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ConocoPhillips Note 18 to 2006 Financial Statements:

Note 18—Contingencies and Commitments

Other Contingencies

We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at December 31, 2006, we had performance obligations secured by letters of credit of \$988 million (of which \$41 million was issued under the provisions of our revolving credit facilities, and the remainder was issued as direct bank letters of credit) and various purchase commitments for materials, supplies, services and items of permanent investment incident to the ordinary conduct of business.

Venezuelan government officials have made public statements about increasing ownership interests in heavy-oil projects required to give the national oil company of Venezuela, Petroleos de Venezuela S.A. (PDVSA) control and up to 60 percent ownership interests. On January 31, 2007, Venezuela's National Assembly passed an "enabling law" allowing the president to pass laws by decree on certain matters, including those associated with heavy-oil production from the Orinoco Oil Belt. PDVSA holds a 49.9 percent interest in the Petrozuata heavy-oil project and a 30 percent interest in the Hamaca heavy-oil project. We have a 50.1 percent interest and a 40 percent interest in the Petrozuata and Hamaca projects, respectively. The impact, if any, of these statements or other potential government actions, on our Petrozuata and Hamaca projects is not determinable at this time.

Long-Term Throughput Agreements and Take-or-Pay Agreements

We have certain throughput agreements and take-or-pay agreements that are in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the company's business. The aggregate amounts of estimated payments under these various agreements are: 2007—\$77 million; 2008—\$69 million; 2009—\$68 million; 2010—\$68 million; 2011—\$69 million; and 2012 and after—\$296 million. Total payments under the agreements were \$66 million in 2006, \$52 million in 2005 and \$64 million in 2004.

ConocoPhillips Supplemental Disclosure in 2006 10-K: Management's Discussions and Analysis of Financial Condition and Results of Operations

Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2006:

	Millions of Dollars			
	Total	Payments Due by Period		
		Up to 1 Year	Year 2-3	Year 4-5
Debt obligations (a)	\$ 27,090	1,598	1,685	12,640
Capital lease obligations	44	10	34	—
Total debt	27,134	1,608	1,719	12,640
Interest on debt	16,692	1,594	3,043	2,704
Operating lease obligations	3,041	584	931	530
Purchase obligations (b)	93,025	35,494	7,701	5,260
Other long-term liabilities (c)				
Asset retirement obligations	5,402	576	404	390
Accrued environmental costs	1,062	270	262	119
Total	\$ 146,356	40,126	14,060	21,643

- (a) Includes \$718 million of net unamortized premiums and discounts. See Note 15—Debt, in the Notes to Consolidated Financial Statements, for additional information.
- (b) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The majority of the purchase obligations are market-based contracts. Includes: (1) our commercial activities of \$48,865 million, of which \$17,611 million are primarily related to the supply of crude oil to our refineries and the optimization of the supply chain, \$7,341 million primarily related to the supply of unfractionated natural gas liquids (NGL) to fractionators, optimization of NGL assets, and for resale to customers, \$7,006 million primarily related to natural gas for resale customers, \$6,166 million related to product purchase, \$3,774 million related to transportation, \$3,557 million on futures, \$1,904 million related to the purchase side of exchange agreements and \$1,506 million related to power trades; (2) \$38,892 million of purchase commitments for products, mostly natural gas and NGL, from CPCChem over the remaining term of 93 years; and (3) purchase commitments for jointly owned fields and facilities where we are the operator, of which some of the obligations will be reimbursed by our co-venturers in these properties.
Does not include: (1) purchase commitments for jointly owned fields and facilities where we are not the operator; (2) our agreement to purchase up to 104,000 barrels per day of Petrozuata crude oil for a market-based formula price over the term of the Petrozuata joint venture (about 35 years) in the event that Petrozuata is unable to sell the production for higher prices; (3) an agreement to purchase up to 165,000 barrels per day of Venezuelan Merey, or equivalent, crude oil for a market price over a remaining 13-year term if a variety of conditions are met; and (4) our contribution of \$7.5 billion, plus accrued interest, over a ten-year period, beginning in 2007, to the upstream joint venture formed with EnCana on January 3, 2007.
- (c) Does not include: Pensions—for the 2007 through 2011 time period, we expect to contribute an average of \$355 million per year to our qualified and non-qualified pension and postretirement medical plans in the United States and an average of \$170 million per year to our non-U.S. plans, which are expected to be in excess of required minimums in many cases. The U.S. five-year average consists of \$435 million for the next two years and then approximately \$305 million per year as our pension plans become better funded. Our required minimum funding in 2007 is expected to be \$80 million in the United States and \$115 million outside the United States.

C. Scott Hobbs

Scott Hobbs has been in the natural gas industry for 30 years with experience in all facets of the business. Over the last six years, Mr. Hobbs has provided consulting services to investment bankers, private equity firms, and other investors evaluating major projects, acquisitions, and divestitures principally involving oil and gas pipelines, processing plants, power plants, and gas distribution assets. During that period, he also served as Executive Chairman of Optigas, Inc., a private midstream (gathering and processing) natural gas company which was sold in March, 2006 to Energy Spectrum, a private equity firm in Dallas, TX.

From 1977 through 2001, Mr. Hobbs worked for Coastal Corporation where he last served as Executive Vice President and Chief Operating Officer for its regulated gas pipeline operations (CIG and WIC) in the Rocky Mountain region. As President of CIG Resources, he was also responsible for certain non-regulated business activities in the Rocky Mountain area. Prior to that, he was Senior Vice President of Gas Supply for all of Coastal's interstate gas pipelines. In 2000 CIG was named the #1 interstate gas pipeline company in the U.S. in a study by Fosters and Co., a Washington, D.C.-based consulting firm. He left Coastal in April 2001 shortly after its merger with El Paso.

In his different positions at Coastal's pipeline subsidiaries, Mr. Hobbs was responsible for operations, engineering, regulatory compliance, and all commercial activities including gas transportation and storage, gathering and processing, gas production and development, and merchant and trading activities. In his tenure as Senior Vice President of Gas Supply, Mr. Hobbs was responsible for renegotiating all of Coastal's "take-or-pay problems" including over \$3 billion of annual gas purchase obligations which resulted from price deregulation and the major regulatory restructuring initiated by the Federal Energy Regulatory Commission in the 1980's. He began his career at Coastal providing audit and consulting services for its accounting and finance group as well as its different operating divisions.

Prior to joining the Coastal Corporation, Mr. Hobbs also worked as an auditor with Price Waterhouse and Co. in New Orleans, LA. He received a Bachelor of Science degree in Accounting from Louisiana State University and holds a CPA license in inactive status. Mr. Hobbs has been active in civic affairs and trade associations holding multiple directorships and memberships.

How AGIA Addresses Competitive Issues
Raised by a Producer-Owned Pipeline

The Palin-Parnell Administration presents

AGIA

The Alaska Gasline Inducement Act

Presentation to the Alaska Legislature

Senate Judiciary Committee

May 11, 2007

Kenneth M. Minesinger

Greenberg Traurig LLP

Overview



- Testimony addresses 4 competitive issues
 - Competitive problems associated with a producer-owned pipeline
 - How AGIA's "Must Have" provisions address those problems
 - Why AGIA's "Must Have" provisions are critically necessary
 - Failure by producers (Exxon, BP, Conoco) to bid in an open season

Qualifications/ Experience

AGIA

The Alaska Gasline Inducement Act

- Have represented several major interstate natural gas pipelines and other clients before the FERC, including in
 - Rate proceedings
 - Certificate proceedings
 - Market power cases
- Have also served as Chairman of the Antitrust Committee of the Energy Bar Association
- Have worked on numerous antitrust matters involving natural gas pipelines and other energy companies

Competitive Problems Raised by a Producer-Owned Pipeline



- Issue addressed in Dec. 21, 2006 memorandum on LB&A website
- Main competitive issue: **vertical market power**
 - Producer-owned pipeline would have an incentive *not* to ship gas produced by competing producers
- This disincentive could manifest itself as follows:
 - **Expansion:** Refusing to expand to ship competing gas, or delaying expansion
 - **Access/Discrimination:**
 - Raising the tariff rate paid by competing producers
 - Other means of restricting/denying access, including subtle forms of discrimination that are difficult for regulators to detect
 - Producer incentive to **delay** project so as not to undermine other projects (LNG) or other gas sales in the Lower 48
 - Vertical relationship could also facilitate **collusion**

Competitive Problems Raised by a Producer-Owned Pipeline



- **Vertical market power issue:** addressed by U.S. DOJ in 1977
 - **Expansion:** The U.S. Attorney General concluded that
 - “it will be in the interest of producer-owners to resist future expansion and thus discourage future entry into Alaskan gas production” ... because the producers’ market power “could be reduced by discovery and development of new fields by other producers”
 - **Access/Discrimination:** U.S. Attorney General also stated:
 - Producer-owned pipeline “would seek to restrict access and throughput to take monopoly profits.”
- DOJ recommended a complete ban on producer-ownership
- Reagan Administration: conditional waiver
- FERC Chairman in 2005: antitrust issues “are still valid and will be addressed” by FERC in certificate proceeding

Competitive Problems Raised by a Producer-Owned Pipeline



- FTC, DOJ and FERC precedent confirms that the competitive concerns raised by DOJ in 1977 about a producer-owned pipeline are still valid:
 - FTC/DOJ vertical merger cases in energy industry: “raising rivals costs”
 - Major FERC orders addressing vertical market power issues over past two decades, including Order Nos 436, 497, 636, 637, 2000, 2004, 2005

How AGIA Addresses Competitive Problems Raised by a Producer-Owned Pipeline



- Unlike 1977 DOJ opinion, AGIA does not advocate a ban on producer ownership of the pipeline
- Instead, AGIA:
 - Invites applications by producers and by independent pipelines
 - Attempts to ameliorate or eliminate competitive problems raised by a producer-owned pipeline

How AGIA Seeks to Address Competitive Problems Raised by a Producer-Owned Pipeline



- **Problem: Incentive Not To Expand**
 - AGIA requires expansion on reasonable terms:
 - The applicant must “commit to expand the proposed project in reasonable engineering increments and on commercially reasonable terms that encourage exploration and development of gas resources in this state”

How AGIA Seeks to Address Competitive Problems Raised by a Producer-Owned Pipeline



- **Problem: Incentive Not To Expand**
 - AGIA also addresses producer/expansion issue by requiring pipeline to hold open seasons for expansion capacity every two years:
 - The applicant must “commit that after the first binding open season, the applicant will assess the market demand for additional pipeline capacity at least every two years through public non-binding solicitations or similar means”

How AGIA Seeks to Address Competitive Problems Raised by a Producer-Owned Pipeline



- **Problem: Refusal To Expand Except on Terms That Deter Exploration**
 - AGIA requires applicant to propose rolled-in rate treatment of expansion costs, up to a 15 percent increase in existing rates
 - The 15 percent roll-in requirement counteracts a producer-owned pipeline's incentive to discourage expansion by proposing incremental rates
 - Rolled-in rates are consistent with FERC policy (rebuttable presumption of roll-in) and federal law (ANGPA) mandating rate criteria which promote exploration, development and production of Alaska gas

How AGIA Seeks to Address Competitive Problems Raised by a Producer-Owned Pipeline



- **Problem: Discrimination/Access**
 - For example, a producer-pipeline is indifferent to high tariff rates, with regard to their own gas, because the money they spend on rates just goes from one pocket to another
 - AGIA requires applicants to commit to low tariff rates, by:
 - committing to a “capital structure for rate-making that consists of no less than 70 percent debt”
 - competing via proposals to manage cost overruns and “provide low transportation rates”
 - These provisions give the State an opportunity to avoid some of the problems experienced with TAPS
 - High tariff rates have reportedly caused some competitors to exit

How AGIA Seeks to Address Competitive Problems Raised by a Producer-Owned Pipeline



- **Problem: Delaying the Project**
 - AGIA requires open season within 36 months, initiation of FERC pre-filing process by a date certain, and filing of certificate application by a date certain
 - Producer-pipeline required to sanction project within one year of FERC certificate because they have the gas supply that would underwrite FT commitments (credit support)
 - AGIA would not permit a producer-owned pipeline to unduly delay project development based, for example, on concerns that:
 - Alaska pipeline could adversely affect producers' investment in worldwide LNG projects
 - Alaska pipeline could adversely affect producers' sales of other gas in Lower 48

AGIA's "Must Haves" Are Critically Important



- State has an opportunity to provide an additional line of defense against competitive problems
- TAPS: State has already seen what can happen when a producer-owned pipeline lacks the normal incentives to expand, increase throughout and serve other shippers
 - Reduced competition, exit by explorers that do not own pipeline
- AGIA's "Must Haves" regarding expansions, open seasons, etc., provide important, additional protections that would not otherwise exist

Open Season

AGIA

The Alaska Gasline Inducement Act

- **What if the producers fail to bid in an open season?**
 - Premature: need to wait and see whether there is a failure to bid, and the facts associated with that failure
 - State and other interested parties can then determine based on the facts whether any antitrust, FERC or other issues have been raised by a failure to bid or a withholding of gas supplies from the market

Conclusion



- AGIA charts a middle ground between (A) banning producer-ownership of the pipeline and (B) negotiating exclusively with the producers
- Instead of banning producer-ownership, AGIA:
 - Attempts to fix the competitive problems
 - Invites producers to build the pipeline on terms consistent with the State's interest in promoting exploration and development of North Slope gas resources
 - Establishes level playing field

**Kenneth M. Minesinger**

Shareholder

Washington, D.C.

Energy & Natural Resources Antitrust & Trade Regulation Litigation

E-mail Kenneth M. Minesinger

Tel: (202) 530-8572 Fax: (202) 261-4746

Kenneth M. Minesinger represents natural gas pipelines, electric power generators, energy marketers, and other participants in the energy industry, focusing his practice on energy regulatory proceedings before the Federal Energy Regulatory Commission and on related antitrust, litigation and transactional matters. Ken's experience reflects the sweeping changes that have occurred in the energy industry in recent years, as the level of competition and consolidation in the industry has steadily increased while at the same time regulation continues to play a central role. Ken has represented energy companies in a wide range of regulatory matters, including complex ratemaking, restructuring, and licensing proceedings, and complaints and investigations into allegations of market manipulation and the exercise of market power. As the competitive issues in energy regulatory proceedings often intersect with the application of the antitrust laws, Ken has also represented energy and non-energy clients on numerous antitrust matters, including mergers and acquisitions, counseling, and litigation.

CONCENTRATION

- Energy regulation
- Antitrust
- Energy litigation

SIGNIFICANT REPRESENTATIONS

- Counsel for major energy companies and other industry participants on numerous FERC regulatory and antitrust matters, including:
 - Rate case preparation and litigation
 - Antitrust compliance and M&A matters
 - Settlement compliance
 - Affiliate code of conduct issues
 - Negotiated rate agreements
 - Market-based rate authorizations
 - FERC certification proceedings
 - Compliance with anti-market manipulation rules
 - Liquefied natural gas ("LNG") safety/siting issues
- Representing State of Alaska regarding efforts to induce commercialization of North Slope gas.
- Outside counsel in recent rate cases and other significant FERC matters for various companies, including El Paso Natural Gas Company, Mojave Pipeline Company, Colorado Interstate Gas Company, Wyoming Interstate Company, and Cheyenne Plains Gas Pipeline.
- Represented major energy companies defending antitrust lawsuits alleging exercise of monopoly power, market division, and market manipulation. Significant experience litigating filed rate doctrine and preemption related

Federal Jurisdiction Issues in these and other energy-related antitrust lawsuits.

