

ALASKA LEGISLATURE COMMITTEE FILES, 2005-2006 0072

12023 SENATE RESOURCES

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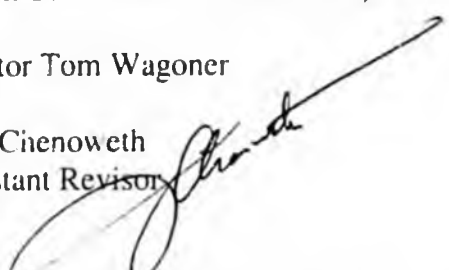
State Capitol
Juneau, Alaska 99801-1182
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MEMORANDUM

March 27, 2006

SUBJECT: Amendment I.1 to CSSB 305(RES), draft version "I"
(Work Order No. 24-GS2052M.1)

TO: Senator Tom Wagoner

FROM: Jack Chienoweth
Assistant Revisor 

Because I could not find "state's best fiscal interests" used in the body of statute or regulatory law, in the accompanying amendment, I have substituted the phrase "the long-term fiscal interests of the state." The substituted material captures the sense of comparable language appearing in the Alaska Stranded Gas Development Act, AS 43.82,¹ and may have come to have some discrete meaning, at least in the context of that related chapter that might prove helpful in the administration of this provision, if it is adopted and enacted into law.

JBC:ljw
06-156.ljw

Enclosure

¹ These examples appear in that Act:
-- "practicable and consistent with *the long-term fiscal interests of the state*," AS 43.82.210(b);
-- "reasonably necessary to protect *the fiscal interests of the state*," AS 43.82.260(d);
-- "to protect *the long-term fiscal interests of the state*," AS 43.82.310(c);
-- "proposed contract terms are in *the long-term fiscal interests of the state*," AS 43.82.400(a)(1); and
-- "if the commissioner determines that the contract is in *the long-term fiscal interests of the state*," AS 43.82.430(b).

24-GS2052M
Chenoweth
3/29/06

AMENDMENT

OFFERED IN THE SENATE BY SENATOR BEN STEVENS
TO: CSSL 305(RES) Work Draft Version "I"

1 Page 18, lines 25 – 29:

2 Delete all material

3

4 Page 20, line 31 – Page 21, line 3:

5 Delete all material

6

7 Page 24, line 5, following "(2)":

8 Insert "ordinary and necessary" has the meaning given "ordinary and
9 necessary" in 26 U.S.C. 162 (Internal Revenue Code) and regulations
10 adopted under that section;"

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12 Renumber the following paragraph accordingly.

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AMENDMENT

OFFERED IN THE SENATE BY SENATOR BEN STEVENS
TO: CSSB 305(RES) Work Draft Version "I"

- 1 Page 7, line 16, following "development .
- 2 Insert " exploration"
- 3
- 4 Page 7, lines 17 – 19:
- 5 Delete all material
- 6
- 7 Page 7, line 30 – Page 8, line 2:
- 8 Delete all material
- 9
- 10 Page 10, lines 25-27:
- 11 Delete all material
- 12
- 13
- 14
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NOTE: This replaces Admin. Amend. #1 – now includes line numbers, notes sections previously approved; and identifies pages and lines for the new "I" CS; otherwise, it is identical. //mj 3-26-06

AMENDMENT

OFFERED IN THE SENATE:

BY SENATOR WAGONER

TO: CSSB 305(RES), draft version 24-GS2052\Y

1 Page 18, line 4: insert after "than zero"

Approved

2 "If a producer does not produce taxable oil or gas during a month, the producer is
3 considered to have generated a positive production tax value if the calculation described in this
4 subsection yields a positive number because the producer's adjusted lease expenditures for a
5 month are less than zero as a result of the producer's receiving a payment or credit under (e) of
6 this section or otherwise."

7
8 Page 18, line 23: insert new paragraph (3)

Approved

9 "(3) an explorer that has taken a tax credit under AS 43.55.024(b) or that has obtained a
10 transferable tax credit certificate under AS 43.55.024(d) for the amount of a tax credit under AS
11 43.55.024(b) is considered a producer, subject to the tax levied under AS 43.55.011(e), to the
12 extent that the explorer generates a positive production tax value as the result of the explorer's
13 receiving a payment or credit described in (e) of this section."

14
15 Page 19, line 29: replace (A) "outlays for capital assets" with

Approved

16 "(A) an expenditure, when incurred, to acquire an item if the acquisition cost is otherwise
17 a direct cost, notwithstanding that the expenditure may be required to be capitalized rather than
18 treated as an expense for financial accounting or federal income tax purposes;"

19
20 Page 21, line 9: replace "amounts that have not been paid" with

Approved

21 "amounts incurred"
22

NOTE: This replaces Admin. Amend. #1 – now includes line numbers, notes sections previously approved; and identifies pages and lines for the new “I” CS; otherwise, it is identical. //mj 3-26-06

Approved

1 Page 21, lines 14-15: after “business entity” delete all material and insert:

2 “, whether or not the transaction is treated as an asset sale for federal income tax
3 purposes.”

5 Page 21, line 11-17: replace “any payment of credit the producer receives for” with

6 “certain payments or credits received by the producer, as provided in this subsection. If
7 one or more payments or credits subject to this subsection are received by a producer during a
8 month or, under (f) of this section, during a calendar year, and if either the total amount of the
9 payments or credits exceeds the amount of the producer’s lease expenditures or the producer has
10 no lease expenditures, the producer shall nevertheless subtract those payments or credits from the
11 lease expenditures or from zero, respectively, and the producer’s adjusted lease expenditures for
12 that month or calendar year are a negative number and shall be applied to the calculation under
13 (a) of this section as a negative number. The payments or credits that a producer must subtract
14 from the producer’s lease expenditures, or from zero, under this subsection are payments or
15 credits received by the producer for”

17 Page 21, line 18-22: Page 19, lines 19-23: delete all material, insert:

18 “(1) the use by another person of a production facility in which the producer has an
19 ownership interest or the management by the producer of a production facility under a
20 management agreement providing for the producer to receive a management fee;”

22 Page 23, line 1 Page 20, line 2: replace (n) (o) with (m) (n) and after “2006:” insert

23 “for purposes of this subsection, if a producer removes from the state, for use outside the
24 state, an asset described in this subparagraph, the value of the asset at the time it is removed is
25 considered a payment received by the producer for the transfer of the asset;”

27 Page 23, line 28 Page 22, line 13: insert “(b),” at the beginning of the line

29 Page 23, lines 29 through 30: replace (d)(2)(L) with (d)(2)(N) and delete “or (d)(2)(M)”

30 Page 22, Line 14: delete “or (d)(2)(O)”

NOTE: This replaces Admin. Amend. #1 – now includes line numbers, notes sections previously approved; and identifies pages and lines for the new "I" CS; otherwise, it is identical. //mj 3-26-06

1 Page 23, line 31: Page 22, Line 16: delete "(d)(2)(L) or (d)(2)(M)" and insert "(e)(3)(A)"

2
3 Page 24, line 10: delete "(d)(2)(L)" and replace with (d)(2)(N): See page 22, line 26: this is
4 now in "I" version, was picked up as a drafting correction

5 +
6 Page 24, line 4: insert after "Revenue Code):"

7 "as amended," See page 22, line 20: this is now in "I" version, was picked up as a
8 drafting correction

9
10 Page 24, lines 12-13: Page 22, Lines 27-28: after "due:" delete all material and insert

11 "if a producer fails to comply with a request under this paragraph, there shall be added to
12 any underpayment determined by the department under this section a penalty in the amount of 20
13 percent of the underpayment."

14
15 Page 24, lines 14-27: Page 22, Line 29 through Page 23, Line 11: delete all material and
16 reorder

17
18 Page 24, lines 28-30: Page 23, Line 12 through 14: delete all material and insert

19 "(n) For purposes of determining the amount of the adjustment by subtraction that must
20 be made to a producer's lease expenditures as a result of the producer's receiving a payment or
21 credit under (e)(3)(A) of this section,"

22
23 Page 25, lines 7-11: Page 23, Lines 22-26: delete all material and reorder

NOTE: "I" version deleted the definition of "ordinary and necessary" which was previously approved by the Committee.

MEMORANDUM

To: Sen. Tom Wagoner, Chair
Senate Resources Committee

From: Joe Balash, Professional Legislative Assistant
Legislative Budget and Audit Committee

Date: March 27, 2006

RE: Section 22 of Draft (RES) CS for SB 305

You have asked for a summary of the changes to proposed AS 43.55.160 contained in the draft committee substitute labeled 24-GS2052\I. All of these changes appear in section 22 of that draft.

Under the proposed legislation, section 160 establishes the tax base against which the tax rate will be applied. It identifies the gross value of the oil and gas at the point of production and then allows a series of costs (or lease expenditures) to be deducted. In this case, we are talking about money flowing out of the taxpayer's wallet. The section relies on a standard of "direct, ordinary, and necessary." Taxpayers are required to make adjustments to those costs in those instances where revenue is flowing back into the wallet of a taxpayer—if they sell an asset or receive facilities access payments.

After introduction of the governor's original legislation, Marvin Kirsner, tax counsel at the firm of Greenberg Traurig, authored a memorandum dated February 27, 2006 that was delivered electronically to every member of the Legislature. He also appeared before the Resources Committee telephonically on March 23. His memorandum delved into those areas in which the state could be exposed to deductions and cost recovery mechanisms that the Legislature might find unacceptable. He offered a series of recommendations to address those concerns.

First, he recommended the provision embodied in subsection (o) [appearing at p. 23, line 12 through p. 24, line 1 of the revised draft CS] that would prevent a taxpayer from churning assets or engaging in what are referred to as "wash sales." You might recall that the Governor's original legislation (and your draft CS) contains an anti-churning provision in the tax credit section of the bill [appearing at p. 10, lines 13-19 of the revised draft CS]. In that case, the administration sought to prevent a taxpayer from buying and selling assets for the sole purpose of accruing multiple tax credits. The same principle applies here—only this section deals with deductions. Keep in mind that a credit is worth 20% of the value of an asset but a deduction is worth 25% of the value due to the tax rate established in the CS.

Second, he recommended that the purchase of a business entity not be allowed as a deduction. For example, when Chevron purchased Unocal last year, you would want to prevent Chevron from deducting 25% of the value of Unocal's Alaska assets against their tax liability on North Slope production. This was embodied in subsection (n) [appearing at p. 22, line 29 through p. 23, line 11 of the revised draft CS]. It was also included in the list of excluded costs as (d)(2)(O) [appearing at p. 19, lines 3-6 of the revised draft CS].

Third, he recommended that the adjustment required under subsection (e)(1) be broadened. The original legislation contains a mechanism to capture revenue received by a producer for providing access to their production facilities. However, that language speaks only to facilities in which the producer has an ownership interest. A producer could sell or otherwise transfer its assets to a non-producer and then provide management services at the facility for a fee. In that event, it was recommended that such revenues be accounted for in the production tax. This was embodied in (e)(3)(B) [appearing at p. 19, lines 21-23 of the revised draft CS].

Finally, he recommended that the State protect itself against inflated pricing in transactions that occur between affiliated parties OR third parties. He recommends two things to accomplish this.

First, exclude as a direct cost that amount which was inflated. This exclusion appears as (d)(2)(N) [appearing at p. 18, line 30 through p. 19, line 2 of the revised draft CS]. An example would be 'Taxpayer A' purchases 50 drill bits at \$100,000 apiece for a total of \$5,000,000 for use at properties in Louisiana and Alaska. Since Louisiana's production tax system does not consider upstream costs, 'Taxpayer A' requests that the 25 drill bits headed for Alaska be priced at \$150,000 and the 25 drill bits headed for Louisiana be priced at \$50,000. The provisions of (d)(2)(N) would allow the department to exclude the inflated \$50,000 per drill bit—a total of \$1,250,000 that would have cost the state \$312,500 if it were deducted.

Second, give the department the tools necessary to conduct the types of audits that the IRS uses to uncover these sorts of inflated transactions. These power are granted in subsection (m) [appearing at p. 22, lines 14-28 of the revised draft CS].

There were numerous references throughout the section of the draft CS that were incorrect and led to confusion amongst the administration as well as committee members and staff. The portion of Administrative Amendment #1 that was not taken up by the committee contained the necessary corrections. Additionally, that amendment contained changes that would make the language more efficient and reduce some redundancies—changes that personnel from the Departments of Law, Revenue and the Office of the Governor agreed were technically correct.

However, the department—as well as the Governor's Chief of Staff—has made clear that it does not feel the additional audit powers granted in subsection (l) are necessary to achieve the goal of protecting the state against inflated price transactions. If the Committee agrees, removing these audit powers is a straight-forward process, mechanically speaking.

Nevertheless, I would like to bring to your attention that the department believes its current regulations protecting the state on transportation charges will accomplish the same goal on upstream charges. However, the department derives its authority on transportation charges from language in AS 43.55.150(a). That language says that the reasonable costs of transportation shall be the 'actual costs' of transportation. The department relies on the 'actual costs' standard to bore down into the transactions between affiliated companies and prevent the state from absorbing more than actual cost to provide transportation. The proposed section we are dealing with for PPT relies on a different standard—costs that are "direct, ordinary, and necessary."

A final note: the revised draft CS no longer contains a definition that may have been removed in error. 'Ordinary and necessary' was defined in the final subsection, (o) [appearing at p. 25, lines 21 through 23 of the "Y" draft CS], as the meaning found in 26 U.S.C. 162 (Internal Revenue Code). If that language is to go back in, 2 of the 3 words in the standard for the department to rely on in allowing costs for deduction purposes will be defined. That will leave the word 'direct.' So, the question the department will have to answer in the future is whether or not the Legislature intended 'direct' costs to mean 'actual' costs. If it is not clear, the department may be faced with challenges to the regulations they intend to adopt.

MEMORANDUM

To: Sen. Tom Wagoner, Chair
Senate Resources Committee

From: Joe Balash, Professional Legislative Assistant
Legislative Budget and Audit Committee

Date: March 28, 2006

RE: Section 22 of Draft (RES) CS for SB 305

You have asked for a description on the origins of the amendments to section 22 of the "I" version of the draft (RES) CS.

As a refresher, Section 22 establishes the tax base (Determination of Production Tax Value) and then makes deductions and requires adjustments.

In a memo dated February 27, 2006, tax counsel Marvin Kirsner identified concerns with the language in the Governor's original legislation. Changes made in the first CS to address those concerns included an expansion of the list of costs which will not qualify for deduction [the (d)(2) list]; adjustments to direct costs [subsection (e)(1) of the revised CS]; increased audit powers for the Department of Revenue [subsection (m) of the revised CS]; and a recapture provision similar to that used in the qualified capital credit section [subsection (o) of the revised CS].

Following the administration's review and comments on the first CS on Saturday, March 18, a teleconference between the department personnel, administration consultant, and tax counsel took place on Monday, March 20 to discuss and resolve issues raised by the department.

Generally speaking, the department gained a better understanding of—and appreciation for—the issues raised. They did, however, continue to voice concern with the increased audit powers [subsection (m) of the revised CS].

With that understanding, over the next two and a half days, we were able to craft language to clean up references and make some adjustments to the sections. Those changes were contained in Administrative Amendment #1. I have attached a 'clean' version of the remaining elements in Administrative Amendment #1, with page and line references adjusted to address the revised CS. I have also attached an email from Assistant Attorney General Rob Mintz indicating their satisfaction with technical changes made.

The department recognized that the revenues derived from 'management fees' for a facility not owned by the producer ought to be captured in the adjustments [subsection (e)(1)(B) in the revised CS]. The lawyers have settled on language to insert on p. 19, lines 19-23.

The recapture provision Kirsner developed for 160(o) on pages 23-4 contains a mechanism to deal with assets purchased in Alaska and then transferred out of the state for use elsewhere. The department recognized the need for this provision and it was agreed that a portion of that section, p. 23, lines 22-26, could be moved into 160(e)(3)(A). The department had hoped to delete the rest of that subsection, but our tax counsel has advised that we retain it.

Kirsner's concern with the acquisition of a business entity was also recognized as a legitimate concern, although it was dealt with by including it as a prohibited item on the direct costs list in 160(d)(2). This allows for the deletion of subsection (n) on p. 22, line 29 through p. 23, line 11.

The remaining area of disagreement lies in the treatment of transactions that are not at arm's length and the tools to deal with them. Subsection (m) establishes a standard and then provides for the adoption of regulations similar to Section 482 of the Internal Revenue Code. It is unclear to me whether or not the department objects only to the audit powers, or to the arm's length standard as well. Attached is a memo from Carolyn Fanaroff of the firm Greenberg Traurig, who was formerly with the Internal Revenue Service, which speaks to the differences between Section 482 and Section 162 of the Internal Revenue Code.

AMENDMENT

OFFERED IN THE SENATE:

BY SENATOR WAGONER

TO: CSSB 305(RES), draft version 24-GS2052\I

Page 19, line 19-23: delete all material, insert

(1) the use by another person of a production facility in which the producer has an ownership interest or the management by the producer of a production facility under a management agreement providing for the producer to receive a management fee;

Page 20, line 2: replace (o) with (n) and after "2006:" insert

for purposes of this subsection, if a producer removes from the state, for use outside the state, an asset described in this subparagraph, the value of the asset at the time it is removed is considered a payment received by the producer for the transfer of the asset;

Page 22, line 13: insert "(b)." at the beginning of the line

Page 22, line 14: delete "or (d)(2)(O)"

Page 22, line 16: delete "(d)(2)(N) or (d)(2)(O)" and insert (e)(3)(A)

Page 22 lines 27-28: after due; delete all material and insert

if a producer fails to comply with a request under this paragraph, there shall be added to any underpayment determined by the department under this section a penalty in the amount of 5 percent of the underpayment.

