

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2321 SCOMM 96: HOUSE SPEC. COMM. ON OIL & GAS, 1995-1996

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ARTICLE XI

FORCE MAJEURE AND CHANGE IN CONDITION

11.1 Effect of Force Majeure. Except for Tesoro's obligations to pay for Oil tendered and to accept and dispose of Royalty Oil, neither party shall be liable for any failure to perform when performance is prevented, in whole or in substantial part, by force majeure after good faith efforts to perform. The term "force majeure" shall mean an event or condition not within the reasonable control of the party claiming the benefit of this excuse. If, however, any material obligation of Tesoro is excused or suspended by a force majeure for sixty successive Days or more, the State will have the right to terminate this Agreement. Before the State exercises its right to terminate, Tesoro and the State shall in good faith negotiate to restore the benefits and obligations of the force majeure condition.

11.2 Responsibility. If a party believes that force majeure has occurred, the party shall immediately notify the other party of its claim of force majeure. If force majeure occurs, that occurrence shall, so far as possible, be remedied with reasonable diligence. Except for Tesoro's obligations to pay for Oil tendered and to accept and dispose of Oil, the disabled party's obligations to perform that are affected by the force majeure shall be suspended from the time that notification occurs until the disability should have been remedied with reasonable diligence, and for no longer.

1 principal face amount of such letter of credit shall be a sum estimated by the Commissioner, in his
2 sole discretion, to be equal to the aggregate purchase price for the approximate total amount of Oil to
3 be tendered by the State to Tesoro during the first seventy five Days following the Date of First
4 Delivery. The letter of credit shall be in a form satisfactory to the Commissioner, but in any event
5 shall not require any documents to be submitted in support of drafts drawn against this letter of credit
6 other than the certified statement of the Commissioner or his designee and the Attorney General of
7 the State of Alaska or his designee that Tesoro is liable to the State for a sum equal to the amount of
8 such draft, and that sum is due and payable in full and has not been timely paid. The letter of credit
9 must be renewed seventy five Days before its expiration so that a letter of credit is continuously valid
10 for seventy five Days after the date of the last delivery of Royalty Oil. If a replacement letter of
11 credit, in a form satisfactory to the Commissioner in his sole discretion, is not received seventy five
12 Days before the expiration of the existing letter of credit, then Tesoro shall be deemed to have
13 materially breached this Agreement, there shall have occurred an event of default under Article 7.1,
14 and all obligations of Tesoro accrued, but not otherwise due and payable under this Agreement, will
15 immediately become due and payable in full.

16 If the State has reasonable grounds for asserting any claims against Tesoro and does
17 assert those claims in an aggregate amount in excess of the aggregate principal face amount of the
18 letter of credit then in effect, Tesoro shall, upon the State's request (whether or not Tesoro may deny,
19 reject or otherwise resist such claims), cause the principal face amount to be increased by an amount
20 equal to the excess. Tesoro shall also automatically increase the principal face amount, without
21 request from the State, whenever the face amount is less than the expected purchase price of seventy
22 five Days of Oil tenders, to an amount equal to the expected purchase price of seventy five Days of

1 Oil tenders. Upon approval of the State in its sole discretion, Tesoro may decrease the principal face
2 amount if the face amount is more than the expected purchase price of seventy five Days of Oil
3 tenders to an amount equal to the expected purchase price of seventy five Days of Oil tenders.

4 The letter of credit must allow drafts to be drawn and presented to the Issuer up to and
5 including the 75th Day after the last delivery of Royalty Oil to Tesoro under this Agreement. The
6 Commissioner may accept such other or additional security as he, in his sole discretion, considers
7 adequate to protect the State.

8 15.2 Reduction of Term. The term of the letter of credit required under Article XV
9 shall be reduced from seventy five Days to sixty Days, if Tesoro and the State can reach an agreement
10 regarding the transportation of Oil if Tesoro defaults under this Agreement. If the parties cannot
11 reach an agreement, then the letter of credit shall remain at seventy five Days or Tesoro shall have the
12 right, in its sole discretion, to terminate this Agreement as provided in Article 2.1.

14 ARTICLE XVI

15 PREFERENTIAL HIRING AND NON-DISCRIMINATION

16 Tesoro agrees to employ Alaska residents and Alaska companies to the extent they are
17 available, willing and qualified for all work performed in Alaska in connection with the Agreement.

18 "Alaska resident" means an individual who has resided in Alaska for one year at the time of
19 employment and "Alaska companies" means companies incorporated in Alaska or whose principal
20 place of business is in Alaska.

1 If this provision is determined to be unconstitutional, then Tesoro agrees to employ
2 Alaska residents and Alaska companies to the extent such preferential hiring is determined to be
3 constitutional.

4 5 **ARTICLE XVII**

6 **APPLICABLE LAW**

7 17.1 Alaska Law. This Agreement shall be governed by and construed in
8 accordance with the laws of the State of Alaska.

9 17.2 Submission to Jurisdiction. Any legal action or proceeding arising out of or
10 relating to this Agreement or for the enforcement of the covenants or obligations of either party must
11 be instituted in a State court of general jurisdiction sitting in the State of Alaska, and Tesoro hereby
12 irrevocably submits to the jurisdiction of that court in any such action or proceeding.

13 14 **ARTICLE XVIII**

15 **WARRANTIES**

16 The purchase and sale of Royalty Oil are subject only to the warranties of the State
17 expressly set forth in this Agreement and the State disclaims and Tesoro waives all other warranties,
18 express or implied in law, whatsoever.

ARTICLE XIX

AMENDMENT

This Agreement may be supplemented, amended, or modified only by written instrument duly executed by the parties.

ARTICLE XX

SUCCESSORS AND ASSIGNS

No assignment, pledge, or encumbrance of this Agreement shall be made by either party without the written consent of the other party. The Commissioner or the Commissioner's designee may grant or deny such consent. Subject to the above requirements in this article, this Agreement will be binding upon and inure to the benefit of each of the parties and its successors and permitted assignees.

ARTICLE XXI

HEADINGS

Headings used in this Agreement are for convenience only and shall not affect its construction.

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1 law or regulation, Tesoro may request that information be held confidential by the State and the State
2 will keep this information confidential.

4 **ARTICLE XXIII**

5 **INTERPRETATION OF TERMS AND CONDITIONS**

6 Any disagreement about the meaning or application of a word, term, or condition in
7 this Agreement will be decided according to the dispute resolution procedure set forth in this article.
8 Either party may give the other written notice of a disagreement. Within 60 days after written notice,
9 Tesoro must present any argument and evidence supporting its view in writing to the Commissioner
10 for consideration. Tesoro shall not have the right to civil litigation-type discovery or a civil litigation-
11 type trial with the right to call or cross-examine witnesses unless granted by the Commissioner in his
12 sole discretion. The Commissioner will subsequently issue a finding on the meaning or application of
13 the disputed word, term, or condition, setting forth the basis for the conclusions. Tesoro agrees to
14 accept findings by the Commissioner under this article which are supported by substantial evidence.

16 **ARTICLE XXIV**

17 **COUNTERPARTS**

18 This Agreement may be executed in multiple counterparts, the parties need not sign
19 the same counterpart. Each counterpart shall be deemed to be an original and all of which taken
20 together shall be one and the same instrument.

SIGNATURES

the State:

THE STATE OF ALASKA

Commissioner
Department of Natural Resources

Date: _____

Tesoro Alaska Petroleum Company:

TESORO ALASKA PETROLEUM COMPANY

By: _____

Its: _____

Date: _____

Tesoro Petroleum Company

TESORO PETROLEUM COMPANY

By: _____

Its: _____

Date: _____

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ACKNOWLEDGEMENT

State of Alaska)
) ss.
Third Judicial District)

THIS IS TO CERTIFY that on the _____ day of _____, 1995, before me,
appeared _____, the commissioner, Department of Natural Resources, State of Alaska; that
Harry A. Noah executed that document under legal authority and with knowledge of its contents; and
that this act was performed freely and voluntarily upon the premises and for the purposes stated in the
document.

Witness my hand and official seal the day and year in this agreement first above
written.

Notary Public in and for Alaska

My commission expires: _____

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THIS IS TO CERTIFY that on the _____ day of _____, 1996, before me, appeared _____ of Tesoro Alaska Petroleum Company, San Antonio, Texas; that _____ executed that document under legal authority and with knowledge of its contents; and that this act was performed freely and voluntarily upon the premises and for the purposes stated in the document.

My commission expires: _____

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My commission expires: _____

EXHIBIT A

CALCULATION OF ROYALTY VALUE

This exhibit shows the mechanics of the price calculation and data sources. Exxon's Royalty Value for the Prudhoe Bay Unit lessees are taken from its Royalty Report. Royalty Value currently is taken from Column H of these reports. An example calculation using the information for January 1995 and a hypothetical RIK volume sold to Tesoro is shown below. Attached are the Royalty Report Summaries for the Prudhoe Bay Unit.

	Exxon's Production from the Prudhoe Bay Unit		Royalty Value from Column H of the Oil Royalty Report Summary		Product of Volume Times Royalty Value
Lisburne Production Center	1,762,900.13	x	\$11.050	=	\$19,480,406.44
Prudhoe Bay IPA	8,807,215.20	x	\$11.110	=	\$97,848,160.87
Total	10,570,115.33				\$117,328,207.31

$$\text{Exxon's Royalty Value} = \$117,328,207.31 \div 10,570,115.33 = \$11.09999$$

Should Article 2.1(b) apply, the Royalty Value will be calculated using the Royalty Value and production volumes for only the initial Participating Areas.

CALCULATION OF INTEREST

Numbers in these examples are illustrative. They do not represent accurate values that may have existed in the past or are forecasted for any time in the future.

Mechanics of the calculations include:

1. The annual interest rate specified in legislation is converted to a daily rate for calculations.
2. Credits are applied to the next monthly payment. Payment for an underpayment is due (a) within 3 business of the date the bill is sent for Initial Billings and initial adjustment or (b) within 30 days of the time the bill is sent for subsequent adjustments. Interest on overpayments stops accruing on the date of the invoice.

Example 1: Initial Billing

Assumptions:

1. Month is February.
2. Royalty Oil delivered to Tesoro in January = 1,240,000 barrels.
3. Royalty Value for January, from Column H of Exxon's Oil Royalty Report Summaries (attached) = \$11.09999.
4. Bill sent to Tesoro on February 1st; Payment due to State by February 6th (Initial Billing date plus three business days).

Method for calculating Tesoro's initial invoice for January deliveries:

Volume	x	Price	=	Initial Billing
1,240,000	x	\$11.09999	=	\$13,763,987.60

Note:

The lessees are required to submit their royalty reports to the State for January's production by the last day in February. For this reason the State will bill Tesoro for January production based on the December Royalty Value. This is an interim value and is subject to revision, since the Agreement requires that Tesoro pay the Monthly Price for the same production month. The revised price is incorporated in the invoice submitted the following month (March).

Example 2: Initial Adjustment

Assumptions:

1. Month is March.
2. Royalty Oil delivered to Tesoro in January = 1,240,000 barrels.
3. Revised Monthly Price for January = \$11.00000.
4. Annual interest rate charged member banks for advances by 12th Federal Reserve District as of January 1st is three percent. Annual rate for contract = 11 percent.
5. Date of Initial Adjustment is March 1st.

Method for calculating Tesoro's revised invoice for January deliveries:

Volume	x	Price	=	Revised Billing
1,240,000	x	\$11.00000	=	\$13,640,000.00

Amount Paid by Tesoro for January deliveries (calculated in Example 1):

\$13,763,987.60

Overpayment for January:

(\$123,987.60)

Difference between Initial Adjustment date (March 1st) and original accrual date (February 6th) = 23 days.

Interest due = $\$123,987.60 \times (11\%/365) \times 23 =$ (\$859.42)

Credit due Tesoro for next month's billing = (\$124,847.02)

Example 3: Subsequent Adjustment

This adjustment is assumed to occur after true-up of BP transportation costs, a reopener for one of the Royalty Settlement Agreements, or for some other reason. It is assumed to occur June 5th.

