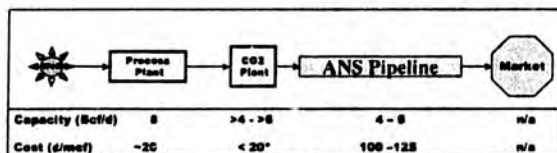


ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2929 SCOMM 128 : HOUSE SPEC.COMM. ON OIL AND GAS, 2001-02

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

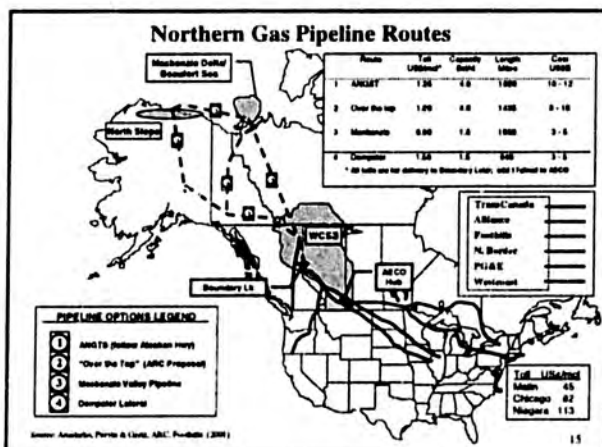
13

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

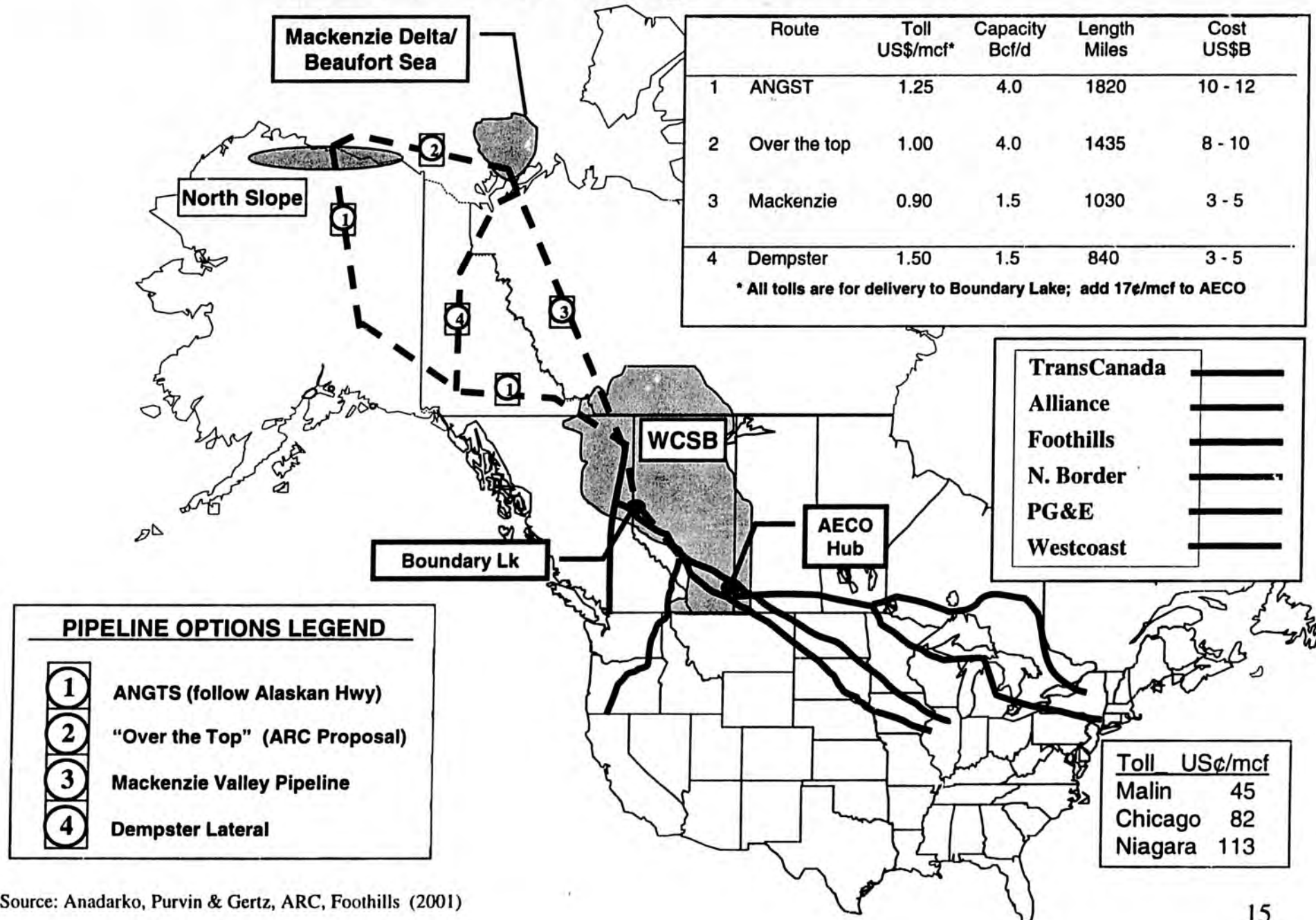
14

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**

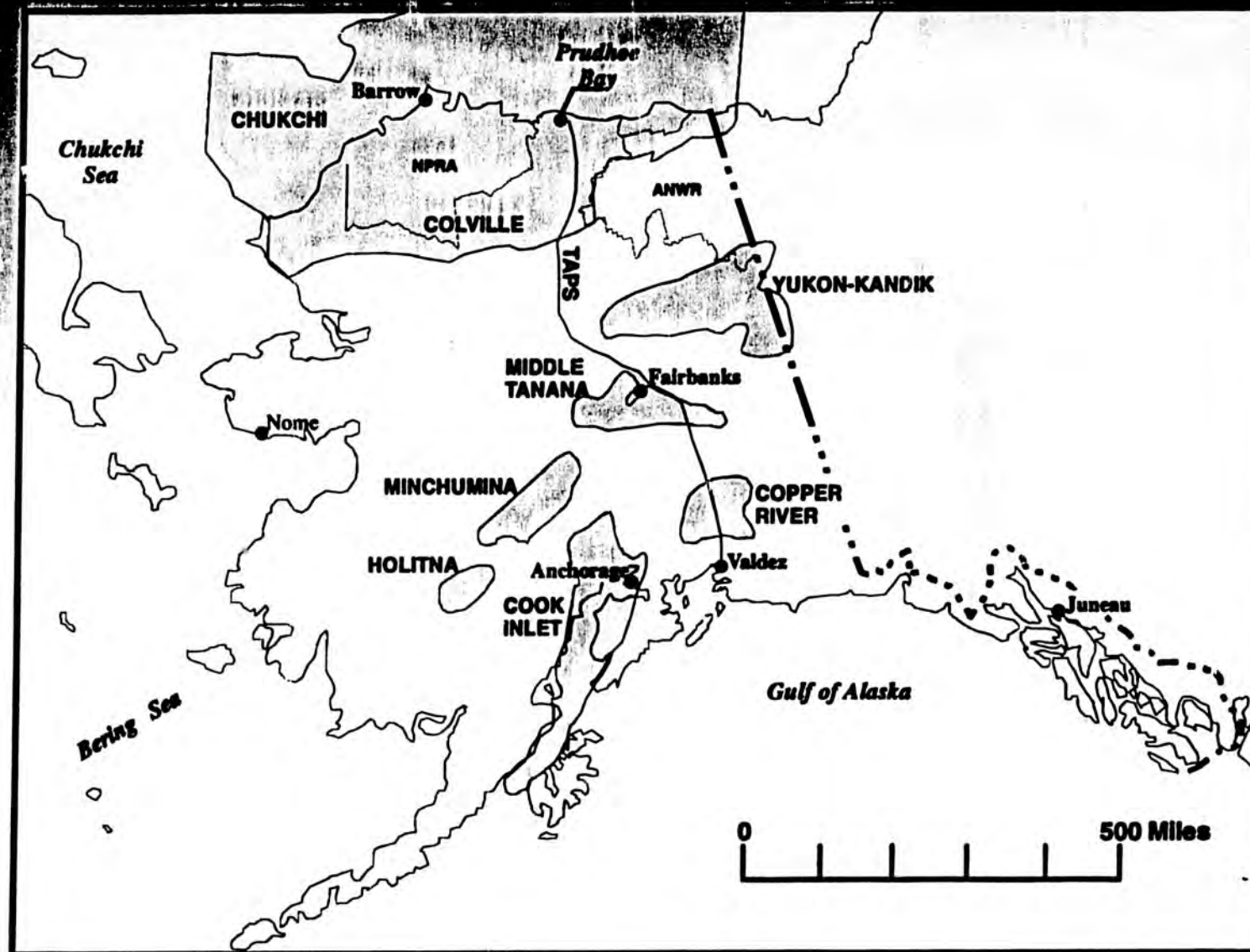


