CHENIERE ENERGY INC
Form 10-Q
November 06, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2006

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 No. 001-16383

CHENIERE ENERGY, INC.

(Exact name as specified in its charter)

Delaware

(State or other jurisdiction of incorporation or organization)

95-4352386

(I.R.S. Employer Identification No.)

717 Texas Avenue, Suite 3100

Houston, Texas

(Address of principal executive offices)

77002

(Zip Code)

(713) 659-1361

(Registrant's telephone number, including area code)

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 x No ¨

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 x Accelerated filer ¨ Non-accelerated filer ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

As of October 31, 2006, there were 55,143,564 shares of Cheniere Energy, Inc. Common Stock, $.003 par value, issued and outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

(in thousands, except share data)

	September 30, 2006 (unaudited)	December 31, 2005 (as adjusted)
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 586,787	$ 692,592
Restricted cash and cash equivalents	139,623	160,885
Restricted certificate of deposit	694	676
Advances to EPC contractor	2,730	8,087
Accounts receivable	4,654	2,912
Derivative assets	9,194	5,468
Prepaid expenses	2,005	843
Total current assets	745,687	871,463
NON-CURRENT RESTRICTED CASH AND CASH EQUIVALENTS	100,098	16,500
PROPERTY, PLANT AND EQUIPMENT, NET	624,026	280,106
DEBT ISSUANCE COSTS, NET	47,401	43,008
INVESTMENT IN LIMITED PARTNERSHIP		
GOODWILL	76,844	76,844
LONG-TERM DERIVATIVE ASSETS		1,837
INTANGIBLE ASSETS	1,283	93
ADVANCES UNDER LONG-TERM CONTRACTS	11,762	
OTHER	5,001	296
Total assets	$ 1,612,102	$ 1,290,147
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 13,792	$ 778
Accrued liabilities	44,304	54,544
Current portion of long-term debt	6,000	6,000
Total current liabilities	64,096	61,322
LONG-TERM DEBT	1,264,500	917,500
DEFERRED REVENUE	41,000	41,000
LONG-TERM DERIVATIVE LIABILITIES	23,978	1,682
OTHER NON-CURRENT LIABILITIES	703	102
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY		
Preferred stock, $.0001 par value, 5,000,000 shares authorized, none issued		
Common stock, $.003 par value		
Authorized: 120,000,000 shares at both September 30, 2006 and December 31, 2005		

Issued and outstanding: 55,109,038 shares at September 30, 2006 and 54,521,131 shares at December 31, 2005	166	164
Additional paid-in-capital	383,736	375,551
Deferred compensation		(9,684)
Accumulated deficit	(153,824)	(101,288)
Accumulated other comprehensive (loss) income	(12,253)	3,798
Total stockholders equity	217,825	268,541
Total liabilities and stockholders equity	$ 1,612,102	$ 1,290,147

The accompanying notes are an integral part of these financial statements.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS

(in thousands, except per share data)

(unaudited)

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005 (as adjusted)	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005 (as adjusted)
Revenues				
Oil and gas sales	$ 737	$ 729	$ 1,572	$ 2,154
Total revenues	737	729	1,572	2,154
Operating costs and expenses				
LNG receiving terminal and pipeline development expenses	2,923	4,127	6,730	14,902
Exploration costs	661	246	2,089	1,347
Oil and gas production costs	61	78	166	166
Impairment of fixed assets	1,628		1,628	
Depreciation, depletion and amortization	896	362	2,080	816
General and administrative expenses	12,044	6,523	37,669	17,114
Total operating costs and expenses	18,213	11,336	50,362	34,345
Loss from operations	(17,476)	(10,607)	(48,790)	(32,191)
Gain on sale of investment in unconsolidated affiliate		20,206		20,206
Equity in net loss of limited partnership		(2,261)		(3,232)
Derivative gain (loss)	(966)	931	(44)	264
Interest expense	(10,886)	(5,058)	(33,120)	(5,058)
Interest income	11,100	4,541	30,978	8,114
Other income	201	295	485	722
Income (loss) before income taxes and minority interest	(18,027)	8,047	(50,491)	(11,175)
Income tax provision	(15,079)		(2,045)	
Income (loss) before minority interest	(33,106)	8,047	(52,536)	(11,175)
Minority interest				97
Net income (loss)	$ (33,106)	$ 8,047	$ (52,536)	$ (11,078)
Net income (loss) per common share basic	$ (0.61)	$ 0.15	$ (0.97)	$ (0.21)
Net income (loss) per common share diluted	$ (0.61)	$ 0.14	$ (0.97)	$ (0.21)
Weighted average number of common shares outstanding				
Basic	54,496	53,938	54,361	53,358
Diluted	54,496	55,749	54,361	53,358

The accompanying notes are an integral part of these financial statements.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY

(in thousands)

(unaudited)

	Common Stock		Treasury Stock		Additional Paid-In Capital	Deferred Compen-sation	Accumulated Deficit	Accumulated Other Compre-hensive Income (loss)	Total Stockholders Equity
	Shares	Amount	Shares	Amount					
Balance December 31, 2005 (as adjusted)	54,521	$ 164		$	$ 375,551	$ (9,684)	$ (101,288)	$ 3,798	$ 268,541
Issuances of stock	360	1			1,727				1,728
Issuances of restricted stock	252	1			(1)				
Reversal of deferred compensation					(9,684)	9,684			
Stock-based compensation					17,075				17,075
Purchase of treasury stock			(24)	(932)					(932)
Retirement of treasury stock	(24)		24	932	(932)				
Comprehensive loss:									
Interest rate swaps								(16,004)	(16,004)
Foreign currency translation								(47)	(47)
Net loss							(52,536)		(52,536)
Balance September 30, 2006	55,109	$ 166		$	$ 383,736	$	$ (153,824)	$ (12,253)	$ 217,825

The accompanying notes are an integral part of these financial statements.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

(in thousands)

(unaudited)

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005 (as adjusted)
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (52,536)	$ (11,078)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation, depletion and amortization	2,080	816
Impairment of unproved properties	416	583
Dry hole expense	894	
Impairment of fixed assets	1,628	
Amortization of debt issuance cost	2,752	
Non-cash compensation	15,975	2,487
Deferred tax provision	2,045	
Equity in net loss of limited partnership		3,232
Gain on sale of investment in unconsolidated affiliate		(20,206)
Non-cash derivative gain	(213)	(282)
Other	(257)	795
Changes in operating assets and liabilities		
Accounts receivable	831	(604)
Prepaid expenses	(380)	(473)
Deferred revenue		15,000
Regulatory assets	(12,343)	
Accounts payable and accrued liabilities	(1,673)	589
NET CASH USED IN OPERATING ACTIVITIES	(40,781)	(9,141)
CASH FLOWS FROM INVESTING ACTIVITIES:		
LNG terminal and pipeline construction-in-progress	(307,559)	(164,541)
Investment in restricted cash and cash equivalents	(62,336)	(203,452)
Advances under long-term contracts	(11,762)	
Purchases of fixed assets	(7,799)	(2,806)
Other	(6,652)	(713)
Oil and gas property additions, net of sales	(2,568)	(705)
Advance to EPC contractor	(2,729)	(16,173)
Investment in limited partnership		(1,592)
Proceeds from sale of investment in unconsolidated affiliate		20,206
NET CASH USED IN INVESTING ACTIVITIES	(401,405)	(369,776)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Debt issuance costs	(11,416)	(42,019)
Repayment of Term Loan	(4,500)	
Purchase of treasury shares	(931)	
Issuance of convertible senior unsecured notes		325,000

Proceeds from Term Loan		600,000
Purchase of issuer call spread		(75,703)
Other		47
Sale of common stock	1,728	2,095
Borrowing under Sabine Pass Credit Facility	351,500	
NET CASH PROVIDED BY FINANCING ACTIVITIES	336,381	809,420
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(105,805)	430,503
CASH AND CASH EQUIVALENTS BEGINNING OF PERIOD	692,592	308,443
CASH AND CASH EQUIVALENTS END OF PERIOD	$ 586,787	$ 738,946
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid for interest (net of amounts capitalized)	$ 37,931	$ 3,238

The accompanying notes are an integral part of these financial statements.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

NOTE 1 Basis of Presentation

The accompanying unaudited consolidated financial statements of Cheniere Energy, Inc. have been prepared in accordance with generally accepted accounting principles in the United States (GAAP) for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. In our opinion, all adjustments, consisting only of normal recurring adjustments necessary for a fair presentation, have been included. As used herein, the terms Cheniere, we, our and us refer to Cheniere Energy, Inc. and its subsidiaries.

Certain reclassifications have been made to conform prior period amounts to the current period presentation. These reclassifications had no effect on net income (loss) or stockholders equity. As discussed below, we changed our method of accounting for investments in oil and gas properties from the full cost method to the successful efforts method of accounting, and as a result, the change in accounting method requires that all prior period financial statements be adjusted to reflect the results and balances that would have been reported had we been following the successful efforts method of accounting from inception.

Interim results are not necessarily indicative of results to be expected for the full fiscal year ending December 31, 2006. All references to issued and outstanding shares, weighted average shares, and per share amounts in the accompanying unaudited consolidated financial statements have been retroactively adjusted to reflect our two-for-one stock split that occurred on April 22, 2005.

For further information, refer to the consolidated financial statements and footnotes included in our annual report on Form 10-K for the year ended December 31, 2005.

New Accounting Pronouncements

In February 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 155, *Accounting for Certain Hybrid Financial Instruments An Amendment of FASB Statements No. 133 and 140.* SFAS No. 155 provides entities with relief from having to separately determine the fair value of an embedded derivative that would otherwise be required to be bifurcated from its host contract in accordance with SFAS No. 133. SFAS No. 155 allows an entity to make an irrevocable election to measure such a hybrid financial instrument at fair value in its entirety, with changes in fair value recognized in earnings. SFAS No. 155 is effective for all financial instruments acquired, issued or subject to a remeasurement event occurring after the beginning of an entity s first fiscal year that begins after September 15, 2006. We believe that the adoption of SFAS No. 155 will not have a material impact on our financial position, results of operations or cash flows.

In March 2006, the FASB issued SFAS No. 156, *Accounting for Servicing of Financial Assets An Amendment to FASB Statement No. 140*. Once effective, SFAS No. 156 will require entities to recognize a servicing asset or liability each time they undertake an obligation to service a financial asset by entering into a servicing contract in certain situations. This statement also requires all separately recognized servicing assets and servicing liabilities to be initially measured at fair value and permits a choice of either the amortization or fair value measurement method for subsequent measurement. The effective date of this statement is for annual periods beginning after September 15, 2006, with earlier adoption permitted as of the beginning of an entity s fiscal year provided the entity has not issued any financial statements for that year. We do not plan to adopt SFAS No. 156 early, and we do not believe that it will have a material impact on our financial position, results of operations or cash flows.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109*. FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes.* It prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This new standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The provisions of FIN No. 48 are to be applied to all tax positions upon initial adoption of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption of FIN No. 48. The cumulative effect of applying the provisions of FIN No. 48 should be reported as an adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year. The provisions of FIN No. 48 are effective for fiscal years beginning after December 15, 2006. Earlier application is permitted as long as the enterprise has not yet issued financial statements, including interim financial statements, in the period of adoption. We believe that the adoption of FIN No. 48 will not have a material impact on our financial position, results of operations or cash flows.

In July 2006, the FASB issued FASB Staff Position (FSP) No. FAS 13-2, *Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction*. FSP No. FAS 13-2 requires that changes in the projected timing of income tax cash flows generated by a leveraged lease transaction be recognized as a gain or loss in the year in which change occurs. The pretax gain or loss is required to be included in the same line item in which the leveraged lease income is recognized, with the tax effect being included in the provision for income taxes. FSP No. FAS 13-2 is effective for fiscal years beginning after December 15, 2006. We believe that the adoption of FSP No. FAS 13-2 will not have a material impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS No. 157 clarifies the principle that fair value should be based on the assumptions market participants would use when pricing an asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, with early adoption permitted. We are currently determining the effect, if any, the adoption of SFAS No. 157 will have on our financial statements.

In September 2006, the FASB issued SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plan an amendment of FASB Statement No. 87, 88, 106 and 132(R)*. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability in its statement of financial position and recognize changes in the funded status in the year in which the changes occur. SFAS No. 158 is effective for fiscal years ending after December 15, 2006. We believe that the adoption of SFAS No. 158 will not have a material impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued FSP No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities*. FSP No. AUG AIR-1 prohibits the use of the accrue-in-advance method for accounting for major maintenance activities and confirms the acceptable methods of accounting for planned major maintenance activities. FSP No. AUG AIR-1 is effective the first fiscal year beginning after December 15, 2006. We believe that the adoption of FSP No. AUG AIR-1 will not have a material impact on our financial position, results of operations or cash flows.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

Change in Method of Accounting for Investments in Oil and Gas Properties

Effective January 1, 2006, we converted from the full cost method to the successful efforts method of accounting for our investments in oil and gas properties. While our primary focus is the development of our liquefied natural gas (LNG) related businesses, we have continued to be involved, to a limited extent, in oil and gas exploration and development activities in the U.S. Gulf of Mexico. We believe that, in light of our current level of exploration and development activities, the successful efforts method of accounting provides a better matching of expenses to the period in which oil and gas production is realized. As a result, we believe that the change in accounting method at that time was appropriate. The change in accounting method constituted a Change in Accounting Principle, requiring that all prior period financial statements be adjusted to reflect the results and balances that would have been reported had we been following the successful efforts method of accounting from our inception. The cumulative effect of the change in accounting method as of December 31, 2004 and 2005 was to reduce the balance of our net investment in oil and gas properties and retained earnings at those dates by $18,237,000 and $17,977,000, respectively. The change in accounting method resulted in an increase in net income of $369,000 for the three months ended September 30, 2005 and a decrease in the net loss of $296,000 for the nine months ended September 30, 2005, and had no significant impact on earnings per share (basic and diluted) for these respective periods (see Note 15 Adjustment to Financial Statements Successful Efforts). The change in method of accounting had no impact on cash or working capital.

Successful Efforts Method of Accounting

We have elected to follow the successful efforts method of accounting for our oil and gas properties. Under this method, production costs, geological and geophysical costs (including the cost of seismic data), delay rentals, costs of unsuccessful exploratory wells, and internal costs directly related to our exploration and development activities are charged to expense as incurred. The costs of property acquisitions, successful exploratory wells, development costs, and support equipment and facilities are initially capitalized when incurred. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we review proved oil and gas properties and other long-lived assets for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amount of the properties is written down to their estimated fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, timing of future production, future capital expenditures and a risk-adjusted discount rate. Individually significant unproved properties are also periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Depreciation, depletion and amortization of proved oil and gas properties is determined on a field-by-field basis using the unit-of-production method over the life of the remaining proved reserves.

Application of SFAS No. 71 to Regulated Operations

During the second quarter of 2006, we determined that certain of our natural gas pipelines to be constructed have met the criteria set forth in SFAS No. 71, *Accounting for the Effects of Certain Types of*

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

Regulation that would require us to capitalize certain costs that have previously been expensed. SFAS No. 71 requires rate-regulated subsidiaries to account for, and report, assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected.

Our application of SFAS No. 71 is based on the current regulatory environment, our current projected tariff rates, and our ability to collect those rates. Future regulatory developments and rate cases could impact this accounting. Although discounting of our maximum tariff rates may occur, we believe the criteria set forth in SFAS No. 71, for its application, are met and the use of regulatory accounting under SFAS No. 71 best reflects the results of future operations in the economic environment in which we will operate. Regulatory accounting requires us to record assets and liabilities that result from the rate-making process that would not be recorded under GAAP for non-regulated entities. We will continue to evaluate the application of regulatory accounting principles based on on-going changes in the regulatory and economic environment.

Capitalized Exploratory Well Costs

In April 2005, the FASB issued FSP No. FAS 19-1, *Accounting for Suspended Well Costs,* which amends FSP No. FAS 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*. Under the provisions of FSP No. FAS 19-1, exploratory well costs continue to be capitalized after the completion of drilling when (i) the well has found a sufficient quantity of reserves to justify completion as a producing well and (ii) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition 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 would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. FSP No. FAS 19-1 provides several indicators that can assist an entity in demonstrating that sufficient progress is being made when assessing the reserves and economic viability of the project.

At September 30, 2006, our suspended well costs for wells on which drilling was completed more than one year ago were $164,000 relating to a single well. There were no suspended well costs charged to expense in the three and nine months ended September 30, 2006.

NOTE 2 Restricted Cash and Cash Equivalents

In August 2006, Cheniere Creole Trail Pipeline, L.P., our wholly-owned subsidiary (CCTP), entered into a purchase order with ILVA S.p.A (ILVA) for the purchase of pipe at an aggregate cost of approximately $175,700,000 (see Note 13 Commitments and Contingencies). Associated with this purchase order, CCTP delivered a standby letter of credit to ILVA in the amount of $87,852,000, to secure CCTP s obligations under the purchase order. This letter of credit required a deposit of $87,852,000 with the issuer of the letter of credit and has been recorded as non-current restricted cash and cash equivalents on our Consolidated Balance Sheet at September 30, 2006. Once the value of the goods and services paid by CCTP exceeds the value of the letter of credit, ILVA will submit a notice of reduction to the issuing bank to reduce the amount of the letter of credit by 100% of any subsequent payments by CCTP. The non-current restricted cash and cash equivalents cash collateral account on deposit with the issuing bank will be reduced by such amount.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

NOTE 3 Property, Plant and Equipment

Property, plant and equipment is comprised of LNG terminal and natural gas pipeline construction-in-progress expenditures, LNG site and related costs, investments in oil and gas properties, and fixed assets, as follows (in thousands):

	September 30, 2006	December 31, 2005 (as adjusted)
LNG TERMINAL COSTS		
LNG terminal construction-in-progress	$ 587,241	$ 271,142
LNG site and related costs, net	1,114	1,249
Total LNG terminal costs	588,355	272,391
NATURAL GAS PIPELINE COSTS		
Pipeline construction-in-progress	20,636	
Pipeline right-of-ways	1,623	
Total natural gas pipeline costs	22,259	
OIL AND GAS PROPERTIES, successful efforts method		
Proved	2,367	97
Unproved	777	1,600
Accumulated depreciation, depletion and amortization	(184)	(57)
Total oil and gas properties, net	2,960	1,640
FIXED ASSETS		
Computers and office equipment	4,863	3,611
Furniture and fixtures	1,310	1,145
Computer software	6,933	1,640
Leasehold improvements	2,278	1,757
Other	123	26
Accumulated depreciation	(5,055)	(2,104)
Total fixed assets, net	10,452	6,075
PROPERTY, PLANT AND EQUIPMENT, net	$ 624,026	$ 280,106

Our developing natural gas pipeline business is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, and we have determined that our pipelines to be constructed have met the criteria found in SFAS No. 71. Accordingly, we began applying the provisions of SFAS No. 71 to the affected pipeline subsidiaries in the second quarter of 2006.