Assumptions:

1. Month is June.
2. Royalty Oil delivered to Tesoro in January = 1,240,000 barrels.
3. Adjusted Monthly Price for January = \$11.11000.
4. Annual interest rate charged member banks for advances by 12th Federal Reserve District as of January 1 assumed to be three percent; as of April 1 and through the third quarter, seven percent. Annual interest rate for contract = 11 percent for the first quarter; 12 percent for the second and third quarter.
5. Tesoro is sent notice of underpayment on June 5th.
6. Tesoro's payment is received on July 5th.

Method for calculating Tesoro's revised invoice for January deliveries:

Volume	x	Price	=	Revised Billing
1,240,000	x	\$11.11000	=	\$13,776,400.00
Amount Paid by Tesoro for January deliveries (calculated in Example 2):				\$13,640,000.00
Underpayment for January deliveries:				\$136,400.00

Days of interest in first quarter (Initial Billing date plus 3 business days through March 31st) = 53

Days of interest in second quarter (April 1 through June 30th) = 91

Days of interest in third quarter (July 1 through July 5) = 5

Interest for first quarter = $\$136,400.00 \times (11\%/365) \times 53 =$ \$2,178.66

Interest for second quarter = $(\$136,400.00 + \$2,178.66) \times (12\%/365) \times 91 =$ \$4,145.97

Interest for third quarter = $(\$136,400.00 + \$2,178.66 + \$4,145.97) \times (12\%/365) \times 5 =$ \$234.62

Payment from Tesoro due to the State within 30 days of invoice date = \$142,959.25

If payment in full not received by or on July 5th then additional interest will accrue from July 6th through the payment receipt date, plus a late payment penalty will be assessed.

*An Analysis of the Department of Natural Resources'
Proposed Three-Year Contract for the Sale of
Prudhoe Bay Royalty Oil to Tesoro Alaska
Petroleum Company*

Tesoro Alaska Petroleum Company
March 29, 1995

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Proposed Three-Year Contract for the Sale of
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*An Analysis of the Department of Natural Resources'
Proposed Three-Year Contract for the Sale of
Prudhoe Bay Royalty Oil to Tesoro*

I. Summary

The Department of Natural Resources ("DNR") is proposing to sell 30% of the state's royalty oil entitlement from the Prudhoe Bay Unit--or about 27% of all North Slope royalty oil--to Tesoro Alaska Petroleum Company ("Tesoro"). Roughly 40,000 barrels per day of royalty oil would be available to Tesoro under the contract.

The contract term would be only three years, and would require that at least 80% of the oil purchased be processed at Tesoro's Nikiski refinery.

The contract requires legislative approval under AS 38.06.055. Royalty oil has been, and remains, the principal feedstock for Tesoro's refinery; indeed, deliveries under the proposed contract would represent about 80% of the refinery's crude supply. There are no other stable, long-term sources of crude for that refinery, and Tesoro's current one-year contract for state royalty oil expires on December 31, 1995.

As a result, if the legislature is unable to act on the proposed contract before it adjourns its 1995 session, Tesoro would lose about 80% of its crude oil supply, and continued operation of the Nikiski refinery would be in peril.^{1/}

Because the proposed contract must be reviewed by the Alaska Royalty Oil and Gas Development Advisory Board ("Royalty Board") before being presented to the

^{1/} By statute, DNR could not even renew Tesoro's one-year purchase contract without the legislature's approval. AS 38.06.055(c).

legislature,^{2/} legislation approving the contract should be ripe for introduction about April 24, 1995. However, and given that time is short, the legislature ought to begin evaluating the proposed contract now.

The legislature will review the proposed contract from two distinct perspectives: (1) as steward of Alaska's economy; and (2) as a seller of oil intent on receiving full value, and adequate security, for its product. This paper looks at the contract from both points of view:

1. The Alaska Economy. Alaska has a longstanding policy of employing a portion of its royalty oil entitlement to promote the growth of, and competition among, in-state oil refiners. As a result, Alaska has become virtually self-sufficient in refined petroleum products, and the resultant competition between the state's three in-state refiners has saved Alaska consumers hundreds of millions of dollars in retail gasoline prices alone.

Alaska's royalty oil policy has succeeded in large measure through royalty oil sales to Tesoro. This despite the fact that, among in-state refiners, Tesoro suffers a considerable competitive disadvantage, principally because its refinery is not directly linked to the Trans Alaska Pipeline. While Tesoro has never asked the state to help level this playing field, future competition can be assured only if the state, through its royalty oil dispositions, does nothing to aggravate the competitive disparity between Tesoro and other in-state refiners.

^{2/} AS 38.06.050(a).

2. The State's Interest in Full Value. *Tesoro has never asked for, nor has it ever received, any subsidy or special allowance in purchasing royalty oil. Certainly the proposed contract grants none. Indeed, DNR has taken considerable advantage of its virtual monopoly position as Tesoro's only realistic principal source of supply.*

Among the document's more rigorous requirements are these:

a. Price. *Tesoro would be obligated, under the proposed contract, to pay a substantial "premium" above the price that the state receives from either: (1) the North Slope producers, in the aggregate, for royalty oil taken in value; or (2) other in-state refiners. In the month of January, 1995, that premium would have been \$.19/bbl.--or, on an annualized basis, about \$2.77 million;*

b. Security. *DNR has always been rightly concerned with the prospect of purchaser default--an event that could force the state to sell royalty oil under distress conditions. The proposed contract affords DNR an extraordinary series of safeguards in this respect. For example: in the past, Tesoro has posted a 60-day letter of credit to guarantee payment of oil delivered under the contract. (MAPCO Petroleum, conversely, posts no letter of credit at all.) The proposed contract lengthens that letter of credit to 75 days, unless Tesoro is able to assign its long-term tanker charter agreement to the state itself, so that DNR would have immediate access to an oil tanker if it found itself holding royalty oil; and*

c. Special Flexibility to Respond to a Lifting of the North Slope Export Ban. *Even if Tesoro takes every barrel allowed under the proposed contract, about 57%*

of the state's ANS royalty oil would remain uncommitted, and available for whatever opportunities a lifting of the ban might create. Moreover, under a special reopener clause in the contract, the state can renegotiate the price term if and when the ban is lifted, and then terminate the contract if reopener negotiations don't yield a price commensurate with a changed ANS market. This clause affords DNR ample discretion to manage both uncommitted royalty oil, and Tesoro's royalty oil, if and when the ban is lifted.

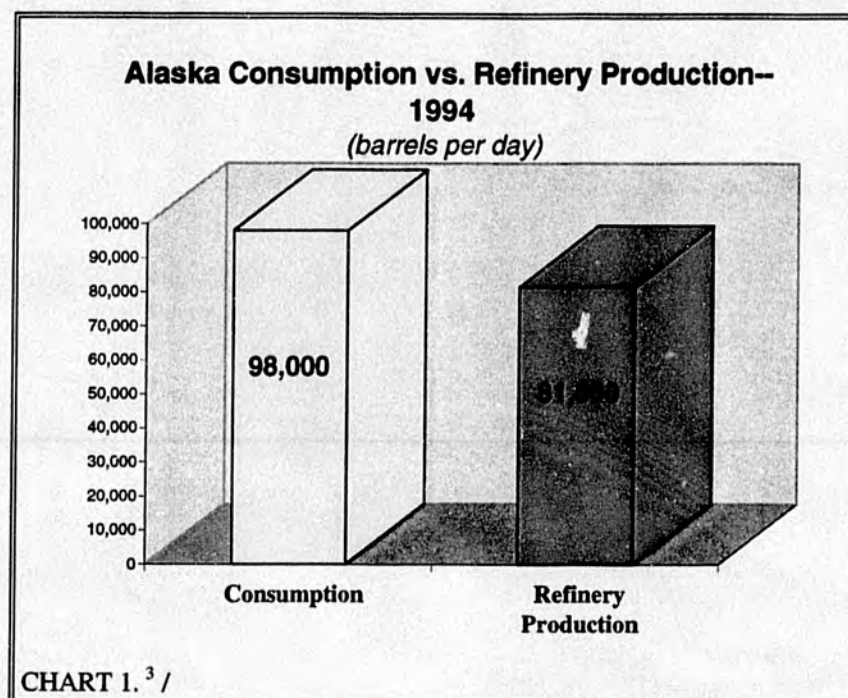
In short, at virtually every turn DNR has exploited its considerable bargaining advantage. This will be the most favorable contract--from the state's perspective--under which any royalty oil has ever been delivered.

Nonetheless, the contract does meet Tesoro's need for a stable source of crude--albeit for only three years. As a result, the contract deserves legislative approval.

II. The Proposed Contract's Contribution to Alaska's Economy and Energy Self-Sufficiency

A. The Proposed Contract is a Continuation of an Alaska Success Story

Alaska has always used a portion of its royalty oil as more than a source of revenue. Since the 1970's, it has employed that oil to make Alaska virtually self-sufficient in gasoline and other refined products. Alaska's refineries actually have the capacity to meet all of the state's refined product needs. While Alaska still imports about 15% of its refined products, those imports reflect shipments to Southeast Alaska and the Arctic--which are beyond the effective distribution reach of in-state refiners.^{4/} As Chart 1 illustrates, except



for those remote-market imports, Alaska's refinery production virtually equals in-state demand.

^{3/} Source: (1) Consumption: DNR, "Historical and Projected Oil and Gas Consumption," Feb. 1994 at 23; (2) Production: Tesoro internal production estimates.

^{4/} DNR, "Preliminary Finding and Determination to Sell Royalty Oil to Tesoro Alaska Petroleum Company," March 21, 1995 ("1995 Tesoro Findings") at 9.

The impact on Alaska consumers has been considerable. A 1992 MAPCO Petroleum study, for example, documented a \$.30/gallon difference in gasoline prices between Anchorage and Southeast Alaska--the higher prices in the Panhandle being attributable, in material part, to the lack of refiner competition in that region. ^{5/} As that study explains, even if only 1/3 of that price differential were attributable to the keen competition encouraged by state royalty oil policy, that policy would still be responsible for a \$450 million savings to Alaska consumers in the 1980's. *Id.* at 1.

Apart from direct consumer benefits, Alaska's refining industry directly employs about 850 people, and pays about \$11 million annually in local and state taxes. For its part, Tesoro employs 552 Alaskans, and it recently completed a \$25 million vacuum unit designed to convert currently-unprofitable residual fuel into more valuable product. This is in addition to the \$236 million in capital improvements that Tesoro has made in Alaska over the past two decades.

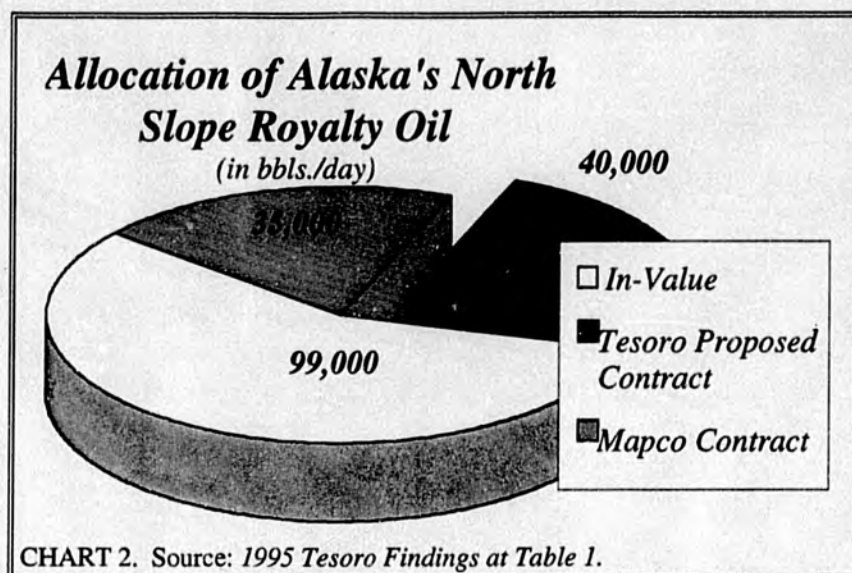
All these benefits flow directly from the Alaska Legislature's clear direction to manage Alaska's royalty oil and gas in a way that encourages in-state energy self-sufficiency. For example, royalty oil can't be exported unless it's surplus to in-state needs, ^{6/} and non-competitive sales must always be made to the buyer that "offers the maximum benefits to citizens of the state"--including the "benefits of refining or processing the oil or gas in the state." AS 38.05.183(e). ^{7/}

^{5/} Purvin & Gertz Study, prepared for MAPCO Petroleum (1992) at 4.