- Successfully defended, at the D.C. Circuit Court of Appeals, FERC orders requiring the conversion of full requirements contracts to fixed quantity contracts and rejecting allegations that pipeline withheld capacity.
- Represented major "clean coal" project in efforts to obtain federal tax credits provided by the Energy Policy Act of 2005.
- Represented a major energy company in negotiating a consent judgment with the Federal Trade Commission regarding the sale of the company's natural gas pipeline and processing assets to another major energy company.
- Represented an oil refining company in responding to and substantially limiting the scope of a civil investigative demand in FTC investigation of increased Midwest refined products prices.
- Successfully represented pipeline, at FERC and the D.C. Circuit, in defending against allegations that its transportation contracts with a shipper were anticompetitive and unduly discriminatory.
- Has successfully obtained FERC approval of transactions under Section 203 of the Federal Power Act, which requires FERC authorization of wholesale electric power mergers and acquisitions.
- Responsible for preparation and filing of electric power marketer's triennial market power update filings for purposes of retaining market-based rate authorization.
- Prior to negotiating settlement of pipeline rate case, obtained an administrative law judge ruling that rejected prudence challenge to pipeline's capital costs and approved an allowed rate of return significantly above the average level usually permitted by FERC.
- Successfully represented an interstate natural gas pipeline in its first general rate case at the FERC, obtaining FERC ruling that rejected prudence challenge and other charges that the pipeline's rates were unjust and unreasonable.
- Has conducted antitrust and FERC compliance seminars for major energy companies.
- Has represented clients on numerous antitrust M&A matters, including transactions involving:
 - Electric generation assets
 - Oil field services companies, including offshore drilling companies, manufacturers of offshore drilling rigs, and oil and gas exploration technology firms
 - Natural gas pipelines
 - Natural gas processing and liquids companies
 - Oil pipelines

PROFESSIONAL & COMMUNITY INVOLVEMENT

- Chairman, Antitrust Committee, Energy Bar Association, 2001
- Vice-Chairman, Antitrust Committee, Energy Bar Association, 2000
- Member, Energy Bar Association, and Antitrust Committee
- Member, American Bar Association, Antitrust Section, Fuel and Energy Committee

ARTICLES, PUBLICATIONS & LECTURES

Articles

- Co-Author, "Energy Law and Transactions," chapter addressing settlements of FERC proceedings
- Co-Author, "A New Broad Brush: Trying to Clean Up Market Behavior, New FERC Rules Raise More Confusion," *Legal Times*, August 16, 2004
- Contributing Editor, as member of Energy Bar Association Antitrust Committee, to several summaries of energy-related antitrust cases published in the *Energy Law Journal*, 1999-2001

CLERKSHIP

- Law Clerk, U.S. District Judge John H. Moore II, Middle District of Florida, 1990-1992






EDUCATION

- J.D., with honors, The George Washington University Law School, 1990
- B.A., with honors, University of Maryland, 1987
 - Phi Beta Kappa

ADMITTED TO PRACTICE

- District of Columbia
- Maryland
- U.S. Court of Appeals for the District of Columbia Circuit
- U.S. Court of Appeals, Fifth Circuit
- U.S. Court of Appeals, Ninth Circuit

RELATED LINKS

- Private Funds Weekly Roundup, v.3, No. 9 
 - GT Alert, March 05, 2007
- Private Funds Weekly Roundup, v.2, No. 43 
 - GT Alert, November 20, 2006
- Private Funds Weekly Roundup, v.2, No. 35 
 - GT Alert, September 25, 2006
- Summary of Key FERC-Related Provisions of the Energy Policy Act of 2005 
 - GT Alert, August 2005
- Greenberg Traurig Adds Energy Attorney from Morrison & Foerster
 - Press Release, February 28, 2005
- Arizona Corporation Commission, Et Al., Petitioners v. Federal Energy Regulatory Commission, Respondent Arizona Public Service Company, Et Al., Intervenor 
 - Article, February 11, 2005

One good point that
Spencer Hosié has made
in the past is that the
duty to show the project
is or is not economic is
on the oil co. not the
state.

If you want to

HOSIE | MCARTHUR LLP
ATTORNEYS AT LAW

SAN FRANCISCO
One Market, Spear Tower, 22nd Floor
San Francisco, California 94105
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May 15, 2007

VIA FACSIMILE 907-465-2381

Representative Carl Gatto
House District 13
State Capitol, Room 411
Juneau, AK 99801

Dear Representative Gatto:

I appreciate the opportunity to provide you with additional information regarding Exxon's assessment of the economic potential of the Point Thomson unit, as Exxon has reported to the SEC and to Wall Street.

As I stated in my testimony last week, when Exxon accounts for the Point Thomson unit in its Form 10-K Annual Reports to the SEC, it capitalizes the unit's exploratory well costs as assets (*See, e.g.*, Exxon's 2005 10-K, Tab 1, attached hereto). The Financial Accounting Standards Board sets very clear requirements that must be met before a company is permitted to capitalize such well costs, which are set forth in FAS 19-1 (Tab 2). Exxon adopted FAS 19-1, beginning with its 2005 10-K (Tab 1, p 55).

This raises a straightforward question: Under these standards, what was Exxon required to conclude about Point Thomson in order to report to the SEC as it did?

Under FAS 19-1, Exxon was required to conclude, among other things, that the exploratory "well had found a sufficient quantity of reserves to justify its completion as a producing well" (Tab 2, FAS 19-1, ¶9 (31), pp. 2-3). More, Exxon was not allowed to capitalize these well costs if there were "substantial doubt about the economic or operational viability of the project," and could not capitalize them "on the chance that . . . current market conditions will change . . . or technology will be developed to make the development of the project economically and operationally viable" (Tab 2, FAS 19-1 ¶9 (31A), p. 3).

HOSIE | MCARTHUR LLP
ATTORNEYS AT LAW

Representative Carl Gatto

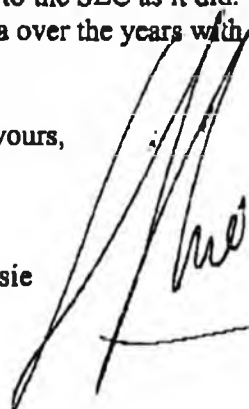
May 15, 2007

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In other words, Exxon could not have believed there was "substantial doubt about the economic or operational viability" of Point Thomson and yet reported its well costs to the SEC as an asset. Put differently, if Exxon believed that the Point Thomson project was uneconomic, it would have been improper for Exxon to report to the SEC as it did. There is no way to reconcile what Exxon has told the State of Alaska over the years with what it represented to the SEC in its financial reports.

Very truly yours,

Spencer Hosie

A handwritten signature in black ink, appearing to read "Spencer Hosie", is written over the typed name. The signature is fluid and cursive, with a long horizontal stroke at the end.

Cc: PTU Team

Enc.

TAB 1

FORM 10-K

Page 1 of 134

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2005

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549**

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2005

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____
Commission File Number 1-2256

EXXON MOBIL CORPORATION

(Exact name of registrant as specified in its charter)

NEW JERSEY
(State or other jurisdiction of
incorporation or organization)

13-5409005
(I.R.S. Employer
Identification Number)

5959 LAS COLINAS BOULEVARD, IRVING, TEXAS 75039-2298

(Address of principal executive offices) (Zip Code)

(972) 444-1000

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, without par value (6,106,332,510 shares outstanding at January 31, 2006)	New York Stock Exchange
Registered securities guaranteed by Registrant: SeaRiver Maritime Financial Holdings, Inc. Twenty-Five Year Debt Securities due October 1, 2011	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer Accelerated filer Non-accelerated filer

FORM 10-K

Page 1 of 6

2. Accounting for Suspended Exploratory Well Costs

Effective July 1, 2005, the Corporation adopted Financial Accounting Standards Board Staff Position FAS 19-1 (FSP 19-1), "Accounting for Suspended Well Costs." FSP 19-1 amended Statement of Financial Accounting Standards No. 19 (FAS 19), "Financial Accounting and Reporting by Oil and Gas Producing Companies," to permit the continued capitalization of exploratory well costs beyond one year if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. There were no capitalized exploratory well costs charged to expense upon the adoption of FSP 19-1.

Prior to the adoption of FSP 19-1, the Corporation carried as an asset the cost of drilling exploratory wells that found sufficient quantities of reserves to justify their completion as producing wells if the required capital expenditure was made and drilling of additional exploratory wells was under way or firmly planned for the near future. Once exploration activities demonstrated that sufficient quantities of commercially producible reserves had been discovered, continued capitalization was dependent on project reviews, which took place at least annually, to ensure that satisfactory progress toward ultimate development of the reserves was being achieved. Exploratory well costs not meeting these criteria were charged to expense.

The following two tables provide details of the changes in the balance of suspended exploratory well costs as well as an aging summary of those costs.

Change in capitalized suspended exploratory well costs:

	2005	2004	2003
	<i>(millions of dollars)</i>		
Balance beginning at January 1	\$1,070	\$ 793	\$1,193
Additions pending the determination of proved reserves	233	139	217
Charged to expense	(62)	(98)	(238)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(82)	(92)	(123)
Foreign exchange/other	(20)	28	44
Ending balance	<u>\$1,139</u>	<u>\$1,070</u>	<u>\$1,093</u>
Ending balance attributed to equity companies included above	\$ 2	\$ 1	\$ 30

Period end capitalized suspended exploratory well costs:

	2005	2004	2003
	<i>(millions of dollars)</i>		
Capitalized for a period of one year or less	\$ 233	\$ 139	\$ 217
Capitalized for a period of between one and five years	485	510	453
Capitalized for a period of between five and ten years	167	172	162
Capitalized for a period of greater than ten years	254	249	261
Capitalized for a period greater than one year - subtotal	<u>\$ 906</u>	<u>\$ 931</u>	<u>\$ 876</u>
Total	<u>\$1,139</u>	<u>\$1,070</u>	<u>\$1,093</u>

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a numerical breakdown of the number of projects with suspended exploratory well costs which had their first capitalized well drilled in the preceding 12 months and those that have had exploratory well costs capitalized for a period greater than 12 months.

	2005	2004	2003
Number of projects with first capitalized well drilled in the preceding 12 months	16	8	13
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	56	61	76
Total	<u>72</u>	<u>69</u>	<u>89</u>

Table of ContentsIndex to Financial Statements**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

Of the 56 projects that have exploratory well costs capitalized for a period greater than twelve months as of December 31, 2005, 18 projects have drilling in the preceding twelve months or exploratory activity planned in the next two years, while the remaining 38 projects are those with completed exploratory activity progressing toward development. The table below provides additional detail for those 38 projects which total \$561 million.

Country/Project	Dec. 31, 2005	Years Wells Drilled	Comment
<i>(millions of dollars)</i>			
Angola			
- Marimba	\$ 11	2001	Development in progress on first phase of Marimba deepwater project with proved reserves booked; development of second phase awaiting capacity in existing/planned infrastructure.
- Mavacola	12	2001 - 2002	Development awaiting capacity in existing/planned infrastructure; planned subsea tieback to floating production system; submission of Declaration of Commerciality in 2005.
- Orquidea/Violeta	6	1999 - 2001	Planned subsea tieback to floating production system; high-resolution 3-D seismic survey in 2004; further technical evaluation and reservoir studies were conducted in 2005.
Australia			
- Gorgon/Jansz	69	1980 - 2003	Gorgon and Jansz resources to be developed as integrated LNG project; Barrow Island land access rights for onshore plant secured in 2003; co-venturers combined their resources and redistributed their equity interests in 2005 with governmental approval; initial project funding and engineering began in 2005.
- Kipper/East Pilchard	10	1986 - 2001	Bass Strait project in design phase; planned tie-in to existing platform; initial Kipper funding began in 2005 following execution of Memorandum of Understanding between co-venturers; development of East Pilchard phase awaiting capacity in existing/planned infrastructure.
- Whiptail	3	2004	Progressing development concept with planned subsea tieback to existing Bass Strait platform.
Canada			
- Hebron	32	1999 - 2000	Progressing development concept with co-venturer following resolution of the Joint Operating Agreement in 2005; recent efforts focused on further technical evaluation of wells and reservoir using seismic reprocessing and well core analysis; initial project funding and engineering began in 2005.
Indonesia			
- Cepu	41	1998 - 2001	Memorandum of Understanding and a Production Sharing Contract were signed in 2005 that extend the license term for 30 years; other agreements are progressing with the Government of Indonesia; initial project funding and engineering began in 2001, with development anticipated upon conclusion of negotiations.
- Natuna	118	1981 - 1983	Intent to proceed to the next phase of development communicated to government in 2004; discussions with government on near-term development work plans are in progress; further technical evaluation and gas marketing activities were progressed in 2005, including discussions with potential customers.

Table of Contents**Index to Financial Statements**

Country/Project	Dec. 31, 2005	Years Wells Drilled	Comment
<i>(millions of dollars)</i>			
Nigeria			
- Ptoro-Isobo	9	2002	Offshore satellite development which will tie back to an existing production facility.
- Other (5 projects)	15	2001 - 2002	Actively pursuing development of several additional offshore satellite discoveries which will tie back to existing production facilities.
Norway			
- Lavrans	20	1995 - 1999	Development awaiting capacity in existing/planned infrastructure; planned subsea tieback to existing floating production system; evaluation of phased ullage filling scenarios is progressing.
- Sarv/Idun	27	1998 - 2002	Planned subsea tieback to floating production system; the export infrastructure and development plan was agreed to with partners in 2005; submission of Plan of Development to the government anticipated in 2006; initial project funding and engineering began in 2005.
- Other (4 projects)	6	1992 - 2002	Progressing several smaller North Sea developments.
Papua New Guinea			
- Hides	35	1993 - 1998	Early engineering studies complete; negotiations with customers on sales terms are in progress; initial project funding and engineering began in 2004; reservoir pressure data acquired in 2005 for ongoing technical evaluation.
Russia			
- Sakhalin 1, Phase 3	26	1996 - 1998	Actively progressing third phase of the Sakhalin-1 project to utilize capacity in facilities and infrastructure in Phase 1; Phase 1 development underway with first production in 2005 and additional development drilling in 2006; progressing Phase 3 development concept with co-venturers and government; plan to conduct further technical evaluation and reservoir studies in 2006.
United Kingdom			
- Phyllis	9	2004	Assessing co-development option with nearby 2005 Barbara discovery.
- Puffin	37	1981 - 1986	Development awaiting capacity in existing infrastructure; planned tieback to existing U.K. North Sea production facility.
- Starling	8	2003	Planned subsea tieback to existing U.K. North Sea facilities; project funding anticipated in 2006.
- Other (2 projects)	3	2002 - 2003	Progressing smaller North Sea developments.
United States			
- Point Thomson	28	1977 - 1980	Progressing development option consisting of tie-in to proposed Alaska gas pipeline; negotiations of gas pipeline fiscal terms with state of Alaska ongoing; conceptual engineering planned for 2006.
Other			
- Various (9 projects)	36	1979 - 2004	Projects primarily awaiting capacity in existing or planned infrastructure.
Total (38 projects)	\$561		

TAB 2

FSP FAS 19-1**FASB STAFF POSITION****No. FAS 19-1****Title:** Accounting for Suspended Well Costs**Date Posted:** April 4, 2005

1. Questions have arisen as to whether there are circumstances that would permit the continued capitalization of exploratory well¹ costs beyond one year, other than when additional exploration wells are necessary to justify major capital expenditures and those wells are under way or firmly planned for the near future.
2. The Board directed the FASB staff to provide guidance on the accounting for exploratory well costs and to propose an amendment to FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, accordingly. The guidance in this FASB Staff Position (FSP) applies to enterprises that use the successful efforts method of accounting as described in Statement 19.

Background

3. Paragraph 19 of Statement 19 requires costs of drilling exploratory wells to be capitalized pending determination of whether the well has found proved reserves. If the well has found proved reserves, the capitalized costs become part of the enterprise's wells, equipment, and facilities; if, however, the well has not found proved reserves, the capitalized costs of drilling the well are expensed, net of any salvage value.
4. In certain circumstances, an exploratory well finds reserves but those reserves cannot be classified as proved when drilling is completed. To meet the classification of proved reserves, the geological and engineering data must support with reasonable certainty that the quantities of reserves are recoverable under *existing economic and operating conditions* (typically, prices and costs at the date that the estimate is made). For example, after reserves are found, an enterprise may be required to obtain additional geological information, government approvals, sales contracts, and project financing before the enterprise can classify the reserves as proved.
5. Paragraphs 31-34 of Statement 19 provide guidance on whether exploratory well costs can continue to be capitalized when the well finds reserves but those reserves cannot be classified as proved when drilling is completed. If reserves cannot be classified as proved in an area requiring a major capital expenditure, paragraphs 31(a) and 34 of Statement 19 require that the cost be carried as an asset provided that (a) there have been sufficient reserves found to justify completion as a producing well if the

¹Exploratory wells and exploratory-type stratigraphic wells, as defined in FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, are referred to collectively as exploratory wells for purposes of this FSP.

