requiring the taking of gas from such leases, it would be in both the State's and the purchaser's best interest to preferentially take RIK volumes from those leases not affected by this Field Cost issue.

We would suggest that the Final Finding, Invitation to Bid, and draft gas supply contract address this situation such that, to the extent possible, RIK volumes shall first be sourced from available State RIK volumes other than those attributable to DL-1 leases within the Point Thomson Unit. If, however, the total State RIK quantities being sold to all purchasers requires the taking of volumes from Point Thomson Unit DL-1 leases, then such more costly Point Thomson Unit DL-1 lease RIK volumes shall be allocated to all RIK gas purchasers on a *pro rata* basis.

For instance, if the PTU DL-1 leases represent five percent (5%) of the total available State North Slope RIK gas volumes, then five percent (5%) of the RIK gas allocated to the purchasers should be attributable to PTU DL-1 lease gas.

14. Conditions Precedent:

We would suggest that the Final Finding, Invitation to Bid, and draft gas supply contract contain the added condition precedent that if no open season has occurred prior to April 30, 2005, either buyer or seller may terminate the contract and commitments made by the respective parties.

In addition, given the real potential for substantial delays in the construction of this pipeline that may be well beyond the reasonable control of the State and buyer, such as an inability to secure rights-of-way across First Nations lands in Canada, we would suggest that the 2011 pipeline completion stipulation be revised along the lines of:

"Either party may terminate the contract and shall be under no further obligation to the other party in the event that an ANS gas pipeline has not been placed in-service by December 31, 2011. Provided, however, if buyer has secured firm transportation service on the pipeline for RIK gas purchases and is unable to terminate its firm transportation obligations with the pipeline despite its best efforts to do so, the State agrees that it will defer its right to terminate the RIK gas purchase contract for a two year period ending December 31, 2013."

15. Field and Conditioning Costs:

We suggest that the language set out in Section III.B should be revised consistent with our comment No. 3 above concerning the location of the Point of Delivery. As we understand the Field Costs situation, through various settlement agreements, the State bears its proportionate share of Field Costs as to royalty gas volumes from the Prudhoe Bay Unit regardless of whether the State takes its gas in-kind or in-value. However, under certain leases within the Point Thomson Unit, the State does not bear its proportionate share of Field Costs as to royalty taken in-value, but does bear these costs for volumes taken in-kind.

We recognize the State's requirement that any RIK sales must yield the State a value equal to or greater than the value the State could have otherwise received through sales of royalty gas in-value. We further recognize that any RIK gas sold which bears a Field Cost that the State would not have otherwise incurred must be borne by the buyer. However, we believe clarification of this point is warranted in the Final Finding, Invitation to Bid, and draft gas supply contract.

However, we are unclear as to whether or not the State bears its proportionate share of gas conditioning costs under the terms of the leases held by the unit owners. If the costs associated with gas conditioning do not follow the same logic and process set out above for Field Costs, then the appropriate handling of these costs need to be addressed in the Final Finding, Invitation to Bid, and draft gas supply contract.

The handling of Field and Conditioning Costs is a complex matter and is interrelated with the established Point of Delivery and the disbursement of proceeds procedures. We suggest that this complex issue be better developed in the Final Finding, Invitation to Bid, and draft gas supply contract.

At a minimum, we believe that the Final Finding, Invitation to Bid, and draft gas supply contract should clearly state that the Base Price derived from the weighted average RIV price is intended to reflect the netback market price for North Slope natural gas sales, after deduction of all actual pipeline tariffs, treating and conditioning fees, and Field Costs that are normally borne by the State in a royalty in-value sale. The buyer shall only be responsible for keeping the State whole as to Field Costs related to quantities of gas attributable to leases that would not bear such costs in a royalty in-value mode.

16. Default Notice and Termination:

The timing set forth in the second bullet point in Section III.E. of the Preliminary Finding is unreasonably restrictive. In all likelihood, the winning bidder under this process will be a large company. Given the substantial segregation of duties within large organizations it is unreasonable to grant the

State the right to suspend performance or terminate the contract if the buyer fails to make full payment within one day's notice that payment is past due.

We strongly recommend that the Final Finding, Invitation to Bid, and draft gas supply contract address this issue with a more reasonable default timeframe. In a large organization it is very likely that a default notice may not reach the attention of levels of management empowered to facilitate such payments within the one day timeframe set forth in the Preliminary Finding.

17. Interpretation of Terms and Conditions:

We request that the language contained in Section III.G. in the Preliminary Finding addressing dispute resolution be modified in the Final Finding, Invitation to Bid, and draft gas supply contract to clarify that the Commissioner's finding may be appealed in court. As currently drafted, it appears that the Commissioner's finding is final. Inasmuch as the Commissioner serves a critical role in the negotiation and application of the RIK gas sales contract in his/her capacity as a representative for the State, his or her findings may fall short of a disinterested, objective assessment of any dispute under the terms of the contract.

18. Other Provisions – Preservation of Intent:

The last sentence in Section III.G. of the Preliminary Finding indicates that the gas sales and purchase contract will contain a provision to facilitate modifications to the contract in order to ensure preservation of the parties' intent should changes in the market occur during the course of the contract. We support such a clause provided that the language is constructed to the mutual satisfaction of both the State and the purchaser.

The State should recognize that any RIK purchaser will be required to secure transportation services for the RIK purchase volumes and such transportation services are likely to carry substantial demand charges (ship-or-pay provisions). Therefore, it is imperative that the purchaser be afforded as much contract certainty as is reasonably possible. We strongly suggest that at a minimum the application of any such "intent preservation" provision be limited to market changes that have a material detrimental impact on the affected party.

19. Section IV. - Analysis of State Benefits:

We recommend that the next to last sentence on page 12 of this Section of the Preliminary Finding be clarified in the Final Finding. Our concern is that the mere purchase of the RIK gas may provide incentive for the purchaser to make in-State investments that it might not otherwise make. We believe the intent of the sentence in question is to state that such in-State investments cannot be induced by subsidization through below-market RIK sales terms. In fact, the

preceding sentence makes specific reference to subsidization prohibitions. We simply request that the Final Finding clarify that an RIK sale alone, which results in incremental in-State investments is not contrary to State regulations so long as such RIK sales terms are not below-market or subsidized.

We thank you in advance for your consideration of these comments as you move forward in the drafting of the Final Order, the Invitation to Bid, and the drafting of the pro forma gas purchase and sales contract. Should you have any questions concerning these comments, please feel free to contact me at 832-636-7139, or Angie Kelly at 832-636-7196.

Respectfully yours,

A handwritten signature in black ink, appearing to read "David D. Anderson", followed by a horizontal line.

David D. Anderson
Manager, International Commercial Development



PHILLIPS Alaska, Inc.
A Subsidiary of PHILLIPS PETROLEUM COMPANY

P. O. BOX 100360
ANCHORAGE, ALASKA 99510-0360
Phone (907) 265-6517

Joseph P. Marushack
Vice President, ANS Gas Commercialization

November 30, 2001

Mr. Kevin Banks, Petroleum Analyst
Department of Natural Resources, Division of Oil and Gas
550 W. 7th Ave. Suite 800
Anchorage, AK 995801

RE: Preliminary Finding and Determination for a Competitive Sale of Alaska North Slope Royalty Gas, dated October 29, 2001.

Dear Mr. Banks:

On behalf of Phillips, thank you for the opportunity to comment on the subject preliminary finding. Our comments fall into two areas: timing of the process and impact to owners of known resources.

Relative to timing, it appears to us that the royalty sale activity does not need to be so quickly paced. The preliminary finding and DNR staff comments at the November 13, 2001 public meeting both indicate that the timing of the RIK sale process is being driven by an expectation that the work of the AGPPT could result in an open season as early as January, 2002. As we have frequently indicated, the Project Team has been working to develop an economic project, obtain Federal enabling regulatory legislation and to progress a framework for fiscal clarity within Alaska. Although progress is being made in Washington, DC, the federal legislation is unlikely to be available before sometime later in 2002. Therefore, we do not foresee holding an open season during 1Q 2002. In fact, it is pre-mature to make any near-term estimates on when an open season might occur. Consequently, we suggest that any RIK sale process be deferred pending greater definition in this area.

Next, we recommend that the findings be expanded to fully consider additional potential impacts.

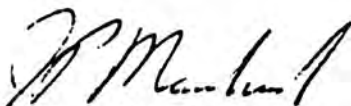
One of the stated reasons for the royalty gas sale is to provide RIK gas as a "back-stop" to gas production that companies with unexplored leases on the North Slope hope to develop. This means that if an RIK purchaser were to exercise its option to stop buying RIK gas, the existing resource owners would suffer a reduction in delivered volumes of equity gas and likely under-utilization of the gas treatment plant and any other on-lease investments made expressly for gas sales. It is the known resource owners who must make the base, long-term, throughput commitments for any pipeline project to be developed. As such our net volume must be known and not subject to reduction. The State's RIK proposal clearly seeks to transfer the benefits of those long-term commitments to new participants without transferring the associated risk. Our

fundamental concern is that this will further burden the economics of the overall project and add uncertainty at a time when we have yet to realize an economic way forward.

We believe that fair and unbiased capacity allocation and expansion procedures, as achieved through the FERC regulatory process, will assure that all gas producers, both present resource owners and potential explorers, have adequate access to transportation capacity. While the backbone of the project will be for existing reserves to be developed, the ability to expand capacity has always been a priority for Phillips and in the joint producer work effort. Creation of and access to such expansion capacity should better occur under an open and non-discriminatory basis as new sources of supply are identified and the markets demand.

Thank you for the opportunity to present these comments on the subject finding. If you desire, we would be happy to follow up these general comments with additional information. If you have any questions or concerns, please do not hesitate to contact me directly at (907) 265-6517.

Sincerely,



Joseph P. Marushack
Vice President, ANS Gas Commercialization
Phillips Alaska, Inc.

bp



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 186612
Anchorage, Alaska 99518-8612
(907) 581-5111

November 30, 2001

Mr. Kevin Banks, Petroleum Analyst
Department of Natural Resources, Division of Oil and Gas
550 W. 7th Ave. Suite 800
Anchorage, AK 995801

RE: Preliminary Finding and Determination for a Competitive Sale of Alaska North Slope Royalty Gas, dated October 29, 2001.

Dear Mr. Banks:

On behalf of both BP Exploration (Alaska) Inc. and our Gas & Power group, I would like to thank you for the opportunity to provide both written and verbal comments on the subject preliminary finding. I hope you and the other DNR staff found our meeting on November 14 beneficial.

Timing

The preliminary finding as well as comments at our meeting both indicate that the timing of this proposed RIK sale is being driven by the perception that the Alaska Gas Producers Pipeline Team may hold an "open season" for pipeline capacity as early as January 2002. We do not foresee any possibility of holding an open season during 1Q 2002 and apologize for any miscommunication in this regard. Indeed it is presently unlikely that an open season will be held anytime during 2002 unless some important government actions are progressed.

As we have stated previously, for a gas pipeline to attract investment, there must be an economic project and there must be a predictable and viable government framework in place to support investment. Both federal regulatory legislation and clarity around State tax and royalty are important pieces of this government framework.

AGPPT is currently working diligently to engineer and design a modern day gas pipeline with competitive tariffs to market, however to date costs are trending above where they need to be. Progress is being made in Washington DC on the enabling regulatory legislation, but current prognosis suggests it is unlikely that it will be available before sometime later in 2002. Finally, much work remains on progressing a framework for fiscal certainty with the State of Alaska and this proposed RIK sale actually highlights the uncertainty of the current fiscal framework under which we must evaluate the economics of this project.

Impact on the Economic Viability of Pipeline Project

As currently structured, this RIK gas sale is being pursued to provide a free capacity access option to parties without proven gas reserves. If the sale proceeds with an option to switch between RIK and RIV on short notice, overall project economics would be materially burdened by the uncertainty in equity gas sales volumes of the known resource owners who will need to make binding contractual commitments to ship gas for many years. This burden on an already marginal project is a clear step in the wrong direction. Such a burden would make it unlikely that producers would subscribe to any open season unless financially compensated for the burden.

For example, an RIK purchaser could use its purchased gas as a backstop for making a firm transportation commitment on a gas line. The balance of the FT commitments to get the line built would be made by the known resource owners. Should an RIK purchaser discover its own gas resources, it could cancel its purchase contract with the state and substitute its own gas into its FT commitment. The State's gas would then revert back to the known resource owners in the form of RIV gas thus reducing the amount of equity gas that the resource owners could export via their own fixed-volume of FT commitment. This reduction would result in a loss of revenue to the known resource owners as well as result in the probable under-utilization of asset investments made at the lease level.

The State's RIK proposal clearly seeks to transfer benefits from long term investors to new participants without transferring the risk associated with the massive investment that will be required to make any gas pipeline a reality. Such subsidies at the expense of those who will ultimately underwrite any new build pipeline are both unfair and, more importantly, reduce the chances of developing an economically viable project.

We believe that fair and unbiased capacity allocation and expansion procedures already exist through the FERC regulatory processes. These processes will be sufficient to assure that all gas producers, both present resource owners and potential explorers, have adequate access to transportation capacity. If the State has reservations in this regard, we are prepared to discuss this further or to meet jointly with FERC officials to gain a full understanding of how FERC ensures fair and consistent rules of access are developed and administered.

