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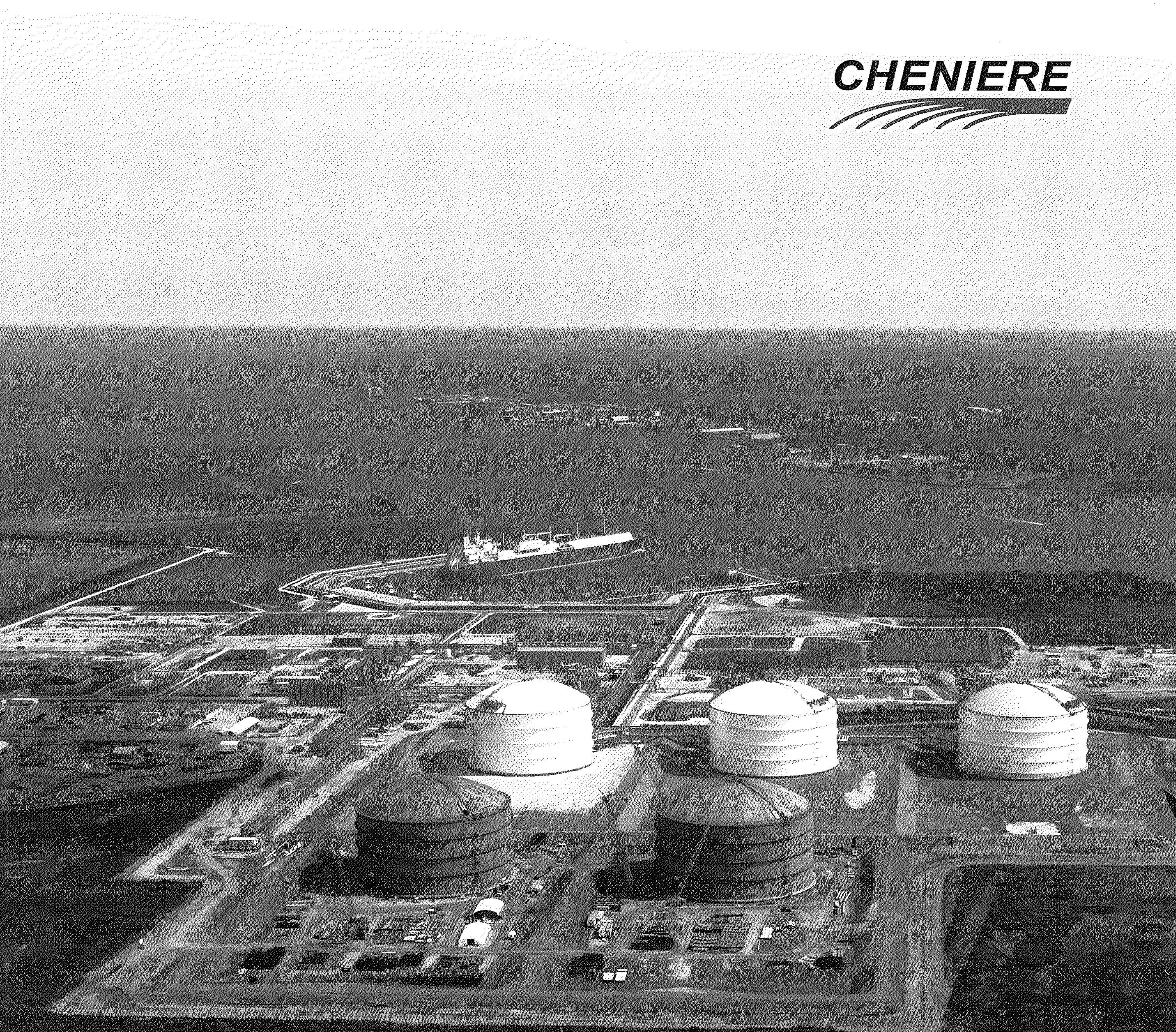

2008 ANNUAL REPORT

Received SEC

APR 29 2009

Washington, DC 20549

CHENIERE

April 27, 2009

Dear Shareholders,

During 2008, the global capital markets disintegrated and made access to funding very difficult. At the same time, the LNG industry experienced a complete reversal of sentiment. While in 2007, the industry expected the United States to become an important importer of LNG, in 2008 the exact opposite was true and the prevailing consensus was that LNG would not be needed in North America for several years.

At the beginning of the year we struggled to raise the remaining capital needed to conduct our business. We reviewed our situation and adjusted our model to prevailing conditions. As a result, we reduced our involvement in gas marketing, limiting that business to sourcing LNG and being able to market the resulting gas in the United States, and completely exited our shipping venture. Downsizing our business, combined with the completion of Phase I of the Sabine Pass terminal, allowed us to reduce our staff by 40 percent. We also entered into alliances with gas marketers, including J.P. Morgan, which will alleviate the need to use our working capital for LNG purchases.

In August, we completed a $250 million financing with GSO Capital Partners, which will give us sufficient liquidity to conduct our business for several years.

In the middle of all this, we completed the first phase of Sabine Pass and Creole Trail Pipeline on time and on budget, and watched both assets and Freeport LNG, in which we hold a 30 percent interest, begin operations. Our technical teams performed brilliantly in the face of a challenging construction environment, surviving two major hurricanes during construction and earning the respect of the industry.

Ironically, as I write this letter, the sentiment for LNG is changing again. The global recession has severely curtailed demand for LNG worldwide; and, combined with the late start of several new liquefaction facilities, is creating a new expectation that LNG will be arriving to the U.S. after all. In the short time from April 2008 to April 2009 the industry consensus reversed course completely, twice. We suffered from the first reversal but are confident that during 2009, the value of the assets we have created will become increasingly apparent.

Our challenge this year will be to correct our balance sheet. The company is too leveraged for the new capital market environment in which the world exists today. Management will focus on deleveraging the company. We will also capitalize on the developing supply surplus in the industry to pursue long-term arrangements to bring LNG to Sabine Pass, either through new terminal use agreements or indexed purchase agreements.

We have survived the storm and are committed to restoring the value of the company. To achieve this goal, we have world class assets, sufficient liquidity for several years and an industry environment once again favorable to our business.

Thank you for your support.

Sincerely,

Charif Souki
Chairman

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2008

OR

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

For the transition period from to

SEC
Mail Processing
Section

APR 28 2009

Washington, DC
101

Commission File No. 001-16383

CHENIERE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	**95-4352386**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
700 Milam Street, Suite 800 **Houston, Texas**	**77002**
(Address of principal executive offices)	**(Zip code)**

Registrant's telephone number, including area code: **(713) 375-5000**

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

Common Stock, $ 0.003 par value	**NYSE Alternext US LLC**
(Title of Class)	**(Name of each exchange on which registered)**

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

None

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer, accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

The aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $196,000,000 as of June 30, 2008.

52,212,143 shares of the registrant's Common Stock were outstanding as of February 17, 2009.

Documents incorporated by reference: The definitive proxy statement for the registrant's Annual Meeting of Stockholders (to be filed within 120 days of the close of the registrant's fiscal year) is incorporated by reference into Part III.

CHENIERE ENERGY, INC.
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CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING STATEMENTS

This annual 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 facts, included herein or incorporated herein by reference are "forward-looking statements." Included among "forward-looking statements" are, among other things:

- statements relating to the construction and operation of each of our proposed liquefied natural gas ("LNG") receiving terminals or our proposed natural gas pipelines, or expansions or extensions thereof, including statements concerning the completion or expansion thereof by certain dates or at all, the costs related thereto and certain characteristics, including amounts of regasification and storage capacity, the number of storage tanks and docks, pipeline deliverability and the number of pipeline interconnections, if any;
- statements that we expect to receive an order from the Federal Energy Regulatory Commission ("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 natural gas production, supply or consumption; future levels of LNG imports into North America; sales of natural gas in North America; and the transportation, other infrastructure or prices related to natural gas, LNG or other energy sources or 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;
- statements regarding any terminal use agreement ("TUA") or other commercial arrangements presently contracted, optioned, marketed or potential arrangements to be 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 LNG regasification or storage capacity that are, or may become, subject to TUAs or other contracts;
- statements regarding counterparties to our TUAs, construction contracts and other contracts;
- statements regarding any business strategy, any business plans or any other plans, forecasts, projections or objectives, including potential revenues and capital expenditures, any or all of which are subject to change;
- statements regarding legislative, governmental, regulatory, administrative or other public body actions, requirements, permits, investigations, proceedings or decisions;
- statements regarding our anticipated LNG 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," "develop," "estimate," "expect," "forecast," "plan," "potential," "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 annual 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 in "Risk Factors." 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 annual report.

DEFINITIONS

In this annual report, unless the context otherwise requires:

- *Bcf* means billion cubic feet;
- *Bcf/d* means billion cubic feet per day;
- *EPC* means engineering, procurement and construction;
- *EPCM* means engineering, procurement, construction and management;
- *LNG* means liquefied natural gas;
- *Mcf* means thousand cubic feet;
- *MMcf/d* means million cubic feet per day;
- *MMBtu* means million British thermal units; and
- *TUA* means terminal use agreement.

PART I

ITEMS 1. AND 2. *BUSINESS AND PROPERTIES*

General

Cheniere Energy, Inc., a Delaware corporation, is a Houston-based company engaged, through its subsidiaries, in the energy business generally. As used in this annual report, the terms "Cheniere", "we", "us" and "our" refer to Cheniere Energy, Inc. and its subsidiaries, including our publicly traded subsidiary partnership, Cheniere Energy Partners, L.P. ("Cheniere Partners"). We are currently engaged primarily in the business of developing and constructing, and then owning and operating, a network of three onshore LNG receiving terminals and natural gas pipelines, and we are also developing a business to market LNG and natural gas, primarily through our wholly-owned subsidiary, Cheniere Marketing, LLC ("Cheniere Marketing"), formerly Cheniere Marketing, Inc.

Our common stock has been publicly traded since July 3, 1996 and is currently traded on the NYSE Alternext US, formerly the American Stock Exchange, under the symbol "LNG". Our principal executive offices are located at 700 Milam Street, Suite 800, Houston, Texas 77002, and our telephone number is (713) 375-5000. Our internet address is http://www.cheniere.com. We provide public access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to these reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the Securities and Exchange Commission ("SEC") under the Exchange Act. These reports may be accessed free of charge through our internet website. We make our website content available for informational purposes only. The website should not be relied upon for investment purposes, nor is it incorporated by reference into this Form 10-K.

Cheniere Energy Partners

In March and April 2007, we and Cheniere Partners completed a public offering of 15,525,000 Cheniere Partners common units. Cheniere Partners received $98.4 million of net proceeds, after deducting the underwriting discount and structuring fees, upon issuance of 5,054,164 common units to the public in the offering. Cheniere Partners invested the $98.4 million of net proceeds that it received from the offering in U.S. Treasury securities to fund a distribution reserve. As part of the offering, we, as a selling unitholder, received $203.9 million of net proceeds in connection with the sale of 10,470,836 of our Cheniere Partners common units to the public. In connection with the offering and in exchange for Cheniere Partners common and subordinated units, we contributed the equity interests in the entity owning the Sabine Pass LNG receiving terminal to Cheniere Partners. As a result of the public offering, our ownership interest in Cheniere Partners is approximately 90.6%.

Business Segments

Our business activities are conducted by three operating segments for which we provide information in our financial statements for the years ended December 31, 2008, 2007 and 2006 as required under Statement of Financial Accounting Standards (SFAS) No. 131, "*Disclosures about Segments of an Enterprise and Related Information*." These three segments are our:

- LNG receiving terminal business;
- natural gas pipeline business; and
- LNG and natural gas marketing business.

Overview of the LNG Industry

LNG is natural gas that, through a refrigeration process, has been reduced to a liquid state, which represents approximately 1/600th of its gaseous volume. The liquefaction of natural gas into LNG allows it to be shipped economically from areas of the world where natural gas is abundant and inexpensive to produce to other areas where natural gas demand and infrastructure exist to justify economically the use of LNG. LNG is transported using oceangoing LNG vessels specifically constructed for this purpose. LNG receiving terminals offload LNG from LNG vessels, store the LNG prior to processing, heat the LNG to return it to a gaseous state and deliver the resulting natural gas into pipelines for transportation to market.

Our Business Strategy

We are pursuing a business strategy with the following primary components:

- complete the development of our Sabine Pass LNG receiving terminal currently under construction in western Cameron Parish, Louisiana on the Sabine Pass Channel with an aggregate designed regasification capacity of approximately 4.0 Bcf/d;
- complete the development and construction of our two additional LNG receiving terminals, Corpus Christi LNG and Creole Trail LNG, upon, among other things, achieving acceptable commercial arrangements, with an aggregate designed regasification capacity of up to approximately 6.0 Bcf/d;
- the development and construction of natural gas pipelines and other infrastructure within North America;
- develop a portfolio of long-term, short-term, and spot LNG purchase agreements; and, enter into business relationships for the domestic marketing of natural gas that is imported by Cheniere Marketing as LNG to the Sabine Pass LNG receiving terminal; and
- pursue other energy business initiatives.