Figure A

Known Hydrate Accumulations

Prudhoe Bay, Alaska

42 TCF (Collett, 1993)

Cirque - Tarn, Alaska

60 TCF (Collett, 1993)

Figure B

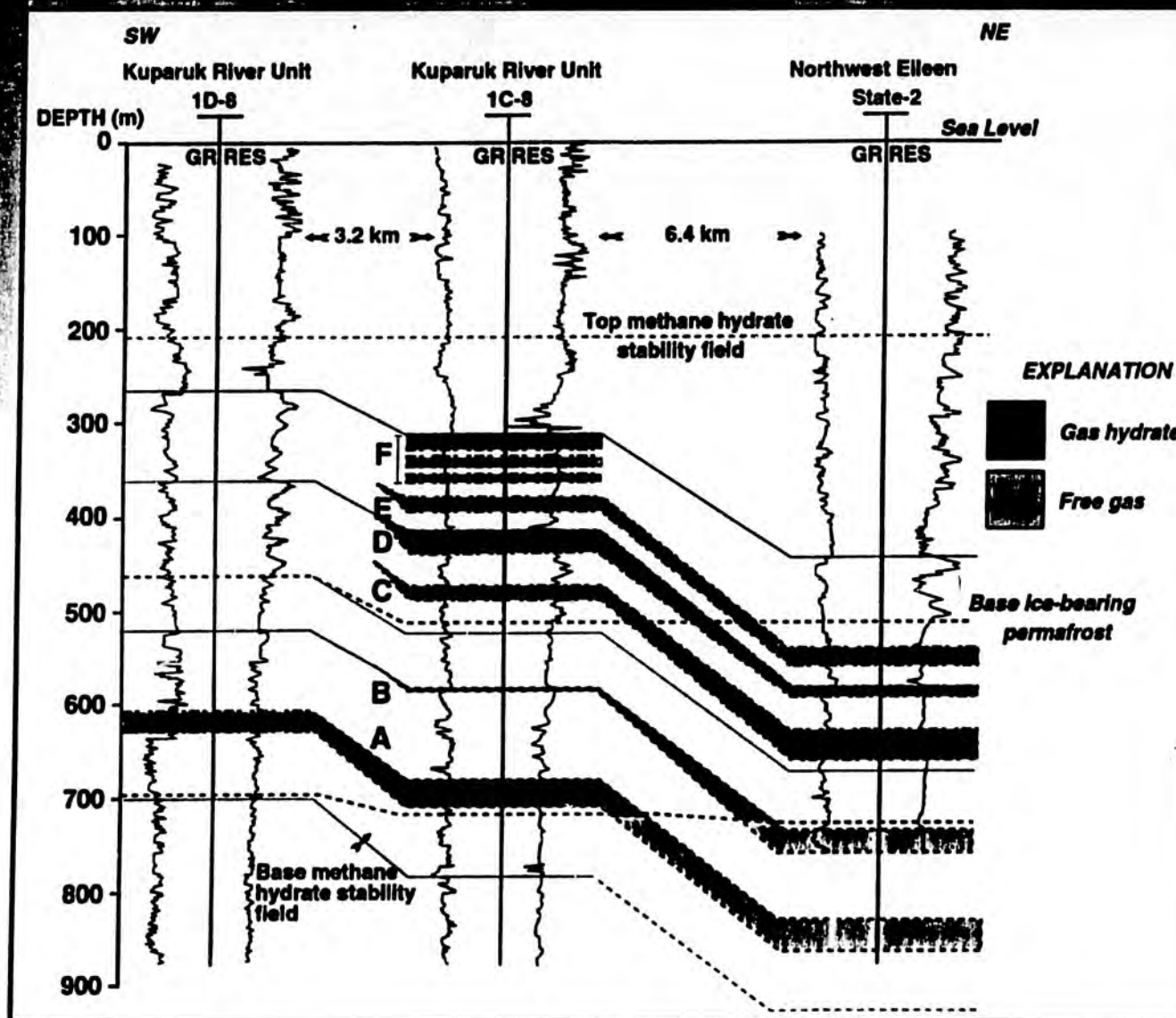
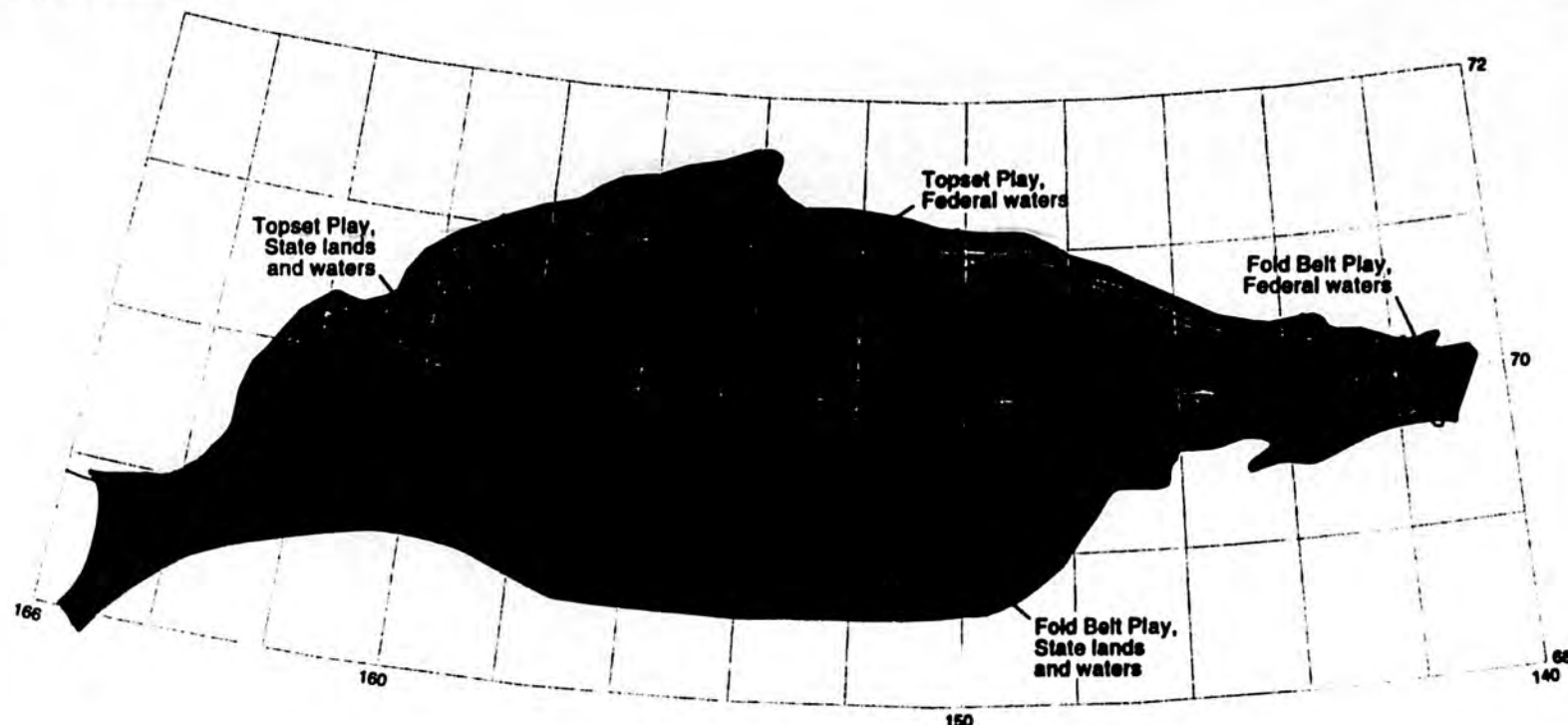