Efforts to fix a problem that doesn't exist with economically burdensome solutions cannot be in the best interest of the State, especially if those solutions could cause a gas pipeline project not to proceed at all.

We and AGPPT have discussed this matter with the State previously and we believe our discussions on this matter have been consistent. However, we regret if we have not been clear and hope this letter will help provide additional clarity.

We respectfully request that the state refrain from taking steps that will further jeopardize the commercial viability of a pipeline project.

Page 3

Prospective Bidding

The above discussion should not be construed to mean that BP is in anyway opposed to the State marketing its royalty gas. Indeed, in the event the State wishes to market its gas in a manner consistent with fair market principles and consistent with the long-term firm transportation commitments necessary, BP could provide a fully competitive offer.

In many respects, a properly structured RIK sale could actually address part of industry's concerns around fiscal stability. Clear and transparent pricing for royalty gas would be an important step towards the fiscal clarity industry is seeking.

We would be happy to follow up these general comments with additional information and discussion at any time. Please do not hesitate to contact me directly at (907) 564-5553.

Sincerely,



Charles J. Coulson
Commercial Manager - Alaska Gas
BP Exploration (Alaska) Inc.

cc: David Welch
Ken Konrad
Pat Pourchot
Ken Freeman



AEC MARKETING (USA) INC.

3700, 707 -8th Avenue S.W.
Calgary, Alberta, Canada T2P 1H5
Phone (403) 261-2560
Fax (403) 290-8588
<http://www.aec.ca>

*rec'd via email on
12/6/01*

November 27, 2001

Department of Natural Resources
Division of Oil and Gas
550 West 7th Ave, Suite 800
Anchorage, Alaska
99501-3560

Attention: Kevin Banks
Petroleum Market Analyst

**Re: Preliminary Finding and Determination for a Competitive Sale of Alaskan North Slope
Royalty Gas**

This letter is in support of Anadarko Petroleum Corporation's comments for consideration in the preparation of the "Final Finding" and the related "Invitation to Bid", as stated in their letter dated November 25, 2001 addressed to Kevin Banks.

AEC strongly advocates the sale of royalty-in-kind gas and the timeline and process set forth within the Preliminary Finding. We believe initiating the royalty-in-kind process and finalizing the awarded gas sales contracts as soon as possible is critical for current and future gas exploration within Alaska.

AEC and Anadarko are prepared to be active explorers for natural gas on the North Slope, provided we have access to the gas pipeline. Our efforts and activities will create competition and attract other gas players, which in turn will increase the State's revenue (e.g., royalties, land sales). We believe this is something unique to new explorers, which the Alaska Gas Producer Pipeline Team can not provide. An example supporting this view is BP's announcement on shutting down their frontier exploration in Alaska and switching to harvest mode.¹ AEC also believes Phillips' exploration will slow in Alaska due to their Conoco merger. We want to emphasize that when you consider the Royalty in Kind bids, there is significant upside benefit to the State that that will come from not only price premiums, but from the exploration activities of new players.

We reiterate our support for this royalty in-kind sales process as set forth in our testimony to the Royalty Board on November 13, 2001. If you have any questions, please contact Alan Sharp at (403) 261-2560.

Yours truly,

Alan Sharp
Director, Northern Business Development

¹ Petroleum News Alaska. Vol.6, No.18. Page 1, "What will it take to get BP's focus back on Alaska?"

RECEIVED

DEC 11 2001

DIV. OF OIL & GAS
DIRECTOR'S OFFICE



December 6, 2001

Mr. Pat Pourchot
Commissioner
State of Alaska
Department of Natural Resources
Division of Oil and Gas
550 West 7th Avenue, Suite 800
Anchorage, AK 99501-3510

Reference: *Williams Comments Submitted to The State of Alaska regarding the Preliminary Finding and Determination for a Competitive Sale of Alaska North Slope Royalty Gas ("Preliminary Finding")*

Dear Mr. Pourchot:

It is with great pleasure that Williams Energy Marketing & Trading submits comments to the State of Alaska pursuant to its request regarding the Preliminary Finding. We have reviewed the Preliminary Finding and respectfully submit the following comments and recommendations, which will become a part of the Published Final Finding and Invitation, scheduled to be published December 12, 2001:

**1. Section I – Introduction and Background
D-Schedule**

A. Proposed Schedule for the 2002 ANS RIK Natural Gas Sale

Williams Comments and/or Recommendation:

In our review of the Proposed Schedule for the 2002 ANS RIK Natural Gas Sale, we feel it is extremely restrictive and may be very difficult to administer by the State of Alaska. Williams recognizes the time constraints due to legislative approvals.

2. Section II – Developing Bid Proposals for The RIK Sale

A. To be considered, proposals must meet the following Minimum Cash Bonus Bid and Base Price Conditions

Williams Comments and/or Recommendation:

The proposed requirement to provide a Cash Bonus Bid is not a normal industry standard. The standard to qualify bidders is typically handled through a type of "Pre-Qualified Bidders Process" to screen for RFP bidders, which meets the desired criteria. Due to the preliminary nature of the pipeline project, a Cash Bonus is premature. However, as the pipeline develops as a viable project, Williams would entertain providing a Cash Advance with certain provisions for recovery.

3. Section II – Developing Bid Proposals for The RIK Sale

C. The following terms should be included in all proposals - Quantity and Transport Risk

Williams Comments and/or Recommendation:

Quantity and Transport should mirror each other in marketing your State Royalty Gas.

4. Section II – Developing Bid Proposals for The RIK Sale

C. The following terms should be included in all proposals - Term

Williams Comments and/or Recommendation

Term and Transport should mirror each other in marketing your State Royalty Gas. The industry standard transportation contract on a new proposed pipeline usually has a minimum term of ten (10) years. Williams' recommends that the State would need to evaluate longer-term structures for their sale of RIK.

Due to our recommendations related to the Cash Bonus Bid our comments are being submitted without a cash advance. I have attached a Williams Overview, which is the information we provide to our customers to Qualify Williams for Bidding. Williams Corporate Credit Rating is BBB+ rated by Standard and Poors Corporation. I have also included for your review Williams' Bank and Trade References.

We are extremely interested in marketing the State of Alaska's Royalty Gas. In addition, Williams is also interested in working with the State of Alaska and the Producer Consortium in a unified effort toward Commercializing the Alaska North Slope Gas. As you know, Williams has a full-time team dedicated to the Alaska North Slope Project.

Williams is extremely cognizant to the State's requirements for bringing In-State Value through this project. In addition, we feel we can provide some creative ideas to market the States Royalty Gas by providing increased value over RIV.

If you have any questions or need additional information, please feel free to call me at 918.573.3603 (office) or 918.645.7409 (cellular).

Sincerely,



Tamara J. Walden
Strategic Business Development
Vice President

TJW/tw

Attachments

Cc: Mark Myers, Director
Bonnie Robson, Deputy Director
Kevin Bank, Petroleum Market Analyst

Appendix B: Summary and Response to Comments

Ken Thompson

Ken Thompson, President of Pacific Rim Leadership Development, LLC and past-president of ARCO Alaska, Inc., responded to the Preliminary Finding in an e-mail dated November 19, 2001 and offered several suggestions as the State moves ahead through the sale process. The following is a summary of his comments and the department's response:

1) Mr. Thompson noted that the State has scheduled the sale process assuming that an "open season" will occur early in 2002. He recommended that State contact the three major North Slope producers to determine whether or not they were indeed planning an "open season" for the first quarter, 2002.

The producer project team has indicated to the department that no decision to hold an open season has been made as of yet. The team also said that an open season would not occur in the first quarter, 2002. The department is also aware that the Foothills Pipeline consortium has made progress to advance a pipeline project of its own and to develop a proposal for the North Slope producers. It is unlikely that an open season for a Foothills Pipeline project will occur in the first quarter, 2002.

The Royalty Board and Legislature must approve any contract(s) that the commissioner negotiates. If there is chance that a pipeline open season will occur anytime during 2002, the State still must proceed with the sale now so that the Legislature may review the contract in its upcoming 2002 session.

2) Mr. Thompson expressed his concern that RIK gas be available to supply in-state needs and advised the department to review its own study of in-state demand completed by Econ One. He recommended that there should be sufficient volumes of RIK gas to replace any potential shortfall of gas supplies in the Cook Inlet region. In a second comment on potential sale volume, he recommended that no more than 100,000 – 250,000 Mcf per day be sold in this sale (assuming total royalty gas production at 500,000 Mcf per day).

Seventy percent of the combined total royalty gas production from the Prudhoe Bay and Pt. Thomson units will be offered in this sale. The remaining 30 percent (possibly 150,000 Mcf per day) will be reserved for possible future competitive sales. In our review of proposals received as a result of the RIK sale offer, future in-state gas demand will be considered.

3) In a similar vein as number 2 above, Mr. Thompson recommends that the State limit the term of the RIK gas sale contract(s) that result from this sale to not more than 5 years.

Given the uncertainty surrounding the gas pipeline project at this stage, the State should preserve as much flexibility in a future RIK program as it can. Some potential buyers will require a RIK gas sale contract term equivalent to the term of

the firm transportation commitment they will have to make in the open season. The State's evaluation of proposals will have to balance the advantages of shorter term contracts to the State against the commercial requirements of the buyers to meet pipeline commitments.

- 4) If the notice of RIK sale yields more than one acceptable proposal, Mr. Thompson recommends that the State consider awarding more than one RIK gas sale contract and thereby create incentives among the buyers to pursue marketing opportunities for the State's RIK gas.

Together with his comments on volumes and contract term above, Mr. Thompson is recommending that the State cultivate customers who will be invited to bid in subsequent RIK sales as part of an ongoing RIK program. Such a program could very well evolve over time, in which the State sells much royalty gas in regular sales to a variety of in-state users and Lower 48 marketers. The department will continually evaluate the merits of such a program.

- 5) Mr. Thompson suggests that the sale price offered by the winning proposal could serve as an indicator of value under the lease terms. This price information could give the State some leverage as the producers make advance the pipeline projects.

It will depend on how the RIK price is ultimately calculated. The State may choose to use the RIK price in its determination of market value under the lease. Insofar as the Base Price is based on the volume-weighted average of the RIV value paid by the lessees, using the Base Price to measure RIV value would be circular.

- 6) Mr. Thompson proposes that the State offer and sell NGLs separately based on liquids prices versus a Btu-adjusted price.

The department is aware that the NGLs in the gas stream could add value to the State's royalty gas, both in terms of energy content per Mcf and also in the value per unit of energy. The requirement that the proposals provide a price that is at least equivalent to the RIV value should protect the State. The lease provisions provide that the State be fully compensated for the value of the liquids.

Anadarko Petroleum Corporation

Anadarko wrote in support of an RIK gas sale to the Royalty Board on November 12, 2001 and commented on the Preliminary Finding in a letter to the department dated November 27, 2001.

In its comments to the Royalty Board, Anadarko stressed its interest to purchase RIK gas "in conjunction with bidding for firm transportation" on the ANS gas pipeline. If Anadarko cannot participate in an open season and secure capacity on the pipeline now, its prospective gas discoveries on the North Slope may be stranded. Without RIK gas to fill a firm transportation commitment, Anadarko predicted it could face ship-or-pay demand charges on the pipeline of \$180 million per year.

Anadarko also predicted that the State could capitalize on the current interest in the State's royalty gas from a number of industry players. The requirement of a minimum cash bonus, potential option payments, and possible in-state investment commitments means that the State may realize some form of compensation for its royalty gas several years in advance of royalty production. The requirement that the price of RIK gas not be less than the value of RIV protects the State from potential downside impacts.

In its comments on the Preliminary Finding, Anadarko reiterated its desire to use RIK gas to cover its firm transportation commitments in the ANS gas pipeline. Anadarko also raised several questions about the contract terms described in the Preliminary Finding.

- 1) Anadarko encouraged the State not to limit the quantity of royalty gas offered in the sale.

The State will offer up to 70 percent of the combined total volume of royalty gas produced in the Prudhoe Bay and Pt. Thomson units.

- 2) Anadarko asked that the State not specify a contract term and instead allow potential buyers to include the length of the contract term commensurate with the term of the firm transportation commitment on the pipeline in their proposals.

The RIK offer will ask potential buyers to describe the contract term that they will require. The State recognizes that some potential buyers will require that the term of the RIK gas sale contract be equivalent to the term of their firm transportation commitments.

- 3) Anadarko asked that the State not define a Point of Delivery until the RIK gas sale contract is finally negotiated. Anadarko anticipates that the royalty gas that will be offered in this sale will require conditioning to extract CO₂ and other diluents. The State should secure these conditioning services for royalty gas prior to delivery to the RIK purchaser.

The contract defines the Point of Delivery as the location or locations where the State receives its royalty gas from the lessees. As for securing conditioning services before tendering its RIK to the buyer, the State may wish to preserve this option but will not take on the obligation to do so now.

- 4) Anadarko asked that the Final Finding include an RIK gas sale contract that will serve as the basis for contract negotiations. Anadarko also wanted the State to provide this contract to potential buyers to solicit comments.

Attached to this Finding is a copy of the *Sample Contract*.

- 5) Anadarko indicated that it would require a substantial volume of RIK to backstop the development of minimum economic gas discovery on the North Slope. For this reason it recommended that the State not award contracts to multiple bidders. The RIK sale offer should

include a provision that will allow a successful proposal to be withdrawn if it is awarded volumes that are less than the quantity proposed.