^{6/} AS 38.05.183(d).

^{7/} The statutes governing the Alaska Royalty Oil and Gas Development Advisory Board likewise create a pronounced bias towards in-state use of royalty oil. AS 38.06.070(a) and (b).

Given that policy, and the considerable benefits that have flowed from it, it's surprising how small a fraction of state royalty oil is actually committed to in-state



refiners. As Chart 2 shows, even if the legislature approves the proposed Tesoro contract, only 43% of the state's ANS royalty oil would be sold to in-state refiners. The rest would still be taken in value.^{8/}

B. Royalty Oil Sales to Tesoro Are Largely Responsible for the Success of the State's Royalty Oil Policy.

The state has profited considerably from its modest investment of royalty oil. Nowhere is this more true than with respect to DNR's royalty oil sales to Tesoro. The Nikiski refinery began operations in the 1960's, supplied in part by Cook Inlet royalty oil. Tesoro began receiving ANS royalty oil in July, 1980, and, by 1987, Tesoro had invested over \$200 million to modify the refinery to process ANS royalty crude. ANS royalty oil has been the principal source of its feedstock ever since.

From that feedstock, Tesoro supplies virtually all of the gasoline sold in Southcentral Alaska, through: (1) its own service stations; and (2) sales to other retailers.

^{8/} A 1992 contract to sell approximately 30,000 bbls./day of royalty oil to Petro Star JV over a 10-year period was terminated by DNR when Petro Star declined to take oil under the contract.

In addition, Tesoro's gasoline is sold by MAPCO in Anchorage, and MAPCO's gasoline is sold by Tesoro in Fairbanks. In this way, consumers at both ends of the Alaska Railbelt benefit from the presence of both refineries through the resultant savings in transportation costs.

Tesoro, to be sure, is not the only player in the Alaska trade, but it is equally plain that Tesoro plays a vital role in the delicate balance of competition and cooperation that, quite remarkably, has made a state as massive and underdeveloped as Alaska virtually self-sufficient in refined petroleum products.

C. Tesoro's Continued Contribution to In-State Refiner Competition Depends on the Continued Availability of Royalty Oil Under Fair Terms

1. The Absence of Any Alternative Source of Supply

As a practical matter, Tesoro has no reliable, long-term source of crude other than ANS royalty oil. Having modified its refinery to accomodate ANS crude, Tesoro now finds itself without any significant private supply source. This because:

- (1) ARCO refines its entire production itself;
- (2) British Petroleum has declined to sell oil to third parties at Valdez because of perceived potential environmental liability; and
- (3) Exxon is interested only in occasional, short-term sales.

Indeed, in 1994 Tesoro lost one of the few private sources of ANS crude heretofore available to it. In 1993, Tesoro purchased about 3,500 bbl./day of Milne Point production from Conoco. However, Conoco sold its Milne Point interest to British

Petroleum at the end of 1993, and BP, for the reasons discussed above, is unwilling to sell Milne Point oil to Tesoro.

2. It's Important to Make Royalty Oil Available to Tesoro Under Competitive Terms, Lest the State Aggravate Tesoro's Competitive Disadvantage

Tesoro's dependency on ANS royalty oil makes it rather tempting for the state to exploit its resultant bargaining advantage. As we'll see in the next section, that's what happened here.

To an extent, DNR has always been strict with its in-state purchasers--a policy of restraint borne in large part of the Alpetco Refinery fiasco. There are, however, prudent limits to that policy. The state hopes to use its royalty oil to enhance in-state refinery competition. When one of those refineries bears an underlying market disadvantage, DNR must take special care to assure that the terms under which royalty oil is made available to that company are no more burdensome than those offered the company's more fortunate competitors.

In Alaska, Tesoro is the disadvantaged company. Tesoro's principal competitors--MAPCO Petroleum and Petro Star--both take ANS crude directly from the Trans Alaska Pipeline ("TAPS"). As a result, neither MAPCO nor Petro Star have to inventory any crude oil at their refineries.

Tesoro, on the other hand, must ship its oil first over the entire length of the TAPS line, and then by tanker from the TAPS terminal at Valdez to the Nikiski refinery. Tesoro resultantly must: (1) always keep about one million barrels of crude oil in inventory; and (2) pay about \$2/bbl. more for its feedstock than either of its competitors. And, the principal component of that additional cost--the cost of tanker transportation from Valdez

to Nikiski--is increasing because of new safety requirements imposed through the federal Oil Pollution Act of 1990.

MAPCO's and Petro Star's proximity to the pipeline not only affords them cheaper crude; it also enables them to dispose of unmarketable refinery product at only a nominal charge--while Tesoro, conversely, must pay dearly to ship that same product south. In particular: Tesoro and MAPCO both produce substantial quantities of heavy "residual" oil, which has no market in Alaska. MAPCO is able to return that product to the TAPS line, paying only a \$.25-\$1.30/bbl. "quality bank" penalty. Tesoro, conversely, must ship its residual oil to the West Coast at a transportation cost of \$3.40/bbl. All tolled, Tesoro receives a much lower value for that product than does MAPCO.

Moreover, in recent years Tesoro has been forced to deal with yet another unwanted element of ANS crude--a product that, once again, MAPCO simply returns to the pipeline. ANS producers have been significantly increasing the LPG component to the crude stream, and Tesoro has been required to spend several million dollars to dispose of the LPG at the refinery. Again, however, MAPCO can reinject this product into the pipeline--which, ironically, even further increases the LPG content of ANS crude oil that Tesoro receives at Valdez.

Yet another example of MAPCO's competitive advantage relates to the recent installation of a benzene stripper at MAPCO's North Pole refinery. This unit reduces or extracts benzene, which MAPCO also reinjects into TAPS. This, in turn, has complicated Tesoro's ability to continue to meet gasoline specifications.

3. *Despite Its Disadvantaged Position, Tesoro Has Never Asked for More than Competitive Access to State Royalty Oil.*

Tesoro has always paid full value for its royalty oil. Indeed, after DNR settled with the ANS producers in the *Amerada Hess* litigation, Tesoro agreed to pay roughly \$95 million in retroactive price increases to bring its past royalty oil payments in line with the theory of "value" won by the agency in *Amerada Hess* negotiations. Tesoro has paid its bills on time--indeed, in recent years it has unfailingly paid its DNR invoices within 10 days of receipt. And it has posted a costly letter of credit to guarantee future payments, even though its chief competitor posted none.

* * *

In light of what we've learned from this section, the proposed contract's pronounced tilt towards DNR will seem rather surprising. This is not a case where the state bends some rule, or grants some favor, to encourage some economic enterprise. It is much the opposite--an experiment in brinksmanship undertaken *despite* the consumer interests at stake, and the disadvantaged position of the purchaser.

III. The Proposed Contract Vigorously Protects the State's Interest as Owner of the Royalty Oil

From the perspective of royalty owner, the state's principal interests in the proposed Tesoro contract are three-fold: (1) price; (2) security; and (3) flexibility in managing royalty oil. In all three respects, the Tesoro contract is uniquely favorable to the state.

A. Price

Until now, DNR has been satisfied, in its sales of royalty oil to in-state refiners, to receive a price commensurate with the amount it would have received had it left the oil with the ANS producers and taken its royalty share in value. As DNR recently said:

Since the first royalty oil sale, the state's policy has been that it would not necessarily maximize revenues from royalty in-kind sales, but that it would not receive less for the people's royalty when taken in-kind and sold than the state would otherwise have received had it left the oil with the lessees and taken its royalty in-value.

DNR, Final Finding and Determination to Sell Royalty Oil to Petro Star Valdez Refinery Joint Venture ("Petro Star Findings"), March 4, 1992 at 6.^{9/} Moreover, DNR has declined to ask for any "premium," above the in-value price, from in-state refiners. In the past, DNR considered charging "premiums" for in-state sales out of its concern that its royalty oil, when taken and sold in-kind anywhere on the West Coast (including Alaska), tended to "displace" other ANS crude from the Pacific Coast, forcing it to the Gulf Coast

^{9/} As noted previously, the Petro Star JV sale was terminated when Petro Star declined to take oil under the contract.

where it would yield a lower price. A "premium" charged the royalty oil buyer, DNR surmised, could offset the revenue loss caused by the "displacement."^{10/}

However, DNR has more recently concluded that the "displacement effect" is no longer a cause for concern, given the "small and decreasing proportion of gulf sales," and the relatively small amount of oil involved.^{11/} With respect to Tesoro's one-year 1995 contract, DNR said:

The proposed sale to Tesoro is unlikely to generate these effects which were a larger concern when so much of the ANS crude oil was shipped to the Gulf Coast...Since the state will clearly benefit from the continued operation of the Tesoro facility and, since the consumers of Alaska are likely to be better off in a more competitive industry, the state does not propose a price premium in this contract.

1994 Tesoro Findings at 14. The same conclusion was reached with respect to the long-term Petro Star sale. *Petro Star Findings* at 11 ("For these reasons, and to encourage the jobs, income, tax, and consumption benefits from in-state refining, the proposed contract does not include a premium.")

In its *Amerada Hess* settlements with the principal ANS producers, DNR defined "value" as a volume-weighted average of the values of ANS oil in different markets. ANS crude is sold along both the West and Gulf coasts, and, of late, Gulf Coast prices have generally been \$.90-\$1.00/bbl. less than West Coast prices. By pegging "value" to a volume-weighted average of these sales, the aggregate "value" is thus lower than if "value" were defined solely with reference to West Coast sales.

^{10/} See, e.g., *Petro Star Findings* at 10-11. As discussed in the following text, no premium was charged Petro Star.

^{11/} *Id.* at 11; see also DNR, "Preliminary Finding and Determination to Sell Royalty Oil to Tesoro Alaska Petroleum Company," August 16, 1994 ("*1994 Tesoro Findings*") at 14.

British Petroleum, for example, sells ANS oil in four different markets, and its settlement agreement provides that:

The Average Valdez Netback shall be a per barrel amount calculated by volume weighted averaging the Valdez Netbacks for each of the four market destinations to which production was delivered: West Coast, Gulf Coast, Hess and Mid-Continent.

ANS Royalty Settlement Agreement between BP Exploration (Alaska) Inc. and State of Alaska, ("BP Settlement") December 31, 1991, Art. 3.2(d). ^{12/}

This is also the deal that DNR struck with other in-state refiners. The State's contract with Petro Star JV incorporated the BP settlement methodology for valuing Petro Star's oil--with Petro Star paying the "average" royalty value from sales to all destination markets, rather than only the West Coast royalty value. *Id.* at Art. 2.3.

The same is true under MAPCO Petroleum's long-term contract.

One would expect, then, that the proposed Tesoro contract would allow the purchaser to pay on the basis of this same volume-weighted average of West and Gulf Coast prices. That, however, isn't what happened. Intent on charging Tesoro, and Tesoro alone, a "premium" for its royalty oil, DNR set Tesoro's price with reference to the value reported under the agency's *Amerada Hess* settlement with Exxon. But Exxon sells its oil only on the West Coast. As a result, and as Chart 3 illustrates, had the contract been in effect in January, 1995, Tesoro would have paid a \$.19/bbl. premium over the

^{12/} While "market baskets" of oil are used to calculate BP's royalty obligations, there is a separate market basket for Gulf Coast placements, so the volume-weighted influence of Gulf Coast prices remains unaffected.

value received from other in-state refiners, and from the ANS producers in the aggregate-- a premium which, over the course of a year, would have approximated \$2.77 million.