Figure D

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



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 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.

CORRECTION

**THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION**



Central Microfilm Services
Department of Education & Early Development
State of Alaska

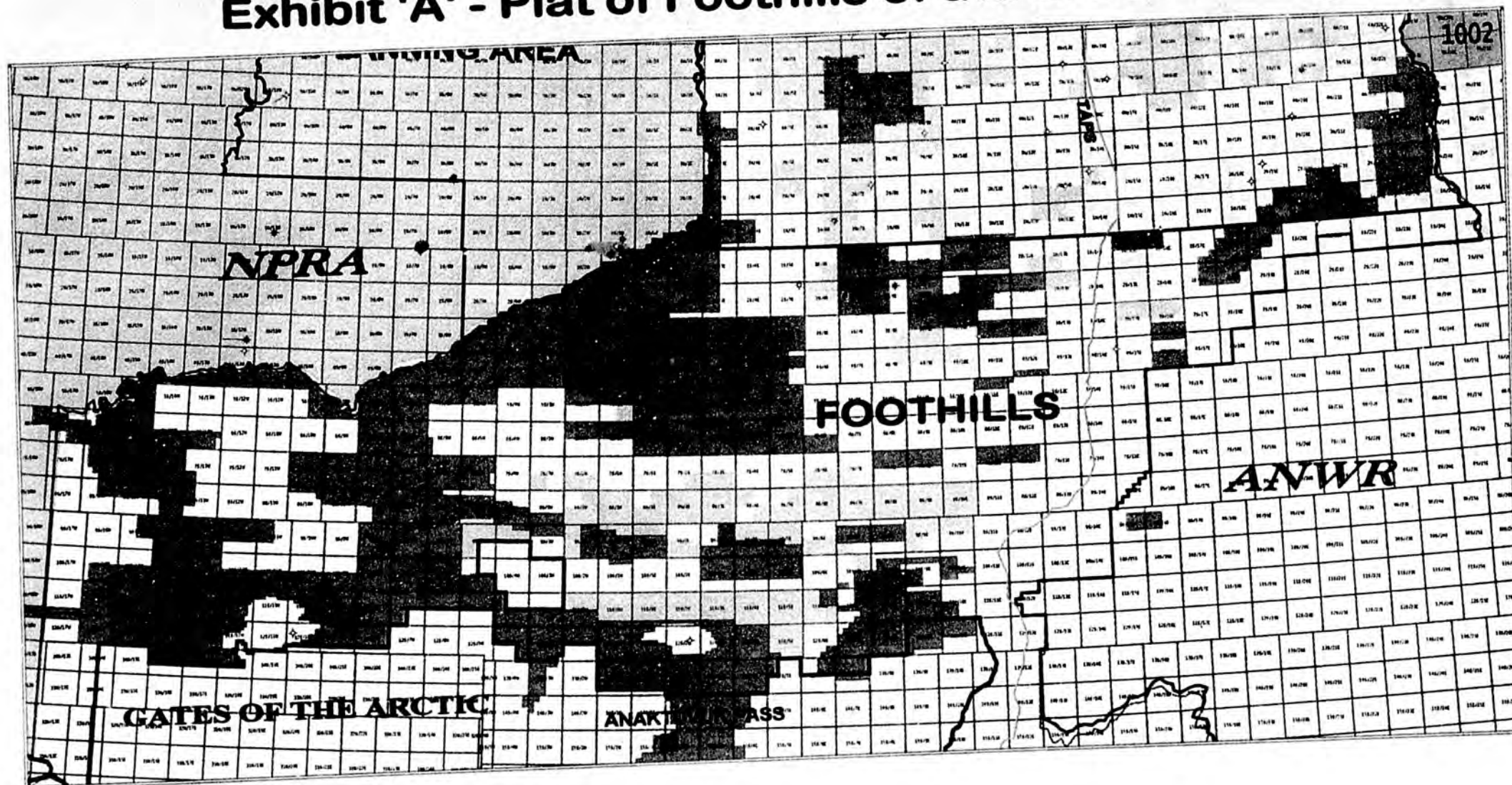
Under this scenario the State could actually realize an increase in royalties paid. If the Pipeline were to be promptly expanded and the State held all or part of the mineral rights underlying the Purchasers' new gas field, the State's royalty volume/value would increase by as much as 43,750 Mcfd (12.50% 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.