Natural gas pipeline costs also include amounts capitalized as an Allowance for Funds Used During Construction (AFUDC). The rates used in the calculation of AFUDC are determined in accordance with guidelines established by the FERC. AFUDC represents the cost of debt and equity funds used to finance our natural gas pipeline additions during construction. AFUDC is capitalized as a part of the cost of our natural gas pipelines. Under regulatory rate practices, we generally are permitted to recover AFUDC, and a fair return thereon, through our rate base after our natural gas pipelines are placed in service.

In the third quarter of 2006, we impaired certain of our leasehold costs related to our current office space at 717 Texas Avenue in Houston, Texas. The impairment was the result of signing our new

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

office lease for space in the North Tower of Houston Pennzoil Place with Sunbelt Management Company (see Note 13 Commitments and Contingencies), and the belief that we would not recover or utilize our leasehold costs in the future. The impact of this impairment in property, plant and equipment was to increase accumulated depreciation by $1,628,000 and recognize an impairment of fixed assets by the same amount in our Consolidated Statement of Operations.

NOTE 4 Investment in Limited Partnership

We account for our 30% limited partnership investment in Freeport LNG Development, L.P. (Freeport LNG) using the equity method of accounting.

For the three and nine months ended September 30, 2005, our equity share of the net loss of the limited partnership was $2,261,000 and $3,232,000, respectively. Our recorded equity share of the Freeport LNG net loss for the three months ended September 30, 2005 includes $1,075,000 (2005 Suspended Loss) related to a portion of our 30% equity share of the second quarter 2005 net loss of the limited partnership. The 2005 Suspended Loss was not recognized as of June 2005 because our investment in Freeport LNG had been reduced to zero, and we did not intend to fund the 2005 Suspended Loss at that time; however, we received additional capital call notices during the third quarter of 2005, which we intended to fund in the fourth quarter of 2005. As a result, we recorded the 2005 Suspended Loss as part of our 30% equity share of the third quarter 2005 net loss of Freeport LNG.

For the three and nine months ended September 30, 2006, our equity share of the net losses of the limited partnership was $1,698,000 and $7,216,000, respectively. As of September 30, 2006, the basis of our investment in Freeport LNG was zero, and as a result, we did not record our share of the losses of the partnership for these periods because we did not guarantee any obligations and have not committed additional financial support to Freeport LNG at this time.

At September 30, 2006 and December 31, 2005, we had cumulative suspended losses of $11,184,000 and $3,968,000, respectively, related to our investment in Freeport LNG.

The financial position of Freeport LNG at September 30, 2006 and December 31, 2005, and the results of Freeport LNG s operations for the three and nine months ended September 30, 2006 and 2005, are summarized as follows (in thousands):

	September 30, 2006	December 31, 2005
Current assets	$ 331,744	$ 380,615
Construction-in-progress	521,665	246,351
Fixed assets, net, and other assets	9,693	9,309
Total assets	$ 863,102	$ 636,275
Current liabilities	$ 60,252	$ 53,533
Notes payable	839,928	595,766
Deferred revenue and other deferred credits	5,748	5,748
Partners deficit	(42,826)	(18,772)
Total liabilities and partners deficit	$ 863,102	$ 636,275

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
Loss from continuing operations	$ (5,659)	$ (3,950)	$ (24,054)	$ (10,771)
Net loss	(5,659)	(3,950)	(24,054)	(10,771)
Cheniere s 30% equity in net loss from limited partnership (1)	$ (1,698)	$ (1,185)(2)	$ (7,216)	$ (3,232)

(1) As discussed above, we did not record the $1,698,000 and $7,216,000 losses in our Consolidated Statement of Operations for the three and nine months ended September 30, 2006 because our investment basis was zero.

(2) Our recorded equity in net loss for the three months ended September 30, 2005 was $2,261,000, including the $1,075,000 2005 Suspended Loss not recorded during the second quarter of 2005.

NOTE 5 Derivative Instruments

Interest Rate Derivative Instruments

In connection with the closing of a credit agreement (the Sabine Pass Credit Facility) in February 2005, Sabine Pass LNG, L.P., a wholly-owned limited partnership (Sabine Pass LNG), entered into swap agreements (the Sabine Swaps) with HSBC Bank, USA and Société Générale. Under the terms of the Sabine Swaps, Sabine Pass LNG is able to hedge against rising interest rates, to a certain extent, with respect to its drawings under the Sabine Pass Credit Facility, up to a maximum amount of $700,000,000. The Sabine Swaps have the effect of fixing the LIBOR component of the interest rate payable under the Sabine Pass Credit Facility with respect to hedged drawings under the Sabine Pass Credit Facility up to a maximum of $700,000,000, at 4.49% from July 25, 2005 through March 25, 2009 and at 4.98%, from March 26, 2009 through March 25, 2012. The final termination date of the Sabine Swaps is March 25, 2012.

In connection with the closing of the amended and restated Sabine Pass Credit Facility (the Amended Sabine Pass Credit Facility) in July 2006, we entered into additional interest rate swap agreements with HSBC Bank, USA and Société Générale (the Amended Sabine Swaps). The Amended Sabine Swaps, along with the original Sabine Swaps, have the combined effect of fixing the LIBOR component of the interest rate payable on borrowings up to a maximum of $1.25 billion at a blended rate of 5.26% from July 25, 2006 through July 1, 2015.

In connection with the closing of a credit agreement (the Term Loan) on August 31, 2005, Cheniere LNG Holdings, LLC, a wholly-owned subsidiary (Cheniere LNG Holdings), entered into interest rate swap agreements with Credit Suisse (the Term Loan Swaps) to hedge against rising interest rates. Under the terms of the Term Loan Swaps, Cheniere LNG Holdings hedged an initial notional amount of $600,000,000. The notional amount declines in accordance with anticipated principal payments under the Term Loan. The Term Loan Swaps have the effect of fixing the LIBOR rate component of the interest rate payable under the Term Loan at 3.75% from August 31, 2005 to September 27, 2007, at 3.98% from September 28, 2007 to September 27, 2008 and at 5.98% from September 28, 2008 to September 30, 2010. The final termination date of the Term Loan Swaps is September 30, 2010.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

Accounting for Hedges

SFAS No. 133, as amended and interpreted by other related accounting literature, establishes accounting and reporting standards for derivative instruments. Under SFAS No. 133, we are required to record derivatives on our balance sheet as either an asset or liability measured at their fair value, unless exempted from derivative treatment under the normal purchase and normal sale exception. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge criteria are met. These criteria require that the derivative is determined to be effective as a hedge and that it is formally documented and designated as a hedge.

We have determined that the Sabine Swaps, Amended Sabine Swaps and Term Loan Swaps (collectively, the Swaps) qualify as cash flow hedges within the meaning of SFAS No. 133 and have designated them as such. At their inception, we determined the hedging relationship of the Swaps and the underlying debt to be highly effective. We will continue to assess the hedge effectiveness of the Swaps on a quarterly basis in accordance with the provisions of SFAS No. 133.

SFAS No. 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income (loss) (OCI) and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. In our case, the impact on earnings is a reduction of $3,183,000 and $5,866,000, respectively, in interest expense for the three and nine months ended September 30, 2006. The ineffective portion of the gain or loss on the derivative instrument, if any, must be recognized currently in earnings. For the three and nine months ended September 30, 2006, we have recognized net derivative losses of $966,000 and $44,000, respectively, into earnings. If the forecasted transaction is no longer probable of occurring, the associated gain or loss recorded in OCI is recognized currently in earnings.

Below is a reconciliation of our accumulated OCI at September 30, 2006 (in thousands):

Net derivative liabilities	$ (12,075)
Effective non-cash items	(102)
Ineffective non-cash items	(29)
Accumulated OCI before foreign currency translation and after income tax	$ (12,206)

The maximum length of time over which we have hedged our exposure to the variability in future cash flows for forecasted transactions is ten years under the Swaps. As of September 30, 2006, $12,992,000 of accumulated net deferred gains on the Swaps, currently included in OCI, are expected to be reclassified to earnings during the next twelve months, assuming no change in the LIBOR forward curves at September 30, 2006. The actual amounts that will be reclassified will likely vary based on the probability that interest rates will, in fact, change. Therefore, management is unable to predict what the actual reclassification from OCI to earnings (positive or negative) will be for the next twelve months.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

NOTE 6 Accrued Liabilities

Accrued liabilities consist of the following (in thousands):

	September 30, 2006	December 31, 2005
LNG terminal construction costs	$ 33,505	$ 39,728
Accrued interest expense and related fees	5,985	4,937
Debt issuance costs	671	3,083
Payroll		2,460
LNG terminal and pipeline development expenses		1,534
Professional and legal services	1,026	1,043
Other accrued liabilities	3,117	1,759
Accrued liabilities	$ 44,304	$ 54,544

NOTE 7 Long-Term Debt

As of September 30, 2006 and December 31, 2005, our long-term debt was comprised of the following (in thousands):

	September 30, 2006	December 31, 2005
Amended Sabine Pass Credit Facility	$ 351,500	$
Convertible Senior Unsecured Notes	325,000	325,000
Term Loan	594,000	598,500
	1,270,500	923,500
Less: Current portion Term Loan	(6,000)	(6,000)
Total long-term debt	$ 1,264,500	$ 917,500

Amended Sabine Pass Credit Facility

In February 2005, Sabine Pass LNG entered into an $822,000,000 Sabine Pass Credit Facility with an initial syndicate of 47 financial institutions. Société Générale serves as the administrative agent and HSBC Bank, USA serves as collateral agent. This Sabine Pass Credit Facility was subsequently amended and restated in July 2006. The Amended Sabine Pass Credit Facility increased the amount of loans available to Sabine Pass LNG from $822,000,000 under the Sabine Pass Credit Facility to $1.5 billion to finance a substantial majority of the costs of constructing and placing into operation Phase 1 and the Phase 2 Stage 1 expansion of our Sabine Pass LNG receiving terminal.

Principal amounts owed under the Amended Sabine Pass Credit Facility must be repaid in semi-annual installments commencing upon the earlier of six months following the term conversion date (as defined in the Amended Sabine Pass Credit Facility) or such earlier date as we may specify upon satisfaction of certain conditions on or before October 1, 2009. Scheduled amortization during the repayment period will be based upon a 19-year mortgage style semi-annual amortization profile with a balloon payment due on the final maturity date of July 1, 2015.

Borrowings under the Amended Sabine Pass Credit Facility bear interest at a variable rate equal to LIBOR plus the applicable margin. The applicable margin varies from 0.875% to 1.125% during the term of the Amended Sabine Pass Credit Facility. Interest is calculated on the unpaid principal amount outstanding and is payable semi-annually in arrears. A commitment fee of 0.50% per annum on the daily, undrawn portion of the lenders commitments is required. Administrative fees must also be paid annually to the agent and the collateral agent.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

The collateral agent holds all of our funds and other investments in certain collateral accounts in Sabine Pass LNG s name but under the exclusive control of the collateral agent.

The Amended Sabine Pass Credit Facility contains customary conditions precedent to any borrowings, as well as customary affirmative and negative covenants. We were in compliance, in all material respects, with these covenants at September 30, 2006 and December 31, 2005. Sabine Pass LNG has obtained, and may in the future seek, consents, waivers and amendments to the Amended Sabine Pass Credit Facility documents. The obligations of Sabine Pass LNG under the Amended Sabine Pass Credit Facility are secured by all of Sabine Pass LNG s personal property, including the terminal use agreements (TUA) with Total LNG USA, Inc. (Total), Chevron USA, Inc. (Chevron) and Cheniere Marketing, Inc. (formerly Cheniere LNG Marketing, Inc.), our wholly-owned subsidiary (Cheniere Marketing), and the partnership interests in Sabine Pass LNG.

During the construction period, all interest costs, including amortization of related debt issuance costs and commitment fees, will be capitalized as part of the total cost of Phase 1 and Phase 2 of our Sabine Pass LNG receiving terminal. As of September 30, 2006 and December 31, 2005, $15,884,000 and $5,323,000, respectively, in commitment fees, interest costs, impact of interest rate swaps and amortization of debt issuance costs had been capitalized and included in LNG terminal construction-in-progress.

Convertible Senior Unsecured Notes

In July 2005, we consummated a private offering of $325,000,000 aggregate principal amount of 2.25% Convertible Senior Unsecured Notes (the Notes) due August 1, 2012 to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended (the Securities Act). The Notes are convertible into our common stock pursuant to the terms of the indenture governing the Notes at an initial conversion rate of 28.2326 per $1,000 principal amount of the Notes, which is equal to a conversion price of approximately $35.42 per share. We may redeem some or all of the Notes on or before August 1, 2012, for cash equal to 100% of the principal plus any accrued and unpaid interest if in the previous ten trading days the volume-weighted average price of our common stock exceeds $53.13, subject to adjustment, for at least five consecutive trading days. In the event of such redemption, we will make an additional payment equal to the present value of all remaining scheduled interest payments through August 1, 2012, discounted at the U.S. Treasury rate plus 50 basis points. The indenture governing the Notes contains customary reporting requirements.

Concurrent with the issuance of the Notes, we also entered into hedge transactions in the form of an issuer call spread (consisting of a purchase and a sale of call options on our common stock) with an affiliate of the initial purchaser of the Notes, having a term of two years, and a net cost to us of $75,703,000. These hedge transactions are expected to offset potential dilution from conversion of the Notes up to a market price of $70.00 per share. The net cost of the hedge transactions is recorded as a reduction to Additional Paid-in-Capital on our Consolidated Balance Sheet in accordance with the guidance of the Emerging Issues Task Force (EITF) Issue 00-19, *Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company s Own Stock*. Net proceeds from the offering were $239,786,000, after deducting the cost of the hedge transactions, the underwriting discount and related fees. As of September 30, 2006, no holders had elected to convert their Notes. Total interest expense recognized for the three and nine months ended September 30, 2006 was $2,173,000 and $6,501,000, respectively, before interest capitalization of $241,000 and $724,000, respectively.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

Term Loan

In August 2005, Cheniere LNG Holdings entered into the $600,000,000 Term Loan with Credit Suisse. The Term Loan has an interest rate equal to LIBOR plus a 2.75% margin and matures on August 30, 2012. In connection with the closing, Cheniere LNG Holdings entered into the Term Loan Swaps with Credit Suisse to hedge the LIBOR interest rate component of the Term Loan. The blended rate of the Term Loan Swaps on the Term Loan results in an annual fixed interest rate of 7.25% (including the 2.75% margin) for the first five years (see Note 5 Derivative Instruments). On December 30, 2005, Cheniere LNG Holdings made the first required quarterly principal payment of $1,500,000. Quarterly principal payments of $1,500,000 are required through June 30, 2012, and a final principal payment of $559,500,000 is required on August 30, 2012. A portion of the loan proceeds is controlled by Credit Suisse and is restricted as to its use.

At September 30, 2006, principal repayments on the Term Loan of $6,000,000 were due within the next 12 months and are classified on the Consolidated Balance Sheet as a current liability. Interest expense for the three and nine months ended September 30, 2006 was $15,802,000 and $41,633,000, respectively, before interest capitalization of $1,122,000 and $3,334,000, respectively, and gains from the Term Loan Swaps of $2,656,000 and $5,207,000, respectively. The Term Loan contains customary affirmative and negative covenants. Cheniere LNG Holdings was in compliance with these covenants, in all material respects, at September 30, 2006. The obligations of Cheniere LNG Holdings are secured by its 100% equity interest in Sabine Pass LNG and its 30% limited partner equity interest in Freeport LNG.

NOTE 8 Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheet for cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to their short-term nature. We use available market data and valuation methodologies to estimate the fair value of debt. This disclosure is presented in accordance with SFAS No. 107, *Disclosures about Fair Value of Financial Instruments*, and does not impact our financial position, results of operations or cash flows.