The State will make the determination to award one or more contracts on the merit of the proposals. If the award is for volumes insufficient to the winning proposal's requirements, the buyer may withdraw its proposal.

6) Anadarko is concerned that bidders not be allowed to initiate contact with the Division of Oil and Gas or the Royalty Board after proposals are revealed at the Opening.

A limitation on buyer-initiated contacts with the division must be specific to the RIK sale. The division will need to deal with some of the same buyers on many other issues. Contact with Royalty Board members by prospective RIK buyers is prohibited by 11 AAC 26.110.

7) According to Anadarko the Preliminary Finding left unclear whether the minimum cash bonus was only assessed against the winning proposal or a non-refundable payment due from all proposals.

Only the winning proposal(s) will be required to pay the minimum cash bonus. The minimum cash bonus will be refunded to buyers whose proposals are rejected. The State will also refund the minimum cash bonus if any of the conditions in Article VIII occur.

8) Anadarko suggested that the RIK gas price not be used in the determination of the RIV price because the RIK price will include a premium price added to the RIV base price.

It will depend on how the RIK price is ultimately calculated. The State may choose to use the RIK price in its determination of market value under the lease. Insofar as the Base Price is based on the volume-weighted average of the RIV value paid by the lessees, using the Base Price to measure RIV value would be circular.

9) Anadarko wants further explanation of the RIV value that appears in the discussion of the Base Price in order to reduce some of the uncertainty in its determination.

The Preliminary Finding included this discussion to provide potential buyers with an appreciation of the potential uncertainty related to the calculation of the Base Price.

10) Anadarko requested that the department consider adopting a reasonable statute of limitations for adjustment of RIV price to be used as the Base Price for RIK.

The department does not accept this recommendation.

11) Anadarko favored the requirement in the Preliminary Finding to impose some punitive recourse should the buyer fail to carry out the proposed in-state investments that appear in its proposal. This provision takes away the incentive for bidders to embellish and/or renege on the in-state investment commitments contained in their proposals.

The department has included those provisions.

12) Anadarko expressed the concern that the volume of gas sold under the contract must not exceed the buyer's firm transportation capacity.

The *Sample Contract* includes a provision that will allow the buyer to reduce its Maximum Quantities up to 50 percent upon two years advance notice. If the buyer wishes to reduce the Maximum Quantities by more than 50 percent, the buyer must pay a fee. The buyer may also adjust its monthly nomination.

13) Anadarko suggested that the State's discretion to nominate RIK gas from the Prudhoe Bay and Pt. Thomson units to supply the contract could disadvantage the buyer because of the way field costs are determined in each unit. Anadarko would prefer to take RIK gas from royalty gas sourced from leases other than the DL-1 leases within the Point Thompson Unit. If state RIK volumes sold to all buyers requires taking RIK from the Pt. Thomson Unit DL-1 leases, then the RIK from the Pt. Thomson DL-1 leases should be prorated to all buyers.

Article 3.1.5. in the *Sample Contract* addresses this issue.

14) Anadarko wants a condition precedent that will allow the buyer or seller to terminate the RIK gas sale contract if no open season has occurred prior to April 30, 2005. Anadarko also provided contract language that would allow the State or the buyer to terminate the RIK gas sale contract if the pipeline is not in-service by December 31, 2011. The State should defer its right to terminate the RIK until December 31, 2013 if the buyer is unable to terminate its firm transportation obligations.

According to Article VII of the *Sample Contract*, either party may terminate the RIK gas sale contract, if the open season for the gas pipeline is not completed by December 31, 2004. The agreement terminates if the pipeline is not in service by July 31, 2012 or no royalty gas has been delivered by that date. The State will refund the minimum cash bonus, without interest, if these conditions precedent occur. The State selected these dates to balance the requirements of potential purchasers with the State's requirements to take advantage of alternative opportunities as soon as possible should the pipeline project be delayed.

15) Anadarko raised several issues with respect to field costs and conditioning costs that may be allowed as royalty deductions in the calculation of value for RIV and RIK. It should be clear that any RIK gas that bears the field cost that the State would not have otherwise incurred must be borne by the buyer. What remains unclear to Anadarko is whether or not the State will bear a proportionate share of the gas conditioning costs. Anadarko would like to see in the RIK sale offer and the RIK gas sale contract how the Base Price based as it is on the RIV value would

include all deductions for transportation, treating and conditioning costs, field costs that might apply to RIK but not RIV.

The principle that governs the calculation of the Base Price is that the State will not be worse off for selling its royalty gas. The department cannot predict how the conditioning costs will be accounted for in the calculation of RIV value. The RIK gas sale contract will require that the purchaser pay any and all field and conditioning costs chargeable against the State's royalty share of gas subject to the contract.

16) Anadarko objected to the timing for the State to suspend performance or terminate the contract if the buyer fails to make full payment within one day's notice that payment is past due.

Article 9.1.1(i) allows two business days.

17) Anadarko recommended that the text in Section III.G. in the Preliminary Finding be redrafted in the Final Finding, RIK sale offer, and RIK gas sale contract to clarify that the Commissioner's finding under the procedures of Article XII "Interpretation of Terms and Conditions" may be appealed in court.

The buyer may appeal the commissioner's decisions. The State is unwilling to add any provision that limits its discretion and deference to its decisions.

18) Anadarko supports the inclusion of a contract provision that will facilitate changes to the RIK gas sale contract in order to preserve the intent of the parties should changes in the market occur during the course of the contract.

The department will consider a Reopener provision in Article XXVI in the *Sample Contract*.

19) Anadarko asked that the Final Finding clarify that an RIK sale that results in incremental in-State benefits is not contrary to state regulations as long as the RIK sale terms do not create a situation where the State is subsidizing the buyer.

The State has an interest in facilitating in-state investments and the State may use its RIK to achieve this goal.

AEC Marketing (USA) Inc.

AEC Marketing (USA) Inc. ("Alberta Energy") supports the RIK gas sale. In a letter dated November 9, 2001 to the Royalty Board, Alberta Energy provided a transcript of its testimony for the Royalty Board hearing. This testimony provides detailed discussion of the situation faced by new explorers in the Brook Range foothills. Alberta Energy fears that the lack of pipeline capacity could postpone production of gas from its prospective exploration targets for more than 20 years. Explorers like Alberta Energy will have to obtain firm transportation capacity in the first open season or face the possibility that an expansion of the pipeline sometime in the future

will not occur when Alberta Energy's will want to develop its prospects. The substantial risk of assuming a firm transportation commitment is a burden on Alberta Energy's exploration program. Alberta Energy is interested in RIK gas as a backstop to its own supply to fill the firm transportation commitment.

In its testimony and referenced in its comments on the Preliminary Finding dated November 27, 2001, Alberta Energy requested that the State leave as many terms and conditions open as possible for the proposals. Given the uncertainty in the details of an RIK gas sale contract, Alberta Energy feels that bidders can bring creativity and innovation to maximize value for the State.

The issue of future access to the pipeline by currently non-producers on the North Slope and potential in-state users of ANS gas prompted the State to conduct the RIK sale. While many terms in the RIK gas sale contract will be open for proposals, other terms dealing with the department's rights in normally found in recent RIK gas sale contracts are not subject to negotiation.

Williams Energy Marketing & Trading

Williams' comment letter arrived on December 6, 2001 after the November 30, 2001 deadline. Williams indicated an interest in marketing the State's ANS royalty gas and provided four comments on the sale:

1) Williams felt that the schedule for the sale was extremely restrictive and may be difficult to administer by the State.

Our schedule is driven by the need to provide RIK gas supply to potential buyers so that the buyers can participate in an open season. Although the open season, if it will occur, will not be scheduled in the first quarter, 2002. The timing of the Legislative session compels the State to hold the RIK gas sale now. Some of the milestones in the schedule published in the Preliminary Finding have been postponed to prepare the Final Finding and other sale documents and to give the State more time to negotiate with the winning proposals.

2) Williams argued that a minimum cash bonus is not a normal industry standard and rather felt that the State should pre-qualify bidders.

The minimum cash bonus is intended to cover the cost of the sale. Only the winning proposal(s) will pay the minimum cash bonus and the cash bonus will be refunded should the any of the conditions precedent in Article VIII occurs.

3) Williams recommended that the volume sold in the RIK gas sale contract equal the transportation capacity.

The buyers of the State's RIK gas will have to arrange their own transportation capacity. Buyers must indicate the volume each will require. The *Sample*

Contract included in the RIK sale offer has quantity provisions that allow for some flexibility to adjust the volume taken by the buyer to match the buyer's firm transportation commitments.

4) Williams also recommended that the term of the contract mirror the term usually found in industry-standard transportation contracts.

The State will consider proposals that include a provision to match the length of the contract term with the firm transportation commitment.

Phillips Alaska, Inc.

In a letter dated November 30, 2001, Phillips recommended that the RIK sale does not need to be so quickly paced. Phillips does not foresee holding an open season during the first quarter 2002. Phillips also said the stated reasons to hold the RIK sale to backstop future gas production from unexplored leases will burden the economics of the pipeline project. Phillips argues that the RIK sale creates a situation that the owners of the proven reserves may be reduced to make room for the new production from the unexplored leases. This reduction may lead to under-utilization of the gas treatment plant and other on-lease investments made for gas sales. This reduction will mean that the known resource owners who bear the risk of building the pipeline will be insufficiently rewarded. The RIK sale will transfer the benefits of the long-term commitments to new participants without transferring the associated risk.

Phillips recommends that fair and unbiased capacity allocation and expansion procedures can be achieved through the FERC regulatory process. Future North Slope gas producers will have access to the pipeline.

The RIK sale is scheduled to allow the Legislature in its next session to vote on the sale. If an open season is scheduled any time during 2002, the RIK gas sale contract(s) must be brought to the 2002 legislative session so that the buyers have gas supplies to fill their transportation commitments.

While an RIK sale may complicate the evaluation of a pipeline project, the ability to shift from RIK to RIV is a lease right of the State that may prove to be very important to the State. Access for explorers is one of the reasons for selling RIK gas now; in-state users may also participate in the sale. The producers acknowledge that the FERC cannot compel a pipeline owner to expand capacity. It is presumed that competitive market forces will provide the necessary incentives.

As to the impact of the RIK sale on the economics of the pipeline project, Phillips has not provided to the State a quantitative analysis. Our qualitative evaluation of the explorer backstop scenario suggest that should the explorers back out RIK gas in place of gas production from their unexplored leases, the producers are provided with the benefits of producing greater equity volumes in the first few years of pipeline operation than they would produce without the sale. After the

switch from RIK to RIV the producers will have the incentive to expand the pipeline to maintain equity volumes. An open season after initial construction could also attract new entrants including in-state users of gas. Phillips may be among those looking for space in the new expansion as its own unexplored leases begin producing.

BP Exploration (Alaska), Inc.

The language of BP's letter, dated November 30, 2001, mirrored that which appeared in the Phillips letter. BP asked that the State refrain from taking steps that would jeopardize the commercial viability of the pipeline project.

BP added that it is not opposed to the State marketing its royalty gas and suggested that it may bid in the RIK sale. BP also suggested that the RIK sale might address some of the industry's concerns about fiscal certainty for the project by providing clear and transparent pricing for royalty gas.

The State's responses to BP's critiques are the same as those listed above for Phillips. Depending on the price structure adopted for the RIK gas sale, the State may choose to refer to the RIK gas price in its evaluation of the value of RIV gas.

Appendix C: In-State Natural Gas Demand and Supply Issues

The Division of Oil and Gas has reviewed the final draft of the "Alaska Natural Gas In-State Demand Study" completed under contract for the Department of Natural Resources by Econ One Research. This report will be available by December 28, 2001. This Appendix is a summary of the study.

Baseline Conditions. The total in-state demand for natural gas was approximately 227 Bcf per year in 2000. This estimate is based on annual usage averaged over the period 1996-2000. It includes LNG exports (78 Bcf per year) and other industrial uses in Southcentral Alaska, as well as approximately 10 Bcf per year of industrial gas usage for TAPS pump station and other North Slope oil field operations (but excludes gas re-injection for enhance oil recovery). Industrial gas usage accounts for about 71 percent of the statewide total. The remainder is somewhat evenly divided between residential/commercial gas usage and gas for electric power generation in Southcentral Alaska. A modest quantity of natural gas (less than 2 Bcf per year) is consumed space heating and power in Barrow and for space heating in Fairbanks.¹

Potential for Growth in Gas Usage. In-state gas usage over the next two decades has the potential to increase by approximately 140 Bcf per year. The potential for growth in gas usage is may arise from several sources. The sources of growth and their estimated additional gas usage in 2020 are:

- Baseline economic growth (27 Bcf per year)
- Expanded residential/commercial gas service in Southcentral and Interior (7 Bcf per year)
- Expanded existing industrial usage at the Kenai Ammonia-Urea plant (4 Bcf per year)
- New plant expansion at the Kenai Ammonia-Urea plant (30 Bcf)
- New petrochemical plant (28 Bcf per year)
- Fuel switching for power generation in Interior communities (30 Bcf per year)
- Gas-by-Wire; central station power generation near Fairbanks (13 Bcf per year)

Three key assumptions underpin the preceding estimates for potential growth in gas usage: (1) relative energy prices in the future are consistent with levels observed today; (2) the state's regional economy exhibits continued gradual economic expansion at rates comparable with the past five years (about a half percent per year in real dollars); and (3) in-state access to ANS gas from a high-pressure, dense-phase gas pipeline from the North Slope to Canadian and Lower-48 destinations is not cost prohibitive.

