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Patrick T. Mulva
Vice President and Controller

ExxonMobil

November 9, 2006

Ms. Jill S. Davis
Branch Chief
U. S. Securities and Exchange Commission
Division of Corporation Finance
100 F Street, N.W., Stop 7010
Washington, D.C. 20549

Re: Exxon Mobil Corporation
Form 10-K for the Fiscal Year ended December 31, 2005
Filed February 28, 2006
Form 10-Q for Fiscal Quarters ended March 31, 2006 and June 30, 2006
Filed May 4, 2006 and August 4, 2006
File No. 1-02256

Dear Ms. Davis:

On behalf of Exxon Mobil Corporation, please find enclosed our responses to your comments regarding the above filings set forth in your letter of September 28, 2006. We appreciate your agreement to extend the timing of our responses pursuant to the October 3, 2006, letter from Mr. David Levy to Mr. Jonathan Duersch. Our responses are numbered to correspond to the numbered comments in your letter.

We acknowledge that:

- the company is responsible for the adequacy and accuracy of the disclosure in the filing;
- staff comments or changes to disclosure in response to staff comments do not foreclose the Commission from taking any action with respect to the filing; and
- the company may not assert staff comments as a defense in any proceeding initiated by the Commission or any person under the federal securities laws of the United States.

If you desire clarification of our responses, please direct any questions to Mr. David Levy, Financial Reporting Manager, at 972-444-1290.

Very truly yours,

By: /s/ Patrick T. Mulva

Name: Patrick T. Mulva
Title: Vice President and Controller

Attachments

c: Jonathan Duersch
Ronald Winfrey

Consolidated Statement of Cash Flows, page 51

1. *Please provide us with a reconciliation of the changes in your comparative balance sheet components to your statement of cash flows for each period presented and include quantified detail of components in "all other items, net". Additionally, please demonstrate how your disclosure in Note 4 has fully complied with the requirement to provide supplemental information about non-cash investing and financing activities. Based on our comparison of the amounts reported on the face of the balance sheet it was not readily apparent how the year-to-year changes were reflected in the amounts reported in your statement of cash flows or further disclosed in Note 4. For example, but without limitation, we were unable to determine whether or not the change in the comparative notes and accounts receivable and long-term debt balance sheet amounts were related exclusively to foreign currency exchange rat e changes, non-cash transactions or cash flow classification. Refer to paragraph 29 of SFAS 95.*

   Below are reconciliations of the change in selected balance sheet accounts detailed on the statement of cash flow for the periods 2005, 2004 and 2003. The reconciliations identify the reported indirect method cash flow adjustment to net income and the reconciling non-cash changes in the account balances. Reconciliations for the other balance sheet accounts that are detailed on the statement of cash flow (e.g., annuity provisions, accrued liability provisions, inventories and prepaid taxes and expenses) are not provided as the reconciling item is limited to foreign exchange. The sign convention in the tables is debits/(credits).

	2005	2004	2003
		(millions of dollars)	
Deferred income tax liabilities, net			
See Income, Excise and Other Taxes footnote for short-term and long-term asset and liability components			
Beginning of year balance	$ (18,952)	$ (19,271)	$ (15,106)
Cash flow statement adjustment - (increase) / decrease	429	1,134	(1,827)
Foreign exchange	975	(891)	(1,235)
Minimum pension liability	(90)	(49)	(381)
Unrealized gain/(loss) on stock investments	236	53	(331)
Other			
Acquisitions and sales of affiliates		72	
Accounting change - FAS 143 adoption			(391)
End of year balance	$ (17,402)	$ (18,952)	$ (19,271)

	2005	2004	2003
Notes and accounts receivable, net			
Beginning of year balance	$ 25,359	$ 24,309	$ 21,163
Cash flow statement adjustment - (increase) / decrease	3,700	472	1,286
Foreign exchange	(1,547)	1,131	1,998
Other			
Acquisitions and sales of affiliates		(35)	15
Tax refund applied to tax liability	(270)	(518)	
Consolidation of affiliate	242		
Settle partner receivable for higher ownership			(153)
End of year balance	$ 27,484	$ 25,359	$ 24,309

	2005	2004	2003
	(millions of dollars)		
Accounts payable and accrued liabilities and income taxes payable, excluding short-term deferred income tax liabilities			
Beginning of year balance	$ (39,214)	$ (31,878)	$ (27,765)
Cash flow statement adjustment - (increase) / decrease	(7,806)	(6,333)	(1,130)
Foreign exchange	2,601	(1,567)	(2,943)
Other			
Acquisitions and sales of affiliates		46	
Accounting change - FIN 46 adoption			(40)
Tax refund applied to tax liability	270	518	
Consolidation of affiliate	(242)		
End of year balance	$ (44,391)	$ (39,214)	$ (31,878)

The table below details the items included in "All other items - net" for the periods 2005, 2004 and 2003. In making decisions on what major classes of reconciling items to include in the Statement of Cash Flows, we consider the nature and significance of the items. We concluded that the nature and significance of the items in "All other items - net" were not individually significant to a meaningful understanding of ExxonMobil's overall cash flow from operations. Therefore, we did not separately include them in the Statement of Cash Flows or supplemental disclosures.