Long-Term Debt (in thousands):

	September 30, 2006	
	Carrying Amount	Estimated Fair Value
Term Loan due 2012 (1)	$ 588,000	$ 588,000
2.25% Convertible Senior Unsecured Notes due 2012 (2)	325,000	345,312
Sabine Pass Credit Facility (3)	351,500	351,500
	$ 1,264,500	$ 1,284,812

(1) The Term Loan bears interest based on a floating rate; therefore, the estimated fair value is deemed to equal the carrying amount of these notes.
(2) The fair value of the Notes is based on the closing bid price as of September 30, 2006.
(3) The Amended Sabine Pass Credit Facility bears interest based on a floating rate; therefore, the estimated fair value is deemed to equal the carrying amount of these notes.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

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(Unaudited)

NOTE 9 Income Taxes

From our inception, we have reported annual net operating losses for both financial reporting purposes and for federal and state income tax reporting purposes. Accordingly, we are not presently a taxpayer and have not recorded a net liability for federal or state income taxes in any of the periods included in the accompanying financial statements. Our Consolidated Statement of Operations for the year ended December 31, 2005 and the six months ended June 30, 2006 included deferred income tax benefits of $2,045,000 and $13,034,000, respectively, for a total of $15,079,000. The deferred income tax benefits recorded for such periods were provided for in accordance with the guidance in paragraph 140 of SFAS No. 109 and EITF *Abstract*, Topic D-32, which, in certain circumstances, requires items reported in pre-tax accumulated OCI to be considered in the determination of the amount of tax benefit that must be reported in the Consolidated Statement of Operations when a net operating loss occurs. In our situation, the specific circumstance related to pre-tax accumulated OCI amounts of $5,843,000 and $43,082,000 recorded as of December 31, 2005 and June 30, 2006, respectively, primarily related to our interest rate swaps. The deferred tax benefits previously reported in our Consolidated Statement of Operations represented the portion of the change in our tax asset valuation account that was allocable to the deferred income tax on the pre-tax income items previously reported in accumulated OCI in our Consolidated Statement of Stockholders Equity. As of September 30, 2006, however, primarily due to the reduction in value of our interest rate swaps, we recorded a pre-tax accumulated other comprehensive loss of $12,253,000 (see Note 5 Derivative Instruments for additional discussion). As a result, we recorded deferred income tax provisions of $15,079,000 and $2,045,000 for the three and nine months ended September 30, 2006, respectively. Such deferred income tax provisions were limited to the amount of deferred income tax benefits reported in prior reporting periods.

Income tax provision included in our reported net loss consisted of the following (in thousands):

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Current federal income tax expense	$	$	$	$
Deferred federal income tax provision	(15,079)		(2,045)	
	$ (15,079)	$	$ (2,045)	$

In May 2006, the State of Texas enacted a new business tax that is imposed on our gross revenues to replace the State s current franchise tax regime. The new legislation s effective date is January 1, 2008, which means that our first Texas margins tax (TMT) return will not become due until May 15, 2008 and will be based on our 2007 operations. Although the TMT is imposed on an entity s gross revenues rather than on its net income, certain aspects of the tax make it similar to an income tax. In accordance with the guidance provided in SFAS No. 109, we have properly determined the impact of the newly-enacted legislation in the determination of our reported state current and deferred income tax liability.

NOTE 10 Net Income (Loss) Per Share

Basic net income (loss) per share is computed by dividing the net income (loss) by the weighted average number of shares of common stock outstanding for the period. The computation of diluted net income (loss) per share reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to net income were exercised or converted into common stock or resulted in the issuance of common stock that would then share in our earnings.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

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The following table reconciles basic and diluted weighted average shares outstanding for the three and nine months ended September 30, 2006 and 2005 (in thousands except for income (loss) per share):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005 (as adjusted)	2006	2005 (as adjusted)
Weighted average common shares outstanding:				
Basic	54,496	53,938	54,361	53,358
Dilutive common stock options (1)		1,811		
Dilutive common stock warrants (1)				
Dilutive Convertible Senior Unsecured Notes (1)				
Diluted	54,496	55,749	54,361	53,358
Basic income (loss) per share	$ (0.61)	$ 0.15	$ (0.97)	$ (0.21)
Diluted income (loss) per share	$ (0.61)	$ 0.14	$ (0.97)	$ (0.21)

(1) Except for the three months ended September 30, 2005, dilutive shares were not included in the calculation, as we had a net loss for each of the periods presented.

NOTE 11 Other Comprehensive Income (Loss)

The following table is a reconciliation of our net income (loss) to our comprehensive income (loss) for the three and nine months ended September 30, 2006 and 2005 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005 (as adjusted)	2006	2005 (as adjusted)
Net income (loss)	$ (33,106)	$ 8,047	$ (52,536)	$ (11,078)
Other comprehensive income (loss) items:				
Cash flow hedges, net of tax	(40,209)	13,255	(16,004)	(2,238)
Foreign currency translation	(13)		(47)	
Comprehensive income (loss)	$ (73,328)	$ 21,302	$ (68,587)	$ (13,316)

NOTE 12 Related Party Transactions

From time to time, officers and employees may charter aircraft for company business travel. We entered into a letter agreement, or charter letter, with an unrelated third-party entity, Western Airways, Inc. (Western), that specified the terms under which it would provide for charter of a Challenger 600 aircraft. One of the Challenger 600 aircraft which could be provided by Western for such services was owned by Bramblebush, L.L.C. (the LLC). The LLC is owned and/or controlled by our Chairman and Chief Executive Officer, Charif Souki. Our Code of Business Conduct and Ethics prohibits potential conflicts of interest. Upon the recommendation of our Audit Committee, which determined that the terms of the charter letter were fair and in our best interest, our Board of Directors unanimously approved the terms of the charter letter in May 2005 and granted an exception under our Code of Business Conduct and

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

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Ethics in order to permit us to charter the Challenger 600 aircraft. For the three and nine months ended September 30, 2006, we incurred zero and $111,000, respectively, related to the charter of the Challenger 600 aircraft owned by the LLC.

NOTE 13 Commitments and Contingencies

In April 2006, Corpus Christi LNG, LLC, our wholly-owned subsidiary (Corpus Christi LNG), entered into an engineering, procurement and construction (EPC) services agreement for preliminary work with La Quinta LNG Partners, LP (La Quinta). La Quinta is a limited partnership whose general partners are Zachry Construction Corporation and AMEC E&C Services, Inc. Under the terms of the agreement, La Quinta will provide Corpus Christi LNG with certain preliminary design, engineering, procurement, pipeline dismantlement, removal and construction, road construction and site preparation work on a reimbursable basis in connection with the Corpus Christi LNG receiving terminal. Payments anticipated to be made by Corpus Christi LNG to La Quinta for work performed under the agreement are not expected to exceed $50,000,000. Such preliminary site work commenced during the second quarter of 2006 and is expected to be completed in early 2007.

In April 2006, Cheniere Marketing entered into a 10-year Gas Purchase and Sale Agreement with PPM Energy, Inc. (PPM), a subsidiary of Scottish Power PLC. Upon completion of certain of our facilities, the agreement provides Cheniere Marketing with the ability to sell to PPM up to 600,000 MMBtus of natural gas per day at a Henry Hub-related market index price, and requires Cheniere Marketing to allocate to PPM a portion of the LNG that it procures under certain planned long-term LNG supply agreements.

In April 2006, CCTP entered into a purchase order with ILVA for the purchase of approximately 15 miles of 42-inch pipe at an aggregate cost of approximately $16,000,000. An initial payment of $500,000 was made to ILVA in May 2006. Additional progress payments will be due on a periodic basis after specified production measures have been achieved. CCTP has the right to terminate the purchase order for its convenience, subject to making specified cancellation payments that begin at $500,000 and increase, depending on the achievement of specified production measures, to 100% of the value after pipe forming but prior to shipment.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

In July 2006, we entered into a lease agreement for new office space with Sunbelt Management Company, to lease four floors (approximately 81,733 square feet) in the North Tower of Houston Pennzoil Place, including an additional floor for one year with a renewal option. The term runs for 10 $^{1}/2$ years from April 2007 through October 2017 with an option to cancel by payment of a fee after the 6th year, and a renewal option to extend for three successive 5-year terms. The base rental for each year will be due and payable in equal installments and is quoted per square footage of net rentable area within the leased premises. In addition, we will pay additional rental in the form of operating expenses plus a 3% management fee. Future annual minimum lease payments are as follows (in thousands):

Year Ending December 31,	Operating Lease
2007	$ 163
2008	807
2009	858
2010	858
2011	858
Thereafter	6,263
Total	$ 9,807

In July 2006, Sabine Pass LNG entered into an engineering, procurement, construction and management (EPCM) Agreement for Phase 2 Stage 1 with Bechtel Corporation (Bechtel) for engineering, procurement, construction and management of construction services in connection with our 1.4 billion cubic feet per day expansion at our Sabine Pass LNG receiving terminal. Bechtel is acting on our behalf as manager. Under the terms of the EPCM agreement, Bechtel will be paid on a cost reimbursable basis, plus a fixed fee in the amount of $18,500,000. A discretionary bonus may be paid to Bechtel at Sabine Pass LNG s sole discretion upon completion of Phase 2.

In July 2006, Sabine Pass LNG entered into an EPC LNG Unit Rate Soil Improvement Contract with Remedial Construction Services, L.P. (Remedial) for engineering, procurement, and construction of soil improvement work. Work includes, but is not limited to, design, surveying, estimating, procurement and transportation of materials, equipment, labor, supervision and construction activities necessary to satisfactorily complete work on the Phase 2 Stage 1 site. The estimated total contract price is $28,500,000. A 10% initial payment of $2,850,000 was made to Remedial in August 2006 and is classified under Other non-current assets on the Consolidated Balance Sheet. Additional progress payments will be paid based on quantities of work performed at unit rates, minus 10% retainage that will be paid upon final completion as well as any credits and early payment discounts applicable.

In July 2006, Sabine Pass LNG entered into an EPC LNG Tank Contract with Diamond LNG LLC (Diamond) and Zachry Construction Corporation (Zachry and collectively with Diamond, the Tank Contractor) for the construction of two Phase 2 Stage 1 tanks. In addition, Sabine Pass LNG has the option for the Tank Contractor to engineer, procure and construct a third tank, with the cost and completion date thereof to be agreed upon if such option is elected on or before March 2007. The estimated total contract price is $140,870,000 for Diamond and Zachry. Initial payments of $6,437,000 were made to Diamond and Zachry in August 2006. Additional milestone payments for work incurred, minus a 5% retainage that will be paid upon final completion, will be based on a lump-sum, fixed price, subject to adjustments based on fluctuations in the cost of labor and change orders.

Under a settlement agreement dated as of June 14, 2001, we agreed to pay to certain interests a royalty related to LNG receiving terminal throughput, which we refer to as the Crest Royalty. This Crest

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(Unaudited)

Royalty is calculated based on the volume of natural gas processed through the Freeport LNG facility and our terminals. The Crest Royalty is subject to a stated maximum of $10,950,000 per year, which is reached when approximately 1.0 Bcf/d is processed at covered LNG facilities. We refer to this as the Maximum Crest Royalty. Freeport LNG has assumed the Crest Royalty obligation for natural gas processed at Freeport LNG s receiving terminal. Freeport LNG has entered into TUAs with ConocoPhillips Company and an affiliate of The Dow Chemical Company, under which capacity payments commence when the Freeport LNG receiving terminal begins commercial operations. The ConocoPhillips TUA is for approximately 0.5 Bcf/d initially and increases to approximately 1.0 Bcf/d in October 2009. The Dow TUA is for approximately 0.5 Bcf/d. Freeport LNG has announced that it expects to commence commercial operations in 2008. If Crest Royalty payments by Freeport LNG for LNG throughput at the Freeport LNG facility are less than the Maximum Crest Royalty, we will be required to pay the Crest Royalty for LNG throughput at our terminals until the Maximum Crest Royalty has been paid.

In August 2006, CCTP entered into a purchase order with CPW America Co. for the purchase of pipe at an aggregate cost of $63,800,000, which is payable in increments beginning with a payment made in the third quarter of 2006. Subsequent payment increments are tied to coil production milestones with additional remaining payments due on a per lot basis related to pipe production shipping and delivery milestones. The purchase order provides that all pipe is to be manufactured between January 1, 2007 and the end of the first week of March 2007, with all pipe delivered prior to April 15, 2007. CCTP has the right to terminate the purchase order for its convenience, subject to making specified cancellation payments that begin at $6,380,000 and increase to 100% of the value of the lots produced depending on the achievement of specified production measures.

In August 2006, CCTP entered into a purchase order with ILVA for the purchase of pipe at an aggregate cost of approximately $175,700,000. Milestone progress payments are due and payable on a per lot basis once the pipe has been shipped from ILVA s pipe mill, and again upon delivery of ex-coatings work in New Iberia, Louisiana. Within 10 days after the execution of the purchase order in August 2006, CCTP delivered a standby letter of credit to ILVA in the amount of $87,852,000 to secure CCTP s obligations under the purchase order. This letter of credit required a deposit of $87,852,000 with the issuer of the letter of credit. Once the value of the goods and services paid by CCTP exceeds the value of the letter of credit, ILVA will submit a notice of reduction to the issuing bank to reduce the amount of the letter of credit by 100% of any subsequent payments by CCTP. The cash collateral account on deposit with the issuing bank will be reduced by such amount. The purchase order provides that all pipe be delivered to New Iberia, Louisiana prior to January 31, 2008. CCTP has the right to terminate the purchase order for its convenience, subject to making specified cancellation payments that begin at $500,000 and increase to 100% of the value of the lots produced depending on the achievement of specified production measures.

NOTE 14 Business Segment Information

We have four business segments: LNG receiving terminal, natural gas pipeline, LNG and natural gas marketing, and oil and gas exploration and development. These segments reflect lines of business for which separate financial information is produced internally and are subject to evaluation by our chief operating decision makers in deciding how to allocate resources.

Our LNG receiving terminal segment is in various stages of developing three, 100% owned, LNG receiving terminal projects along the U.S. Gulf Coast at the following locations: Sabine Pass LNG in western Cameron Parish, Louisiana on the Sabine Pass Channel; Corpus Christi LNG near Corpus

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

Christi, Texas; and Creole Trail LNG at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. In addition, we own a 30% limited partner interest in a fourth project, Freeport LNG, located on Quintana Island near Freeport, Texas.

Our natural gas pipeline segment is in various stages of developing three, 100% owned, natural gas pipelines in connection with our three LNG receiving terminals to provide access to North American natural gas markets. Development efforts to date have focused primarily on feasibility analysis and on advancing our pipeline projects through the regulatory review and authorization process.

Our LNG and natural gas marketing segment is in an early stage of development. To optimize the utilization of our LNG receiving terminal capacity, we intend to purchase LNG from foreign suppliers, arrange transportation of LNG to our network of LNG receiving terminals, arrange the transportation of revaporized natural gas through our pipelines and other interconnected pipelines and sell natural gas to buyers in the North American market. In addition, we also expect to enter into domestic natural gas purchase and sale transactions as part of our marketing activities.

Our oil and gas exploration and development segment explores for oil and natural gas using a regional database of approximately 7,000 square miles of regional 3D seismic data. Exploration efforts are focused on the shallow waters of the Gulf of Mexico offshore of Louisiana and Texas and consist primarily of active interpretation of our seismic data and generation of prospects, through participation in the drilling of wells, and through farm-out arrangements and back-in interests (a reversionary interest in oil and gas leases reserved by us) whereby the capital costs of such activities are borne primarily by industry partners. This segment participates in drilling and production operations with industry partners on the prospects that we generate.

The following table summarizes revenues, net income (loss) and total assets for each of our operating segments (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005 (as adjusted)	2006	2005 (as adjusted)
Revenues:				
LNG receiving terminal	$	$	$	$
Natural gas pipeline				
LNG and natural gas marketing				
Oil and gas exploration and development	737	729	1,572	2,154
Total	737	729	1,572	2,154
Corporate and other (1)				
Total consolidated	$ 737	$ 729	$ 1,572	$ 2,154
Net income (loss):				
LNG receiving terminal	$ (9,064)	$ (8,300)	$ (32,387)	$ (16,738)
Natural gas pipeline (2)	667	(761)	9,477	(6,792)
LNG and natural gas marketing	(1,305)		(4,144)	
Oil and gas exploration and development	(975)	20,523	(3,352)	20,415
Total	(10,677)	11,462	(30,406)	(3,115)
Corporate and other (1)	(22,429)	(3,415)	(22,130)	(7,963)

Total consolidated	$ (33,106)	$ 8,047	$ (52,536)	$ (11,078)

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

	September 30, 2006	December 31, 2005 (as adjusted)
Total assets:		
LNG receiving terminal	$ 1,097,133	$ 783,837
Natural gas pipeline	30,412	
LNG and natural gas marketing	3,232	
Oil and gas exploration and development	4,053	2,328
Total	1,134,830	786,165
Corporate and other (1)	477,272	503,982
Total consolidated	$ 1,612,102	$ 1,290,147

(1) Includes corporate activities and certain intercompany eliminations.

(2) Natural gas pipeline income for the nine months ended September 30, 2006, includes the impact of the regulatory asset recorded in the second quarter of 2006 as prescribed by SFAS No. 71. Not including the impact of the recognition of this regulatory asset, natural gas pipeline income would have been a net loss of $3,209,000 for the nine months ended September 30, 2006.