LNG Receiving Terminal Business

We began developing our LNG receiving terminal business in 1999 and were among the first companies to secure sites and commence development of new LNG receiving terminals in North America. We focused our development efforts on three LNG receiving terminal projects: 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. Our ownership interest in the Sabine Pass LNG receiving terminal is held through Cheniere Partners, in which we hold an approximate 90.6% interest. Cheniere Partners owns a 100% interest in Sabine Pass LNG, L.P. ("Sabine Pass LNG"), which is currently constructing the Sabine Pass LNG receiving terminal. We currently own 100% interests in both the Corpus Christi and Creole Trail LNG receiving terminal projects. In addition, we own a 30% limited partner interest in a fourth LNG receiving terminal project, Freeport LNG, located on Quintana Island near Freeport, Texas.

Sabine Pass LNG Receiving Terminal

Development

We are constructing the Sabine Pass LNG receiving terminal in western Cameron Parish, Louisiana, on the Sabine Pass Channel. In 2003, we formed Sabine Pass LNG to own, develop and operate the Sabine Pass LNG receiving terminal. We have leases for three tracts of land consisting of 853 acres in Cameron Parish, Louisiana for the project site. The Sabine Pass LNG receiving terminal was designed, and permitted by the FERC, with an initial regasification capacity of approximately 2.6 Bcf/d and three LNG storage tanks with an aggregate LNG storage capacity of approximately 10.1 Bcf and two unloading docks capable of handling the largest LNG carriers currently being operated or built. In June 2006, Sabine Pass LNG received approval from the FERC to expand the Sabine Pass LNG receiving terminal by adding up to three additional LNG storage tanks, vaporizers and related facilities, and we are increasing the regasification capacity of the Sabine Pass LNG receiving terminal from approximately 2.6 Bcf/d to 4.0 Bcf/d (with peak capacity of 4.3 Bcf/d) and increasing the aggregate LNG storage capacity from approximately 10.1 Bcf to 16.8 Bcf.

Construction

We have completed physical construction of the initial 2.6 Bcf/d of sendout capacity and 10.1 Bcf of storage capacity at the Sabine Pass LNG receiving terminal and are now able to accept commercial cargoes. In order to complete commissioning and testing of this initial phase of the facility, our primary construction contractor, Bechtel Corporation ("Bechtel"), will need to complete specified outstanding work items. Construction of the remaining 1.4 Bcf/d of sendout capacity and 6.7 Bcf of storage capacity was approximately 88% complete as of December 31, 2008, and we anticipate achieving full operability, with total sendout capacity of approximately 4.0 Bcf/d and storage capacity of approximately 16.8 Bcf, during the third quarter of 2009.

Our estimated aggregate construction, commissioning and operating cost budget through the achievement of full operability of the Sabine Pass LNG receiving terminal, with approximately 4.0 Bcf/d of total sendout capacity and five storage tanks with approximately 16.8 Bcf of aggregate storage capacity, is approximately $1,559 million, excluding financing costs. Of this amount, approximately $1,416 million of construction and commissioning costs had been incurred as of December 31, 2008. Our remaining construction, commissioning and operating costs are anticipated to be funded from working capital and restricted cash and cash equivalents designated for construction. Our cost estimates are subject to change due to such items as cost overruns, change orders, increased component and material costs, LNG costs, escalation of labor costs and increased spending to maintain our construction schedule.

Customers

The entire approximately 4.0 Bcf/d of regasification capacity that will be available at the Sabine Pass LNG receiving terminal upon completion of construction has been fully reserved under three long-term TUAs, under which Sabine Pass LNG's customers are required to pay fixed monthly fees, whether or not they use the terminal. Because we achieved commercial operability of the Sabine Pass LNG receiving terminal in September 2008, capacity reservation fee TUA payments will begin to be made by our third-party customers as follows:

- Total LNG USA, Inc. ("Total") has reserved approximately 1.0 Bcf/d of regasification capacity and has agreed to make monthly capacity payments to Sabine Pass LNG aggregating approximately $125 million per year for 20 years commencing April 1, 2009. Total, S.A. has guaranteed Total's obligations under its TUA up to $2.5 billion, subject to certain exceptions; and

- Chevron U.S.A., Inc. ("Chevron") has reserved approximately 1.0 Bcf/d of regasification capacity and has agreed to make monthly capacity payments to Sabine Pass LNG aggregating approximately $125 million per year for 20 years commencing not later than July 1, 2009. Chevron Corporation has guaranteed Chevron's obligations under its TUA up to 80% of the fees payable by Chevron.

In addition, Cheniere Marketing has reserved the remaining 2.0 Bcf/d of regasification capacity, and is entitled to use any capacity not utilized by Total and Chevron. Cheniere Marketing began making its TUA payment in the fourth quarter of 2008. Cheniere Marketing is required to make monthly capacity payments aggregating approximately $250 million per year for the period from January 1, 2009, through at least the third quarter of 2028. Cheniere has guaranteed Cheniere Marketing's obligations under its TUA.

Under each of these TUAs, Sabine Pass LNG is also entitled to retain 2% of the LNG delivered for the customer's account, which Sabine Pass LNG will use primarily as fuel for revaporization and self-generated power at the Sabine Pass LNG receiving terminal.

Each of Total and Chevron has paid us $20 million in nonrefundable advance capacity reservation fees, which will be amortized over a 10-year period as a reduction of each customer's regasification capacity fees payable under its TUA.

Corpus Christi LNG Receiving Terminal

We are also developing the Corpus Christi LNG receiving terminal near Corpus Christi, Texas. We formed Corpus Christi LNG, L.P. ("Corpus Christi LNG") in May 2003 to develop the terminal. The Corpus Christi LNG receiving terminal is located on 612 acres and was designed, and permitted by the FERC, with a regasification capacity of approximately 2.6 Bcf/d, three LNG storage tanks with an aggregate LNG storage capacity of approximately 10.1 Bcf and two unloading docks capable of handling the largest LNG carriers currently being operated or built. In December 2005, the FERC issued an order authorizing Corpus Christi LNG to commence initial construction of the Corpus Christi LNG receiving terminal, subject to satisfaction of certain conditions specified by the FERC. In order to accelerate the timing of its development of the Corpus Christi LNG receiving terminal, Corpus Christi LNG commenced in April 2006 preliminary site work, which has since been completed. We will contemplate making a final investment decision to complete construction of the Corpus Christi LNG receiving terminal upon, among other things, achieving acceptable commercial arrangements and entering into acceptable financing arrangements.

Creole Trail LNG Receiving Terminal

We are also developing an LNG receiving terminal at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. We formed Creole Trail LNG, L.P. ("Creole Trail LNG") in December 2004 to develop the terminal. We have options to lease tracts of land comprising 1,750 acres in Cameron Parish, Louisiana for the project site. The Creole Trail LNG receiving terminal was designed, and permitted by the FERC, with a regasification capacity of 3.3 Bcf/d, four LNG storage tanks with an aggregate LNG storage capacity of 13.5 Bcf and two unloading docks capable of handling the largest LNG carriers currently being operated or built. In June 2006, the FERC authorized Creole Trail LNG to site, construct and operate the Creole Trail LNG receiving terminal. We will contemplate making a final investment decision to commence construction of the Creole Trail LNG receiving terminal upon, among other things, achieving acceptable commercial arrangements and entering into acceptable financing arrangements.

Other LNG Receiving Terminal Sites

We continue to evaluate, and may develop, additional sites that we believe may be commercially desirable locations for LNG receiving terminals.

Other LNG Receiving Terminal Interests—Freeport LNG

We own a 30% limited partner interest in Freeport LNG Development, L.P. ("Freeport LNG"), which has constructed an LNG receiving facility on Quintana Island near Freeport, Texas. The first phase of the project includes regasification capacity of 1.75 Bcf/d, one dock, two LNG storage tanks with an aggregate LNG storage capacity of 6.7 Bcf, and a 9.4-mile, 42-inch diameter pipeline through which natural gas will be transported to customer redelivery points at Stratton Ridge, Texas. A proposed second phase, which has received FERC approval, would include additional regasification capacity of up to 2.25 Bcf/d, a second dock, and a third LNG storage tank. Freeport LNG is also currently constructing 7.5 Bcf of underground salt cavern storage at Stratton Ridge which is expected to be completed and integrated with the LNG receiving terminal operations in the first quarter of 2011.

Freeport LNG has entered into TUAs with three customers: The Dow Chemical Company for approximately 500 MMcf/d of regasification capacity; ConocoPhillips Company for approximately 900 MMcf/d of regasification capacity; and MC Global Gas Corporation, a wholly owned subsidiary of Mitsubishi Corporation, for approximately 150 MMcf/d of regasification capacity. In June 2008, Freeport LNG achieved commercial operability, and it began receiving TUA payments from its customers in the second half of 2008.

In March 2008 and May 2008, we received cash call notices from Freeport LNG requesting that we provide further financial support due to higher than expected commissioning and performance testing costs. During 2008, we funded the cash calls and have recorded $4.8 million of additional losses in Freeport LNG. In addition, Freeport LNG distributed $4.8 million of dividends to us in October 2008.

LNG Receiving Terminal Competition

New supplies to meet North America's natural gas demand could be developed from a combination of the following sources:

- existing producing regions in the United States, Canada and Mexico;
- frontier regions in Alaska, northern Canada and offshore deepwater;
- areas currently restricted from exploration and development due to public policies, such as areas in the Rocky Mountains and offshore Atlantic, Pacific and Gulf of Mexico coasts; and
- imported LNG.

In addition, demand for energy currently met by natural gas could alternatively be met by other energy forms such as coal, hydroelectric, oil, wind, solar and nuclear energy. LNG will face competition from each of these energy sources.

We compete with other companies to construct LNG receiving terminals in economically desirable locations. According to the FERC, as of January 15, 2009, there were eight existing LNG receiving terminals in North America, two of which are offshore facilities for receiving natural gas regasified from LNG onboard specialized LNG vessels, as well as other new LNG receiving terminals or expansions approved or proposed to be constructed. To the extent that we may desire to sell regasification capacity in our LNG receiving terminals, we will compete with other third-party LNG receiving terminals or existing terminals having uncommitted capacity.

In addition, in connection with our efforts to obtain LNG to exploit our retained capacity at the Sabine Pass LNG receiving terminal or to commission, test or maintain the terminal, we must compete in the world LNG market to purchase and transport cargoes of LNG.

LNG Receiving Terminal Governmental Regulation

Our LNG receiving terminal operations are subject to extensive regulation under federal, state and local statutes, rules, regulations and other laws. Among other matters, these laws require that we engage in consultations with certain federal and state agencies and that we obtain certain permits and other authorizations before commencement of construction and operation of LNG receiving terminals. This regulatory burden increases the cost of constructing and operating the LNG receiving terminals, and failure to comply with such laws could result in substantial penalties.

FERC

In order to site and construct our proposed LNG receiving terminals, we must receive and are required to maintain authorization from the FERC under Section 3 of the Natural Gas Act of 1938 ("NGA"). In addition, orders from the FERC authorizing construction of an LNG receiving terminal are typically subject to specified conditions that must be satisfied throughout the construction, commissioning and operation of terminals. Throughout the life of our LNG receiving terminals, they will be subject to regular reporting requirements to the FERC and the U.S. Department of Transportation regarding the operation and maintenance of the facilities.

In 2005, the Energy Policy Act of 2005 ("EPAct") was signed into law. The EPAct gave the FERC exclusive authority to approve or deny an application for the siting, construction, expansion or operation of an LNG receiving terminal. The EPAct also amended the NGA to prohibit market manipulation and the NGA and the Natural Gas Policy Act of 1978 ("NGPA") to increase civil and criminal penalties for any violations of the NGA, NGPA and any rules, regulations or orders of the FERC up to $1.0 million per day per violation. The FERC issued a final rule making it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to the FERC's jurisdiction, to defraud, make an untrue statement or omit a material fact or engage in any practice, act or course of business that operates or would operate as a fraud.

Other Federal Governmental Permits, Approvals and Consultations

In addition to the FERC authorization under Section 3 of the NGA, our construction and operation of LNG receiving terminals are also subject to additional federal permits, approvals and consultations required by certain other federal agencies, including: Advisory Counsel on Historic Preservation, U.S. Army Corps of Engineers, U.S. Department of Commerce, National Marine Fisheries Services, U.S. Department of the Interior, U.S. Fish and Wildlife Service, U.S. Environmental Protection Agency ("EPA") and U.S. Department of Homeland Security.

Our LNG receiving terminals will also be subject to U.S. Department of Transportation siting requirements and regulations of the U.S. Coast Guard relating to facility security. Moreover, our LNG receiving terminals will also be subject to local and state laws, rules and regulations.

LNG Receiving Terminal Environmental Regulation

Our LNG receiving terminal operations are subject to various federal, state and local laws and regulations relating to the protection of the environment. These environmental laws and regulations may impose substantial penalties for noncompliance and substantial liabilities for pollution. Many of these laws and regulations restrict or prohibit the types, quantities and concentration of substances that can be released into the environment and can lead to substantial liabilities for non-compliance or releases. Failure to comply with these laws and regulations may also result in substantial civil and criminal fines and penalties.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)

CERCLA, also known as the "Superfund" law, imposes liability, without regard to fault, on certain classes of persons who are considered to be responsible for the spill or release of a hazardous substance into the environment. Potentially liable persons include the owner or operator of the site where the release occurred and persons who disposed or arranged for the disposal of hazardous substances at the site. Under CERCLA, responsible persons may be subject to joint and several liability. Although CERCLA currently excludes petroleum, natural gas, natural gas liquids and LNG from its definition of "hazardous substances," this exemption may be limited or modified by the U.S. Congress in the future.