FSP FAS 19-1

required capital expenditure is made, and (b) drilling of the additional exploratory wells is under way or firmly planned for the near future. If either of those two criteria is not met, the enterprise must expense the exploratory well costs.

6. For all other exploratory wells not addressed in paragraphs 31(a) and 34, paragraph 31(b) requires the capitalized costs to be expensed if the reserves cannot be classified as proved after one year following the completion of drilling.

7. Application of paragraphs 31 and 34 of Statement 19 to the facts and circumstances commonly faced by oil- and gas-producing companies in the current exploration and development environment has become a concern. For example, exploration activities are frequently performed in more remote areas, to greater depths, and in more complex geological formations than the exploration activities that occurred when the FASB issued Statement 19 in 1977. These changes in exploration activities have resulted in an increased frequency of exploratory wells that successfully find reserves that cannot be recognized as proved when drilling is completed and a lengthened evaluation period for determining whether the reserves qualify as proved. There are diverse views on how an enterprise should evaluate the criteria in paragraphs 31 and 34 in this changed environment—specifically, the one-year capitalization period.

FASB Staff Position

8. The FASB staff believes that exploratory well costs should continue to be capitalized when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project.²

Amendment to Statement 19

9. The Board has agreed to replace paragraphs 31–34 of Statement 19 with the following:

Accounting When Drilling of an Exploratory Well or an Exploratory-type Stratigraphic Well Is Completed

31. As specified in paragraph 19, the costs of drilling an exploratory well or an exploratory-type stratigraphic well are capitalized as part of the enterprise's uncompleted wells, equipment, and facilities pending the determination of whether the well has found proved reserves. If proved reserves are found, the capitalized costs of drilling the well shall be reclassified as part of the costs of the enterprise's wells and related equipment and facilities at that time. If proved reserves are not found, the capitalized costs of drilling the well shall be charged to expense. However, an exploratory well or an exploratory-type stratigraphic well may be determined to have

² For purposes of this FSP, a project may include more than one exploratory well or exploratory-type stratigraphic well if the reserves are intended to be extracted in a single integrated producing operation (for example, the producing wells will operate with shared infrastructure).

FSP FAS 19-1

found oil and gas reserves, but those reserves cannot be classified as proved when drilling is completed. In those cases, the capitalized drilling costs shall continue to be capitalized if the well has found a sufficient quantity of reserves to justify its completion as a producing well^{2a} and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project.^{2b} (Refer to paragraphs 32–34 for guidance on assessing whether an enterprise is making sufficient progress on assessing the reserves and the economic and operating viability of the project.)

31A. If either of those criteria is not met, or if an enterprise obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well or exploratory-type stratigraphic well shall be assumed to be impaired and its costs, net of any salvage value, shall be charged to expense. Further, an enterprise shall not continue to capitalize exploratory well costs on the chance that (a) current market conditions will change (for example, an increase in the market price of oil or gas), or (b) technology will be developed to make the development of the project economically and operationally viable.

Progress on Assessing Reserves

32. All relevant facts and circumstances shall be evaluated when determining whether an enterprise is making sufficient progress on assessing the reserves and the economic and operating viability of the project. The following are some indicators, among others, that an enterprise is making sufficient progress. No single indicator is determinative. An entity should evaluate indicators in conjunction with all other relevant facts and circumstances.

- a. Commitment of project personnel who are at the appropriate levels and who have the appropriate skills
- b. Costs are being incurred to assess the reserves and their potential development
- c. An assessment process covering the economic, legal, political, and environmental aspects of the potential development is in progress
- d. Existence (or active negotiations) of sales contracts with customers for the oil and gas
- e. Existence (or active negotiations) of agreements with governments, lenders, and venture partners
- f. Outstanding requests for proposals for development of any required facilities
- g. Existence of firm plans, established timetables, or contractual commitments, which may include seismic testing and drilling of additional exploratory wells
- h. Progress is being made on contractual arrangements that will permit future development
- i. Identification of existing transportation and other infrastructure that is or will be available for the project (subject to negotiations for use).

33. Long delays in the assessment or development plan (whether anticipated or unexpected) may raise doubts about whether the enterprise is making sufficient progress to continue the capitalization of exploratory well or exploratory-type

Invoice

 Print
  Email

Invoice Reference # 7782014

Registration Date: May 16, 2007
Invoice Date: May 16, 2007
Issued By: PNWER

Event: 2007 PNWER 17th Annual Summit - Anchorage, Alaska (Copy)
Date/Time: Sunday, July 22, 2007 6:00 PM - Thursday, July 26, 2007 12:00 PM

The following individual(s) are registered for the event:

Reference #	Name	Company/Organization	Type
7782014	Hon. Craig Johnson	Alaska State Legislature	Legislator

Billed To:

Craig Johnson
 Alaska State Legislature
 716 West 4th Avenue, Suite 640
 Anchorage, AK 99501
 907-269-0200
 rep_craig_johnson@legis.state.ak.us

Event Fees	Quantity	Unit Price	Amount
Legislator registration - Reminder to register for the tours from pnwer2007.org	1	\$395.00	\$395.00
Subtotal:			\$395.00
Total:			\$395.00

Summary of Transactions	Date	Amount	Balance
Transaction Amount	16-May-2007	\$395.00	\$395.00
Current Balance:			\$395.00

Payment Information

Payment Method: Bill My State/Prov.

Code:

Payment Instructions:

You may pay by check or credit card. If you are a legislator you may request to have your state/prov. billed. Please send checks to PNWER 2200 Alaskan Way Suite 460 Seattle, WA 98121

Refund Information

To apply for a refund, type in the email address and the password used for registration. Follow the steps for a refund request.



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Stan Hubbard

Signature of Camera Operator

6-4-2009

Date

**6/7/07 TAPS
TARRIFF
PROCEED-
INGS, & OIL
PIPELINE
INTEGRITY &
CORROSION
(FILE 1)**



**House Resources Committee
Alaska State Legislature
Representative Carl Gatto, Co-Chairman**

May 25, 2007

To: (H) Resources Members

RE: Hearings

Anchorage LIO

Thursday, June 7th 9:00am-5:00pm

- TAPS tariff proceedings before the FERC
 - Oil pipeline integrity and corrosion
- Both meetings will be teleconferenced

Based on comments from members I have decided to hold hearings on these issues Thursday, June 7th to ensure maximum participation. Hearing materials will be available shortly.

Thank you.

CG/cr

Alaska State Capitol, Room 124 • Juneau, Alaska 99801
Committee Aide - Cody Rice
(907) 269-0220 phone • (907) 269-0221 fax

BP EXPLORATION (ALASKA) INC.



FACSIMILE TRANSMITTAL SHEET

TO: Honorable Craig Johnson FROM: Tonia Bonock / PJ

COMPANY: Alaska Legislative DATE: 8/2/07 11:00 AM - 11:40 11:50

FAX NUMBER: (907) 465-3072 218204 TOTAL NO. OF PAGES INCLUDING COVER: 11

PHONE NUMBER: (907) 465-4993 SENDER'S REFERENCE NUMBER: N/A

RE: Responses to 8/1/07 Resource Committee Meeting

URGENT FOR REVIEW PLEASE COMMENT PLEASE REPLY PLEASE RECYCLE

NOTES/COMMENTS:

bp



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

August 2, 2007

BY FACSIMILE (without attachments) and OVERNIGHT DELIVERY

Hon. Carl Gatto
Hon. Craig Johnson
Co-Chairs, House Resources Committee
Alaska State Legislature
Alaska State Capitol
Juneau, Alaska 99801

Re: Responses to Requests from June 7, 2007 Meeting of House Resources Committee

Dear Representatives Gatto and Johnson:

BP Exploration (Alaska) Inc. ("BPXA") appreciates the opportunity to respond to several requests from the June 7, 2007 meeting of the House Resources Committee. Please find below the answers to each of the Members' requests, which we have reproduced for your convenience.

Requests from Rep. Seaton

• Requests from September 2006 Memoranda

Rep. Paul Seaton posed four questions to BPXA in two memoranda, dated September 7, 2006 and September 14, 2006.^{1/}

1. **I requested from BP verification of information [that] has circulated that the clean pigging was not done previously because TAPS Pump Station #1 could not handle the built-up volume of sludge with its filtration system and other arrangements were not made to alternatively handle that volume of sludge. I requested any BP correspondence with TAPS on the issue.**

Since BP is an owner of Alyeska, how can it justify not pigging the transit lines it operates in the Prudhoe Bay unit handling market oil while the same market oil in

^{1/} As Rep. Dahlstrom explained at the June 7 meeting, these requests were not originally addressed to BPXA in September 2006. BPXA was provided a copy of the requests shortly before the June 7 meeting.

TAPS requires a substantial expenditure and aggressive cleaning pig and smart pigging schedule as outlined (in the memorandum)? [Question from September 7, 2006 memorandum, "Transit Lines and TAPS Pigging Schedules"]

As I explained in my testimony at the June 7 meeting, the frequency of pigging^{2/} on the oil transit lines ("OTLs") in the Prudhoe Bay Unit ("PBU") and on the Trans-Alaska Pipeline System ("TAPS") may differ due to a number of factors, including operational requirements and for corrosion management reasons. As I described at the June 2007 meeting, BPXA runs maintenance pigs frequently on North Slope production lines and employs full-time crews dedicated to those pigging operations.

The sales-quality crude oil in the PBU OTLs is not "the same market oil" flowing through the TAPS. Indeed, the primary reason that the Alyeska Pipeline Service Company ("Alyeska"), which operates the TAPS, runs maintenance pigs at the frequency Rep. Seaton notes is that the TAPS market oil is a combination of crude oil from a wide number of different North Slope fields and operators. Some of these oils are prone to develop paraffin that can form on the interior of the pipeline. Over the approximately 800-mile length of the TAPS, this paraffin can, when the temperature drops, reduce the efficiency of the pipeline hydraulics system. Maintenance pig runs are thus required at more frequent intervals to combat the paraffin build-up. BPXA's approach to maintenance pig runs is consistent with Alyeska's flow regime strategy for lines on which, for example, paraffin build-up or temperature present issues. In comparison to the TAPS however, the PBU OTLs, which are only eight miles long on either side of Pump Station 1, carry crude oil that is relatively sweet, runs at higher temperatures, and does not contain high levels of paraffin.

As I further testified at the June 7 meeting, in-line inspections are typically undertaken to provide information as to the integrity of a line. BPXA has historically monitored the 16-mile section of the PBU OTL system via several inspection techniques, including in-line inspection and external ultrasonic inspection. It is an industry-accepted practice to use ultrasonic inspection techniques where the lines are readily accessible above ground and are relatively short in length. The TAPS system is, as noted, approximately 800 miles long, and approximately 50% of the line is buried below ground level. Those circumstances make in-line inspection the only practical means of inspection.

Regarding Rep. Seaton's statements about Pump Station #1, BPXA respectfully submits several points of clarification. First, cleaning pig runs were "done previously," *i.e.*, prior to the runs in 2006 to which Rep. Seaton appears to refer, on the PBU OTLs. Second, based on experience from those prior cleaning pig runs in the Eastern Operating Area ("EOA") in the early 1990s in which some scale flakes or chips collected in the screens^{2/} of Pump Station #1,

^{2/} "Pigging" encompasses three different types of activities: runs by cleaning pigs, runs by maintenance pigs (which are a type of cleaning pig that are used both to ensure that lines are clean and for other operational reasons), and in-line inspection (colloquially known as "smart pigging").

^{2/} Pump Station #1 does not have a "filtration system."

there was some discussion between BPXA and Alyeska in 2006 about the potential presence of solids^{4/} in future pigging runs.^{5/} Third, it is not the case that "other arrangements were not made" to address this potential issue. To the contrary and among other things, modifications were made to Tank 110 in 2006 to allow it to handle any solids that were returned as a result of pigging runs, and a series of runs were completed in 2006.^{6/} Finally, subsequent pigging runs did not result in a particularly high "volume of sludge." Indeed, Alyeska assessed the pigging returns sent to Tank 110 during those 2006 pigging activities and reported a total of only 32 barrels of sediment and 292 barrels of water recovered for all the EOA (Flow Station ("FS") 2-to-Skid 50) and Western Operating Area ("WOA") (Gathering Center ("GC") 1-to-Skid 50) OTLs.^{7/} These totals are well within the base, sediment & water ("BS&W") specifications for the amount of oil that has been shipped through those lines.

- 2. We would like to see a copy and analysis of the pressure log data for the pigging operations on BP transit lines in 1992 and again in 2006. We would like to determine if any increased pressure needed to move a pig down a line with a lot of contamination built up could have caused or played a role in the subsequent pipeline leaks. [Request from September 14, 2006 memorandum, "BP Transit lines pigging information request"]**

This request appears to assume a condition that did not exist. As described in response to Question 1, Alyeska assessed pigging returns from the 2006 pigging activities on the EOA and WOA OTLs and reported minimal returns of sediment and water. Similarly, when BPXA maintenance-pigged the Lisburne Production Center ("LPC") OTL (another North Slope OTL not part of the PBU) in 2006, the runs returned minimal solids (less than 5 gallons) and revealed minimal damage.

BPXA does not believe that pressure in the lines played a role in the OTL leaks in 2006. BPXA's analysis of the pipeline operating pressures associated with its extensive pigging operations in the WOA and EOA OTLs in 2006 shows no significant increases in pressure

^{4/} For purposes of these responses, "solids" means material in the lines that contains both organic and inorganic matter.

^{5/} BPXA is providing correspondence (without attachments, which in many cases are voluminous) with Alyeska that it has identified regarding this issue. BPXA has not conducted a forensic search of correspondence but believes it has identified the principal communications on this matter. This correspondence is attached hereto as Exhibit 1 and bears the Bates labels BPXA-AKLEGIS000001-29.

^{6/} See, e.g., Letter from Jerry Brossia, State of Alaska Joint Pipeline Office, to Robert I. Shoaf, Compliance Officer for Alyeska, copying Nolan Heath, et al. (Sept. 27, 2006) (reflecting approval for Alyeska to modify Tank 110, as described) (attached hereto as Exhibit 2). This correspondence bears the Bates labels BPXA-AKLEGIS000030-31.

^{7/} See Letter from Joynor, Alyeska Vice President of Oil Movements, to Brossia and Michael Thompson, State of Alaska Joint Pipeline Office (Dec. 20, 2006) (attached hereto as Exhibit 3). This correspondence bears the Bates labels BPXA-AKLEGIS000032-43. BPXA did not pig the segment of the WOA OTL from GC2 to GC1; this segment (also known as "OT21") was instead removed from service and decommissioned.

Figure 2. EOA: FS2-to-FS1 OTL, hourly average pressure data overlaid with pigging events.

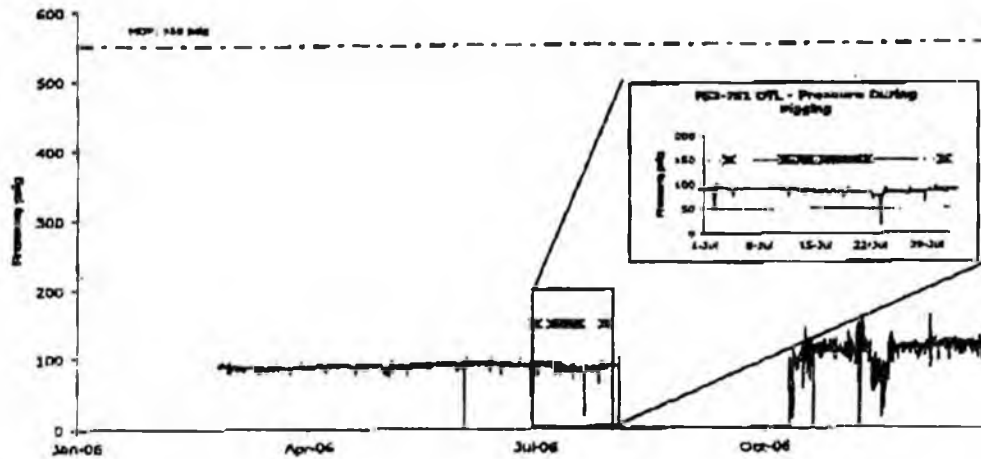


Figure 3. EOA: FS1-to-Skid 50 OTL, hourly average pressure data overlaid with pigging events.