This latter assumption merits further consideration. The results in the division's study of in-state natural gas demand and supply suggest that several factors may challenge the economics of in-state access to ANS gas. For example, under the assumptions: (1) 100 percent penetration for 11,000 residential customers, (2) a gas commodity price comparable to what ENSTAR currently pays for gas in Southcentral, and (3) a 12-year payback for the \$1,000 cost of home furnace and water heater conversion, expanded residential gas usage in the Interior region is approximately

¹ Barrow residents consume gas from local gas fields. Northern Eclipse, LLC ships daily truckloads of LNG from Southcentral Alaska to Fairbanks Natural Gas LLC, the local distribution company in Fairbanks.

competitive with electricity, the next least-cost alternative. But 100 percent penetration is not likely and a 12-year payback is not attractive.²

In effect, economies of scale for expansion of residential service to the Interior region do not appear to be sufficient to offset the levelized capital costs for gas transmission from the North Slope to Fairbanks (\$1.00 per Mcf), gasoline tap and meter/stepdown (\$0.05 per Mcf) and the corresponding distribution system (\$2.29 per Mcf).

Industrial operations in Southcentral and the North Slope account for the bulk of current gas usage. The potential for increased gas usage by greater utilization of existing industrial capacity is limited to perhaps 3-to-4 Bcf per year at the Ammonia-Urea plant in Kenai, based on historic gas consumption rates. A moderately-sized Internet data center would consume modest quantities of gas (less than 1 Bcf per year). However, a relatively large Internet data center (one-million square feet) could consume as much as 4.3 Bcf per year. A polyethylene petrochemical plant similar to the facility under study by Williams could draw 300-400 Bcf per year for ethane extraction and possibly other natural gas liquid components. But most of this gas would be re-injected back into the gas pipeline in the form of methane, destined for other downstream markets. Net gas usage at the petrochemical probably would be less than 30 Bcf per year.

The in-state gas demand and supply study identified community power-generating facilities in the Interior region that could potentially switch their primary fuel to natural gas. Fuel oil and diesel facilities in the Interior region of the state were the most attractive candidates. There are approximately 200 MWs of capacity in this region that could shift from fuel oil to natural gas. This alternative appears to meet first-order economic criteria but at a very small scale (30 Bcf per year).

The study also considered using ANS gas for central-station electric power generation and transmission in the Interior region (gas-by-wire). The economics of a 250 MW combined cycle facility stack up favorably with the costs of existing generating units. However, the state does not have a potential capacity need until the year 2014.

In sum, the economics of supplying ANS gas for the applications outlined above as a whole do not appear to be favorable. Where the economics are close (fuel switching and gas-by-wire) additional, detailed engineering analysis of related transportation and distribution alternatives is required before conclusions can be reached.

The Cook Inlet Gas Demand and Supply Balance. Setting aside the potential for future increases in gas usage, the evidence regarding existing gas supply and demand in Cook Inlet suggests that, without access to additional gas reserves, annual gas deliverability in the ENSTAR system may fall short of potential demand (at current, relative energy prices) before 2010. This imbalance stems in part from a long-standing availability of relatively inexpensive gas to Southcentral users in all customer classifications. To some extent, gas producers and consumers have responded to the potential for future supply shortages. For example, the Regulatory Commission of Alaska recently approved a gas purchase agreement between ENSTAR and Unocal that ties gas price to a three-year moving average of the Henry Hub spot market price

² Penetration in areas currently served by ENSTAR in Southcentral Alaska is approximately 80 percent.

with a floor of \$2.75 per Mcf. The agreement also commits Unocal to an aggressive program of gas exploration in the Cook Inlet.³ The impact of rising gas prices is likely to result in curtailment of industrial gas usage. Also, a situation of acute supply shortage is likely to reduce the U.S. Department of Energy's willingness to renew an application to extend the license to export LNG to Japanese Utilities beyond the current expiration date of April 2009.

The division's investigation of in-state gas demand and supply evaluated the potential for ANS gas to serve the demand-supply imbalance in the Southcentral region. Preliminary findings indicate that a the levelized cost of a 16-to-20 inch spur pipeline linking Southcentral with the ANS gas pipeline at Fairbanks could be competitive with energy alternatives (such as fuel oil or LNG imports into Cook Inlet) if annual throughput exceeds 30-to-40 Bcf per year. For example, a 20-inch spur pipeline operating at an average of 40 Bcf per year for 30 years would imply meter-station step-down charges and levelized transmission charges of approximately \$1.00 per Mcf (excluding the toll to Fairbanks, as well as local distribution and gas commodity charges). In order to be competitive, the spur pipeline would be required to serve a segment of the existing Southcentral customer base now served by local gas reserves in the Cook Inlet Basin. This result could be favorably influence by scale economies from:

- Sharing spur pipeline transmission charges over a wider customer base along the energy belt;
- Higher rates of penetration than those observed among Southcentral users within the existing ENSTAR system;
- System-wide averaging of distribution charges; and
- Baseline growth in all customer classes including industrial users and expanded gas service.

³ Regulatory Commission of Alaska. Docket Number U-01-7, Order 8. *Order Conditionally Approving TA 117-4 (Gas Sales Agreement) and Requiring Filing*. October 25, 2001.

Appendix D: *Sample Contract* for the Sale of ANS Royalty Gas

**SAMPLE CONTRACT
FOR THE SALE OF
ANS ROYALTY GAS**

This Sample Contract shows the type of contract the State expects to negotiate for the sale of ANS Royalty Gas. It is illustrative only. It is not an offer to sell ANS Royalty Gas. Volumes are expressed in MMcf and prices are expressed as dollars per MMcf. It may be appropriate to use MMBtus instead of MMcfs. Negotiations with purchasers will set the actual terms and conditions of contracts for the sale of ANS Royalty Gas.

TABLE OF CONTENTS

Article I – Definitions	2
Article II – Special Commitments	4
Article III – Sale and Purchase of Gas	4
Article IV – Invoicing and Payment	8
Article V – Buyer’s Representations and Obligations	12
Article VI – Security	13
Article VII – Measurements	16
Article VIII – Effective Date and Term	16
Article IX – Default or Termination	17
Article X – Disposition of Royalty Gas	20
Article XI – Non-Waiver	21
Article XII – Interpretation of Terms and Conditions	21
Article XIII – Severability	22
Article XIV – Force Majeure	22
Article XV – Notices	23
Article XVI – Rules and Regulations	24
Article XVII – Sovereign Power of the State	24
Article XVIII – Applicable Law	24
Article XIX – Warranties	25
Article XX – Amendment	25
Article XXI – Successors and Assigns	25
Article XXII – Records	25
Article XXIII – Employment of Alaska Residents	26
Article XXIV – Counterparts	27
Article XXV – Miscellaneous	27
Article XXVI – Reopener	28
Schedule 1 – Royalty Gas Purchase Schedule	29
Exhibit 1 – Example of Calculation of Base Price	30
Exhibit 2 – Sample Calculation of Invoice Price	31
Exhibit 3 – Sample Calculation of Interest and Late Payment Penalty	32

SAMPLE CONTRACT

Page 1 of 32

**AGREEMENT FOR THE SALE AND
PURCHASE OF ROYALTY GAS**

This Agreement is between the State of Alaska ("State") and _____
("Buyer"). The effective date of this Agreement is _____, 2002.

**ARTICLE I
DEFINITIONS**

As used in this Agreement, the terms listed below shall have the following meanings:

1.1 "Commissioner" means the Commissioner of the Alaska Department of Natural Resources or the Commissioner's designee.

1.2 "Day" means a period of twenty-four (24) consecutive hours, beginning at 12:00:01 a.m., Alaska Standard Time.

1.3 "Gas" means natural gas tendered in gaseous phase by the Lessees to the State as royalty. Gas [includes] [excludes] natural gas liquids ("NGLs") tendered by the Lessees as Royalty Gas.

1.4 "Gas Pipeline" means the pipeline and related facilities to be constructed to deliver ANS gas from the North Slope to markets inside or outside the State of Alaska.

1.5 "Leases" means the oil and gas leases issued by the State and subject to the terms of either the Prudhoe Bay Unit Agreement or Point Thomson Unit Agreement.

1.6 "Lessee" means a person, as "person" is defined in Alaska Statutes 01.10.060, owning a working interest in any of the Leases.

1.7 "Mcf"; "MMcf"; "Bcf" – "Mcf" means one thousand (1,000) Standard Cubic Feet; "MMcf" means one million (1,000,000) Standard Cubic Feet; and "Bcf" means one billion (1,000,000,000) Standard Cubic Feet.

1.8 "MMBtu" means one million (1,000,000) British Thermal Units.

1.9 "Month" means a period beginning at 12:00:01 a.m., Alaska Standard Time, on the first Day of the calendar Month and ending at 12:00:01 a.m., Alaska Standard Time, on the first Day of the following calendar Month.

1.10 "Nomination" is defined in Paragraph 3.1.4.

1.11 "Open Season" means the period during which shippers must contract for space on the Gas Pipeline.

1.12 "Parties" means, collectively, Buyer and State.

1.13 "Party" means Buyer or State, individually.

1.14 "Point of Delivery" means the location or locations where the State receives Royalty Gas in-kind from the Lessees.

1.15 "Reserved Gas" is defined in Paragraph 3.1.5(a).

1.16 "Royalty Gas" means that portion of Total Royalty Gas the State has agreed to sell to Buyer and Buyer has agreed to purchase under this Agreement.

1.17 "Royalty Value" is defined and calculated as shown in Paragraph 3.3.1 and Exhibit 1.

1.18 "Total Royalty Gas" means the total volume of Gas produced each Day from the Prudhoe Bay and Point Thomson units that the State takes as its royalty under the Leases, whether in-kind or in-value.

1.19 "Unit Agreement" means the Prudhoe Bay or Point Thomson unit agreement, as appropriate.

1.20 "Unit" means the Prudhoe Bay Unit or the Point Thomson Unit, as appropriate.

ARTICLE II

SPECIAL COMMITMENTS

[This Article is reserved for Special Commitments offered by Buyer. A Special Commitment could be a commitment to in-state processing, in-state use, in-state investment, in-state exploration, local hire, or anything else that Buyer offers to enhance its proposal. Performance of a Special Commitment must be measurable and enforceable. A Buyer is not required to propose a Special Commitment. Special Commitments may be given weight in the State's evaluation process.]

ARTICLE III

SALE AND PURCHASE OF GAS

3.1 Quantity.

3.1.1 **Maximum Quantities.** The State agrees to sell and the Buyer agrees to buy each day Royalty Gas in the quantities shown in the attached Schedule 1, "Royalty Gas Purchase Schedule." The quantities shown in Schedule 1 are the Maximum Quantities available to Buyer.

3.1.2 **Reduction in Maximum Quantities.** The Buyer may at any time reduce the Maximum Quantities by giving two years notice. No quantity shown in Schedule 1 may be reduced by more than fifty percent (50%).

3.1.3 **No Guarantee of Quantity.** The State can deliver Royalty Gas only to the extent it receives Royalty Gas from the Lessees. The quantity of Total Royalty Gas available to the State may vary and may be interrupted from time to time depending on a variety of factors, including the rate of production from the Leases and Units. Furthermore, the State is or may be required to nominate Royalty Gas as a percentage of Total Royalty Gas, and not by quantity. The State disclaims and Buyer waives any guarantee, representation, or warranty, either express or implied, that a specific quantity of the total, daily, monthly, average or aggregate Royalty Gas will be delivered to Buyer under this Agreement. Buyer disclaims any interest in or right to stored Royalty Gas to which the State is or may become entitled.

3.1.4 Monthly Nomination to Take Less Than the Maximum Quantities. Buyer may request an increase or decrease in the quantity of Royalty Gas it will take each Month (a "Nomination"). A Nomination must be in writing and shall be effective on the first Day of the seventh Month after the Nomination is received by the State. The Nomination for any Month:

- a. cannot exceed the Maximum Quantities for that Month; and
- b. cannot change the Nomination for the prior Month by more than the percent change allowed by the applicable Unit Agreement.

3.1.5 Source of Royalty Gas. The State will deliver the quantities nominated by Buyer first from the Prudhoe Bay Unit and, if adequate Royalty Gas is not available from the Prudhoe Bay Unit, then from the Point Thomson Unit, subject to the following rules and conditions:

- a. The State reserves for later sale or any other use thirty percent (30%) of the Total Royalty Gas produced each Month from each Unit ("Reserved Gas"). Reserved Gas shall not be available to supply quantities nominated by Buyer.
- b. If the quantity of Total Royalty Gas sold under this Agreement and any other agreements exceeds seventy percent (70%) of the Total Royalty Gas produced each Month from the Prudhoe Bay Unit, the quantities nominated by Buyer shall be taken pro rata from the Prudhoe Bay Unit based on the ratio of Buyer's nominated quantities for the Month to total quantities nominated by all buyers for the Month. For example, assume (1) that the Prudhoe Bay Unit produces 1,000 MMcf in a given Month, (2) that Buyer's Nomination for that Month is 500 MMcf, and (3) that all other buyers under other agreements have nominations which total 400 MMcf. After the State's reservation of 30 percent (which could be reduced by a later sale), 700 MMcf are available. Nominations total 900 MMcf. Buyer would therefore receive

from the Prudhoe Bay Unit $500/900 \times 700 = 388$ MMcf, and the balance (112 MMcf) from the Point Thomson Unit.