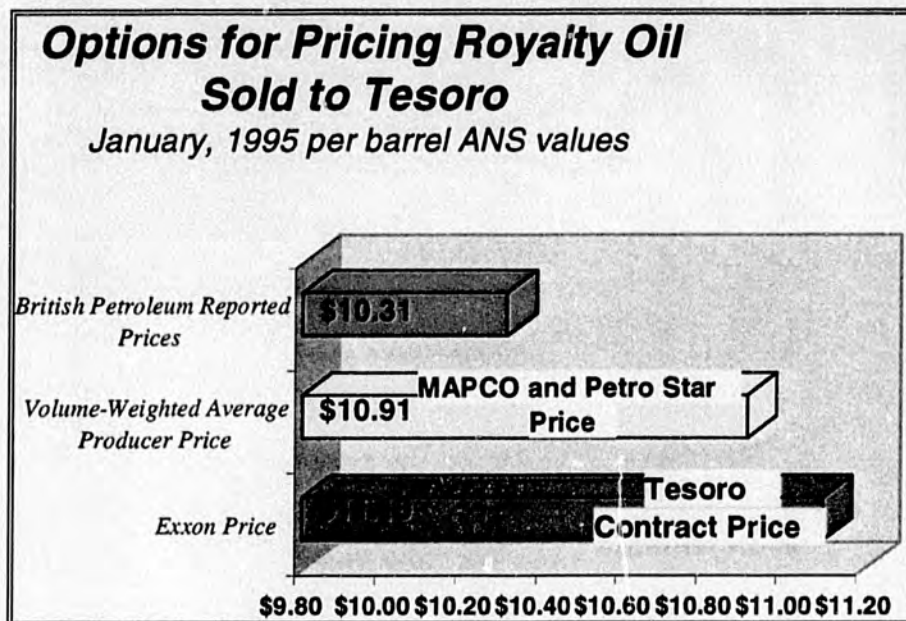


CHART 3. Source:
1995 Tesoro
Findings at Table 2.

¹³ /

Finally,
not only is
Tesoro charged a
significant
“premium.”

Moreover, the

proposed contract also provides that the State can continue to “adjust” that price upwards as it obtains “more accurate information”--the adjustment period running for the full period permissible under the applicable statute of limitations. Art. 5.3.

B. Security

1. The Letter of Credit

DNR has always faced two risks in selling its royalty oil:

¹³ / Table 2 of the 1995 Tesoro Findings mistakenly lists the January, 1995 volume-weighted average of all producer prices as \$11.027. This is due to an inadvertent failure to include British Petroleum Gulf Coast sales, and the correct figure of \$10.91/bbl. was agreed to in a phone conversation with DNR Division of Oil and Gas’ Kevin Banks on March 24, 1995.

Further, had Petro Star actually taken delivery of royalty oil under its now-terminated 1992 contract, its actual volume-weighted average price would have been about \$.21/bbl. less than the \$10.91 price depicted in the chart--or, about \$10.70/bbl. This is because Petro Star had contracted for Kuparuk River Unit production, which is subject to an approximately \$.21/bbl. Kuparuk Pipeline tariff. However, since Petro Star would have paid that tariff to the pipeline company, the net cost of that royalty oil to Petro Star would have been the same as if it had taken Prudhoe Bay oil. Therefore, the price term of the Petro Star contract is more fairly depicted as the same volume-weighted average price paid by MAPCO.

(1) A certain quantity of oil might be delivered before the state discovered that the buyer would be in default. The state wants to be paid for that oil; and

(2) The state is obligated to give the ANS producers a certain amount of advance notice before it can require those producers to take the royalty oil back, and pay the state in-value. This is the so-called "denomination" period; and, while the state could sell its royalty oil to someone else during that waiting period, it fears receiving a lower price because it would be a distress sale.

Taking Risk (2) first, prior to 1992 the applicable ANS leases and unit agreements generally provided for six months' "denomination" notice--that is, the state could find itself holding six months of oil if the buyer defaulted. Nonetheless, prior to 1992 the state either: (1) required no letter of credit at all, as with MAPCO Petroleum's long-term contract; or (2) asked for only a 60-day letter of credit, as it did with every Tesoro royalty oil contract.

The 60-day letter of credit (or "LOC") was used because it was the commercial norm. In the private sector, longer-term oil purchases are usually secured, at most, by a 60-day LOC.

Thus, the risk posed by a "distress sale" during the "denomination" period was never the determining factor in DNR's security requirements. DNR never went beyond the bounds of commercial reason, because in doing so it would have risked placing in-state refiners at a further disadvantage--which, of course, would have offended Alaska's royalty oil policy.

Moreover, every *Amerada Hess* settlement reduced the "denomination" period to 90 days--unless, as in BP's case, the producer notified the state that, "after making documented good faith efforts,...it is unable to obtain acceptable vessel transportation" for the oil. *BP Settlement* at Art. 2.1(b). Given today's depressed market among independent U.S. flag oil tankers, it's doubtful that such a claim of "force majeure" could be made. And, in any event, the declaration of "force majeure" is intended as the exception, rather than the rule.

The point being, of course: if an across-the-board six-month "denomination" period wasn't enough to warrant more than a 60-day letter of credit, the general lessening of that period by half would hardly seem to warrant a more lengthy LOC.

Nor would Risk (1) seem to warrant anything more than the traditionally-acceptable 60-day LOC. Nonetheless, DNR did require a 90-day LOC in its 1992 royalty oil sale to Petro Star JV.^{14/} In justifying that requirement, DNR imagined that 70 days of unpaid-for oil might be delivered before the state could declare a default. A 90-day LOC, DNR reasoned, was necessary to secure payment for that oil--the remaining 20 days' value in the LOC being in the nature of liquidated damages for Risk (2).^{15/}

^{14/} This is the only royalty oil contract to contain the 90-day LOC requirement, and the Petro Star contract was a special case. The contract was intended to aid Petro Star's plan to build a then-nonexistent Valdez refinery. It was thus a speculative endeavor that presented the State with some of the same risks that it faced with the Alpetco contract years previous.

Tesoro, by contrast, has been a buyer in good standing for a quarter century, and in recent years has unfailingly paid its royalty oil bills within about 10 days of receipt.

Moreover, it should be noted that Petro Star JV never purchased any royalty oil under that contract. One can reasonably surmise that it didn't do so, in part, because the security requirements extended beyond the bounds of commercial reasonableness and availability.

^{15/} *Petro Star Findings* at 14.

DNR's 70-day timeline, however, wouldn't apply to the proposed Tesoro contract. Under that contract, DNR would bill Tesoro within 10 business days after the end of each month of delivery, and Tesoro would be required to remit payment *within 3 business days* of billing. *Id.* at Arts. 5.1 and 5.4. Since DNR can declare a default, and cease deliveries of oil, as soon as "Tesoro does not pay in full any sum owed under this Agreement at the time when payment is due," ^{16/} DNR risks, at most, about 47 days of unpaid-for deliveries under the contract--a risk more than amply covered by a 60-day letter of credit. ^{17/}

Nevertheless, the proposed contract requires a 75-day letter of credit. *Id.* at Art. 15.1. And the difference is no small matter to Tesoro. Tesoro's current 60-day letter of credit with DNR consumes over 25% of Tesoro's total credit capacity. A 75-day LOC would reduce the company's available credit capacity by an additional \$8-9 million. And, based on current Pump Station 1 crude prices, a 75-day letter of credit would increase the banking charges associated with the LOC by about \$156,000 per year--to a total annual cost of about \$780,000.

The increase is apparently motivated by DNR's newly-heightened concern over the availability of tanker capacity to ship any royalty oil that it, or the ANS producers, might find themselves holding in the event of Tesoro's default. In that respect, the contract does allow Tesoro to reduce the term of the LOC to the traditional 60 days--but only if Tesoro can obtain a long-term charter with a tanker company for deliveries anywhere on the West Coast (rather than simply the Nikiski refinery), and then assign that charter to DNR so that

^{16/} *Id.* at Art. 7.1(ii).

^{17/} The 47 days is inclusive of : (1) a month's delivery of oil; (2) 10 days to render the bill; (3) 3 days' payment grace period; and (4) 4 intervening non-business days.

the agency could directly employ the tanker (or further assign the charter to an ANS producer) in the event of Tesoro's default. *Id.* at Art. 15.2.

Through this remarkable clause, DNR would have a ready answer to BP, or any other ANS producer, should that producer attempt to decline royalty oil on 90 days' notice under the *Amerada Hess* settlements' "force majeure" provisions.

DNR thus finds itself doubly protected with: (1) a more-than-sufficient 75-day LOC; or (2) a 60-day LOC, coupled with an ironclad charter, in-hand, with rates acceptable to DNR, to assure prompt transport of any oil--by itself or an ANS producer--should a default occur.

But while DNR is amply protected under the security clause, Tesoro isn't protected at all. The LOC can be reduced to 60 days only "if Tesoro and the State can reach an agreement" on a mutually-acceptable tanker charter--a rather gossamer contingency, from Tesoro's perspective. If DNR doesn't like the price term of the charter, for example, or is displeased with the charter in any respect, Tesoro will have to retain the 75-day LOC.

2. *Tesoro's Solvency*

As with other royalty oil contracts, the proposed Tesoro contract allows DNR to terminate the agreement: (1) "[i]f Tesoro becomes unable to pay any of its debts when due, or should otherwise become insolvent"; or (2) "[t]here is a material adverse change in Tesoro's condition, business, or property which may appreciably affect its ability to perform." *Id.* at Arts. 7.1(v) and 7.2.

More importantly, DNR is aware that its royalty oil is being purchased by a company with decades of good standing with the agency. With respect to the future, DNR has recently said:

Tesoro Alaska's parent company in February 1994 implemented a dramatic recapitalization plan which should provide the company with an immediate improvement in cash flow....Following resolution of Tesoro's dispute with the State of Alaska, implementation of the recapitalization plan, and issuance of additional common stock, the value of Tesoro's common stock has approximately doubled.

1994 Tesoro Findings at 9-10.

3. *The Absolute Nature of Tesoro's Obligation to Accept Delivery of Royalty Oil*

Although the contract rigorously protects DNR should the state ever be required to dispose of royalty oil after a default, DNR's overriding goal is to assure that this never happens. Here again, the contractual safeguards are extraordinary. Tesoro's obligations to take royalty oil "are absolute, and will not be excused or discharged by the operation of any disability of Tesoro, force majeure...or any other reason or cause." *Id.* at Art. 29.

The document continues:

(1) Tesoro may be required to periodically provide DNR with "satisfactory evidence or reasonable assurance" of Tesoro's continued ability to arrange transportation for the oil from Valdez. Art. 2.8;

(2) While, on six months' notice, Tesoro may take less than the maximum quantity of oil made available under the contract, to do so it must pay a penalty equal to

.75% of the difference in price between what it actually takes, and what it is entitled to take. Art 2.11;

(3) Tesoro remains obligated to immediately inform DNR of "any material adverse change" in its financial condition. Art. 3.2;

(4) Even if the agreement is terminated by consent, or through no fault of Tesoro's, Tesoro agrees to "continue to take and purchase the State's royalty oil...for up to six Months following termination if the State, in its sole discretion, so requires." Art. 8.1; and

(5) "If for any reason, Tesoro is unable or refuses to accept or receive any Oil" tendered under the contract, "Tesoro shall nevertheless be and remain responsible for the disposal of that Oil and for paying the State for the Oil as though it had been received..." Art 8.2.

It is, in sum, hard to envision a contract more protective of the seller's interest.

C. DNR's Retained Flexibility to Manage Royalty Oil

With renewed optimism over the possible lifting of the ANS oil export ban, DNR has paid special attention to retaining its flexibility to deal with market changes that may occur within the Tesoro contract period. Of course, we've seen that, even with the Tesoro contract, the state retains about 99,000 bbl./day of North Slope royalty oil--or about 57% its total--to use as it sees fit if the ban is lifted.

DNR, however, wanted more. It insisted on a special clause in the Tesoro contract giving it broad discretion to renegotiate the contract's price term if and when the ban is lifted. In pertinent part, the clause provides:

Neither the State nor Tesoro shall have the right to reopen this Agreement, unless the United States Congress lifts the export ban on ANS crude now in effect. Anytime after the export ban is lifted, either Tesoro or the State may reopen this Agreement for purchase price only...Upon issuance and receipt of a notice to reopen, Tesoro and the State will promptly commence good faith negotiations in an attempt to establish a new purchase price. If a new purchase price is not agreed to by Tesoro and the State within three months after giving the notice to reopen, either Tesoro or the State may terminate this Agreement upon nine months written notice to the other.

Art. 2.4(a). Of course, from Tesoro's perspective this clause injects a worrisome element of uncertainty, and a three-year contract doesn't bind the state for such a lengthy period of time that a price reopener clause of any kind would ordinarily seem warranted. Thus, the special benefit afforded DNR by this clause is simply another example of the unusually high price that Tesoro will pay to keep the Nikiski refinery open.