Page 22, line 29 through Page 23, line 11: delete all material and reorder

Page 23, line 12-14: delete all material and insert

(n) For purposes of determining the amount of the adjustment by subtraction that must be made to a producer's lease expenditures as a result of the producer's receiving a payment or credit under (e)(3)(A) of this section,

Page 23, lines 22-26: delete all material and reorder

ALASKA STATE LEGISLATURE

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SENATOR BERT K. STEDMAN

MEMORANDUM

To: Senator Tom Wagoner/ Mary Jackson
From: Senator Bert Stedman/ Kim Carnot *KHC For B.J.*
Date: March 28, 2006
Re: Progressivity Formula Tracking

The progressive feature is a surcharge; it is in addition to the base PPT tax. The surcharge is a monthly payment on gross oil production, separate from the PPT tax on net revenues. The surcharge is triggered by a threshold price to prevent diminishment of the state share in times of high oil prices. The surcharge results in an effective tax rate that is less than the nominal tax rate. Because the surcharge is measured on gross value of the oil at production, the formula includes a factor of "1-PPT rate" in order to reflect the built in deductibility of the surcharge (similar to royalty payments and property tax payments).

As amended in the Senate Resources Committee, the ANS price based progressivity feature is applied on total taxable barrels of oil at the point of production, is triggered by a \$40 price per barrel, and has an accelerator of .002.

SB 305

No progressivity concept

CS SB 305 (RES) Version "Y"

Page 5 Line 30 through Page 6 Line 5

(g) In addition to the taxes levied under (e) and (f) of this section, for each month for which the average United States Gulf Coast price for that month of West Texas Intermediate crude oil is more than \$40 a barrel, there is levied upon the producer of oil or gas a tax for oil or gas produced during that month from each lease or property in the state, less any oil or gas the ownership or right to which is exempt from taxation. The tax is equal to .20 percent for each \$10 increment or portion of the increment that the average price of oils exceeds \$40 a barrel.

Y.39 Offered by Senator Stedman

Page 5 Line 30 through Page 6 Line 5

(g) In addition to the taxes levied under (e) and (f) of this section, there is levied upon the producer of oil a tax for oil produced during that month from each lease or

DISTRICT A

Ketchikan • Sitka • Petersburg • Wrangell
Pelican • Elfin Cove • Port Alexander • Sarman • Myers Chuck • Thorne Bay • Coffman Cove • Hollis

AMENDMENT

OFFERED IN THE SENATE:

BY SENATOR WAGONER

TO: CSSB 305(RES), draft version 24-GS2052\1 (dated 3-27-06)

1 Page 7, line 14, after "amount of" insert:

2 "20 percent of that expenditure."

3

4 Page 7, lines 15 through 19, delete all material.

5

6 Page 7, line 30, through page 8, line 18, delete all material.

7

8 Page 10, line 26-27, following "Federal Energy Regulatory Commission," insert:

9 "the"

10

11 page 18, line 25, following "a pipeline. facility" insert:

12 "other asset"

13

14 Page 18, line 28, following "successor" insert:

15 "regulatory"

16

17 Page 20, lines 12 through page 21 line 3, delete all material and insert deleted materials
18 into Sec. 13, on page 10, line, 28 as new subsection (i)

19

20 Page 10, line 28, renumber accordingly.

21

22

23 Page 20, line 31 through page 21, line 3: delete all material.

24

1 Page 24, line 5: Insert new (2):

2 “(2) “ordinary and necessary” has the meaning given “ordinary and necessary”
3 in 26 U.S.C. 162 (Internal Revenue Code) and regulations adopted under that section;

4 Page 24, line 5, renumber accordingly.

5

6 Page 27, lines 31-32, and Page 28, lines 1-3, delete all material.

7

8

9

SB

314

ALASKA STATE SENATE

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Senate Bill 314 Sponsor Statement

"An Act limiting retroactive adjustments in the sale price of state royalty oil sold by the state to a refiner."

This legislation corrects an unintended consequence resulting from the State's filing of a protest with Federal Energy Regulatory Commission (FERC) regarding interstate tariff rates on the Trans Alaska Pipeline System (TAPS). Senate Bill 314 amends AS 38.05.183(f) so as to disallow retroactive adjustments in the sale price of royalty oil where a TAPS transportation rate change has occurred.

The effect of the State's filing (from January 1, 2005 forward) is to create a potential retroactive payment for any in-state refinery purchasing State royalty oil until the FERC case is settled. This could be as late as August of 2009. Though the State is a signer to both the ten year royalty oil contract with Flint Hills Resources Alaska (effective April 1, 2004) and the TAPS Settlement Methodology (TSM) which governs TAPS rates through 2009, the State chose to challenge TSM prior to 2009 thus creating retroactivity potential for Flint Hills Resources Alaska (FHRA).

The negative impact on FHRA and other entities has been real and immediate. FHR must reserve for this potential liability up to \$50 million dollars per year. With up to five years to settle the case with FERC, accumulated retroactive liability could reach \$200 million or more. This has caused FHRA to cancel a \$175 million clean fuels project and a \$91 million naphtha stabilizer project.

In addition, low margin products such as naphtha have been discontinued in 2006 and FHRA is purchasing 10,000 barrels less per day of State royalty oil, for which a premium is paid. This has also resulted in the loss of approximately \$7 million in shipping revenue for the Alaska Railroad and \$1 million in fuel flowage fees for the Port of Anchorage. FHRA is also not able to provide long term contracts to fuel customers such as Golden Valley Electric Association because of the uncertainty caused by potential retroactivity.

Senate Bill 314 eliminates the uncertainty for buyers of State royalty oil and encourages investment and product production decisions to be based on genuine market factors rather than the prospect of tariff retroactivity. It also restores fairness in terms of avoiding retroactivity with respect to raw materials that have long since been manufactured and sold into the marketplace.

Flint Hills Resources Alaska / Tariff Retroactivity

Rec'd
From FLINT
HILLS / WAF

Talking points:

Since March 2005, Flint Hills Resources has had a series of meetings with the DNR to address the State's change in position towards TAPS Settlement Methodology and the resulting uncertainty of the price of crude oil we purchase to use in our refinery.

Our first response from the state occurred on Friday, Feb. 24, when the DNR released its letter to the media before Flint Hills Resources had received a copy.

Never have we asked for a subsidy or handout. Our goal has been – and continues to be – to achieve pricing certainty for the crude oil we've purchased since January 2005.

Example: As an example, how would you react if the electric company, with historical usage records, could retroactively charge you an additional \$100 per month for your past usage? You no longer have the ability to turn down the thermostat or add insulation or take any action to respond to the higher price. That's what we're faced with.

The simple solution to that onerous uncertainty is to amend our RIK contract with the state. Flint Hills Resources asked the DNR to support a change in the company's contract to purchase state-owned crude oil. The requested change would have eliminated the pricing uncertainty the company faces due to a lawsuit pending before the Federal Energy Regulatory Committee. The change would simply give our company certainty of its crude purchase price from January, 2005 through the future, pending the matter's ultimate resolution.

The DNR is correct in asserting that we were aware of the potential for future pipeline tariff decisions. However, these decisions were set to be reviewed in 2009, and the state was, we thought, contractually prohibited from disputing the current TAPS Settlement Methodology. The January 2005 court filing to speed up that decision – and the State's support of that change – fundamentally changes the business climate in which we operate.

In the past year, because of the uncertainty of retroactivity, we have made decisions to shelve our plans to spend more than \$175 million to build new units to produce low-sulfur fuels, instead investing \$15 million with another refinery in-state to produce those products. We've deferred a \$90 million naphtha stabilizer project that would have further expanded our production capability, and employed additional people as well as contractors to work on the construction project. We decided to discontinue naphtha production in 2006, because it was the least profitable of our product lines and we knew we couldn't pass along increased costs to customers, should retroactivity be put in place. This decision reduced the Alaska Railroad's revenues by about \$7 million per year.

Without a response from the DNR, we will continue to move forward, assuming the worst-case scenario in running our business. We will factor in higher crude costs in all of our decisions and act accordingly.

3/16/06

Crude Pricing Example under current RIK Contract with FHR & the State

FHR pays ANS west coast delivered price for crude, less the interstate tariff and plus pump state one to North Pole tariff. For every one dollar change in crude price for FHR, there is a \$25.50 million swing in the annual price paid for crude based on 70,000 barrels of royalty crude purchased per day.

Example at assumed \$50 per barrel west coast delivered, an intrastate tariff of \$1.50 per barrel from pump station one to North Pole, and alternative interstate tariffs of \$3.50 and \$2.50 per barrel.

	<u>Assumed Current</u>	<u>Potential</u>
ANS West Coast delivered price:	\$50.00	\$50.00
Less current assumed interstate tariff:	- 3.50	- 2.50
Add assumed intrastate PS #1 to NP:	<u>+1.50</u>	<u>+1.50</u>
Final price per example:	\$48.00	\$49.00

So with potential price increase of just \$1.00 per barrel, annual crude costs can rise by as much as \$25.5 million. The filers in the current FERC case would like the tariff to drop to \$1.50, which would price the crude at \$50.00 in the above example and add up to \$51 million in additional annual crude costs. If the FERC case takes years to settle and the request for lower tariffs prevails, the retroactivity could amount to multiples of between \$25.5 and \$51 million per year.

This situation results in both uncertainty and unfairness to refiners and consumers.

(3)mf

Excerpts from briefs filed with the Federal Energy Regulatory Commission relative to the negative impacts of Quality Bank Retroactivity.

Attached are excerpts from legal briefings filed by eight parties with the Federal Energy Regulatory Commission (FERC). These excerpts are from briefs of September 12, 2003, under FERC OR89-2. They are from Volume 2 beginning on page 186 of the section on retroactivity.

The eight Parties included PetroStar and the State of Alaska. This brief was filed with the FERC prior to the Administrative Law Judge's (ALJ's) issuance of his decision in the quality bank case. The purpose of the brief was to convince the ALJ not to order retroactive liability on the residual cut in the quality bank case. While this is a different case and issue than the current tariff issue, the principle is in fact identical between the two; that is the potential for multi-year retroactive liability is unfair, hurtful to consumers, impedes business planning, impedes development and expansion, and harms all involved. It is clear the State and PetroStar recognized these issues when they filed this legal argument (along with the other Eight Parties). Thus, this is an issue that is apparent to the State and the business community. In 2005, the U.S. Congress passed legislation to mitigate Quality Bank retroactivity.*

*Comments by Flint Hills Resources relative to the attached FERC briefing excerpts.

b. Because the Refiners Could Not Mitigate The Impact of Retroactive Adjustments, Awarding Refunds Now Would Be Unfair to the Refiners and Would Not Put The Parties In The Positions They Would Have Been In Had The Commission Not Erred

Awarding refunds would be unfair to the refiners for a different reason. The refiners continuously "optimize" their operations to obtain the best fit between their costs and conditions in the marketplace. Since changing the Quality Bank methodology after the fact would deprive them of the opportunity to optimize and thereby mitigate the impact of refunds, ExxonMobil will collect more from the refiners than it would have if the methodology on which refunds are based had been in place from the start.

(1) The Refiners Continuously Optimize Their Operations To Reflect The Quality Bank

Refiners make profits if they sell the fuels they manufacture for more than the costs of making those fuels. They optimize their operations by running their facilities efficiently and making those fuels that they can place in the market at profitable prices. The refiners consider Quality Bank impacts when they determine what products to make as well as when they decide how much product they can sell at a profit. In short, the Quality Bank is "part and parcel" of a refiner's decisions as to how to run its business. Tr. 11,904:11-20.

The Quality Bank thus plays an integral role in the refiners' business. As Ms. Dayton explained:

[The refiners] must make operational decisions within their refineries to optimize operations. Within differing limits, a refinery

can vary its operating parameters, its choices of fuels, and its product slates to reflect the impacts of the TAPS Quality Bank on its economics. Under some circumstances, Quality Bank considerations may even make it economically unreasonable for a refinery to participate in a given fuel market.

Ex. PAI-22 at 13:2-6.

Resid valuation is a major part of these Quality Bank considerations. As Ms. Dayton testified, changing the Resid valuation has a leveraged impact on the refiners' cost structures. Tr. 11,907:5-10. Petro Star operations show why. Petro Star neither makes nor retains Resid, Tr. 11,735:23-24; 11,748:12-19, but it retains *other* cuts. Consequently, when Petro Star returns all the Resid it receives, its return stream contains a higher percentage of Resid than the common stream. Tr. 11,580:18 – 11,581:22. In December 2001, for example, the Petro Star Valdez Refinery ("PSVR") return stream contained 20.6% Resid, compared to the passing stream percentage of 16.6%. *Id.*; Ex. PSI-17 at 1-2.¹ Moreover, as illustrated in Ex. PSI-17 at 1-2, Resid is both a relatively high volume constituent of ANS crude and very low priced (in December 2001, the second lowest priced cut after normal butane, which makes up only 2.6% of the passing stream). As this example shows, lower Resid valuations greatly increase Quality Bank assessments against the refiners.

¹ Quality Bank assessments are calculated by subtracting the per barrel value of the return stream from the per barrel value of the "reference stream" (i.e., the common stream formed when the return and passing streams are commingled, valued at the weighted average values of the return and passing streams).

Mr. Boltz, a Petro Star executive, explained why increased Quality Bank assessments have so great an impact. Assessments against refinery return oil must be borne by products made from the much smaller volume of oil that the refinery retains. Petro Star retains approximately twenty-five percent of the crude it receives, or about one barrel for every three it returns. Tr. 11,607:15-19. Consequently, the \$1.00/barrel assessment against return oil illustrated in Exhibit PSI-17 translates into a \$3.00/barrel (or approximately 7 cents/gallon) cost added to products that Petro Star makes for sale or its own use. Tr. 11,574:5-13.²

Costs of this magnitude directly affect a refiners' ability to make a profit. As Mr. Boltz explained, refining "is a business of fractions of a penny per gallon." Tr. 11,713:2. If costs increase relative to prices, it can become unprofitable for Petro Star to sell to some of its customers:

We evaluate every bid that we enter into, whether it be for jet fuel or marine diesel or whatever it is, and we look at that from the standpoint of what are our costs associated with providing that material? What is the sales price, and make a decision as to whether or not we can be competitive for those volumes. In some situations, we just aren't competitive.

Tr. 11,741:20 - 11,742:1. As already discussed, Quality Bank costs are a significant part of Petro Star's overall cost, and Petro Star must consider them when it decides whether fuel can be manufactured and sold at a profit. In the real

² The assessment against Petro Star's return oil is calculated from the data presented at p. 2 of Ex. PSI-17 by subtracting the stream value of the PSVR return stream (\$18.22371) from \$19.22516, which is the weighted average of the return stream and the PSVR passing stream value. Three dollars per barrel is converted to cents/gallon by dividing by 0.42.

world, margins on jet fuel can be very small, Tr. 11,740:8-12, and high volume jet fuel customers are likely to be the first ones to become unprofitable. Tr. 11,741:5-20. When this happens—and it does—Petro Star adjusts by retaining less crude and making less product. Tr. 11,607:15-19; Tr. 11,741:16-20.

(2) The Refiners Cannot Mitigate Quality Bank Impacts If A New Methodology Is Imposed Retroactively

The refiners cannot optimize to a Quality Bank methodology unless they know what the methodology will be and when it will be effective. Then they can decide whether to change product slates or fuel usage, and whether to reduce their production runs because they will no longer make a profit selling to some of their customers, or *increase* production to better manage their costs or sell to wider markets. Ex. PSI-1 at 6: 14-19. Ms. Dayton explained how this is a crucial, continuous process that significantly reduces the refiners' Quality Bank assessments:

So setting that extreme to the side, I think the refiners are going to optimize around whatever and take advantage of or change their product slate around whatever methodology is in place. Be it a good change or a bad change, it doesn't make any difference. They're going to go in, and they're going to make decisions where the Quality Bank may be advantageous to them to take the decision to do something. . . . And to the extent that the Quality Bank changes, they're going to make modifications to mitigate whatever those changes are. . . . I think they've always been successful in working toward mitigating what we thought the payments – the payments that they were going to make were going to be.

Tr. 12,674:2 – 12,675:1. If a new methodology is imposed retroactively, the refiners will have no chance to make any of the adjustments that Ms. Dayton describes.

The refiners do not have the ability to recoup retroactive Quality Bank assessments from their customers except in very unusual circumstances. As Mr. Boltz testified, Petro Star sells most of its fuel to the major airlines, the Armed Forces, and the fishing industry, and its customers would not enter into agreements that provided for future price increases. Tr. 11,736:12-18. Petro Star has only a single contract with a local public utility that provides for a limited pass-through of retroactive Quality Bank adjustments. Ex. PSI-1 at 8:2-11; Tr. 11,723:17-18. Ms. Dayton similarly testified that, in her experience, except in the case of public utilities, fuel sales contracts do not typically allow for retroactive adjustments, Tr. 12,675:14 – 12,677:4. Even Dr. Toof acknowledged that the likelihood of building such provisions into sales contracts was “limited.” Tr. 12,392:20-21.

Finally, the refiners cannot recover the ground they lose if they forego opportunities because there *might* be retroactive Quality Bank assessments in the future. For example, as already described, Petro Star’s larger customers tend to have the thinnest margins, and a few pennies difference in cost can be the difference between profit and loss. If Petro Star mistakenly predicts that a future methodology will significantly increase costs *and* be imposed retroactively, and on that basis foregoes sales that otherwise would be profitable, those sales—both

their profits and their contributions to fixed cost burdens—will be gone for good.