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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



1002

- ☐ 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

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**NORTHERN
ECONOMICS**

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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
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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:

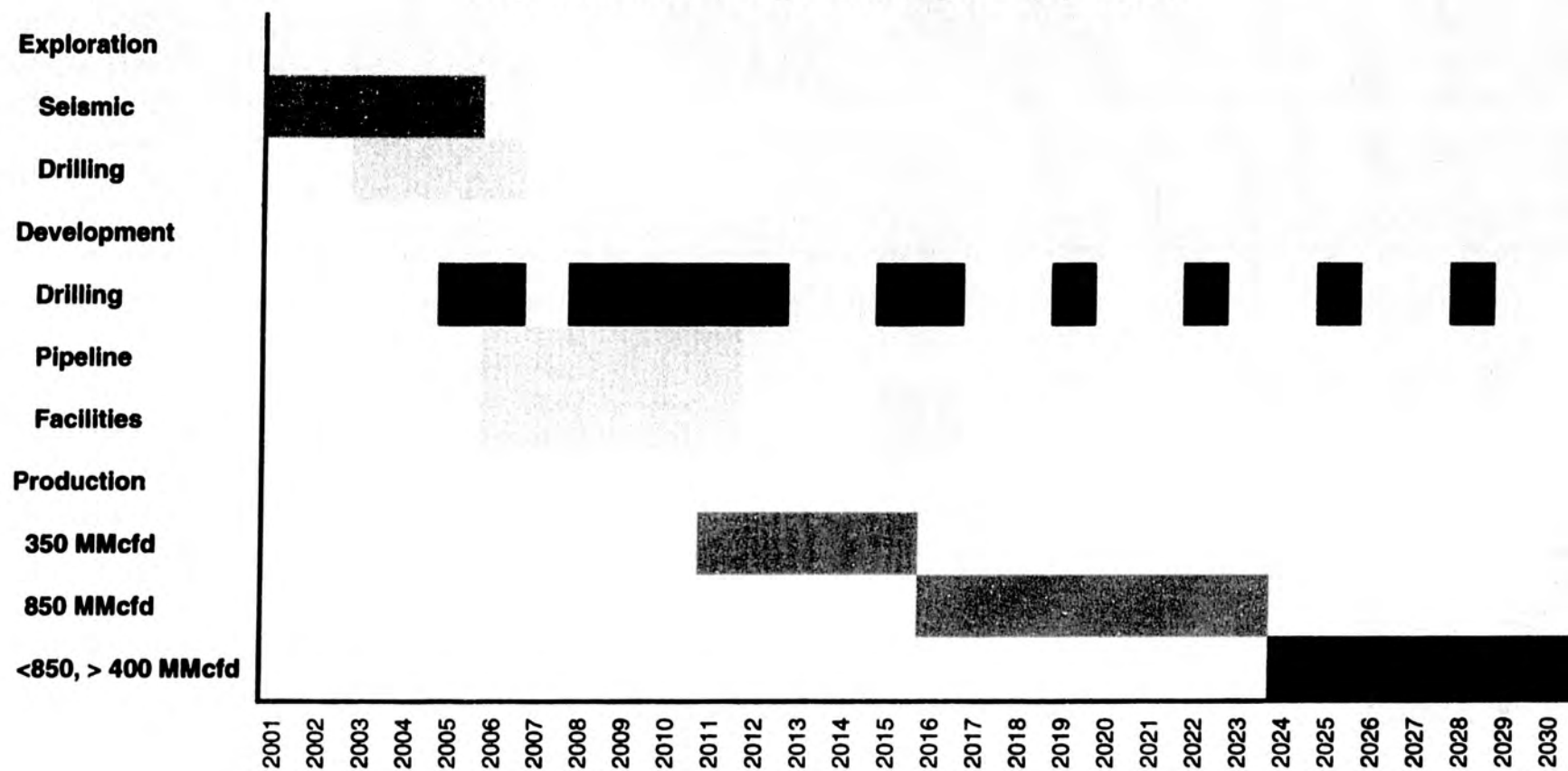
- Personnel
- Business services
- Equipment and supplies
- Construction activity
- Transportation
- Labor support
- Other