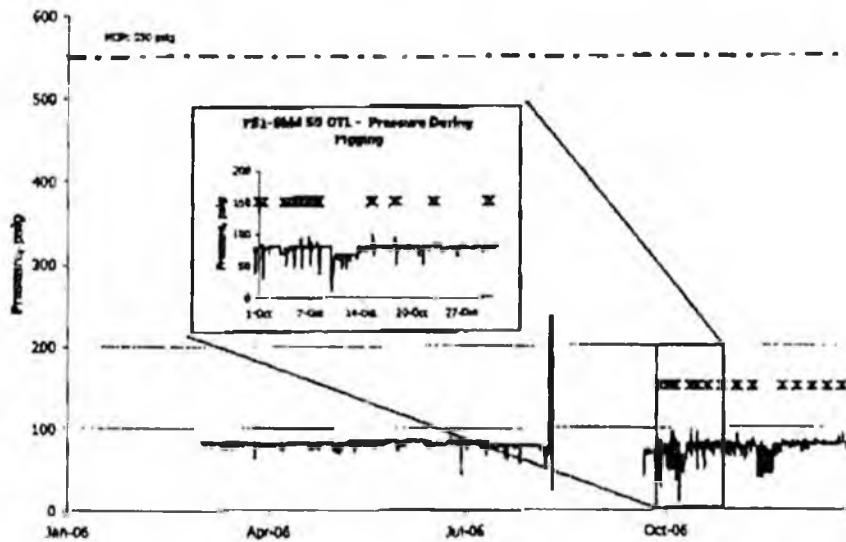


Figure 2. EOA: FS2-to-FS1 OTL, hourly average pressure data overlaid with pigging events.

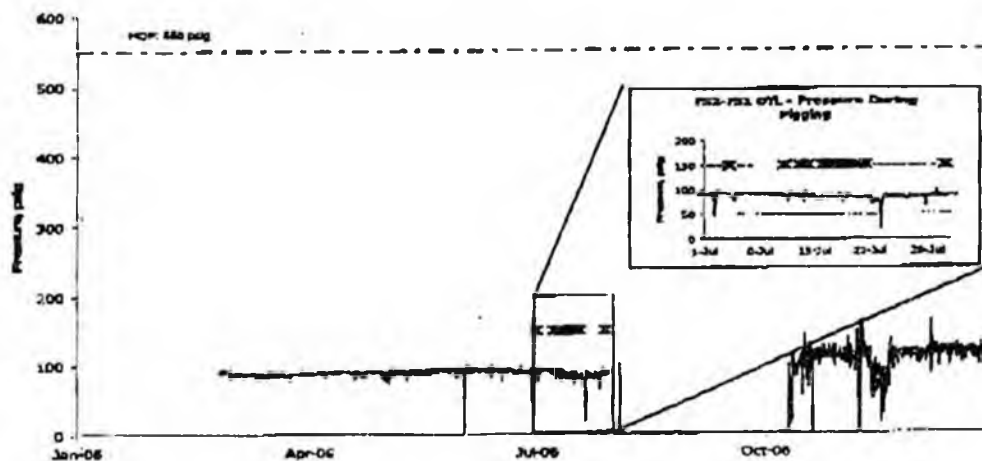


Figure 3. EOA: FS1-to-Skid 50 OTL, hourly average pressure data overlaid with pigging events.

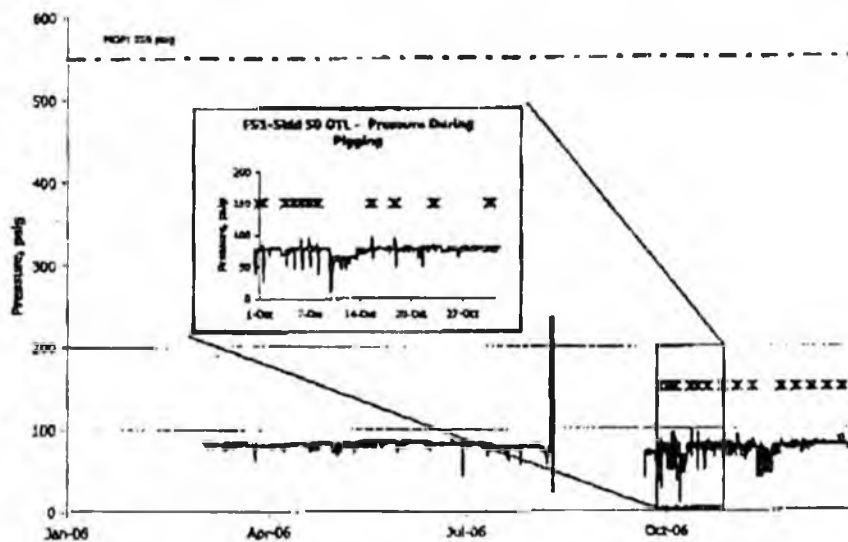
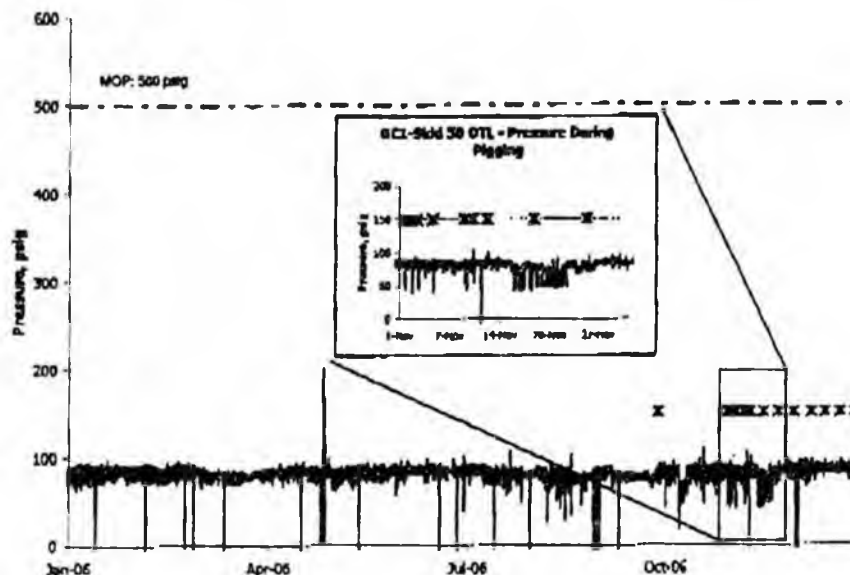


Figure 4. WOA: GCI-to-Skid 50 OTL, 5-minute average pressure data overlaid with pigging events.



3. Please provide the committee with a two-year summary of the pigging done on transit pipelines in fields that BP operates worldwide. Please specify which examples of the pigging frequency in other BP operated fields are similar to the Prudhoe Bay NS transit lines.

We have been provided information that standard industry practice is to pig often to prevent problems. We have been informed that each field has different oil and gas characteristics that require different procedures but nowhere to our understanding is regular pigging not done. If you have examples of such, please specify and provide details of the reasons for such a low maintenance determination. [Request from September 14, 2006 memorandum]

As Rep. Seaton notes, each field has different characteristics, including the type and quality of crude produced; the weather conditions and terrain in which the field is located; the level of pressure needed to move crude through pipelines; and whether the pipelines must be buried below ground or travel through water. The pipelines themselves are in turn specific to the field; among other things, pipelines differ in terms of metallurgy and size. These differences, in both fields and pipelines, are all part of the calculus that informs decisions about the maintenance procedures used on any given pipeline, including decisions whether and when to run cleaning and/or maintenance pigs and/or to conduct in-line inspections. As noted above in response to Question 1, BPXA's cleaning and maintenance pig data on the PBU OTLs show that there has been very little sediment build-up in them over time.

BPXA has previously explained that there are two different types of pipelines in the PBU that carry crude oil: OTLs, which carry sales quality oil downstream of processing facilities, and flow lines (sometimes also known as "production gathering lines"), which carry multi-phase flow from well heads to processing facilities. The leaks in 2006 occurred in the EOA and WOA OTLs, which are large-diameter, low-stress, above-ground lines. BPXA operates no other large-diameter, low-stress, above-ground OTLs and is not aware of any such lines being operated by any affiliate. Meaningful comparison to other lines of different sizes that are used in different service, under different conditions, and to transport oil of different quality and/or composition is thus not possible.

BPXA understands Rep. Seaton's statement regarding standard industry practice to refer to maintenance pigging. As BPXA has previously explained, it is not aware of any industry standard or recommended industry practice with respect to cleaning or maintenance pigging.

4. **Was the fact that the Prudhoe Bay transit lines were carrying much less than design volumes combined with the idea that the pipeline diameter could be reduced by sludge accumulation without increasing pump pressure or otherwise impacting the operational efficiency of the line a consideration in the determination not to clean or maintenance pig the transit lines? [Question from September 14, 2006 memorandum]**

BPXA has not identified any correlation between operational efficiency of the OTLs and the potential for reduced cross-sectional area, and that potential was not a consideration in the maintenance strategy of the OTLs. BPXA has also not observed any appreciable change in the operating pressure of the system due to the accumulation of solids.

The flow in the OTLs has naturally lost velocity over time as a result of the declining production of the field, and any change in cross-sectional area of the OTLs would likely have been masked by this natural decline in output. In any event, prior to the leaks BPXA saw no indications of restrictions in the line that might have led to reduced throughput.

BPXA's post-leak analysis bears out these observations. Even though BPXA understands, in retrospect, that the reduction in volume of oil may have contributed to the circumstances that led to the leaks in the OTLs in 2006, the reduction in the cross-sectional area of the lines due to build-up of solids was relatively minor during the 10-year period prior to the 2006 leaks. As discussed above in response to Question 1, cleaning and maintenance pigging of the OTLs in 2006 revealed very little sediment build-up over time.

- Oral questions from June 7 meeting

Rep. Seaton posed the following questions at the hearing on June 7:

5. **What percentage of the lines that BP is operating in the Prudhoe Bay Unit will the 18 smart pig runs in 2007 encompass?**

Of the 18 in-line inspections that BPXA has planned for 2007, 16 are being performed on PBU pipelines; the others are being performed on a Badami pipeline and a Milne Point Unit pipeline. These 16 PBU pipelines account for 10% (16 of 164) of all PBU pipelines transporting crude oil (both flowlines and OTLs).^{10/}

6. **Has BP billed Conoco or Exxon for the repairs and the maintenance that arose from the shutdown, the bypass line and those repairs yet? If they have been billed, [has] that been turned down? If they haven't been billed, when [is BP] planning on billing for that?**

BPXA's working interest owner partners, ExxonMobil and ConocoPhillips, have approved the funds and are making payments for the spill response, subsequent inspections, and bypass construction. BPXA has submitted an Authorization for Expenditure request for the OTL replacement to ExxonMobil and ConocoPhillips, and that request is under review. Neither ExxonMobil nor ConocoPhillips has refused to pay any bills sent to them regarding any of these activities.

Question from Rep. Johnson at June 7 meeting

7. **Will the costs of replacement of the affected lines be treated as a tax deduction under [the Petroleum Production Tax] by BP?**

BPXA has previously provided a written response to this question. On February 15, 2007, Doug Suttles, President of BPXA, submitted a letter on this subject to the Honorable Members of the Alaska State Legislature. A copy of that letter is attached hereto as Exhibit 4. This correspondence bears the Bates labels BPXA-AKLEGIS000044-45.

^{10/} The total number of pipelines does not include facility piping or well lines, which, due to the nature of their construction (i.e., they are of smaller diameter and shorter lengths and include sharp bends), cannot readily be in-line inspected using current technology.

Question from Rep. Fairclough, who attended the June 7 meeting of the Committee, joined by Rep. Seaton

8. Are the deconstructions of the affected OTLs being charged against the dismantlement, removal, & restoration ("DR&R") fund? If so, will that charge decrease the fund? How would such a charge affect the FERC and rate calculations in the future? Would such a charge result in the DR&R fund being hit twice, for removal of a portion of the line and for the expense of creating a new line?

When oil and gas assets are constructed, an estimate of the costs for DR&R of those assets is established as a future obligation (or "liability") by the corporation owning the assets and recorded as a provision on its balance sheet. The DR&R provision is an accounting entry and does not represent the establishment of a specific "fund" or escrow account. When the assets (or a portion of the assets) are removed, the actual costs incurred in the related DR&R activity are charged against this provision such that the total DR&R provision for the assets (or portion of the assets) will decrease. When a new pipeline is installed, the DR&R provision is increased to reflect the new obligation associated with the new pipeline. Thus, in the case of the replacement of the PBU OTLs, the provision will be reduced with respect to the old pipeline and increased with respect to the new pipeline. This accounting treatment is in accordance both with U.S. Generally Accepted Accounting Principles and BPXA's internal accounting policy.

With regard to Rep. Fairclough's question about the Federal Energy Regulatory Commission ("FERC") and future rate calculations, the PBU OTLs are not common carrier pipelines and thus are not subject to FERC tariffs. The costs to remove and/or replace these OTLs will therefore not impact tariff rates.

* * *

These responses contain highly sensitive, private business information and documents. Accordingly, BPXA believes that the State is required to treat and maintain this letter and these documents as confidential under the commercial privacy protection afforded by Article I, Section 22 of the Alaska Constitution; AS 40.25.120(a)(4); and AS 40.25.120(b)(6). BPXA respectfully requests that the confidentiality of this letter and these documents be preserved and that, if you wish to consider whether any of this information or these documents should be made public, BPXA be provided 60 days notice prior to any such disclosure to any third party, including other governmental entities.

Hon. Carl Gallo
Hon. Craig Johnson
August 2, 2007
Page 10

Please feel free to call me if I may be of further assistance.

Sincerely,

 FOR
TONY BROCK

Tony Brock, Technical Director
BP Exploration (Alaska), Inc.

Attachments: as stated

cc: Hon. Charlie Huggins, Chair, Senate Resources Committee
Hon. Paul Seaton
Hon. Anna Fairclough (by overnight delivery only, without exhibits)

ALASKA STATE HOUSE OF REPRESENTATIVES



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REPRESENTATIVE PAUL SEATON DISTRICT 35

Memorandum

From: Rep. Paul Seaton
To: House Resources Co-Chair Rep. Ralph Samuels
House Resources Co-Chair Rep. Jay Ramras
Senate Resources Chair Sen. Tom Wagoner
Date: September 7, 2006
Re: Transit Lines and TAPS Pigging Schedules

BP testified to the Joint House and Senate Resources Committee meeting on August 18th that they did not think they needed to pig clean and smart pig the transit lines because they were handling market ready oil - that is oil with the majority of the water and contaminants removed. However, other information has circulated that the clean pigging was not done previously because TAPS Pump Station #1 could not handle the built-up volume of sludge with its filtration system and other arrangements were not made to alternatively handle that volume of sludge. I requested from BP verification of that information and any BP correspondence with TAPS on the issue at the last meeting and am awaiting a response.

Additional information available from Alyeska Stakeholders Information Office published August 2006 entitled "Pigging the Trans Alaska Pipeline System" says that "cleaning pigs run weekly or every other week, smart pigs are scheduled every three years...." and "...in 29 years of operation, 60 smart pigs have been run to inspect the pipeline."

Please submit the following question for an answer at the next Resources meeting: since BP is an owner of Alyeska, how can it justify not pigging the transit lines it operates in the Prudhoe Bay unit handling market oil while the same market oil in TAPS requires a substantial expenditure and aggressive cleaning pig and smart pigging schedule as outlined above?