IV. Conclusion

Because DNR used every bit of its bargaining leverage in forging the contract's terms, the proposed Tesoro contract raises no controversies from the state's perspective as an oil seller. As a policy matter, the contract is simply a continuation of Alaska's successful program of promoting in-state refiner competition. As a technical matter, the contract gives the state a price premium; secures the state's interest as surely as any contract could do; and provides the state with ample flexibility to respond to changes in the ANS market.

True, the contract is quite tough on Tesoro. Tesoro should have access to royalty oil under the same terms as its competitors, and the proposed contract doesn't meet that goal. But there isn't time to have that debate. The proposed contract needs to be approved by the legislature before this May's adjournment, and it is rather apparent that the legislature can do that with the absolute assurance that the State of Alaska is getting a very good deal.

*An Analysis of the Department of Natural Resources'
Proposed Three-Year Contract for the Sale of
Prudhoe Bay Royalty Oil to Tesoro Alaska
Petroleum Company*

Executive Summary

Tesoro Alaska Petroleum Company
March 29, 1995

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Executive Summary

**Tesoro Alaska Petroleum Company
March 29, 1995**

The Department of Natural Resources ("DNR") is proposing to sell 30% of the state's royalty oil entitlement from the Prudhoe Bay Unit--or about 27% of all North Slope royalty oil--to Tesoro Alaska Petroleum Company ("Tesoro"). Roughly 40,000 barrels per day of royalty oil would be available to Tesoro under the contract.

The contract term would be only three years, and would require that at least 80% of the oil purchased be processed at Tesoro's Nikiski refinery.

The contract requires legislative approval under AS 38.06.055. Royalty oil has been, and remains, the principal feedstock for Tesoro's refinery; indeed, deliveries under the proposed contract would represent about 80% of the refinery's crude supply. There are no other stable, long-term sources of crude for that refinery, and Tesoro's current one-year contract for state royalty oil expires on December 31, 1995.

As a result, if the legislature is unable to act on the proposed contract before it adjourns its 1995 session, Tesoro would lose about 80% of its crude oil supply, and continued operation of the Nikiski refinery would be in peril. ^{1/}

Because the proposed contract must be reviewed by the Alaska Royalty Oil and Gas Development Advisory Board ("Royalty Board") before being presented to the legislature, ^{2/} legislation approving the contract should be ripe for introduction about April 24, 1995. However, and given that time is short, the legislature ought to begin evaluating the proposed contract now.

^{1/} By statute, DNR could not even renew Tesoro's one-year purchase contract without the legislature's approval. AS 38.06.055(c).

^{2/} AS 38.06.050(a).

The legislature will review the proposed contract from two distinct perspectives: (1) as steward of Alaska's economy; and (2) as a seller of oil intent on receiving full value, and adequate security, for its product. From either perspective, the proposed contract offers a very good deal to the State of Alaska:

1. The Alaska Economy. Alaska has a longstanding policy of employing a portion of its royalty oil entitlement to promote the growth of, and competition among, in-state oil refiners. As a result, Alaska has become virtually self-sufficient in refined petroleum products, and the resultant competition between the state's three in-state refiners has saved Alaska consumers hundreds of millions of dollars in retail gasoline prices alone.

Alaska's royalty oil policy has succeeded in large measure through royalty oil sales to Tesoro. This despite the fact that, among in-state refiners, Tesoro suffers a considerable competitive disadvantage, principally because its refinery is not directly linked to the Trans Alaska Pipeline. While Tesoro has never asked the state to help level this playing field, future competition can be assured only if the state, through its royalty oil dispositions, does nothing to aggravate the competitive disparity between Tesoro and other in-state refiners.

2. The State's Interest in Full Value. Tesoro has never asked for, nor has it ever received, any subsidy or special allowance in purchasing royalty oil. Certainly the proposed contract grants none. Indeed, DNR has taken considerable advantage of its virtual monopoly position as Tesoro's only realistic principal source of supply.

Among the document's more rigorous requirements are these:

a. Price. Tesoro would be obligated, under the proposed contract, to pay a substantial "premium" above the price that the state receives from either: (1) the North Slope producers, in the aggregate, for royalty oil taken in value; or (2) other in-state refiners. In the month of January, 1995, that premium would have been \$.19/bbl.--or, on an annualized basis, about \$2.77 million;

b. Security. DNR has always been rightly concerned with the prospect of purchaser default--an event that could force the state to sell royalty oil under distress conditions. The proposed contract affords DNR an extraordinary series of safeguards in this respect. For example: in the past, Tesoro has posted a 60-day letter of credit to guarantee payment of oil delivered under the contract. (MAPCO Petroleum, conversely, posts no letter of credit at all.) The proposed contract lengthens that letter of credit to 75 days, unless Tesoro is able to assign its long-term tanker charter agreement to the state itself, so that DNR would have immediate access to an oil tanker if it found itself holding royalty oil; and

c. Special Flexibility to Respond to a Lifting of the North Slope Export Ban. Even if Tesoro takes every barrel allowed under the proposed contract, about 57% of the state's ANS royalty oil would remain uncommitted, and available for whatever opportunities a lifting of the ban might create. Moreover, under a special reopener clause in the contract, the state can renegotiate the price term if and when the ban is lifted, and then terminate the contract if reopener negotiations don't yield a price commensurate with a changed ANS market. This clause affords DNR ample discretion to

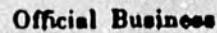
manage both uncommitted royalty oil, and Tesoro's royalty oil, if and when the ban is lifted.

In short, at virtually every turn DNR has exploited its considerable bargaining advantage. This will be the most favorable contract--from the state's perspective--under which any royalty oil has ever been delivered.

Nonetheless, the contract does meet Tesoro's need for a stable source of crude--albeit for only three years. As a result, the contract deserves legislative approval.

SCOMM

96:4



HOUSE RESOURCES STANDING COMMITTEE
HOUSE SPECIAL COMMITTEE ON OIL AND
GAS

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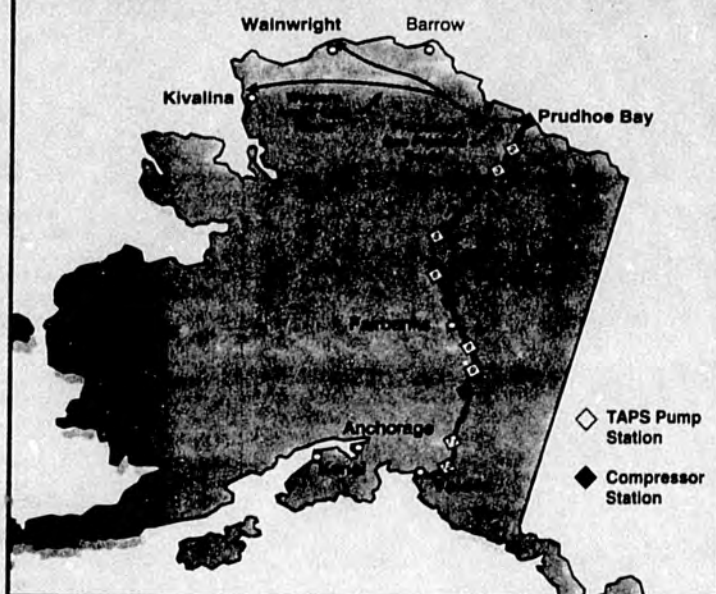
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ANS Gas Commercialization Southern and Western Route Alternatives



Slope gas market for 2005-2010?

ANCHORAGE—At a joint press conference in Anchorage on July 17, BP and ARCO said the timing for exporting North Slope natural gas liquids now appears to be about 2005-2010, and that more study is needed to make a liquefied natural gas (LNG) exporting project economically viable.

The announcement came after a 17-month study by the key North Slope oil producers and natural gas owners, BP Exploration, ARCO and Exxon.

The study concluded that significant uncertainty remains in the areas of fiscal and regulatory climate, market timing, product pricing and project costs, and that costly engineering design can be justified only after progress is made on these issues.

The study included alternate routes from Prudhoe Bay to locations on Alaska's western coast as a way to reduce the project's overall cost. Western routes would be considerably shorter than the

trans Alaska pipeline route to Valdez, chosen by Yukon Pacific Corp., the firm which has studied a gas export project for years.

'A project of this magnitude will require the involvement and cooperation of many parties...'

John Morgan

The current estimated cost of the project, about \$15 billion, is too high, say the gas owners. They cite infrastructure sharing, innovative pipeline construction methods and deploying larger but as few LNG ships as possible as ways to reduce the project's cost.

The study's review of com-

peting LNG developments in the Northwest shelf of Australia, Indonesia, Malaysia and the Middle East underscore the fact Alaska gas will face tough competition in the LNG arena, even after 2005.

"A project of this magnitude will require the involvement and cooperation of many parties, including both the state and federal governments," says BPXA President John Morgan.

With 46 trillion cubic feet of natural gas, the Prudhoe Bay field is one of the nation's richest gas deposits. Currently, a large portion of that gas is reinjected into the reservoir to aid oil recovery. But with the field's natural decline, by the year 2005 and beyond, that level of gas reinjection will not be required.

BP owns 21 percent of the Prudhoe Bay field's gas, while ARCO and Exxon each own 32 percent. Alaska's royalty share is 13 percent, and eight other owners have two percent interest.



**YUKON
PACIFIC
CORPORATION**

TRANS-ALASKA GAS SYSTEM
1049 WEST FIFTH
ANCHORAGE, AK 99501-1930

A Business Unit of CSX Corporation

ALASKA SENATE RESOURCES COMMITTEE

**Briefing on Alaska Natural Gas Project
Anchorage, Alaska**

January 29, 1996

**Written Responses & Background
Information**

TABLE OF CONTENTS

Committee Questions and YPC Responses	1-6
YPC Permits and Authorizations	Exhibit 1
LNG Project Financing	Exhibit 2
TAGS Construction Costs and Timeline	Exhibit 3
TAGS Competition: Cost Comparisons	Exhibit 4
Asian LNG Market: Demand Projections	Exhibit 5
TAGS Competition: Projects, Start-up Dates, Annual Volumes	Exhibit 6
The Post-2000 Demand Window: The Effects of Competition on an Alaskan Project . . .	Exhibit 7
Oil Loss vs. Gas Sale	Exhibit 8
Possible North Slope Gas Supply Scenarios	Exhibit 9



Committee Questions and YPC Responses



Senate Resources Committee Questions and Yukon Pacific Corporation Responses

Q HOW CURRENT ARE THE PERMITS THAT YOU HAVE? WHAT PORTION OF THEM ARE FEDERAL PERMITS AND WHAT PORTION ARE STATE PERMITS?

A See exhibit 1. All permits are current.

Q WHAT IS YOUR PROPOSED METHOD FOR FINANCING THE LIQUEFACTION FACILITIES, PIPELINE AND TRANSPORTATION SYSTEM?

A *It is far too early to "propose" a method for financing TAGS. We will modify your question just slightly, respond and then explain.*

Revised Question:

Q IF YOU HAD THE GAS SUPPLY, HOW WOULD YOU PROPOSE TO FINANCE THE LIQUEFACTION FACILITIES, PIPELINE AND TRANSPORTATION SYSTEM?

A *Limited recourse financing using any number of variations of the Japanese Import Model.*

In large-scale projects like LNG "grass-roots" projects, it is very difficult for project sponsors to fully undertake all of the various project risks. Therefore, it is important to establish a cooperative financing structure in which the related parties, such as gas producers, gas buyers, engineering procurement and construction EPC contractors, ship builders, shippers, governmental organizations and financial institutions, share the various types of project risk.

Historically, the Japanese have played a very important role in assuming certain aspects of risk for all of the LNG projects delivering gas to their country.

Japanese Governmental Organizations:

For decades the Japanese Government has been directly supportive of and involved in importing natural resources which are essential for the development of the Japanese economy through not only funding but also in guaranteeing certain aspects of LNG projects. Japanese governmental institutions which have provided these funding/guaranteeing sources include: The Export Import Bank of Japan (JEXIM), Overseas Economic Cooperation Fund (OECF), Japan National Oil Corporation (JNOC) and The Japan Development Bank (JDB).

Japanese Buyers:

Japanese buyers participate in the financing of LNG projects as equity participants of LNG importing/financing companies, as borrowers of import credit of JEXIM and, as guarantors of limited recourse financing. Most importantly, Japanese buyers provide off-take guarantees under long-term sales contracts which support the establishment of a project finance structure.