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 MMcf/d for the first five-years followed by 850 MMcf/d 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 MMcf/d 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
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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

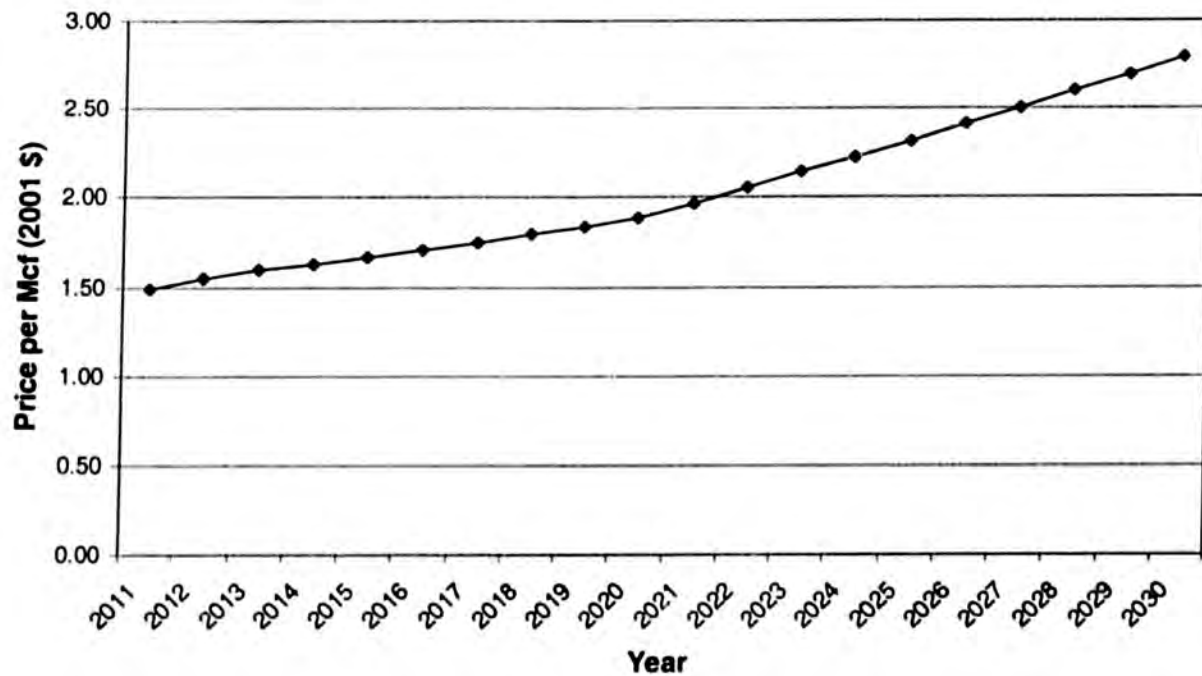
Year	Industrial (Mcf) from EIA	Electricity Generators (mcf) from EIA	Average (mcf)	Production (MMcfd) Provided by Anadarko	Wellhead Netback Price	Total Revenue (2001 \$ Millions)
2011	3.63	3.53	3.58	350.00	\$1.49	\$190.35
2012	3.68	3.59	3.64	350.00	\$1.55	\$197.37
2013	3.73	3.64	3.69	350.00	\$1.60	\$203.76
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