3.1.6 State's Warranty of Title. The State warrants that it has good and marketable title to the Royalty Gas delivered and sold under this Agreement.

3.2 Quality.

3.2.1 Quality of Royalty Gas. The Royalty Gas sold under this Agreement shall be of the same quality as the Royalty Gas produced from the Units and delivered by the Lessees to the State at the Point of Delivery. The quality of the Royalty Gas may vary from time to time. The State disclaims, and Buyer waives, any guarantee, representation, or warranty, either expressed or implied, of merchantability, fitness for use, or suitability for any particular use or purpose, or otherwise, and of any specific, average, or overall quality or characteristic of Royalty Gas delivered under this Agreement. Buyer specifically waives any claim that any liquid or other hydrocarbons delivered with the Royalty Gas are not Royalty Gas for purposes of this Agreement.

3.3 Price of Royalty Gas. The Buyer shall pay the State a Royalty Gas price ("Price") for each Mcf of Royalty Gas purchased from the State. The Price shall equal the Base Price plus the Price Premium.

3.3.1 Base Price. The Base Price shall be the greater of \$___ per Mcf or the Royalty Value per Mcf for Gas taken from each Unit. The Royalty Value shall be the volume-weighted average of the amounts per Mcf paid in royalty by all Lessees each Month on Total Royalty Gas not taken in-kind, plus any processing and field costs incurred by the State on the Royalty Gas which would not have been incurred if the Royalty Gas had been taken in value. An example of the calculation of the Base Price is shown in Exhibit 1.

3.3.2 Price Premium. [This paragraph is reserved for any price premium a Buyer wishes to offer.]

3.4 Reservation Fee. If, in any Month, Buyer does not nominate the Maximum Quantities in effect for that Month, Buyer shall pay, in addition to the Price, a reservation fee equal to _____ percent of the Price on the difference in quantity between the Maximum Quantities and the quantity of Royalty Gas actually purchased as a result of Buyer's Nomination for the Month.

3.5 Current and Future Agreements, and Arbitration and Litigation Results Between the State and the Lessees.

3.5.1 Non-Intervention. The Buyer shall not intervene or otherwise participate in any way in any discussions, negotiations, agreements, settlements, reopeners, audits, arbitration, or litigation between the State and Lessees pertaining to royalty, nor shall the Buyer have any independent right to invoke any provision of any agreement between the State and Lessees.

3.5.2 Binding Effect. The Buyer agrees to be conclusively bound by the terms of any agreements, settlements, reopeners, audits, arbitration, or litigation between the State and Lessees pertaining to royalty, regardless of whether the Buyer agrees with or consents to the agreements, settlements, reopeners, audits, arbitration, or litigation.

3.6 Delivery of Royalty Gas.

3.6.1 Day of First Delivery. The State will make its first delivery of Royalty Gas to Buyer at the Point of Delivery immediately upon the State's first receipt of Royalty Gas from the Lessees.

3.6.2 Later Deliveries. After the first delivery, the State shall tender Royalty Gas to Buyer at the Point of Delivery immediately upon receipt of the Royalty Gas from the Lessees.

3.7 Passage of Title and Risk of Loss. Title to, and risk of loss of, the Royalty Gas shall pass from the State to Buyer for all purposes when the State tenders the Royalty Gas to Buyer at the Point of Delivery. Buyer shall bear all risk and responsibility for the Royalty Gas after passage of title.

3.8 Indemnification After Passage of Title. Buyer shall indemnify and hold the State harmless from and against any and all claims, costs, damages (including reasonably foreseeable consequential damages), expenses, or causes of action arising from or related to any transaction or event in any way related to the Royalty Gas after title has passed to Buyer.

3.9 Transportation Arrangements. Buyer shall make all arrangements for, and bear all costs of, transportation of the Royalty Gas from the Point of Delivery to, through, and away from the Gas Pipeline, and shall be responsible for meeting any requirements imposed by the Gas Pipeline or any other pipeline used to transport the Royalty Gas purchased under this Agreement. On the State's request, Buyer shall provide the State with evidence of (1) the arrangements for transportation of the Royalty Gas from the Point of Delivery, to, through, and away from the Gas Pipeline; (2) arrangements for resale, exchange, or other disposal of the Royalty Gas; (3) arrangements for the treating, conditioning, or processing of the Royalty Gas; (4) information on specific deliveries of Royalty Gas by Buyer to the Gas Pipeline. Buyer's failure to provide information, evidence, or assurances requested by the State shall, at the State's election and after notice to Buyer, constitute a material default under this Agreement.

3.10 Absolute Obligations. Buyer's obligations to pay for the Royalty Gas, provide security as required by Article 6 and 10.3, pay reservation fees, and purchase, transport, and dispose of Royalty Gas are absolute. These obligations shall not be excused or discharged by the operation of any disability of Buyer, event of force majeure, impracticability of performance, change in conditions, or other reason or cause.

ARTICLE IV

INVOICING AND PAYMENT

4.1 Production Month Invoices. On or before the tenth business Day of each Month after the first Month of delivery of Royalty Gas, the State shall send to Buyer a statement of account with

an invoice for the total amount due for the estimated quantity of Royalty Gas delivered to Buyer during the immediately preceding Month and the estimated Price applicable to those deliveries. The State will base its estimates on the best information reasonably available to the State. The State shall adjust production month invoices as provided in Article 4.4 and Article 4.6.

4.2 Payment of Production Month Invoices. Buyer shall pay the total amount of each production month invoice, in full, on or before the third business Day after the date of the statement of account that includes the invoice. Any amount not paid in full on or before the third business Day after the date of the statement of account shall accrue interest as provided in Article 4.8, and become subject to the late payment provisions of Article 4.10, and any other remedies available to the State under this Agreement or at law.

4.3 Adjustments. Buyer acknowledges that any time after a production month invoice is sent, the State may receive more accurate information concerning the actual quantity, quality, and Price for Royalty Gas delivered to Buyer. Buyer agrees that any time such information becomes available to the State, the State may make adjustments to the preceding invoice(s), and invoice Buyer for the adjustments, plus interest as provided in Article 4.8 on the amount of any adjustment.

Buyer should expect adjustments to be made over a period of years and to increase the Price for Royalty Gas.

4.4 Initial Adjustments. Any adjustment made to an invoice issued during the immediately preceding month is an initial adjustment.

4.5 Payment of Initial Adjustments. Buyer shall pay the total amount of each initial adjustment invoice, plus interest as provided in Article 4.8, in full, on or before the third business Day after the date of the statement of account that includes the initial adjustment invoice. If an adjustment is due to Buyer for an overpayment, the State shall credit or refund to Buyer the amount of the overpayment, plus interest as provided in Article 4.8, on or before the third business Day after

i

the date of the statement of account that includes the initial adjustment invoice. Any amount Buyer does not pay in full when due shall become subject to the late payment provisions of Article 4.10, and any other remedies available to the State under this Agreement or at law.

4.6 Subsequent Adjustments. Any adjustment made to an invoice issued prior to the immediately preceding month is a subsequent adjustment.

4.7 Payment of Subsequent Adjustments. Buyer shall pay in full the total amount of each subsequent adjustment invoice, plus interest as provided in Article 4.8, on or before the thirtieth Day after the date of the statement of account that includes the subsequent adjustment invoice. If an adjustment is due to Buyer for an overpayment, the State shall credit or refund to Buyer the amount of the overpayment, plus interest as provided in Article 4.8, on or before the thirtieth Day after the date of the statement of account that includes the adjustment invoice. Any amount Buyer does not pay in full when due shall become subject to the late payment provisions of Article 4.9, and any other remedies available to the State under this Agreement or at law.

4.8 Interest. All amounts Buyer does not pay in full when due under this Agreement, and all amounts invoiced as adjustments for underpayments and overpayments for Royalty Gas delivered to Buyer, shall bear interest from the date accrued until paid in full at the rate provided by Alaska Statute 38.05.135(d), or as that statutory provision may later be amended. In this Agreement, "date accrued" means the third business Day after the date of the first statement of account that contains the production month invoice to which the initial or subsequent adjustment applies. Exhibits 2 and 3 illustrate accrual of interest and other calculations under Article IV.

4.9 Non-Termination and Limitations. Buyer acknowledges that the State may continue to make adjustments after termination of this Agreement, and agrees that the provisions of Articles IV and IX shall survive termination of this Agreement for any reason.

4.10 Late Payment Penalty. In addition to all other remedies available to the State, if Buyer fails to make timely payment in full of any amount due, Buyer shall pay the State an amount equal to five percent of the amount not timely paid as a late payment penalty, in addition to the amount not paid when due, plus interest as provided in Article 4.8 from the date accrued until paid in full.

4.11 Disputed Payments. If a dispute arises concerning the amount of an invoice, Buyer agrees to pay the full amount of the invoice when due pending final resolution of the dispute.

4.12 Confidential Information. The State and Buyer agree that the State may invoice Buyer for, and Buyer agrees to pay, amounts that are based upon confidential information held or received by the State. If confidential information is used as the basis for an invoice, upon receipt of a written request from Buyer, the State shall furnish to Buyer a certified statement of the Commissioner to the effect that, based upon the best information available to the State, the invoiced amounts are correct.

4.13 Manner of Payment. Buyer shall pay all invoices in full within the times specified and without any deduction, set off, or withholding. Buyer shall pay all invoices by wire transfer of immediately available funds to the State's account at the following address:

State Street Bank & Trust Company
Boston, Massachusetts
ABA No. 011000028
For credit to the State of Alaska
General Investment Fund, AY01
Account No. 00657189
Attn: Kim Chan, Public Funds

Buyer shall pay an invoice in any other manner or to any other address the State has specified in an invoice or by other written notice. All other payments due shall be paid in the same manner and according to the same time schedule provided in this Article. If payment falls due on a Saturday, Sunday, or legal federal holiday, payment shall be made on the next business day.

4.13.1 Direct Payment to Lessees. If the State directs Buyer in an invoice or other writing to remit all or a portion of a payment required under this Agreement directly to one or more of the Lessees, Buyer shall remit the payment to the Lessee or Lessees in the manner designated by the State, and within the time limits specified in Article IV. The State may, in writing, authorize a Lessee to request direct remittance of all or a portion of a payment due under this Agreement, and to designate the manner for payment. Unless otherwise specified by the State in writing, the balance of a direct partial payment to a Lessee, and all subsequent payments, shall be made to the State in accordance with Article IV.

4.13.2 Direct Payment to Other Third Parties. Upon a determination by the State that remittance to a third party of an amount due under this Agreement will assist the State in monitoring or enforcing the Agreement, the State may direct Buyer in an invoice or other writing to remit all or a portion of a payment due under this Agreement directly to a designated third party other than a Lessee, and Buyer shall remit the payment to the designated third party in the manner designated by the State, and within the time limits specified in Article IV. Unless otherwise specified by the State in writing, the balance of a direct partial payment to a third party, and all subsequent payments, shall be made to the State in accordance with Article IV.

4.13.3 Direct Payment to State. In the event of any default by Buyer, including, without limitation, failure to make any payment when due, the State may demand payment directly from any person or entity which purchases Royalty Gas from Buyer.

ARTICLE V

BUYER'S REPRESENTATIONS AND OBLIGATIONS

5.1 Good Standing and Due Authorization. Buyer warrants that it is, and shall remain at all times during the term of this Agreement: (1) a corporation organized and existing under the laws of the United States or of a state, territory, or the District of Columbia; (2) qualified to do

business in Alaska; and (3) in good standing with the State. Buyer warrants that it has all corporate power and authority necessary, and has performed all corporate action required, to enter into and fulfill its obligations under this Agreement.

5.2 Financial Condition. Buyer warrants: (1) that all financial information submitted to the State is complete, accurate, and fairly represents Buyer's financial condition at the time of submission; and (2) that there has been no material change in Buyer's financial condition, business operations, or properties since it submitted the financial information to the State. Buyer warrants that the financial information was prepared in accordance with generally accepted accounting principles. Buyer shall immediately inform the State of any material change in its financial condition, business operations, agreements, or property that may affect its ability to perform its obligations under this Agreement. Buyer shall immediately inform the State of any significant change in ownership of Buyer or of Buyer's parent company or affiliates.

5.3 Financial Statements. Within one hundred and twenty Days after the end of its fiscal year, Buyer shall, at its own cost and expense, submit to the State a complete financial report. The report shall include Buyer's balance sheet as of the close of the fiscal year and the income statement for that year prepared in accordance with generally accepted accounting principles. The report shall include a copy of Buyer's annual report (if any) filed with the United States Securities and Exchange Commission pursuant to Section 13 or 15(d) of the Security Exchange Act of 1934. From time to time the State may require submission of additional financial information in such form or forms as the State may prescribe.

ARTICLE VI

SECURITY

6.1 Letter of Credit. Seven months before the Day of First Delivery, Buyer shall deliver to the State an irrevocable stand-by letter of credit (the "Letter"). The Letter shall be in a form

satisfactory to the Commissioner and shall be in effect by the Day of First Delivery. It shall be issued for the benefit of the State by a state or national banking institution of the United States that is insured by the Federal Deposit Insurance Corporation and has an aggregate capital and surplus amount of not less than One Hundred Million Dollars (\$100,000,000) ("Issuer"), or other banking institution acceptable to the Commissioner. The principal face amount of the Letter shall be an amount estimated by the Commissioner to be equal to the value of all Royalty Gas to be delivered by the State to Buyer during the 180 Days immediately following the Day of First Delivery. The Letter shall not require the State to submit any documentation in support of drafts drawn against it other than a certified statement by the Commissioner and the State's Attorney General that Buyer is liable to the State for an amount of money equal to the amount of the draft, that the amount of money is due and payable in full, and it has not been timely paid.