NOTE 15 Adjustment to Financial Statements Successful Efforts

As a result of our election to change our method of accounting for investments in oil and gas properties as discussed in Note 1 Basis of Presentation , adjustments have been made to the financial statements of prior periods as required by SFAS No. 154, *Accounting Changes and Error Corrections*. The effects of the change as it relates to financial data for the periods presented are displayed below (in thousands, except per share data):

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

Statement of Operations

(Unaudited)

	Three Months Ended September 30, 2006		
	As Computed Under Full Cost	As Reported Under Successful Efforts	Effect of Change
Revenues	$ 737	$ 737	$
Operating costs and expenses:			
LNG receiving terminal and pipeline development expenses	2,923	2,923	
Exploration costs		661	661
Oil and gas production costs	61	61	
Impairment of fixed assets	1,628	1,628	
Depreciation, depletion and amortization	1,065	896	(169)
Ceiling test write-down	4,472		(4,472)
General and administrative expenses	12,044	12,044	
Total operating costs and expenses	22,193	18,213	(3,980)
Loss from operations	(21,456)	(17,476)	3,980
Non-operating loss	(551)	(551)	
Loss before income taxes	(22,007)	(18,027)	3,980
Income tax benefit (provision)	(15,079)	(15,079)	
Net loss	$ (37,086)	$ (33,106)	$ 3,980
Net loss per share basic and diluted	$ (0.68)	$ (0.61)	$ 0.07

	Three Months Ended September 30, 2005		
	As Originally Reported	As Reported Under Successful Efforts	Effect of Change
Revenues	$ 729	$ 729	$
Operating costs and expenses:			
LNG receiving terminal and pipeline development expenses	4,127	4,127	
Exploration costs		246	246
Oil and gas production costs	78	78	
Depreciation, depletion and amortization	682	362	(320)
Ceiling test write-down			
General and administrative expenses	6,523	6,523	
Total operating costs and expenses	11,410	11,336	(74)

Loss from operations		(10,681)		(10,607)		74
Non-operating income		18,359		18,654		295
Income before income taxes		7,678		8,047		369
Income tax benefit (provision)						
Net income	$	7,678	$	8,047	$	369
Net income per share basic	$	0.14	$	0.15	$	0.01
Net income per share diluted	$	0.14	$	0.14	$	

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

Statement of Operations

(Unaudited)

	Nine Months Ended September 30, 2006		
	As Computed Under Full Cost	As Reported Under Successful Efforts	Effect of Change
Revenues	$ 1,572	$ 1,572	$
Operating costs and expenses:			
LNG receiving terminal and pipeline development expenses	6,730	6,730	
Exploration costs		2,089	2,089
Oil and gas production costs	166	166	
Impairment of fixed assets	1,628	1,628	
Depreciation, depletion and amortization	3,030	2,080	(950)
Ceiling test write-down	17,295		(17,295)
General and administrative expenses	37,669	37,669	
Total operating costs and expenses	66,518	50,362	(16,156)
Loss from operations	(64,946)	(48,790)	16,156
Non-operating loss	(1,876)	(1,701)	175
Loss before income taxes	(66,822)	(50,491)	16,331
Income tax provision	(2,045)	(2,045)	
Net loss	$ (68,867)	$ (52,536)	$ 16,331
Net loss per share basic and diluted	$ (1.27)	$ (0.97)	$ 0.30

	Nine Months Ended September 30, 2005		
	As Originally Reported	As Reported Under Successful Efforts	Effect of Change
Revenues	$ 2,154	$ 2,154	$
Operating costs and expenses:			
LNG receiving terminal and pipeline development expenses	14,902	14,902	
Exploration costs		1,347	1,347
Oil and gas production costs	166	166	
Depreciation, depletion and amortization	1,737	816	(921)
Ceiling test write-down			
General and administrative expenses	17,114	17,114	
Total operating costs and expenses	33,919	34,345	426

Loss from operations	(31,765)	(32,191)	(426)
Non-operating income and minority interest	20,294	21,016	722
Loss before income taxes	(11,471)	(11,175)	296
Minority interest	97	97	
Income tax benefit (provision)			
Net income (loss)	$ (11,374)	$ (11,078)	$ 296
Net income (loss) per share basic and diluted	$ (0.21)	$ (0.21)	$

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

Balance Sheet

(Unaudited)

	September 30, 2006		
	As Computed Under Full Cost	As Reported Under Successful Efforts	Effect of Change
Current assets	$ 745,687	$ 745,687	$
Oil and gas properties, net	4,606	2,960	(1,646)
Other property, plant and equipment, net	621,066	621,066	
Total property, plant and equipment, net	625,672	624,026	(1,646)
Other non-current assets	242,389	242,389	
Total assets	$ 1,613,748	$ 1,612,102	$ (1,646)
Current liabilities	$ 64,096	$ 64,096	$
Non-current liabilities	1,330,181	1,330,181	
Common stock	166	166	
Additional paid-in capital	383,736	383,736	
Accumulated deficit	(152,178)	(153,824)	(1,646)
Accumulated other comprehensive loss	(12,253)	(12,253)	
Total stockholders equity	219,471	217,825	(1,646)
Total liabilities and stockholders equity	$ 1,613,748	$ 1,612,102	$ (1,646)

	December 31, 2005		
	As Originally Reported	As Adjusted	Effect of Change
Current assets	$ 871,463	$ 871,463	$
Oil and gas properties, net	19,617	1,640	(17,977)
Other property, plant and equipment, net	278,466	278,466	
Total property, plant and equipment, net	298,083	280,106	(17,977)
Other non-current assets	138,578	138,578	
Total assets	$ 1,308,124	$ 1,290,147	$ (17,977)
Current liabilities	$ 61,322	$ 61,322	$

Non-current liabilities	960,284	960,284	
Common stock	164	164	
Additional paid-in capital	375,551	375,551	
Deferred compensation	(9,684)	(9,684)	
Accumulated deficit	(83,311)	(101,288)	(17,977)
Accumulated other comprehensive income	3,798	3,798	
Total stockholders equity	286,518	268,541	
Total liabilities and stockholders equity	$ 1,308,124	$ 1,290,147	$ (17,977)

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

Statement of Cash Flows

(Unaudited)

	Nine Months Ended September 30, 2006		
	As Computed Under Full Cost	As Reported Under Successful Efforts	Effect of Change
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (68,867)	$ (52,536)	$ 16,331
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	3,030	2,080	(950)
Impairment of fixed assets	1,628	1,628	
Ceiling test write-down	17,295		(17,295)
Dry hole expense		894	894
Impairment of unproved property		416	416
Other adjustments	20,302	20,302	
Changes in operating assets and liabilities	(13,565)	(13,565)	
NET CASH USED IN OPERATING ACTIVITIES	(40,177)	(40,781)	(604)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas property additions, net of sales	(3,172)	(2,568)	604
Other cash flows from other investing activities	(398,837)	(398,837)	
NET CASH USED IN INVESTING ACTIVITIES	(402,009)	(401,405)	604
NET CASH PROVIDED BY FINANCING ACTIVITIES	336,381	336,381	
NET DECREASE IN CASH AND CASH EQUIVALENTS	(105,805)	(105,805)	
CASH AND CASH EQUIVALENTS BEGINNING OF PERIOD	692,592	692,592	
CASH AND CASH EQUIVALENTS END OF PERIOD	$ 586,787	$ 586,787	$

	Nine Months Ended September 30, 2005		
	As Originally Reported	As Reported Under Successful Efforts	Effect of Change
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (11,374)	$ (11,078)	$ 296
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	1,737	816	(921)
Impairment of unproved properties		583	583
Other adjustments	(13,974)	(13,974)	

Changes in operating assets and liabilities	14,512	14,512	
NET CASH USED IN OPERATING ACTIVITIES	(9,099)	(9,141)	(42)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas property additions, net of sales	(747)	(705)	42
Other cash flows from other investing activities	(369,071)	(369,071)	
NET CASH USED IN INVESTING ACTIVITIES	(369,818)	(369,776)	42
NET CASH PROVIDED BY FINANCING ACTIVITIES	809,420	809,420	
NET INCREASE IN CASH AND CASH EQUIVALENTS	430,503	430,503	
CASH AND CASH EQUIVALENTS BEGINNING OF PERIOD	308,443	308,443	
CASH AND CASH EQUIVALENTS END OF PERIOD	$ 738,946	$ 738,946	$

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

NOTE 16 Share-Based Compensation

We have granted options to purchase common stock to employees, consultants and outside directors under the Cheniere Energy, Inc. Amended and Restated 1997 Stock Option Plan (1997 Plan) and the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (2003 Plan). Prior to January 1, 2006, we accounted for grants made under the 1997 Plan and 2003 Plan using the intrinsic value method under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* and related interpretations, and applied SFAS No. 123, *Accounting for Stock-Based Compensation*, as amended by SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*, for disclosure purposes only. Under APB Opinion No. 25, stock-based compensation cost related to stock options was not recognized in net income since the options granted under those plans had exercise prices greater than or equal to the market value of the underlying stock on the date of grant.

Effective January 1, 2006, we adopted SFAS No. 123 (revised 2004), *Share-Based Payment*, which revised SFAS No. 123 and superseded APB No. 25. SFAS No. 123R requires that all share-based payments to employees be recognized in the financial statements based on their fair values at the date of grant. The calculated fair value is recognized as expense (net of any capitalization) over the requisite service period, net of estimated forfeitures, using the straight-line method under SFAS No. 123R. We consider many factors when estimating expected forfeitures, including types of awards, employee class and historical experience. The statement was adopted using the modified prospective method of application, which requires compensation expense to be recognized in the financial statements for all unvested stock options beginning in the quarter of adoption. No adjustments to prior periods have been made as a result of adopting SFAS No. 123R. Under this transition method, compensation expense for share-based awards granted prior to January 1, 2006, but not yet vested as of January 1, 2006, and not previously amortized through the pro forma disclosures required by SFAS No. 123, will be recognized in our financial statements over their remaining service period. The cost was based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123. As allowed by SFAS No. 123, compensation cost associated with forfeited options was reversed for disclosure purposes in the period of forfeiture. As required by SFAS No. 123R, compensation expense recognized in future periods for share-based compensation granted prior to adoption of the standard will be adjusted for the effects of estimated forfeitures.

For the nine months ended September 30, 2006 and 2005, the total stock-based compensation expense recognized in our net loss was $15,975,000 and $2,487,000, respectively. The impact of adopting SFAS No. 123R on our results of operations for the first nine months of 2006 was an increase in expenses of $12,721,000, with a corresponding increase in our loss from operations, loss before income taxes and minority interest, and net loss resulting from the first-time recognition of compensation expense associated with employee stock options. The impact on our basic and diluted net loss per common share was an increase in per share net loss of $0.23. For the nine months ended September 30, 2006 and 2005, the total stock-based compensation cost capitalized as part of the cost of capital assets was $1,100,000 and $109,000, respectively.

The total unrecognized compensation cost at September 30, 2006 relating to non-vested share-based compensation arrangements granted under the 1997 Plan and 2003 Plan, before any capitalization, was $70,944,000. That cost is expected to be recognized over six years, with a weighted average period of 2.2 years.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

The adoption of SFAS No. 123R had no effect on net cash flow. Had we been a taxpayer, we would have recognized cash flow resulting from tax deductions in excess of recognized compensation cost as a financing cash flow. We received total proceeds from the exercise of stock options of $1,728,000 and $1,575,000 in the nine months ended September 30, 2006 and 2005, respectively.

The following table illustrates the pro forma net income and earnings per share that would have resulted in the three and nine months ended September 30, 2005 from recognizing compensation expense associated with accounting for employee stock-based awards under the provisions of SFAS No. 123. The reported and pro forma net income and earnings per share for the three and nine months ended September 30, 2006 are provided for comparative purposes only, as stock-based compensation expense is recognized in the financial statements under the provisions of SFAS No. 123R (in thousands, except per share data).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005 (as adjusted)	2006	2005 (as adjusted)
Net income (loss) as reported	$ (33,106)	$ 8,047	$ (52,536)	$ (11,078)
Add: Stock-based employee compensation included in net income (loss) (1)	5,079	842	15,975	2,487
Deduct:				
Total stock-based employee compensation expense determined under fair value method for all awards, net of related income tax (1)(2)	(5,079)	(4,576)	(15,975)	(11,353)
Pro forma net income (loss)	$ (33,106)	$ 4,313	$ (52,536)	$ (19,944)
Net income (loss) per share				
Basic as reported	$ (0.61)	$ 0.14	$ (0.97)	$ (0.21)
Diluted as reported	$ (0.61)	$ 0.14	$ (0.97)	$ (0.21)
Basic pro forma	$ (0.61)	$ 0.08	$ (0.97)	$ (0.37)
Diluted pro forma	$ (0.61)	$ 0.08	$ (0.97)	$ (0.37)

(1) Three and nine months ended 2005 conformed to 2006 presentation.
(2) Fair value of stock options computed using Black-Scholes-Merton option pricing model and the value of non-vested stock based on intrinsic value in accordance with SFAS No. 123R and SFAS No. 123.

Stock Options

During the first nine months of 2006, we issued options to purchase 476,220 shares of our common stock under the 2003 Plan. This included options to purchase 131,220 shares, granted to employees primarily as hiring incentives, having an exercise price equal to the stock price on the date of grant, graded vesting over four years, and a 10-year contractual life; an option to purchase 300,000 shares granted to our Chairman of the Board and Chief Executive Officer having an exercise price of $90.00, graded vesting over three years beginning in March 2010, and a 10-year contractual life; a fully vested option to purchase 25,000 shares granted to one of our directors having an exercise price equal to the stock price on the date of grant and a 10-year contractual life; and an option to purchase 20,000 shares having an exercise price equal to the stock price on the date of grant, graded vesting over two years, and a

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

five-year contractual life granted to a consultant in exchange for services. These options are being accounted for in accordance with the guidance in SFAS No. 123R, with the exception of the consultant grant, which is being accounted for in accordance with the relevant accounting guidance for equity instruments granted to a non-employee.

We estimate the fair value of stock options under SFAS No. 123R at the date of grant using a Black-Scholes-Merton valuation model, which is consistent with the valuation technique we previously utilized to value options for the footnote disclosures required under SFAS No. 123. The following table provides the weighted average assumptions used in the Black-Scholes-Merton option valuation model to value options granted in the three and nine months ended September 30, 2006 and 2005, respectively. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant. The expected term (estimated period of time outstanding) of options granted in 2006 is based on the simplified method of estimating expected term for plain vanilla options allowed by Securities and Exchange Commission (SEC) Staff Accounting Bulletin No. 107 and varies based on the vesting period and contractual term of the option. Prior to 2006, the expected term was based on our historical experience and estimate of future behavior of employees. Expected volatility for options granted in 2006 is based on an equally weighted average of the implied volatility of exchange traded options on our common stock expiring more than one year from the measurement date, and historical volatility of our common stock for a period equal to the option's expected life. Prior to 2006, estimated volatility was based solely on the historical volatility of our common stock for a period equal to the option s expected life. We have not declared dividends on our common stock.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005 (as adjusted)	2006	2005 (as adjusted)
Risk-free rate	4.8%	3.8-4.2%	4.3-4.8%	3.6-4.4%
Expected life (in years)	6.3	6.8	6.9	6.8
Expected volatility range	58%	77-80%	52-69%	77-101%
Weighted average volatility	58%	79%	65%	96%
Expected dividends	0.0%	0.0%	0.0%	0.0%

The table below provides a summary of option activity under the combined plans as of September 30, 2006, and changes during the nine months then ended:

	Options (in thousands)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2006	5,125	$ 28.66		
Granted	476	70.89		
Exercised	(381)	36.58		
Forfeited or Expired	(31)	37.35		
Outstanding at September 30, 2006	5,189	34.15	7.5	$ 29,302

Exercisable at September 30, 2006	1,009	$	12.12	4.4	$	18,658

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

The weighted average grant-date fair value of options granted during the nine months ended September 30, 2006 and 2005 was $23.50 and $20.19, respectively. The total intrinsic value of options exercised during the nine months ended September 30, 2006 and 2005 was $11,455,000 and $17,292,000, respectively.

Stock and Non-Vested Stock

We have granted stock and non-vested stock to employees and outside directors under the 2003 Plan. Prior to January 1, 2006, we accounted for grants of non-vested stock using the intrinsic value method under the recognition and measurement principles of APB No. 25 and recognized the computed value of the non-vested stock in stockholders equity as an increase in additional paid-in-capital and a corresponding reduction in stockholders equity attributable to deferred compensation. The balance in deferred compensation was amortized ratably over the vesting period to non-cash compensation expense (before any capitalization) with a corresponding decrease in the deferred compensation balance.

Under SFAS No. 123R, grants of non-vested stock continue to be accounted for on an intrinsic value basis. No recognition of deferred compensation is made in stockholders equity. Instead, the amortization of the calculated value of non-vested stock grants is accounted for as a charge to non-cash compensation and an increase in additional paid-in-capital over the requisite service period. With the adoption of SFAS No. 123R, we offset the remaining unamortized deferred compensation balance ($9,684,000 at December 31, 2005) in stockholders equity against additional paid-in-capital. Amortization of the remaining unamortized balance will continue under SFAS No. 123R as described above.

In January 2006, 78,671 shares having three-year graded vesting were issued to certain of our executive officers. In the nine months ended September 30, 2006, a total of 209,180 shares of non-vested stock having four-year graded vesting were issued to new employees.

The table below provides a summary of the status of our non-vested shares under the 2003 Plan as of September 30, 2006, and changes during the nine months then ended (in thousands except for per share information):

	Non-Vested Shares	Weighted Average Grant-Date Fair Value Per Share
Non-vested at January 1, 2006	550	$ 21.06
Granted (1)	287	38.06
Vested	(222)	8.08
Forfeited	(10)	34.33
Non-vested at September 30, 2006	605	$ 33.74

(1) Includes an award of 25,000 non-vested shares granted under the French Addendum to the 2003 Plan, which were not issued and outstanding at September 30, 2006.

The weighted average grant-date fair value of non-vested stock granted during the nine months ended September 30, 2006 and 2005 was $38.06 and $33.17, respectively. The total grant-date fair value of shares vested during the nine months ended September 30, 2006 and 2005 was $1,759,388 and $1,716,000, respectively.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

(Unaudited)

Share-Based Plan Descriptions and Information

Our 1997 Plan provides for the issuance of stock options to purchase up to 5,000,000 shares of our common stock, all of which have been granted. Non-qualified stock options were granted to employees, contract service providers and outside directors. Option terms for the remaining unexercised options are five years with vesting that generally occurs on a graded basis over three years.