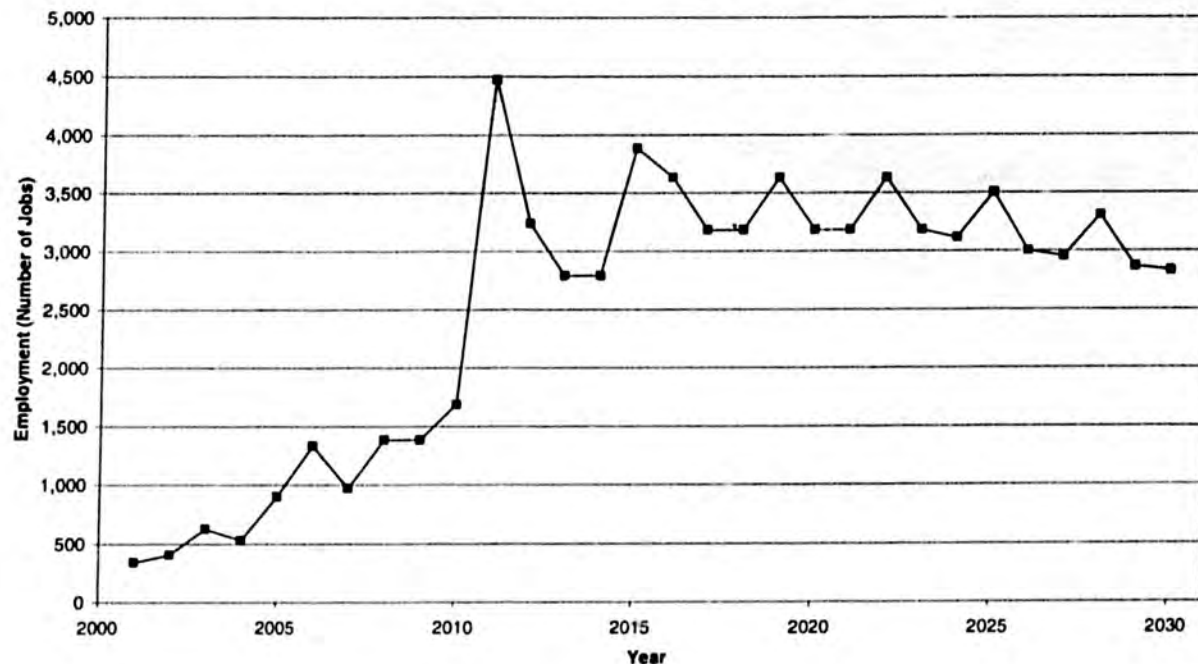


Table 3-2 provides NSB estimates for direct, indirect, and induced employment for exploration, development, and production of Anadarko/AEC ANS foothills gas operations. Like the state, the largest share of the impacts for the NSB is from expenditures of government revenues. The largest direct impact 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.