	2005	2004	2003
	(millions of dollars)		
Change in Other assets, excluding deferred income taxes	$ 18	$ (44)	$ 277
Change in Deferred credits and other long-term obligations	(103)	139	(1)
Foreign exchange on non-functional currency cash	(267)	129	211
Foreign exchange on non-functional currency debt	276	(136)	(75)
Non-cash asset retirement obligation additions to Accrued liabilities	(226)	(57)	(317)
Tax on exercised stock options credited to retained earnings	224	182	108
Interest on discounted debt, prior year dry hole spending, and all other	(140)	169	69
All other items - net	$ (218)	$ 382	$ 272

Financial statement Note 4, "Cash Flow Information" discusses the non-cash change in Mobil Services (Bahamas) Ltd. long-term debt in 2005. There were no other significant non-cash investing or financing transactions in 2005, 2004 and 2003. Below are reconciliations of the change in the balance sheet amounts for short-term debt ("notes and loans payable") and long-term debt for the Statement of Cash Flows for the periods 2005, 2004 and 2003. The reconciliations identify the reported cash flows and the reconciling non-cash transactions. Comment 1 at the bottom of the table discusses the Mobil Services (Bahamas) Ltd. debt change. The FIN 46 item in Comment 2 to the table was disclosed in Note 8, "Equity Company Information" in 2003. None of the other non-cash reconciling items were significant to be included in financial statement Note 4. The sign convention in the table is debits/(credits).

Reconciliation of Changes in Debt	2005		2004		2003	
	Short-Term	Long-Term	Short-Term	Long-Term	Short-Term	Long-Term
			(millions of dollars)			
Beginning of year balance	$ (3,280)	$ (5,013)	$ (4,789)	$ (4,756)	$ (4,093)	$ (6,655)
Cash flows:						
(Additions) to short-term and long-term	(377)	(195)	(450)	(470)	(715)	(127)
Reductions in short-term and long-term	687	81	2,243	562	1,730	914
Net reductions less than 90-day maturity	1,306		66		322	
Non-cash changes:						
Foreign currency rate changes	59	19	(49)	(21)	(192)	(45)
Interest accruals on discounted debt	(42)	(143)	(133)	(128)	(127)	(115)
Long-term to short-term reclassification/other	(124)	159	(168)	138	(1,698)	1,633
Deconsolidations (see Comment 1)		(1,128)		(338)		
FIN 46 consolidations (see Comment 2)					(16)	(361)
End of year balance	$ (1,771)	$ (6,220)	$ (3,280)	$ (5,013)	$ (4,789)	$ (4,756)

Comment 1: During 2005, Mobil Services (Bahamas) Ltd. issued a $972 million variable rate note due 2035 and a $156 million variable rate note due 2016 to a consolidated ExxonMobil affiliate. During 2004, Mobil Services (Bahamas) Ltd. issued a $311 million variable rate note due 2034 and a $27 million variable rate note due 2011 to a consolidated ExxonMobil affiliate. The $972 million and $311 million notes are detailed in the long-term debt footnote (Note 12 in 2005 Form 10-K). These affiliates were later deconsolidated when ExxonMobil no longer had control in 2005 and 2004, respectively, and the notes classified as long-term third-party debt.

Comment 2: ExxonMobil implemented Financial Accounting Standards Board Interpretation No. 46(R) in the fourth quarter of 2003 by consolidating three operating entities in which the Corporation had a variable interest primarily through lease commitments and certain guarantees extended by the Corporation. These entities were previously accounted for under the equity method.

Note 8 Property Plant and Equipment and Asset Retirement Obligation

2. *We note your capitalized interest costs. Please disclose your accounting policy for interest capitalization.*

We will expand our disclosure in Note 1, "Summary of Accounting Policies – Plant, Property and Equipment" in the Form 10-K for the year ended December 31, 2006, as follows:

> Interest costs incurred to finance expenditures during the construction phase of multi-year projects are capitalized as part of the historical cost of acquiring the constructed assets. Capitalized interest costs are included in property, plant and equipment and are depreciated over the service life of the related assets.