Awards providing for the issuance of up to an aggregate of 11,000,000 shares of our common stock may be made under our 2003 Plan. These awards may be in the form of non-qualified stock options, incentive stock options, purchased stock, restricted (non-vested) stock, bonus (unrestricted) stock, stock appreciation rights, phantom stock, and other stock-based performance awards deemed by the Compensation Committee to be consistent with the purposes of the 2003 Plan. To date, the only awards made by the Compensation Committee have been in the form of non-qualified stock options, restricted stock and bonus stock. Beginning in 2005, stock options granted to employees as hiring incentives have been granted at the money with 10-year terms and graded vesting over four years. Prior to that time, stock options granted as hiring incentives were granted at the money with five-year terms and graded vesting over three years. Retention grants made to employees provide for exercise prices at or in excess of the stock price on the grant date, 10-year terms, and graded vesting over three years, which commences on the fourth anniversary of the grant date. Restricted stock that has been granted as a hiring incentive vests over four years on a graded basis, while restricted stock granted from a bonus pool vests over three years. Shares issued under the 2003 Plan are generally newly issued shares.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This quarterly report contains certain statements that are, or may be deemed to be, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). All statements, other than statements of historical fact, included herein or incorporated herein by reference are forward-looking statements. Included among forward-looking statements are, among other things:

- statements that we expect to commence or complete construction or commence operation of each of our proposed liquefied natural gas (LNG) receiving terminals or our proposed pipelines, including any expansions or extensions thereof, by certain dates, or at all;

- statements that we expect to receive Draft Environmental Impact Statements or Final Environmental Impact Statements from the Federal Energy Regulatory Commission (FERC) by certain dates, or at all, or that we expect to receive an order from the FERC authorizing us to construct and operate proposed LNG receiving terminals or proposed pipelines by certain dates, or at all;

- statements regarding future levels of domestic or foreign natural gas production or consumption or future levels of LNG imports into North America or sales of natural gas in North America, regardless of the source of such information, or the transportation or other infrastructure or prices related to natural gas, LNG or other hydrocarbon products;

- statements regarding any financing transactions or arrangements, or ability to enter into such transactions, whether on the part of Cheniere or at the project level, including financing arrangements for which we may have received commitment letters;

- statements relating to the construction of our proposed LNG receiving terminals and our proposed pipelines, including statements concerning the engagement of any engineering, procurement and construction (EPC) contractor, or any engineering, procurement, construction and management (EPCM) contractor, and the anticipated terms and provisions of any agreement with an EPC or EPCM contractor, and anticipated costs related thereto;

- statements regarding any terminal use agreement (TUA) or other agreement to be entered into or performed substantially in the future, including any cash distributions and revenues anticipated to be received and the anticipated timing thereof, and statements regarding the amounts of total regasification capacity that are, or may become subject to, TUAs or other contracts;

- statements that our proposed LNG receiving terminals and pipelines, when completed, will have certain characteristics, including amounts of regasification and storage capacities, a number of storage tanks and docks, pipeline deliverability and the number of pipeline interconnections, if any;

- statements regarding our business strategy, our business plans or any other plans, forecasts or objectives, any or all of which are subject to change;

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statements regarding any Securities and Exchange Commission (SEC) or other governmental or regulatory inquiry or investigation;

statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;

statements regarding our anticipated LNG supply and natural gas marketing activities; and

any other statements that relate to non-historical or future information.

These forward-looking statements are often identified by the use of terms and phrases such as achieve, anticipate, believe, estimate, expect, forecast, plan, project, propose, strategy and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve assumptions, risks and uncertainties, and these expectations may prove to be incorrect. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this quarterly report.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of a variety of factors, including those discussed under Risk Factors in our annual report on Form 10-K for the year ended December 31, 2005. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. These forward-looking statements are made as of the date of this quarterly report. Other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

BUSINESS AND OPERATIONS

General

We are engaged primarily in the business of developing and constructing, and then owning and operating, a network of three, 100% owned, onshore LNG receiving terminals, and related natural gas pipelines, along the Gulf Coast of the United States. We are also in the early stages of developing a business to market LNG and natural gas. To a limited extent, we are also engaged in oil and natural gas exploration and development activities in the Gulf of Mexico. We operate four business segments: LNG receiving terminal, natural gas pipeline, LNG and natural gas marketing, and oil and gas exploration and development.

LNG Receiving Terminals

Our three LNG receiving terminals are currently in various stages of development at the following locations: Sabine Pass LNG in western Cameron Parish, Louisiana on the Sabine Pass Channel; Corpus Christi LNG near Corpus Christi, Texas; and Creole Trail LNG at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. In addition, we own a 30% limited partner interest in a fourth project, Freeport LNG, located on Quintana Island near Freeport, Texas. Our three terminals have an aggregate designed regasification capacity of approximately 9.9 Bcf/d, subject to further expansion. We have entered into long-term TUAs with Total LNG, Inc. (Total) and Chevron USA, Inc. (Chevron) for an aggregate of approximately 2.0 Bcf/d of the available regasification capacity at Sabine Pass LNG. We have also agreed to amend and restate the existing TUA with Cheniere Marketing, Inc. (formerly Cheniere LNG Marketing, Inc.), our wholly-owned subsidiary (Cheniere Marketing), to reserve approximately 2.0 Bcf/d (currently 1.5 Bcf/d) of regasification capacity at Sabine Pass LNG. In addition, Cheniere Marketing also is a party to a TUA reserving approximately 1.0 Bcf/d of regasification capacity at our Corpus Christi LNG receiving terminal.

Construction of Phase 1 of our Sabine Pass LNG receiving terminal commenced in March 2005, and we anticipate commencing operations at that terminal in 2008. In July 2006, we received authorization to construct Phase 2 of our Sabine Pass LNG receiving terminal from the FERC and issued a notice to proceed to our EPC and other contractors to begin construction.

In order to accelerate the timing of the development of our Corpus Christi LNG facility, we elected to commence preliminary site work, including certain design and engineering work associated with site preparation for the Corpus Christi LNG receiving terminal during the second quarter of 2006. Such preliminary site preparation work is expected to be completed in early 2007. In June 2006, the FERC granted authorization under Section 3 of the Natural Gas Act, to site, construct and operate the Creole Trail LNG receiving terminal.

Natural Gas Pipelines

We anticipate developing and constructing natural gas pipelines from each of our three LNG receiving terminals to provide access to North American natural gas markets.

In February 2006, Cheniere Sabine Pass Pipeline, L.P., our wholly-owned subsidiary (Sabine Pass Pipeline L.P.), entered into an EPC pipeline contract with Willbros Engineers, Inc. (Willbros) for the engineering, procurement, construction and construction management of our proposed Sabine Pass pipeline, a 16-mile, 42-inch diameter natural gas pipeline designed to transport 2.6 Bcf/d of natural gas from our Sabine Pass LNG receiving terminal, running easterly along a corridor that will allow for interconnection points with existing interstate and intrastate natural gas pipelines near Johnson Bayou, Louisiana. Subject to FERC approval of the implementation plan for construction of this pipeline, we anticipate beginning construction in early 2007 and anticipate commencing operations of the pipeline in the fourth quarter of 2007. For more information on this transaction, please refer to the discussion under the caption Liquidity and Capital Resources Natural Gas Pipelines Sabine Pass Pipeline.

In June 2006, the FERC issued an order authorizing our wholly-owned subsidiary, Cheniere Creole Trail Pipeline, L.P. (CCTP), to construct a proposed 117-mile, dual 42-inch diameter pipeline, designed to transport 3.3 Bcf/d of natural gas from our proposed Creole Trail LNG receiving terminal, running north/northeasterly along a corridor through six Louisiana parishes and terminating near Rayne, Louisiana. We refer to this as the Creole Trail Pipeline.

At the request of Cheniere Marketing, CCTP is seeking approval from the FERC to authorize construction of an approximately 18-mile, 42-inch diameter pipeline interconnection between the Sabine Pass pipeline and the Creole Trail pipeline systems. Among other things, this would allow Cheniere Marketing to make deliveries of natural gas from our Sabine Pass LNG receiving terminal to delivery points on the Creole Trail pipeline system.

Cheniere Marketing is currently the sole holder of the entire capacity on both the Creole Trail pipeline and the Sabine Pass pipeline. Cheniere Marketing has entered into a 10-year gas purchase and sale agreement with PPM Energy, Inc., a subsidiary of Scottish Power PLC (PPM), pursuant to which Cheniere Marketing will make supplies of regasified LNG from the Sabine Pass LNG terminal available to PPM at delivery points on the Creole Trail pipeline.

LNG and Natural Gas Marketing

Our LNG and natural gas marketing business is in its early stages of development. We intend to utilize a portion of our planned LNG receiving terminal regasification capacity through Cheniere Marketing, which has agreed to reserve approximately 2.0 Bcf/d of regasification capacity at the Sabine Pass LNG receiving terminal and has reserved 1.0 Bcf/d of regasification capacity at the Corpus Christi LNG receiving terminal. To optimize the utilization of this capacity, we intend to purchase LNG from foreign suppliers, arrange transportation of LNG to our network of LNG receiving terminals, arrange the transportation of revaporized natural gas through our pipelines and other interconnected pipelines and sell natural gas to buyers in the North American market. In addition, we expect to enter into domestic natural gas purchase and sale transactions as part of our marketing activities.

Oil and Gas Exploration and Development

Although our focus is primarily on the development of LNG-related businesses, we continue to be involved to a limited extent in oil and gas exploration, development and exploitation, and in exploitation of our existing 3D seismic database through prospect generation. We have historically focused on evaluating and generating drilling prospects using a regional and integrated approach with a large seismic database as a platform. From time to time, we will invest in drilling a share of these prospects and may pursue opportunities in other geographic locations as well.

LIQUIDITY AND CAPITAL RESOURCES

We are primarily engaged in LNG-related business activities. Our three LNG receiving terminal projects, as well as our related proposed natural gas pipelines, will require significant amounts of capital and are subject to risks and delays in completion. In addition, our marketing business will need a substantial amount of capital for hiring employees, satisfying creditworthiness requirements of contracts and developing the systems necessary to implement our business strategy. Even if successfully completed and implemented, our LNG-related business activities are not expected to begin to operate and generate cash flows before the first quarter of 2008, at the earliest. As a result, our business success will depend to a significant extent upon our ability to obtain the funding necessary to construct our three LNG receiving terminals and related pipelines, to bring them into operation on a commercially viable basis and to finance the costs of staffing, operating and expanding our company during that process.

We currently estimate that the cost of completing our three LNG receiving terminals will be approximately $3 billion, before financing costs. In addition, we expect that capital expenditures of approximately $800 million to $1 billion will be required to construct our three related natural gas pipelines.

As of September 30, 2006, we had working capital of $681.6 million. However, we must augment our existing sources of working capital with significant additional funds in order to carry out our long-term business plan. We currently expect that our capital requirements will be financed in part through cash on hand, issuances of project-level debt, equity or a combination of the two and in part with net proceeds of debt or equity securities issued by Cheniere or its subsidiaries or other borrowings.

LNG Receiving Terminals

Sabine Pass LNG

We currently estimate that the cost of constructing Phase 1 of the Sabine Pass LNG receiving terminal will be approximately $900 million to $950 million, before financing costs. The Phase 2 Stage 1 expansion of the Sabine Pass LNG receiving terminal, including the construction of two tanks and related facilities, is estimated to cost approximately $500 million to $550 million, before financing costs. Funding for Phase 1 and Phase 2 Stage 1 is described below.

Amended Sabine Pass Credit Facility

In February 2005, Sabine Pass LNG entered into an $822.0 million credit agreement with a syndicate of financial institutions. This original credit facility was subsequently amended and restated on July 21, 2006. On such date, Sabine Pass LNG entered into a First Amended and Restated Credit

Agreement with Société Générale (the Agent), HSBC Bank USA, National Association (the Collateral Agent) and the lenders named therein (the Amended Sabine Pass Credit Facility). The Amended Sabine Pass Credit Facility increased the amount of loans available to Sabine Pass LNG from $822.0 million under the original credit facility to $1.5 billion to finance Phase 1 and Phase 2 Stage 1 construction of the Sabine Pass LNG receiving terminal.

Principal must be repaid in semi-annual installments commencing upon the earlier of six months following the term conversion date (as defined in the Amended Sabine Pass Credit Facility) or such earlier date as may be specified by Sabine Pass LNG upon satisfaction of certain conditions on or before October 1, 2009. Scheduled amortization during the repayment period will be based upon a 19-year mortgage style semi-annual amortization profile with a balloon payment due on the final maturity date, July 1, 2015.

Borrowings under the Amended Sabine Pass Credit Facility bear interest at a variable rate equal to LIBOR plus the applicable margin. The applicable margin varies from 0.875% to 1.125% during the term of the Amended Sabine Pass Credit Facility. Interest is calculated on the unpaid principal amount outstanding and is payable semi-annually in arrears. A commitment fee of 0.50% per annum on the daily, undrawn portion of the lenders commitments is required. Administrative fees must also be paid annually to the Agent and the Collateral Agent.

The Collateral Agent holds all funds and other investments of Sabine Pass LNG in certain collateral accounts in the name of Sabine Pass LNG but under the exclusive control of the Collateral Agent.

In connection with the closing of the Amended Sabine Pass Credit Facility, Sabine Pass LNG entered into additional interest rate swap agreements with HSBC Bank USA and Société Générale. The new swap agreements, along with similar agreements entered into in connection with the closing of the original Sabine Pass credit agreement in February 2005, have the combined effect of fixing the LIBOR component of the interest rate payable on borrowings up to a maximum of $1.25 billion at a blended rate of 5.26% from July 25, 2006 through July 1, 2015 (see Note 5 Derivative Instruments of our Notes to Consolidated Financial Statements). See also the discussion under the caption Pending Senior Secured Notes Offering below with regard to a pending sale of notes by Sabine Pass LNG.

Phase 1 EPC Agreement

In December 2004, Sabine Pass LNG entered into a lump-sum turnkey EPC agreement with Bechtel Corporation (Bechtel) for the construction of Phase 1 of the Sabine Pass LNG receiving terminal. Under the EPC agreement, Bechtel agreed to provide Sabine Pass LNG with services for the engineering, procurement and construction of the receiving terminal. Except for certain third-party work specified in the EPC agreement, the work to be performed by Bechtel includes all of the work required to achieve substantial completion and final completion of Phase 1 of the LNG receiving terminal in accordance with the requirements of the EPC agreement. This lump-sum turnkey EPC agreement for Phase 1 remains in effect.

Sabine Pass LNG agreed to pay to Bechtel a contract price of $646.9 million plus certain reimbursable costs for the work performed under the EPC agreement. This contract price is subject to adjustment for changes in certain commodity prices, contingencies, change orders and other items. As of September 30, 2006, change orders for $89.1 million were approved, thereby increasing the total contract price to $736.1 million. We anticipate that additional change orders, intended to mitigate ongoing effects of the 2005 hurricanes will not exceed $25 million.

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Phase 2 Stage 1 Construction Agreements

On July 21, 2006, Sabine Pass LNG entered into three construction agreements in connection with the Phase 2 expansion of the Sabine Pass LNG receiving terminal as follows:

Sabine Pass LNG and Bechtel have entered into an EPCM Agreement for Phase 2 Stage 1 pursuant to which Bechtel will provide design and engineering services for Phase 2 Stage 1 of the LNG receiving terminal, except for such portions to be designed by other contractors and suppliers of equipment, materials and services that contract directly with Sabine Pass LNG; construction management services to manage the construction of the LNG receiving terminal; and performance of a portion of the construction. Under the terms of the EPCM Agreement, Bechtel will be paid on a cost reimbursable basis, plus a fixed fee in the amount of $18.5 million. A discretionary bonus may be paid to Bechtel at Sabine Pass LNG s sole discretion upon completion of Phase 2 Stage 1.

An EPC LNG Tank Contract (the Tank Contract) was entered into by Sabine Pass LNG with Zachry Construction Corporation (Zachry) and Diamond LNG LLC (Diamond and collectively with Zachry, the Tank Contractor). The Tank Contractor will furnish all plant, labor, materials, tools, supplies, equipment, transportation, supervision, technical, professional and other services, and perform all operations necessary and required to satisfactorily engineer, procure and construct two Phase 2 tanks. In addition, Sabine Pass LNG has the option (to be elected on or before March 31, 2007) for the Tank Contractor to engineer, procure and construct a third tank, with the cost and completion date thereof to be agreed upon after if the option is elected. The Tank Contract provides for a lump-sum, fixed price payable to the Tank Contractor in the amount of approximately $140.9 million (the Contract Price) for the construction of the two Phase 2 Stage 1 tanks. The Contract Price is subject to adjustment based on fluctuations in the cost of labor and change orders.

An EPC LNG Unit Rate Soil Contract has been entered into with Remedial Construction Services, L.P. (the Soil Contractor). The Soil Contractor is required to furnish all plant, labor, materials, tools, supplies, equipment, transportation, supervision, technical, professional and other services, and perform all operations necessary and required to satisfactorily conduct soil remediation and improvement on the Phase 2 site. Upon issuing a final notice to proceed, Sabine Pass LNG paid the Soil Contractor an initial payment of approximately $2.9 million. The Soil Contract price is based on unit rates (the Unit Prices). Payments under the Soil Contract will be made based on quantities of work performed at Unit Prices.

Customer TUAs

Total has paid Sabine Pass LNG nonrefundable advance capacity reservation fees of $20.0 million in the aggregate in connection with the reservation under a 20-year TUA of approximately 1.0 Bcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal. These capacity reservation fee payments will be amortized over a 10-year period as a reduction of Total s regasification capacity fees payable under the TUA.

Chevron has paid Sabine Pass LNG nonrefundable advance capacity reservation fees of $20.0 million in the aggregate in connection with the reservation under a 20-year TUA of approximately 1.0 Bcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal. These capacity reservation fee payments will be amortized over a 10-year period as a reduction of Chevron regasification capacity fees payable under the TUA.

Sabine Pass LNG has agreed to amend and restate its current TUA with Cheniere Marketing to reserve approximately 2.0 Bcf/d of regasification capacity at our Sabine Pass LNG receiving terminal.

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Corpus Christi LNG

We currently estimate that the cost of constructing the Corpus Christi LNG receiving terminal will be approximately $650 million to $750 million, before financing costs. This estimate is based in part on our negotiations with a major international EPC contractor. Our cost estimate is subject to change due to such items as cost overruns, change orders, changes in commodity prices (particularly steel) and escalating labor costs.