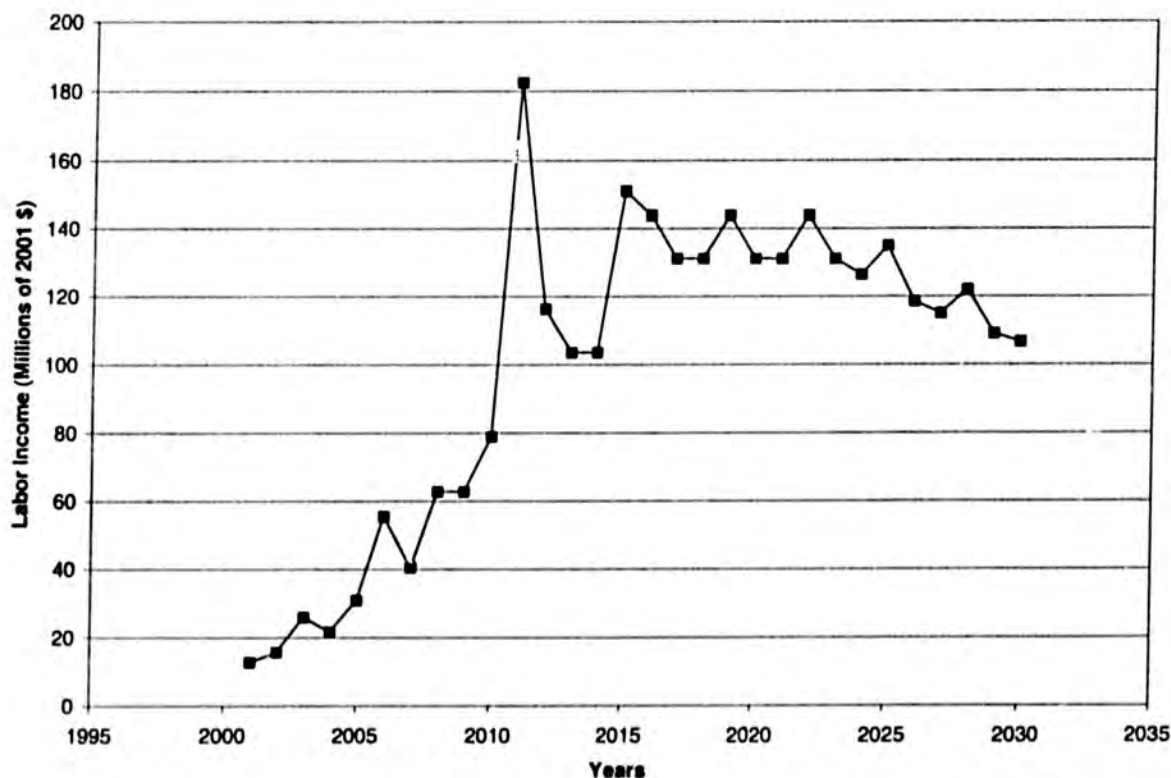
Figure 4-1. Annual Labor Income for the State of Alaska from the Anadarko/AEC ANS Foothills Gas Project, 2001-2030

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

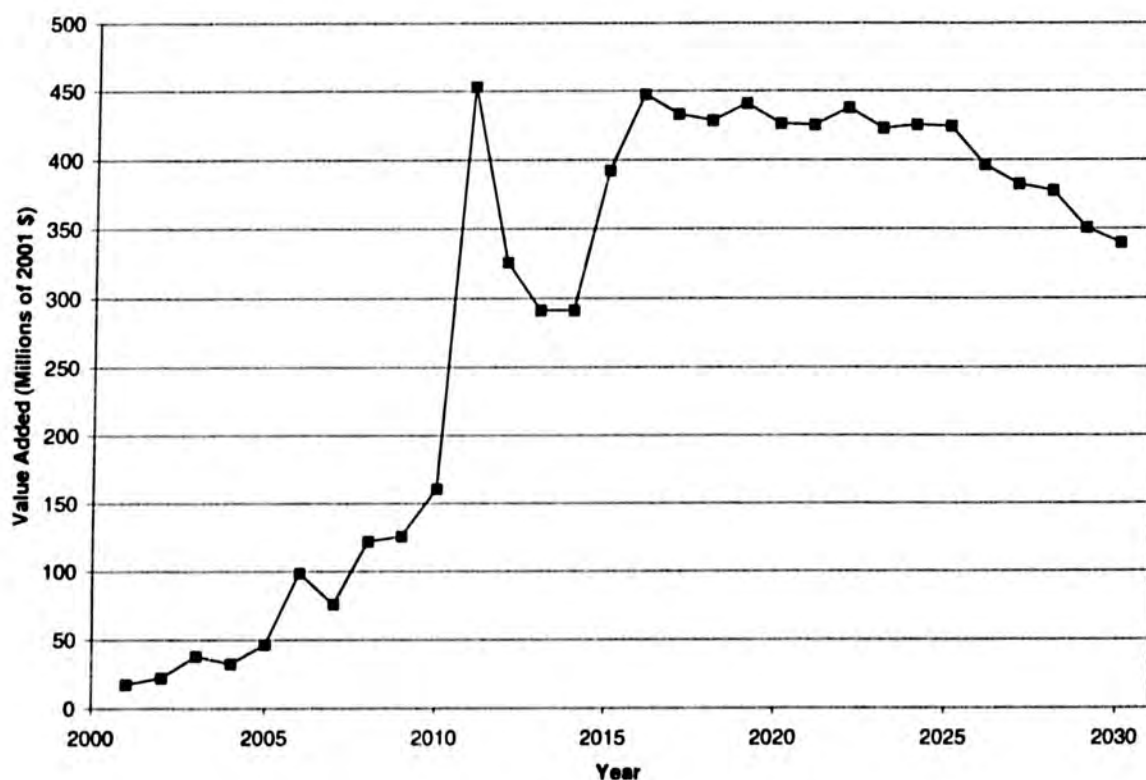


Table 4-4 presents NSB impact estimates for value-added from ANS foothill natural gas project. Direct expenditures by Anadarko/AEC contributed total value-added of \$471 million. Payments by Anadarko/AEC for property taxes were the reason for the large direct value-added impact. NSB revenue expenditures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