3. *We note your disclosure indicating that you do not record asset retirement obligations for downstream and chemical facilities. Please expand your disclosure to address whether there is a legal obligation associated with the retirement of your downstream and chemical facilities. To the extent legal asset retirement obligations exist, it appears you may need to expand your disclosures to address why you do not record the associated asset retirement obligations. In the event you believe asset retirement obligations cannot be reasonably estimated please expand your disclosures stating that fact and identify the reasons those obligations cannot be reasonably estimated. Refer to paragraph 22 of SFAS 143.*

   We will expand our disclosure in Note 8, "Property, Plant and Equipment and Asset Retirement Obligations" in the Form 10-K for the year ended December 31, 2006, as follows:

   > Asset retirement obligations for downstream and chemical facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations, and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations.

<u>Note 14 Litigation and Other Contingencies, page 68</u>

4. *Please expand your disclosures to clarify your policy regarding litigation and contingencies that are reasonably possible. Please explain how you determine whether or not to disclose a particular matter or matters which may be significant individually or in the aggregate.*

   We will expand our disclosure in the first paragraph of Note 14, "Litigation and Other Contingencies" in the Form 10-K for the year ended December 31, 2006, as follows:

   > A variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits and tax disputes. Management has regular litigation and tax reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. The Corporation does not record liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated, or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasib le, an estimate of the possible loss.

ExxonMobil will continue to defend itself vigorously in these matters. Based on a consideration of all relevant facts and circumstances, the Corporation does not believe the ultimate outcome of any currently pending lawsuit against ExxonMobil will have a materially adverse effect upon the Corporation's operations or financial condition.

We will similarly expand the “Litigation and Other Contingencies” section of our MD&A disclosure on critical accounting policies.

5. *We note that potential domestic lawsuits or claims exist regarding certain environmental contamination from the use of methyl tertiary butyl ether (MTBE). We understand that uncertainty exists as to the legal merits of these claims or how claims may potentially be settled. Please tell us how you have evaluated the likelihood that a liability may have been incurred relating to your use of MTBE.*

As part of our regular review process, management, in consultation with internal and external counsel, has determined that we have no current MTBE lawsuits or claims which meet the FAS 5 recognition criteria to establish an accrued liability. This is due to considerable uncertainties about both the viability of plaintiffs' liability allegations and determination as to whether or not the plaintiffs have incurred any damages.

Supplemental Information on Oil and Gas Exploration and Production Activities (unaudited), page 76

6. *Please remove the subtotal “Total before year end price/cost revisions” and include the impact of year-end price/cost revisions within the applicable line item consistent with Illustration 4 in Appendix A of SFAS 69. Please explain how you calculated the amount reported in the revisions and improved recovery line items as compared to the year end price/cost revisions line item.*

We believe that the disclosure of the effects of the year-end price/cost revisions was consistent with our reporting obligations. The inclusion of the line showing "Total before year end price/cost revisions" enhances the disclosure by providing additional information to the investor reflecting management's basis for investment decisions.

As previously disclosed on page 80 of our 2005 Form 10-K, the use of year-end prices for reserves estimation introduces short-term price volatility into the process since annual adjustments are required based on prices occurring on a single day. ExxonMobil believes that this approach is inconsistent with the long-term nature of the natural resources business where production from individual projects often spans multiple decades. The use of prices from a single date is not relevant to the investment decisions made by the company and annual variations in reserves based on such year-end prices are not of consequence to how the business is actually managed.

Additionally, we believe that the appropriateness of disclosure for this matter should be considered in the light of Paragraph 41 of the Statement of Financial Accounting Standards (SFAS) No. 69, "Disclosures about Oil and Gas Producing Activities", which states that the illustrations present formats that <u>may</u> (underline added) be used to disclose certain information required by the statement. In this particular instance, we believe that the format in our 2005 Form 10-K provided more useful disclosure than that in Illustration 4 in Appendix A of SFAS 69.

"Revisions" line items are calculated based on evaluation or revaluation of already available and/or new geologic, reservoir or production data as well as changes to royalty rates and underlying price assumptions. These underlying price assumptions are the same assumptions that are used by management for capital investment decisions and in the company's annual planning and budgeting processes. "Improved recovery" line items are additions to existing fields attributable to the initiation or the expansion of commercial-scale secondary or tertiary recovery programs. The same price assumptions used in calculating "revisions" are used for calculating "improved recovery" additions.

The amounts shown on the "Year end price/cost revisions" line represent the difference in reserves volume from calculating reserves based on price and cost assumptions used by management for capital investment decisions and in the company's annual planning and budget process and those reserves volumes calculated on the basis of December 31 prices.