The Letter shall provide that the State has the right to draw and present drafts to the Issuer through _____ months after the State's last delivery of Royalty Gas to Buyer under this Agreement. The Letter shall be in effect continuously from the Day of First Delivery through _____ months after the date of the State's last delivery of Royalty Gas to Buyer. If the Letter is not in effect for any reason, (1) Buyer shall be deemed to have materially breached this Agreement; (2) a default under Article IX will have occurred; and (3) all Buyer's obligations, expenses, and liabilities accrued as of that date, whether yet due and payable, shall become immediately due and payable in full.

If the State asserts a claim or claims that equal a total amount of money greater than the principal face amount of the Letter in effect, Buyer shall, upon the State's request, cause the principal face amount of the Letter to be increased by an amount sufficient to secure the total amount of the State's claims. Buyer is subject to this obligation even if Buyer denies, rejects, or otherwise contests the State's claims.

If the principal face amount of the effective letter of credit is ever less than the estimated price of 180 Days of Royalty Gas deliveries, Buyer shall automatically and immediately cause the principal face amount of the effective Letter to be increased to an amount equal to the estimated price of 180 Days delivery of Royalty Gas. If the principal face amount of the effective Letter is greater than the estimated price of 180 Days delivery of Royalty Gas, upon written approval of the Commissioner, in the Commissioner's sole discretion, Buyer may decrease the principal face amount of the Letter to an amount equal to the estimated price of 180 Days delivery of Royalty Gas.

6.2 Security Contract. Upon approval by the Commissioner, in the Commissioner's sole discretion, as alternative security to the Letter required in Article 6.1, Buyer may deliver to the State: (1) an irrevocable stand-by letter of credit in the principal face amount estimated by the Commissioner to be equal to the value of Royalty Gas to be delivered by the State to Buyer during the 90 Days immediately following the Day of First Delivery; and (2) an irrevocable contract between a major oil company ("Promisor") and Buyer for the direct benefit of the State, in which the Promisor agrees to assume full liability for Royalty Gas upon notice that Buyer is in default of this Agreement ("Security Contract"). The 90-Day letter of credit shall be subject to all the terms and conditions of Article 6.1. The Security Contract shall designate the State as intended third-party beneficiary and shall be in effect by the Day of First Delivery. It shall provide that upon written notice by the Commissioner to Buyer and the Promisor that Buyer is in default of this Agreement, the Promisor shall immediately assume full liability for purchase, transportation, and disposal of a minimum of 90 Days deliveries of Royalty Gas from the Point of Delivery. It shall provide the State a direct right of action against Buyer and the Promisor, jointly and severally, to enforce the Security Contract, regardless of whether the State takes action to enforce this Agreement against Buyer. It shall also provide that the Promisor has no right of action against the State and may not assert against the State any defense it may have against Buyer under the Security Contract.

6.3 Special Security. [Reserved for additional or other security a Buyer may offer.]

6.4 Other Security. The Commissioner may, in the Commissioner's sole discretion, require such other or additional security from Buyer as the Commissioner considers adequate to protect the State's interest. [The State may require (1) an escrow account of \$___ per Mcf to pay for adjustments or (2) that the Letter be maintained in an amount sufficient to pay for adjustments after the State stops delivering Royalty Gas.]

ARTICLE VII MEASUREMENTS

7.1 Measurements. Procedures used for metering and measuring the Royalty gas shall be in accordance with the procedures in effect in the Units.

ARTICLE VIII EFFECTIVE DATE AND TERM

8.1 Approval. This Agreement is subject to approval under Alaska Statute 38.06.055. If all approvals required by AS 38.06.055 have not been obtained by August 31, 2002, either Party may terminate the Agreement on 30 Days notice. If an Open Season for the Gas Pipeline is not completed by December 31, 2004, either Party may terminate this Agreement on 30 Days notice.

8.2 Term. [The term will be determined by the proposal.] Termination of this Agreement shall not relieve either party from any expense, liability, or other obligation or any remedy that has accrued or attached prior to the date of termination. For Royalty Gas actually delivered under this Agreement, termination of this Agreement shall not relieve Buyer of its obligation to pay all production month invoices, initial adjustments, subsequent adjustments, and interest, and, where applicable, penalties, costs, attorney fees, and any other charges related to the Royalty Gas actually delivered. The provisions of Article IV shall survive termination of this Agreement.

8.3 No Delivery of Royalty Gas. This Agreement shall terminate on July 31, 2012 if the Gas Pipeline is not in service by that date or if no Royalty Gas has been delivered by that date.

8.4 If the conditions set forth in Article 8.1 fail and this Agreement is not approved by August 31, 2002, or is terminated under Article 8.1, or if the Gas Pipeline is not in service by July 31, 2012, the State shall return to the Buyer the bonus paid by the Buyer, without interest.

ARTICLE IX DEFAULT OR TERMINATION

9.1 Default.

9.1.1 Events of Default. The Commissioner may, in the Commissioner's sole discretion, suspend, terminate, or reduce the State's obligation to tender, deliver, and sell Royalty Gas to Buyer, and may exercise any one or more of the rights and remedies provided in this Agreement, or at law, if any one or more of the following events of default occur:

- (i) Buyer fails to pay in full any sum of money owed under this Agreement within two business Days after the State gives Buyer notice that payment is past due and has not been paid;
- (ii) Within five Days after written request from the State, Buyer fails to provide written assurances satisfactory to the State of its intention to perform its obligations under this Agreement and evidence or assurances of transportation arrangements under Article 3.9;
- (iii) There is a substantial change in Buyer's financial condition, business operations, agreements, or property or ownership that may affect Buyer's ability to perform its obligations under this Agreement, and within five Days after a request by the State, Buyer is unable or unwilling to provide the State with adequate assurance of continued performance;

- (iv) Buyer fails to perform any of its obligations under this Agreement, and cannot cure the non-performance or the non-performance continues for more than thirty Days after the State has notified Buyer of its non-performance;
- (v) Any representation or warranty made by Buyer in this Agreement is found to have been materially false or incorrect when made; or
- (vi) Buyer fails, or is unable for any reason (including reasons beyond Buyer's control), to maintain the [security letter of credit] [other security] required under Article VI, regardless of Buyer's willingness or ability to perform any other obligations under this Agreement.

9.1.2 Default by Inability to Pay. Buyer shall immediately provide the State with written notice if Buyer is unable to pay any of its debts when due or is otherwise insolvent. Upon such notice from Buyer, or if the State independently determines that Buyer is unable to pay any of its debts when due or is otherwise insolvent, the State's obligations to deliver and sell Royalty Gas to Buyer shall automatically and immediately terminate without any requirement of notice to Buyer or other action by the State. Within thirty Days after termination under this Article 9.1.2, the State shall have the right, upon written notice to Buyer, to reinstate all of the State's and Buyer's obligations under this Agreement retroactive to the date of termination.

9.2 State's Remedies. If Buyer defaults under this Agreement, in addition to all other remedies available to the State under this Agreement or at law, the following remedies shall be available to the State in the Commissioner's sole discretion.

9.2.1 Buyer's Obligations Become Due. All monetary obligations Buyer has accrued under this Agreement, even if not yet due and payable, shall immediately be due and payable in full.

9.2.2 State May Dispose of Royalty Gas. The State may dispose of some or all of the Royalty Gas to third parties. If the State exercises this remedy, regardless of whether this Agreement is terminated, Buyer shall be and remain liable to the State for the amount of the difference between the Price for the Royalty Gas under Article III and the actual price the State receives from disposition of the Royalty Gas to third parties.

9.2.3 Indemnification for Loss. Buyer shall hold the State harmless and indemnify it against all liability, damages, expenses, attorney's fees and costs, and losses arising out of Buyer's default, termination of the State's obligations, and disposal of the Royalty Gas to third parties. Additionally, if Buyer defaults in the payment of the Base Price, Buyer shall pay the State 100% of costs and attorney fees incurred by the State in pursuing payment of the Base Price, regardless of whether litigation is commenced and regardless of whether legal services are provided by the Attorney General's office or private counsel.

9.2.4 Damages for Breach of Special Commitments. If a Buyer offers Special Commitments, the Buyer should propose liquidated damages payable upon its failure to perform those Special Commitments.

9.2.5 Other Rights and Remedies. The State shall have the right cumulatively to exercise all rights and remedies provided in this Agreement and by law, and obtain all other relief available under law or at equity, including mandatory injunction and specific performance, except that Buyer's Special Commitments shall not be subject to specific performance.

9.3 Limitation of Buyer's Remedies. If the State breaches or defaults in any of its obligations under this Agreement, Buyer shall not obtain a temporary restraining order or preliminary injunction preventing the State from disposing of the Royalty Gas subject to this Agreement.

9.4 Termination. [If Buyer wishes to have the right to terminate the contract or to reduce the quantities shown in Schedule 1 by more than 50 percent, there will be a fee to be negotiated as part of the contract.]

9.5 Article Survives Termination. This Article survives termination of the Agreement.

ARTICLE X DISPOSITION OF ROYALTY GAS

10.1 Disposition of Royalty Gas Upon Default or Termination. Buyer acknowledges that the State may be required to provide six Months notice to the Lessees before the State may decrease its in-kind Nomination of Royalty Gas in any Month. It is within the Commissioner's sole discretion to request a waiver of any notice provision, condition, or requirement of a Lease, Unit Agreement, settlement agreement or other agreement. If this Agreement terminates for default or any other reason, Buyer shall continue to accept and pay for Royalty Gas through the first Day of the Month following expiration of six months after the date of termination, if the Commissioner, in the Commissioner's sole discretion, so requires. If this Agreement terminates for default or any other reason, and the Commissioner, in the Commissioner's sole discretion, chooses to dispose of the Royalty Gas to a third party during the notice period for decreases in in-kind nominations, Buyer shall be and remain liable to the State for the amount of the difference between the Price for the Royalty Gas under Article III and the actual price the State receives from disposition of the Royalty Gas to third parties.

10.2 Inability to Receive Royalty Gas. If Buyer is unable or refuses to accept or receive Royalty Gas, Buyer shall nevertheless remain liable for disposal and payment for Royalty Gas as though it had been accepted by Buyer. The Commissioner may, in the Commissioner's sole discretion, waive this requirement.

10.3 Security for Disposal of Royalty Gas. To secure Buyer's obligations to purchase and dispose of Royalty Gas, upon the Commissioner's request, Buyer shall assign or otherwise transfer to the State, or its designee, all or part of Buyer's right, title, and interest in any arrangements for transportation of the Royalty Gas to, through, and away from the Gas Pipeline, whether such interests are under nominations, leases, contracts, tariffs, or other agreements. The State will incur liability or obligations under any assignment or transfer only to the extent the State actually exercises its rights to succeed to Buyer's interests under and obtain the benefits of the assignments or transfer.

ARTICLE XI NON-WAIVER

11.1 Non-Waiver. The failure of either party to insist upon strict or a certain performance, or acceptance by either party of a certain performance or course of performance under this Agreement shall not: (1) constitute a waiver or estoppel of the right to require certain performance or claim breach by similar performance in the future; (2) affect the right of either party to enforce any provision; or (3) affect the validity of any part of this Agreement.

ARTICLE XII INTERPRETATION OF TERMS AND CONDITIONS

12.1 Interpretation of Terms and Conditions. Any disagreement or dispute about the meaning or application of a word, term, or condition, or about a right or obligation in this Agreement shall be decided according to the dispute resolution procedure set forth in this Article. The procedure set forth in this Article shall be initiated by either party providing written notice of the disagreement or dispute to the other party. No later than sixty Days after either party provides written notice, Buyer and the State shall each present any arguments and evidence supporting their views of the disputed term or condition in writing to the Commissioner for consideration. Buyer

shall not have the right to civil litigation-type discovery or a civil litigation-type trial with the right to call or cross-examine witnesses unless granted by the Commissioner, after request. Within thirty Days after both parties submit their arguments and evidence, the Commissioner shall issue a finding interpreting the meaning or application of the disputed word, term, or condition, and shall set forth the basis for the conclusions. Buyer agrees to accept findings of the Commissioner under this Article that are reasonable and not arbitrary.

ARTICLE XIII SEVERABILITY

13.1 Severability. If a court decrees any provision of this Agreement to be invalid, all other provisions of this Agreement shall remain valid. If, however, invalidation of a provision impairs a material right or remedy under this Agreement, either party may terminate this Agreement by notice to the other party as provided under Article XV.

ARTICLE XIV FORCE MAJEURE

14.1 Effect of Force Majeure. Except for Buyer's absolute obligations to pay for the Royalty Gas, provide security, pay reservation fees, and purchase, transport and dispose of Royalty Gas, neither party shall be liable for failure to perform if performance is substantially prevented by force majeure after good faith efforts to perform. If Buyer is prevented by force majeure from performing any material obligation for sixty successive Days or more, the State, in the Commissioner's sole discretion, shall have the right to terminate this Agreement. Before the State exercises this right, the Commissioner may require Buyer to negotiate in good faith to restore performance.