The limited recourse financing structure also contemplates that the commercial banks will also assume some part, but not all of the project risk. In order for the commercial banks to assume these risks certain project attributes would be expected. These would include, but not be limited to the following:

- 1) Adequate gas reserves committed to the project,*
- 2) Development and completion of the project by the project sponsors,*
- 3) LNG sales contracts including reasonable pricing formulas and "take of pay" clause.*

See exhibit 2 for a diagram of how the TAGS financial structure might look employing these attributes and for other examples of how various LNG projects have been financed making use of these financing schemes.

Q

WHAT IS YOUR ESTIMATED TIMELINE AND COST FOR CONSTRUCTION FOR THESE FACILITIES?

A

See exhibit 3 for TAGS construction timeline and project cost.

Q

CAN YUKON PACIFIC AND ITS PARTNERS FINANCE AND CONSTRUCT THE FULL SYSTEM WITHOUT EQUITY INVESTMENTS BY THE PRODUCERS?

A

Yes, provided the required volume of gas is committed to the TAGS project because the 25 year gas sales contracts with Asian buyers are the basis for financing.

Q

WHAT WELLHEAD RATE CAN YOU PAY TO MAKE THE INVESTMENT VIABLE?

A

It depends. There are many variables which will impact the project's viability. As examples, market ramp-up and cost of capital will greatly influence TAGS economics. These factors and the ultimate price the market agrees to pay will dictate the value available to the wellhead. See exhibit 4 for a generic comparison of TAGS economics vs. other competing projects.

What we would envision, however, is the netback to be expressed as a function of the sales price. As an example the netback calculation might look something like this:

$$(\text{Sales Price}_{\text{Tokyo}} - \text{Marine}) \times 12.5\% = \text{Wellhead value}$$

Sales Price _{Tokyo} =	\$4.00/MMBTU
Marine =	\$1.00/MMBTU
Wellhead Value =	\$.375/MMBTU

Q

WHAT DOES THE MARKET PROJECT FOR SUPPLY AND DEMAND OF GAS?

A

See exhibit 5.

Q

WHAT IS THE EXPLANATION OF THIS DISCREPANCY?

A

First, the discrepancy can best be depicted by a listing of the proposed projects which are competing for the same markets and the stated time they seek to begin deliveries as shown on exhibit 6.

*Second, the view taken by YPC seeks to ensure that Alaska benefits from the undeniable market demand. The earlier date **minimizes risk to Alaska** from a competing project taking the market share. All of the competing start-up projects also have the potential to **expand**, with the very real prospect of blocking Alaska from ever getting its gas into the market at all. See exhibit 7.*

*Third, YPC is **not** bound by the 1991 Issues Resolution Agreement (IRA) which modified the Prudhoe Bay Unit Operating Agreement. YPC believes the economic trades formalized by this agreement and not the "market window" are part of the reason for the discrepancy in proposed start dates for North Slope gas sales.*

*Fourth, YPC is not convinced by the PBU producers oil loss scenarios if gas sales occur. Gas sales result in **certain** revenues. Oil loss is speculative, far out in time if it should occur, and can be mitigated if it does. Loss of oil, gas and condensate from Point Thomson **which cannot be developed without a gas line**, must also be factored in. See exhibit 8.*

Fifth, a successful Alaska gas project is not only designed to provide gas to Asian markets. Perhaps the most commonly overlooked and important benefit to Alaskans is to provide low cost energy to Stevens Village, Fairbanks, Glenallen and Valdez. Even Anchorage may need North Slope gas as projected supplies run out in about 15 years. In other words, waiting may not only cause a loss of the Asia markets, it may result in an inability to provide much needed inexpensive fuel to Alaskans.

Q CAN GAS FROM POINT THOMSON START FLOWING AS EARLY AS 2003-2004 IN THE GAS PIPELINE, WITH COMMITMENT THAT PRUDHOE BAY GAS WILL FOLLOW WITHIN TIME CERTAIN?

A YPC believes this is possible. Phillips Petroleum alluded to this fact at the Juneau AOGA meeting held in January and has discussed the concept with the Division of Oil and Gas. Obviously, more work needs to be done, but it is surely worth the attempt because it ensures an early start without disrupting the Prudhoe Bay Unit WIO's stated plans to start gas sales from Prudhoe Bay Unit between 2005-2010. See exhibit 9.

Q WHAT, IF ANYTHING, WOULD HELP ADVANCE THE DATE FOR THIS PROJECT BY ON YEAR TO 18 MONTHS?

A First, *serious* progress on solving the State's fiscal gap including a *commitment* from the State to enter into a tax treaty regarding the North Slope gas project. This would help alleviate producer concerns which appear to be a major impediment to TAGS progress.

Second, continued study and encouragement of the Point Thomson possibility and use of the JPO to ensure consistent and efficient permitting for that project. This can be the State's first real attempt to partner with the industry to develop a new oil and gas unit.

Third, serious assistance by the State to resolve PBU problems in a non-confrontational way. Again, this will allow the State and the industry to demonstrate real commitment to partnering.

Fourth, a joint marketing trip by the PBU operators, the Point Thomson operators and the permit holders for the project to obtain commitments and hold meaningful discussions on market participation in price reduction opportunities including: shortening the "ramp-up" period to full production, project financing, use of larger ships and precommitments to quantities beyond the 14 million tonnes per year needed for economic viability.

Fifth, continued commitment by both the Knowles and Clinton administrations to actively support and promote the *only* U.S. start-up LNG export project competing in the international marketplace.

*Sixth, encourage producers to conduct studies of various aspects of the project **in parallel** instead of "in series" as they currently do.*

*Missing from this list is any request to have State officials visit market countries to assist in marketing. This is **not** an inadvertent omission. Past State visits by DNR & DOC Commissioners, for example, have been disastrous to TAGS marketing efforts. The State's role is here in Alaska. Help is not needed in the marketplace. State officials should work on balancing the budget, gas development and partnering concepts, and not complicate ongoing marketing efforts.*

YPC Permits and Authorizations

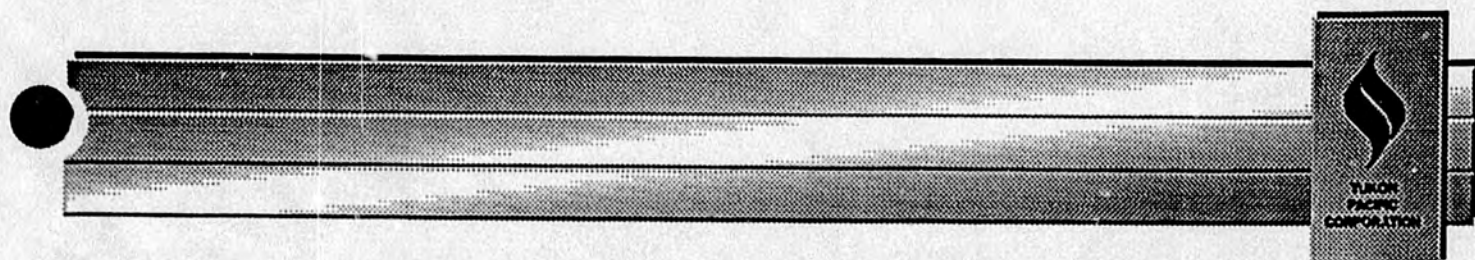


TAGS PERMITS AND AUTHORIZATIONS

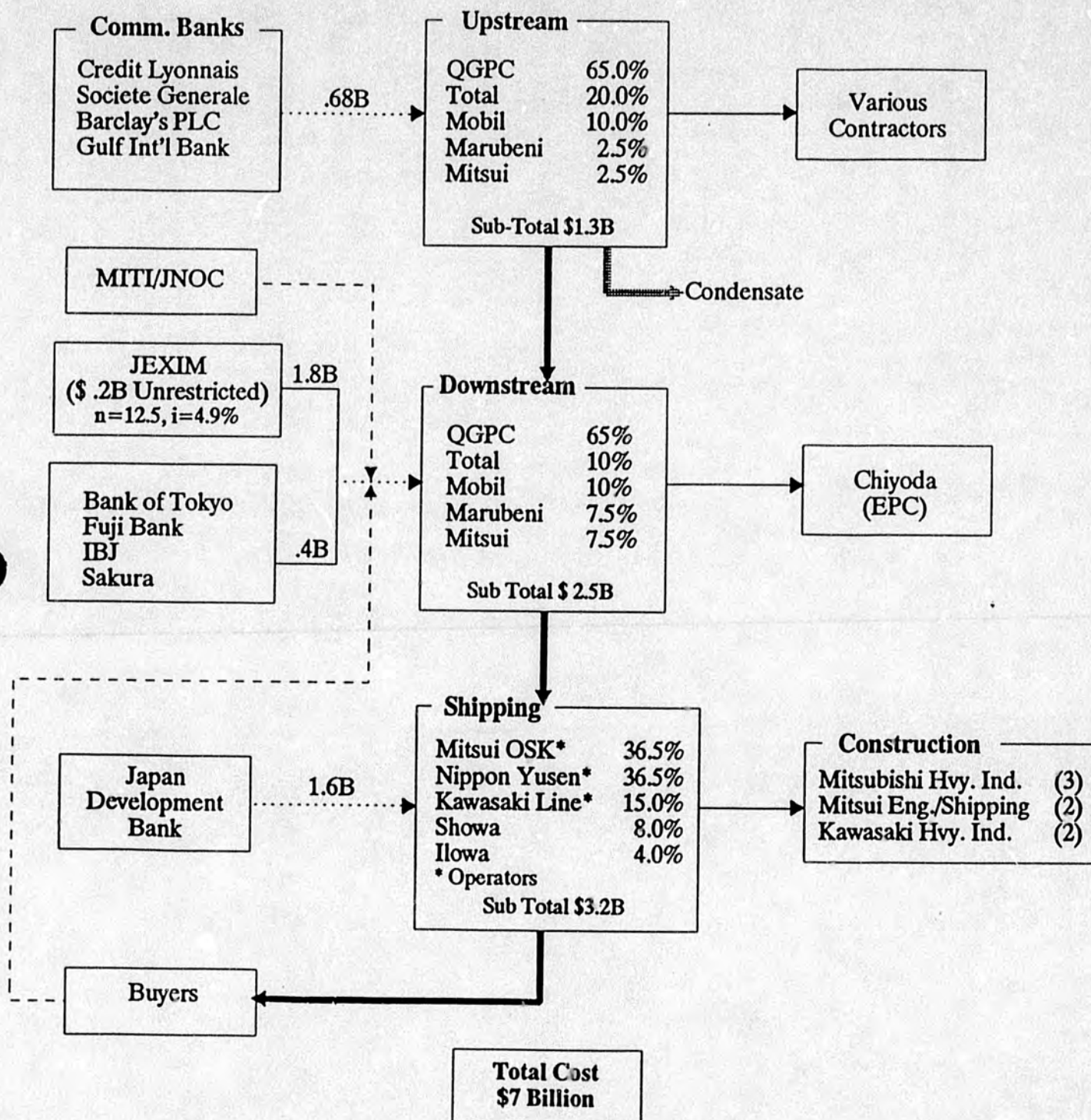
Over the past twelve years YPC has secured or satisfied all of the necessary legal approvals and requirements to export North Slope natural gas to Asia. These include:

1. **Presidential Approval:** *Presidential Finding Concerning Alaska Natural Gas: Removes impediment to Alaska natural gas exports required by Section 12 of the Alaska Natural Gas Transportation Act (15 U.S.C. 719j), January 13, 1988;*
2. **Project Wide Environmental Impact Statement¹:** *Trans-Alaska Gas System Final Environmental Impact Statement, June 1988 (17 Federal and State agencies);*
3. **Ahtna Right-of-Way¹:** *Grants to Yukon Pacific Corporation the right to designate and acquire certain rights in any and all lands acquired by or otherwise available to Ahtna under the Alaska Native Claims Settlement Act of 1971 which are reasonably necessary to construct, maintain operate or terminate the pipeline, October 14, 1988;*
4. **Federal Right-of-Way¹:** *Right-of-Way Grant for the Trans-Alaska Gas System from The United States of America to The Yukon Pacific Corporation, October 17, 1988;*
5. **State Right-of-Way¹:** *Trans-Alaska Gas System Conditional Right-of-Way Lease, December 10, 1988;*
6. **DOE's Authorization for Export of Gas¹:** *DOE/FE Opinion and Order No. 350, Order Granting Authorization to Export Liquefied Natural Gas From Alaska; Limiting of FERC's jurisdiction, November 16, 1989;*
7. **Confirmation of Order 350¹:** *DOE/FE Opinion and Order No. 350-A, Order Denying Requests for Rehearing and Modifying Prior Order for Purpose of Clarification, March 8, 1990;*
8. **Anderson Bay Final Environmental Impact Statement¹:** *Yukon Pacific Corporation LNG Project: Final Environmental Impact Statement, March 1995;*
9. **Order Granting NGA Section 3 Authorization for the Siting, Construction and Operation of LNG Facility:** *Federal Energy Regulatory Commission's approval of Anderson Bay, Port Valdez, Alaska as the place of export, May 22, 1995;*