7. *Please explain why you believe it is appropriate to disclose other than proved reserve quantities. Note that Instruction 5 to Item 102 of Regulation S-K states that estimates of oil or gas reserves other than proved are not permitted to be disclosed in any document publicly filed with the Commission.*

We believe our disclosure was appropriate given our reporting obligations under Regulation S-K, Item 102, Instruction 5. Paragraph 16 of FAS 69 states that if important economic factors affect an enterprise's proved reserves, explanation shall be provided. As stated in our response to comment number 6, the use of year-end prices for reserves estimation introduces short-term price volatility into the process.

The method we used to portray our proved reserves provides investors with both the volumes that are relevant to how ExxonMobil manages its investment decisions as well as the volumes calculated using year-end prices. We believe this disclosure is very useful to investors in making informed investment decisions while complying with Securities and Exchange Commission regulations.

Also, we believe that the volumes we disclosed were proved reserves based on the price assumptions we use for planning and budgeting processes. As stated in previous comment letters in 2004, we disagreed with the Securities and Exchange Commission's interpretation of Regulation S-X, Rule 4-10 requiring the use of year-end prices in determining proved reserves. We also believed that the use of year-end prices and costs for purposes other than the calculation of the Standardized Measure of Oil and Gas is not mandated by SFAS 69. Commencing with 2004 results in our Form 10-K for 2004, however, we said that we would incorporate year-end pricing into our proved reserves estimates. We have done this but we have also shown the proved reserves volumes consistent with how we believe they should be calculated.

8. *Please clarify the nature of proved reserves attributed to Imperial Oil Limited. It is our understanding that a certain portion includes Bitumen and other heavy oil.*

The proved reserves attributed to Imperial Oil Limited in the Supplemental Information on Oil and Gas Exploration and Production Activities are related to conventional oil and gas producing operations in Western and offshore Eastern Canada and heavy oil production near Cold Lake in the province of Alberta. At year-end 2005, after adjustment for year-end price effects, proved reserves attributable to Imperial Oil Limited for conventional oil and natural gas liquids accounted for 83 million barrels, heavy oil (Cold Lake) accounted for 551 million barrels while natural gas accounted for 747 billion cubic feet.

The Cold Lake reserves are a very heavy crude oil contained in the Clearwater formation and are produced through pumping unit equipped wells. Cyclic steam stimulation (alternating cycles of high pressure steam injection, soak and production for each well) is used to improve flow of the crude oil to the well bore, increasing recovery efficiency.

Proved oil and gas reserves attributable to Imperial Oil Limited do not include any reserves for the Syncrude tar sands operation. Syncrude recovers tar sands using open-pit mining methods to extract the crude bitumen. For Form 10-K reporting purposes, the Syncrude volumes are considered as mining and reported separately from the proved oil and gas reserves.

Engineering Comments

Form 8-K dated February 15, 2006

9. *We note that you have reported proved reserve additions of 1.6 billion oil equivalent barrels in Qatar. Please address each of the following:*

   a. *Tell us how you are entitled to these reserves.*

   The 2005 proved reserve additions of 1.6 billion oil-equivalent barrels (OEB) for Qatar reported in the February 15, 2006, Form 8-K filing are predominantly related to two major developments, Ras Laffan LNG 3 (RL 3) and the Al Khaleej Gas project, along with revisions related to other Qatar LNG ventures with Qatar Petroleum. The Ras Laffan LNG 3 (RL 3) development had a proved reserve addition of 1.1 billion OEB, and phase one of the Al Khaleej Gas project had a proved reserve addition of 0.4 billion OEB. The other Qatar LNG ventures had cumulative proved reserve additions of 0.1 billion OEB due to technical and working interest related revisions.

   The State of Qatar granted entitlement to the reserves related to the Ras Laffan LNG 3 (RL 3) development under a Development and Fiscal Agreement (DFA) and to the reserves related to the Al Khaleej Gas project under a Development and Production Sharing Agreement (DPSA). The entitlement to the reserves related to the other Qatar LNG ventures were granted by the State of Qatar under separate existing DFA agreements.

   The DFA and DPSA agreements provide the right to develop, extract, and market the produced hydrocarbons and obligate the participants to fund their respective share of the capital investments and costs. Under the DFA agreements, participant entitlements are based on their working interest share. Under the DPSA agreement, participant entitlements are based on cost recovery, profit sharing, and related fiscal terms using the “economic interest” method to determine reserve quantities.

   b. *Indicate whether or not you have contracts in place to sell the gas reserves claimed in Qatar. If not, tell us where and how you intend to market the LNG from the Qatar gas project.*

   The reserve addition of 1.6 billion oil-equivalent barrels (OEB) in Qatar in 2005 is supported by both Qatari domestic and export sales. Pipeline gas from the Al Khaleej Gas project, which commenced operation in 2005, is sold under long-term sales agreements into the domestic market in Qatar. This project contributed 0.3 billion OEB of natural gas and 0.1 billion OEB of related condensate and natural gas liquids to the total reserve addition.