Ex. PSI-1 at 7:12-14. Ms. Dayton explained:

So with regard to the impacts with the Quality Bank, there are going to be consequences to their finances if they don't expand relative to the changes that might happen with the Quality Bank, equally to the fact that there may be impacts to them if they do expand. . . .

[I]f, 10 years down the road, some methodology comes into place that said I should have made that change 10 years ago, there's no way to go back and capture that. As I said, the market will get filled by some means, you know. So there's no way to say okay, I didn't expand 10 years ago because I was uncertain about that. 10 years later, now I'm certain. There's no way to go back and put that market share back in place or sell that product in the future, because it is truly a consumed product in these cases. So there's no way to undo that decision.

Tr. 12,637:24 – 12,638:20.

Petro Star's experience illustrates this dilemma. Petro Star had to choose between emphasizing diesel fuel production and processing less crude or processing more crude to produce more jet fuel. The former approach would have foregone economies of scale and minimized sales to Petro Star's larger, low margin jet fuel customers. Tr. 11,738:19 – 11,739:5. Petro Star followed the latter strategy so it could participate in the growing Alaska jet fuel market, achieve economies of scale, and allocate its fixed costs over more barrels of product.

Tr. 11,738:10-14. As Mr. Boltz explained:

[O]ur general approach to optimizing the refineries has been one of maximizing the jet fuel cut and also maximizing our throughput. We could have gone in a completely different direction here, and we could have maximized the diesel fuel and minimized throughputs and concentrated on efficiencies. Because of the way the Quality

Bank has been during this period of time, the optimum position for us was to increase capacity.

Tr. 11,715:10-17. Had a different Quality Bank methodology been in place, Petro Star would have optimized differently. Tr. 11,714:4 – 11,715:21; 11,736:19-25. Optimizing differently would have minimized any increases in Quality Bank assessments. As Ms. Dayton concluded:

[The refiners] would have made different decisions had different methodologies been in place, and therefore . . . those refunds that would have been assessed against them would have been significantly less had they been – and maybe none. I think they have been very successful in optimizing their operations around whatever methodologies are in place to minimize what those payments are, and I would expect them to do that.

Tr. 11,903:10-20. Thus, the prudent choice for the refiners has been to optimize against the methodologies that the Commissions determined should be implemented was reasonable for the refiners. Choosing to optimize to a more favorable methodology would have put the refiners at unjustifiable risk. Choosing a less favorable methodology, as discussed above, would have made them incur unrecoverable losses. As Mr. Boltz testified, to reject the Commissions' determinations, the refiners would have had to know that some different methodology would be implemented retroactively. Ex. PSI-1 at 6:14-21.

(3) The Quality Bank Has Been A Moving Target For The Refiners, And It Will Continue To Be A Moving Target Until This Case Is Decided

None of the events that led up to the current proceeding provided useful foreknowledge of what Resid valuation the Commissions ultimately will adopt, more than fourteen years after the parties' dispute over appropriate Quality Bank

valuations began in 1989. The 1993 settlement and associated orders established the distillation methodology, and the Commission selected FO-380 as the Resid reference price. ExxonMobil, among others, had complained that the Commission's proposed methodology would overvalue Resid, but proposed the unmodified 1993 settlement (i.e., viscosity blending) or return to the gravity methodology as alternatives. See Trans Alaska Pipeline System, 66 FERC ¶ 61,188, at 61,417 (1994).³ The Commissions rejected both of these approaches. On rehearing, as on appeal in OXY, the range of choices consisted of: (1) the FO-380 valuation selected by the Commissions, (2) the discarded gravity methodology, or (3) the unmodified 1993 settlement – the latter two already rejected by the Commissions. See Tr. 12,317:20 – 12,318:6.

The OXY decision made clear that the Resid valuation question was not settled but did not provide greater precision. The court held that the Commission's Resid valuation was not supported by the record, and decided that ExxonMobil should be allowed to renew its arguments in favor of a viscosity blending approach. OXY, 64 F.3d at 695-696.

The 1997 settlement proposals presented a choice between the Nine Party Settlement, ultimately approved by the Commission, and the ExxonMobil and Tesoro positions, which continued the Resid blending argument. See Trans Alaska Pipeline System, 81 FERC ¶ 61,319, at 62,464-465 (1997); Trans Alaska

³ Exxon also challenged the reference price selected for the gasoil cut, but that issue is not relevant to this proceeding. See id. at n.12.

Pipeline System, 80 FERC ¶ 63,015, at 65,227-229 (1997). In its own unilateral settlement proposal, ExxonMobil proposed a modified gravity methodology for Pump Station 1 but a distillation methodology based in part on Resid viscosity for the return streams. See Ex. WAP-269 at 15, 27, 38. Once again, the ExxonMobil and Tesoro alternatives to the Commission-approved methodology did not survive.

In Exxon, the court accepted the coker feedstock value approach but found an insufficient correlation between the Resid proxy price (FO-380 – 4.5¢) and calculated coker feedstock values. Exxon, 182 F.3d at 41. The court remanded for determination of a valuation method that better tracked Resid's value as a coker feedstock, Id. at 42, and the 2000 settlement proposals followed.

Meanwhile, ExxonMobil filed its complaint challenging the distillation methodology in its entirety and advocating a return to gravity. See Tesoro Alaska Petroleum Co. v. FERC, 234 F.3d 1286, 1288 (2000) ("Tesoro"). Although the FERC dismissed ExxonMobil's complaint, Exxon Co., U.S.A. v. Amerada Hess Pipeline Corp., 87 FERC ¶ 61,133 (1999), its decision was reversed and remanded on appeal in Tesoro, 234 F.3d at 1294. The Tesoro court thus again changed the landscape by leaving the way clear for ExxonMobil to resuscitate the gravity methodology.

Against this history of the parties' shifting positions and legal uncertainty, it was reasonable for the refiners to optimize against the methodologies in effect. Mr. Boltz explained:

If Petro Star had cut back its production based on a mistaken prediction that a new Quality Bank methodology would be imposed retroactively, it would have needlessly incurred losses that it has no means to recover. Moreover, none of the participants in the Quality Bank other than Exxon Mobil have ever sought to have a new Resid valuation methodology imposed retroactively. Similarly, except for the special case of the West Coast Heavy Distillate valuation, none of the participants in the Quality Bank other than Exxon Mobil currently seek retroactive application of any of the other proposed valuations. Further, to my knowledge, other pipelines that used distillation-based quality bank methodologies prior to TAPS did so by agreement among their shippers, so that adjustments would not be imposed retroactively without the shippers' consent. Taking drastic steps such as withdrawing from markets based on Exxon Mobil's or Tesoro's shifting litigation positions since 1993 would not have been prudent.

Ex. PSI-1 at 7:12 – 8:1.⁴ The refiners thus had no reasonable choice other than to optimize based on the valuation methodologies in place.

(4) The Solutions Offered By EMT To The Refiners' Dilemma Are Not Reasonable

EMT witnesses offer up three "suggestions" as to how the refineries should have operated since 1993. First, the refiners should have made better contracts with their crude suppliers and thereby reduced the risk of retroactive Quality Bank assessments. Second, they should have reserved against either the worst case or most likely outcome of this proceeding. Finally, they should have optimized their

⁴ As Mr. Boltz testified, the Eight Parties' settlement position developed for this hearing provided sufficient precision that Petro Star could have begun to accrue a reserve against the possibility that the settlement would be imposed retroactively. Tr. 11,718:23 – 11,719:1. However, as discussed below, accrual is a different question than optimization.

operations to either the worst case or most likely outcome. None of these suggestions is realistic.

With respect to EMT's first "suggestion," the refiners are in no position to pass Quality Bank risks on to their crude oil suppliers. The Petro Star and Williams refineries receive all their crude from TAPS. They must buy their crude oil from the North Slope producers (whether or not through intermediaries) or from the State. Their sellers, on the other hand, produce a fungible product that can be sold on the open market or that they may need for their own West Coast refineries. This is not a buyer's market.

Moreover, as Mr. Boltz explained, the refiners' Quality Bank liability is not incurred on the barrels that the refiners buy but on barrels they borrow. Tr. 11,744:4-19. The refiners need to process significantly more crude than they retain - in Petro Star's case, about four times as much. In essence, they borrow this oil and then reimburse their suppliers for the Quality Bank assessments that result when they return it to TAPS. EMT witnesses may be correct in assuming that the agreements that govern these arrangements are bargained for, but they have adduced no shred of evidence that the refiners did not get the best bargain they could. Mr. Boltz summed up how risk is usually allocated between producer and refiner:

JUDGE WILSON: Do you own the barrels while they're in your refinery, the return barrels, or does the crude supplier own them as they go through your refinery?

THE WITNESS: The reason I hesitate is what flashed into my mind, if we have a catastrophic spill, I'm sure we own them.

Tr. 11,744:24 – 11,754:4. Once again, this is not a buyer's market.

Contrary to EMT's second "suggestion," establishing reserves would not have kept the refiners whole. Both Dr. Pavlovic and Dr. Toof testified that had the refiners been prudent, they would have set up reserves, although they are inconsistent in whether they would have recommended that the refiners reserve against some undefined worst case or most likely case scenarios. Ex. EMT-123 at 9:3-6; Tr. 12,312:20 – Tr. 12,313:1. As discussed below, the Commission-determined methodologies reasonably appeared at the times they were in effect to be the most likely, and reserves against most likely case scenarios therefore were unnecessary. More importantly, however, neither Dr. Pavlovic nor Dr. Toof address the fact that reserves cannot remedy the effects of optimizing to the wrong methodology.

Nor do reserves address cash flow impacts. From a cash standpoint, there is no way a seller of crude oil or refined petroleum products will be able to recover the years of refunds prospectively in the marketplace. Its only option to "hedge" on the cash side is to have tried to charge higher prices over the years to cover the possibility of having to pay refunds, thereby prematurely passing the risk of refund costs primarily to Alaskan consumers. However, even then there is no assurance that the marketplace would allow the charging of higher prices.

Simply put, if a refiner optimizes to one methodology, and then a different methodology is imposed retroactively, the refinery will have lost the opportunity to optimize to the new methodology. Ms. Dayton illustrated this problem. She showed how, unlike a "typical" regulated utility, if a refiner optimizes against one methodology, setting up a reserve does not keep it whole if a different methodology is implemented. Ms. Dayton posits that a refiner could make \$110,000 profit under either "Methodology A" or "Methodology B" if allowed to optimize, but it only \$100,000 if it optimizes to the "wrong" methodology. If the refiner believes that "Methodology A" will be in effect and optimizes to it, but reserves \$10,000 against the possibility that "Methodology B" will be imposed retroactively, it will end up with \$110,000 dollars only if "Methodology A" prevails. If "Methodology B" prevails, the refiner will pay the reserve, net only \$100,000, and have no way to make up the \$110,000 it would have made if it had optimized to "Methodology B" in the first place. Unless the refinery selects the right methodology, it will lose at least some of the benefits of optimization if some other methodology is imposed retroactively. Ex. PAI-71 at 14:16 - 16:4.⁵

⁵ Ms. Dayton contrasts the refiners' dilemma with the ability of public utilities to hedge against similar uncertainty:

If a regulated entity charges rates that it knows are being challenged, the entity can hedge its risk against the possibility of making refunds by establishing a reserve equal to that part of the rate being challenged. If the rate ultimately is revised, the entity can make refunds from its reserve and be in the same position as if the new rate had been in effect the entire time. If the rate is upheld on

As to EMT's third "suggestion," the most reasonable course open to the refiners was to optimize to the Commission-determined methodologies, as demonstrated in detail above.

c. The Standards for the Exercise of Equitable Discretion Require the Commission to Balance the Equities of All Interests, Including the Public Interest

The public interest would not be served by the imposition of retroactive refunds. Prospective implementation of Quality Bank methodologies facilitates efficient economic planning; retroactive implementation frustrates efficient economic planning. The Quality Bank litigation has been long, tortuous, and unpredictable. In 1989, the parties did not know where they would be in 1993. In 1993, they did not know where they would be in 2004. If refunds are available, parties must continuously make their economic decisions in light of such uncertainty. Production companies will not know the value of the oil in their fields, and will have a more difficult time making investment and exploration decisions. The refiners will have an even more difficult time. As already discussed, making optimization decisions is at the core of their business. If they know what the Quality Bank methodology is, they can operate as efficiently as

appeal, the entity terminates the reserve and takes the full amount of the reserve into its revenues. In either event, the entity is in the same position as if the final decision on the rate had been in effect the entire period.

Ex. PAI-71 at 13:22 - 14:6.

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possible. If they do not – if refunds are available – the Quality Bank builds inefficiency into their operations unless they can foretell the future.

EMT argues that, to the contrary, refunds are necessary for efficiency because otherwise parties would delay and “game the system.” Tr. 12,414:8 – 12,415:1. EMT failed to adduce any evidence that this is a real problem. See Tr. 12,449:4 – 12,450:1. In fact, in this very proceeding, *all* the parties agreed to retroactive implementation of the Heavy Distillate valuation despite the enormous magnitude of the refunds that must be paid by the refiners. See EMT-610 at 1 (through 2002, Petro Star and Williams would owe \$23.7 and \$45.9 million respectively). As Mr. Boltz explained, Heavy Distillate presented a special case in that the reference price had been frozen and the parties not only knew it was incorrect, but had agreed to within a penny on the correct price. Tr. 11,709:2-8; Tr. 1801:25 – 1892:20. Given these circumstances, Petro Star was able to accrue a reserve against its refund liability. Tr. 1891:3-23. Moreover, because the new price would be consistent with the old one, it was unnecessary to reoptimize Petro Star’s

refineries. Tr. 1891:3-6; Tr. 1892:7-11; Tr. 11,726:14-20.⁶

In addition, retroactivity would have a negative impact on consumers. As discussed above, inefficiency is inherent in the uncertainty that attaches to the possibility of refunds except in unusual circumstances. To the extent that parties could trigger a serious danger of refund obligations simply by filing a complaint or appeal, an aggressive competitor could attempt to cause its rivals to cut production or forego sales that would be profitable unless there were refunds. Ex. PSI-1 at 8:14-18. This would be particularly true if EMT's views on refunds were adopted, and refiners were obliged to plan for worst-case outcomes. See Tr. 12,409:23 – 12,410:5; Tr. 12,312:20 – 12,313:1 (refiners should probably weight different outcomes and establish reserves against the worst case). Indeed, in this case, ExxonMobil is seeking refunds back to 1993 on the grounds that they would have been available under a worst case (Resid blending) that has been repeatedly and decisively rejected by Commission and court and abandoned even by ExxonMobil. Competition will suffer if the refiners should cut back their sales merely because they have notice that there might be a change in the Quality Bank,

⁶ Dr. Toof noted that ExxonMobil's Heavy Distillate receipts from the refiners would approximately balance payments that ExxonMobil would make to other producers at Pump Station 1. Tr. 12,425:3-20. He considered the Heavy Distillate issue to be "very similar" to the issues surrounding Resid valuation after 2000, Tr. 12,397:23 – 12,398:1-7, and hinted that the parties' alignments, not the frozen price, distinguished the Heavy Distillate and Resid issues. Tr. 12,393:20-23. For the reasons already discussed, the Eight Parties believe that the Heavy Distillate issue is unique for the reasons stated by Mr. Boltz and that the situation in 2000 was uncertain for the reasons already discussed.

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and consumers will suffer along with it. By contrast, granting refunds will not spur crude oil production or provide any other public benefit.

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Senate Bill 314 Sponsor Statement

"An Act limiting retroactive adjustments in the sale price of state royalty oil sold by the state to a refiner."

This legislation corrects an unintended consequence resulting from the State's filing of a protest with Federal Energy Regulatory Commission (FERC) regarding interstate tariff rates on the Trans Alaska Pipeline System (TAPS). Senate Bill 314 amends AS 38.05.183(f) so as to disallow retroactive adjustments in the sale price of royalty oil where a TAPS transportation rate change has occurred.

The effect of the State's filing (from January 1, 2005 forward) is to create a potential retroactive payment for any in-state refinery purchasing State royalty oil until the FERC case is settled. This could be as late as August of 2009. Though the State is a signer to both the ten year royalty oil contract with Flint Hills Resources Alaska (effective April 1, 2004) and the TAPS Settlement Methodology (TSM) which governs TAPS rates through 2009, the State chose to challenge TSM *prior* to 2009 thus creating retroactivity potential for Flint Hills Resources Alaska (FHRA).

The negative impact on FHRA and other entities has been real and immediate. FHR must reserve for this potential liability up to \$50 million dollars per year. With up to five years to settle the case with FERC, accumulated retroactive liability could reach \$200 million or more. This has caused FHRA to cancel a \$175 million clean fuels project and a \$91 million naphtha stabilizer project.

In addition, low margin products such as naphtha have been discontinued in 2006 and FHRA is purchasing 10,000 barrels less per day of State royalty oil, for which a premium is paid. This has also resulted in the loss of approximately \$7 million in shipping revenue for the Alaska Railroad and \$1 million in fuel flowage fees for the Port of Anchorage. FHRA is also not able to provide long term contracts to fuel customers such as Golden Valley Electric Association because of the uncertainty caused by potential retroactivity.

Senate Bill 314 eliminates the uncertainty for buyers of State royalty oil and encourages investment and product production decisions to be based on genuine market factors rather than the prospect of tariff retroactivity. It also restores fairness in terms of avoiding retroactivity with respect to raw materials that have long since been manufactured and sold into the marketplace.

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What will SB 314 do?

- SB 314 proposes the enactment of a statutory prohibition on "retroactive price adjustment" terms in existing and future RIK contracts. It will cause an amendment of the price term in the existing RIK contract between the State and Flint Hills Resources.

How will FHR's RIK Contract Change?