Clean Air Act (CAA)

Our LNG receiving terminal operations are subject to the federal CAA and comparable state and local laws. We may be required to incur certain capital expenditures over the next several years for air pollution control equipment in connection with maintaining or obtaining permits and approvals addressing other air emission-related issues. We do not believe, however, that our operations will be materially adversely affected by any such requirements.

The U.S. Supreme Court has ruled that the EPA has authority under existing legislation to regulate carbon dioxide and other heat-trapping gases in mobile source emissions. In addition, Congress has considered proposed legislation directed at reducing "greenhouse gas emissions." It is not possible at this time to predict how future regulations or legislation may address greenhouse gas emissions and impact our business. However, future regulations and laws could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial position, results of operations and cash flows.

Clean Water Act (CWA)

Our LNG receiving terminal operations are also subject to the federal CWA and analogous state and local laws. Pursuant to certain requirements of the CWA, the EPA has adopted regulations concerning discharges of wastewater and storm water runoff. This program requires covered facilities to obtain individual permits, participate in a group permit or seek coverage under an EPA general permit.

Resource Conservation and Recovery Act (RCRA)

The federal RCRA and comparable state statutes govern the disposal of "hazardous wastes." In the event any hazardous wastes are generated in connection with our LNG receiving terminal operations, we are subject to regulatory requirements affecting the handling, transportation, treatment, storage and disposal of such wastes.

Endangered Species Act

Our LNG receiving terminal operations and planned construction activities may also be restricted by requirements under the Endangered Species Act, which seeks to ensure that human activities neither jeopardize endangered or threatened animal, fish and plant species nor destroy or modify their critical habitats.

As with the industry generally, our operations will entail risks in these areas, and compliance with these laws and regulations increases our overall cost of doing business. While these laws and regulations affect our capital expenditures and earnings, we believe that these laws and regulations do not affect our competitive position in the industry because our competitors are similarly affected. Environmental laws and regulations have historically been subject to frequent revision and reinterpretation. Consequently, we are unable to predict the future costs or other future impacts of environmental regulations on our future operations.

Natural Gas Pipeline Business

We formed Cheniere Pipeline Company, a wholly-owned subsidiary, to develop natural gas pipelines to provide access to North American natural gas markets for customers of our Sabine Pass and proposed Corpus Christi and Creole Trail LNG receiving terminals. We are also developing other pipeline projects not primarily related to our LNG receiving terminals. Our pipeline systems developed in conjunction with our LNG receiving terminals will interconnect with multiple interstate pipelines, providing a means of delivering revaporized natural gas from our LNG receiving terminals to various North American natural gas markets. Our other projects are market focused, seeking to connect natural gas supplies to growing markets. Our ultimate decisions regarding pipeline connections to our facilities will depend upon future events, including, in particular, customer preferences and general market demand for natural gas from a particular LNG receiving terminal.

Creole Trail Pipeline

Development

In October 2007, the FERC approved an application to merge our Sabine Pass Pipeline into our Creole Trail Pipeline, thereby creating an integrated pipeline system of approximately 153 miles in length. The Creole Trail

Pipeline is being constructed in two phases. Phase 1, which is currently in-service and operating, consists of 94 miles of natural gas pipeline connecting the Sabine Pass LNG receiving terminal to numerous interconnection points with existing interstate and intrastate natural gas pipelines in southwest Louisiana. Phase 2, once constructed, will consist of approximately 59 miles of natural gas pipeline running from the terminus of Phase 1 east to a terminus near Rayne, Louisiana with interconnections to additional existing interstate natural gas pipelines.

Construction & Operation

Phase 1 of the Creole Trail Pipeline commenced construction in the second quarter of 2007 and was placed into service, in segments, between April and June 2008. In conjunction with the pipeline, six delivery meter stations were commissioned, which provide access to eight major interstate and intrastate natural gas pipeline systems. The total cost to construct Phase 1 of the Creole Trail Pipeline was approximately $552 million, net of anticipated rebates and before financing costs, with only minimal construction costs remaining in 2009.

We will contemplate making a final investment decision to construct Phase 2 of the Creole Trail Pipeline upon, among other things, achieving acceptable commercial arrangements and entering into acceptable financing arrangements.

Customers

We offered capacity on our Creole Trail Pipeline to potential customers through a formal open season process, and awarded Cheniere Marketing all of the capacity in the Creole Trail Pipeline. Cheniere Marketing and Creole Trail Pipeline agreed to a firm transportation agreement for transportation at a negotiated rate in June 2007. In April 2008, Creole Trail Pipeline and Cheniere Marketing mutually agreed to terminate the aforementioned firm transportation agreement. Cheniere Marketing subsequently entered into an interruptible transportation agreement with Creole Trail Pipeline. 2.0 Bcf/d of firm transportation capacity is available to customers with whom we enter into TUAs for our LNG receiving terminal capacity and who may also desire to enter into agreements for the transportation of revaporized gas on the Creole Trail Pipeline.

Corpus Christi Pipeline

We formed Cheniere Corpus Christi Pipeline, L.P., a wholly-owned subsidiary, to develop a 24-mile, 48-inch interstate natural gas pipeline that is designed to transport 2.6 Bcf/d of regasified LNG, from the Corpus Christi LNG receiving terminal northwesterly along a corridor that will allow for interconnection points with various interstate and intrastate natural gas transmission pipelines. The FERC issued an order in April 2005 authorizing us to construct, own and operate the Corpus Christi Pipeline, subject to specified conditions that must be satisfied. We will contemplate making an investment decision to commence construction of the Corpus Christi Pipeline upon, among other things, achieving acceptable commercial arrangements and entering into acceptable financing arrangements to build the Corpus Christi LNG receiving terminal.

Other Pipelines

We continue to evaluate, and may develop, additional pipelines that we believe may be commercially desirable based on customer preferences and general market demand for natural gas. Currently, we are evaluating the following pipeline projects:

Cheniere Southern Trail Pipeline

As currently contemplated, the Cheniere Southern Trail Pipeline would involve the construction of approximately 350 miles of up to 42-inch diameter pipeline that is currently estimated to cost approximately $1.5 billion, before financing costs. We will contemplate making a final investment decision to commence construction of the Cheniere Southern Trail Pipeline upon, among other things, entering into acceptable commercial arrangements, applying for and receiving FERC authorization to construct and operate the pipeline and obtaining adequate financing to construct the Cheniere Southern Trail Pipeline.

Frontera Pipeline

In September 2007, we entered into an equity purchase agreement with Tidelands Oil & Gas Corporation and acquired an 80% interest in Frontera Pipeline, LLC ("Frontera"), an entity which owns 100% of Sonora Pipeline, LLC and Terranova Energia. In October 2008, we acquired the remaining 20% interest in Frontera from Tidelands. Frontera, through Sonora and Terranova, is developing the Burgos Hub Project, which is a proposed integrated pipeline project traversing the United States and Mexico border, and the potential construction of a related underground natural gas storage facility in Mexico. The aggregate cost to construct the project is currently estimated to be approximately $700 million to $800 million, before financing costs. Our cost estimate is subject to change due to such items as cost overruns, change orders, delays in construction, increased component and material costs, escalation of labor costs and increased spending to maintain our construction schedule. We will contemplate making a final investment decision in the Burgos Hub Project upon, among other things, receiving all required authorizations to construct and operate the pipeline and storage facility, arranging appropriate financing and entering into acceptable commercial arrangements for the pipeline and storage facility.

Natural Gas Pipeline Competition

Our existing and proposed pipelines will compete with intrastate and other interstate pipelines throughout the Gulf Coast region. The principal elements of competition among pipelines are rates, terms of service, access to supply and flexibility and reliability of service. In addition, the FERC's continuing efforts to increase competition in the natural gas industry are increasing the natural gas transportation options of a pipeline's traditional customers.

Our pipelines will face competition from other intrastate and/or interstate pipelines that connect with our LNG receiving terminals. In particular, our Creole Trail Pipeline competes with the Kinder Morgan Louisiana Pipeline owned by Kinder Morgan Energy Partners, L.P. ("Kinder Morgan"). Kinder Morgan is building a 3.2 Bcf/d take-away pipeline system from the Sabine Pass LNG receiving terminal. Total and Chevron have both signed agreements with Kinder Morgan securing 100% of the initial capacity on the Kinder Morgan Louisiana Pipeline for 20 years.

Natural Gas Pipeline Governmental Regulation

Interstate Natural Gas Pipelines

Under the NGA, the FERC is granted authority to approve , and if necessary, set "just and reasonable rates" for the transmission or sale of natural gas in interstate commerce. It also gives FERC the authority to grant certificates allowing construction and operation of facilities used in interstate gas transmission and authorizing the provision of services. Under the NGA, the FERC's jurisdiction generally extends to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale. However, FERC's jurisdiction does not extend to the production, gathering, or local distribution of natural gas.

In general, the FERC's authority to regulate interstate natural gas pipelines and the services that they provide includes:

- rates and charges for natural gas transportation and related services;
- the certification and construction of new facilities;
- the extension and abandonment of services and facilities;

- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and
- various other matters.

Failure to comply with the NGA can result in the imposition of administrative, civil and criminal remedies, including civil and criminal penalties which were recently increased under the EPAct.

The natural gas industry has been regulated since 1938 when the NGA was enacted. Among other things, the FERC regulates the transportation rates and terms and conditions of service of interstate natural gas pipelines. See "—Rates" below. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines; however, the FERC may or may not continue this approach in the future.

We have received authorization from the FERC to provide firm and interruptible transportation services, as well as parking and lending services, for our pipelines based on cost of service rates. Beginning in the mid-1980s, the FERC initiated a number of regulatory changes intended to create a more competitive environment in the natural gas marketplace. Among the most important of these changes were:

- Order No. 436 (1985), which requires open-access, nondiscriminatory transportation of natural gas;
- Order No. 497 (1988), which set forth new standards and guidelines imposing certain constraints on the interaction between interstate natural gas pipelines and their marketing affiliates and imposing certain disclosure requirements regarding that interaction;
- Order No. 636 (1992), which required interstate natural gas pipelines that perform open-access transportation under blanket certificates to "unbundle" or separate their traditional merchant sales services from their transportation and storage services and to provide comparable transportation and storage services with respect to all natural gas supplies whether purchased from the pipeline or from other merchants such as marketers or producers. Order No. 636 also permitted pipeline customers to release all or part of their firm transportation capacity to third parties. Order No. 636 has been affirmed in all material respects upon judicial review; and
- Order No. 637 (2000), which, among other things, required pipelines to implement imbalance management services; restricted the ability of pipelines to impose penalties for imbalances, overruns and non-compliance with operational flow orders; and implemented new pipeline reporting requirements.

In November 2003, the FERC issued a series of orders adopting revised Standards of Conduct (Order No. 2004) that apply uniformly to interstate natural gas pipelines. These Standards of Conduct were designed to govern relationships between the pipeline and any energy affiliate, rather than governing conduct between the pipeline and its marketing affiliate. However, in 2006, Order No. 2004, as applied to natural gas pipelines, was vacated by a federal court, and the FERC issued an interim rule to address the relationship between natural gas pipelines and marketing affiliates. In October 2008, the FERC replaced the interim Standards of Conduct with Order 717 to be effective January 30, 2009. We have established the required policies and procedures to comply with the Standards of Conduct, and are subject to audit by the FERC to review compliance, policies and our training programs.

Our pipelines that interconnect with our LNG receiving terminals are interstate natural gas pipelines. We are required to obtain authorization from the FERC pursuant to Section 7 of the NGA to construct and operate these pipelines. The rates that we charge are subject to the FERC's regulation under Section 4 of the NGA. Our interstate pipelines also are subject to the FERC's open access requirements and the FERC's Standards of Conduct. The FERC's exercise of jurisdiction over interstate natural gas pipelines is substantially broader than its exercise of jurisdiction over LNG receiving terminals.

Natural Gas Pipeline Safety

Louisiana and Texas administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), which requires certain pipelines to comply with safety standards in constructing and operating the pipelines and subjects the pipelines to regular inspections. Failure to comply with the NGPSA may result in the imposition of administrative, civil and criminal remedies.

The Pipeline Safety Improvement Act of 2002 ("PSIA"), which is administered by the U.S. Department of Transportation Office of Pipeline Safety, governs the areas of testing, education, training and communication. The PSIA requires pipeline companies to perform extensive integrity tests on natural gas transmission pipelines that exist in high population density areas designated as "high consequence areas." Pipeline companies are required to perform the integrity tests on a seven-year cycle. The risk ratings are based on numerous factors, including the population density in the geographic regions served by a particular pipeline, as well as the age and condition of the pipeline and its protective coating. Testing consists of hydrostatic testing, internal electronic testing, or direct assessment of the piping. In addition to the pipeline integrity tests, pipeline companies must implement a qualification program to make certain that employees are properly trained. In December 2003, the U.S. Department of Transportation issued a final rule requiring pipeline operators to develop integrity management programs for gas transportation pipelines. The final rule requires pipeline operators to perform ongoing assessments of pipeline integrity; identify and characterize applicable threats to pipeline segments that could impact a high consequence area; improve data collection, integration and analysis; repair and remediate the pipeline, as necessary; and implement preventive and mitigation actions. This rule incorporates the requirements of the PSIA.