The remaining 1.2 billion OEB reserve addition is based on 1.0 billion OEB of LNG exports from Qatar and 0.2 billion barrels of related condensate and gas liquids that are produced and recovered from the gas and are sold into commodity markets.

The market for LNG is comprised of (i) long-term contract sales and (ii) sales into commodity markets for natural gas (i.e., actively traded markets such as the United States and Europe) in a manner similar to sales of crude oil and crude oil products. The 1.0 billion OEB reserve addition relating to LNG is supported by both types of sales. A portion of the booked reserves is underpinned by existing long-term contracts. The remainder of the reserve addition is supported by anticipated sales into global commodity markets and additional term sales.

c. *Indicate whether or not your financing arrangements related to the Qatar gas project with Qatar Petroleum require you to have contracts in place to sell the reserves that will be processed in the related facilities.*

The financing arrangements are based on a mixture of LNG sales as described in section (b). The terms of a planned $10 billion debt program (70% from lenders/investors; 30% in co-loans from ExxonMobil) and the initial debt offering in 2005 under that program, which were accepted by banks and bond investors, recognized the liquidity of the targeted gas markets and did not require that all of the volumes be contracted when the initial financing was arranged. The financing terms also do not require that additional volumes be contracted for additional debt to be incurred.

d. *Furnish to us the future production schedules and cash flow projections with gas price assumptions, capital costs, operating costs and transportation costs you and your financiers considered in making your investment decision.*

Attachments I, II and III contain information provided to potential lenders/investors in the Ras Laffan LNG II (RL II) and Ras Laffan LNG 3 (RL 3) debt offering made in 2005. The planned $10 billion debt program, which is being raised in separate tranches, provides funding for investment expenditures of the RL II (trains 3, 4 and 5) and RL 3 (trains 6 and 7) developments. The first tranche of bonds ($2.25 billion) was issued in 2005, and the second tranche ($1.55 billion) was issued in the third quarter of 2006. Both offerings were highly rated -- A1 by Moody's, A by S&P and A+ by Fitch -- and were significantly oversubscribed. The material in the attachments was prepared by third party consultants hired on behalf of lenders/investors for the 2005 debt offering, and it was distributed to potential lenders/investors on a confidential basis.

e. *Please submit a brief history of the development of the North field as well as a narrative of your future development plans.*

The North Field was discovered in 1971 and is recognized as the largest nonassociated gas field in the world. First gas production for domestic markets started in 1991.

Qatar Liquefied Gas Company Ltd. (Qatargas) was formed in 1984 to produce gas and initiate LNG sales from the North Field in Qatar. ExxonMobil's involvement with the North Field began in 1992 when a Mobil affiliate acquired an interest in Qatargas. This venture began producing in 1996 from its allocated block within the North Field and selling LNG under a long-term contract to Japan.

In 1993, Qatar Petroleum (QP) and Mobil formed another joint venture, Ras Laffan LNG Ltd., to develop and produce gas from another block of the North Field allocated by the State of Qatar. This venture, RL I, began deliveries from the first LNG train in 1999 and the second LNG train in 2000 on a plot neighboring Qatargas in Ras Laffan City. Another QP/ExxonMobil joint venture, Ras Laffan LNG II, was formed in 2001 to develop gas from neighboring blocks of the North Field. Production and LNG sales began from a third train in 2004, a fourth in 2005, and a fifth train will start up in 2007. Further LNG ventures, Qatargas II and Ras Laffan LNG 3, were formed in 2004 and 2005, respectively, to continue to develop and produce gas from the North Field.

In 2000, the State of Qatar and an affiliate of ExxonMobil executed a Development and Production Sharing Agreement to develop and produce gas for domestic consumption. The first phase of gas production from the Al Khaleej Gas project began in 2005. The second phase is expected to begin production in 2009.

In addition, ExxonMobil has signed a Heads of Agreement for a Gas-to-Liquids project and is planning the development of North Field gas resources to be allocated by the State of Qatar for the project.