- FHR's Price Term is defined in Article 2.3 as:

ANS Spot Price - \$1.55 - Tariff Allowance + Quality Bank Adjustment - Line Loss.

- The contract defines the "Tariff Allowance" as:

"Tariff Allowance" means the sum of (1) the average, weighted by ownership, of the Minimum Interstate TAPS Tariff (Pump Station No. 1 to Valdez Marine Terminal) for each owner in effect on the Day the Sale Oil is tendered by the State to Buyer; and (2) any tariffs paid by Buyer for shipment of Sale Oil upstream of Pump Station No. 1. "Minimum Interstate TAPS Tariff" means the effective TAPS tariff on file with the Federal Energy Regulatory Commission ("FERC") for each carrier on a given Day, excluding incentive tariffs."

- On February 13, 2006, FHR asked DNR to amend the retroactive requirement. SB 314 would require that such an amendment be adopted by the commissioner.

~~"If a tariff which has been used in the calculation of a Tariff Allowance is changed or subject to a refund order by the FERC, the Tariff Allowance will be recalculated using the changed FERC ordered tariff, the Sale Oil Price will be adjusted accordingly, and the resulting refund to the State (or credit to Buyer) will be made in accordance with Article III. The changed FERC ordered tariff shall be used in the calculation of the price of Sale Oil delivered to Buyer on and after the date of the FERC order, but not before. If a FERC-ordered tariff is suspended or enjoined from implementation, the Tariff Allowance shall not be recalculated until the suspension or injunction is lifted and the FERC order is implemented and goes into effect."~~
The changed FERC ordered tariff shall be used in the calculation of the price of Sale Oil delivered to Buyer on and after the date of the FERC order, but not before.
 [Deletions are indicated in strikeout; additions are underlined.]

- The retroactive provision in the FHR contract was agreed to at the expense of other considerations for the State. The retroactive provision is just one part of a larger deal in which the state agreed to the \$1.55 per barrel discount on ANS spot price, provided

FHR with an option to reduce volumes purchased, added a built in automatic reopener to lower FHR's price after five years.

How does FHR's retroactive obligation arise?

- When FHR and the state negotiated the RIK contract in 2004, both were well aware that the Regulatory Commission of Alaska had two years before determined that the methodology used to calculate the TAPS intrastate tariff exceeded the "just and reasonable" rate standard required by law. (The RCA's decision has been affirmed in Alaska superior court.) The state and FHR agreed that, should the interstate TAPS tariff be changed by a ruling of the FERC so that refunds to shippers would be required, then FHR would pay the state the difference between the temporary and the new permanent tariffs. (Similarly, if the permanent FERC tariff were higher, the contract requires that the state will refund the difference to FHR.)
- An independent (i.e., non-TAPS owner) ANS oil producer challenged the 2005 TAPS interstate tariffs submitted to the FERC by the TAPS owners on the grounds that the interstate tariffs failed to meet the Interstate Commerce Act's requirement that tariffs be "just and reasonable." The FERC, pending a full hearing, suspended the 2005 and 2006 proposed tariffs, making them temporary and refundable. The state joined the complaint charging that the interstate TAPS tariffs were discriminatory when compared to the intrastate rates for essentially the same transportation service.

How much State revenue is at stake?

- The 2005 and 2006 proposed interstate tariffs are \$3.71 and \$3.96 per barrel, respectively. The RCA ordered for this same service is \$1.96. FHR has purchased an average of about 55,000 barrels per day of RIK oil from the state in 2005-06. Using the RCA tariff as an indicator of what the FERC may do in January 2007, FHR could owe the state approximately \$100 million for the 2005-07 period. Twenty-five percent of these amounts, i.e., \$25 million, will be paid to the Permanent Fund.
- According to the "fact sheet" accompanying SB 314, the total amount that FHR may owe the State could be \$200 million depending on the extent of FERC appeals.
- If FHR's contract is changed, FHR will be given a benefit that the ANS lessees do not have. According to the lease contracts and the royalty settlement agreements, the lessees will have to adjust retroactive that amount they owe the state for taking royalty in-value. This means that RIK will be less than RIV if SB 314 passes. The State would have been better off, i.e., received higher royalty revenues, if it had chosen not to sell to FHR.

- SB 314 does not require that the State receive anything in return for relieving FHR of its retroactive obligation. This lack of an enforceable and measurable commitment jeopardizes the constitutionality of SB314.

Constitutional Issues:

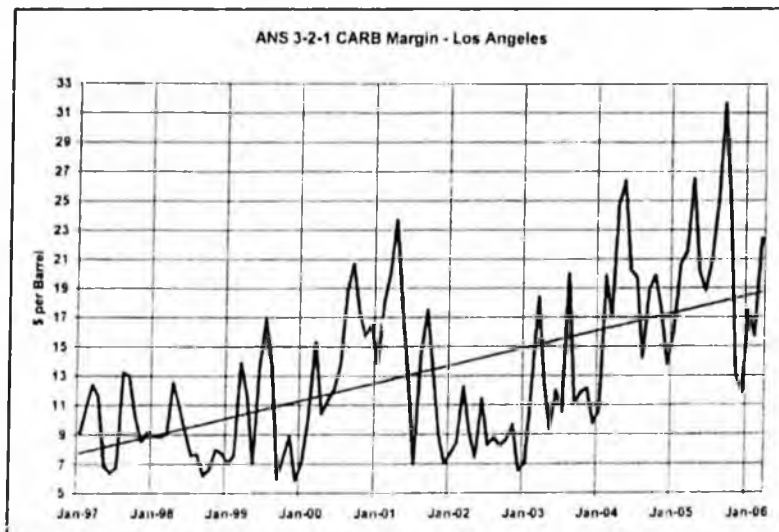
- The Department of Law has identified three potential constitutional problems with SB 314: impairment of contracts; separation of powers; and a violation of Article VIII, Section 2.
- DNR can comment on this last item. Article VIII, Section 2 states

“The legislature shall provide for the utilization, development, and conservation of all natural resources belonging to the State, including land and waters, for the maximum benefit of the people.”
- In the ANS Royalty Litigation, Alaska Superior Court Judge Compton ruled that the “maximum benefit” requirement prohibits the commissioner of DNR from collecting royalties “in kind” if the amount realized would be less than if taken “in value.” For the reasons stated above and assuming as FHR, the legislative “fact sheet,” and DNR’s own modeling of the FHR’s potential liability, RIK will be less than RIV if the FERC rules to lower the interstate tariff as the RCA did in 2002.
- If SB 314 were to require that the commissioner negotiate a trade from FHR such that FHR would provide some compensating non-price benefit in return for the relieving FHR of its retroactive obligation, the “maximum benefit” might be achieved. This non-price benefit would have to have a definite commitment required of FHR and that the benefit would have to be measurable and sufficiently balance what the State gives up. This assumes that there may be more latitude to amend the FHR contract than Judge Compton ruling requires.

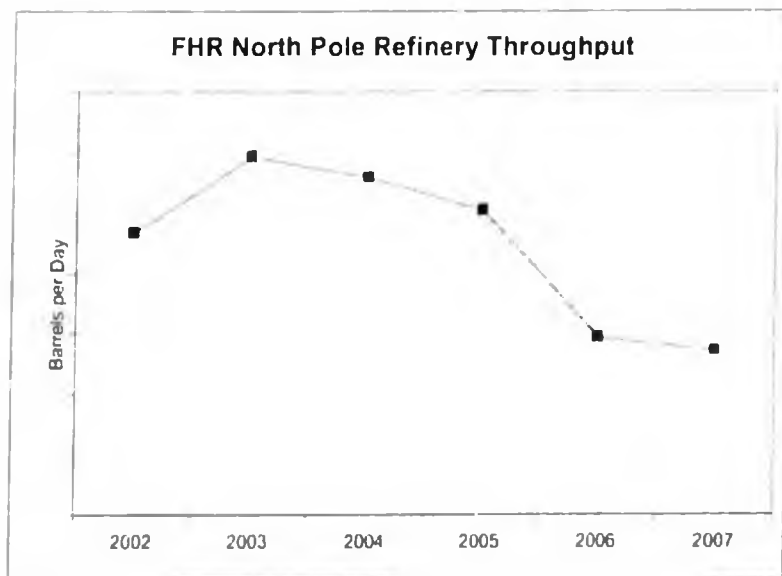
FHR Economics

- Consider that FHR can acquire crude oil at a substantially lower price than West Coast refineries (at the RIK netback price plus the intrastate tariff between Pump Station No. 1 and North Pole) and sells its products at a price only slightly less than West Coast refineries (after accounting for FHR’s cost of railroading its products from Fairbanks to Anchorage).
- DNR hired Baker & O’Brien to review information supplied by FHR. In the two years that FHR has owned the North Pole refinery, it has very favorable margins.

Even considering the margins of the last five years, the North Pole refinery has experienced positive earnings.



- FHR has very limited opportunities to invest in the refinery as evidenced by FHR's decision to buy, instead of producing clean diesel, from Tesoro. FHR indicated to DNR that the uncertainty caused by the retroactive tariff allowance provision in its RIK price contributed to this decision but a doubling of anticipated project costs contributed to this decision.
- FHR has indicated that a prospective rise in the RIK price will mean that FHR will try to maximize cash flow by reducing costs by reducing throughput and avoiding new investment.



- Relieving FHR of its retroactive obligations will not likely contribute to lower product prices. To assume that FHR can influence prices downward or upward because of its costs is to assume that FHR has market power in what should be a fairly competitive market.
- The question for policy makers is what will (can?) FHR do if the retroactive provision of its contract is changed.

Future RIK Contracts

- If SB 314 passes, and the constitutional “maximum benefit” requirement is resolved, DNR will have to draft conforming regulations. Today the commissioner is prohibited from selling RIK for less than RIV under 11 AAC 03.030.

Kevin Banks
Department of Natural Resources
April 2006

Best Interest Finding and Determination

For the Sale of

Alaska North Slope Royalty Oil

To

Flint Hills Resources Alaska, LLC



Alaska Department of
**NATURAL
RESOURCES**
DIVISION OF OIL & GAS

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

February 12, 2004

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Executive Summary

The Department of Natural Resources has negotiated a proposed ten-year contract to sell the State's North Slope royalty oil to Flint Hills Resources Alaska, LLC (FHR). FHR is negotiating the purchase of the assets of Williams Alaska Petroleum, Inc. including its refinery at North Pole, Alaska. This document summarizes the terms of the State's royalty oil sale contract and describes the criteria and considerations underlying the determination that this sale of royalty oil in-kind (RIK) is in the State's best interest.

UNDER THE PROPOSED CONTRACT FLINT HILLS RESOURCES WILL BE OBLIGATED TO MEET THE FOLLOWING TERMS:

- **Price**

FHR will pay a price calculated using the following formula:

$$\text{ANS Spot Price} - \$1.55 - \text{Tariff Allowance} + \text{Quality Bank Adjustment} - \text{Line Loss}$$

DNR forecasts the future additional royalty revenues under the proposed contract to be \$0.30 per barrel or approximately \$2.6 million to \$8.4 million per year.

- **Special Commitments**

As additional consideration for the RIK purchase, FHR agrees to:

1. Invest approximately \$100 million to install clean fuels processing equipment and facilities in the North Pole Refinery and/or elsewhere in Alaska.
2. Fulfill and enhance the previous commitments made by Williams Alaska Petroleum Inc. to the Government Hill Community Council in Anchorage to address concerns about gasoline storage tanks near Government Hill and undertake additional projects to improve the Anchorage Tank Farm facility.
3. Continue to ship refined products to Anchorage via the Alaska Railroad.
4. Study the use and viability of the hydrant fueling system at the Fairbanks International Airport (FIA), concentrate on promoting FIA to cargo carriers, evaluate and possibly upgrade FIA fuel distribution facilities, and charge a jet fuel customer in Fairbanks the same or lower price as FHR charges that same customer in Anchorage.
5. Maintain the wholesale truck rack prices for gasoline in Fairbanks at a price not to exceed the wholesale truck rack prices for gasoline in Anchorage.

- **In-State Processing**

FHR will make all commercially reasonable efforts to insure that the royalty oil it purchases under this contract will be processed at the North Pole Refinery or exchanged for oil that will be processed at the North Pole refinery. FHR's substantial investments, both in purchase of the North Pole refinery and in its contractual agreement to invest in Clean Fuels facility upgrades, further ensure the continued long-term prospects for in-state refining of State royalty oil.

- **Local Hire**

FHR agrees to employ Alaska residents and Alaska companies.

IN RETURN FOR THESE PROVISIONS THE STATE WILL PROVIDE:

- **Quantity**

The State agrees to sell to FHR ANS royalty oil within the range of 24,000 to 77,000 barrels per day, or nearly FHR's total refinery requirements, for the ten-year contract term. The State may limit the amount of oil sold to not more than 85 percent of the State's total North Slope royalty oil.

- **Term**

The term of the contract is ten years.

I. Introduction

The commissioner of the Department of Natural Resources (DNR), on behalf of the State of Alaska, has negotiated a long-term contract to sell the State's North Slope royalty oil to Flint Hills Resources Alaska, LLC (FHR) and Flint Hills Resources, Inc. (as guarantor), both of which are subsidiaries of Koch Industries, Inc. FHR has executed a contract for the purchase of the assets of Williams Alaska Petroleum Inc. (Williams) including Williams' North Pole refinery. FHR's contract with Williams is contingent on FHR's successful negotiation of a ten-year contract for purchase of State North Slope royalty oil to provide feedstock for the refinery.

The State proposes this sale of RIK oil to relieve market conditions for crude oil to meet in-state needs. The negotiations that have resulted in the attached proposed contract have been carried out under the procedures for a non-competitive disposition of royalty oil set out in 11 AAC 03.024. Under the terms of this contract the sale price for the royalty oil will exceed the amount the State would have received by taking its royalty oil in-value.

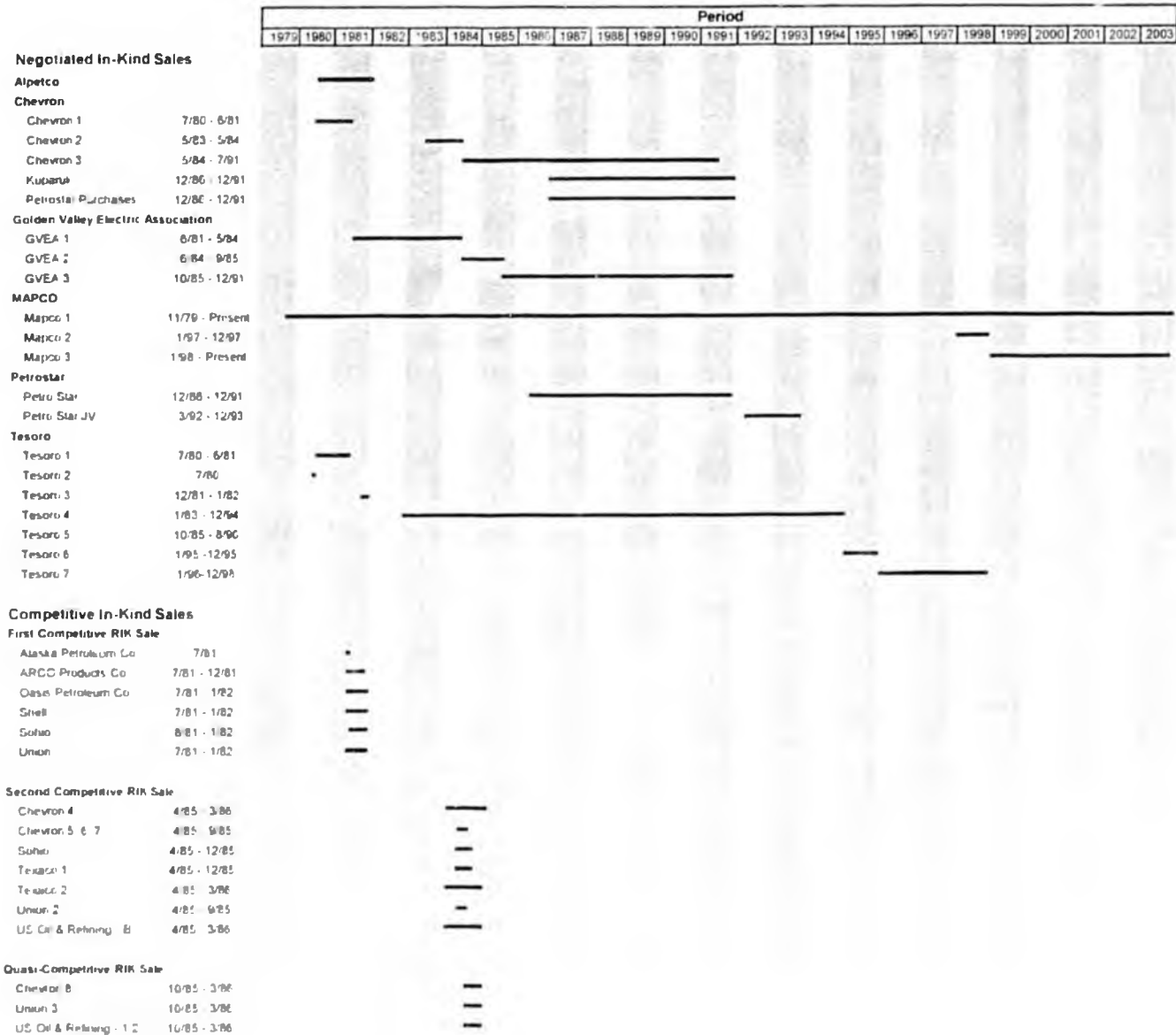
From an in-depth consideration of the potential economic, environmental, and social impacts, and the various requirements for sale of the State's royalty oil, with a focus on the criteria specified under the terms of AS 38.05.183(a) and (e) and AS 38.06.070(a), the commissioner finds that a negotiated long-term contract for the sale of the State's royalty oil to FHR is in the State's best interest.

