

5/11/07

PRESENTA-

TION:

NATURAL

GAS

PIPELINE

PROJECT

Gas Line Consultants

You heard the producers' experts,
now hear from others.

Guest speakers:

Spencer Hosie, Rick Harper, Don Shepler, Ken Minesinger, Scott Hobbs, and
Bill Sparger.



1:00-3:00 Friday May 11

ROOM 124

House Rules
JBCjr

ALASKA GASLINE INDUCEMENT ACT

Testimony by C. Scott Hobbs

House Resources Committee

May 11, 2007

Discussion Topics

- Advantages and risks of contracting for FT vs. owning the pipeline
- Accounting for FT Agreements
- Producer Economics
- Conclusions

Advantages and Risks of Contracting for FT vs. Owning the Pipeline

Advantages

- Avoided front end capital requirements
- Improved project economics
- Risks avoided and/or allocated to pipeline sponsor
- Avoided drain on human resources
- Regulatory and construction expertise of experienced pipeline operators

Risks

- Cost Overruns on pipeline
- Ability to finance the project
- Loss of control over Project
 - Design and Route
 - Project Schedule
 - Tariff provisions and rate designs
 - Expansions for competitors

Accounting for Firm Transportation Agreements

- FT agreements are not debt, not capitalized or recorded on the balance sheet.
- When disclosed - in a footnote or supplemental disclosure in the 10-K. (ConocoPhillips examples)
- FT agreements should enhance the financial position of a producer/shipper.
- Ratings Agencies will consider contractual obligations and incremental cash flows created by that obligation – e.g., marketable vs. stranded gas reserves.

Producer Economics

- Department of Natural Resources' model of the producer economics is reasonable based on the best information currently available.
- Producers have provided no economic studies to support their contention that this project is not commercially viable.
- The primary drivers for the producer economics are:
 - Gas reserves and deliverability
 - Treatment and transportation costs to market
 - Commodity prices
 - Additional development costs
 - Operating costs, taxes, and royalties

Producer Economics

- Difficult to construct a reasonable worst case scenario where the producers do not continue to enjoy favorable economics with significant upside potential.
- Including the large capital costs and lower returns of the gas pipeline in the project economics reduces the economic metrics (IRR, NPV and PI) to more publicly "acceptable" levels.
- Capitalizing the producer FT commitment in these economic calculations is inconsistent with the accounting treatment of these costs in their financial statements.

Conclusions

- There are real advantages to the producers in contracting for FT vs. constructing and owning the pipeline.
- Contracting for FT on an independently owned pipeline will not adversely affect the producers financial statements. In fact, it should enhance their financial position.
- The producers should enjoy favorable returns under any reasonable scenario, whether they own the pipeline project or contract with a third party.

ALASKA NATURAL GAS PIPELINE PROJECT

**Testimony on AGIA
of W. H. Sparger**

**House Resources Committee
May 11, 2007**

EPC

Energy Project Consultants, LLC

Introduction

- William H. (Bill) Sparger
- Energy Project Consultants. LLC
- Consultant for Administration AGIA team
- Over 35 years of experience in natural gas pipeline project management, engineering and construction management – onshore, offshore and LNG
- Engineering management positions at two major lower 48 natural gas pipeline companies

Terminology

- “Project” – the natural gas pipeline following the southern Alaska/Canada route
- “Producers” – existing three North Slope oil producers
- “North America” – United States and Canada

Unfounded “Concerns”

- Shippers bear all of the financial risks of project cost overruns
- Producers must have economic certainty
- Producers are the only ones qualified to construct the project
- Schedules with milestone dates drive up the project cost – “firm dates are bad”

Unfounded “Concerns”

- Shippers bear all of the financial risks of project cost overruns
 - Negotiated rates – risk sharing may be included
 - Firm transportation
 - Rockies Express model

Unfounded “Concerns”

- Producers must have economic certainty
 - Supply/upstream – as certain as it gets
 - Pipeline/midstream – negotiated rates
 - Market/downstream – a normal business risk

Unfounded “Concerns”

- Producers are the only ones qualified to construct the project
 - Producers do not normally construct or own onshore natural gas pipelines in the Lower 48
 - Pipeline companies execute large projects frequently and for a living – Rockies Express
 - North American pipeline companies are very familiar with applicable regulatory requirements

Unfounded “Concerns”

- Schedules with milestone dates drive up the project cost – “firm dates are bad”
 - Realistic schedules are a project necessity
 - Projects without schedules tend to go on indefinitely
 - Schedules can be (and are) adjusted as circumstances change – subject to evaluation of overall business financial impact

Other Unfounded “Concerns” and issues

- Leading edge technology is required to reduce project costs
- Mega projects are “different
- AGIA requirement for a “detailed” project description is premature and costly
- Currently proposed schedule may be able to be shortened

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 the 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



- 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., Intervenors 
 - 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
T: 415.247.6000 F: 415.247.6001

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

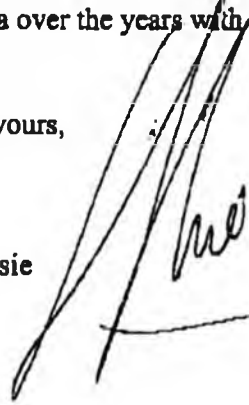
May 15, 2007

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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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[Table of Contents](#)[Index to Financial Statements](#)

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>

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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.

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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.
- Særv/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.

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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).

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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

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