Attachment I
Train Performance*

Train Volumes (units as indicated)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Train 3 FOB LNG Production (MT)	4.7	4.7	4 .7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Train 4	1.0	2.6	3.3	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Train 5	0.0	0.0	3.1	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	3.7
Train 6	0.0	0.0	0.0	2.9	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Train 7	0.0	0.0	0.0	0.0	1.6	7.7	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Total FOB LNG Production	**5.7**	**7.3**	**11.1**	**17.0**	**23.5**	**29.6**	**29.7**	**29.7**	**29.7**	**29.7**	**29.7**	**29.7**	**29.7**	**29.7**	**29.7**	**29.7**	**29.7**	**29.7**	**29.7**	**29.7**	**29.7**	**29.7**	**28.7**
Train 3 Inlet Gas (bcf)	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2
Train 4	63.7	160.9	200.7	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0
Train 5	0.0	0.0	189.9	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	286.0	227.4
Train 6	0.0	0.0	0.0	177.6	480.1	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9
Train 7	0.0	0.0	0.0	0.0	99.3	476.3	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9	481.9
Total Inlet Gas	**323.9**	**421.1**	**650.8**	**1009.8**	**1411.7**	**1790.5**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1796.1**	**1737.5**
Train 3 Field Condensate (mmbbl)	8.0	7.9	7.8	7.7	7.7	7.6	7.5	7.4	7.4	7.3	7.2	7.1	7.1	7.0	6.9	6.9	6.8	6.7	6.7	6.6	6.5	6.5	6.4
Train 4	1.9	4.9	6.1	8.6	8.5	8.4	8.3	8.2	8.2	8.1	8.0	7.9	7.8	7.8	7.7	7.6	7.5	7.5	7.4	7.3	7.2	7.2	7.1
Train 5	0.0	0.0	5.8	8.7	8.6	8.5	8.4	8.3	8.2	8.2	8.1	8.0	7.9	7.8	7.8	7.7	7.6	7.5	7.5	7.4	7.3	7.2	5.7
Train 6	0.0	0.0	0.0	5.6	15.0	14.9	14.8	14.6	14.5	14.3	14.2	14.1	13.9	13.8	13.6	13.5	13.4	13.2	13.1	13.0	12.8	12.7	12.6
Train 7	0.0	0.0	0.0	0.0	3.1	14.9	14.9	14.8	14.6	14.5	14.3	14.2	14.1	13.9	13.8	13.6	13.5	13.4	13.2	13.1	13.0	12.8	12.7
Total Field Condensate	**9.9**	**12.8**	**19.7**	**30.6**	**42.9**	**54.3**	**54.0**	**53.4**	**52.9**	**52.4**	**51.8**	**51.3**	**50.8**	**50.3**	**49.8**	**49.3**	**48.8**	**48.3**	**47.8**	**47.4**	**46.9**	**46.4**	**44.5**
Train 3 Plant Condensate (mmbbl)	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Train 4	0.3	0.7	0.9	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Train 5	0.0	0.0	0.9	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.1
Train 6	0.0	0.0	0.0	0.7	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Train 7	0.0	0.0	0.0	0.0	0.4	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Total Plant Condensate	**1.5**	**1.9**	**3.0**	**4.5**	**6.3**	**7.9**	**8.0**	**8.0**	**8.0**	**8.1**	**8.1**	**8.2**	**8.2**	**8.2**	**8.3**	**8.3**	**8.4**	**8.4**	**8.4**	**8.5**	**8.5**	**8.6**	**8.3**
Train 3 Propane (MT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Train 4	0.0	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Train 5	0.0	0.0	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Train 6	0.0	0.0	0.0	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5
Train 7	0.0	0.0	0.0	0.0	0.1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Propane	**0.0**	**0.2**	**0.4**	**0.8**	**1.1**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.5**
Train 3 Butane (MT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Train 4	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Train 5	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
Train 6	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Train 7	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Butane	**0.0**	**0.1**	**0.2**	**0.3**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Train 3 Sulphur (MT)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Train 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Train 5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Train 6	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Train 7	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	0.1	**0.1**	**0.1**	**0.1**	**0.3**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
Train 3 Helium (MT)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Train 4	0.1	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Train 5	0.0	0.0	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4
Train 6	0.0	0.0	0.0	0.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Train 7	0.0	0.0	0.0	0.0	0.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Total Helium	**0.6**	**0.8**	**1.2**	**2.1**	**3.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.2**

*Source: Stone & Webster Consultants Limited reports prepared for the 2005 Bond financing by Ras Laffan Natural Gas Company Limited (II) and Ras Laffan Natural Gas Company Limited (3)