Energy Policy Act of 2005

The EPAct and the FERC's policies promulgated thereunder contain numerous provisions relevant to the natural gas industry and to interstate pipelines. See "—LNG Receiving Terminal Governmental Regulation."

Rates

Under the NGA, rates charged for the interstate transportation of natural gas must be just and reasonable and not unduly discriminatory or preferential. Amounts collected by the pipeline that the FERC finds unlawful are subject to refund with interest.

Natural Gas Pipeline Environmental Regulation

Our natural gas pipeline business is subject to the same federal, state and local laws and regulations relating to the protection of the environment that are applicable to our LNG receiving terminals. See "—LNG Receiving Terminal Environmental Regulation" above.

LNG and Natural Gas Marketing Business

Our wholly-owned subsidiary, Cheniere Marketing, is developing a LNG and natural gas marketing business. Its principal asset is a TUA at the Sabine Pass LNG receiving terminal. In April 2008, we commenced a cost savings program in connection with the downsizing of our natural gas marketing business activities, the nearing completion of significant construction activities for both the Sabine Pass LNG receiving terminal and Creole Trail Pipeline and the seeking of alternative arrangements for our time charter interests in two LNG vessels. We have unwound, terminated or assigned our commitments under our domestic natural gas agreements on terms we believe to be acceptable and have cancelled both of our LNG vessel charters.

In June 2008, we announced that we had entered into a domestic marketing agreement for the sale of LNG with J.P. Morgan Ventures Energy Corporation ("JPMorgan Ventures"), a wholly-owned subsidiary of J.P. Morgan Chase & Co. ("JPMorgan"). The agreement provides a framework under which Cheniere Marketing may offer to sell to JPMorgan Ventures all or a portion of the LNG from each cargo it acquires on delivery to the Sabine Pass LNG receiving terminal, and under which JPMorgan Ventures will utilize a portion of Cheniere Marketing's TUA capacity for storage and regasification services related to the portion of the LNG cargo that JPMorgan Ventures purchases. JPMorgan Ventures has also acquired a "first look" right through March 31, 2009 under which JPMorgan Ventures will have the preemptive right to acquire LNG on the same pricing terms that Cheniere Marketing offers to its other customers. JPMorgan will guarantee all of J.P. Morgan Ventures' obligations under this agreement, including any LNG purchases executed under this agreement. Subsequently, we have entered into similar framework agreements with various other counterparties for the sale of LNG.

Our LNG and natural gas marketing business segment is seeking to develop a portfolio of long-term, short-term, and spot LNG purchase agreements, and will focus on entering into business relationships such as the one entered into with JPMorgan for the domestic marketing of natural gas that is imported by Cheniere Marketing as LNG to the Sabine Pass LNG receiving terminal.

LNG and Natural Gas Marketing Competition

Our LNG purchase efforts compete for supplies of LNG with:

- large, multinational and national companies with longer operating histories, more development experience, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources;
- oil and gas producers who sell or control LNG derived from their international oil and gas properties; and
- purchasers located in other countries, in which prevailing market prices can be substantially different than those in the U.S.

Our natural gas marketing efforts compete for sales of natural gas with a variety of competitors including:

- major integrated marketers who have large amounts of capital to support their marketing operations and offer a full-range of services and market numerous products other than natural gas;
- producer marketers who sell their own natural gas production or the production of their affiliated natural gas production company;
- small geographically focused marketers who focus on marketing natural gas for the geographic area in which their affiliated distributor operates; and
- aggregators who gather small volumes of natural gas from various sources, combine them and sell the larger volumes for more favorable prices and terms than would be possible selling the smaller volumes separately.

LNG and Natural Gas Marketing Governmental Regulation

In 1992 and 1993, the FERC concluded that sellers of short-term or long-term natural gas supplies would not have market power over the sale for resale of natural gas. The FERC established light-handed regulation over sales for resale of natural gas and adopted regulations granting blanket certificates to allow entities selling natural gas to make interstate sales for resale at negotiated rates. In 2003, the FERC amended the blanket marketing certificates to require that all sellers adhere to a code of conduct with respect to natural gas sales. The code of conduct addresses such matters as natural gas withholding, manipulation of market prices, communication of accurate information and record retention.

The EPAct contains provisions intended to prohibit the manipulation of the natural gas markets and is applicable to our LNG and natural gas marketing business as well. See "—LNG Receiving Terminal Business Governmental Regulations."

The prices at which we will sell natural gas are not regulated, insofar as the interstate market is concerned and, for the most part, are not subject to state regulation. We are permitted to make sales of natural gas for resale in interstate commerce pursuant to a blanket marketing certificate automatically granted by the FERC. Our sales of natural gas will be affected by the availability, terms and cost of pipeline transportation. As noted above, under "—Natural Gas Pipeline Business—Natural Gas Pipeline Governmental Regulation," the price and terms of access to pipeline transportation are subject to extensive federal and state regulation.

Oil and Gas Exploration, Development and Exploitation Activities

Our focus is primarily on the development and operation of LNG-related businesses. We have retained interests in the form of working interests, overriding royalty interests (a share of the hydrocarbons produced from an oil and gas property, free of the expense of production) and back-in working interests (whereby we retain a reversion right to a working interest in a well at payout but bear none of the cost of drilling the initial well). At December 31, 2008, we had interests in fifteen active wells, including three working interests and fifteen override interests. Three wells have both a working and override interest. We have an interest in three wells that are currently not producing. There are no plugging and abandonment costs expected in 2009. As a result of the lack of materiality to our consolidated financial statements taken as a whole, our oil and gas exploration, development and exploitation activities have been excluded as a separately disclosed operating segment.

Financial Information about Segments

For information about our segments' revenues, profits and losses and total assets, see Note 24—"Business Segment Information" of our Notes to Consolidated Financial Statements.

Subsidiaries

Our assets are generally held by or under our operating subsidiaries. We conduct most of our operations through these subsidiaries, including our operations relating to the development and operation of our LNG receiving terminal business, the development and operation of our pipeline business and our marketing business.

Employees

We had 208 full-time employees as of February 17, 2009.

ITEM 1A. *RISK FACTORS*

The following are some of the important factors that could affect our financial performance or could cause actual results to differ materially from estimates contained in our forward-looking statements. We may encounter risks in addition to those described below. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, may also impair or adversely affect our business, results of operation, financial condition, liquidity and prospects.

The risk factors in this report are grouped into the following categories:

- Risks Relating to Our Financial Matters;
- Risks Relating to Our LNG Receiving Terminal Business;
- Risks Relating to Our Natural Gas Pipeline Business;
- Risks Relating to Our LNG and Natural Gas Marketing Business;
- Risks Relating to Our LNG Businesses in General; and
- Risks Relating to Our Business in General.

Risks Relating to Our Financial Matters

We have substantial indebtedness, which we will need to refinance in whole or in part at or prior to maturity.

As of December 31, 2008, we had $3.2 billion of indebtedness, consisting primarily of a $400.0 million term loan due 2012 ("2007 Term Loan"), $550.0 million of 7 ¼% Senior Secured Notes due 2013 (the "2013 Notes"), $1,628.3 of 7 ½% Senior Secured Notes due 2016 (the "2016 Notes" and collectively with the 2013 Notes, the "Senior Notes"), $325.0 million aggregate principal amount of Convertible Senior Unsecured Notes due 2012 ("Convertible Senior Unsecured Notes") and $250.0 million in convertible term loans due 2018 ("2008 Convertible Loans"). We will need to refinance all or a portion of our indebtedness. We may not be able to refinance our indebtedness as needed, on commercially reasonable terms or at all.

Our substantial indebtedness could adversely affect our ability to operate our business and prevent us from satisfying or refinancing our debt obligations.

Our substantial indebtedness could have important adverse consequences, including:

- making it more difficult for us to satisfy or refinance our debt obligations;
- limiting our ability to obtain additional financing to fund our capital expenditures, working capital, acquisitions, debt service requirements or liquidity needs for general business or other purposes;
- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service debt, including indebtedness that we may incur in the future;
- limiting our ability to compete with other companies that are not as highly leveraged;
- limiting our ability to react to changing market conditions in our industry and to economic downturns;
- limiting our flexibility in planning for, or reacting to, changes in our business and future business opportunities;
- making us more vulnerable than a less leveraged company to a downturn in our business or in the economy;
- limiting our ability to attract customers; and
- resulting in a material adverse effect on our business, results of operations and financial condition if we are unable to service or refinance our indebtedness or obtain additional financing, as needed.

Our substantial indebtedness and the restrictive covenants contained in our debt agreements may not allow us the flexibility that we need to operate our business in an effective and efficient manner and may prevent us from taking advantage of strategic and financial opportunities that would benefit our business.

Our ability to satisfy or refinance our debt obligations will depend upon our future operating performance. Prevailing economic conditions and financial, business and other factors, many of which are beyond our control, will also affect our ability to make payments on our debt obligations. We will need to seek to refinance all or a portion of our existing indebtedness on or before maturity, even if market conditions for such refinancings are adverse at the time. We may not be able to refinance any of our indebtedness on commercially reasonable terms or at all.

We have not been profitable historically, and we are currently experiencing negative operating cash flow. Our ability to achieve profitability and generate positive operating cash flow in the future is subject to significant uncertainty.

We had net losses of $356.5 million and $181.8 million for the years ended December 31, 2008 and 2007, respectively. In the future, we may incur operating losses and experience negative operating cash flow. We do not expect current cash inflows to be sufficient to fund our 2009 expenditures. We are dependent upon our existing cash resources.

Our existing level of cash resources, negative cash flow and limited ability to obtain additional financing could cause us to have inadequate liquidity and could materially and adversely affect our business, financial condition and prospects.

As of December 31, 2008, we had $102.2 million of cash and cash equivalents and $460.9 million of restricted cash and cash equivalents and U.S. Treasury securities, including $71.1 million of restricted cash to be used to complete construction and commissioning of the Sabine Pass LNG receiving terminal. Our ability to generate positive operating cash flow and achieve profitability, so as to enhance our liquidity position in the future, is subject to a number of risks, including those discussed below.

Our future liquidity may also be affected by the timing of construction financing availability in relation to the incurrence of construction costs and other outflows and by the anticipated timing of receipt of cash flow under TUAs and other sales of capacity in relation to the incurrence of projected project operating expenses. Many other factors (including factors beyond our control) could also result in a disparity between liquidity sources and cash needs, including factors such as construction delays and breaches of agreements.

Our substantial existing indebtedness, prevailing economic and market conditions, as well as other factors, have adversely affected the availability and cost of additional financing, which has adversely affected our liquidity, business, financial condition and prospects.

Our ability to generate needed amounts of cash is substantially dependent upon our TUAs with two third-party Sabine Pass LNG customers, and we will be materially and adversely affected if either customer fails to perform its TUA obligations for any reason.

Our future results and liquidity are dependent upon performance by Chevron and Total, each of which has entered into a TUA with Sabine Pass LNG and agreed to pay us approximately $125 million annually commencing during 2009. We are dependent on each customer's continued willingness and ability to perform its obligations under its TUA. We are also exposed to the credit risk of the guarantors of these customers' obligations under their TUAs in the event that we must seek recourse under a guaranty. If any customer fails to perform its obligations under its TUA, our business, results of operations, financial condition and prospects could be materially adversely affected, even if we were ultimately successful in seeking damages from that customer or its guarantor for a breach of the TUA.

Each customer's TUA for capacity at the Sabine Pass LNG receiving terminal is subject to termination under certain circumstances.

The long-term TUAs with each of Total and Chevron contain various termination rights. For example, each customer may terminate its TUA if the Sabine Pass LNG receiving terminal experiences a *force majeure* delay for longer than 18 months, fails to redeliver a specified amount of natural gas in accordance with the customer's redelivery nominations or fails to accept and unload a specified number of the customer's proposed LNG cargoes. We may not be able to replace these TUAs on desirable terms, or at all, if they are terminated.

Our ability to generate needed amounts of cash is also substantially dependent upon our ability to commercially exploit the capacity at the Sabine Pass LNG terminal that we have reserved for our own account.

Our ability to generate positive operating cash flow and achieve profitability in the future is also significantly dependent upon our ability to commercially exploit the TUA capacity that our subsidiary, Cheniere Marketing, LLC ("Cheniere Marketing") has reserved at the Sabine Pass LNG receiving terminal. As discussed below under "—Risks Relating to Our LNG and Natural Gas Marketing Business—We may not be able to commercially exploit the capacity we have reserved at the Sabine Pass LNG receiving terminal", there are significant risks attendant to Cheniere Marketing's future ability to generate operating cash flow. Failure by Cheniere Marketing to succeed in commercially exploiting its reserved TUA capacity at the Sabine Pass LNG receiving terminal could materially and adversely affect our business, results of operations, financial condition and prospects.