II. Background

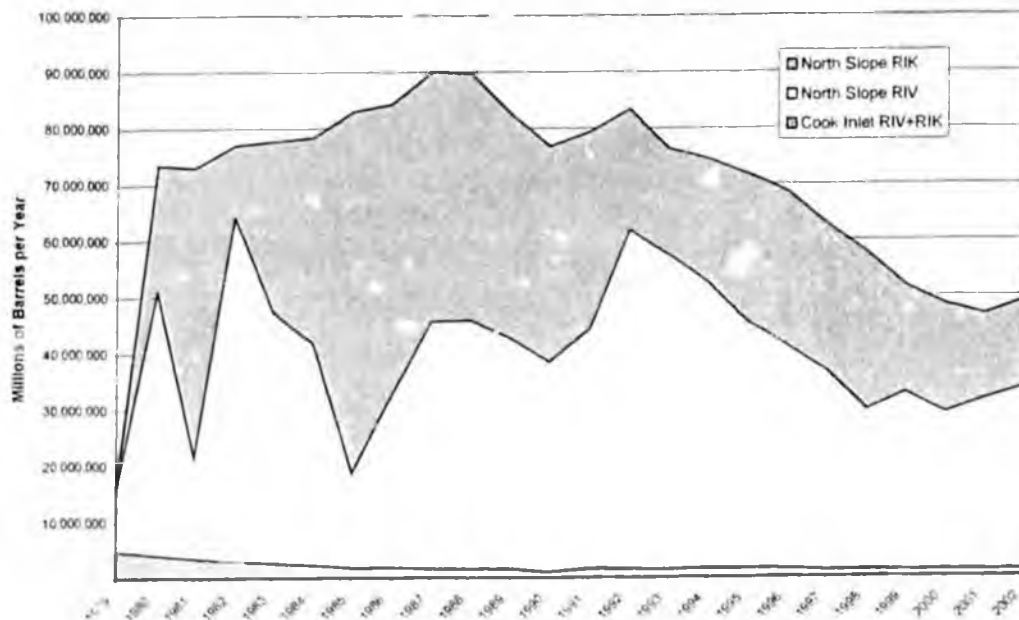
The State of Alaska owns the mineral estate, including oil and gas, under State-owned lands. It has entered into lease agreements with third parties who explore for, develop, and produce oil and gas from these lands. The State receives a royalty share of 12.5 to as much as 33-1/3 percent of the oil and gas produced from these leased lands, which it may take either "in-kind" (RIK) or "in-value" (RIV). When the State takes its royalty as RIV, the lessees who produce the oil market the State's share along with their own production and pay the State the value of its royalty share. When the State takes its royalty share of the oil as RIK, it assumes ownership of the oil, and the commissioner disposes of it through sale procedures designated either "competitive" or "non-competitive" under AS 38.05.183.

Over the years the State has sold nearly half of its royalty oil to in-state refineries, and occasionally has auctioned its royalty oil to customers in the Lower 48. Figure 1 summarizes the many North Slope RIK contracts since 1979 and Figure 2 illustrates the average annual volumes of royalty oil committed to these contracts during this period.

**Figure 1: Major North Slope Royalty in-Kind Sales Contracts
1979-2003**



**Figure 2: Composition of Total North Slope Royalty Dispositions
1979-2003**
Royalty in-Kind (RIK) and Royalty in-Value (RIV)



A. The Current Royalty In-Kind Contracts with Williams

When the Prudhoe Bay field began production, the State entered a 25-year contract to sell North Slope royalty oil to Earth Resources, Inc. who later built the refinery at North Pole, Alaska. The 25-year Earth Resources royalty oil contract supplied the North Pole refinery with an average of 35,000 barrels of royalty oil per day and was eventually assigned to Mapco Alaska, Inc. In 1997, the State and Mapco Alaska, Inc. negotiated a one-year contract for approximately 13,000 barrels per day to augment the supply of royalty oil delivered under the 25-year contract. In 1998, the State and Mapco "extended" this one-year contract by negotiating a new five-year contract that was subsequently approved by the Legislature. This five-year contract provided an average of 22,800 barrels per day in addition to the 35,000 barrels per day delivered under the old 25-year contract. Later in 1998 Mapco sold its Alaskan assets and assigned both the 25-year contract and the 5-year contract to Williams. Under these contracts, the State was obliged to deliver only royalty oil produced from the Prudhoe Bay Unit. These two contracts expired on December 31, 2003.

Following the expiration of the 1978 and 1998 RIK contracts on December 31, 2003, the State has continued to supply the North Pole refinery with royalty oil for feedstock under a short-term contract between the State and Williams that will expire on March 31, 2004.¹ The State has

¹ See Alaska Department of Natural Resources, October 1, 2003, "Best Interest Finding and Determination for the Sale of Alaska North Slope Oil" for a copy of this short-term contract.

executed a second short-term RIK contract with Williams to provide the refinery with an uninterrupted supply of royalty oil through September 30, 2004² to enable the continued operation of the refinery while the Department of Natural Resources and FHR conclude their negotiations on the proposed RIK contract that is the subject of this Finding and Determination. The two short-term RIK contracts are required to accommodate the nomination procedures required under the State leases, unit agreements, and the royalty settlement agreements between the State and the North Slope producers. The leases and agreements require the State to nominate the monthly quantity of royalty oil it elects to take in-kind 90 to 180 days before the production month for which the RIK nomination is made. The State must therefore execute its RIK sale contracts three to six months in advance of the month of first delivery in order to limit State nominations to quantities that are the contractual obligation of the ultimate RIK purchaser. Thus, the State's second short-term contract with Williams for deliveries to the North Pole refinery beginning April 1, 2004, was required to be executed prior to January 1, 2004.

The short-term contracts obligate Williams to take RIK oil that the State will nominate before the conclusion of Williams' refinery sale to FHR and the execution of the State's proposed RIK contract with FHR. The proposed RIK contract with FHR can not become effective until DNR (1) publishes the commissioner's findings on whether the contract serves the best interests of the State; (2) convenes the Alaska Royalty Oil and Gas Development Board ("Royalty Board") to review the contract (11 AAC 03.020); and (3) receives approval for execution of the multi-year contract from the Legislature. After the sale of the refinery is completed and provided that the State's long-term RIK contract with FHR receives all required approvals, FHR will take over the operation of the North Pole refinery and the RIK oil nominated under the short-term Williams' contracts will be assigned to FHR. FHR will pay for the RIK oil assigned to it under the terms (including price) set forth in the proposed long-term RIK contract.

B. RIK Oil Sale Procedure

Before executing a contract for the disposition of royalty oil in-kind, the commissioner must find that the disposition is in the best interests of the State. The commissioner establishes the terms, conditions, and methods of disposition of the State's royalty oil that is taken in-kind. The oil may be sold under "competitive" or "non-competitive" procedures. RIK oil may be sold under the "non-competitive" procedures if the commissioner determines that the best interest of the State will be served by a non-competitive sale. (AS 38.05.183(a)). In making this determination, the commissioner must consider the criteria listed in AS 38.05.183(e) and AS 38.06.070(a). The RIK contract must be awarded to the prospective buyer whose proposal offers maximum benefits to the citizens of the State.

In March of 2003, Williams met with staff at the Division of Oil and Gas and requested a new five-year RIK contract to fully supply the North Pole refinery feedstock requirements following expiration of the 1978 and 1998 RIK contracts. Williams informed the State that it was actively seeking to sell its Alaska assets and intended to assign the proposed RIK contract to the purchaser of the North Pole refinery. In early July 2003, FHR met with the Governor and his staff and indicated that it intended to buy the Williams' North Pole refinery and that a long-term

² See Alaska Department of Natural Resources, December 29, 2003, "Best Interest Finding and Determination for the Sale of Alaska North Slope Oil" for a copy of this second short-term contract.

contract with the State would make it possible for FHR to upgrade the properties it would acquire. The Governor called a meeting for July 29, 2003, and invited all potential in-state purchasers of North Slope RIK to discuss what terms each company might offer the State.

As a result of these meetings, and after consideration of all the criteria of AS 38.05.183(e) and AS 38.06.070(a), the commissioner determined that FHR was the prospective buyer whose proposal offered the maximum benefits to the citizens of the State, and agreed to negotiate an RIK contract directly with FHR. Individual findings on each of the statutory criteria are set out in Sections IV and V, below.

The commissioner determined that the sale of RIK oil to FHR would relieve market conditions by providing crude oil required for the continued operation of the North Pole refinery. In addition, the State would benefit from a sale price throughout the term of the long-term contract that would be higher than the volume-weighted average of the reported netback prices applicable to royalty oil taken in-value for the same period. The commissioner concluded, on balance, that entering into a long-term RIK sale contract with FHR, on the terms and conditions as included in the attached proposed contract, is in the best interests of the State.

This Best Interest Finding and Determination and a copy of the proposed RIK contract are available from the State by contacting:

Division of Oil and Gas
Attn: Kevin Banks
550 W. 7th Ave, Suite 800
Anchorage, Alaska 99501
Phone: (907) 269-8781
E-mail: [kreb@dnr.state.ak.us](mailto:krb@dnr.state.ak.us)

and will also be published on the Division of Oil and Gas website at:

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

A copy of the proposed RIK oil sale contract is attached as an appendix to this Best Interest Finding and Determination.

III. Discussion Contract Provisions

The proposed contract represents an evolution of RIK contract terms of the most recent (1998) State RIK contract with Williams as modified through negotiations between the State and FHR. The 1998 RIK contract with Williams is the latest in a 25 year history of long-term contracts between the State and the in-state refineries. This section is a summary of the essential terms of the proposed contract.

A. Price (Section 2.3 and Appendix 2)

The price per barrel of the royalty oil sold to FHR is set each month and is defined by the equation:

$$\text{ANS Spot Price} - \$1.55 - \text{Tariff Allowance} + \text{Quality Bank Adjustment} - \text{Line Loss}$$

Each of the elements of this equation are explained below:

1. ANS Spot Price

The ANS Spot Price is a monthly average of the daily average prices reported by three industry trade publications: Platt's Oilgram Price Report, Telerate online data reporting service, and Reuters online data reporting service. The ANS Spot Price represents the market value for North Slope oil sold on the U.S. West Coast. Judging by the prevalence of its use among the many buyers and sellers of North Slope oil, the use of the ANS Spot Price as defined in the proposed RIK contract is a credible and reliable measure of the ANS market. The Alaska Department of Revenue has adopted a similar definition for use in its calculation of Prevailing Value for production tax purposes.

The FHR contract contemplates the possibility that one or more of these reporting services may fail to publish a market price for North Slope oil or that the ANS Spot Price may no longer accurately represent the price for North Slope oil in the U.S. West Coast. In the first case, the ANS Spot Price will be calculated by using data from the remaining reporting services. In the second case, FHR and the State will attempt to arrive at a mutually agreeable alternative source of data to determine the ANS Spot Price.

2. \$1.55 per Barrel Deduction

Unlike former long-term RIK contracts between the State and in-state refinery customers, the proposed FHR contract does not directly reference the RIV netback value in the price term. The flat \$1.55 per barrel deduction from the ANS Spot Price replaces the actual (adjustable) marine transportation cost factor included in former RIK contracts. This is a deduction that FHR makes to its price paid for RIK oil, and thus the smaller the deduction, the higher the price paid by FHR to the State.

The \$1.55 deduction provides a premium to the State compared to DNR data on the deduction for marine transportation costs for the last three years allowed in the royalty settlement agreements with the lessees to calculate the RIV netback. The RIV netback is subject to change as the lessees are audited and when a current marine transportation cost "reopener" with ExxonMobil is resolved.³ DNR's estimate of the deduction for marine transportation costs for

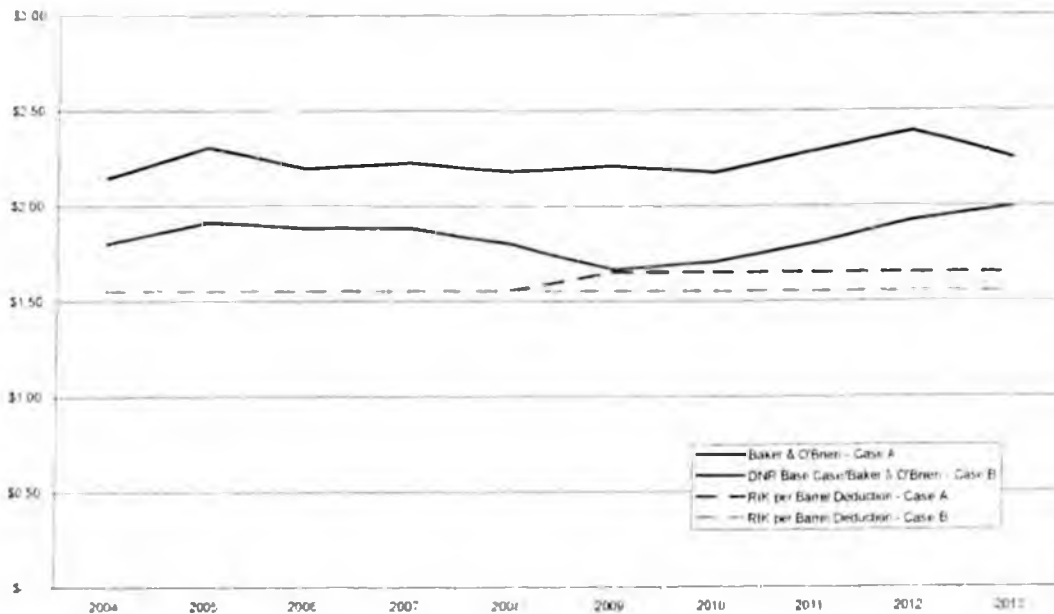
³ Each of the royalty settlement agreements with the North Slope lessees provides opportunities for the State or the lessee to renegotiate elements of the RIV netback formula. The State and ExxonMobil are currently disputing the calculation of ExxonMobil's destination value, marine transportation cost deduction, and the deduction for line losses.

the last three years allowed in the royalty settlement agreements ranges from \$1.73 to \$1.92. Based on a somewhat optimistic view of where the State may end up when the RIV netback is finally determined, DNR concluded that the difference between the RIV deduction for marine transportation and the RIK \$1.55 per barrel deduction yielded a premium of \$0.30 over this three year period.

The \$1.55 per barrel deduction is subject to revision at the end of year five of the proposed contract term. The revision will be calculated as follows: First, the State will take an average of the deduction for marine transportation costs for years 3, 4, and 5 of the contract term used to calculate the RIV netback. Second, subtract \$0.30 from this average. If the result is less than \$1.45 per barrel, then the RIK per barrel deduction for the years 6-10 will be \$1.45. If the result is greater than \$1.65, the RIK per barrel, then the RIK per barrel deduction for years 6-10 will be \$1.65.

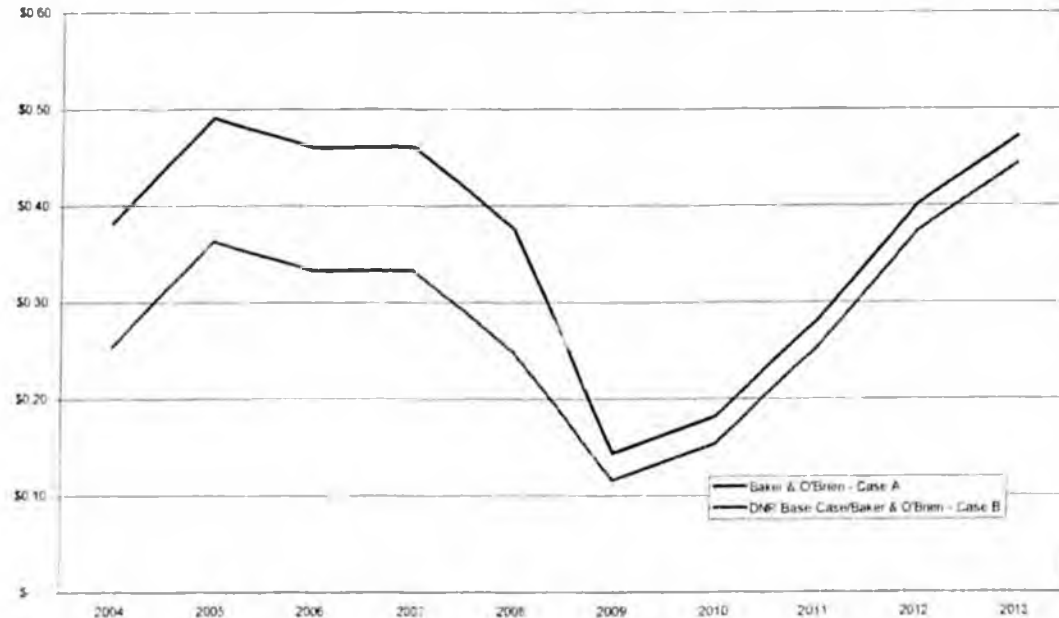
DNR prepared a forecast of the RIV deduction for marine transportation costs for RIV and retained Baker & O'Brien to review the methodology used by DNR.⁴ The results of this work are shown in Figure 3 and 4. Two forecasts are illustrated and both employ a hypothetical revision of the RIK per barrel deduction after year five of the proposed contract. The DNR base case suggests that the proposed contract will yield an average premium of about \$0.30 per barrel over the RIV netback for the ten-year term of the contract. Baker & O'Brien's Case A suggests that the proposed contract will yield a premium of \$0.36 per barrel. The difference in these two forecasts is explained by the different predictions DNR and Baker O'Brien assumed about the outcome of the current reopener dispute with ExxonMobil.