Attachment II
Case Commodity Prices*

Commodity Prices (units as indicated) (real 2005)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Brent ($/bbl)	38.50	32.78	27.31	26.87	26.92	26.99	27.09	27.24	27.43	27.69	28.00	28.36	28.76	29.15	29.51	29.83	30.08	30.27	30.42	30.52	30.59	30.64	30.68
JCC ($/bbl)	38.25	33.12	28.10	27.56	27.43	27.39	27.43	27.54	27.72	27.97	28.28	28.64	29.03	29.42	29.79	30.10	30.35	30.55	30.69	30.79	30.86	30.92	30.95
Henry Hub ($/mmBtu)	6.39	5.73	4.82	4.22	4.20	4.24	4.29	4.37	4.44	4.53	4.16	4.40	4.53	4.65	4.73	4.80	4.86	4.95	5.02	5.07	5.13	5.17	5.21
North West Europe($/mmBtu)	4.93	4.39	3.84	3.57	3.43	3.30	3.26	3.22	3.18	3.16	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15
Field Condensate ($/bbl)	40.27	34.92	29.41	28.74	28.73	28.77	28.85	28.98	29.16	29.40	29.70	30.05	30.43	30.80	31.15	31.45	31.70	31.88	32.02	32.12	32.19	32.24	32.27
Plant Condensate ($/bbl)	38.21	32.68	27.78	27.30	27.29	27.32	27.41	27.53	27.71	27.94	28.22	28.55	28.91	29.27	29.60	29.89	30.12	30.30	30.43	30.53	30.59	30.64	30.67
Propane Price ($/tonne)	344.97	312.12	283.38	264.51	252.80	242.94	242.47	241.77	242.96	244.22	245.55	248.02	250.56	253.14	255.81	258.53	260.17	261.79	263.40	265.00	266.59	267.15	267.66
Butane Price ($/tonne)	343.76	304.53	270.17	256.83	248.23	238.37	237.32	236.83	237.28	238.59	240.73	243.25	246.00	248.72	251.23	253.63	255.83	257.58	258.95	259.99	260.81	262.26	262.78
IPE GasOil Price ($/tonne)	349.48	303.42	254.40	247.40	243.11	241.17	241.76	242.75	244.19	246.13	248.57	251.48	254.63	257.79	260.70	263.21	265.24	266.80	267.95	268.76	269.32	270.64	270.92

*Source: Stone & Webster Consultants Limited and Purvin & Gertz Inc. reports prepared for the 2005 Bond Financing by Ras Laffan Natural Gas Company Limited (II) and Ras Laffan Natural Gas Company Limited (3)