Our ability to develop our planned LNG receiving terminals and pipelines and to pursue our other business plans is contingent on our ability to obtain funding. If we are unable to do so, we may be unable to implement or complete our business plan, and our business may ultimately be unsuccessful.

We will need substantially more financing to complete all of our proposed LNG receiving terminals and natural gas pipelines. Prevailing economic and market conditions, as well as other factors, have caused us to defer or limit expenditures we might otherwise have made in developing our business. Such deferrals or limitations in the development of our business could continue and could adversely affect our ability to pursue our business strategy, our results of operations, our financial condition and our prospects. To fund these development projects, we plan to pursue a variety of sources of funding, including some or all of the following:

- debt and/or equity financing at the project level;
- debt and/or equity financing by Cheniere or its subsidiaries; and
- asset sales, to the extent permitted, and joint venture arrangements by Cheniere or its subsidiaries.

Our ability to obtain these or other types of financing will depend, in part, on factors beyond our control, such as the status of various debt and equity markets at the time financing is sought and such markets' view of our industry and prospects at such time. In particular, currently tight lending conditions may make it more time consuming and expensive for us to obtain financing, if we can obtain financing at all. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, if at all, even if our development projects could otherwise proceed on schedule. In addition, our ability to obtain some types of financing may be dependent upon our ability to obtain other types of financing. For example, project-level debt financing is typically contingent upon a significant equity capital contribution from the project sponsor. As a result, even if we are able to identify potential project-level lenders, we may still have to obtain another form of external financing for us to fund an equity capital contribution to the project subsidiary. Moreover, any future project-level debt financing for additional LNG receiving terminals or pipelines would likely be conditioned upon our prior receipt of commitments from third parties to pay for the projected capacity of the terminals or pipelines, as well as our achievement of additional milestones. A failure to obtain financing at any point in the development process of any of our projects could cause us to delay or fail to complete our business plan, which could cause our business to be unsuccessful.

Even if we are able to obtain financing, the terms required may adversely affect our business.

In order to obtain many types of financing, we may have to accept terms that are disadvantageous to us or that may have an adverse impact on our current or future business, operations or financial condition. For example:

- borrowings or debt issuances may subject us to certain restrictive covenants, including covenants restricting our ability to raise additional capital or cross-defaults to our other indebtedness;
- borrowings or debt issuances at the project level may subject the project entity to restrictive covenants, including covenants restricting its ability to make distributions to us or limiting our ability to sell our interests in such entity;
- additional sales of interests in our projects would reduce our interest in future revenues once the projects commence operations;
- the prepayment of terminal use fees by, or a business development loan from, prospective customers would reduce future revenues once the LNG receiving terminals commence operations;
- offerings of our equity securities would cause dilution for holders of our common stock and Series B Preferred Stock;
- our ability to borrow funds under some project financing arrangements would likely be subject to our satisfying the conditions and covenants in the financing and the construction schedule agreed to at the time we entered into such arrangement. If circumstances changed, we could need to seek waivers of conditions or covenants under our financing arrangements to prevent defaults thereunder and acceleration thereof, which we might not be able to obtain on a timely basis, or at all; and
- we could be required to make equity contributions before we could borrow under certain financing arrangements.

Risks Relating to Our LNG Receiving Terminal Business

We may not complete in a timely and cost-effective manner, or at all, the remaining construction and commissioning of the Sabine Pass LNG receiving terminal or the construction and commissioning of our other planned LNG receiving terminals.

Factors that could adversely affect our planned construction, completion and commissioning of our existing and planned LNG receiving terminals include:

- failure by contractors to fulfill their obligations under their construction contracts, or disagreements with them over their contractual obligations;
- failure to enter into satisfactory additional agreements with contractors;
- shortages of materials or delays in delivery of materials;
- cost overruns and difficulty in obtaining sufficient debt or equity financing to pay for such additional costs;
- difficulties or delays in obtaining LNG for commissioning activities at acceptable costs;
- failure to obtain and retain all necessary governmental and third-party permits, licenses and approvals for construction and operation;
- weather conditions, such as hurricanes and floods, and other catastrophes, such as explosions, fires and accidents;
- difficulties in attracting and maintaining a sufficient skilled and unskilled workforce;
- increases in the level of labor costs and the existence of any labor disputes;

- resistance in the local community due to safety, environmental or security concerns; and
- local and general economic and infrastructure conditions.

These factors could also adversely affect the timing or cost of completing the remaining 1.4 Bcf/d of sendout capacity and 6.7 Bcf of storage capacity that remained under construction at the Sabine Pass LNG receiving terminal as of December 31, 2008

Cost overruns and delays in the completion of the Sabine Pass LNG receiving terminal or in the construction of our proposed LNG receiving terminals, as well as difficulties in obtaining funding for additional costs, could have a material adverse effect on our business, results of operations, financial condition, liquidity and prospects.

We have experienced cost overruns of the construction, cool down, commissioning and completion of the Sabine Pass LNG receiving terminal. Our ultimate construction costs for Sabine Pass or other proposed LNG receiving terminals and pipelines may be significantly higher than our current estimates as a result of additional cost overruns, change orders under existing or future construction contracts, increased component and material costs, escalating labor costs, limited availability of labor, delays in construction and increased spending to maintain construction schedules.

Furthermore, in order to cover future increased construction costs, we would likely need to obtain additional funding. If we fail to obtain sufficient funding, our business plan could fail. Our ability to obtain debt or equity financing that may be needed to provide additional funding to cover increased construction costs will depend, in part, on factors beyond our control, such as the status of various capital and industry markets at the time financing is sought. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, if at all. Even if we are able to obtain financing, we may have to accept terms that are disadvantageous to us or that may have a material adverse effect on our current or future business, results of operations, financial condition and prospects.

We are dependent on contractors for the successful completion of our LNG receiving terminals.

We have limited experience constructing LNG receiving terminals. Timely and cost-effective completion of the Sabine Pass LNG receiving terminal and our other proposed LNG receiving terminals in compliance with agreed specifications is central to our business strategy and is highly dependent on our existing or future contractors' performance under their agreements with us. Our contractors' ability to perform successfully under their contracts is dependent on a number of factors, including their ability to:

- design and engineer the Sabine Pass LNG receiving terminal and our other proposed LNG receiving terminals to operate in accordance with specifications;
- engage and retain third-party subcontractors and procure equipment and supplies;
- respond to difficulties such as equipment failure, delivery delays, schedule changes and failure to perform by subcontractors, some of which are beyond their control;
- attract, develop and retain skilled personnel, including engineers;
- post required construction bonds and comply with the terms thereof;
- manage the construction process generally, including coordinating with other contractors and regulatory agencies; and
- maintain their own financial condition, including adequate working capital.

Although some of our existing EPC contracts provide for liquidated damages, if the contractor fails to perform in the manner required with respect to certain of its obligations, the events that trigger a requirement to pay liquidated damages may delay the completion or impair the operation of the affected facility, and any liquidated damages that we receive may not be sufficient to cover the damages that we suffer as a result of any such delay or impairment. In addition, each contractor's liability for liquidated damages is subject to a cap. Each of our material agreements with contractors is also subject to termination by the contractor prior to completion of construction under certain circumstances, including extended delays (of 100 days or more) caused by *force majeure* events and our insolvency, breach of material obligations not subject to adjustment by change order, or failure to pay undisputed amounts.

Furthermore, disagreements with our contractors about different elements of the construction process could lead to the assertion of rights and remedies under their contracts and increase the cost of the project or result in a contractor's unwillingness to perform further work on the project. If any contractor is unable or unwilling to perform according to the negotiated terms and timetable of its respective agreement for any reason or terminates its agreement, we would be required to engage a substitute contractor. This would likely result in significant project delays and increased costs.

To commission and test our LNG receiving terminals or in order to maintain their cryogenic readiness, we may need to purchase and process LNG. The cost of such LNG may exceed our estimates, and we may not be able to acquire it at an affordable price or at all. Furthermore, even if we are able to acquire LNG, we may not be able to resell the regasified LNG for a profit or at all.

LNG storage tanks and other equipment at our LNG receiving terminals must undergo a commissioning and testing process before commencement of operations. The commissioning process requires a substantial quantity of LNG as well as access to adequate LNG vessels to deliver the LNG. As of December 31, 2008, we had obtained three cargoes of LNG for commissioning at the Sabine Pass LNG receiving terminal. Our construction cost estimates include amounts to cover our estimated net costs of acquiring the LNG necessary to complete the commissioning and testing process at our LNG receiving terminals. Our actual cost to obtain LNG necessary for the commissioning and testing process could exceed our estimates, and the overrun could be significant.

Risks associated with acquiring LNG include the following:

- we may be unable to enter into contracts for the purchase of the LNG, and may be unable to obtain vessels to deliver such LNG, on terms reasonably acceptable to us or at all;
- we may bear the commodity price risk associated with purchasing the LNG, holding it in inventory for a period of time and selling the regasified LNG; and
- we may be unable to obtain financing for the purchase and shipment of the LNG on terms that are reasonably acceptable to us or at all.

Our failure to obtain LNG, LNG vessels, or both, on economical terms, or our inability to finance the purchase of LNG for commissioning or for maintenance of cryogenic readiness to provide services under our TUAs, could impede completion of commissioning and testing or provide our TUA customers with the opportunity to interrupt or terminate their payment under their TUAs. Any of these occurrences could have a material adverse effect on our business, results of operations, financial condition and prospects.

We may be required to purchase natural gas to provide fuel at the Sabine Pass LNG receiving terminal, which would increase operating costs and could have a material adverse effect on our results of operations.

Sabine Pass LNG's three TUAs provide for an in-kind deduction of 2% of the LNG delivered to the Sabine Pass LNG receiving terminal, which we will use primarily as fuel for revaporization and self-generated power and to cover natural gas unavoidably lost at the facility. There is a risk that this 2% in-kind deduction will be insufficient for these needs and that we will have to purchase additional natural gas from third parties. We will bear the cost and risk of changing prices for any such fuel.

We may not be able to enter into satisfactory TUAs with third-party customers for regasification capacity at our proposed LNG receiving terminals, as we have sought to do in order to implement and complete our business plan. We may change our business strategy as to how and when we market LNG receiving terminal capacity.

Our current business strategy calls for us to enter into long-term TUAs for a portion of the regasification capacity at our proposed LNG receiving terminals, including a commitment to pay capacity reservation fees. The portion of our total regasification capacity that we plan to commit under such long-term TUAs has changed in the past and may change in the future for various reasons, including responding to market factors or perceived opportunities that we believe may be available to us. Our ability to obtain financing for a proposed LNG receiving facility may be contingent on our ability to enter into commercial agreements in advance of the commencement of construction. To date, we have not entered into any third-party agreements for either of our proposed LNG receiving terminals.

We may experience difficulty attracting additional customers because we are a small, developing company with no operating history in the LNG business. In order to succeed, we must convince additional potential customers, among other things, that we will be able to secure adequate financing for the construction of the proposed LNG receiving terminals and related natural gas pipelines that we are developing and that these projects will be approved by appropriate governmental agencies.

We may also change our business strategy due to our inability to enter into agreements with additional customers or based on our views regarding future prices, demand and supply of natural gas and regasification capacity. If our efforts to market LNG receiving terminal and related pipeline capacity are not successful, our business, results of operations, financial condition and prospects could be materially adversely affected.

Failure to obtain and maintain approvals and permits from governmental and regulatory agencies with respect to the development and operation of our LNG receiving terminals could impede completion or operation and could have a material adverse effect on us.

The design, construction and operation of our LNG receiving terminals is a highly regulated activity. The FERC's approval under Section 3 of the Natural Gas Act of 1938, or the NGA, as well as several other material governmental and regulatory approvals and permits, are required in order to construct and operate an LNG receiving terminal. Although we have obtained all of the necessary authorizations to construct and operate the Sabine Pass LNG receiving terminal, such authorizations are subject to ongoing conditions imposed by regulatory agencies. Failure to obtain and maintain any of these approvals and permits could have a material adverse effect on our business, results of operations, financial condition and prospects.

Hurricanes or other disasters could adversely affect us.

In August and September of 2005, Hurricanes Katrina and Rita damaged coastal and inland areas located in Texas, Louisiana, Mississippi and Alabama. Construction at the Sabine Pass LNG receiving terminal site was temporarily suspended in connection with Hurricane Katrina, as a precautionary measure. Approximately three weeks after the occurrence of Hurricane Katrina, the terminal site was again secured and evacuated in anticipation of Hurricane Rita, the eye of which made landfall to the east of the site. As a result of these 2005 storms and related matters, the Sabine Pass LNG receiving terminal experienced construction delays and increased costs. In September 2008, Hurricane Ike struck the Texas and Louisiana coast and we experienced damage at the Sabine Pass LNG receiving terminal.

Future storms and related storm activity and collateral effects, or other disasters such as explosions, fires, floods or accidents, could result in damage to, delays or cost increases in construction of, or interruption of operations at, our LNG receiving terminals or related infrastructure.

After our LNG receiving terminals are placed in service, their businesses will involve significant operational risks.