ALASKA STATE HOUSE OF REPRESENTATIVES



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345 W. Sterling Hwy
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Session:
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State Capital
Room 102

REPRESENTATIVE PAUL SEATON DISTRICT 35

Memorandum

From: Rep. Paul Seaton
To: House Resources Co-Chair Rep. Ralph Samuels
House Resources Co-Chair Rep. Jay Ramras
Senate Resources Chair Sen. Tom Wagoner
Date: September 14, 2006
Re: BP Transit lines pigging information request

Please submit the following requests for information to BP for so we can have a discussion of the matter at the next Resources meeting:

1. We would like to see a copy and analysis of the pressure log data for the pigging operations on BP transit lines in 1992 again in 2006. We would like to determine if any increased pressure needed to move a pig down a line with a lot of contamination built up could have caused or played a role in the subsequent pipeline leaks.

2. Please provide the committee with a two-year summary of the pigging done on transit pipelines in fields that BP operates worldwide. Please specify which examples of the pigging frequency in other BP operated fields are similar to the Prudhoe Bay NS transit lines.

We have been provided information that standard industry practice is to pig often to prevent problems. We have been informed that each field has different oil and gas characteristics that require different procedures but nowhere to our understanding is regular pigging not done. If you have examples of such, please specify and provide details of the reasons for such a low maintenance determination.

3. Was the fact that the Prudhoe Bay transit lines were carrying much less than design volume combined with the idea that the pipeline diameter could be reduced by sludge accumulation without increasing pump pressure or otherwise impacting the operational efficiency of the line a consideration in the determination not to clean or maintenance pig the transit lines?

BP EXPLORATION (ALASKA) INC.



FACSIMILE TRANSMITTAL SHEET

TO: Honorable Craig Johnson FROM: Tony Poncek / PJ
 COMPANY: AK legislature DATE: 8/2/07 11:00 AM - 11:40 11:50
 FAX NUMBER: (907) 465-3872 269504 TOTAL NO. OF PAGES INCLUDING COVER: (11)
 PHONE NUMBER: (907) 465-4993 SENDER'S REFERENCE NUMBER: N/A
 RE: Responses to 8/1/07 YOUR REFERENCE NUMBER:
Resource Committee Meeting

URGENT FOR REVIEW PLEASE COMMENT PLEASE REPLY PLEASE RECYCLE

NOTES/COMMENTS:

bp



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

August 2, 2007

BY FACSIMILE (without attachments) and OVERNIGHT DELIVERY

Hon. Carl Gatto
Hon. Craig Johnson
Co-Chairs, House Resources Committee
Alaska State Legislature
Alaska State Capitol
Juneau, Alaska 99801

Re: Responses to Requests from June 7, 2007 Meeting of House Resources Committee

Dear Representatives Gatto and Johnson:

BP Exploration (Alaska) Inc. ("BPXA") appreciates the opportunity to respond to several requests from the June 7, 2007 meeting of the House Resources Committee. Please find below the answers to each of the Members' requests, which we have reproduced for your convenience.

Requests from Rep. Seaton

- Requests from September 2006 Memoranda

Rep. Paul Seaton posed four questions to BPXA in two memoranda, dated September 7, 2006 and September 14, 2006.^{1/}

1. **I requested from BP verification of information [that] has circulated that the clean pigging was not done previously because TAPS Pump Station #1 could not handle the built-up volume of sludge with its filtration system and other arrangements were not made to alternatively handle that volume of sludge. I requested any BP correspondence with TAPS on the issue.**

Since BP is an owner of Alyeska, how can it justify not pigging the transit lines it operates in the Prudhoe Bay unit handling market oil while the same market oil in

^{1/} As Rep. Dahlstrom explained at the June 7 meeting, these requests were not originally addressed to BPXA in September 2006. BPXA was provided a copy of the requests shortly before the June 7 meeting.

TAPS requires a substantial expenditure and aggressive cleaning pig and smart pigging schedule as outlined [in the memorandum]? [Question from September 7, 2006 memorandum, "Transit Lines and TAPS Pigging Schedules"]

As I explained in my testimony at the June 7 meeting, the frequency of pigging^{2/} on the oil transit lines ("OTLs") in the Prudhoe Bay Unit ("PBU") and on the Trans-Alaska Pipeline System ("TAPS") may differ due to a number of factors, including operational requirements and for corrosion management reasons. As I described at the June 2007 meeting, BPXA runs maintenance pigs frequently on North Slope production lines and employs full-time crews dedicated to those pigging operations.

The sales-quality crude oil in the PBU OTLs is not "the same market oil" flowing through the TAPS. Indeed, the primary reason that the Alyeska Pipeline Service Company ("Alyeska"), which operates the TAPS, runs maintenance pigs at the frequency Rep. Seaton notes is that the TAPS market oil is a combination of crude oil from a wide number of different North Slope fields and operators. Some of these oils are prone to develop paraffin that can form on the interior of the pipeline. Over the approximately 800-mile length of the TAPS, this paraffin can, when the temperature drops, reduce the efficiency of the pipeline hydraulics system. Maintenance pig runs are thus required at more frequent intervals to combat the paraffin build-up. BPXA's approach to maintenance pig runs is consistent with Alyeska's flow regime strategy for lines on which, for example, paraffin build-up or temperature present issues. In comparison to the TAPS however, the PBU OTLs, which are only eight miles long on either side of Pump Station 1, carry crude oil that is relatively sweet, runs at higher temperatures, and does not contain high levels of paraffin.

As I further testified at the June 7 meeting, in-line inspections are typically undertaken to provide information as to the integrity of a line. BPXA has historically monitored the 16-mile section of the PBU OTL system via several inspection techniques, including in-line inspection and external ultrasonic inspection. It is an industry-accepted practice to use ultrasonic inspection techniques where the lines are readily accessible above ground and are relatively short in length. The TAPS system is, as noted, approximately 800 miles long, and approximately 50% of the line is buried below ground level. Those circumstances make in-line inspection the only practical means of inspection.

Regarding Rep. Seaton's statements about Pump Station #1, BPXA respectfully submits several points of clarification. First, cleaning pig runs were "done previously," *i.e.*, prior to the runs in 2006 to which Rep. Seaton appears to refer, on the PBU OTLs. Second, based on experience from those prior cleaning pig runs in the Eastern Operating Area ("EOA") in the early 1990s in which some scale flakes or chips collected in the screens^{3/} of Pump Station #1,

^{2/} "Pigging" encompasses three different types of activities: runs by cleaning pigs, runs by maintenance pigs (which are a type of cleaning pig that are used both to ensure that lines are clean and for other operational reasons), and in-line inspection (colloquially known as "smart pigging").

^{3/} Pump Station #1 does not have a "filtration system."

there was some discussion between BPXA and Alyeska in 2006 about the potential presence of solids^{4/} in future pigging runs.^{5/} Third, it is not the case that "other arrangements were not made" to address this potential issue. To the contrary and among other things, modifications were made to Tank 110 in 2006 to allow it to handle any solids that were returned as a result of pigging runs, and a series of runs were completed in 2006.^{6/} Finally, subsequent pigging runs did not result in a particularly high "volume of sludge." Indeed, Alyeska assessed the pigging returns sent to Tank 110 during those 2006 pigging activities and reported a total of only 32 barrels of sediment and 292 barrels of water recovered for all the EOA (Flow Station ("FS") 2-to-Skid 50) and Western Operating Area ("WOA") (Gathering Center ("GC") 1-to-Skid 50) OTLs.^{7/} These totals are well within the base, sediment & water ("BS&W") specifications for the amount of oil that has been shipped through those lines.

2. We would like to see a copy and analysis of the pressure log data for the pigging operations on BP transit lines in 1992 and again in 2006. We would like to determine if any increased pressure needed to move a pig down a line with a lot of contamination built up could have caused or played a role in the subsequent pipeline leaks. [Request from September 14, 2006 memorandum, "BP Transit lines pigging information request"]

This request appears to assume a condition that did not exist. As described in response to Question 1, Alyeska assessed pigging returns from the 2006 pigging activities on the EOA and WOA OTLs and reported minimal returns of sediment and water. Similarly, when BPXA maintenance-pigged the Lisburne Production Center ("LPC") OTL (another North Slope OTL not part of the PBU) in 2006, the runs returned minimal solids (less than 5 gallons) and revealed minimal damage.

BPXA does not believe that pressure in the lines played a role in the OTL leaks in 2006. BPXA's analysis of the pipeline operating pressures associated with its extensive pigging operations in the WOA and EOA OTLs in 2006 shows no significant increases in pressure

^{4/} For purposes of these responses, "solids" means material in the lines that contains both organic and inorganic matter.

^{5/} BPXA is providing correspondence (without attachments, which in many cases are voluminous) with Alyeska that it has identified regarding this issue. BPXA has not conducted a forensic search of correspondence, but believes it has identified the principal communications on this matter. This correspondence is attached hereto as Exhibit 1 and bears the Bates labels BPXA-AKLEGIS000001-29.

^{6/} See, e.g., Letter from Jerry Brossia, State of Alaska Joint Pipeline Office, to Robert I. Shoaf, Compliance Officer for Alyeska, copying Nolan Heath, et al. (Sept. 27, 2006) (reflecting approval for Alyeska to modify Tank 110, as described) (attached hereto as Exhibit 2). This correspondence bears the Bates labels BPXA-AKLEGIS000030-31.

^{7/} See Letter from Joynor, Alyeska Vice President of Oil Movements, to Brossia and Michael Thompson, State of Alaska Joint Pipeline Office (Dec. 20, 2006) (attached hereto as Exhibit 3). This correspondence bears the Bates labels BPXA-AKLEGIS000032-43. BPXA did not pig the segment of the WOA OTL from GC2 to GC1; this segment (also known as "OT2!") was instead removed from service and decommissioned.

Figure 2. EOA: FS2-to-FS1 OTL, hourly average pressure data overlaid with pigging events.

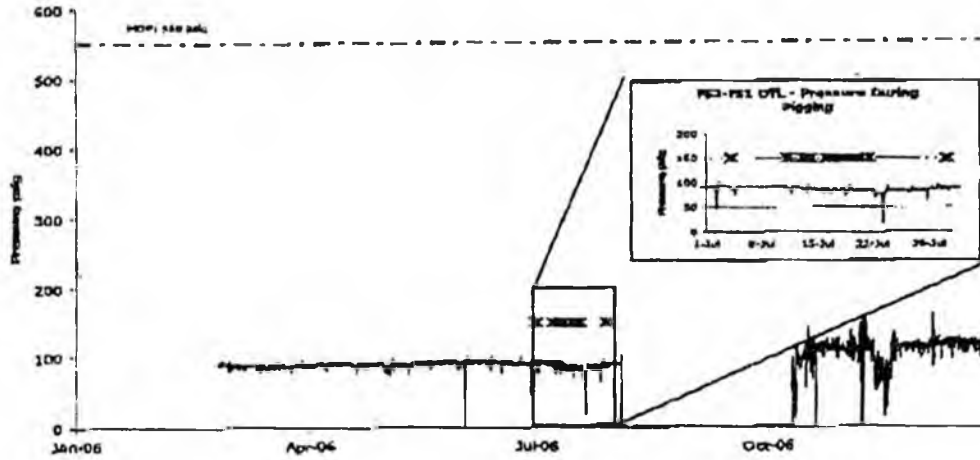


Figure 3. EOA: FS1-to-Skid 50 OTL, hourly average pressure data overlaid with pigging events.

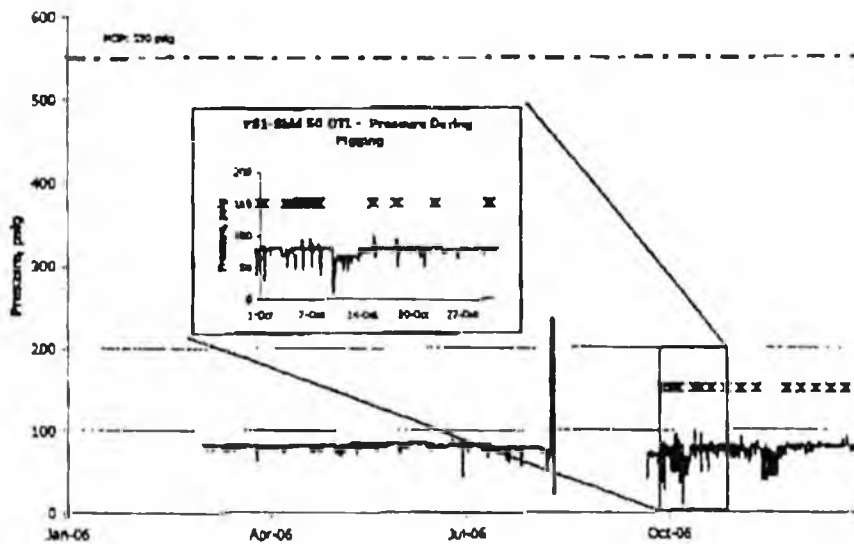


Figure 2. EOA: FS2-to-FS1 OTL, hourly average pressure data overlaid with pigging events.

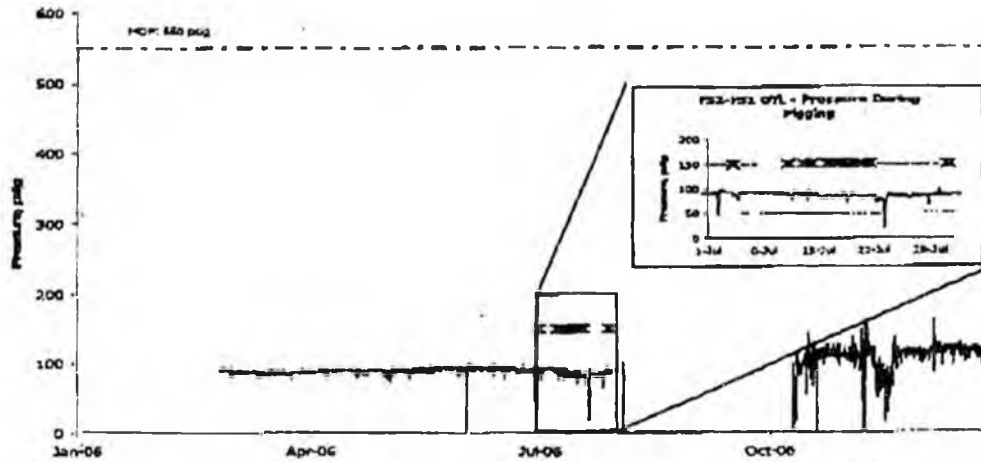
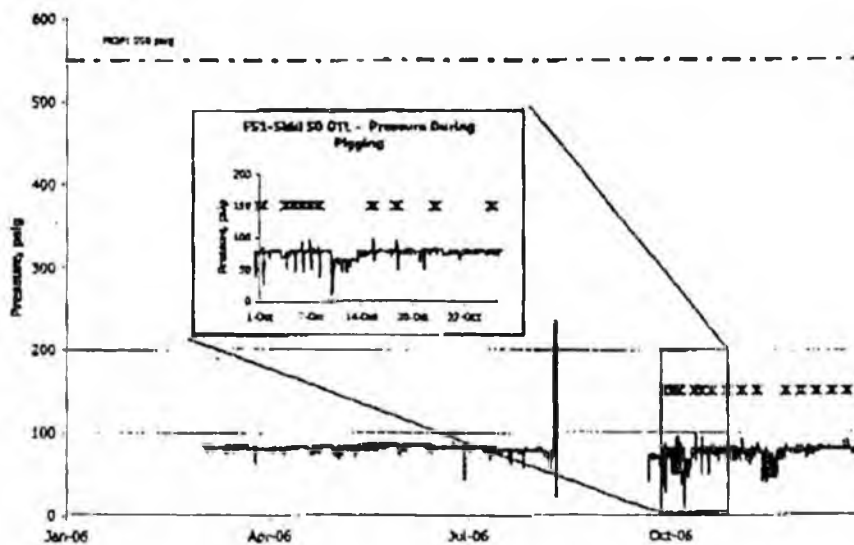
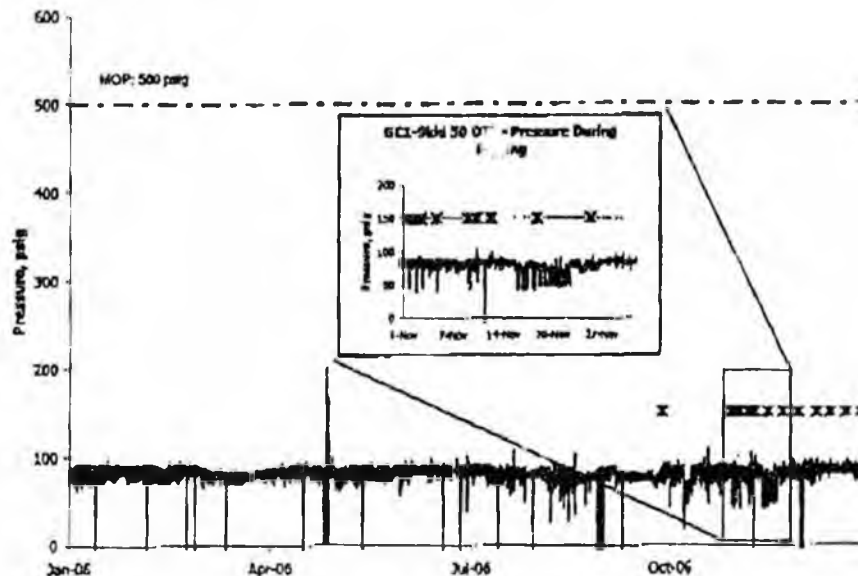


Figure 3. EOA: FS1-to-Skid 50 OTL, hourly average pressure data overlaid with pigging events.