Attachment III
Base Case Summary Cash Flow*

Summary Results ($ million unless otherwise stated)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
LNG Revenue	794	1,143	1,738	2,755	4,332	5,849	6,172	6,440	6,685	6,950	6,810	7,204	7,562	7,914	8,235	8,550	8,858	9,203	9,535	9,849	10,179	10,478	10,632
Condensate Revenue	410	521	671	1,034	1,509	1,971	2,043	2,086	2,134	2,187	2,246	2,310	2,378	2,448	2,517	2,585	2,649	2,710	2,768	2,824	2,879	2,932	2,904
LPG Revenue	—	74	170	304	440	562	585	601	622	644	667	694	723	752	783	815	846	877	908	941	974	1,007	1,000
Other Revenue	253	40	40	56	77	108	109	109	109	109	109	109	109	109	109	109	109	109	108	109	108	108	107
Total Revenue	**1,457**	**1,778**	**2,618**	**4,148**	**6,357**	**8,489**	**8,910**	**9,237**	**9,549**	**9,890**	**9,832**	**10,317**	**10,771**	**11,223**	**11,645**	**12,059**	**12,461**	**12,898**	**13,320**	**13,722**	**14,140**	**14,526**	**14,643**
Gas Royalties	329	481	624	937	1,364	1,790	1,897	1,967	2,040	2,122	2,105	2,216	2,325	2,433	2,534	2,632	2,728	2,832	2,933	3,029	3,129	3,225	3,253
Liquids Royalties	48	66	95	159	262	362	371	379	389	399	410	423	436	449	463	476	489	501	513	524	536	547	548
Shipping	84	205	364	706	1,029	1,427	1,471	1,490	1,509	1,528	1,548	1,568	1,590	1,611	1,634	1,657	1,680	1,705	1,730	1,756	1,778	1,796	1,712
Tax	—	—	—	—	—	—	153	324	339	351	364	548	1,169	1,685	1,806	1,964	2,119	2,290	2,505	2,760	3,014	3,132	3,246
Train Operating Costs	57	90	124	151	182	215	221	226	232	238	243	250	256	262	269	275	282	289	297	304	312	319	327
Other Costs	276	15	40	66	72	87	87	88	89	75	75	76	77	77	78	79	79	80	81	82	82	83	31
Total Operating Costs	**794**	**857**	**1,246**	**2,018**	**2,910**	**3,881**	**4,201**	**4,475**	**4,596**	**4,712**	**4,746**	**5,080**	**5,852**	**6,519**	**6,783**	**7,083**	**7,378**	**7,698**	**8,059**	**8,455**	**8,851**	**9,102**	**9,118**
CFADS	**663**	**921**	**1,372**	**2,130**	**3,448**	**4,608**	**4,709**	**4,762**	**4,952**	**5,178**	**5,086**	**5,237**	**4,919**	**4,705**	**4,862**	**4,976**	**5,083**	**5,200**	**5,261**	**5,268**	**5,289**	**5,424**	**5,525**
Programme Debt Principal Repayments	—	—	—	—	—	180	373	393	415	439	463	488	516	546	577	610	601	635	672	710	750	793	838
Interest & Commitment Fees	56	156	308	402	513	546	532	512	490	467	444	421	393	364	334	301	268	233	196	156	115	71	24
Total Senior Debt Service	**56**	**156**	**308**	**402**	**513**	**726**	**904**	**905**	**905**	**906**	**908**	**909**	**909**	**910**	**911**	**911**	**869**	**868**	**867**	**866**	**865**	**864**	**863**
DSCR (times)	8.25	5.89	4.45	5.29	6.73	6.34	5.21	5.26	5.47	5.72	5.60	5.76	5.41	5.17	5.34	5.46	5.85	5.99	6.07	6.08	6.11	6.28	6.49
Pre Capital Expenditure Cash Flow	**607**	**765**	**1,063**	**1,727**	**2,935**	**3,882**	**3,805**	**3,857**	**4,047**	**4,272**	**4,178**	**4,328**	**4,010**	**3,795**	**3,951**	**4,065**	**4,214**	**4,332**	**4,394**	**4,402**	**4,424**	**4,560**	**4,662**
Capital Expenditure	2,219	3,059	2,739	1,734	964	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Finance Costs	91	51	92	68	203	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Costs to be Funded	**2,309**	**3,110**	**2,830**	**1,802**	**1,167**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Pre Financing Cash Flow	**(1,703)**	**(2,345)**	**(1,767)**	**(75)**	**1,768**	**3,882**	**3,805**	**3,857**	**4,047**	**4,272**	**4,178**	**4,328**	**4,010**	**3,795**	**3,951**	**4,065**	**4,214**	**4,332**	**4,394**	**4,402**	**4,424**	**4,560**	**4,662**
Equity Financing / (Repayments)	1,088	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Programme Bond Debt Utilisation and Bank Drawings	1,221	3,110	2,830	1,802	1,037	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total Financing	**2,309**	**3,110**	**2,830**	**1,802**	**1,037**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Post Financing Cash Flow	**607**	**765**	**1,063**	**1,727**	**2,805**	**3,882**	**3,805**	**3,857**	**4,047**	**4,272**	**4,178**	**4,328**	**4,010**	**3,795**	**3,951**	**4,065**	**4,214**	**4,332**	**4,394**	**4,402**	**4,424**	**4,560**	**4,662**
Change in DSRA	—	0	0	0	0	(4)	1	(0)	0	0	2	0	0	1	1	(21)	(0)	(0)	(1)	(1)	(1)	(1)	(431)
Pre Distributions Cash Flow	**607**	**765**	**1,063**	**1,727**	**2,805**	**3,885**	**3,804**	**3,857**	**4,047**	**4,272**	**4,176**	**4,328**	**4,010**	**3,794**	**3,951**	**4,086**	**4,214**	**4,333**	**4,395**	**4,402**	**4,425**	**4,560**	**5,094**
DSRA Balance	68	118	197	251	454	451	452	451	452	452	454	454	454	455	456	435	434	434	433	433	432	431	—
Programme Debt Closing Balance	2,300	4,331	7,161	8,963	10,000	9,820	9,447	9,054	8,639	8,200	7,736	7,248	6,732	6,186	5,610	5,000	4,399	3,764	3,092	2,382	1,632	838	(0)
EBITDA	790	1,066	1,615	2,641	4,103	5,489	5,687	5,914	6,117	6,342	6,240	6,607	6,906	7,208	7,484	7,755	8,018	8,308	8,584	8,844	9,117	9,358	9,596
EBIT	699	902	1,371	2,232	3,456	4,619	4,809	5,036	5,239	5,464	5,362	5,729	6,028	6,329	6,606	6,878	7,140	7,431	7,706	7,966	8,239	8,480	8,718
PAT	630	738	1,103	1,682	2,463	3,270	3,318	3,402	3,627	3,877	3,799	4,020	3,744	3,578	3,785	3,990	4,179	4,392	4,575	4,751	4,926	5,133	5,345

*Source: Stone & Webster Consultants Limited and Purvin & Gertz Inc. reports prepared for the 2005 Bond Financing by Ras Laffan Natural Gas Company Limited (II) and Ras Laffan Natural Gas Company Limited (3)