14.2 Notice of Force Majeure. If a party believes that force majeure has occurred, the party shall immediately notify the other party of its claim of force majeure. Except for Buyer's

absolute obligations to pay for the Royalty Gas, provide security, pay reservation fees, and purchase, transport and dispose of Royalty Gas, the disabled party's obligations to perform that are affected by the force majeure shall be suspended from the time of notification to the other party until the disability caused by the force majeure should have been remedied with reasonable diligence.

ARTICLE XV **NOTICES**

15.1 Method. Unless otherwise specifically provided in this Agreement, all notices, requests, demands, or statements shall be in writing and delivered to the address specified in this Article in person, by telecopier or other form of facsimile, by United States mail, postage prepaid, registered or certified with a return receipt requested, to the party to be notified. A statement of account the State delivers to Buyer by telecopy shall be deemed delivered to Buyer when the State's telecopier confirms that it was received at Buyer's telecopy number. A notice, request, demand, or statement delivered by United States mail shall be deemed delivered on the earlier of expiration of seven Days after it is deposited in the mail, or upon the date of receipt by the party to whom it is directed. A notice, request, demand, or statement delivered in any other manner shall be effective only if and when received by the party to whom it is directed. The address of the parties shall be as follows:

State: State of Alaska
Commissioner of Natural Resources
400 Willoughby Avenue
Juneau, Alaska 99801

and Director, Division of Oil and Gas
550 W 7th Avenue, Suite 800
Anchorage, Alaska 99501-3560
Telecopy No.: 907-269-8938

Buyer: _____

Telecopy No.: _____

15.2 Change of Address. Each party may notify the other of changes in its address by delivering written notice of the change.

ARTICLE XVI

RULES AND REGULATIONS

16.1 Rules and Regulations. This Agreement is subject to all applicable laws of the State of Alaska, and orders, rules, and regulations of the United States, the State of Alaska, and any duly constituted agency of the State of Alaska.

ARTICLE XVII

SOVEREIGN POWER OF THE STATE

17.1 Sovereign Power of the State. This Agreement shall not be interpreted to limit in any way the State's ability to exercise any sovereign or regulatory powers, whether conferred by constitution, statute, or regulation. The State's exercise of any sovereign or regulatory power shall not be deemed to enlarge any of Buyer's rights, or limit any of Buyer's obligations or liabilities under this Agreement.

ARTICLE XVIII

APPLICABLE LAW

18.1 Governing Law. This Agreement, and all matters arising from or related to this Agreement, shall be governed, construed, and determined by the laws of the State of Alaska.

18.2 Jurisdiction. After exhaustion of the dispute resolution provisions in Article XII, any legal action or proceeding arising out of or related to this Agreement shall be brought in a state court of general jurisdiction sitting in the State of Alaska, and Buyer hereby irrevocably submits to the jurisdiction of that court in any such action or proceeding.

**ARTICLE XIX
WARRANTIES**

19.1 Warranties by State. The purchase and sale of Royalty Gas under this Agreement are subject only to the warranties the State has expressly set forth in this Agreement. The State disclaims and Buyer waives all other warranties, express or implied in law.

**ARTICLE XX
AMENDMENT**

20.1 Amendment. This Agreement may be supplemented, amended, or modified only by written instrument duly executed by the parties and, where required, approved under Alaska Statute 38.06.055.

**ARTICLE XXI
SUCCESSORS AND ASSIGNS**

21.1 Successors and Assigns. No assignment, pledge, or encumbrance of this Agreement shall be made by either party without first obtaining the written consent of the other party, which shall not be unreasonably withheld. The Commissioner may consent on behalf of the State. Subject to the requirement of written consent, this Agreement shall be binding upon and inure to the benefit of each of the parties and their successors and permitted assignees, and they must agree in writing to be bound by this Agreement.

**ARTICLE XXII
RECORDS**

22.1 Preservation of Records. Buyer shall maintain and preserve all books, accounts, and records that relate to or arise from performance of this Agreement for six years from the date of the transaction or date of the latest adjustment relating to the transaction, or for any longer period requested by the State if, in the State's sole discretion and opinion, the books, accounts, and records are relevant to a pending audit, arbitration, or litigation. Buyer shall also maintain and preserve all

books, accounts, and records, in its possession or control, that belong to any third party with whom Buyer contracts for the performance of any part of this Agreement. Buyer and the State shall not be required to retain any records for more than six years from the time of a transaction unless retention of such records is specifically required by applicable law or regulation, or this Agreement. Buyer shall maintain its records within the State or make the records available to the State at Buyer's principal office in the State within thirty Days after written request by the State.

22.2 Inspection of Records. Buyer and the State shall each accord to the other and the other's authorized agents, attorneys, and auditors access during reasonable business hours to any and all property, records, books, documents, or indices related to Buyer's or the State's performance under this Agreement and which are under possession or control of the party from which access is sought, so the other party may inspect, photograph, and make copies of the property, records, books, documents, or indices. The State shall not be required to disclose any information, data, or records that is required by state or federal law or regulation, or by agreement with the person supplying the record, to be held confidential. If information the State obtains from Buyer may be held confidential under state or federal law or regulation, Buyer must request in writing that the State hold the information confidential, and the State shall keep the information confidential to the extent and for the term provided by the applicable law or regulation.

ARTICLE XXIII

EMPLOYMENT OF ALASKA RESIDENTS

23.1 Employment of Alaska Residents. Buyer shall comply with all valid federal, state, and local laws in hiring Alaska residents and companies, and shall not discriminate against Alaska residents and companies. Within the constraints of law, Buyer voluntarily agrees to employ Alaska residents and Alaska companies to the extent they are available, willing, and qualified for work performed in Alaska in connection with this Agreement. "Alaska resident" means an individual who

is physically present in Alaska with the intent to remain in the state indefinitely. An individual may demonstrate an intent to remain in the state by maintaining a residence in the state, possessing a resident fishing, trapping or hunting license, or receiving a permanent fund dividend. "Alaska companies" means companies incorporated in Alaska or whose principal place of business is in Alaska. If a court invalidates any portion of this provision, Buyer agrees to employ Alaska residents and Alaska companies to the extent permitted by law.

ARTICLE XXIV **COUNTERPARTS**

24.1 Counterparts. This Agreement may be executed in multiple counterparts. It is not necessary for the parties to sign the same counterpart. Each duly executed counterpart shall be deemed to be an original and all executed counterparts taken together shall be considered to be one and the same instrument.

ARTICLE XXV **MISCELLANEOUS**

25.1 Agreement Not to Be Construed Against Either Party as Drafter. The Parties recognize that this Agreement is the product of the joint efforts of the Parties and agree that it shall not be construed against either Party as drafter.

25.2 Entire Agreement. This Agreement constitutes the entire agreement and understanding between the Parties about the subject matter of this transaction and all prior agreements, understandings, and representations, whether oral or written, about this subject matter are merged into and superseded by this written Agreement.

25.3 Headings. The headings throughout this Agreement are for reference purposes only and shall not be construed or considered in interpreting the terms and provisions of this Agreement.

25.4 Authority to Sign. Each person signing this Agreement warrants that he or she has authority to sign the Agreement.

25.5 Further Assurances. The Parties agree to do such further acts or execute such further documents as may reasonably be required to implement this Agreement.

ARTICLE XXVI
REOPENER

[This Article is reserved for any reopeners which the Parties consider necessary.]

STATE OF ALASKA:

By _____
Its _____
Date _____

BUYER:

By _____
Its _____
Date _____

SCHEDULE 1

Royalty Gas Purchase Schedule	
Month¹	Quantity (MMcf/Day)

¹Because the date of first production is not known, the "month" column will be expressed as first production month, second production month, and so on.

SAMPLE CONTRACT

Page 29 of 32

EXHIBIT 1

EXAMPLE OF CALCULATION OF BASE PRICE

[To be prepared as part of the final contract.]

EXHIBIT 2**SAMPLE CALCULATION OF INVOICE PRICE**

[To be prepared as part of the final contract.]

EXHIBIT 3

SAMPLE CALCULATION OF INTEREST
AND LATE PAYMENT PENALTY

[To be prepared as part of the final contract.]

N:\SJWVLM\Gas Agreement (12-20)

SOLICITATION FOR OFFERS .
TO PURCHASE ALASKA NORTH SLOPE
ROYALTY GAS



Alaska Department of
**NATURAL
RESOURCES**
DIVISION OF OIL & GAS

550 West 7th Avenue, Suite 800
Anchorage, Alaska 99501-3510

December 26, 2001

STATE OF ALASKA
SOLICITATION FOR OFFERS
TO PURCHASE ALASKA NORTH SLOPE
ROYALTY GAS

DECEMBER 26, 2001

The Department of Natural Resource, Division of Oil and Gas ("Division"), gives notice under Title 38, Alaska Statutes, of its intention to sell royalty gas that may be produced from Alaska's North Slope (ANS) upon completion of a natural gas pipeline. By this notice, potential buyers are invited to submit offers to purchase the State's royalty-in-kind (RIK) gas. Offers must be received at the address listed below no later than **January 31, 2002**. All offers received by the deadline will be opened and announced at a public meeting scheduled on **February 1, 2002** at 8:30 a.m. in Room 240 of the Robert B. Atwood Building, 550 West Seventh Avenue, Anchorage, Alaska.

DNR reserves the right to amend or cancel this Solicitation for Offers at any time. Any interested person who wants to be notified directly of amendments or cancellation should provide the name, telephone number and address of the contact person to Kevin Banks at krb@dnr.state.ak.us; by fax to (907) 269-8938; or by mail to DO&G, 550 West Seventh Avenue, Suite 800, Anchorage, Alaska 99501-3510.

To be considered under this Solicitation, offers must meet the following Minimum Cash Bonus and Base Price conditions. Paragraphs 1-7, below, are negotiable terms.

1. **MINIMUM CASH BONUS.** In order to participate in the competitive sale, the potential buyer's offer must commit to a minimum cash bonus. The minimum cash bonus must equal \$1.00 per Mcf per day of Maximum Quantities the buyer proposes to purchase (see e.g., *Sample Contract* at Article 3.1.1).
2. **BASE PRICE.** The potential buyer must offer a base price. For the purposes of this competitive RIK sale offer "Base Price" is defined in Article 3.3.1 in the *Sample Contract*. The State will consider offers that include a different mechanism than the method outlined in the *Sample Contract* to calculate the Base Price so long as it is consistent with the definition of Base Price as the volume-weighted average of the amounts paid by the lessees for royalty gas in-value. If the State is not satisfied with a proposed Base Price mechanism, the State will detail a mechanism it considers acceptable.

In addition to the Minimum cash Bonus and Minimum Base Price, potential buyers are encouraged to include some or all of the following terms in their offers. The Division will consider the benefits to the State that the additional terms would provide when it evaluates the offers.

3. **PRICE PREMIUM.** Potential buyers may offer a price premium over and above the Base Price. It will be considered along with proposed Special Commitments in evaluating the benefits of an offer to the State.
4. **OPTION PRICE.** If the potential buyer wishes to have the right to terminate the contract or reduce the Maximum Quantities (i.e., the amount of gas the buyer has contracted to purchase) by more than 50 percent, the buyer should include the option price it proposes to pay for the right (see e.g., *Sample Contract* at Article 9.4).
5. **SPECIAL COMMITMENTS.** Potential buyers may offer Special Commitments in addition to the Minimum Cash Bonus and Base Price. Special Commitments may be offered with or without a price premium or option price. The price premium or option price and Special Commitments that are offered will be considered separately and jointly to determine the potential benefits to the State. Performance of Special Commitments must be measurable and enforceable by the State (see e.g., *Sample Contract* at Article II).
6. **QUANTITY OF GAS.** The State will offer up to 70 percent of its royalty gas from the Prudhoe Bay and Point Thomson Units. Offers must include an estimate of the amount of gas the buyer proposes to purchase (see, e.g., *Sample Contract* at Article 3.1.1 and Schedule I concerning "Maximum Quantities").
7. **TERM.** Potential Buyers must specify in their offers the time period proposed for a State Royalty Gas Sale Contract. In no case will the term of a contract entered into as a result of this Solicitation to Offer begin until a gas pipeline and related facilities are constructed to deliver ANS gas to markets inside or outside of Alaska. No gas will be delivered under a State Royalty Gas Sale Contract until ANS gas is produced and delivered by the lessees to the State. The term of any contract entered into as a result of this Solicitation to Offer will be contingent as provided in the terms of Articles 8.1, 8.2, 8.3 and 8.4 of the *Sample Contract*.
8. **SOURCE OF GAS.** The State assumes that royalty gas delivered under a State Royalty Gas Sale Contract will come from the Prudhoe Bay Unit and the presently undeveloped Point Thomson Unit (see the *Sample Contract* at Article 3.1.5). The right of the State to determine the source of the royalty gas to be delivered under the State Royalty Gas Sale Contract is a non-negotiable term.
9. **POINT OF DELIVERY.** For purposes of this Solicitation for Offers, the points of delivery for the State's RIK gas are not yet determined. The State Royalty Gas Sale Contract will define the Point(s) of Delivery as the transfer point(s) where the State receives its royalty gas in-kind from the lessees (see e.g., *Sample Contract* at Article 1.14). This term is non-negotiable.
10. **FIELD AND CONDITIONING COSTS.** The State Royalty Gas Sale Contract will require that the buyer pay any and all field and conditioning costs chargeable against the State's royalty share of gas delivered under the contract. This term is non-negotiable.