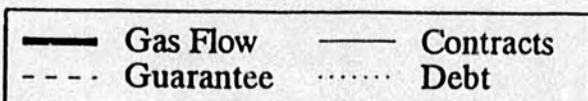
● LNG Project Financing



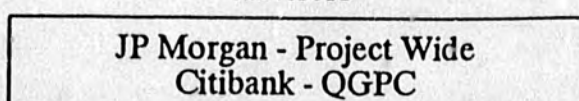
Qatargas Project Scheme 6 MMT



Legend



Advisors



SUCCESSFUL FINANCING
OF
LNG "GRASS-ROOTS" PROJECTS
FOR THE FAR EAST MARKET

INTRODUCTION

1. BASIC PROJECT STRUCTURE
2. FINANCING SOURCES
3. RISK SHARING
4. PROJECT FINANCE FOR LNG
"GRASS-ROOTS" PROJECTS

APPENDIX FINANCING STRUCTURES OF
INDONESIA LNG PROJECTS

- (i) The First Indonesian LNG Project
- (ii) LNG Expansion Projects in Indonesia

INTRODUCTION

With the rapid increase of demand of LNG as a clean energy source in the Far East market today, many "grass-roots" projects, such as Alaska North Slope Project, Indonesia Natuna Project, Sakhalin Project, and Oman Project, are under contemplation.

Needless to say, LNG "grass-roots" projects, which consist of gas gathering units, gas treatment facilities, pipelines, liquefaction plants, LNG tankers and the other related facilities, require huge amounts of capital and involve high risks. For materialization of such a large-scale LNG "grass-roots" project, therefore, successful arrangement of the financing will be very significant. This paper, as a general study on financing of large-scale LNG "grass-roots" projects for the Far East market, examines several selected problem areas to be solved concerning project structure and financing structure for the successful financing from the lenders' viewpoint.

For your reference, financing structures of Indonesia LNG projects are set out in the Appendix.

1. BASIC PROJECT STRUCTURE

Before going to the detailed study of financing, it is very important to build up a solid basic project structure. Without this step, the process in structuring a finance scheme would become inefficient.

For designing of a basic project structure, it is necessary to make clear the roles of key players, such as gas owners, LNG buyers, governments (or governmental organizations) of the host and buyers' countries, and so on. Within this stage, key players' commitment should be confirmed in the following manner:

- (1) Gas owners should clearly show their commitment to the project including capital contribution, based on a corporate consensus, and inform of a detailed development plan including various studies on the project.
- (2) LNG buyers' commitments, in a form of Letter of Intent, should be secured.
- (3) Governmental support from the host and buyers' countries should be clearly stated.
- (4) Mutual agreements between gas producers and related parties in buyers' countries on cooperation for risk sharing in the project should be concluded.

In many LNG projects for the Far East market, Japanese Trading Companies, called "Sogo Shosha" have played a very important role, ranging from the coordinator/promoter of the project to the participant in finance, as shown in Exhibit 1. The role and the form of involvement in the project of Sogo Shosha also should be determined in this stage.

MAJOR JAPANESE TRADING COMPANIES
AND
LNG PROJECTS

TRADING COMPANY	LNG PROJECT (YEAR OF FIRST SHIP)	ROLES
MITSUBISHI CORP.	• Alaska Kenai Project(1969) • Brunei Project (1972) • Malaysia Project (1983) • Indonesia Arun Expansion Project (1984) • Australia Project(1989)	Sales Agent ("SA.") Equity Participation(25%), SA. Equity Participation(17.5%), SA. Equity Participation in Indonesia LNG(10%), SA. Equity Participation in Mi/Mi, SA.
MTSUI & CO., LTD.	• Abu Dhabi Project (1977) • Australia Project (1989) • Qatar Project	Equity Participation(24.5%), SA. Equity Participation in Mi/Mi, SA. Equity Participation(7.5%), SA.
NISHO IWAI	• Indonesia Project (1977)	Equity Participation in JILCO (10%), SA.
MARUBENI CORP.	• Qatar Project	Equity Participation (7.5%), SA.
C. ITOH & Co.	• Algeria Project • Sakhalin Project	Spot Sales Arrangement Equity Participation (28.828%) in SODECO
SUMITOMO CORP.	• Australia Bonapart Project.	Promoter

2. FINANCING SOURCES

As shown in Exhibit 2, most of the existing LNG projects for the Far East market depended a lot on import credit/overseas investment credit provided by The Export Import Bank of Japan (J.EXIM). It is because both credits have advantages compared to other sources in respect of cost and availability for massive amounts of funding.

Import credits are provided to Japanese corporations for the import of LNG (see the finance scheme of the First Indonesian LNG Project [Exhibit 7]), while overseas investment credits are provided to Japanese corporations for their overseas investment activities as project sponsors (see finance scheme of Indonesian Train E Project [Exhibit 8]). However, the terms in both credits will be basically the same.

Japanese commercial banks have been also involved in most of the LNG financing on both a corporate guarantee basis and a limited recourse finance basis.

In co-finance with J.EXIM, Japanese commercial banks provided their loan for 30-40% of the total amount (The share of commercial banks is determined under the Japanese Government guideline). And Japanese commercial banks sometimes participated in the special purpose company for LNG import and/or financing as equity holders.

In limited recourse finances (so called "project finance") as well, Japanese commercial banks have played leading roles and provided considerable amount of loans, which we will refer to later.

For future LNG "grass-roots" projects as well, J.EXIM and Japanese commercial banks are considered to continue to play major roles, but (i) Korean sources, and (ii) international financing institutions should also be examined as potential financing sources.

FINANCE SOURCES USED FOR EXISTING LNG PROJECTS

— For The Far East Market —

PROJECT (Year of First Ship)	JAPAN-EXIM		Commercial Syndicated Loan	Sponsors Loan/Equity	Other Sources
	Import Credit	Overseas Investment Credit			
1. Alaska (1969)				○	
2. Brunei (1972)		○	○	○	US EXIM (Export Credit)
3. Abu Dabi (1977)	○	○	○	○	
4. Indonesia - Original - (1977)	○		○		OECP (YEN Credit)
5. Malaysia (1983)	○	○	○	○	US EXIM (Export Credit)
6. Indonesia - Expansion - (1984)	○		○		
7. Indonesia - for Korea - (1984)				○	
8. Australia - Phase II - (1989)	○	○	○	○	
9. Indonesia - for Taiwan - (1990)		○	○		

* EXIM Co-Finance

(i) Korean Sources

The existing LNG projects for Taiwan and Korea have not involved their own countries' finance sources, and they were financed by international commercial banks on a limited recourse basis.

In Korea, however, there is The Export Import Bank of Korea, a governmental financing institution for international business, which is a very similar organization to J.EXIM. Through its activity for providing import credit for the purchasing of natural resources, K.EXIM might be one of the potential financing sources for future LNG projects which involves Korean LNG buyers.

(In Taiwan, there are no special governmental financial agencies to support
the international trade and business.)

(ii) International Financing Institutions

International Financing Institutions such as World Bank, IFC, ADB have never been involved in the existing LNG projects for the Far Eastern market. It is because the World Bank and ADB are historically concentrated not on natural resource development projects, but on infrastructure projects in the developing countries when the projects are not justified according to commercial investment criteria.

However, they have mentioned recently that because of both environmental and economic reasons, they have an interest in being involved in natural gas development projects and LNG projects.

3. RISK SHARING

In large-scale projects like LNG "grass-roots" projects, it is very difficult for project sponsors to fully undertake project risk in various categories. Therefore, it is significant to establish a cooperative financing structure in which the related parties, such as gas producers, gas buyers, engineering procurement and construction (EPC) contractors, ship builders, shippers, the governmental organizations and financial institutions, share the various types of project risk. As you can see in Exhibit 3, project sponsors succeeded in sharing major risks with other parties in some recent projects.

Other than project sponsors, we can identify several parties who may take project risks to some extent in LNG projects for the Far East market.

(a) Japanese Governmental Organizations

The Japanese Government has been supportive of importing natural resources which are essential for the development of the Japanese economy. Support of this kind has been provided through its financing agencies and its petroleum agencies.

As you can see in the examples described in the Appendix, such agencies have been deeply involved not only in funding but in guaranteeing for the existing LNG projects. Following is a list of Japanese governmental institutions which should be examined as prospective funding/guarantee sources for LNG projects.

The Export Import Bank of Japan (J.EXIM)
Overseas Economic Cooperation Fund (OECF)
Japan National Oil Corporation (JNOC)
Overseas Petroleum Development Co., Ltd. (JNOC's Subsidiary)
Japan Petroleum Exploration Co., Ltd. (JNOC's Subsidiary)
The Development Bank of Japan (For LNG tanker finance)

(As for details of these institutions, please refer to the enclosed information)

MAJOR PROJECT RISK TAKERS IN THE FINANCE FOR EXISTING LNG PROJECTS

— For The Far East Market —

PROJECT (Year of First Ship)	(A) GOVERNMENT OF BUYERS' COUNTRY*	(B) BUYERS	(C) COMMERCIAL BANKS	PROJECT SPONSORS		
				GOVERNMENT OF HOST COUNTRY*	JAPANESE (TRADING FIRMS)	OIL COMPANY
1. Alaska (1969)						○ (Phillips, Marathon)
2. Brunei (1972)				○ (Brunei Government)	○ (Mitsubishi)	○ (Shell)
3. Abu Dabi (1977)				○ (ADNOC)	○ (Mitsui)	○ (BP, TOTAL)
4. Indonesia -Original- (1977)	○	○				
5. Malaysia (1983)				○ (PETRONAS)	○ (Mitsubishi)	○ (SHELL)
6. Indonesia -Expansion- (1984)	○	○				
7. Indonesia -for Korea- (1984)						○ (Mobil)
8. Australia -Phase II- (1989)			○		○ (MIMI)	○ (Shell, BP, Chevron, BHP Woodside)
9. Indonesia -for Taiwan- (1990)			○			

*Including Governmental Organization

(b) Japanese LNG Buyers

If you review some Indonesian LNG projects, you may notice that Japanese LNG buyers played important roles as a risk taker. In these projects, Japanese buyers (most of them are utility companies) participated in the financing as equity participants of LNG importing/financing companies, as borrowers of import credit of J.EXIM, and as guarantors of limited recourse financing. Moreover, Japanese buyers almost always took a part of marketing risk by providing off-take guarantee under the long-term sales contracts, which support the establishment of a project finance structure.

(c) Commercial Banks

Japanese commercial banks took major project risks in recent LNG projects, such as the Australia North West Shelf Project and the Indonesia "Train E" Project. We will discuss the so-called "project finance" where financial institutions will take some of the project risks in the next section.

4. PROJECT FINANCE FOR LNG "GRASS-ROOTS" PROJECTS

Generally speaking, the term "project finance" is used to refer to a financing structure in which the financing is not primarily dependent on the credit support of the sponsors. But here in this paper, we would like to define it as a financing structure where commercial banks take some part of (not all of) the major project risks.

It is true that "project finance" schemes are well applied to large-scale LNG "grass-roots" projects, but there are some required conditions for commercial banks to build up a financing scheme for these projects on a "project finance" basis or a limited recourse finance basis.

The followings are deemed to be basic requirements for "project finance."