Our LNG receiving terminals will face risks associated with operating the facilities. These risks will include, but will not be limited to, the following:

- the facilities' performing below expected levels of efficiency;
- breakdown or failures of equipment or systems;
- operational errors by vessel or tug operators or others;
- operational errors by us or any contracted facility operator or others;
- labor disputes; and
- weather-related interruptions of operations.

Risks Relating to Our Natural Gas Pipeline Business

Expanding our business by constructing additional pipelines subjects us to risks.

The construction of a new pipeline involves numerous regulatory, environmental, political and legal uncertainties beyond our control and requires the expenditure of significant amounts of capital that we will be required to finance through borrowings, through the issuance of additional equity or from operating cash flow. If we undertake these projects, they may not be completed on schedule, at the budgeted cost or at all. Whenever we build a new pipeline, the construction may occur over an extended period of time, and we will not receive any revenues until the pipeline has been completed and customers pay for transportation service on the pipeline. Moreover, we may construct pipelines to capture anticipated future growth in a region in which such growth does not materialize. As a result, our pipelines may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. Our ability to obtain financing for a pipeline construction project may depend upon the level of LNG import activity in the areas proposed to be served by the project as well as our ability to obtain commitments from LNG suppliers and other customers to utilize the newly constructed pipeline.

Our existing and proposed pipelines will be dependent upon a few potential customers, and our pipeline business could be materially and adversely affected if we lost any one of those customers.

We do not currently have any third-party, firm transportation customers for our existing or proposed pipelines. Failure to obtain any third-party, firm transportation customers could have a material adverse impact on our business.

Failure to obtain and maintain approvals and permits from governmental and regulatory agencies with respect to the development and operation of our natural gas pipelines would have a detrimental effect on us and our pipeline projects.

The design, construction and operation of natural gas pipelines and the transportation of natural gas are all highly regulated activities. FERC approval under Section 7 of the NGA, as well as several other material state governmental and regulatory approvals and permits, are required in order to construct and operate a pipeline. We must also obtain several other material governmental and regulatory approvals and permits in order to construct and operate pipelines, including several under the Clean Air Act and the Clean Water Act from the U.S. Army Corps of Engineers and the Louisiana Department of Environmental Quality. We have no control over the timing of the review and approval process nor can we predict the outcome of the process. We do not know whether or when any such approvals or permits can be obtained, or whether or not any third parties will attempt to interfere with our ability to obtain and maintain such permits or approvals. If we are unable to obtain and maintain the necessary approvals and permits, we may not be able to recover our investment in the projects. Failure to obtain and maintain any of these approvals and permits could have a material adverse effect on our business, results of operations, financial condition and prospects.

Our existing and proposed natural gas pipelines, including their FERC gas tariffs, are subject to FERC regulation.

Our FERC tariffs contain pro forma transportation agreements, which must be filed and approved by FERC. Before we enter into a transportation agreement with a shipper that contains a term that materially deviates from our tariff, we must seek FERC approval. The FERC may approve the material deviation in the transportation agreement; however, in that case, the materially deviating terms must be made available to our other similarly-situated customers. If we fail to seek FERC approval of a transportation agreement that materially deviates from our tariff, or if FERC audits our contracts and finds deviations that appear to be unduly discriminatory, FERC could conduct a formal enforcement investigation, resulting in serious penalties and/or onerous ongoing compliance obligations.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation.

The FERC could change its current ratemaking policies, and those changes could have adverse effects on our proposed pipelines.

Any reduction in the capacity of, or the allocations to, interconnecting, third-party pipelines could cause a reduction of volumes transported in our existing and proposed pipelines, which would adversely affect our revenues and cash flow.

We will be dependent upon third-party pipelines and other facilities to provide delivery options to and from our pipelines. If any pipeline connection were to become unavailable for volumes of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our ability to continue shipping natural gas to end markets could be restricted, thereby reducing our revenues. Any permanent interruption at any key pipeline interconnect which caused a material reduction in volumes transported on our pipelines could have a material adverse effect on our business, results of operations and financial condition.

Our pipeline business could be materially adversely affected if we lose the right to situate our pipelines on property owned by third parties.

We do not anticipate owning the land on which our proposed pipelines will be constructed, and we are subject to the possibility of increased costs to obtain and retain necessary land use. We anticipate obtaining the right to construct and operate our pipelines on land owned by third parties for a period of time. If we were to lose these rights or be required to relocate our pipelines, our business could be materially adversely affected.

Pipeline safety integrity programs and repairs may impose significant costs and liabilities on us.

The Federal Office of Pipeline Safety has issued a final rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate certain areas along their pipelines and to take additional measures to protect pipeline segments located in what the rule refers to as "high consequence areas" where a leak or rupture could potentially do the most harm. The final rule requires operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;

- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

We will be required to initiate pipeline integrity testing programs that are intended to assess pipeline integrity. The rule, or an increase in public expectations for pipeline safety, may require additional reporting and more frequent inspection or testing of our pipeline facilities. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures. Should we fail to comply with the Office of Pipeline Safety's rules and related regulations and orders, we could be subject to penalties and fines.

Risks Relating to Our LNG and Natural Gas Marketing Business

We may be unable to commercially exploit the capacity at the Sabine Pass LNG terminal that we have reserved for our own account.

The success of our LNG and natural gas marketing business will be significantly dependent upon our ability to commercially exploit the TUA capacity that Cheniere Marketing has reserved at the Sabine Pass LNG receiving terminal. That, in turn, is subject to substantial risks, including the following:

- Cheniere Marketing does not have unconditional agreements or arrangements for any supplies of LNG, or for the utilization of capacity that it has contracted for under its TUA with us and may not be able to obtain such agreements or arrangements on economical terms, or at all;
- Cheniere Marketing does not have unconditional commitments from customers for the purchase of the natural gas it proposes to sell from our LNG receiving terminal, and it may not be able to obtain commitments or other arrangements on economical terms, or at all;
- in order to arrange for supplies of LNG, and for transportation, storage and sales of natural gas, Cheniere Marketing will require significant credit support and funding, which we may not be able to obtain on terms that are acceptable to us, or at all; and
- even if Cheniere Marketing is able to arrange for and finance supplies and transportation of LNG to the Sabine Pass LNG receiving terminal, and for transportation, storage and sales of natural gas to customers, it may experience negative cash flows and adverse liquidity effects due to fluctuations in supply, demand and price for LNG, for transportation of LNG, for natural gas and for storage and transportation of natural gas.

Cheniere Marketing has a limited operating history, limited capital, no credit rating and an unproven business strategy. In addition, we have a non-investment grade corporate rating of CCC+ from Standard and Poor's, which limits our ability to enhance the creditworthiness of Cheniere Marketing. These factors create financial obstacles and exacerbate the risk that Cheniere Marketing will not be able to enter into commercial arrangements with third parties to commercially exploit its capacity at the Sabine Pass LNG receiving terminal on commercially advantageous terms or at all.

In pursuing each aspect of our plan to commercially exploit Cheniere Marketing's TUA capacity at the Sabine Pass LNG receiving terminal, we will encounter competition, including competition from major energy companies and other competitors with significantly greater resources.

Any or all of these factors, as well as risk factors described elsewhere and other risk factors that we may not be able to anticipate, control or mitigate, could have a material adverse effect on our ability to commercially exploit Cheniere Marketing's TUA capacity at the Sabine Pass LNG receiving terminal, which in turn could materially and adversely affect the business, results of operations, financial condition, prospects and liquidity.

We are in the early stages of developing our LNG and natural gas marketing business.

We have recently begun developing our LNG and natural gas marketing business. To date, the business has been unprofitable and has a limited operating history upon which to evaluate our business strategy or the future prospects of the business. Since inception, our LNG and natural gas marketing business has had net operating losses. The ability of our LNG and natural gas marketing business to generate revenues in the future will depend upon whether we can successfully develop and implement our business strategy and make the transition from a development stage business to an operating business. We may encounter many expenses, delays, problems and difficulties that we have not anticipated and for which we have not planned in developing and operating our LNG and natural gas marketing business.

Our use of hedging arrangements may adversely affect our future results of operations or liquidity.

To reduce our exposure to fluctuations in the price, volume, timing, location, quality and credit risk associated with the marketing of LNG and natural gas, we use futures, swaps and option contracts traded or cleared on NYMEX and over-the-counter options and swaps with other natural gas merchants and financial institutions. Hedging arrangements would expose us to risk of financial loss in some circumstances, including when:

- expected supply is less than the amount hedged;
- the counterparty to the hedging contract defaults on its contractual obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

Our hedging arrangements may also limit the benefit that we would receive from increases in the prices for natural gas. The use of derivatives also may require the posting of cash collateral with counterparties, which can impact working capital when commodity prices change.

The limited operating history of, and limited capital resources and credit available to, our LNG and natural gas marketing business limit our ability to develop that business.

We have limited the amount of capital available to our LNG and natural gas marketing business. The business currently has limited access to third-party sources of financing. Other investment-grade marketing companies have greater financial, technical and marketing resources and access to LNG supply than we do. Our LNG and natural gas marketing business is in its early stages of development and may not generate sufficient revenues and cash flows to cover the significant fixed costs of the business. The limited capital and credit available to our LNG and natural gas marketing business, along with a lack of cash flows, may inhibit our ability to develop that business.

Our exposure to the performance and credit risks of counterparties under agreements may adversely affect our results of operations, liquidity and access to financing.

Our LNG and natural gas marketing business involves our entering into various purchase and sale, hedging, and other transactions with numerous third parties (commonly referred to as "counterparties"). In such arrangements, we are exposed to the performance and credit risks of our counterparties, including the risk that one or more counterparties fails to perform its obligation to make deliveries of commodities and/or to make payments. These risks may increase during periods of commodity price volatility. Defaults by suppliers and other counterparties may adversely affect our results of operations, liquidity and access to financing.

Risks Relating to Our LNG Businesses in General

Failure of imported LNG to be a competitive source of energy for North American markets could materially adversely affect our business, financial condition, results of operations and prospects.

The success of our LNG receiving terminal business, our natural gas pipeline business and our LNG and natural gas marketing business (collectively, our "LNG businesses"), is primarily dependent upon LNG being a competitive source of energy in North America.

In North America, due mainly to a historically abundant supply of natural gas, imported LNG has not historically been a major energy source. Our business plan is based, in part, on the belief that LNG can be produced and delivered at a lower cost than the cost to produce some domestic supplies of natural gas, or other alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas may be discovered in North America, which could further increase the available supply of natural gas and could result in natural gas being available at a lower cost than imported LNG. In addition to natural gas, LNG also competes in North America with other sources of energy, including coal, oil, nuclear, hydroelectric, wind and solar energy.

Other continents have a longer history of importing LNG and, due to their geographic proximity to LNG producers and limited pipeline access to natural gas supplies, may be willing and able to pay more for LNG, thereby reducing or eliminating the supply of LNG available in North American markets. Current and futures prices for natural gas in markets that compete with North America have been higher than prices for natural gas in North America, which has adversely affected the volume of LNG imports into North America. If LNG deliveries to North America continue to be constrained due to stronger demand from these competing markets, our ability and the ability of existing and prospective third-party TUA customers to import LNG into North America on a profitable basis may be adversely affected.

Political instability in foreign countries that have supplies of natural gas, or strained relations between such countries and the U.S., may also impede the willingness or ability of LNG suppliers and merchants in such countries to export LNG to the U.S. Furthermore, some foreign suppliers of LNG may have economic or other reasons to direct their LNG to non-U.S. markets or to competitors' LNG receiving terminals in the U.S.

As a result of these and other factors, LNG may not be a competitive source of energy in North America. The failure of LNG to be a competitive supply alternative to domestic natural gas, oil and other alternatives could adversely affect our ability to enter into additional TUAs with customers and could also impede the ability to import LNG into North America on a commercial basis of us and our TUA customers, which could inhibit our growth and cause us operating losses. Any significant impediment to the ability to import LNG into the United States generally or to our LNG receiving terminals specifically could have a material adverse effect on us, on our third-party LNG receiving terminal customers, and on our LNG businesses, results of operations, financial condition and prospects.

Cyclical or other changes in the demand for LNG regasification capacity may adversely affect our LNG businesses and the performance of our TUA customers, and could reduce our operating revenues and may cause us operating losses.

The economics of our LNG businesses could be subject to cyclical swings, reflecting alternating periods of under-supply and over-supply of LNG importation capacity and available natural gas, principally due to the combined impact of several factors, including:

- additions to competitive regasification capacity in North America, Europe, Asia and other markets, which could divert LNG from our existing and proposed LNG receiving terminals;
- insufficient LNG liquefaction capacity worldwide;
- insufficient LNG tanker capacity;

- reduced demand and lower prices for natural gas;
- increased natural gas production deliverable by pipelines, which could suppress demand for LNG;
- cost improvements that allow competitors to offer LNG regasification services at reduced prices;
- changes in supplies of, and prices for, alternative energy sources such as coal, oil, nuclear, hydroelectric, wind and solar energy, which may reduce the demand for natural gas;
- changes in regulatory, tax or other governmental policies regarding imported LNG, natural gas or alternative energy sources, which may reduce the demand for imported LNG and/or natural gas;
- adverse relative demand for LNG in North America compared to other markets, which may decrease LNG imports into North America; and
- cyclical trends in general business and economic conditions that cause changes in the demand for natural gas.