Figure 3: RIV Marine Transportation Deduction Versus RIK Differential



⁴ Dileep Sirur, Baker & O'Brien, Inc., Dallas, TX. Personal Communication, December 22, 2003.

Figure 4: RIK Contract Premium



3. Tariff Allowance

The Tariff Allowance provides an additional deduction from the ANS Spot Price equal to the average cost of pipeline transportation paid in transporting ANS oil to the spot markets on the U.S. West Coast. It is calculated as the sum of the ownership-weighted average minimum interstate TAPS tariff filed for each of the TAPS owners, plus any tariffs paid by FHR for shipment of royalty oil on pipelines on the North Slope upstream of Pump Station No. 1. Buyers and sellers in the Alaska market generally set contract prices in recognition that Alaska sales are an alternative to interstate shipments to the U.S. West Coast, and pricing terms are set accordingly.

All prior State RIK contracts for ANS oil have provided oil from the Prudhoe Bay Unit. Under the proposed contract with FHR, the State has the option of providing royalty oil from any ANS production unit, and the additional allowance for tariffs paid on pipelines upstream of Pump Station No.1 is a reimbursement of FHR's additional tariff costs incurred due to the State's choice of production unit. The State will also provide line fill for these upstream pipelines; i.e., the inventory of barrels delivered and sold under the terms of the proposed contract will be tracked in such a way that FHR will take delivery of barrels counted at the inlet of the pipelines but pay for the barrels counted at Pump Station No. 1. These terms will make FHR indifferent to the State's selection of the production unit from which the RIK oil is provided. In return, the

State has the freedom to maximize value by judiciously nominating royalty oil from different combinations of North Slope production units.

The Tariff Allowance is one of the elements of the price term in the proposed contract that is subject to retroactive adjustments. The Tariff Allowance may be adjusted if the tariff used in the calculation of the Tariff Allowance at the time of FHR's payment is changed (or subject to a refund order) by the Federal Energy Regulatory Commission (FERC) at a later date.

4. Quality Bank Adjustment

The Quality Bank Adjustment is a positive or negative number that reflects the value of different streams of oil that are shipped in TAPS. The Quality Bank is administered by the owners of TAPS and regulated by the FERC. Oil tendered for shipment at Pump Station No. 1 is produced from several different production units and the shippers of oil of lesser value must reimburse the shippers of oil of greater value for the degradation of value of the co-mingled mixture of oil. Similarly, the refineries in North Pole and Valdez also take oil out of TAPS, extract the valuable components of the oil in manufacturing petroleum products, and re-inject into the pipeline a mixture of lower valued components. The return streams from the refineries bear a quality bank payment to each of the owners of the passing TAPS stream.

The Quality Bank Adjustment in the proposed contract is calculated as the difference of the value of royalty oil where it is tendered at the point of sale—either at Pump Station No. 1 or at the entry into a pipeline upstream of Pump Station No. 1—and the value of the oil in TAPS downstream of the PetroStar Valdez refinery. Appendix 2 in the proposed contract provides an example for how the Quality Bank Allowance is calculated for RIK oil produced at the Duck Island Unit and processed in the unit's Endicott Main Production facilities. The State may readjust the Quality Bank Allowance if the Quality Bank administrator recalculates one of the values used in the calculation of the Quality Bank Allowance. After six months the only retroactive adjustments of the Quality Bank Allowance that may occur are those that result from a direct order issued by the FERC.

5. Line Loss

Line Loss is a per barrel amount equal to

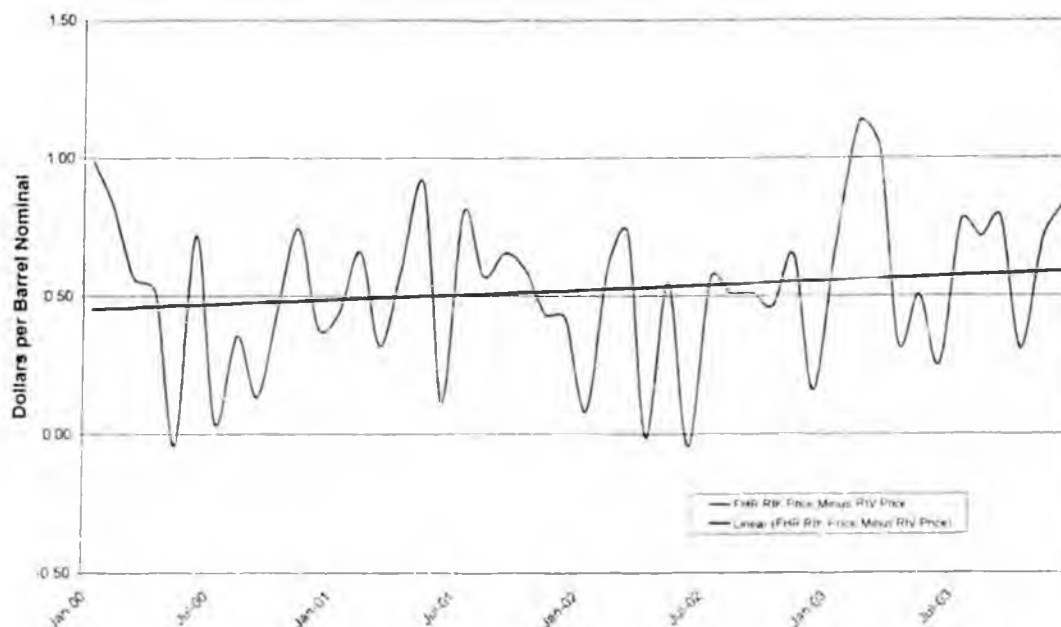
$$(.0009) \times (\text{ANS Spot Price} - \$1.55 - \text{Tariff Allowance} + \text{Quality Bank Adjustment}).$$

This term accounts for the minor change in the volumes of oil delivered at Valdez caused as compared to the volumes tendered at Pump Station No. 1. A line loss element also appears in the netback formulas in the royalty settlement agreements.

In summary, the price term in the proposed contract provides a mechanism that replaces the RIV netback formulas embedded in the price term of former RIK contracts. On the basis of the difference between the deduction for marine transportation costs in the RIV netback and the \$1.55 per barrel deduction in the proposed contract, the State will realize a premium of \$0.30. This represents a conservative estimate of the value of the proposed contract. There are

differences in other elements of the RIV formulas that may also contribute to additional benefits for the State. The calculation of the destination value in the RIV netback and the ANS Spot Price in the proposed contract is one element in each formula that may be the source of an additional premium for the State. Figure 5 shows a historical comparison between the RIV netback value at Pump Station No. 1 and the RIK price. If the proposed contract were in place in 2000-2003, the State would have earned \$0.52 per barrel more than RIV netback value.⁵

**Figure 5: Backcast of Proposed FHR RIK Contract Price
Difference from RIV Netback**



B. Special Commitments (Article V and Appendix 4)

Appendix 4 of the contract lists the Special Commitments agreed to by FHR. These commitments are listed here followed by a brief explanation.

1. Clean Fuels Processing

After performing an engineering study, FHR will install necessary equipment and complete such modifications to its North Pole Refinery, or will participate in the modification of other refinery facilities in Alaska, as required to produce gasoline and on-road, off-road, marine, and rail diesel fuels that meet or exceed all U.S. Environmental Protection Agency ("EPA") low sulfur fuel requirements ("Clean Fuels"). FHR will make commercially reasonable efforts to complete necessary installations and modifications on or before the effective dates of the Clean

⁵ A comparison between the proposed contract price and the price paid by Williams over the same time period (2000-2003) yields a premium of \$0.46 per barrel. Williams' 25-year contract price is equal to the RIV netback; Williams' 1998 contract price is equal to the RIV netback price plus \$0.15 per barrel.

Fuels requirements of the EPA regulations. These projects will result in a significant reduction in gasoline and diesel sulfur levels.

The EPA Clean Fuels regulations require that U.S. refineries must supply low-sulfur on-road diesel by June 2006.⁶ Low sulfur diesel must be available for new heavy-duty vehicles equipped with emission control devices that will be introduced in the 2007 model year, i.e., the fall of 2006. Low sulfur "Tier 2" gasoline and non-road diesel must be supplied by 2010.

FHR's total project costs are expected to exceed \$100 million and will likely include the construction of processing units, including hydrotreating, a hydrogen plant and sulfur removal equipment. The construction project will have a significant, though temporary, impact on the local and State economy. Most of the equipment to be installed will be manufactured outside of Alaska, and so the personal income and employment effects will be generated by the construction activities on-site and will depend on the availability of skilled workers who are residents of Alaska.

In a study provided by Anadarko Petroleum, Inc. and EnCana Oil and Gas (formerly AEC Oil and Gas, Inc.) in support of their 2002 proposal to buy North Slope royalty gas the proportion of in-state expenditures to total expenditures for the development phase of their North Slope Foothills project was approximately 46 percent.⁷ This suggests a conservative estimate of \$40 million for in-state expenditures could apply to FHR's Clean Fuels projects. This same study also indicated that the largest in-state development cost item was personnel expenses at 20 percent of total. If the Anadarko study is any indication, FHR's project will inject \$20 million into the State economy in the form of wages and salaries. Applying the Anadarko analogy to the FHR Clean Fuels projects, DNR estimates 100 to 200 direct jobs during construction with possibly twice that for indirect jobs.⁸ To the extent that FHR's preferred strategy to produce Clean Fuels in Alaska will involve improvements at the North Pole refinery these construction jobs will occur in the Fairbanks North Star Borough and the central Alaska region.

Impacts on local and statewide employment and personal income from construction will be temporary. Incremental long-term employment and personal income effects generated by the Clean Fuels projects at North Pole of the refinery should be rather small.⁹

2. Anchorage Tank Farm Evaluation.

⁶ 40 CFR Parts 69, 80, 86. Diesel fuels must meet a 15 parts per million sulfur standard. Under current EPA regulations, diesel fuels must meet a 500 ppm sulfur standard.

⁷ Northern Economics, Inc. January 2002. "Economic Impacts of Anadarko Exploration, Development, and Production of Alaska North Slope Foothills Gas Operations" p. 2-7.

⁸ Additional support for the estimate can be found in the number of construction jobs generated by a 1995 expansion project conducted by Tesoro Alaska Petroleum Company at its Nikiski, Alaska refinery. Installation of a \$26 million vacuum unit upgrade generated 180 direct and indirect jobs. Alaska Department of Natural Resources, September 1995. "Final Finding and Determination to sell Royalty Oil to Tesoro Alaska Petroleum Company" p. 18.

⁹ In 1998 Williams Alaska Petroleum, Inc. invested in a \$70 million expansion of the North Pole refinery. Williams indicated that the expansion created 17 new jobs. Alaska Department of Natural Resources, March 1998. "Final Finding and Determination to Sell Royalty Oil to MAPCO Alaska Petroleum Alaska, Inc." p. 13.

FHR agrees to discharge the commitments previously made by Williams in the "Memorandum of Agreement between Williams Alaska Petroleum, Inc. and The Government Hill Community Council" (attached as Appendix 6 to the proposed contract). The key requirements are as follows:

- a. Remove three (3) tanks from east of the Ocean Dock Road with a total capacity of over 5,500 barrels;
- b. Refrain from installing additional tanks east of the Ocean Dock Road;
- c. Evaluate all remaining tanks east of the Ocean Dock Road to determine whether they comply with all State and Federal requirements for overfill protection, fire protection, tank seal monitoring, potential for change of product service, and possible removal of additional tanks, and prompt remediation of any violations of these requirements;
- d. Installation of new tanks west of the Ocean Dock Road will occur provided that existing tanks on the east side of Ocean Dock Road are retired and removed on a tank-for-tank basis; and
- e. Continue cooperative efforts in connection with the ongoing Bulk Fuel Hazard Study currently underway through the Municipality of Anchorage.

3. Shipment by Rail.

Williams currently ships refined products by rail under contract with Alaska Railroad Corporation (an Agreement originally entered by MAPCO Alaska Petroleum Inc. in May of 1993). Williams transported about 1.4 million gallons per day of jet fuel during 2001, plus naphtha, and about 3,000 barrels per day of gasoline by rail to south central Alaska. As part of FHR's refinery acquisition from Williams, FHR will assume the rights and obligations of Williams under the rail agreement and continue to ship refined products to Anchorage through the term of its current railroad contract until 2013.

4. Fairbanks International Airport.

The proposed contract requires FHR and the State to jointly explore commercially reasonable options for increasing passenger and cargo air traffic through the Fairbanks International Airport (FIA), with a focus on promoting the FIA to cargo carriers operating between Asia and Europe. FHR shall also evaluate the airport's fuel distribution facilities and the feasibility of using or upgrading the existing hydrant fueling system.

Alaska's three refineries supply all of the in-state jet fuel consumed at the international airports in Anchorage and Fairbanks, and at military bases in the state.¹⁰ The North Pole refinery is the largest producer of jet fuel in Alaska. It accounts for about two thirds of total jet fuel consumption, as shown in Table 1.¹¹ While the North Pole refinery accounts for more than half of the Anchorage jet fuel consumption, the Fairbanks International Airport will remain an important jet fuel market for FHR.

¹⁰ Jet fuel is generally not imported into Alaska unless unusual circumstances arise, such as the West Coast longshoremen strike of mid 2002, which resulted in greater-than-usual air cargo activity.

¹¹ Dileep Sirur, Baker and O'Brien, Inc., Dallas, TX. Personal Communication, November 11, 2003.

Table 1: Regional Composition of Jet Fuel Production by Refinery
(Barrels per Day)

	TOTAL	Williams	PetroStar	Tesoro	Chevron¹²
Anchorage	52,000	29,000	3,400	13,600	6,000
Fairbanks	3,500	3,300	200	---	---
Military	5,100	1,400	3,700	---	---
TOTAL	60,600	33,700	7,300	13,600	6,000

The proposed RIK contract further provides for jet fuel price parity between Fairbanks and Anchorage. FHR has agreed that it will charge a jet fuel customer at the Fairbanks International Airport the same or lower jet fuel price as FHR charges that customer at the Anchorage International Airport.

5. Wholesale Gasoline Rack Price Parity

FHR agrees, for the term of the proposed contract, to maintain its wholesale truck rack posted price for gasoline in Fairbanks at a price not to exceed its wholesale truck rack posted price for gasoline in Anchorage on an annual simple average basis (within a tolerance/variation of 1 cent per gallon (cpg)). If the annual average variation of these posted prices exceeds 1 cpg, FHR will, in the first 90 days of the following year, reduce the variation below 1 cpg, averaged over the year-plus-90-day period. This provision will not apply to gasoline exchanges.

A review of OPIS wholesale gasoline truck rack price show that for the period January 2000 through October 2003, Fairbanks prices averaged 1.5 cpg lower than Anchorage prices for regular and premium grades.¹³ These are wholesale prices, not prices that consumers pay at the pump. Furthermore, posted prices do not necessarily reflect prices realized in actual transactions. Discounts (also known as "Temporary Competitive Allowances" or "TCAs") are offered about two or three times per year, but can last for extended periods and are offered to just a few customers.

A significant volume of gasoline is offered in exchanges between Williams and Tesoro. Williams provides approximately 500 to 600 barrels per day (21,000-25,000 gallons per day) to Tesoro in Fairbanks for an equal volume from Tesoro to Williams in Anchorage. Tesoro pays 4-5 cpg as an "exchange premium" for this arrangement because it can avoid the transportation charge to physically haul gasoline northbound on the Alaska Railroad. Tesoro's incentive to participate in this exchange arises from the fact that Tesoro's Nikiski refinery produces more gasoline than Tesoro can sell to its customers in the south central region. Tesoro's alternatives to

¹² Chevron purchased jet fuel for re-sale from Williams under a 5-year contract.

¹³ Dileep Sirur, Baker and O'Brien, Inc., Dallas, TX. Personal Communication, December 9, 2003. OPIS refers to the Oil Price Information Service, Rockville, Md. OPIS reports Alaska posted wholesale rack prices for only Fairbanks and Anchorage.

the exchange are to reduce gasoline production at the Nikiski refinery or to export the excess gasoline production at distressed prices. This suggests that the exchange premium paid by Tesoro is unlikely to put any upward pressure on the price of gasoline in Fairbanks relative to Anchorage. The effective cost to Tesoro at Fairbanks of the exchange is likely to be well below its Anchorage wholesale price plus the exchange premium.

The parity provision in the proposed contract will help to ensure that differences in pricing strategies between Fairbanks and Anchorage will not arise. Also, the parity provision will not adversely affect the exchange arrangements that contribute to supply efficiencies between the two communities that can benefit the consumer. On the other hand, the practice of using TCAs means that the parity provision will create transparency in the market at the expense of including all transactions.

C. In-State Processing (Article IV)

FHR will use "all commercially reasonable efforts" to process royalty oil purchased under the proposed contract in the North Pole refinery. FHR may exchange royalty oil for other crude oil that is also processed in the refinery. By comparison, in its 1998 contract Williams agreed to process at least 80 percent of the sale oil at its refinery in its current and prior RIK purchase agreements. Production capacity and processing equipment for the Williams' refinery at North Pole is compared with other Alaska refineries in Table 2.