Site Preparation

In order to accelerate the timing of its development of this facility, Corpus Christi LNG elected in April 2006 to commence preliminary site work and entered into an engineering, procurement and construction services agreement for preliminary work with La Quinta LNG Partners, L.P. (La Quinta). La Quinta is a limited partnership whose general partners are Zachry and AMEC E&C Services, Inc. Under the terms of the agreement, La Quinta will provide Corpus Christi LNG with certain preliminary design, engineering, construction and site preparation work on a reimbursable basis in connection with the Corpus Christi LNG receiving terminal. Such preliminary site work commenced during the second quarter of 2006 and is expected to be completed in early 2007. Payments anticipated to be made by Corpus Christi LNG to La Quinta for work performed under the agreement are not expected to exceed $50 million. We will contemplate making a final investment decision to complete construction of this facility upon, among other things, achieving acceptable commercial arrangements.

Funding

We currently expect to fund the amounts payable under the La Quinta EPC agreement from existing cash balances. The remainder of the project cost is expected to be funded through project financing similar to that used for our Sabine Pass LNG receiving terminal, existing cash, proceeds from debt or equity offerings, or a combination thereof. If these types of financing are not available, we will be required to seek alternative sources of financing, which may not be available on acceptable terms, if at all.

Customers

Cheniere Marketing has entered into a TUA with Corpus Christi LNG for 1.0 Bcf/d of regasification capacity at the Corpus Christi LNG receiving terminal.

Creole Trail LNG

We currently estimate that the cost of constructing the Creole Trail LNG receiving terminal will be approximately $850 million to $950 million, before financing costs. Our cost estimate is preliminary and subject to change. We currently expect to fund the costs of the Creole Trail LNG terminal project using financing similar to that used for our Sabine Pass LNG receiving terminal, proceeds from future debt or equity offerings, existing cash or a combination thereof. If these types of financing are not available, we will be required to seek alternative sources of financing, which may not be available on acceptable terms, if at all.

Other LNG Interests

We have a 30% limited partner interest in Freeport LNG Development, L.P. (Freeport LNG). Under the limited partnership agreement of Freeport LNG, development expenses of the Freeport LNG project and other Freeport LNG cash needs generally are to be funded out of Freeport LNG s own cash flows, borrowings or other sources, and, up to a pre-agreed total amount, with capital contributions by the limited partners. In July 2004, Freeport LNG entered into a credit agreement with ConocoPhillips Company to provide a substantial majority of the debt financing for the initial phase of the project. We received capital calls, and made capital contributions, in the amount of approximately $2.1 million in 2005. In December 2005, Freeport LNG announced that it had closed a $383.0 million private placement of notes, which will be used to fund the remaining portion of the initial phase of the project and potentially a portion of the cost of expanding the LNG receiving terminal and the development of underground salt cavern gas storage. As a result of such financing being obtained, we do not anticipate that any capital calls will be made upon the limited partners of Freeport LNG in the foreseeable future.

Although no capital calls are currently outstanding, and we do not anticipate any in the foreseeable future, additional capital calls may be made upon us and the other limited partners of Freeport LNG. In the event of each such future capital call, we will have the option either to contribute the requested capital or to decline to contribute. If we decline to contribute, the other limited partners could elect to make our contribution and receive back twice the amount contributed on our behalf, without interest, before any Freeport LNG cash flows are otherwise distributed to us. We currently expect to evaluate Freeport LNG capital calls on a case-by-case basis and to fund additional capital contributions that we elect to make using cash on hand and funds raised through future equity or debt offerings or other borrowings.

Natural Gas Pipelines

We estimate that approximately $800 million to $1 billion of total capital expenditures will be required to construct our three proposed natural gas pipelines. We currently expect to fund the costs of our three pipeline projects from our existing cash balances, project financing, proceeds from future debt or equity offerings, or a combination thereof. If these types of financing are not available, we will be required to seek alternative sources of financing, which may not be available on acceptable terms, if at all.

Sabine Pass Pipeline

In February 2006, Sabine Pass Pipeline L.P. entered into an EPC pipeline contract with Willbros. Under the EPC pipeline contract, Willbros will provide Sabine Pass Pipeline L.P. with services for the management, engineering, material procurement, construction and construction management of the Sabine Pass pipeline. Sabine Pass Pipeline L.P. entered into the EPC pipeline contract sufficiently in advance of commencement of physical construction of the pipeline in order to perform detailed engineering and procure materials. This EPC pipeline contract, among other things, provides for a guaranteed maximum price of approximately $67.7 million, subject to adjustment under certain circumstances, as provided in the contract. We estimate that the total cost to construct the Sabine Pass pipeline, including certain work not included in the EPC pipeline contract, such as interconnection with third-party pipelines, will be approximately $98 million. Our total cost estimate is preliminary and subject to change due to such items as cost overruns, change orders, changes in commodity prices (particularly steel) and escalation of labor costs.

Creole Trail Pipeline

CCTP has entered into purchase orders with two suppliers for the procurement of pipe anticipated to be sufficient to construct the approximately 252 miles required for the Creole Trail pipeline, which is comprised of 117 miles of dual 42-inch diameter pipe and 18 miles of 42-inch diameter interconnection. The aggregate cost of these purchase orders is approximately $255 million, payable in increments, as described below.

In August 2006, CCTP entered into a purchase order with CPW America Co. for the purchase of pipe at an aggregate cost of approximately $63.8 million, which is payable in increments beginning with a payment of $6.4 million made in August 2006. Subsequent payment increments are tied to coil production milestones with additional remaining payments due on a per lot basis related to pipe production shipping and delivery milestones. The purchase order provides that all pipe is to be manufactured between January 1, 2007 and the end of the first week of March 2007, with all pipe delivered prior to April 15, 2007. CCTP has the right to terminate the purchase order for its convenience, subject to making specified cancellation payments that begin at $6.3 million and increase to 100% of the value of the lots produced depending on the achievement of specified production measures.

In August 2006, CCTP also entered into a purchase order with ILVA S.p.A. (ILVA) for the purchase of pipe at an aggregate cost of approximately $175.7 million. Milestone progress payments are due and payable on a per lot basis once the pipe has been shipped from ILVA s pipe mill, and again upon delivery of ex-coatings work in New Iberia, Louisiana. Within 10 days after the execution of the purchase order, CCTP delivered a standby letter of credit to ILVA in the amount of $87.9 million to secure CCTP s obligations under the purchase order. This letter of credit required a deposit of $87.9 million with the issuer of the letter of credit. Once the value of the goods and services paid by CCTP exceeds the value of the letter of credit, ILVA will submit a notice of reduction to the issuing bank to reduce the amount of the letter of credit by 100% of any subsequent payment by CCTP. The cash collateral account on deposit with the issuing bank will also be reduced by such amount. The purchase order provides that all pipe is to be delivered to New Iberia, Louisiana prior to January 31, 2008. CCTP has reserved the right to terminate the purchase order for its convenience, subject to making specified cancellation payments that begin at $0.5 million and increase, depending on the achievement of specified production measures, to 100% of the value after pipe forming but prior to shipment.

In addition to the above, CCTP also entered into a purchase order in April 2006 with ILVA for the purchase of approximately 15 miles of 42-inch pipe at an aggregate cost of approximately $16 million. An initial payment of $0.5 million was made to ILVA in May 2006. Additional progress payments will be due on a periodic basis after specified production measures have been achieved. CCTP has the right to terminate the purchase order for its convenience, subject to making specified cancellation payments that begin at $0.5 million and increase, depending on the achievement of specified production measures, to 100% of the value after pipe forming but prior to shipment.

Construction contracts have not been entered into for either the Creole Trail or Corpus Christi pipeline.

LNG and Natural Gas Marketing

We are in the early stages of developing our LNG and natural gas marketing business. We will need to spend funds to develop our marketing business, including capital required to satisfy any creditworthiness requirements under contracts. These costs are expected to be incurred to develop the systems necessary to implement our business strategy and to hire additional employees to conduct our natural gas marketing activities. We expect to fund these expenses with available cash balances.

In April 2006, Cheniere Marketing entered into a 10-year Gas Purchase and Sale Agreement with PPM. Upon completion of certain of our facilities, the agreement provides Cheniere Marketing the ability to sell to PPM up to 600,000 MMBtus of natural gas per day at a Henry Hub-related market index price, and requires Cheniere Marketing to allocate to PPM a portion of the LNG that it procures under certain planned long-term LNG supply agreements.

Other Capital Resources

Convertible Senior Unsecured Notes

In July 2005, we consummated a private offering of $325.0 million aggregate principal amount of Convertible Senior Unsecured Notes due August 1, 2012 (the Notes) to qualified institutional buyers pursuant to Rule 144A under the Securities Act. The Notes bear interest at a rate of 2.25% per year. The Notes are convertible into our common stock pursuant to the terms of the indenture governing the Notes at an initial conversion rate of 28.2326 per $1,000 principal amount of the Notes, which is equal to a conversion price of approximately $35.42 per share. We may redeem some or all of the Notes on or before August 1, 2012, for cash equal to 100% of the principal plus any accrued and unpaid interest if in the previous 10 trading days the volume-weighted average price of our common stock exceeds $53.13, subject to adjustment, for at least five consecutive trading days. In the event of such a redemption, we will make an additional payment equal to the present value of all remaining scheduled interest payments through August 1, 2012, discounted at the U.S. Treasury rate plus 50 basis points. The indenture governing the Notes contains customary reporting requirements.

Concurrently with the issuance of the Notes, we also entered into hedge transactions in the form of an issuer call spread (consisting of a purchase and a sale of call options on our common stock) with an affiliate of the initial purchaser of the Notes, having a term of two years and a net cost to us of $75.7 million. These hedge transactions are expected to offset potential dilution from conversion of the Notes up to a market price of $70.00 per share. The net cost of the hedge transactions will be recorded as a reduction to Additional Paid-in-Capital on our Consolidated Balance Sheet in accordance with the guidance of EITF Issue 00-19, *Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company s Own Stock*. Net proceeds from the offering were $239.8 million, after deducting the cost of the hedge transactions, the underwriting discount and related fees. As of September 30, 2006, no holders had elected to convert their Notes.

Term Loan

In August 2005, Cheniere LNG Holdings, LLC, a wholly-owned subsidiary (Cheniere LNG Holdings) entered into a $600.0 million Term Loan with Credit Suisse. The Term Loan has an interest rate equal to LIBOR plus a 2.75% margin and terminates on August 30, 2012. In connection with the closing Cheniere LNG Holdings entered into swap agreements with Credit Suisse (the Term Loan Swaps) to hedge the LIBOR interest rate component of the Term Loan. The blended rate of the swap agreements on the Term Loan results in an annual fixed interest rate of 7.25% (including the 2.75% margin) for the first five years (see Note 5 Derivative Instruments of our Notes to Consolidated Financial Statements). On December 30, 2005, Cheniere LNG Holdings made the first required quarterly principal payment of $1.5 million. Quarterly principal payments of $1.5 million are required through June 30, 2012, and a final principal payment of $559.5 million is required on August 30, 2012. The Term Loan contains customary affirmative and negative covenants. The obligations of Cheniere LNG Holdings are secured by its 100% equity interest in Sabine Pass LNG and its 30% limited partner equity interest in Freeport LNG.

Under the provisions of the Term Loan, Cheniere LNG Holdings was required to fund from the loan proceeds a total of $216.2 million into two collateral accounts. These funds are restricted and to be disbursed only for the payment of interest and principal due under the Term Loan, reimbursement of certain expenses, and funding of additional capital contributions to Sabine Pass LNG as required under the Amended Sabine Pass Credit Facility. Because these accounts are controlled by Credit Suisse, the collateral agent, our cash and cash equivalent undisbursed balance of $140.8 million held in these accounts as of September 30, 2006 is classified as restricted on our Consolidated Balance Sheet. Of this amount, $12.0 million is classified as non-current due to the timing of certain required debt amortization payments.

Pending Senior Secured Notes Offering

On November 1, 2006, we announced that Sabine Pass LNG had agreed to issue $550.0 million of 7.25% senior secured notes due 2013 and $1,482.0 million of 7.50% senior secured notes due 2016. Proceeds from the senior secured note sale, scheduled to close November 9, 2006, are intended to be used to: repay borrowings under, and replace, the Amended Sabine Pass Credit Facility; to repay, together with other funds, the Term Loan; to fund a reserve account for scheduled interest payments of the senior secured notes through May 2009; to fund the remaining costs to complete Phase 1 and Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal; and to pay related transaction costs and expenses.

Short-Term Liquidity Needs

We anticipate funding our more immediate liquidity requirements, including expenditures related to the construction of our LNG receiving terminals and pipelines, the growth of our marketing business and our oil and gas exploration, development and exploitation activities, through a combination of any or all of the following:

- cash balances;
- drawings under the Amended Sabine Pass Credit Facility;
- issuances of debt and equity securities, including issuances of common stock pursuant to exercises by the holders of existing options;
- LNG receiving terminal capacity reservation fees; and
- collection of receivables.

Historical Cash Flows

Net cash used in operating activities increased to $40.8 million during the nine months ended September 30, 2006 compared to $9.1 million in the same period of 2005. This $31.7 million increase was primarily due to continued development of our LNG receiving terminals and related pipelines and increased costs to support such activities.

Net cash used in investing activities was $401.4 million during the nine months ended September 30, 2006 compared to net cash used in investing activities of $369.8 million during the nine months ended September 30, 2005. During the first nine months of 2006, we invested $307.6 million relating to our LNG receiving terminal and pipeline construction activities and we increased our investment in restricted cash and cash equivalents by $62.3 million ($87.9 million to secure a letter of credit, and net of debt payments for interest and principal). In the first nine months of 2006, we also made advances under certain EPC and long-term contracts totaling $14.5 million and invested $8.0 million and $2.6 million in fixed assets and oil and gas drilling activities (net of sales), respectively. During the first nine months of 2005, we invested $164.5 million in construction-in-progress costs related to our LNG receiving terminals. We also advanced $16.2 million (net of $16.1 million credited against invoices and transferred to construction-in-progress) to Bechtel related to the construction of our Sabine Pass LNG receiving terminal. The remaining cash used in investing activities for the first nine months of 2005 primarily related to transfers to the Sabine Pass LNG restricted cash collateral accounts under the original Sabine Pass credit agreement, purchase of fixed assets, advances to Freeport LNG and oil and gas property additions. These uses of cash were partially offset by $20.2 million in proceeds received from the sale of our interest in Gryphon Exploration Company (Gryphon).

Net cash provided by financing activities during the first nine months of 2006 was $336.4 million compared to $809.4 million in the same period of 2005. During the first nine months of 2006, we received proceeds from borrowings under the original Sabine Pass credit agreement and the Amended Sabine Pass Credit Facility totaling $351.5 million and $1.7 million received from the issuance of common stock related to stock option exercises. These proceeds were partially offset by $4.5 million in Term Loan principal payments, $3.0 million in debt issuance costs related to the original Sabine Pass credit agreement, which became due when the first borrowing was made thereunder, and $8.4 million in

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debt issuance costs relating to the refinancing of this facility during the third quarter of 2006. In addition, we paid federal withholding taxes of $0.9 million in exchange for 24,300 shares of our common stock, which related to common stock previously awarded to an executive officer that vested in February 2006. During the first nine months of 2005, we received proceeds from the issuance of the Notes and under the Term Loan in the amounts of $249.3 million (net of $75.7 million for the issuer call spread) and $600.0 million, respectively. In addition, we received $2.1 million in proceeds from the exercise of stock options and warrants. These proceeds were partially offset by $42.0 million in debt issuance costs related to the original Sabine Pass credit agreement, the Notes and the Term Loan.

Due to the factors described above, our cash and cash equivalents decreased to $586.8 million as of September 30, 2006 compared to $692.6 million at December 31, 2005, and our working capital decreased to $681.6 million as of September 30, 2006 compared to $810.1 million at December 31, 2005.

Issuances of Common Stock

During the first nine months of 2006, a total of 283,068 shares of our common stock were issued pursuant to the exercise of stock options, resulting in net cash proceeds of $1.7 million. In addition, 76,534 shares of common stock were issued in satisfaction of cashless exercise of options to purchase 97,801 shares of common stock.

In January 2006, 78,671 shares were issued to executive officers in the form of non-vested (restricted) stock awards related to our performance in 2005. During the first nine months of 2006, we issued 209,180 shares of non-vested restricted stock to new employees.

We paid federal payroll withholding taxes of $0.9 million in exchange for 24,300 shares of our common stock, which related to common stock previously awarded to an executive officer that vested in February 2006. These shares were initially recorded as treasury shares, at cost, but were retired in June 2006.

Off-Balance Sheet Arrangements

As of September 30, 2006, we had no off-balance sheet debt or other such unrecorded obligations, and we have not guaranteed the debt of any other party.