Dup?

Figure 4. WOA: GCI-to-Skid 59 OTL, 5-minute average pressure data overlaid with pigging events.



3. Please provide the committee with a two-year summary of the pigging done on transit pipelines in fields that BP operates worldwide. Please specify which examples of the pigging frequency in other BP operated fields are similar to the Prudhoe Bay NS transit lines.

We have been provided information that standard industry practice is to pig often to prevent problems. We have been informed that each field has different oil and gas characteristics that require different procedures but nowhere to our understanding is regular pigging not done. If you have examples of such, please specify and provide details of the reasons for such a low maintenance determination. [Request from September 14, 2006 memorandum]

As Rep. Seaton notes, each field has different characteristics, including the type and quality of crude produced; the weather conditions and terrain in which the field is located; the level of pressure needed to move crude through pipelines; and whether the pipelines must be buried below ground or travel through water. The pipelines themselves are in turn specific to the field; among other things, pipelines differ in terms of metallurgy and size. These differences, in both fields and pipelines, are all part of the calculus that informs decisions about the maintenance procedures used on any given pipeline, including decisions whether and when to run cleaning and/or maintenance pigs and/or to conduct in-line inspections. As noted above in response to Question 1, BPXA's cleaning and maintenance pig data on the PBU OTLs show that there has been very little sediment build-up in them over time.

BPXA has previously explained that there are two different types of pipelines in the PBU that carry crude oil: OTLs, which carry sales quality oil downstream of processing facilities, and flow lines (sometimes also known as "production gathering lines"), which carry multi-phase flow from well heads to processing facilities. The leaks in 2006 occurred in the EOA and WOA OTLs, which are large-diameter, low-stress, above-ground lines. BPXA operates no other large-diameter, low-stress, above-ground OTLs and is not aware of any such lines being operated by any affiliate. Meaningful comparison to other lines of different sizes that are used in different service, under different conditions, and to transport oil of different quality and/or composition is thus not possible.

BPXA understands Rep. Seaton's statement regarding standard industry practice to refer to maintenance pigging. As BPXA has previously explained, it is not aware of any industry standard or recommended industry practice with respect to cleaning or maintenance pigging.

- 4. Was the fact that the Prudhoe Bay transit lines were carrying much less than design volumes combined with the idea that the pipeline diameter could be reduced by sludge accumulation without increasing pump pressure or otherwise impacting the operational efficiency of the line a consideration in the determination not to clean or maintenance pig the transit lines? [Question from September 14, 2006 memorandum]**

BPXA has not identified any correlation between operational efficiency of the OTLs and the potential for reduced cross-sectional area, and that potential was not a consideration in the maintenance strategy of the OTLs. BPXA has also not observed any appreciable change in the operating pressure of the system due to the accumulation of solids.

The flow in the OTLs has naturally lost velocity over time as a result of the declining production of the field, and any change in cross-sectional area of the OTLs would likely have been masked by this natural decline in output. In any event, prior to the leaks BPXA saw no indications of restrictions in the line that might have led to reduced throughput.

BPXA's post-leak analysis bears out these observations. Even though BPXA understands, in retrospect, that the reduction in volume of oil may have contributed to the circumstances that led to the leaks in the OTLs in 2006, the reduction in the cross-sectional area of the lines due to build-up of solids was relatively minor during the 10-year period prior to the 2006 leaks. As discussed above in response to Question 1, cleaning and maintenance pigging of the OTLs in 2006 revealed very little sediment build-up over time.

- Oral questions from June 7 meeting

Rep. Seaton posed the following questions at the hearing on June 7:

5. **What percentage of the lines that BP is operating in the Prudhoe Bay Unit will the 18 smart pig runs in 2007 encompass?**

Of the 18 in-line inspections that BPXA has planned for 2007, 16 are being performed on PBU pipelines; the others are being performed on a Badami pipeline and a Milne Point Unit pipeline. These 16 PBU pipelines account for 10% (16 of 164) of all PBU pipelines transporting crude oil (both flowlines and OTLs).^{10/}

6. **Has BP billed Conoco or Exxon for the repairs and the maintenance that arose from the shutdown, the bypass line and those repairs yet? If they have been billed, [has] that been turned down? If they haven't been billed, when [is BP] planning on billing for that?**

BPXA's working interest owner partners, ExxonMobil and ConocoPhillips, have approved the funds and are making payments for the spill response, subsequent inspections, and bypass construction. BPXA has submitted an Authorization for Expenditure request for the OTL replacement to ExxonMobil and ConocoPhillips, and that request is under review. Neither ExxonMobil nor ConocoPhillips has refused to pay any bills sent to them regarding any of these activities.

Question from Rep. Johnson at June 7 meeting

7. **Will the costs of replacement of the affected lines be treated as a tax deduction under [the Petroleum Production Tax] by BP?**

BPXA has previously provided a written response to this question. On February 15, 2007, Doug Suttles, President of BPXA, submitted a letter on this subject to the Honorable Members of the Alaska State Legislature. A copy of that letter is attached hereto as Exhibit 4. This correspondence bears the Bates labels BPXA-AKLEGIS000044-45.

^{10/} The total number of pipelines does not include facility piping or well lines, which, due to the nature of their construction (i.e., they are of smaller diameter and shorter lengths and include sharp bends), cannot readily be in-line inspected using current technology.

Question from Rep. Fairclough, who attended the June 7 meeting of the Committee, joined by Rep. Scaton

8. **Are the deconstructions of the affected OTLs being charged against the dismantlement, removal, & restoration ("DR&R") fund? If so, will that charge decrease the fund? How would such a charge affect the FERC and rate calculations in the future? Would such a charge result in the DR&R fund being hit twice, for removal of a portion of the line and for the expense of creating a new line?**

When oil and gas assets are constructed, an estimate of the costs for DR&R of those assets is established as a future obligation (or "liability") by the corporation owning the assets and recorded as a provision on its balance sheet. The DR&R provision is an accounting entry and does not represent the establishment of a specific "fund" or escrow account. When the assets (or a portion of the assets) are removed, the actual costs incurred in the related DR&R activity are charged against this provision such that the total DR&R provision for the assets (or portion of the assets) will decrease. When a new pipeline is installed, the DR&R provision is increased to reflect the new obligation associated with the new pipeline. Thus, in the case of the replacement of the PBU OTLs, the provision will be reduced with respect to the old pipeline and increased with respect to the new pipeline. This accounting treatment is in accordance both with U.S. Generally Accepted Accounting Principles and BPXA's internal accounting policy.

With regard to Rep. Fairclough's question about the Federal Energy Regulatory Commission ("FERC") and future rate calculations, the PBU OTLs are not common carrier pipelines and thus are not subject to FERC tariffs. The costs to remove and/or replace these OTLs will therefore not impact tariff rates.

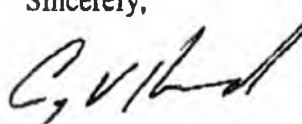
* * *

These responses contain highly sensitive, private business information and documents. Accordingly, BPXA believes that the State is required to treat and maintain this letter and these documents as confidential under the commercial privacy protection afforded by Article I, Section 22 of the Alaska Constitution; AS 40.25.120(a)(4); and AS 40.25.120(L)(6). BPXA respectfully requests that the confidentiality of this letter and these documents be preserved and that, if you wish to consider whether any of this information or these documents should be made public, BPXA be provided 60 days notice prior to any such disclosure to any third party, including other governmental entities.

Hon. Carl Gatto
Hon. Craig Johnson
August 2, 2007
Page 10

Please feel free to call me if I may be of further assistance.

Sincerely,

 FOR
TONY BROCK

Tony Brock, Technical Director
BP Exploration (Alaska), Inc.

Attachments: as stated

cc: Hon. Charlie Huggins, Chair, Senate Resources Committee
Hon. Paul Seaton
Hon. Anna Fairclough (by overnight delivery only, without exhibits)

Alaska State Legislature

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Fax: (907) 373-4745

Representative Carl Gatto

August 10, 2007

Dear Craig,

I am forwarding to you information sent by BP that you might want to consider. Please call if you want to discuss issues considered in BP's response.

A handwritten signature in cursive script that reads "Carl".

Carl

STATE OF ALASKA

SARAH PALIN, GOVERNOR

411 WEST 4th AVENUE, FIRST FLOOR
ANCHORAGE, ALASKA
99501

**ALASKA NATURAL GAS
DEVELOPMENT AUTHORITY**

TELEPHONE: (907) 257-1347

June 19, 2007

To: Alaska Oil & Gas Conservation Commission

**Amendment to Rule 9 Pool Off-Take Rates
CO 341D for Prudhoe Oil Pool – Prudhoe Bay Field**

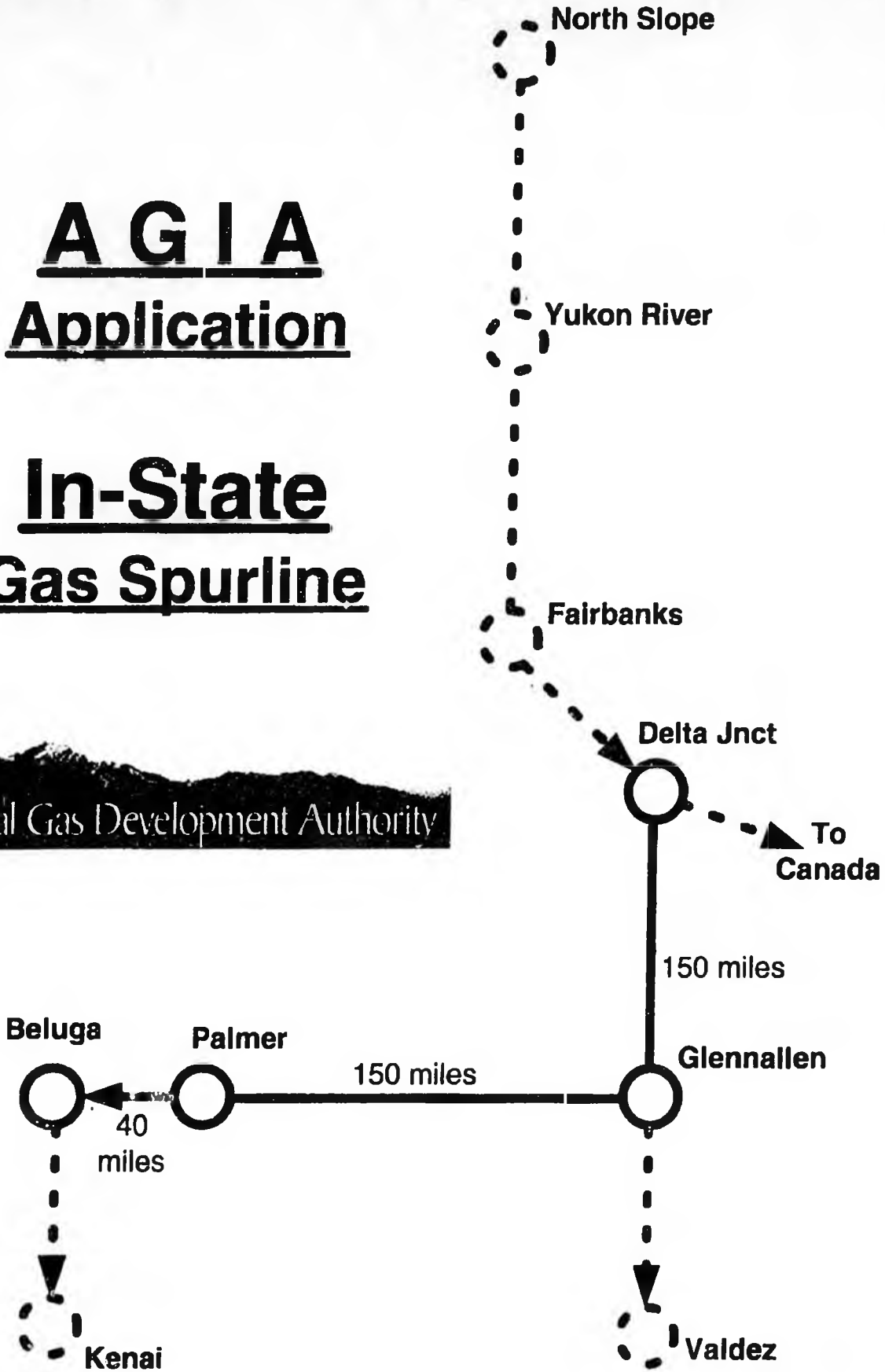
The Alaska Natural Gas Development Authority (ANGDA) is preparing an application in compliance with the provisions of the Alaska Gasline Initiative Act (AGIA) for an in-state gas pipeline linking Delta Junction to the Cook Inlet area through Glennallen. ANGDA will publicly offer this application, as an addendum, for inclusion in any major North Slope gas pipeline proposal. Our work schedule is targeted towards an October 1, 2007, submission deadline.

Our base estimate of 250 mmscfd (0.25 BCFPD) includes all residential needs for heat and electricity in-state, but excludes any existing or future industrial/export gas consumption. The State's 3 TCF of royalty gas is sufficient to satisfy these residential needs for 30 years. Industrial/export gas consumers will be included in an "open season" early next year and incorporated into the system design if commitments are made at that time. An addition of up to 1 BCFPD of industrial/export use will significantly lower the gas pipeline delivery costs for residential energy consumers.

A key part of the State's mandated application requirements under AGIA relates to the financing strength of the proposed pipeline project. ANGDA's preliminary contacts with major financial institutions, potential equity investors, and pipeline owner/operators, indicates that the regulatory availability of gas from Prudhoe Bay must be a certainty prior to any serious consideration of financial commitment.

AGIA
Application

In-State
Gas Spurline



Proposed Amendment to CO 341D Rule 9

Prior to committing gas for sale during a binding open season process, the operator must obtain approval from the Commission of a depletion plan that insures a greater ultimate recovery and prevents waste of oil and gas.

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
333 West 7th Avenue, Suite 100
Anchorage, Alaska 99501

Re: Inquiry into amending)
Rule 9 ("Pool Off-Take Rates").) Prudhoe Oil Pool
CO 341D, for the Prudhoe Oil Pool,) Prudhoe Bay Field
Prudhoe Bay Field)

July 10, 2007

REPORT OF THE COMMISSION INQUIRY
INTO AMENDING RULE 9 ("POOL OFF-TAKE RATES"), CO 341D,
FOR THE PRUDHOE OIL POOL, PRUDHOE BAY FIELD

On June 19, 2007, the Alaska Oil and Gas Conservation Commission ("Commission") held a public hearing (pursuant to AS 31.05.030(b)) to consider amending Rule 9 ("Pool Off-Take Rates") of Conservation Order ("CO") 341D for the Prudhoe Oil Pool, Prudhoe Bay Field, to require approval of a depletion plan prior to a significant gas offtake. This report presents the Commission's conclusions:

- No change in Rule 9 is necessary at this time.
- Prudhoe Bay operator must demonstrate, through existing reporting mechanisms, that they are implementing near-term strategies to maximize oil recovery prior to gas sales.