Table 2: Alaskan Refinery Capacity
(Barrels per Stream Day)

Company	Location	Atmospheric Crude Oil Distillation	Vacuum Distillation	Hydro- cracking	Reforming
ConocoPhillips	Kuparuk	16,000	0	0	0
BP	Prudhoe Bay	14,200	0	0	0
Williams	North Pole	227,513	6,000	0	0
PetroStar	North Pole	18,000	0	0	0
PetroStar	Valdez	50,000	0	0	0
Tesoro	Kenai	80,000	19,800	9,050	12,000
TOTAL		405,713	25,800	9,050	12,000

As discussed above, the North Pole refinery is the largest in the state. It produces the following product slate:

Gasoline & Naphtha	19%
Jet Fuel	57
Diesel	19
Gas Oil	4
Asphalt	<u>1</u>
Total	100%

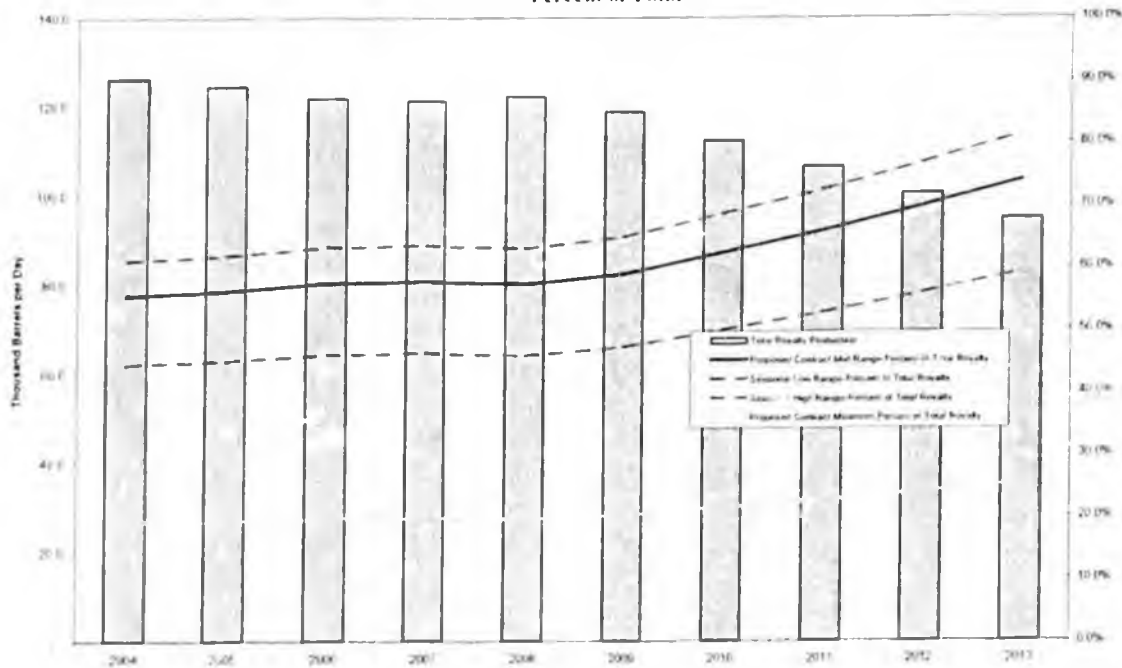
D. Employment of Alaska Residents (Article XXIV)

FHR agrees to employ Alaska residents and companies "to the extent they are available, willing, and at least as qualified as other candidates."

E. Quantity (Section 2.1)

The FHR contract will initially provide between 24,000 to 77,000 barrels per day of royalty oil from the North Slope or nearly the total oil supply requirements of the North Pole refinery.¹⁴ The range is intended to approximate the seasonal fluctuation in the refinery's requirements. Based on DNR North Slope oil production forecast, the initial quantity will commit 44 to 62 percent of the State's North Slope royalty oil to FHR in 2004. Owing to an anticipated decline in North Slope oil production over time, the initial contract quantity will likely equal between 59 and 82 percent of the State's North Slope royalty oil by 2013. Figure 5 illustrates the State's forecast of total North Slope Royalty oil and the percent of royalty oil committed to the FHR contract.

**Figure 6: Total Royalty Production and Proposed Contract Quantity
Percent of Total**



¹⁴ The range is equal to 80 percent and 110 percent of 70,000 barrels per day.

Even as these percentages may rise and/or fluctuate through time, the commissioner retains the right to limit the amount of the monthly royalty oil production supplied to the refinery to not more than 85 percent of total North Slope royalty oil or not more than 95 percent of the royalty oil produced from any single production unit.

FHR has the right to reduce the initial amount of royalty oil it takes under the contract after the first year of the contract following a six-month notice of the reduction. Additional reductions are allowed at intervals of not less than 12 months following the most recent reduction. FHR may not reduce below a minimum quantity to less than 24,000 barrels per day in the first five years of the contract term except for Force Majeure (see below) or a shut down of the refinery. During the second five years of the contract term FHR may reduce the quantity to zero, but otherwise the 24,000 barrels per day minimum remains.

FHR may also subsequently request an increase in the quantity of royalty oil 12 months after the most recent reduction. Approval of a requested increase will be in the discretion of the commissioner and the total quantity may never be increased above the initial contract quantity range.

In negotiating this quantity provision, DNR recognized that FHR sought to limit its exposure to major changes in the markets for its products. For example, should a change in jet cargo traffic occur in the next ten years because more efficient airplanes and routes are employed, FHR might reduce its manufacture of jet fuel and reduce its quantity of royalty oil. Under this scenario, the State would be able to sell the royalty oil once committed to FHR to buyers in other markets (or let the lessees take the royalty oil in-value). By the same token, the State did not want to provide FHR with the unbridled ability to arbitrage its royalty oil supply against the potential supply of oil from other North Slope producers. This situation would disadvantage independent North Slope producers (those producers without the marine transportation capability to sell oil Outside) whose "natural" market for their oil are the in-state refineries. Furthermore, unfettered ability to reduce the amount of oil taken by FHR has the potential of denying the State the potential revenue benefits of the contract.

By limiting changes in quantity to once every 12 months with six-month notice, the contract cannot easily set a cap on the value of North Slope oil sold in the state. The lead-time imposed by these requirements will make it somewhat difficult for FHR to find alternative suppliers unless those suppliers are willing to provide oil to FHR under long-term contracts. The minimum quantity requirement preserves for the State its price premium over RIV value on at least 24,000 barrels per day in the first five years of the contract. The discretion of the commissioner to refuse to increase the quantity once FHR has reduced it (as the commissioner would certainly do if the royalty oil were committed to another buyer) provides a disincentive for FHR to stop taking royalty oil in the second five years of the contract.

F. Term (Article IX):

From the start of negotiations FHR consistently held that it requires a ten year contract term in order to provide ten years of certainty of feedstock supply, if FHR was to commit to purchase of the North Pole refinery and major investment in clean fuels technology. Alaska statutes require that any contract for sale of State royalty oil be approved by the Alaska legislature if the contract term exceeds one year. The Governor is committed to have legislation introduced immediately following action on the proposed contract by the Royalty Board to provide for legislative approval of the total contract term of ten years. The proposed contract is drafted with a "one year plus nine year" term in order that the commissioner may execute the contract and FHR may proceed with its purchase and operation of the North Pole refinery during the interim period between the date of the Governor's signing of enacted legislation approving the proposed contract, and the effective date of the legislation 90 days later.

G. Other Contract Provisions

1. Invoicing and payment (Article III):

DNR will send monthly invoices and FHR will pay by the later of the third business day of the date of the invoice or the twentieth calendar day of the month. If adjustments are required after the initial payment and qualify under the price provisions, the State will send an invoice for the adjustment and FHR will pay by the later of the third business day or the twentieth of the month. Any amount not paid by the date required shall bear interest as required by AS 38.05 '35(d), and will be subject to a penalty equal to five percent of the total amount not timely paid.

2. Security (VI and VII):

Flint Hills Resources Alaska, LLC is the buyer and the wholly owned subsidiary of Flint Hill Resources, LLC who is the guarantor under the proposed contract. The provisions of contract Articles VI and VII describe the obligation FHR Alaska, LLC as buyer, and FHR, LLC as guarantor, to pay amounts due and provide assurances of performance.

FHR, LLC will hire a Financial Analyst, approved by the commissioner to evaluate the financial health of FHR, LLC. Each year the Financial Analyst will render an opinion in the form of an Opinion Letter about FHR, LLC's current and future credit rating by Standard and Poor's and Moody's. The Opinion Letter will identify all documents reviewed in forming the opinion, identify people interviewed in forming the opinion, state the current long term and short term credit ratings of FHR, LLC, and express an opinion whether those ratings are likely to fall below a Standard and Poor's BBB+ or Moody's Baal rating.

If the opinion states that FHR's bond rating is likely to fall below those levels FHR must provide the State an irrevocable stand-by letter of credit issued for the benefit of the State in the principal face amount reasonably estimated by the commissioner to be equal to the price of all oil to be delivered during the 90 days immediately following notice of requirement for the letter. At \$26.00 per barrel, the price under the proposed contract using data for December 2003, and

average deliveries of 70,000 barrels per day, the face value of the letter of credit would be approximately \$165 million.

3. Dispute Resolution (Article XIII):

This provision sets out the process that the State and FHR will use should disputes arise. FHR and Alaska agree to accept the findings of the commissioner "...that are supported by substantial evidence in light of the whole record."

4. Force Majeure (Article XV)

The proposed contract provides relief for either party from a liability to perform if the performance is substantially prevented by Force Majeure. FHR is not relieved from its obligations to pay, provide assurances of its financial health, or accept royalty oil nominated for delivery under the quantity provisions of the proposed contract. Various Force Majeure events are described. If the Force Majeure event cannot be remedied in 180 days the commissioner may terminate the contract with sixty days notice.

IV. Analysis of State Benefits

Section IV sets out the commissioner's analysis of the benefits to the State from the proposed sale of ANS royalty oil to FHR, considering the criteria set out from AS 38.05.183(e) and AS 38.06.070(a).

A. The cash value offered:

The State considers the cash value of the proposed contract from two perspectives. First, the absolute magnitude of the future RIK revenues is based on the product of price and quantity provided in the proposed contract. The price is expected to range between \$16.60 and \$22.56 based on the Alaska Department of Revenue projections of the ANS spot price, Tariff Allowances, Quality Banks, and DNR's estimate for Line Loss.¹⁵ The proposed contract stipulates a RIK quantity ranging between 24,000 and 77,000 barrels per day.¹⁶ These upper and lower quantities translate to 44 and 62 percent of the State's total royalty share of production, respectively. Over time, as total ANS production declines, these RIK limits will increase, as a proportion of the total (to 69 and 82, respectively, in 2013).

These price and quantity provisions, combined with assumptions about the future spot price of ANS crude on the U.S. West Coast, imply annual total RIK revenues ranging from a low of \$198 million to a high of \$634 million, depending on quantity nominated, with an overall average of \$368 million.

The second cash value perspective looks to the incremental RIK revenue premium over the RIV alternative. As a non-competitive RIK sale to relieve "market conditions," the sales price throughout the term of the disposition must be higher than the volume-weighted average of

¹⁵ Alaska Department of Revenue, *Fall 2003 Revenue Sources Book*, Table 45 p. 35.

¹⁶ The range is calculated as 70,000 plus 10 percent and minus 20 percent.

the current reported netback prices filed by lessees for royalty purposes. The price shown above implies a premium of approximately \$0.30 per barrel over revenues generated under RIV, based on DNR's forecast of the RIV alternative.¹⁷ DNR forecasts the future royalty revenues under the proposed contract to be approximately \$2.6 to \$8.4 million per year above revenues if taken as RIV.¹⁸

B. The projected effects of the sale, exchange or other Disposal on the economy of the State:

In addition to the above described \$2.6 to \$8.4 million annual royalty revenue increase above the RIV alternative, the proposed contract will facilitate substantial capital expenditures for the installation of equipment to process Clean Fuels in Alaska. Of the total project cost estimate of over \$100 million, up to \$40 million may be spent in Alaska to build these improvements with \$20 million injected into the State economy in the form of wages and salaries. The Clean Fuels project could lead to as much as 100 to 200 direct jobs during construction with possibly twice that number of indirect jobs. To the extent that FHR's preferred strategy to produce Clean Fuels in Alaska will involve improvements at the North Pole refinery, construction employment will occur in the Fairbanks North Star Borough and the central Alaska region. Impacts on local and statewide employment and personal income from construction will be temporary. Incremental long-term employment and personal income effects generated by the Clean Fuels projects at North Pole of the refinery should be rather small.

Further, completion of the FHR refinery acquisition depends on a successful implementation of the proposed contract between FHR and the State. The proposed State RIK contract will help to ensure that transactions costs associated with the refinery sale are kept to a minimum. A delay of the sale of the North Pole refinery could result in deterioration of commercial arrangements with existing wholesale products buyers (e.g., airlines for jet fuel) and result in greater product imports into Alaska, with consequent job losses and higher in-state jet fuel intermediate prices and gasoline retail prices.

Finally, the business experience and qualifications of FHR as the new owner of North Pole refinery will ensure a seamless transition and ongoing success in operations at the North Pole Refinery.¹⁹ FHR's core business is refining and its financial condition is well suited to support new investments at the North Pole refinery.

¹⁷ See Section III. A.1. DNR's forecast of the RIV alternative assumes that the destination value in the royalty settlement agreements will, over time, be revised through reopeners to achieve a value at or close to the ANS Spot Price. The \$0.30 per barrel premium used here is the difference between the RIV deduction for marine transportation costs and \$1.55.

¹⁸ This range is based on multiplying the \$0.30 per barrel premium times the minimum 24,000 barrels per day and maximum 77,000 barrels per day quantity FHR may purchase under the proposed contract.

¹⁹ The proposed contract gives FHR the right to assign the contract to a third party at a future date. The right of assignment qualifies the reliance of specific attributes and qualifications attached to a particular RIK purchaser, such as FHR.

C. The projected benefits of refining or processing the oil or gas in the state:

The North Pole refinery was expanded in 1998 and has a total capacity throughput of 227,500 barrels per day of ANS shipped to the refinery via TAPS. It consumes about 64,000 barrels of crude per day on average to manufacture petroleum products and, after removing the lighter components used to make petroleum products, returns the remaining 150,000 barrels per day of residual oil to TAPS. About 60 percent of refinery output is jet fuel. The remainder is evenly divided between gasoline/naphtha and diesel. These products are marketed to customers in Alaska, Western Canada and the Pacific Rim.

The refinery transported about 1.4 million gallons per day of jet fuel during 2003 and accounts for 56 percent of jet fuel consumption statewide, including military bases. Approximately half of the gasoline manufactured at the refinery is sold through Williams' branded retail stores throughout the state. Approximately 3,000 barrels per day of gasoline are shipped by rail to south central Alaska. FHR's commitment to process Clean Fuels in Alaska will mean that Alaska will not have to import low sulfur diesel and gasoline at potentially higher prices.

D. The ability of the prospective buyer to provide refined products or by-products for distribution and sale in the state with price or supply benefits to the citizens of the State:

Production capacity and processing equipment for the North Pole refinery is listed above in Table 7. The North Pole refinery has run successfully for 25 years and has seen several expansions. As buyer of the North Pole refinery, FHR brings considerable expertise and financial strength to Alaska. FHR is a wholly owned subsidiary of Koch Industries, a large, privately held company with interests in refining, chemicals, and fertilizer manufacturing. FHR operates a petrochemical refinery complex in Corpus Christi, Texas and another plant in Rosemount, Minnesota. It has controlling interests in Canadian oil sands development, as well as other Canadian crude oil marketing, trading, transportation and storage operations. In addition, FHR markets jet fuel, diesel, heating oil, gasoline, and other petroleum products.

The proposed contract requires that FHR use all commercially reasonable efforts to insure that royalty oil will be processed at the North Pole refinery. Furthermore, FHR is investing over \$265 million to purchase the North Pole refinery and has committed to implement construction projects that will likely total over \$100 million more, to allow for processing of Clean Fuels in Alaska. These financial commitments will bind FHR to a long-term presence in Alaska and ensure continued in-state refining to the benefit of Alaska citizens.

E. The revenue needs and projected fiscal condition of the State:

The State budget gap (the difference between unrestricted general fund revenues and general fund budget expenditures) is forecast to rise from \$275 million in FY 2004 to \$951 million in 2010, absent new revenue sources. Despite fairly stable oil production through 2010, the oil and gas sector's contribution to general fund revenue is expected to decline from 86% in 2004 to 77% in 2010 due to increasing production from new, lower-netback-value fields and a

higher economic limit factor (ELF).²⁰ The long-term cash proceeds from the sale of RIK gas and the premium over RIV will not fill this gap, but every positive contribution to State revenues is important to the State's fiscal balance, and the proposed contract would generate approximately \$2.6 to \$8.4 million per year in incremental revenue (over RIV) to help fill the State's fiscal gap.

F. Present and projected local and regional needs for oil and gas products and by-products:

Total annual fuel sales in Alaska by major product type are summarized in Table 3. The trend in annual fuel sales tends to be increasing for most products, except for modest downturns in 2000 (gasoline and No. 2 diesel) and in 2001 (jet fuel). Average annual jet fuel consumption increased 3.4 percent from 1997 to 2000, and then declined sharply before rebounding in 2002. The jet fuel decline in 2001 is probably related to the sharp nationwide decline in commercial aviation in the fourth quarter of 2001. Seasonal data (not reported) indicate that jet fuel consumption has recovered from the demand shocks of September 2001 and is consistent with average annual growth exhibited prior to 2001. Alaska's refineries supply nearly all of the in-state jet fuel consumed based on EIA data on prime supplier sales.²¹ Total motor gasoline gas consumption exhibits a stationary pattern over the past six years. Annual average aviation gasoline consumption has increased slightly.