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RESULTS OF OPERATIONS

Three Months Ended September 30, 2006

vs. Three Months Ended September 30, 2005

Consolidated Results (in thousands):

	Three Months Ended September 30, 2006					
	LNG Receiving Terminal	Natural Gas Pipeline	LNG & Natural Gas Marketing	Oil & Gas Exploration & Development	Corporate & Other	Consolidated
Revenue	$	$	$	$ 737	$	$ 737
Operating costs and expenses						
LNG receiving terminal and pipeline development expenses	3,150	(227)				2,923
Exploration costs				661		661
Oil and gas production costs				61		61
Impairment of fixed assets					1,628	1,628
Depreciation, depletion and amortization	36		13	113	734	896
General and administrative expenses	1,305	2	1,292	877	8,568	12,044
Total operating costs and expenses	4,491	(225)	1,305	1,712	10,930	18,213
Income (loss) from operations	(4,491)	225	(1,305)	(975)	(10,930)	(17,476)
Derivative loss	(966)					(966)
Interest expense	(5,662)	241			(5,465)	(10,886)
Interest income	2,055				9,045	11,100
Other income		201				201
Income tax provision					(15,079)	(15,079)
Net income (loss)	$ (9,064)	$ 667	$ (1,305)	$ (975)	$ (22,429)	$ (33,106)

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	Three Months Ended September 30, 2005 (as adjusted)					
	LNG Receiving Terminal	Natural Gas Pipeline	LNG & Natural Gas Marketing	Oil & Gas Exploration & Development	Corporate & Other	Consolidated
Revenue	$	$	$	$ 729	$	$ 729
Operating costs and expenses						
LNG receiving terminal and pipeline development expenses	3,367	760				4,127
Exploration costs				246		246
Oil and gas production costs				78		78
Depreciation, depletion and amortization	16			13	333	362
General and administrative expenses	1,824	1		370	4,328	6,523
Total operating costs and expenses	5,207	761		707	4,661	11,336
Income (loss) from operations	(5,207)	(761)		22	(4,661)	(10,607)
Gain on sale of investment in unconsolidated affiliate				20,206		20,206
Equity in net loss of limited partnership	(2,261)					(2,261)
Derivative gain	931					931
Interest expense	(2,381)				(2,677)	(5,058)
Interest income	618				3,923	4,541
Other income				295		295
Net income (loss)	$ (8,300)	$ (761)	$	$ 20,523	$ (3,415)	$ 8,047

Financial results for the third quarter of 2006 reflect a net loss of $33.1 million, or $0.61 per share (basic and diluted), compared to net income of $8.0 million, or $0.15 per basic share and $0.14 per diluted share for the third quarter of 2005.

The major factors contributing to our net loss of $33.1 million during the third quarter of 2006 were charges for general and administrative (G&A) expenses of $12.0 million, an income tax provision of $15.1 million, interest expense of $10.9 million and LNG receiving terminal and pipeline development expenses of $2.9 million, partially offset by interest income of $11.1 million. The tax provision relates to the portion of the change in our tax asset valuation account that is allocable to the deferred income tax on items reported in accumulated other comprehensive income (loss) primarily related to derivative instruments in accordance with Statement of Financial Accounting Standard (SFAS) No. 109, *Account for Income Taxes*, and EITF *Abstract*, Topic D-32. The major factors contributing to our net income of $8.0 million during the third quarter of 2005 was the $20.2 million gain on the sale of our investment in Gryphon, which was partially offset by LNG receiving terminal and pipeline development expenses of $4.1 million and G&A expenses of $6.5 million.

As of January 1, 2006, we adopted SFAS No. 123R, *Share-Based Payment*, which requires that all share-based payments to employees be recognized in the financial statements based on their fair value at the date of grant. As a result, we recorded $4.0 million of non-cash compensation expense related to stock options in the third quarter of 2006.

LNG Receiving Terminal Segment

Financial results for our LNG receiving terminal segment for the third quarter of 2006 reflect a net loss of $9.1 million, compared to a net loss of $8.3 million for the third quarter of 2005.

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LNG development expenses were 9% lower in the third quarter of 2006 ($3.1 million) than in the third quarter of 2005 ($3.4 million). Our development expenses primarily included professional fees associated with front-end engineering and design work, obtaining orders from the FERC authorizing construction of our facilities and other required permitting for our planned LNG receiving terminals. Other expenses directly related to the development of our LNG receiving terminals include the expenses of our employees directly involved in the LNG development activities. For the third quarter of 2006, employee-related costs (net of capitalization) increased to $2.4 million (including an increase of $1.0 million for non-cash compensation primarily resulting from stock option expense) from $1.1 million for the same period in 2005. The increase in employee-related costs was due to an increase in the average number of employees engaged in LNG terminal development activities from 34 in the third quarter of 2005 to 70 in the third quarter of 2006. The increase in employee-related costs was offset during the third quarter of 2006 by lower engineering and technical costs associated with our Creole Trail and Corpus Christi LNG receiving terminals and the expansion of our Sabine Pass LNG receiving terminal due to increased construction activities replacing development activities at our Sabine Pass and Corpus Christi LNG receiving terminals. In addition, development activities for our proposed Creole Trail LNG receiving terminal decreased during the third quarter of 2006.

G&A expenses were 27% lower in the third quarter of 2006 ($1.3 million) than in the third quarter of 2005 ($1.8 million). Our G&A expenses primarily related to a management fee (net of capitalization) as prescribed by contractual management services agreements between Sabine Pass LNG and two other wholly-owned subsidiaries, evaluation of software required for Sabine Pass LNG receiving terminal operations, and Hurricane Rita relief efforts. The $0.5 million decrease in the third quarter of 2006 compared to the same period in the previous year was primarily due to decreased software evaluation and other employee costs.

The increase in interest income and interest expense (net of capitalization) of $1.4 million and $3.3 million, respectively, from the third quarter of 2005 to the same period in 2006 was due to the borrowings from the Term Loan being outstanding for three months in the third quarter of 2006, as compared to being outstanding for approximately one month in the third quarter of 2005.

The net loss in the third quarter of 2005 includes a $2.3 million equity loss relating to our equity share of the loss of Freeport LNG.

Natural Gas Pipeline Segment

Financial results for our natural gas pipeline segment for the third quarter of 2006 reflect net income of $0.7 million, compared to a net loss of $0.8 million for the third quarter of 2005.

Natural gas pipeline development expenses decreased $1.0 million in the third quarter of 2006 to a negative expense of $0.2 million compared to an expense of $0.8 million in the third quarter of 2005. Historically, our natural gas pipeline development expenses primarily included professional fees associated with front-end engineering and design work, obtaining orders from the FERC authorizing construction of our pipelines and other required permitting for our planned natural gas pipelines. During the second quarter of 2006, however, we recognized regulatory assets, as prescribed by SFAS No. 71 (see Note 3 Property, Plant and Equipment of our Notes to Consolidated Financial Statements), that had previously been expensed as pipeline development expenses. The third quarter of 2006 natural gas pipeline development expense includes the deferral of certain engineering and feasibility costs relating to a proposed segment of our Creole Trail pipeline in accordance with SFAS No. 71. These costs, which had previously been expensed, will be deferred until the FERC application is approved and the final investment decision is made, at which time these deferred costs will be transferred to construction-in-process. The $0.8 million of development expense during the third quarter of 2005 related to front-end engineering and design work completed for the Creole Trail pipeline.

LNG and Natural Gas Marketing Segment

Financial results for our LNG and natural gas marketing segment for the third quarter of 2006 reflect a net loss of $1.3 million, compared to zero for the third quarter of 2005, as we had not begun development of this segment at that time. G&A expenses incurred in the third quarter of 2006 were primarily related to employee costs and legal and consulting fees.

Oil and Gas Exploration and Development Segment

Financial results for our oil and gas exploration and development segment for the third quarter of 2006 reflect a net loss of $1.0 million, compared to net income of $20.5 million for the third quarter of 2005. The decrease in net income was primarily attributable to the $20.2 million gain on the sale of our investment in Gryphon in the third quarter of 2005. G&A expenses increased in 2006 compared to 2005 as a result of non-cash share-based compensation primarily from stock option expenses.

Corporate and Other

Financial results for corporate and other activities for the third quarter of 2006 reflect a net loss of $22.4 million, compared to a net loss of $3.4 million for the third quarter of 2005.

G&A expenses increased $4.3 million, or 100%, to $8.6 million in the third quarter of 2006 compared to $4.3 million in the third quarter of 2005. The increase in G&A expenses primarily resulted from the expansion of our business (including increases in our corporate staff from an average of 54 employees in the third quarter of 2005 to an average of 106 employees in the third quarter of 2006). Included in G&A expenses is an increase in non-cash compensation of $2.7 million primarily resulting from stock option expenses. Corporate employee-related costs for the third quarter of 2006 and 2005 included non-cash compensation of $3.1 million and $0.4 million, respectively.

In the third quarter of 2006, we impaired $1.6 million of our leasehold costs related to our current office space at 717 Texas Avenue in Houston, Texas. The impairment was the result of signing our new office lease for space in Houston Pennzoil Place (see Note 13 Commitments and Contingencies of our Notes to Consolidated Financial Statements), and the belief that we would not recover our leasehold costs in the future.

Interest income was $5.1 million greater in the third quarter of 2006 ($9.0 million) than in the third quarter of 2005 ($3.9 million). The increase in interest income was due to the increase in cash balances and average interest rates from September 30, 2005 to September 30, 2006.

A tax provision of $15.1 million was recognized in the third quarter of 2006 relating to the portion of the change in our tax asset valuation account that is allocable to the deferred income tax on items reported in accumulated OCI primarily related to derivative instruments in accordance with SFAS No. 109, *Accounting for Income Taxes*, and EITF *Abstract*, Topic D-32. The deferred tax provision recorded in the third quarter of 2006 was limited to the amount of tax benefit previously recorded, which was reduced to zero in the third quarter of 2006.

Interest expense was $5.5 million in the third quarter of 2006 compared to $2.7 million in the third quarter of 2005. The increase in interest expense was due to the increase in outstanding indebtedness from September 30, 2005 to September 30, 2006.

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Nine Months Ended September 30, 2006

vs. Nine Months Ended September 30, 2005

Consolidated Results (in thousands):

	Nine Months Ended September 30, 2006					
	LNG Receiving Terminal	Natural Gas Pipeline	LNG & Natural Gas Marketing	Oil & Gas Exploration & Development	Corporate & Other	Consolidated
Revenue	$	$	$	$ 1,572	$	$ 1,572
Operating costs and expenses						
LNG receiving terminal and pipeline development expenses	15,540	(8,810)				6,730
Exploration costs				2,089		2,089
Oil and gas production costs				166		166
Impairment of fixed assets					1,628	1,628
Depreciation, depletion and amortization	100		20	172	1,788	2,080
General and administrative expenses	5,389	13	4,124	2,673	25,470	37,669
Total operating costs and expenses	21,029	(8,797)	4,144	5,100	28,886	50,362
Income (loss) from operations	(21,029)	8,797	(4,144)	(3,528)	(28,886)	(48,790)
Derivative loss	(44)					(44)
Interest expense	(17,220)	371			(16,271)	(33,120)
Interest income	5,906				25,072	30,978
Other income		309		176		485
Income tax provision					(2,045)	(2,045)
Net income (loss)	$ (32,387)	$ 9,477	$ (4,144)	$ (3,352)	$ (22,130)	$ (52,536)

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	Nine Months Ended September 30, 2005 (as adjusted)					
	LNG Receiving Terminal	Natural Gas Pipeline	LNG & Natural Gas Marketing	Oil & Gas Exploration & Development	Corporate & Other	Consolidated
Revenue	$	$	$	$ 2,154	$	$ 2,154
Operating costs and expenses						
LNG receiving terminal and pipeline development expenses	8,111	6,791				14,902
Exploration costs				1,347		1,347
Oil and gas production costs				166		166
Depreciation, depletion and amortization	25			43	748	816
General and administrative expenses	4,071	1		1,111	11,931	17,114
Total operating costs and expenses	12,207	6,792		2,667	12,679	34,345
Loss from operations	(12,207)	(6,792)		(513)	(12,679)	(32,191)
Gain on sale of investment in unconsolidated affiliate				20,206		20,206
Equity in net loss of limited partnership	(3,232)					(3,232)
Derivative gain	264					264
Interest expense	(2,381)				(2,677)	(5,058)
Interest income	721				7,393	8,114
Other				722		722
Minority interest	97					97
Net income (loss)	$ (16,738)	$ (6,792)	$	$ 20,415	$ (7,963)	$ (11,078)

Financial results for the nine months ended September 30, 2006 reflect a net loss of $52.5 million, or $0.97 per share (basic and diluted), compared to a net loss of $11.1 million, or $0.21 per share (basic and diluted), for the nine months ended September 30, 2005.

The major factors contributing to our net loss of $52.5 million during the first nine months of 2006 were G&A expenses of $37.7 million, interest expense of $33.1 million and LNG receiving terminal and pipeline development expenses of $6.7 million, partially offset by interest income of $31.0 million. Included in the $6.7 million of LNG receiving terminal and pipeline development expenses is a credit of $12.3 million. This credit represents the amount of pipeline development expenses previously charged to expense that constitute a regulatory asset as a result of our application of SFAS No. 71 beginning in the second quarter of 2006 (see Note 3 Property, Plant and Equipment of our Notes to Consolidated Financial Statements). Our net loss for the first nine months of 2006 excluding the $12.3 million credit was $64.8 million, or $1.19 per share (basic and diluted). The major factors contributing to our net loss of $11.1 million during the first nine months of 2005 were LNG receiving terminal and pipeline development expenses of $14.9 million and G&A expenses of $17.1 million, which were significantly offset by a $20.2 million gain on the sale of our investment in Gryphon.

As a result of our adoption of SFAS No. 123R, *Share-Based Payment*, on January 1, 2006, we recorded $12.7 million of non-cash compensation expense related to stock options in the first nine months of 2006.

LNG Receiving Terminal Segment

Financial results for our LNG receiving terminal segment for the first nine months of 2006 reflect a net loss of $32.3 million, compared to a net loss of $16.7 million for the first nine months of 2005.

LNG development expenses were 91% higher in the first nine months of 2006 ($15.5 million) than in the first nine months of 2005 ($8.1 million). Our development expenses primarily include costs of front-end engineering and design work, obtaining orders from the FERC authorizing construction of our facilities and other required permitting for our planned LNG receiving terminals. Other expenses directly related to the development of our LNG receiving terminals, include expenses of our LNG employees directly involved in the development activities. The $7.4 million increase in development expenses for the first nine months of 2006 compared to the first nine months of 2005 primarily resulted from an increase in employee-related costs (net of capitalized costs) of $3.0 million (including an increase of $2.8 million of non-cash compensation primarily resulting from stock option expense) and engineering, legal and other technical costs of $2.8 million. The increase in employee-related costs was due to our increase in the average number of employees from 27 in the first nine months of 2005 to 57 in the first nine months of 2006. This increase in employees resulted from the continued increase and development of our LNG receiving terminal business. In addition, the $3.9 million increase in engineering, legal and other technical and engineering costs was due to the increased front-end engineering and design work related to our Corpus Christi and Creole Trail LNG receiving terminals and our Sabine Pass LNG receiving terminal expansion. Finally, we recognized land site rental expense in the first nine months of 2006 of $1.1 million compared to zero in the same period in 2005. Land site rental charges were expensed in the first nine months of 2006 in accordance with FASB issued FSP 13-1.

G&A expenses were 32% higher in the first nine months of 2006 ($5.4 million) than in the first nine months of 2005 ($4.1 million). Our G&A expenses primarily related to a management fee (net of capitalization) as prescribed by a contractual management service agreement between Sabine Pass LNG and two other wholly-owned subsidiaries, software evaluation costs and costs associated with Hurricane Rita relief. The $1.3 million increase between periods was primarily due to an increase in software evaluation costs relating to Sabine Pass LNG receiving terminal operations, Hurricane Rita relief efforts and an additional two months of contractual management fees (net of capitalization) related to the Sabine Pass LNG receiving terminal.

Interest income and interest expense increased $5.2 million and $14.8 million, respectively, from the first nine months of 2005 compared to the first nine months of 2006. The increase in interest expense was due to the borrowings from the Term Loan beginning in the third quarter of 2005. The increase in interest income was due to investment income on the proceeds from the Term Loan.

The derivative loss was $44,000 in the first nine months of 2006 compared to a derivative gain of $0.3 million for the first nine months of 2005. The changes in derivative gain and loss were related to the ineffective portion of our interest rate swaps gains and losses and resulted from changes in interest rates.

Natural Gas Pipeline Segment

Financial results for our natural gas pipeline segment for the first nine months of 2006 reflect net income of $9.5 million, compared to a net loss of $6.8 million for the first nine months of 2005.

Natural gas pipeline development expenses decreased $15.6 million in the first nine months of 2006 to a negative $8.8 million compared to an expense of $6.8 million in the first nine months of 2005. Historically, our natural gas pipeline development expenses primarily included professional fees associated with front-end engineering and design work, obtaining orders from the FERC authorizing construction of our facilities and other required permitting for our planned natural gas pipelines. During the first nine months of 2006, however, we recognized regulatory assets, as prescribed by SFAS No. 71

(see Note 1 Basis of Presentation of our Notes to Consolidated Financial Statements), that had previously been expensed as pipeline development expenses. The impact of recording these regulatory assets reduced natural gas pipeline development expenses in the first nine months of 2006 by $12.3 million. Natural gas pipeline development expenses for the first nine months of 2006, excluding the impact of recording regulatory assets, would have been $3.5 million. Not including the impact of the recognition of regulatory assets in the first nine months of 2006, there was a decrease in natural gas pipeline development expenses of $3.3 million between periods. The decrease was primarily related to front-end engineering and design work, much of which was completed in 2005, for the Creole Trail pipeline.

LNG and Natural Gas Marketing Segment

Financial results for our LNG and natural gas marketing segment for the first nine months of 2006 reflect a net loss of $4.1 million, compared to zero for the first nine months of 2005, as we had not begun development of this segment at that time. G&A expenses incurred in the first nine months of 2006 were primarily related to employee costs and legal and consulting fees.

Oil and Gas Exploration and Development Segment

Financial results for our oil and gas exploration and development segment for the first nine months of 2006 reflect a net loss of $3.4 million, compared to net income of $20.4 million for the first nine months of 2005. The decrease in net income was primarily due to the $20.2 million gain on the sale of our investment in Gryphon in the third quarter of 2005. G&A expenses increased in 2006 as a result of non-cash share-based compensation primarily resulting from stock option expense.

Corporate and Other

Financial results for our corporate and other activities for the first nine months of 2006 reflect net loss of $22.2 million, compared to a net loss of $8.0 million for the first nine months of 2005.