Rule 9 (which is among the Prudhoe Oil Pool pool rules that the Commission adopted in 1977) limits gas offtake from the Prudhoe Oil Pool to 2.7 billion standard cubic feet per day ("bscfd"). Because of the likelihood that Prudhoe Oil Pool gas will eventually be part of major gas sales, the Commission decided, in 2005, to investigate the need to update Rule 9 given the reservoir's development and information that has become available since 1977. Public hearings regarding revising Rule 9 were held on March 3, 2005, and May 19, 2005. In a December 5, 2005, report, the Commission noted that the Prudhoe Working Interest Owners ("WIOs") had agreed to provide access to their reservoir simulation and engineering studies so that the Commission could analyze the affects of different gas offtake rates and gas sales startup dates on total hydrocarbon recovery from the Prudhoe Oil Pool.

Based on reservoir model evaluations and studies provided by the WIOs, on February 15, 2007, Blaskovich Services, Inc., a reservoir engineering consultant, provided the Commission a confidential study on the potential impacts of major gas sales on hydrocarbon recovery from the Prudhoe Oil Pool ("Gas Offtake Study"). Oral and written summaries of the study were presented at a February 28, 2007, public hearing.

The Gas Offtake Study found insufficient information on which to justify increasing the offtake rate above 2.7 bscfd, but concluded that an early, high rate gas sale could result in the loss of a substantial volume of hydrocarbons, but even greater volumes could be lost if gas sales

are too delayed. The study noted that offtake from gas sales is at least 8 years away. The study included several recommendations. First, before commitments to sell gas are made, to evaluate the potential impact of the offtake on total hydrocarbon recovery, a hydrocarbon depletion plan should be developed; the plan should take into account the offtake startup date, offtake rate, and liquid loss mitigation efforts. Second, to maximize total hydrocarbon recovery, the field should be prepared for gas sales through the implementation of near-term strategies that focus on increasing oil recovery prior to gas offtake and ensuring that facility and well downtime are minimized. Third, the Commission should receive periodic updates on the depletion planning efforts.

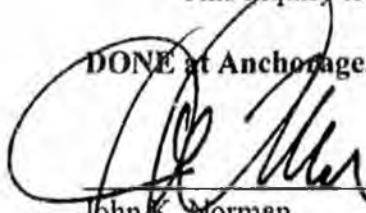
Following up on the recommendations of the Gas Offtake Study, at the June 19, 2007, public hearing, the Commission's staff proposed adding to Rule 9 the following: "Prior to committing gas for sale during a binding open season process, the operator must obtain approval from the Commission of a depletion plan that insures a greater ultimate recovery and prevents waste of oil and gas." The Commission's consultant, who prepared the study, explained how the proposed amendment was consistent with the recommendations. Also, the Commission received oral and written testimony on the proposed amendment from the field operator and members of the public.

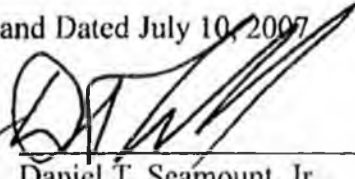
Based on the Gas Offtake Study and multiple hearings regarding Rule 9, the Commission has decided—at this time—not to amend the rule to require a Commission-approved hydrocarbon depletion plan prior to a gas sale. First, given that any major gas offtake as a result of a gas sale is still many years away, amending Rule 9 now to require such a plan is unnecessary; second, even in the absence of such a plan, the waste of oil and gas—including the waste of oil for gas—is prohibited pursuant to AS 31.05.095; third, the Commission already receives depletion plan-related information in the WIOs' annual surveillance report (which is required pursuant to CO 341D Rule 11), annual plan of development (which is required by the Department of Natural Resources ("DNR")), and annual field overview presentation (which is also required by DNR); and fourth, at the time (if ever) that an amendment is sought to increase the 2.7 bscfd gas offtake rate, Rule 9 can be amended to include a depletion plan requirement.

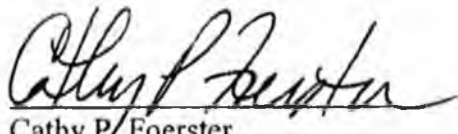
By not now taking action to amend Rule 9, the Commission retains the right to again consider requiring a Commission-approved hydrocarbon depletion plan prior to any major gas sales or to impose any other requirements that are consistent with the conclusions and recommendations of the Gas Offtake Study as part of any future amendment to Rule 9.

This inquiry is terminated.

DONE at Anchorage, Alaska, and Dated July 10, 2007


John K. Norman
Chairman


Daniel T. Seamount, Jr.
Commissioner


Cathy P. Foerster
Commissioner



BP Exploration (Alaska) Inc
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

August 2, 2007

BY FACSIMILE (without attachments) and OVERNIGHT DELIVERY

Hon. Carl Gatto
Hon. Craig Johnson
Co-Chairs, House Resources Committee
Alaska State Legislature
Alaska State Capitol
Juneau, Alaska 99801

Re: Responses to Requests from June 7, 2007 Meeting of House Resources Committee

Dear Representatives Gatto and Johnson:

BP Exploration (Alaska) Inc. ("BPXA") appreciates the opportunity to respond to several requests from the June 7, 2007 meeting of the House Resources Committee. Please find below the answers to each of the Members' requests, which we have reproduced for your convenience.

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- Requests from September 2006 Memoranda

Rep. Paul Seaton posed four questions to BPXA in two memoranda, dated September 7, 2006 and September 14, 2006.¹

1. **I requested from BP verification of information [that] has circulated that the clean pigging was not done previously because TAPS Pump Station #1 could not handle the built-up volume of sludge with its filtration system and other arrangements were not made to alternatively handle that volume of sludge. I requested any BP correspondence with TAPS on the issue.**

Since BP is an owner of Alyeska, how can it justify not pigging the transit lines it operates in the Prudhoe Bay unit handling market oil while the same market oil in

¹ As Rep. Dahlstrom explained at the June 7 meeting, these requests were not originally addressed to BPXA in September 2006. BPXA was provided a copy of the requests shortly before the June 7 meeting.

TAPS requires a substantial expenditure and aggressive cleaning pig and smart pigging schedule as outlined [in the memorandum]? [Question from September 7, 2006 memorandum, "Transit Lines and TAPS Pigging Schedules"]

As I explained in my testimony at the June 7 meeting, the frequency of pigging^{2/} on the oil transit lines ("OTLs") in the Prudhoe Bay Unit ("PBU") and on the Trans-Alaska Pipeline System ("TAPS") may differ due to a number of factors, including operational requirements and for corrosion management reasons. As I described at the June 2007 meeting, BPXA runs maintenance pigs frequently on North Slope production lines and employs full-time crews dedicated to those pigging operations.

The sales-quality crude oil in the PBU OTLs is not "the same market oil" flowing through the TAPS. Indeed, the primary reason that the Alyeska Pipeline Service Company ("Alyeska"), which operates the TAPS, runs maintenance pigs at the frequency Rep. Seaton notes is that the TAPS market oil is a combination of crude oil from a wide number of different North Slope fields and operators. Some of these oils are prone to develop paraffin that can form on the interior of the pipeline. Over the approximately 800-mile length of the TAPS, this paraffin can, when the temperature drops, reduce the efficiency of the pipeline hydraulics system. Maintenance pig runs are thus required at more frequent intervals to combat the paraffin build-up. BPXA's approach to maintenance pig runs is consistent with Alyeska's flow regime strategy for lines on which, for example, paraffin build-up or temperature present issues. In comparison to the TAPS however, the PBU OTLs, which are only eight miles long on either side of Pump Station 1, carry crude oil that is relatively sweet, runs at higher temperatures, and does not contain high levels of paraffin.

As I further testified at the June 7 meeting, in-line inspections are typically undertaken to provide information as to the integrity of a line. BPXA has historically monitored the 16-mile section of the PBU OTL system via several inspection techniques, including in-line inspection and external ultrasonic inspection. It is an industry-accepted practice to use ultrasonic inspection techniques where the lines are readily accessible above ground and are relatively short in length. The TAPS system is, as noted, approximately 800 miles long, and approximately 50% of the line is buried below ground level. Those circumstances make in-line inspection the only practical means of inspection.

Regarding Rep. Seaton's statements about Pump Station #1, BPXA respectfully submits several points of clarification. First, cleaning pig runs were "done previously," *i.e.*, prior to the runs in 2006 to which Rep. Seaton appears to refer, on the PBU OTLs. Second, based on experience from those prior cleaning pig runs in the Eastern Operating Area ("EOA") in the early 1990s in which some scale flakes or chips collected in the screens^{3/} of Pump Station #1,

^{2/} "Pigging" encompasses three different types of activities: runs by cleaning pigs, runs by maintenance pigs (which are a type of cleaning pig that are used both to ensure that lines are clean and for other operational reasons), and in-line inspection (colloquially known as "smart pigging").

^{3/} Pump Station #1 does not have a "filtration system."

there was some discussion between BPXA and Alyeska in 2006 about the potential presence of solids^{4/} in future pigging runs.^{5/} Third, it is not the case that "other arrangements were not made" to address this potential issue. To the contrary and among other things, modifications were made to Tank 110 in 2006 to allow it to handle any solids that were returned as a result of pigging runs, and a series of runs were completed in 2006.^{6/} Finally, subsequent pigging runs did not result in a particularly high "volume of sludge." Indeed, Alyeska assessed the pigging returns sent to Tank 110 during those 2006 pigging activities and reported a total of only 32 barrels of sediment and 292 barrels of water recovered for all the EOA (Flow Station ("FS") 2-to-Skid 50) and Western Operating Area ("WOA") (Gathering Center ("GC") 1-to-Skid 50) OTLs.^{7/} These totals are well within the base, sediment & water ("BS&W") specifications for the amount of oil that has been shipped through those lines.

2. **We would like to see a copy and analysis of the pressure log data for the pigging operations on BP transit lines in 1992 and again in 2006. We would like to determine if any increased pressure needed to move a pig down a line with a lot of contamination built up could have caused or played a role in the subsequent pipeline leaks.** [Request from September 14, 2006 memorandum, "BP Transit lines pigging information request"]

This request appears to assume a condition that did not exist. As described in response to Question 1, Alyeska assessed pigging returns from the 2006 pigging activities on the EOA and WOA OTLs and reported minimal returns of sediment and water. Similarly, when BPXA maintenance-pigged the Lisburne Production Center ("LPC") OTL (another North Slope OTL not part of the PBU) in 2006, the runs returned minimal solids (less than 5 gallons) and revealed minimal damage.

BPXA does not believe that pressure in the lines played a role in the OTL leaks in 2006. BPXA's analysis of the pipeline operating pressures associated with its extensive pigging operations in the WOA and EOA OTLs in 2006 shows no significant increases in pressure

^{4/} For purposes of these responses, "solids" means material in the lines that contains both organic and inorganic matter.

^{5/} BPXA is providing correspondence (without attachments, which in many cases are voluminous) with Alyeska that it has identified regarding this issue. BPXA has not conducted a forensic search of correspondence but believes it has identified the principal communications on this matter. This correspondence is attached hereto as Exhibit 1 and bears the Bates labels BPXA-AKLEGIS000001-29.

^{6/} See, e.g., Letter from Jerry Brossia, State of Alaska Joint Pipeline Office, to Robert I. Shoaf, Compliance Officer for Alyeska, copying Nolan Heath, et al. (Sept. 27, 2006) (reflecting approval for Alyeska to modify Tank 110, as described) (attached hereto as Exhibit 2). This correspondence bears the Bates labels BPXA-AKLEGIS000030-31.

^{7/} See Letter from Joynor, Alyeska Vice President of Oil Movements, to Brossia and Michael Thompson, State of Alaska Joint Pipeline Office (Dec. 20, 2006) (attached hereto as Exhibit 3). This correspondence bears the Bates labels BPXA-AKLEGIS000032-43. BPXA did not pig the segment of the WOA OTL from GC2 to GC1; this segment (also known as "OT21") was instead removed from service and decommissioned.

Figure 2. EOA: FS2-to-FS1 OTL, hourly average pressure data overlaid with pigging events.

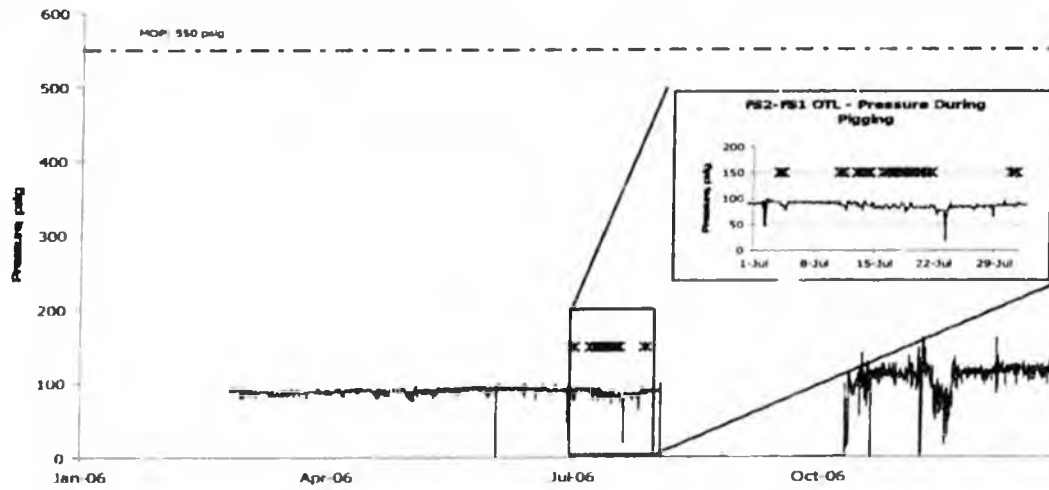


Figure 3. EOA: FS1-to-Skid 50 OTL, hourly average pressure data overlaid with pigging events.

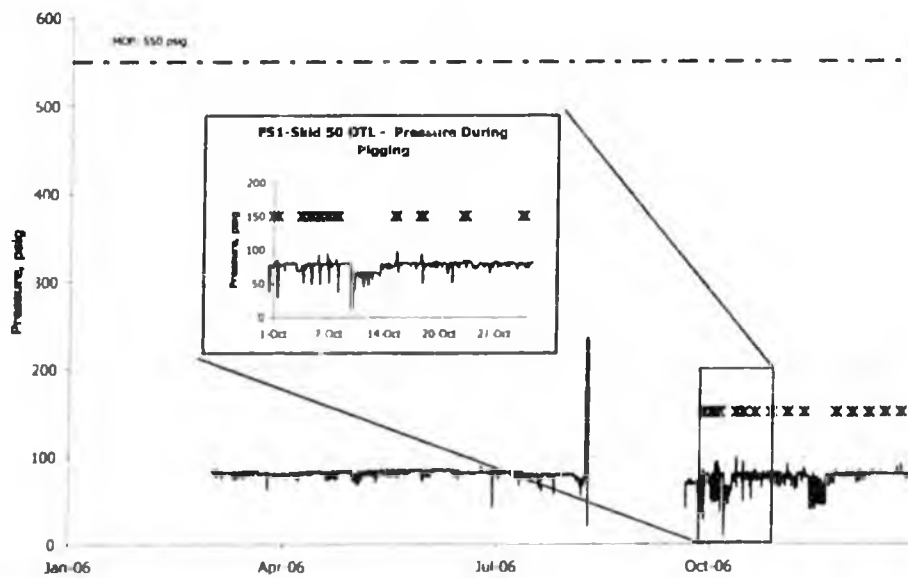


Figure 2. EOA: FS2-to-FS1 OTL, hourly average pressure data overlaid with pigging events.