Table 3: Prime Supplier Sales for Alaska, 1998 - 2002
(Thousands of Gallons per Day)

Year	Transportation Fuels				Non-Transport Fuel		
	Total ^a Gasoline	Aviation Gasoline	Jet Fuel ^b	No. 2 Diesel	Total Fuel Sold	No. 2 Heating Oil	No. 2 Distillate
1998	771.4	57.6	2,285.2	427.7	3,541.9	357.4	785.1
1999	784.4	58.7	2,434.4	467.2	3,744.7	295.9	W
2000	744.8	58.7	2,502.9	396.5	3,702.9	287.6	684.1
2001	761.3	61.2	2,461.9	462.5	3,746.9	227.4	689.8
2002	755.2	55.3	2,777.1	512.8	4,100.4	W	639.3

I. Jet Fuel Consumption and Airport Operations

Alaska's three refineries supply all of the jet fuel consumed at the international airports in Anchorage and Fairbanks, and at military bases in the state.²² The international airport

²⁰ Alaska Department of Revenue, *Fall 2003 Revenue Sources Book*, Table 2-8, p. 18.

²¹ Prime suppliers include firms that produce, import, or transport petroleum products across state boundaries and local marketing areas, and sell the products to local distributors, local retailers, or end users. According to the EIA, prime supplier sales within a given state may serve as a proxy for consumption but may not equal actual consumption by the end-users in the state because a product may be sold by a prime supplier in one state and transported by local distributors to another state for final consumption. Southeast Alaska communities import jet fuel and other products from the Lower 48.

²² Jet fuel is generally not imported into Alaska unless unusual circumstances arise, such as the West Coast longshoremen strike of mid-2002, which resulted in greater-than-usual air cargo activity.

complexes in Anchorage and Fairbanks play a significant role in the state's economy. The Ted Stevens Anchorage International Airport alone employs 9,100 workers with a \$367 million annual payroll.²³ During the 1990s air cargo landings grew at an average annual rate of 9 percent, consistent with doubling in eight years.

Total statewide jet fuel consumption, driven largely by the strong growth at Ted Stevens Anchorage International Airport, increased from 2.3 million gallons per day in 1998 to 2.8 million gallons per day in 2002, an average annual rate of 4 percent per year.

2. Supply and Demand for Gasoline

The North Pole refinery and the Tesoro refinery in Nikiski are the only Alaska refineries that produce gasoline, with combined total production capacity of 22,000 barrels per day.²⁴ Gasoline production from these two refineries exceeds total in-state demand of about 16,000 barrels per day. The excess production (about 6,000 barrels per day, produced by Tesoro) is exported to the U.S. West Coast and to foreign consumers.

Approximately 300 retail outlets sell motor gasoline currently in Alaska. Williams' and Tesoro branded service stations account for about half of this total.

H. The desirability of localized capital investment, increased payroll, secondary development and other possible effects of the sale:

The proposed contract includes several special commitments that could involve investment spending and improved refinery operations. These are outlined above and include the Clean Fuels project, a promise to examine feasibility to upgrade the Fairbanks International Airport hydrant fueling system, and potential tank farm improvements at the Port of Anchorage. In addition, FHR's substantial investment in purchasing the North Pole refinery, and its commitment to additional capital investment in the State, provide a more secure, long-term prospect for continued refinery payroll in the North Pole and Fairbanks region.

I. The projected social impacts of the transaction:

The sale by itself will have no incremental social impacts. If there were no RIK contract executed to supply crude oil to the refinery, however, operations at the refinery might be suspended or cut back with possibly serious social consequences caused by worker lay-offs and fuel product supply disruptions.

²³ Equals onsite annual average employment and payroll at Ted Stevens International Airport in 2000. These figures do not include "offsite jobs generated by airport business purchases and workers spending their earnings within the community." (Scott Goldsmith, "Ted Stevens Anchorage International Airport: Economic Significance 2000," Institute of Social and Economic Research, July 2001.)

²⁴ The PetroStar refineries in Fairbanks and Valdez produce only jet fuel and diesel.

J. The projected additional costs and responsibilities that could be imposed upon the State and affected political subdivisions by development related to the transaction:

The proposed contract is expected to generate negligible additional public-sector costs and responsibilities. The proposed contract could result in improvements in the utilization of existing capacity but the growth of new basic-sector jobs over the long run is expected to be small. Refinery direct employment of approximately 150 full time equivalent, high-wage positions is expected to remain the same. Indirect and induced employment effects, induced population expansion are not expected to vary from recent patterns as a result of the transaction. Industry-related property tax revenues should rise as a consequence of the Clean Fuels investments at the refinery. Construction jobs related to the Clean Fuels project are expected to be temporary.

According to a recent Commonwealth North study by the Institute of Social and Economic Research, each new basic-sector job creates a \$1,100 annual burden on public finances.²⁵ This transaction is not expected to generate many new long-term basic sector jobs and should therefore not significantly increase public-sector costs. As indicated above, the potential unrestricted general fund revenues from this transaction are expected to be positive \$2.6 to \$8.4 million per year.

K. The existence of specific local or regional labor or consumption markets or both which should be met by the transaction:

The Williams refinery at North Pole employs approximately 150 full time positions, representing about 1/3 of total direct oil and gas employment for the five largest petroleum-related companies in the greater Fairbanks area.²⁶ The annual payroll associated with these refinery jobs ranges between \$8 to \$12 million. The refinery generates additional "indirect" jobs and payroll through vendors that provide goods and services to the refinery, as well as "induced" jobs through local spending of direct and indirect payroll. The refinery and its employees generate between \$3 and \$4 million per year in property tax revenues to the Fairbanks Northstar Borough.

The proposed contract is expected to have a small impact on long-term, direct refinery employment, other than by providing more assurance of continued operation of a refinery in the Fairbanks region. The proposed contract could increase property tax revenues if the Clean Fuels project adds \$100 million investment to the tax base for the North Pole refinery.

²⁵ See http://www.iser.uaa.alaska.edu/Products_2/StrategiesforGrowth.pdf.

²⁶ The companies are: Alyeska Pipeline Service Company, ConocoPhillips (formerly ARCO), BP Exploration, PetroStar, and Williams Alaska Petroleum. See Information Insights "Economic Impact of the Petroleum Industry on the Fairbanks North Star Borough," December 1999.

L. The projected positive and negative environmental effects related to the transaction:

There are positive environmental provisions included in the special commitments contained in the FHR's proposed contract.²⁷ The Clean Fuels project will provide potentially lower priced, low sulfur diesel and gasoline instead of importing such fuels into Alaska. FHR will also continue and complete the Anchorage tank farm improvements which include evaluation of facilities to determine compliance with State and Federal requirements including overfill protection, fire protection, tank seal monitoring, potential for change of product service, and possible removal of additional tanks, and prompt remediation of any violations of these requirements.

M. The projected effects of the proposed transaction upon existing private commercial enterprise and patterns of investments:

Flint Hills Resources agrees to the following special commitments that ensure continuation and and/or enhancement of existing commercial relationships involving the North Pole refinery.

1. Shipment by Rail

Williams currently ships refined products by rail under an agreement with Alaska Railroad Corporation (an Agreement originally entered by MAPCO Alaska Petroleum Inc. in May of 1993). As part of Buyer's refinery acquisition from Williams, FHR will assume the rights and obligations of Williams under the rail agreement and continue to ship refined products to Anchorage.

2. Air Traffic Marketing and Structural Improvement Study

FHR and the State will jointly explore commercially reasonable options for increasing passenger and cargo air traffic through the Fairbanks International Airport. FHR will work with the Fairbanks International Airport to concentrate on promoting the Fairbanks International Airport to cargo carriers operating between Asia and Europe and otherwise and will evaluate, and possibly upgrade, the airport's fuel distribution facilities, including the feasibility of using or upgrading the hydrant fueling system.

²⁷ FHR has past issues regarding environmental compliance, including \$10 million in fines in 2001 for criminal violations regarding a cover-up of improper benzene emissions at its Corpus Christi refinery and over \$300 million in payments to settle lawsuits regarding pipeline spills in Texas. FHR spokesmen have indicated to the press that the company "has worked hard to improve its environmental record." Anchorage Daily News, November 18, 2003.

V. Findings and Determination

A. Disposal of the Royalty Oil In-kind is in the State's Best Interest

In accordance with AS 38.05.182, the Commissioner determines that it is in the best interest of the State to take its royalty oil in-kind to provide necessary crude oil supplies to the North Pole refinery.

B. Competitive Bidding is Waived

The Commissioner determines, in accordance with AS 38.05.183(a) and 11 AAC 03.030, that the best interest of the State will be served by sale of its royalty oil in-kind to FHR under non-competitive procedures to relieve market conditions. The proposed contract will promote the interest of the State through increased revenues and by facilitating uninterrupted operation of the North Pole refinery.

In deciding to sell RIK to FHR under the proposed contract the commissioner considered that without the contract the State will receive less revenue because its royalty oil would be taken in-value without the potential \$0.30 per barrel price premium. FHR is uniquely qualified and positioned to assume ownership of the North Pole refinery and has agreed to provide significant additional benefits to Alaska through the Special Commitments of the proposed contract.

A copy of this Finding and Determination is being delivered to the Royalty Board as notification under 11 AAC 03.040 that the commissioner has determined that the best interest of the State does not require competitive bidding in this circumstance.

C. The RIK Oil Sale Will Relieve Market Conditions

A non-competitive sale of royalty oil is permitted where necessary to relieve market conditions. DNR regulations, at 11 AAC 03.024, provide that a non-competitive sale of RIK oil may be held to relieve "market conditions" when one of four alternative conditions is met. The proposed FHR contract meets two of the alternative conditions:

(1) in a noncompetitive disposition of royalty oil, gas, or associated substances the commissioner estimates that the sale price throughout the term of the disposition will be higher than the volume-weighted average of the current reported netback prices filed by the lessees for royalty purposes for those filing periods applicable to the term of the disposition; and...

(3) the royalty oil, gas, or associated substances disposed of will be used to meet in-state needs for crude oil, gas, or associated substances or petroleum products and the sale price of that royalty oil, gas, or associated substances is at least equal to the in-value amount which would have been received by the state during the same period.

The proposed contract will relieve market conditions because it will provide needed crude oil supplies to the North Pole refinery and the price for oil delivered throughout the term of the contract will provide a potential premium of \$0.30 per barrel over the volume-weighted average of the netback prices reported by the North Slope lessees.

D. The Proposed RIK Oil Sale Offers Maximum Benefits to the State

When RIK oil is to be sold through a process other than by competitive bid, the commissioner must award the disposal to the prospective buyer whose proposal offers the maximum benefits to the State. In making the award the commissioner must consider the criteria set out in AS 38.05.183(e) and in AS 38.06.070(a). The commissioner's in-depth review and consideration of all of the required statutory criteria is set out above in Section IV of this Best Interest Finding and Determination. The commissioner finds that the proposed sale of ANS royalty oil to FHR, under the terms and conditions of the attached proposed contract, offers the maximum benefit to the State.

E. Alaska Royalty Oil and Gas Development Board

This finding and determination and a copy of the proposed contract is being submitted to the Royalty Board in compliance with AS 38.05.183(e) and 11 AAC 03.024 and 11 AAC 03.040, which require the commissioner to give written notice to the Board of intent to waive competitive bidding of an RIK sale.

F. Legislative Approval

Legislative approval is required for RIK oil dispositions with a term of more than one year. (AS 38.05.183). Legislation approving the sale has been prepared and is intended to be introduced immediately following receipt of written recommendations from the Alaska Royalty Oil and Gas Development Board.

VI. Conclusion

On careful consideration of the circumstances of the proposed sale, material information and legal requirements, the commissioner determines, in accordance with AS 38.05.183, that the best interest of the State does not require this RIK oil sale to be made by competitive bid, and that the proposed contract with FHR offers maximum benefits to its citizens.

<Signed>

2/12/04

Thomas E. Irwin
Commissioner

Date

Appendix A
Proposed Contract

AGREEMENT FOR THE SALE OF

ROYALTY OIL

BETWEEN AND AMONG

THE STATE OF ALASKA,

FLINT HILLS RESOURCES, LLC, A DELAWARE LIMITED LIABILITY COMPANY

AND

FLINT HILLS RESOURCES ALASKA, LLC, AN ALASKA LIMITED LIABILITY

COMPANY

EFFECTIVE _____, 2004

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**AGREEMENT FOR THE SALE AND
PURCHASE OF ROYALTY OIL**

This Agreement is between the State of Alaska ("State"), Flint Hills Resources Alaska, LLC, an Alaska Limited Liability Company ("Buyer") and Flint Hills Resources, LLC, a Delaware Limited Liability Company ("Guarantor"). Buyer, an indirect wholly-owned subsidiary of Guarantor, intends to purchase the refinery at North Pole, Alaska now owned by Williams Alaska Petroleum, Inc. The effective date of this Agreement is the first Day on which it has been signed by all Parties.

**ARTICLE I
DEFINITIONS**

As used in this Agreement, the terms listed below shall have the following meanings:

- 1.1 "Affiliate" is defined in Section 22.1
- 1.2 "ANS" means the Alaska North Slope.
- 1.3 "ANS Spot Price" is defined in Section 2.3.
- 1.4 "Assignee" is defined in Section 22.1.
- 1.5 "BP" means BP Exploration (Alaska) Inc. and its successors and assigns.
- 1.6 "Business Day" means any day, or part of a day, during which federally chartered banks are open for business in the place designated in this Agreement for payment.
- 1.7 "Closing" is defined in Section 2.4.1.
- 1.8 "Commissioner" means the Commissioner of the Alaska Department of Natural Resources or the Commissioner's designee.
- 1.9 "CPAI" means ConocoPhillips Alaska, Inc. and its successors and assigns.

1.10 "Day" means a period of twenty-four consecutive hours, beginning at 12:01 a.m., Alaska Local Time.

1.11 "Day of First Delivery" is defined in Section 2.4.1.

1.12 "Enactment" is defined in Section 9.4.

1.13 "ExxonMobil" means ExxonMobil Corporation and its successors and assigns.

1.14 "Financial Analyst" is defined in Section 6.3.

1.15 "FERC" means Federal Energy Regulatory Commission.

1.16 "Force Majeure" is defined in Section 15.2

1.17 "Initial Term" is defined in Section 9.2.

1.18 "Leases" means the oil and gas leases issued by the State on the Alaska North Slope from which the State takes or may take Royalty Oil in-kind.

1.19 "Lessee" means a person owning a working interest in any of the Leases.

1.20 "Letter" is defined in Section 7.1.

1.21 "Letter Effective Date" is defined in Section 7.2.

1.22 "Line Loss" is defined in Section 2.3.

1.23 "Minimum Interstate TAPS Tariff" is defined in Section 2.3.

1.24 "Month" means a period beginning at 12:01 a.m., Alaska Local Time, on the first Day of the calendar Month and ending at 12:01 a.m., Alaska Local Time, on the first Day of the following calendar Month.

1.25 "Moody's" means Moody's Investor's Services, Inc., a subsidiary of Moody's Corporation, and its successors.

1.26 "Notice" means written notice in accordance with Article XVI.

1.27 "Notice Effective Date" is defined in Section 16.2.

1.28 "Opinion Letter" is defined in Section 6.3.

1.29 "Parties" means, collectively, Buyer, Guarantor and State.

1.30 "Party" means Buyer, Guarantor or State, individually.

1.31 "Person" is defined in AS 01.10.060.

1.32 "Point of Delivery" means the transfer point at which the State receives Royalty Oil in-kind from the Lessees.

1.33 "Price" is defined in Section 2.3.

1.34 "Process" is defined in Section 4.1.

1.35 "PSVR Reference Stream" is the blended TAPS stream immediately downstream from the Petro Star Valdez Refinery.

1.36 "Quality Bank" means a system of calculations administered under the authority of the FERC that accounts for the differences in value between the individual tendered streams and the delivered co-mingled stream of TAPS.

1.37 "Quality Bank Adjustment" is defined in Section 2.3.

1.38 "RIV Marine Cost" is defined in Appendix 5.

1.39 "Royalty Oil" means the total volume of crude petroleum oil and other hydrocarbons and associated substances from the Leases, including such substances as crude oil, condensate, natural gas liquids, or return oil from crude oil topping plants, that may be blended with crude oil before the Point of Delivery and tendered as a common stream to the State as Royalty Oil that the State may take in-kind, regardless of whether the State takes the Royalty Oil in-kind.

1.40 "Royalty Settlement Agreement" means any written royalty settlement agreement.

1.41 "Sale Oil" means the oil the State has agreed to sell to the Buyer, and the Buyer has agreed to purchase from the State under this Agreement.

1.42 "Standard and Poor's" means Standard and Poor's, a division of McGraw-Hill Companies, Inc., and its successors.

1.43 "TAPS" means the Trans Alaska Pipeline System

1.44 "Tariff Allowance" is defined in Section 2.3.

1.45 "Unit" has the meaning defined in 11 AAC 83.395(7).

1.46 "Unit Agreement" means any unit agreement for a Unit from which the State takes or may take Royalty Oil.

1.47 "Williams" means Williams Alaska Petroleum, Inc.

1.48 "Williams' Alaska Properties" means the following assets currently owned by Williams: (a) a refinery located near North Pole, Alaska; (b) a petroleum products terminal located at or near the Fairbanks International Airport; (c) a petroleum products terminal located at Anchorage, Alaska; and (d) tangible and intangible assets related to the properties described in (a), (b), and (c).

ARTICLE II

SALE AND PURCHASE OF ROYALTY OIL

2.1 Quantity.

2.1.1 Sale Oil Quantity. The State agrees to sell to Buyer, and Buyer agrees to purchase from the State, an initial Sale Oil quantity of a maximum of 77,000 barrels per Day and a minimum of 56,000 barrels per Day averaged for the Month of Sale Oil delivery, as nominated by Buyer in accordance with Section 2.1.5. The Commissioner may limit the total amount of