G&A expenses increased $13.6 million, or 113%, to $25.5 million in the first nine months of 2006 compared to $11.9 million in the first nine months of 2005. The increase in G&A expenses primarily resulted from the expansion of our business (including increases in corporate staffing from an average of 42 employees in the first nine months of 2005 to an average of 89 employees in the first nine months of 2006). Included in G&A expenses is an increase in non-cash compensation of $8.2 million primarily resulting from stock option expenses. Corporate employee-related costs for the first nine months of 2006 and 2005 included non-cash compensation of $9.5 million and $1.3 million, respectively.

In the third quarter of 2006 we impaired $1.6 million of our leasehold costs related to our current office space at 717 Texas Avenue in Houston, Texas. The impairment was the result of signing our new office lease for space in Houston Pennzoil Place (see Note 13 Commitments and Contingencies of our Notes to Consolidated Financial Statements), and the belief that we would not recover our leasehold costs in the future.

Interest income was $17.7 million greater in the first nine months of 2006 ($25.1 million) than in the first nine months of 2005 ($7.4 million). The increase in interest income was due to the increase in cash balances and average interest rates between periods.

A tax provision of $2.0 million was recognized in the first nine months of 2006 relating to the portion of the change in our tax asset valuation account that was allocable to the deferred income tax on items reported in accumulated OCI on derivative instruments in accordance with SFAS No. 109, *Accounting for Income Taxes*, and EITF *Abstract*, Topic D-32.

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Interest expenses was $13.6 million greater in the first nine months of 2006 ($16.3 million) than in the first nine months of 2005 ($2.7 million). The increase in interest expense was due to average debt outstanding for the first nine months of 2006 being significantly higher than in the first nine months of 2005.

OTHER MATTERS

Critical Accounting Estimates and Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives but involve an implementation and interpretation of existing rules, and the use of judgment, to the specific set of circumstances existing in our business. We make every effort to comply properly with all applicable rules on or before their adoption, and we believe that the proper implementation and consistent application of the accounting rules are critical. However, not all situations are specifically addressed in the accounting literature. In these cases, we must use our best judgment to adopt a policy for accounting for these situations. We accomplish this by analogizing to similar situations and the accounting guidance governing them.

Accounting for LNG Activities

Generally, we begin capitalizing the costs of our LNG receiving terminals and related pipelines once the individual project meets the following criteria: (i) regulatory approval has been received, (ii) financing for the project is available and (iii) management has committed to commence construction. Prior to meeting these criteria, most of the costs associated with a project are expensed as incurred. These costs primarily include professional fees associated with front-end engineering and design work, costs of securing necessary regulatory approvals, and other preliminary investigation and development activities related to our LNG receiving terminals and related pipelines.

Generally, costs that are capitalized prior to a project meeting the criteria otherwise necessary for capitalization include: land costs, costs of lease options and the costs of certain permits, which are capitalized as intangible LNG assets. The costs of lease options are amortized over the life of the lease once it is obtained. If no lease is obtained, the costs are expensed. Site rental costs and related amortization of capitalized options have been capitalized during the construction period through the end of 2005. Beginning in 2006, such costs have been expensed as required by the Financial Accounting Standards Board (FASB) Staff Position (FSP) 13-1.

During the construction periods of our LNG receiving terminals, we capitalize interest and other related debt costs in accordance with SFAS No. 34, *Capitalization of Interest Cost*, as amended by SFAS No. 58, *Capitalization of Interest Cost in Financial Statements That Include Investments Accounted for by the Equity Method (an Amendment of FASB Statement No. 34)*. Upon commencement of operations, capitalized interest, as a component of the total cost, will be amortized over the estimated useful life of the asset.

Regulated Operations

Our developing natural gas pipeline business is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, and we have determined that certain of our pipeline systems to be constructed have met the criteria set forth in SFAS No. 71. Accordingly, we have applied the provisions of SFAS No. 71 to the affected pipeline subsidiaries beginning in the second quarter of 2006.

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Our application of SFAS No. 71 is based on the current regulatory environment, our current projected tariff rates, and our ability to collect those rates. Future regulatory developments and rate cases could impact this accounting. Although discounting of our maximum tariff rates may occur, we believe the standards required by SFAS No. 71 for its application are met and the use of regulatory accounting under SFAS No. 71 best reflects the results of future operations in the economic environment in which we will operate. Regulatory accounting requires us to record assets and liabilities that result from the rate-making process that would not be recorded under GAAP for non-regulated entities. We will continue to evaluate the application of regulatory accounting principles based on on-going changes in the regulatory and economic environment. Items that may influence our assessment are:

- inability to recover cost increases due to rate caps and rate case moratoriums;
- inability to recover capitalized costs, including an adequate return on those costs through the rate-making process and the FERC proceedings;
- excess capacity;
- increased competition and discounting in the markets we serve; and
- impacts of ongoing regulatory initiatives in the natural gas industry.

Natural gas pipeline costs include amounts capitalized as an Allowance for Funds Used During Construction (AFUDC). The rates used in the calculation of AFUDC are determined in accordance with guidelines established by the FERC. AFUDC represents the cost of debt and equity funds used to finance our natural gas pipeline additions during construction. AFUDC is capitalized as a part of the cost of our natural gas pipelines. Under regulatory rate practices, we generally are permitted to recover AFUDC, and a fair return thereon, through our rate base after our natural gas pipelines are placed in service.

Revenue Recognition

LNG receiving terminal capacity reservation fees are recognized as revenue over the term of the respective TUAs. Advance capacity reservation fees are deferred initially.

Change in Method of Accounting for Investments in Oil and Gas Properties

Effective January 1, 2006, we converted from the full cost method to the successful efforts method of accounting for our investments in oil and gas properties. While our primary focus is the development of our LNG-related businesses, we have continued to be involved, to a limited extent, in oil and gas exploration and development activities in the U.S. Gulf of Mexico. We believe that, in light of our current level of exploration and development activities, the successful efforts method of accounting provides a better matching of expenses to the period in which oil and gas production is realized. As a result, we believe that the change in accounting method at this time is appropriate. The change in accounting method constitutes a Change in Accounting Principle, requiring that all prior period financial statements be adjusted to reflect the results and balances that would have been reported had we been following the successful efforts method of accounting from our inception. The cumulative effect of the change in accounting method as of December 31, 2004 and 2005 was to reduce the balance of our net investment in oil and gas properties and retained earnings at those dates by $18.2 million and $18.0 million, respectively. The change in accounting method resulted in a decrease in the net loss of $369,000 and $296,000 for the three and nine months ended September 30, 2005, respectively, and had no impact on earnings per share (basic and diluted) for these respective periods (see Note 15 Adjustment to Financial Statements Successful Efforts of our Notes to Consolidated Financial Statements). The change in method of accounting had no impact on cash or working capital.

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Cash Flow Hedges

As defined in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, cash flow hedge transactions hedge the exposure to variability in expected future cash flows (i.e., in our case, the variability of floating interest rate exposure). In the case of cash flow hedges, the hedged item (the underlying risk) is generally unrecognized (i.e., not recorded on the balance sheet prior to settlement), and any changes in the fair value, therefore, will not be recorded within earnings. Conceptually, if a cash flow hedge is effective, this means that a variable, such as a movement in interest rates, has been effectively fixed so that any fluctuations will have no net result on either cash flows or earnings. Therefore, if the changes in fair value of the hedged item are not recorded in earnings, then the changes in fair value of the hedging instrument (the derivative) must also be excluded from the income statement or else a one-sided net impact on earnings will be reported, despite the fact that the establishment of the effective hedge results in no net economic impact. To prevent such a scenario from occurring, SFAS No. 133 requires that the fair value of a derivative instrument designated as a cash flow hedge be recorded as an asset or liability on the balance sheet, but with the offset reported as part of OCI, to the extent that the hedge is effective. Any ineffective portion will be reflected in earnings.

Goodwill

Goodwill is accounted for in accordance with SFAS No. 142, *Goodwill and Other Intangible Assets.* We perform an annual goodwill impairment review in the fourth quarter of each year, although we may perform a goodwill impairment review more frequently whenever events or circumstances indicate that the carrying value may not be recoverable.

Share-Based Compensation Expense

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123R using the modified prospective transition method, and therefore have not restated prior periods results. Under this method, we recognize compensation expense for all share-based payments granted after January 1, 2006 and prior to, but not yet vested as of, January 1, 2006, in accordance with SFAS 123R using the Black-Scholes-Merton option valuation model. Under the fair value recognition provisions of SFAS 123R, we recognize stock-based compensation net of an estimated forfeiture rate and only recognize compensation cost for those shares expected to vest on a straight-line basis over the requisite service period of the award. Prior to the adoption of SFAS 123R, we accounted for share-based payments under APB No. 25 and accordingly, did not recognize compensation expense for options granted that had an exercise price greater than or equal to the market value of the underlying common stock on the date of grant.

Determining the appropriate fair value model and calculating the fair value of share-based payment awards require the input of highly subjective assumptions, including the expected life of the share-based payment awards and stock price volatility. We believe that implied volatility, calculated based on traded options of our common stock, combined with historical volatility is an appropriate indicator of expected volatility and future stock price trends. Therefore, expected volatility for the quarter ended September 30, 2006 was based on a combination of implied and historical volatilities. The assumptions used in calculating the fair value of share-based payment awards represent our best estimates, but these estimates involve inherent uncertainties and the application of management judgment. As a result, if factors change and we use different assumptions, our stock-based compensation expense could be materially different in the future. In addition, we are required to estimate the expected forfeiture rate and only recognize expense for those shares expected to vest. If our actual forfeiture rate is materially different from our estimate, the stock-based compensation expense could be significantly different from what we have recorded in the current period. See Note 16 Share-Based Compensation of our Notes to Consolidated Financial Statements for a further discussion on share-based compensation.

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NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments An Amendment of FASB Statements No. 133 and 140.* SFAS No. 155 provides entities with relief from having to separately determine the fair value of an embedded derivative that would otherwise be required to be bifurcated from its host contract in accordance with SFAS No. 133. SFAS No. 155 allows an entity to make an irrevocable election to measure such a hybrid financial instrument at fair value in its entirety, with changes in fair value recognized in earnings. SFAS No. 155 is effective for all financial instruments acquired, issued or subject to a remeasurement event occurring after the beginning of an entity s first fiscal year that begins after September 15, 2006. We believe that the adoption of SFAS No. 155 will not have a material impact on our financial position, results of operations or cash flows.

In March 2006, the FASB issued SFAS No. 156, *Accounting for Servicing of Financial Assets An Amendment to FASB Statement No. 140*. Once effective, SFAS No. 156 will require entities to recognize a servicing asset or liability each time they undertake an obligation to service a financial asset by entering into a servicing contract in certain situations. This statement also requires all separately recognized servicing assets and servicing liabilities to be initially measured at fair value and permits a choice of either the amortization or fair value measurement method for subsequent measurement. The effective date of this statement is for annual periods beginning after September 15, 2006, with earlier adoption permitted as of the beginning of an entity s fiscal year provided the entity has not issued any financial statements for that year. We do not plan to adopt SFAS No. 156 early, and we do not believe that it will have a material impact on our financial position, results of operations or cash flows.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109.* FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes.* It prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This new standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The provisions of FIN No. 48 are to be applied to all tax positions upon initial adoption of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption of FIN No. 48. The cumulative effect of applying the provisions of FIN No. 48 should be reported as an adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year. The provisions of FIN No. 48 are effective for fiscal years beginning after December 15, 2006. Earlier application is permitted as long as the enterprise has not yet issued financial statements, including interim financial statements, in the period of adoption. We believe that the adoption of FIN No. 48 will not have a material impact on our financial position, results of operations or cash flows.

In July 2006, the FASB issued FSP No. FAS 13-2, *Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction*. FSP No. FAS 13-2 requires that changes in the projected timing of income tax cash flows generated by a leveraged lease transaction be recognized as a gain or loss in the year in which change occurs. The pretax gain or loss is required to be included in the same line item in which the leveraged lease income is recognized, with the tax effect being included in the provision for income taxes. FSP No. FAS 13-2 is effective to fiscal years beginning after December 15, 2006. We believe that the adoption of FSP No. FAS 13-2 will not have a material impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS No. 157 clarifies the principle that fair value should be based on the assumptions market participants would use when pricing an asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, with early adoption permitted. We are currently determining the effect, if any, the adoption of SFAS No. 157 will have on our financial statements.

In September 2006, the FASB issued SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plan an amendment of FASB Statement No. 87, 88, 106 and 132(R)*. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability in its statement of financial position and recognize changes in the funded status in the year in which the changes occur. SFAS No. 158 is effective for fiscal years ending after December 15, 2006. We believe that the adoption of SFAS No. 158 will not have a material impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued FSP No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities*. FSP No. AUG AIR-1 prohibits the use of the accrue-in-advance method for accounting for major maintenance activities and confirms the acceptable methods of accounting for planned major maintenance activities. FSP No. AUG AIR-1 is effective the first fiscal year beginning after December 15, 2006. We believe that the adoption of FSP No. AUG AIR-1 will not have a material impact on our financial position, results of operations or cash flows.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The development of our LNG receiving terminal business is based upon the foundational premise that prices of natural gas in the U.S. will be sustained at levels of $3.00 per Mcf or more. Should the price of natural gas in the U.S. decline to sustained levels below $3.00 per Mcf, our ability to develop and operate LNG receiving terminals could be materially adversely affected.

We produce and sell natural gas, crude oil and condensate. As a result, our financial results can be affected as these commodity prices fluctuate widely in response to changing market forces. We have not entered into any derivative transactions related to our oil and gas producing activities.

We have cash investments that we manage based on internal investment guidelines that emphasize liquidity and preservation of capital. Such cash investments are stated at historical cost, which approximates fair market value on our Consolidated Balance Sheet.

Interest Rates

We are exposed to changes in interest rates, primarily as a result of our debt obligations. The fair value of our fixed rate debt is affected by changes in market rates. We utilize interest rate swap agreements to mitigate exposure to rising interest rates. We do not use interest rate swap agreements for speculative or trading purposes.

At September 30, 2006, we had approximately $1.3 billion of debt outstanding. Of this amount, our $325.0 million of Notes bore a fixed interest rate of 2.25%. The Term Loan and Sabine Pass Credit Facility, totaling $594.0 million and $351.5 million, respectively, bear interest at floating rates; however, we entered into interest rate swaps with respect to these loan amounts (see Note 5 Derivative Instruments of our Notes to Consolidated Financial Statements).

The following table summarizes the fair market values of our existing interest rate swap agreements as of September 30, 2006 (in thousands):

Variable to Fixed Swaps

Maturity Date	Weighted Average Notional Principal Amount	Fixed Interest Rate (Pay)	Weighted Average Interest Rate	Fair Market Value (1)
September through December 2006	$ 1,061,423	3.75-5.69%	US $ LIBOR BBA	$ 917
January through December 2007	1,331,839	3.75-5.69%	US $ LIBOR BBA	9,175
January through December 2008	1,657,754	3.98-5.98%	US $ LIBOR BBA	1,043
January through December 2009	1,821,581	4.49-5.98%	US $ LIBOR BBA	(7,411)
January through December 2010	1,674,520	4.98-5.98%	US $ LIBOR BBA	(6,376)
January through December 2011	1,249,996	4.98-5.69%	US $ LIBOR BBA	(1,943)
January through December 2012	1,250,012	4.98-5.69%	US $ LIBOR BBA	(3,210)
January through December 2013	881,483	5.69%	US $ LIBOR BBA	(3,742)
January through December 2014	619,214	5.69%	US $ LIBOR BBA	(1,831)
January through June 2015	597,166	5.69%	US $ LIBOR BBA	(1,406)
				$ (14,784)

(1) The fair market value is based upon a marked-to-market calculation utilizing an extrapolation of third-party mid-market LIBOR rate quotes at September 30, 2006.

Item 4. Disclosure Controls and Procedures

We maintain a set of disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports filed by us under the Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. As of the end of the period covered by this report, we evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Exchange Act. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures are effective.

On July 1, 2006, we implemented a new accounting system that contains general ledger, accounts payable and receivable, fixed assets and other related accounting functions. Certain new accounting processes and procedures were implemented at that time to support the new accounting system. This system change is the result of our process to evaluate and upgrade or replace our previous system and related processes to support our evolving operational needs. During the quarter ended September 30, 2006, the new accounting system and supporting processes were used by us to record and report our financial results. Except for the accounting system implementation, there was no change in our internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended September 30, 2006, and that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are, and in the future may be, involved as a party to various legal proceedings, which are incidental to the ordinary course of business. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of these matters. In the opinion of management and legal counsel, as of September 30, 2006, there were no known threatened or pending legal matters that could reasonably be expected to have a material adverse impact on our consolidated results of operations, financial position or cash flows.

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As previously disclosed, we received a letter dated December 17, 2004 advising us of a nonpublic, informal inquiry being conducted by the SEC. On August 9, 2005, the SEC informed us that it had issued a formal order and commenced a nonpublic factual investigation of actions and communications by Cheniere, its current or former directors, officers and employees and other persons in connection with our agreements and negotiations with Chevron, the Company s December 2004 public offering of common stock, and trading in our securities. The scope, focus and subject matter of the SEC investigation may change from time to time, and we may be unaware of matters under consideration by the SEC. We have cooperated fully with the SEC informal inquiry and intend to continue cooperating fully with the SEC in its investigation.

Item 6. Exhibits

(a) Each of the following exhibits is filed herewith:

10.1	Change Orders 34, 35, 36, 37 and 38 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation
10.2	Change Order 1 to Agreement for Engineering, Procurement, Construction and Management of Construction Services for the Sabine Phase 2 Receiving, Storage and Regasification Terminal Expansion, dated July 21, 2006, between Sabine Pass LNG, L.P. and Bechtel Corporation
31.1	Certification by Chief Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
31.2	Certification by Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
32.1	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CHENIERE ENERGY, INC.

/s/ Craig K. Townsend
Vice President and Chief Accounting Officer

(on behalf of the registrant and as principal accounting officer)

Date: November 6, 2006