- (a) Adequate reserve should be confirmed on a recoverable basis by the reputable independent consultant.
- (b) Development and completion of the project should be guaranteed by gas producers.
- (c) LNG sales contracts including pricing formula should be concluded on the acceptable terms and conditions to the lenders. ("take or pay" clause should be required)
- (d) Project assets should be granted as a first ranked mortgage to the lenders and all rights, and benefits under the related project agreements should be also assigned to the lenders.
- (e) Adequate level of debt service coverage ratio in project cashflow projection should be secured in lenders' analysis as well.
- (f) Cash flow mechanism and cash flow priority including establishment of escrow account should be satisfactorily arranged for the lenders.

On the premise that these required conditions are fulfilled, it will be possible to employ a project financing structure for future LNG "grass roots" projects for the Far East market with the following risk sharing pattern in each risk category:

(a) Reserve Risk

If the adequate reserve of natural gas is proven on a recoverable basis by an internationally reputable consultant, reserve risk can be shared among gas producers, financial institutions including commercial banks, and possibly buyers.

(b) Natural Gas Development and Plant Construction Risk

Natural gas development and plant construction risk, such as cost overrun and delay in completion and shortfalls in expected capacity/efficiency of production, should basically be undertaken by gas producers.

However, some part of this risk (especially, completion risk of liquefaction plant) can be shared with financial institutions if terms and conditions in EPC contracts are acceptable and partial guarantees are provided by producers. In this case, it is preferable for financial institutions that turnkey lumpsum EPC contracts will be reputable and experienced.

(c) Operating and Marketing Risk

LNG buyers and financial institutions involved in the projects require reliable operating capabilities of a project company or its operating and maintenance agreement concluded with an experienced operator in technical and commercial aspects.

As for marketing risk, the financial institutions require a long-term sales contract with "take or pay" clause which is consistent with the amount and period of the debt service.

(d) Political Risk

In any cross-border financing, financial institutions will take political risk which occurs under a collapse of the existing political/legal order in the host/borrowers country, such as alternation in exchange, transfer, and tax regulations, nationalization of the project assets and so on.

Especially for projects in developing countries, financiers are more careful to study those risks. In this part, the support of both governments of LNG exporting and importing countries will be expected.

(e) Force Majeure Risk

We understand that so-called force majeure risk should basically be shared among all related parties in a sense of co-operation. The range of force majeure, however, is carefully discussed and agreed by all related parties, and those risks are particularly acute to the pre-completion phase of the project.

(f) Credit/Financial Risk

Some part of projects risk above mentioned are resorted to project sponsors (gas producers and equity participants). Therefore, financiers assess the credit worthiness and management capabilities of the sponsors that they rely on to ensure the success of the project.

In this way, project risks in LNG projects can be shared by the related parties. EXHIBIT 4 shows the summary of this.

RISK SHARING FOR FINANCING

ITEMS OF RISKS	RISK TAKERS
(a) Reserve Risks	• Gas Producers • Financial Institutions
(b) Construction and Development	• Gas Producers • EPC Contractors • Financial Institutions
(c) Operating & Maintenance	• Gas Producers • Financial Institutions
(d)/(e) Political Risks/Force Majeure Risks	• Government of Host Country • Government Agencies of Financers Country • Financial Institutions • Gas Producers
(f) Credit/Financial Risks	• Financial Institutions

APPENDIX

FINANCING STRUCTURES OF
INDONESIA LNG PROJECTS

- (i) The First Indonesian LNG Project
- (ii) LNG Expansion Projects in Indonesia

(i) The First Indonesian LNG Project

On December 3, 1973 the first Indonesian LNG sales contract was signed between Pertamina and Japanese LNG buyers, the outline of which is shown in Exhibit 5.

The project cost for the construction of liquefaction facilities and LNG tankers was more than US\$ 1 billion and it was not easy for the Indonesian government/Pertamina to procure such a huge amount. They tried to find a way to raise funds in a cooperation with Japanese LNG buyers getting support from Japanese governmental authorities and Japanese related parties.

Such cooperation for financing was quite different from the past LNG projects at that time, where gas producers and/or liquefaction company had financed for the projects by themselves and sold LNG to buyers.

The scheme and main features of financing for the project are illustrated in EXHIBIT 6 and 7.

The financing for the building of LNG tankers was arranged by a shipper, named Burmast East Shipping Corp., and ship builder, General Dynamics, utilizing a guarantee facility provided by the Maritime Administration of the US Department of Commerce.

And LNG receiving terminals in Japan were build and funded by LNG buyers. Financing for the main body of the project consisted of Yen Credit of Overseas Economic Cooperation Fund, one of the Japanese government authorities, and import credit of The Export Import Bank of Japan (J.EXIM) through Japan Indonesian LNG Co., Ltd. (JILCO), which was established specially for the purpose of financing for the first Indonesia LNG project.

OECD Yen Credits are Japanese official overseas development aid and basically to be provided for the construction of infrastructure projects. It was quite exceptional that Yen Credit was provided to a natural resource development Indonesian LNG project. Such special yen credit could be provided only if a project is very significant for both the recipient country and Japan. The repayment term of the yen credit extended 25 years with a grace period of seven years and the interest rate was fixed on 3% p.a.

The co-financing of EXIM with commercial banks made loans to JILCO for this project. Import credits are usually borrowed by importers(trading firms and/or buyers of natural resources) and re-lent to exporters. In the case of the Indonesian LNG project a project company was set up, and risk-taking by the utility companies was in the form of guaranteeing the EXIM co-financing syndicate. This project was the first case where Japanese utilities companies exposed themselves to such risk-taking, although partly covered off through official support programs. Their actual assumption of risk was limited to 40%, because Japan National Oil Corporation(JNOC), a government agency, guaranteed 60% of the loans.

A project company is sometimes set up when a number of entities import products from the same overseas project. The establishment of such a company has several merits; the clerical control of the loans can be facilitated, coordination among the related parties can be easier, and importers sometimes prefer guarantees to loans when indicating their obligations on their balance sheet.

Project companies are usually set up with a small equity capital. JILCO's paid-in capital was Japanese Yen 1.5 billion. The parties that have an equity share in a project are generally importers and trading firms. In the case of JILCO, many companies other than importers cooperated because the project was of national importance.

The amount of the JILCO import credit was equal to the total cost of the construction of the liquefaction facilities (except portions covered by yen credits). This was rather unusual. The reason for EXIM's approval of the full amount was that all LNG from the liquefaction facilities was to be exported to Japan, which was in urgent need of LNG.

As a measure to ensure the repayment of JILCO loans, a certain percentage of LNG sales proceeds is credited to the escrow accounts in the US from which principal and interest are repaid. The reliability of the cash flow of this project to these accounts was enhanced by the fact that development of natural gas fields, construction and operation of the liquefaction facilities, construction and operation of LNG tankers and other activities were undertaken by parties with excellent technological know how and experience; and by the fact that the Japanese buyers themselves had concluded the take-or-pay contract.

The JILCO's loans were made in US dollars, but a certain percentage of EXIM co-finance was denominated in yen. Accordingly, JILCO took a foreign exchange risk.

The First Indonesia-Japan LNG Sales Contract

1. Buyers and their respective purchase quantity:

(thousand tonnes per year)

Chubu Electric Power Co., Inc.	1,700
Kansai Electric Power Co., Inc.	2,400
Kyushu Electric Power Co., Inc.	1,500
Nippon Steel Corporation	600
Osaka Gas Company, Ltd.	1,300
TOTAL	7,500

2. Take or Pay : Buyers assume take-or-pay obligation subject to availability.
3. Transport : Pertamina's responsibility. Title of LNG passes on delivery into a buyer's receiving facility.
4. Term : 1977-99
5. Price : Price is escalated according to the movements of Indonesian crude oils and transport costs.

Finance for The First Indonesian LNG Project

1. Share of Loan :

Exim Banks	80%
Commercial Banks	20%

2. Amounts:

ARUN	US\$523 million equivalent (mixture of yen and US dollars)
BADAK	US\$375 million equivalent (mixture of yen and US dollars)

3. Interest Rates(JILCO's funding cost):

Commercial Banks	
US Dollar	LIBOR + margin
YEN	Long-term prime lending rate + margin
EXIM	Fixed

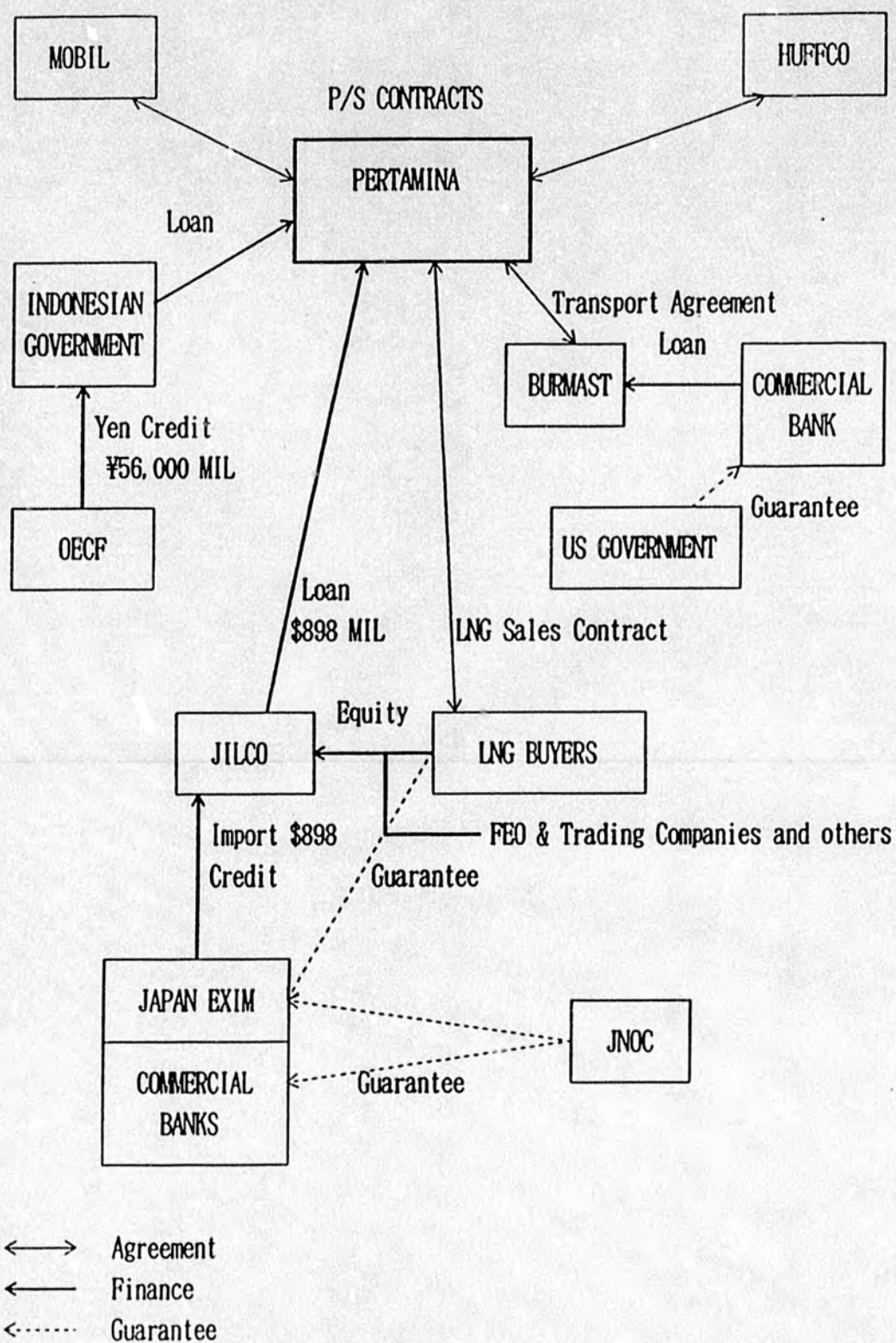
Terms :	
ARUN	16 years
BADAK	15 years

Guarantee :	JNOC	60%
	LNG Buyers	40%

Escrow Account :	Certain percentage of sales proceeds is credited to the escrow account.
------------------	---

Overseas:	Certain percentage of the loans was insured.
Investment:	
Insurance:	

Finance Scheme of The First Indonesian LNG Project



"Trustee Borrowing Scheme" for Indonesian Train E Project

EXHIBIT 8

Trustee Borrowing Scheme