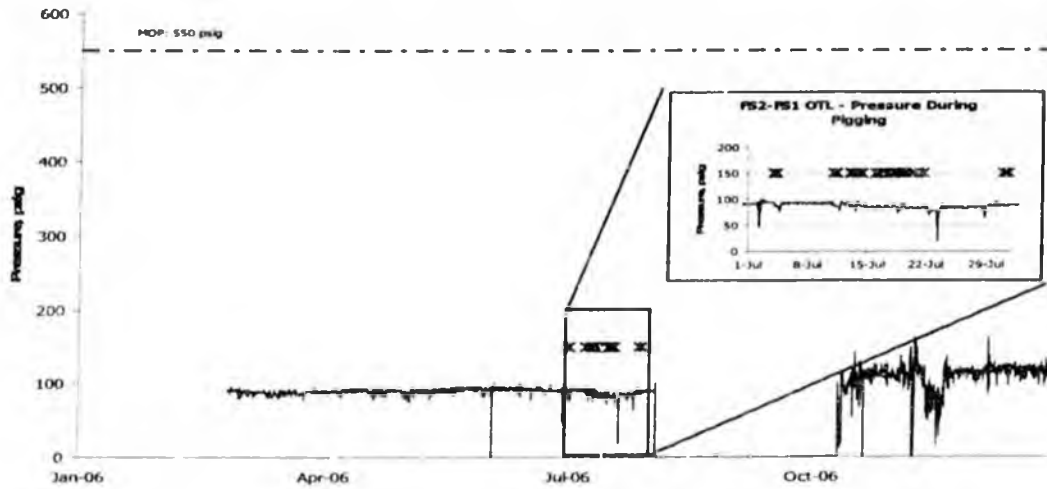


Figure 3. EOA: FS1-to-Skid 50 OTL, hourly average pressure data overlaid with pigging events.

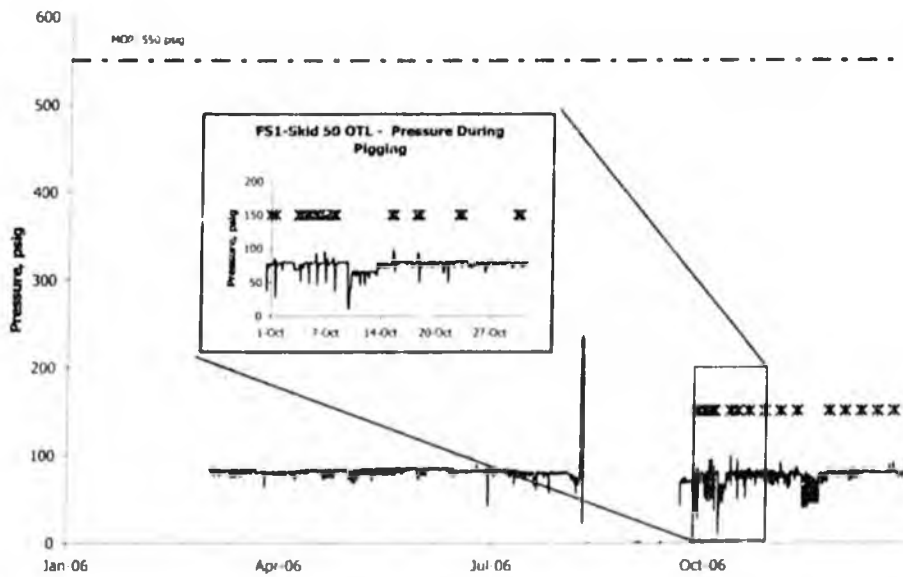
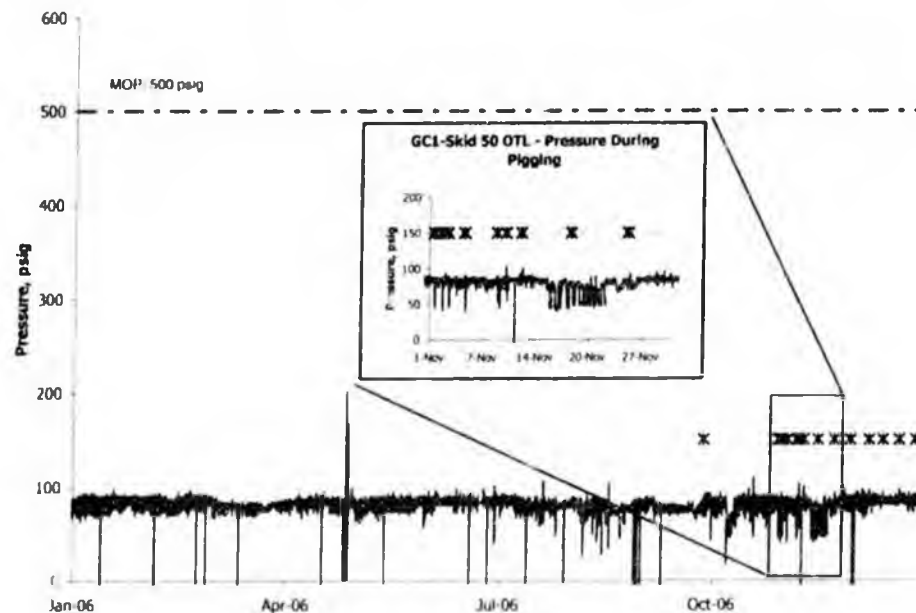


Figure 4. WOA: GCI-to-Skid 50 OTL, 5-minute average pressure data overlaid with pigging events.



3. Please provide the committee with a two-year summary of the pigging done on transit pipelines in fields that BP operates worldwide. Please specify which examples of the pigging frequency in other BP operated fields are similar to the Prudhoe Bay NS transit lines.

We have been provided information that standard industry practice is to pig often to prevent problems. We have been informed that each field has different oil and gas characteristics that require different procedures but nowhere to our understanding is regular pigging not done. If you have examples of such, please specify and provide details of the reasons for such a low maintenance determination. [Request from September 14, 2006 memorandum]

As Rep. Seaton notes, each field has different characteristics, including the type and quality of crude produced; the weather conditions and terrain in which the field is located; the level of pressure needed to move crude through pipelines; and whether the pipelines must be buried below ground or travel through water. The pipelines themselves are in turn specific to the field; among other things, pipelines differ in terms of metallurgy and size. These differences, in both fields and pipelines, are all part of the calculus that informs decisions about the maintenance procedures used on any given pipeline, including decisions whether and when to run cleaning and/or maintenance pigs and/or to conduct in-line inspections. As noted above in response to Question 1, BPXA's cleaning and maintenance pig data on the PBU OTLs show that there has been very little sediment build-up in them over time.

BPXA has previously explained that there are two different types of pipelines in the PBU that carry crude oil: OTLs, which carry sales quality oil downstream of processing facilities, and flow lines (sometimes also known as "production gathering lines"), which carry multi-phase flow from well heads to processing facilities. The leaks in 2006 occurred in the EOA and WOA OTLs, which are large-diameter, low-stress, above-ground lines. BPXA operates no other large-diameter, low-stress, above-ground OTLs and is not aware of any such lines being operated by any affiliate. Meaningful comparison to other lines of different sizes that are used in different service, under different conditions, and to transport oil of different quality and/or composition is thus not possible.

BPXA understands Rep. Seaton's statement regarding standard industry practice to refer to maintenance pigging. As BPXA has previously explained, it is not aware of any industry standard or recommended industry practice with respect to cleaning or maintenance pigging.

4. **Was the fact that the Prudhoe Bay transit lines were carrying much less than design volumes combined with the idea that the pipeline diameter could be reduced by sludge accumulation without increasing pump pressure or otherwise impacting the operational efficiency of the line a consideration in the determination not to clean or maintenance pig the transit lines?** [Question from September 14, 2006 memorandum]

BPXA has not identified any correlation between operational efficiency of the OTLs and the potential for reduced cross-sectional area, and that potential was not a consideration in the maintenance strategy of the OTLs. BPXA has also not observed any appreciable change in the operating pressure of the system due to the accumulation of solids.

The flow in the OTLs has naturally lost velocity over time as a result of the declining production of the field, and any change in cross-sectional area of the OTLs would likely have been masked by this natural decline in output. In any event, prior to the leaks BPXA saw no indications of restrictions in the line that might have led to reduced throughput.

BPXA's post-leak analysis bears out these observations. Even though BPXA understands, in retrospect, that the reduction in volume of oil may have contributed to the circumstances that led to the leaks in the OTLs in 2006, the reduction in the cross-sectional area of the lines due to build-up of solids was relatively minor during the 10-year period prior to the 2006 leaks. As discussed above in response to Question 1, cleaning and maintenance pigging of the OTLs in 2006 revealed very little sediment build-up over time.

- Oral questions from June 7 meeting

Rep. Seaton posed the following questions at the hearing on June 7:

5. What percentage of the lines that BP is operating in the Prudhoe Bay Unit will the 18 smart pig runs in 2007 encompass?

Of the 18 in-line inspections that BPXA has planned for 2007, 16 are being performed on PBU pipelines; the others are being performed on a Badami pipeline and a Milne Point Unit pipeline. These 16 PBU pipelines account for 10% (16 of 164) of all PBU pipelines transporting crude oil (both flowlines and OTLs).^{10/}

6. Has BP billed Conoco or Exxon for the repairs and the maintenance that arose from the shutdown, the bypass line and those repairs yet? If they have been billed, [has] that been turned down? If they haven't been billed, when [is BP] planning on billing for that?

BPXA's working interest owner partners, ExxonMobil and ConocoPhillips, have approved the funds and are making payments for the spill response, subsequent inspections, and bypass construction. BPXA has submitted an Authorization for Expenditure request for the OTL replacement to ExxonMobil and ConocoPhillips, and that request is under review. Neither ExxonMobil nor ConocoPhillips has refused to pay any bills sent to them regarding any of these activities.

Question from Rep. Johnson at June 7 meeting

7. Will the costs of replacement of the affected lines be treated as a tax deduction under [the Petroleum Production Tax] by BP?

BPXA has previously provided a written response to this question. On February 15, 2007, Doug Suttles, President of BPXA, submitted a letter on this subject to the Honorable Members of the Alaska State Legislature. A copy of that letter is attached hereto as Exhibit 4. This correspondence bears the Bates labels BPXA-AKLEGIS000044-45.

^{10/} The total number of pipelines does not include facility piping or well lines, which, due to the nature of their construction (*i.e.*, they are of smaller diameter and shorter lengths and include sharp bends), cannot readily be in-line inspected using current technology.

Question from Rep. Fairclough, who attended the June 7 meeting of the Committee, joined by Rep. Seaton

8. **Are the deconstructions of the affected OTLs being charged against the dismantlement, removal, & restoration ("DR&R") fund? If so, will that charge decrease the fund? How would such a charge affect the FERC and rate calculations in the future? Would such a charge result in the DR&R fund being hit twice, for removal of a portion of the line and for the expense of creating a new line?**

When oil and gas assets are constructed, an estimate of the costs for DR&R of those assets is established as a future obligation (or "liability") by the corporation owning the assets and recorded as a provision on its balance sheet. The DR&R provision is an accounting entry and does not represent the establishment of a specific "fund" or escrow account. When the assets (or a portion of the assets) are removed, the actual costs incurred in the related DR&R activity are charged against this provision such that the total DR&R provision for the assets (or portion of the assets) will decrease. When a new pipeline is installed, the DR&R provision is increased to reflect the new obligation associated with the new pipeline. Thus, in the case of the replacement of the PBU OTLs, the provision will be reduced with respect to the old pipeline and increased with respect to the new pipeline. This accounting treatment is in accordance both with U.S. Generally Accepted Accounting Principles and BPXA's internal accounting policy.

With regard to Rep. Fairclough's question about the Federal Energy Regulatory Commission ("FERC") and future rate calculations, the PBU OTLs are not common carrier pipelines and thus are not subject to FERC tariffs. The costs to remove and/or replace these OTLs will therefore not impact tariff rates.

* * *

These responses contain highly sensitive, private business information and documents. Accordingly, BPXA believes that the State is required to treat and maintain this letter and these documents as confidential under the commercial privacy protection afforded by Article I, Section 22 of the Alaska Constitution; AS 40.25.120(a)(4); and AS 40.25.120(b)(6). BPXA respectfully requests that the confidentiality of this letter and these documents be preserved and that, if you wish to consider whether any of this information or these documents should be made public, BPXA be provided 60 days notice prior to any such disclosure to any third party, including other governmental entities.

Hon. Carl Gatto
Hon. Craig Johnson
August 2, 2007
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Please feel free to call me if I may be of further assistance.

Sincerely,

 FOR
TONY BROCK

Tony Brock, Technical Director
BP Exploration (Alaska), Inc.

Attachments: as stated

cc: Hon. Charlie Huggins, Chair, Senate Resources Committee
Hon. Paul Seaton
Hon. Anna Fairclough (by overnight delivery only, without exhibits)

Exhibit

1

CORRESPONDENCE WITH ALYESKA RE: 2006 PIGGING OPERATIONS

Tab	Description	Bates Number(s)
1	E-mail chain entitled "GBP Oil Transit Line Pigging" (Mar. 27, 2006)	BPXA-LEGIS000001
2	E-mail from GPB, Prod Opt TL (BPXA) to J.D. Kling, Alyeska, entitled "Pig file comments OT21" (Apr. 15, 2006)	BPXA-LEGIS000002
3	Letter from Steve Marshall, President, BPXA, to Kevin M. Hostler, Alyeska President & Chief Executive Officer (Apr. 25, 2006)	BPXA-LEGIS000003
4	Letter from Hostler to Marshall, copying TAPS Owners Committee (May 12, 2006)	BPXA-LEGIS000004-6
5	Letter from Hostler to A.N. Bolea, BP Pipelines (Alaska) Inc., et al. (May 12, 2006)	BPXA-LEGIS000007-9
6	E-mail from Bruce J. Williams, BPXA, to Michael W. Joynor, Alyeska Manager of Oil Movements, copying Randal Buckendorf, BPXA, entitled "GR scan data for OT lines" (May 19, 2006 3:02 PM)	BPXA-LEGIS000010
7	E-mail from Per Wangstrom, BPXA, to Williams et al., entitled "Latest GPB Oil Transit Line Solids Loading Estimate" (May 19, 2006 3:18 PM)	BPXA-LEGIS000011
8	Letter from Joynor to Marshall, copying Kathy Zinn, Alyeska (May 22, 2006)	BPXA-LEGIS000012
9	Letter from Maureen L. Johnson, BPXA Vice President for Greater Prudhoe Bay ("GPB"), to Joynor (May 23, 2006)	BPXA-LEGIS000013
10	E-mail from Williams to Joynor, copying Brett W. Leach et al., entitled "Lisburne solids measurements" (May 31, 2006)	BPXA-LEGIS000014
11	E-mail from Joynor to Katharine Fontaine, copying Gregg E. Knutsen, entitled "Pigging Assessment Discussion" (June 2, 2006)	BPXA-LEGIS000015
12	Letter from Kemp Copeland, GPB Field Manager, to Joynor (June 6, 2006)	BPXA-LEGIS000016
13	Letter from Hostler to Marshall, copying Zinn (June 7, 2006)	BPXA-LEGIS000017-18
14	E-mail from Fontaine to Joynor, copying Williams, entitled "Final Solids information from BPXA" (June 22, 2006)	BPXA-LEGIS000019-20
15	Letter from Copeland to Joynor (June 27, 2006)	BPXA-LEGIS000021
16	Letter from Joynor to Johnson, copying Hostler et al. (June 29, 2006)	BPXA-LEGIS000022-23
17	Letter from Marshall to Hostler (July 24, 2006)	BPXA-LEGIS000024-25

CORRESPONDENCE WITH ALYESKA RE: 2006 PIGGING OPERATIONS

Exhibit I (con't)

Tab	Description	Bates Number(s)
18	Letter from Marshall to Hostler (Aug. 9, 2006)	BPXA-LEGIS000026
19	E-mail from Joynor to Ian G. Livett, BPXA, entitled "Existing level of tank bottom solids in Tank 110 at PS01" (Sept. 29, 2006)	BPXA-LEGIS000027
20	E-mail discussion among Perry A. Markley, Alyeska; Livett; and Joynor, entitled "APSC EOA S&W Results" (Oct. 30-Nov. 1, 2006)	BPXA-LEGIS000028-29