11. **PAYMENTS.** The State Royalty Gas Sale Contract gas contract will specify that the State will bill the buyer each month using a "best estimate" of price and volume. The State will make adjustments in later months as additional information about price and volume becomes available. This term is non-negotiable.
12. **SECURITY.** The potential buyer is required to provide security to protect the State's interests. The *Sample Contract* discusses potentially acceptable forms of security (see the *Sample Contract* at Article VI). Although the requirement to provide security is non-negotiable, the security terms may be negotiated to some degree.
13. **PREQUALIFICATION.** In order to be eligible to submit an offer, an individual, corporation, or other entity must first apply to the Division of Oil and Gas for qualification to offer. In order to qualify, an applicant must be (A) a person who has reached the age of majority and who is a citizen of the United States; (B) a corporation organized and existing under and by virtue of the laws of the United States or of any state, territory, or the District of Columbia and qualified to do business in Alaska; or (C) an association of the above. To qualify, a corporation must be authorized to do business in the State of Alaska.
 - a. **APPLICATION FOR QUALIFICATION.** An individual, corporation or other entity who is not already qualified with the Division of Oil and Gas must prequalify by completing the attached form entitled "Qualification to Offer," before submitting an offer under this Solicitation for Offers. The completed application must be received by the Division of Oil and Gas, Attn: Kevin Banks, at 550 West Seventh Avenue, Suite 800, Anchorage, AK 99501-3510, no later than 4:30 p.m., Alaska Standard Time, **January 17, 2002.**

An applicant must provide additional information concerning the applicant's financial standing and financial capability to perform the terms of a State Royalty Gas Sale Contract if the Division of Oil and Gas requests such information. Upon the applicant's written request as provided in AS 38.05.035(a)(9)(D), the Commissioner will hold confidential cost data and financial information contained in the application to the extent provided by law.
 - b. **QUALIFICATION DETERMINATIONS.** No later than **January 25, 2002**, the Commissioner will determine the applicant's eligibility to submit an offer. The Division will notify each applicant of its eligibility by mail or telefax.
14. **OTHER QUALIFICATIONS.** A prospective buyer must be able to demonstrate to the Commissioner's satisfaction that it has the financial ability, necessary management skills, and experience to perform the terms of a State Royalty Gas Sale Contract.
15. **OFFERS.** Only prequalified applicants may submit offers. Each offer must be submitted on the "Offer for State Royalty Gas" form (Offer form) attached to this Solicitation.

- a. **SIGNATURES.** Each prospective buyer, or the buyer's authorized representative, must sign the Offer form. By signing the Offer form, the prospective buyer, or the buyer's authorized representative, certifies that it has full authority to submit an offer to purchase the State's royalty gas, and to negotiate and bind the prospective buyer to the terms and conditions of a State Royalty Gas Sale Contract if such a contract results from the offer.
- b. **SUBMITTING OFFERS.** Offers must be submitted to the Director, Division of Oil and Gas, 550 West Seventh Avenue, Suite 800, Anchorage, AK 99501-3510. Offers may be delivered personally or by mail. Offers must be received no later than 4:30 p.m., Alaska Standard Time, **January 31, 2002.**

Offers must be submitted separately in a sealed envelope that has the prospective buyer's name, address, and "OFFER FOR ROYALTY GAS, January 31, 2002" clearly printed on the front.

- c. **LATE OFFERS.** Only offers received at the location specified in this Solicitation by 4:30 p.m., Alaska Standard Time on **January 31, 2002** will be accepted. Late offers will be returned unopened.
16. **REJECTION OF OFFERS.** The Commissioner may reject any or all offers at any time before or after the opening. The Commissioner may reject any offer that does not conform to the requirements of this Solicitation. The Commissioner will reject any offer as provided under 11 AAC 03.210 and any offer that proposes a Royalty Gas Price that is not equal to at least Royalty Value as it is defined in Article 3.3 of the *Sample Contract* ("the volume-weighted average of the amounts per Mcf paid in royalty by all lessees each month on total royalty gas not taken in-kind, plus any processing and field costs incurred by the State on the royalty gas which would not have been incurred if the royalty gas had been taken in value").
17. **OPENING OF OFFERS.** Offers will be opened and considered in the following manner:
- a. **OPENING.** Offers will be opened and read at a public meeting at 8:30 a.m. on **January 29, 2002.** Immediately after the opening, the Division of Oil and Gas will evaluate offers and the Commissioner will determine whether any offers should be rejected as provided in paragraph 16 of this Solicitation. The remaining offers will then be evaluated for contract awards.
 - b. **REJECTED OFFERS.** A prospective buyer who believes that its offer was rejected in error may request a conference with the Commissioner. A request for a conference must be received by mail or telefax no later than 4:30 p.m. Alaska Standard Time, **February 8, 2000,** at the Division of Oil and Gas, 550 West Seventh Avenue, Suite 800, Anchorage, Alaska 99501-3510, FAX at (907) 269-8938. Conferences will be held no later than **February 15, 2002.** At the

conference, any and all objections to the Commissioner's rejection of the offer must be presented in writing.

- c. **FINAL ACCEPTANCE OF OFFER.** On or before **February 15, 2002**, the Commissioner will announce the offers that have been awarded State Royalty Gas Sale Contracts.

18. **EXECUTION OF STATE ROYALTY GAS SALE CONTRACTS.** The Commissioner and the successful buyers will execute State Royalty Gas Sale Contracts approximately **March 15, 2002**. The parties to the State Royalty Gas Sale Contracts will agree that neither party may bring an action against the other concerning any provision of this Solicitation for Offers or the process that resulted in the State Royalty Gas Sale Contract between the parties, except as expressly provided in the State Royalty Gas Sale Contract.
19. **APPROVAL.** Legislative approval of the State Royalty Gas Sale Contract is required under AS 38.05.055. Prior to submission to the legislature for approval, the Alaska Royalty Oil and Gas Development Advisory Board must review the contract and make a recommendation to the Legislature.
20. **NON-ASSIGNABILITY OF RIGHTS.** Any rights, privileges and obligations of an individual, corporation, or other entity that may arise under this Solicitation may be exercised only by the individual, corporation, or entity to which they have accrued, unless the Commissioner consents in writing to an assignment of the rights, privileges, or obligations.
21. **TERMINATION OF SOLICITATION FOR OFFERS.** This Solicitation for Offers will be of no further force and effect and any rights, privileges, or obligations created or accruing under it shall terminate upon the earliest of the following occurrences: 1) the Commissioner withdraws the Solicitation for Offers before any offers are received by the State; 2) the Commissioner's rejection of all offers that are submitted under the Solicitation; or 3) the Commissioner's announcement of the offers that have been accepted for State Royalty Gas Sale Contracts. .
22. **TERMINATION OF RIGHTS ON DEFAULT.** In the event that a potential buyer fails to accept the State's award of the buyer's offer, or fails or refuses to execute the State Royalty Gas Sale Contract, any and all rights the potential buyer may have or have acquired under the Solicitation or any subsequent related event or procedure are terminated immediately upon the default.

In evaluating offers, the Commissioner will consider:

1. The cash value offered;
2. The projected effects of the sale, exchange or other disposal on the economy of the State;
3. The projected benefits of refining or processing the gas in the State;

4. The ability of the prospective buyer to provide refined products or by-products for distribution and sale in the State with price or supply benefits to the citizens of the State;
5. The revenue needs and projected fiscal condition of the State;
6. The existence and extent of present and projected local and regional needs for gas products and by-products, the effect of State or federal commodity allocation requirements which might be applicable to those products and by-products, and the priorities among competing needs;
7. The desirability of localized capital investment, increased payroll, secondary development and other possible effects of the sale, exchange or other disposition of gas or both;
8. The projected social impacts of the transaction;
9. The projected additional costs and responsibilities which could be imposed upon the State and affected political subdivisions by development related to the transaction;
10. The existence of specific local or regional labor or consumption markets or both which should be met by the transaction;
11. The projected positive and negative environmental effects related to the transaction; and
12. The projected effects of the proposed transaction upon existing private commercial enterprise and patterns of investments.

In addition, the Commissioner will consider the financial responsibility of the prospective buyers.

**State of Alaska
Department of Natural Resources**

**Alaska North Slope
Royalty Gas Sale
Qualification to Offer**

An individual, corporation or other entity must be qualified with the Division of Oil and Gas before they are entitled to submit an offer for the Alaska North Slope Royalty Gas Sale. In order to apply for qualification, an applicant must submit this completed application form to the Division of Oil and Gas by the close of business on **January 17, 2002**, at the address listed below.

Name of Applicant: _____
(Individual, Corporation or other entity name)

Mailing Address: _____

Telephone: _____

In order to qualify, the applicant must be (A) any person who has reached the age of majority and who is a citizen of the United States; (B) any corporation organized and existing under and by virtue of the laws of the United States or of any state, territory or the District of Columbia and qualified to do business in Alaska; or (C) any association of the above.

A. Individuals must complete this section:

I, _____, certify, that as an applicant for qualification to offer in the State of Alaska Royalty Gas Sale, I am a citizen of the United States, and am of the age of majority. (The age of majority in Alaska is 18 years, except for those who are emancipated earlier by marriage or court order.)

Dated _____

Signature: _____

(Full Name)

(Printed or Typed Name)

Street Address or P.O. Box

City, State, Zip Code

(Area Code) Telephone Number

Social Security Number *

An agent who is signing this application form on behalf of an individual or other unincorporated entity must submit, with the application, an original or certified copy of a notarized power of attorney instrument authorizing the agent to act on behalf of the individual.

*Provision of social security number is voluntary, used solely to prevent duplication of records and assure accuracy.

B. Corporations must have on file at the Division of Oil and Gas, or submit with this application, the following information:

1. A copy of the 2001 Certificate of Compliance for those corporations which have been incorporated in the State of Alaska (also known as "Domestic" corporations), or a Certificate of Authority from those corporations which have been incorporated outside the State of Alaska (also known as "Foreign" corporations).
2. A list of current officers authorized to sign a offer on behalf of the corporation.
3. An original or certified copy of a notarized power of attorney if an agent who is not a current officer of the corporation is authorized to act on its behalf.

If this information is already on file with the Division of Oil and Gas, the qualification number is _____.

If the information is not already on file with DO&G, it may be obtained from the Alaska Department of Community and Economic Development, Division of Banking, Securities and Corporations. Inquiries about incorporating in Alaska or qualifying a foreign corporation to do business in Alaska may also be addressed.

C. A partnership or unincorporated association must submit the following:

1. A statement describing the business relationship between members of the association or partnership.
2. A statement of qualifications for each member of the association or partnership attesting that each member has reached the age of majority. If some or all of the members are incorporated entities, all information required for corporations (described in Section B of this form) must also be submitted.
3. If an agent is signing the offer form on behalf of the partnership or association, an original or certified copy of a notarized power of attorney defining the agent's authority to sign the offer on behalf of the partnership or association must be attached to this application.

D. All Applicants must submit the following:

To qualify for eligibility to submit an offer in the Royalty Gas Sale, the applicant must demonstrate that it possesses the management skills and experience the Commissioner determines necessary to perform all terms of the Royalty Gas Sale contract. The Commissioner will consider the applicant's demonstrated capability in financial management, gas movement, and contract management.

Describe below, and on any additional pages necessary, the applicant's experience with the purchase and disposal of gas and the transportation facilities and equipment available to the applicant for performance under the sample royalty gas contract:

The applicant must provide additional information if requested by the Division of Oil and Gas concerning the applicant's financial standing and financial capability to perform the terms of the State Royalty Gas Sale Contract. Upon the applicant's written request, the Commissioner will hold confidential, to the extent provided by law, cost data or financial information contained in the application that the applicant designates as confidential under AS 38.05.035(a)(9)(D).

The completed application must be addressed to the Division of Oil and Gas, Attn: Kevin Banks, 550 West Seventh Avenue, Suite 800, Anchorage, AK 99501-3510, and be received no later than 4:30 p.m., Alaska Standard Time, January 17, 2002.

Submission of false information in this application or in support of this application may result in the immediate withdrawal of the application or award, the cancellation of a contract if it has been executed or, if discovered prior to the opening, may result in disqualification from participating in the sale. In addition, the commissioner may disqualify a potential purchaser from participating in future sales of state royalty gas.

I certify that all of the information provided on this application or in support of this application is accurate and complete.

Date

Authorized Signature

Printed or Typed Name

THE UNITED STATES OF AMERICA)) ss.
STATE OF _____)

On this _____ day of _____, 20__, before me, the undersigned, a Notary Public duly commissioned and sworn, appeared _____, personally known to me, or proved to me on the basis of satisfactory evidence, to be the person whose name is subscribed to the within Statement.

WITNESS my hand and official seal.

Notary Public in and for the State of _____
My commission expires _____

**State of Alaska
Department of Natural Resources
Alaska North Slope Royalty Gas Sale
Offer**

Name of Offeror _____

Address _____

Contact Person _____ Phone No _____

To the Commissioner of Natural Resources:

In response to the State's Solicitation for Offers issued December 26, 2001, the undersigned offeror, having been qualified by the Commissioner, makes the attached offer for Alaska North Slope Royalty Gas.

Additional information that the Commissioner may read at the public hearing to be held February 1, 2002 is below:

Offeror: _____

Date: _____

By: _____

Title: _____

Attach Proposal