These factors could materially adversely affect our ability, and the ability of current and prospective TUA customers, to procure supplies of LNG to be imported into North America and to procure customers for regasified LNG at economical prices, or at all.

Insufficient development of additional LNG liquefaction capacity worldwide could adversely affect our LNG businesses and the performance of our TUA customers, and could have a material adverse effect on our business, results of operations, financial condition, liquidity and prospects.

Commercial development of an LNG liquefaction facility takes a number of years and requires substantial capital investment. Many factors could negatively affect continued development of LNG liquefaction facilities, including:

- increased construction costs;
- economic downturns, increases in interest rates or other events that may affect the availability of sufficient financing for LNG projects on commercially reasonable terms;
- decreases in the price of LNG and natural gas, which might decrease the expected returns relating to investments in LNG projects;
- the inability of project owners or operators to obtain governmental approvals to construct or operate LNG facilities;
- political unrest in exporting countries or local community resistance in such countries to the siting of LNG facilities due to safety, environmental or security concerns; and
- any significant explosion, spill or similar incident involving an LNG liquefaction facility or LNG carrier.

There may be shortages of LNG vessels worldwide, which could adversely affect our LNG businesses and the performance of our TUA customers, and could have a material adverse effect on our business, results of operations, financial condition, liquidity and prospects.

The construction and delivery of LNG vessels requires significant capital and long construction lead times, and the availability of the vessels could be delayed to the detriment of our LNG businesses and our TUA customers because of:

- an inadequate number of shipyards constructing LNG vessels and a backlog of orders at these shipyards;
- political or economic disturbances in the countries where the vessels are being constructed;
- changes in governmental regulations or maritime self-regulatory organizations;

- work stoppages or other labor disturbances at the shipyards;
- bankruptcy or other financial crisis of shipbuilders;
- quality or engineering problems;
- weather interference or a catastrophic event, such as a major earthquake, tsunami or fire; and
- shortages of or delays in the receipt of necessary construction materials.

Decreases in the demand for and price of natural gas could lead to reduced development of LNG projects worldwide, which could adversely affect our LNG businesses and the performance of our TUA customers, and could have a material adverse effect on our business, results of operations, financial condition, liquidity and prospects.

The development of domestic LNG receiving terminals and LNG projects generally is based on assumptions about the future price of natural gas and the availability of imported LNG. Natural gas prices have been, and are likely to continue to be, volatile and subject to wide fluctuations in response to one or more of the following factors:

- relatively minor changes in the supply of, and demand for, natural gas in relevant markets;
- political conditions in international natural gas producing regions;
- the extent of domestic production and importation of natural gas in relevant markets;
- the level of demand for LNG and natural gas in relevant markets, including the effects of economic downturns or upturns;
- weather conditions;
- the competitive position of natural gas as a source of energy compared with other energy sources; and
- the effect of government regulation on the production, transportation and sale of natural gas.

Adverse trends or developments affecting any of these factors could result in decreases in the price of natural gas, leading to reduced development of LNG projects worldwide. Such reductions could adversely affect our LNG businesses and the performance of our TUA customers, and could have a material adverse effect on our business, results of operations, financial condition, liquidity and prospects.

Our LNG businesses face competition, including competing LNG receiving terminals and related pipelines from competitors with far greater resources.

Many competing companies have secured access to, or are pursuing development or acquisition of, LNG import infrastructure to serve the U.S. natural gas market. Some industry analysts have predicted substantial excess LNG receiving capacity in North America for at least several years based on terminals currently in operation or under construction. Competitors faced by our LNG businesses in the U.S. include major energy corporations (e.g., BG, BP, Chevron, ConocoPhillips and Dow Chemical). In addition, other competitors have developed or reopened additional LNG receiving terminals in Europe, Asia and other markets, which also compete with our existing and proposed LNG facilities. Almost all of these competitors have longer operating histories, more development experience, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources and access to LNG supply than we do. The superior resources that these competitors have available for deployment could allow them to compete successfully against our LNG businesses, which could have a material adverse effect on our business, results of operations, financial condition, liquidity and prospects.

Terrorist attacks or military campaigns may adversely impact our LNG businesses.

A terrorist incident involving an LNG facility or LNG carrier may result in delays in, or cancellation of, construction of new LNG facilities, including our proposed LNG receiving terminals and related natural gas pipelines, which would increase our costs and decrease our cash flows. A terrorist incident may also result in temporary or permanent closure of existing LNG facilities, which could increase our costs and decrease our cash flows, depending on the duration of the closure. Operations at our LNG receiving terminals could also become subject to increased governmental scrutiny that may result in additional security measures at a significant incremental cost to us. In addition, the threat of terrorism and the impact of military campaigns may lead to continued volatility in prices for natural gas that could adversely affect our LNG businesses.

Risks Relating to Our Business in General

Our initiatives to pursue downstream and upstream opportunities as part of our overall energy business strategy may not be successful and, even if successful, could expose us to greater and unanticipated risks.

We may not be successful in our efforts to pursue any or all of our downstream opportunities such as natural gas pipeline development or natural gas marketing, or in our efforts to pursue any or all of our upstream opportunities such as securing foreign LNG supply arrangements. If we are successful in pursuing one or more of these downstream or upstream opportunities, we will likely incur greater risks than we expect to incur in our LNG receiving terminal business, and some of those risks we will not be able to anticipate.

We are subject to significant operating hazards and uninsured risks, one or more of which may create significant liabilities and losses for us.

The construction and operation of our proposed LNG receiving terminals and pipelines, as well as the conduct of our oil and gas exploration and production business, are subject to inherent risks associated with these types of operations, including explosions, pollution, release of toxic substances, fires, hurricanes and adverse weather conditions, and other hazards, each of which could result in significant delays in commencement or interruptions of operations and/or in damage to or destruction of our facilities or damage to persons and property. In addition, our operations and the facilities and vessels of third parties on which our operations are dependent face possible risks associated with acts of aggression or terrorism.

We do not, nor do we intend to, maintain insurance against all of these risks and losses. We may not be able to maintain desired or required insurance in the future at rates that we consider reasonable. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our business, results of operations, financial condition, liquidity and prospects.

Existing and future environmental and similar laws and regulations could result in increased compliance costs or additional operating costs and restrictions.

Our business is and will be subject to extensive federal, state and local laws and regulations that control, among other things, discharges to air and water; the handling, storage and disposal of hazardous chemicals, hazardous waste, and petroleum products; and remediation associated with the release of hazardous substances. Many of these laws and regulations, such as the CAA, the Oil Pollution Act, the CWA, and the RCRA, and analogous state laws and regulations, restrict or prohibit the types, quantities and concentration of substances that can be released into the environment in connection with the construction and operation of our LNG receiving terminals and require us to maintain permits and provide governmental authorities with access to our facilities for inspection and reports related to our compliance. Violation of these laws and regulations could lead to substantial fines and penalties or to capital expenditures related to pollution control equipment that could have a material adverse effect on our business, results of operations, financial condition, liquidity and prospects. CERCLA and similar state laws impose liability, without regard to fault or the lawfulness of the original conduct, for the release of certain types or quantities of hazardous substances into the environment. As the owner and operator of an LNG receiving terminal and pipeline, we could be liable for the costs of cleaning up hazardous substances released into the environment and for damage to natural resources.

Existing environmental laws and regulations may be revised or reinterpreted or new laws and regulations may be adopted or become applicable to us. For example, the adoption of frequently proposed legislation implementing a carbon tax on energy sources that emit carbon dioxide into the atmosphere, may have a material adverse effect on the ability of our customers (i) to import LNG, if imposed on them as importers of potential emission sources, or (ii) to sell regasified LNG, if imposed on them or their customers as natural gas suppliers or consumers. In addition, as we consume retainage gas at our LNG receiving terminal, this carbon tax may also be imposed on us directly. Other future legislation and regulations, such as those relating to the transportation and security of LNG imported to our LNG receiving terminal through the Sabine Pass Channel, could cause additional expenditures, restrictions and delays in our business and to our planned construction, the extent of which cannot be predicted and which may require us to limit substantially, delay or cease operations in some circumstances. Revised, reinterpreted or additional laws and regulations that result in increased compliance costs or additional operating costs and restrictions could have a material adverse effect on our business, results of operations, financial condition, liquidity and prospects.

We may experience increased labor costs, and the unavailability of skilled workers or our failure to attract and retain key personnel could adversely affect us.

We are dependent upon the available labor pool of skilled employees. We compete with other energy companies and other employers to attract and retain qualified personnel with the technical skills and experience required to construct our proposed LNG receiving terminals and pipelines and to provide our customers with the highest quality service. A shortage in the labor pool of skilled workers or other general inflationary pressures or changes in applicable laws and regulations could make it more difficult for us to attract and retain personnel and could require an increase in the wage and benefits packages that we offer, thereby increasing our operating costs. For example, in the aftermaths of Hurricanes Katrina and Rita, Bechtel and certain subcontractors temporarily experienced a shortage of available skilled labor necessary to meet the requirements of the Sabine Pass LNG receiving terminal construction plan. As a result, we agreed to change orders with Bechtel concerning additional activities and expenditures to mitigate the hurricanes' effects on the construction of the Sabine Pass LNG receiving terminal. Any increase in our operating costs could materially adversely affect our business, results of operations, financial condition and prospects.

We depend on our executive officers for various activities. We do not maintain key person life insurance policies on any of our personnel. Although we have arrangements relating to compensation and benefits with certain of our executive officers, we do not have any employment contracts or other agreements with key personnel binding them to provide services for any particular term. The loss of the services of any of these individuals could seriously harm us.

Our lack of diversification could have an adverse effect on our financial condition and results of operations.

Substantially all of our anticipated revenue in 2009 will be dependent upon one asset, the Sabine Pass LNG receiving terminal. Due to our lack of asset and geographic diversification, an adverse development at the Sabine Pass LNG receiving terminal or in the LNG industry would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets and operating areas.

Some of our economic value is derived from our ownership of a minority interest in an entity over which we exercise no day-to-day control.

We own a 30% limited partner interest in Freeport LNG. Some of our value is attributable to this investment. In this report, we may use the words "our," "we" or "us" in describing this investment or its assets and operations; however, we do not exercise control over Freeport LNG. The management team of Freeport LNG could make business decisions without our consent that could impair the economic value of our investment in Freeport LNG. Any such diminution in the value of our investment could have an adverse impact on our business, results of operations, financial condition and prospects.

We may have to take actions that are disruptive to our business strategy to avoid registration under the Investment Company Act of 1940.

The Investment Company Act of 1940, or Investment Company Act, requires registration for companies that are engaged primarily in the business of investing, reinvesting, owning, holding or trading in securities. Registration as an investment company would subject us to restrictions that are inconsistent with our fundamental business strategy.

A company may be deemed to be an investment company if it owns investment securities with a value exceeding 40% of the value of its total assets (excluding government securities and cash items) on an unconsolidated basis, unless an exemption or safe harbor applies. Securities issued by companies other than majority-owned subsidiaries are generally counted as investment securities for purposes of the Investment Company Act. We own a minority equity interest in Freeport LNG, which could be counted as an investment security. We generally plan to invest our liquid assets in commercial paper or other assets that may be considered investment securities in order to achieve higher yields from our available funds than investments in government securities and money market or similar cash investments would provide. Based on our board of directors' determination of the value of our subsidiaries, we estimate that less than 40% of our assets consist of investment securities. However, in the event we acquire additional investment securities in the future, or if the value of our interests in companies that we do not control were to increase relative to the value of our controlled subsidiaries, we might be required to invest some portion of our liquid assets in government securities or cash items that yield lower returns than our proposed investments, or, in the alternative, we might be required to divest some of our non-controlled business interests, or take other action, in order to avoid being classified as an investment company.

We may engage in operations or make substantial commitments and investments outside the United States, which would expose us to political, governmental and economic instability and foreign currency exchange rate fluctuations.

Conducting operations or making commitments and investments outside of the United States will cause us to be affected by economic, political and governmental conditions in the countries where we engage in business. Any disruption caused by these factors could harm our business. Risks associated with operations, commitments and investments outside of the United States include risks of:

- currency fluctuations;
- war;
- expropriation or nationalization of assets;
- renegotiation or nullification of existing contracts;
- changing political conditions;
- changing laws and policies affecting trade, taxation and investment;
- multiple taxation due to different tax structures; and
- the general hazards associated with the assertion of sovereignty over certain areas in which operations are conducted.

Because our reporting currency is the United States dollar, any of our operations conducted outside the United States would face additional risks of fluctuating currency values and exchange rates, hard currency shortages and controls on currency exchange. We would be subject to the impact of foreign currency fluctuations and exchange rate changes on our reporting for results from those operations in our financial statements.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

ITEM 3. *LEGAL PROCEEDINGS*

We may in the future 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, as of December 31, 2008, there were no threatened or pending legal matters that would have a material impact on our consolidated results of operations, financial position or cash flows.

ITEM 4. *SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS*

None.

PART II

ITEM 5. *MARKET PRICE FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES*

Our common stock has traded on the NYSE Alternext US (formerly the American Stock Exchange) under the symbol LNG since March 24, 2003. The table below presents the high and low daily closing sales prices of the common stock, as reported by the NYSE Alternext US, for each quarter during 2007 and 2008.

	High	Low
Three Months Ended		
March 31, 2007	$32.50	$27.08
June 30, 2007	41.23	31.45
September 30, 2007	41.60	34.64
December 31, 2007	41.73	31.87
Three Months Ended		
March 31, 2008	$32.68	$19.80
June 30, 2008	20.66	4.37
September 30, 2008	4.98	2.13
December 31, 2008	4.47	0.95

As of February 17, 2009, we had 52 million shares of common stock outstanding held by approximately 1,021 record owners.

We have never paid a cash dividend on our common stock. We currently intend to retain earnings to finance the growth and development of our business and do not anticipate paying any cash dividends on the common stock in the foreseeable future. Any future change in our dividend policy will be made at the discretion of our board of directors in light of our financial condition, capital requirements, earnings, prospects and any restrictions under any financing agreements, as well as other factors the board of directors deems relevant.

Issuer Purchases of Equity Securities

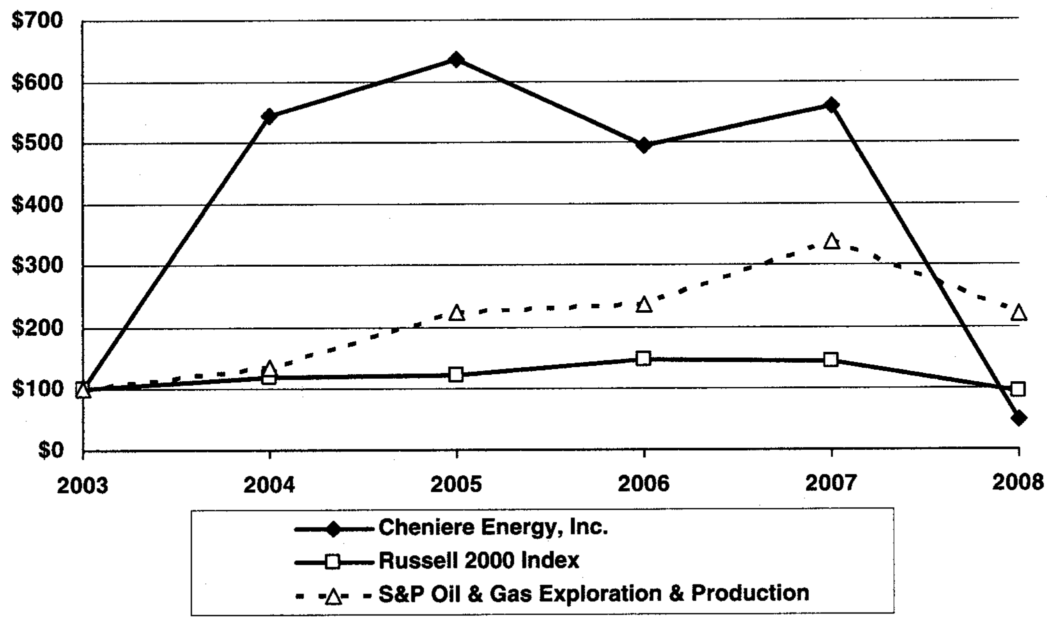
During the three months ended December 31, 2008, we purchased 143,220 shares of restricted stock at an average cash price of $2.86 per share related to restricted stock vested in December 2008 that was returned to the Company by employees to cover taxes.

Total Stockholder Return

The following graph compares the cumulative total stockholder return on our common stock against the S&P Oil and Gas Exploration and Production Index, and the Russell 2000 Index for the five years ending December 31, 2008. The graph was constructed on the assumption that $100 was invested in our common stock, the S&P Oil and Gas Exploration and Production Index and the Russell 2000 Index on December 31, 2003 and that any dividends were fully reinvested.

COMPANY/INDEX	2003	2004	2005	2006	2007	2008
CHENIERE ENERGY, INC.	$100	$544	$636	$494	$558	**$ 49**
RUSSELL 2000 INDEX	$100	$118	$124	$146	$144	**$ 95**
S&P OIL & GAS EXPLORATION & PRODUCTION INDEX	$100	$135	$224	$235	$339	**$222**

COMPARISON OF CUMULATIVE FIVE YEAR TOTAL RETURN



The "Total Stockholder Return" information contained in this Item 5 of this Annual Report on Form 10-K is not deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Exchange Act or to the liabilities of Section 18 of the Exchange Act, and will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent we specifically incorporate it by reference into such a filing.

ITEM 6. *SELECTED FINANCIAL DATA*

Selected financial data set forth below are derived from our audited Consolidated Financial Statements for the periods indicated. The financial data should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations and our Consolidated Financial Statements and Notes thereto included elsewhere in this report.

	Year Ended December 31, (in thousands, except per share data)				
	2008	**2007**	**2006**	**2005 (5) (as adjusted)**	**2004 (5) (as adjusted)**
Revenues	$ 7,144	$ 647	$ 2,371	$ 3,005	$ 1,998
LNG terminal and pipeline development expenses	10,556	34,656	12,099	22,020	17,166
Exploration costs	128	1,116	3,138	2,839	2,662
Depreciation, depletion and amortization	24,346	6,393	3,131	1,325	507
General and administrative expenses	122,678	122,046	58,012	29,145	12,476
Restructuring charges (1)	78,704	—	—	—	—
Loss from operations	(244,188)	(163,940)	(75,874)	(52,561)	(30,930)
Loss from equity method investments	(4,800)	(191)	—	(1,031)	(1,346)
Gain on sale of investment in unconsolidated affiliate (2)	—	—	—	20,206	—
Reimbursement from limited partnership investment	—	—	—	—	2,500
Loss on early extinguishment of debt (3)	(10,691)	—	(43,159)	—	—
Derivative gain (loss) (4)	4,652	—	(20,070)	837	—
Interest expense, net	(130,648)	(104,557)	(53,968)	(17,373)	(4)
Interest income	20,337	82,635	49,087	17,520	501
Minority interest	8,777	3,425	—	97	2,862
Net loss	(356,471)	(181,777)	(145,853)	(29,538)	(24,876)
Net loss per share (basic and diluted) (5)	$ (7.53)	$ (3.60)	$ (2.68)	$ (0.56)	$ (0.64)
Weighted average shares outstanding (basic and diluted) (5)	47,365	50,537	54,423	53,097	38,895

	December 31,				
	2008	**2007**	**2006**	**2005 (5) (as adjusted)**	**2004 (6) (as adjusted)**
Cash and cash equivalents	$ 102,192	$ 296,530	$ 462,963	$ 692,592	$308,443
Restricted cash and cash equivalents	301,550	228,085	176,827	122,217	—
Working capital	350,459	427,511	588,034	770,797	305,752
Non-current restricted cash and cash equivalents	138,483	478,225	1,071,722	55,844	—
Non-current restricted U.S. Treasury securities	20,829	63,923	—	—	—
Property, plant and equipment, net	2,170,158	1,645,112	748,818	280,106	2,643
Debt issuances costs, net	57,676	44,005	41,545	43,008	1,302
Goodwill	76,844	76,844	76,844	76,844	—
Total assets	2,922,070	2,962,299	2,604,488	1,290,147	315,330
Long-term debt, net of discount	2,832,673	2,757,000	2,357,000	917,500	—
Long-term debt—related parties, net of discount	332,054	—	—	—	—
Long-term deferred revenue	37,500	40,000	41,000	41,000	23,000
Total liabilities	3,526,663	3,264,413	2,461,241	1,021,606	28,966
Total stockholders' equity	$ (604,593)	$ (302,114)	$ 143,247	$ 268,541	$286,364

(1) In the second quarter of 2008, we announced a cost savings program in connection with the downsizing of our natural gas marketing business activities, the nearing completion of significant construction activities for both the Sabine Pass LNG receiving terminal and Creole Trail Pipeline and the seeking of alternative arrangements for our time charter interest in two LNG vessels (See Note 4—"Restructuring Charges" of our Notes to Consolidated Financial Statements).
(2) In 2005, our investment in Gryphon Exploration Company was sold to Woodside Energy (USA), generating net cash proceeds and a gain to Cheniere of $20.2 million.
(3) Amount in 2008 relates to losses on the termination of the Bridge Loan in August 2008. Amounts in 2006 primarily relate to losses on the termination of a Sabine Pass LNG credit facility and term loan in November 2006. See Note 18—"Long-Term Debt and Long-Term Debt—Related Parties" of our Notes to Consolidated Financial Statements.
(4) Amounts in 2006 primarily relate to losses on the termination of hedge transactions related to the termination of a Sabine Pass LNG credit facility and term loan in November 2006.
(5) Net loss per share and weighted average shares outstanding have been restated to reflect a two-for-one stock split that occurred on April 22, 2005.
(6) Amounts reported for the years ended December 31, 2005 and 2004 have been adjusted to reflect the change in our method of accounting for investments in oil and gas properties from the full cost method to the successful efforts method.

ITEM 7. *MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION*

Introduction

The following discussion and analysis presents management's view of our business, financial condition and overall performance and should be read in conjunction with our consolidated financial statements and the accompanying notes in Item 8, "Financial Statements and Supplementary Data." This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future. Our discussion and analysis include the following subjects:

- Overview of Business
- Overview of 2008 Events
- Liquidity and Capital Resources
- Contractual Obligations
- Results of Operations
- Off-Balance Sheet Arrangements
- Inflation and Changing Prices
- Summary of Critical Accounting Policies and Estimates
- Recently Issued Accounting Standards Not Yet Adopted

Overview of Business

We operate three segments: LNG receiving terminal business, natural gas pipeline business, and LNG and natural gas marketing business. To a limited extent, we continue to be engaged in oil and natural gas exploration, development and exploitation activities in the Gulf of Mexico.

LNG Receiving Terminal Business

We have focused our LNG receiving terminal development efforts on the following three projects: the Sabine Pass LNG receiving terminal in western Cameron Parish, Louisiana on the Sabine Pass Channel; the

Corpus Christi LNG receiving terminal near Corpus Christi, Texas; and the Creole Trail LNG receiving terminal at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. In addition, we own a 30% interest in Freeport LNG Development, L.P. ("Freeport LNG") which has constructed an LNG receiving terminal located on Quintana Island near Freeport, Texas.

Our ownership interest in the Sabine Pass LNG receiving terminal is held through Cheniere Energy Partners, L.P. ("Cheniere Partners"), a Delaware limited partnership, in which we hold an approximate 90.6% interest as a result of the completion of a public offering of common units in Cheniere Partners. Cheniere Partners owns a 100% interest in Sabine Pass LNG, L.P. ("Sabine Pass LNG"), which is constructing the Sabine Pass LNG receiving terminal. We currently own 100% interests in the proposed Corpus Christi and Creole Trail LNG receiving terminals. The three LNG receiving terminals under development by us have an aggregate designed regasification capacity of approximately 10.1 Bcf/d, subject to expansion.

Construction of the Sabine Pass LNG receiving terminal commenced in March 2005, and we achieved commercial operability in September 2008 with initial sendout capacity of approximately 2.6 Bcf/d and storage capacity of approximately 10.1 Bcf. We anticipate achieving full operability of the Sabine Pass LNG receiving terminal with a total sendout capacity of approximately 4.0 Bcf/d and total storage capacity of approximately 16.8 Bcf during the third quarter of 2009. Sabine Pass LNG has entered into long-term terminal use agreements ("TUAs") with Total LNG USA, Inc. ("Total"), Chevron U.S.A., Inc. ("Chevron") and Cheniere Marketing, LLC ("Cheniere Marketing"), our wholly-owned subsidiary formerly known as Cheniere Marketing, Inc., for the entire 4.0 Bcf/d of regasification capacity that will be available at the Sabine Pass LNG receiving terminal upon completion of construction.

We will contemplate making final investment decisions to complete construction of the Corpus Christi LNG receiving terminal and to commence construction of the Creole Trail LNG receiving terminal upon, among other things, entering into acceptable commercial and financing arrangements.

Natural Gas Pipeline Business

We are developing natural gas pipelines to provide access to North American natural gas markets from our LNG receiving terminals, and to serve growing natural gas markets with diverse new sources of natural gas supplies. We have focused our natural gas pipeline development efforts on the following three projects: the Creole Trail Pipeline originating at the Sabine Pass LNG receiving terminal to points of interconnection with multiple interstate and intrastate natural gas pipelines throughout southern Louisiana; the Corpus Christi Pipeline originating at the Corpus Christi LNG receiving terminal to points of interconnection with interstate and intrastate natural gas pipelines in South Texas; and the Cheniere Southern Trail Pipeline originating in southern Louisiana to a point of interconnection with the Florida Gas Transmission Pipeline in western Florida. We have also purchased 100% interest in the Frontera Pipeline project, a combined transportation and storage project designed to serve industrial and power generation customers in northeastern Mexico (the "Burgos Hub Project").

As of December 31, 2008, Phase 1 of the Creole Trail Pipeline, consisting of 94 miles of natural gas pipeline, had been constructed and placed into commercial operation. In conjunction with Phase 1 of the Creole Trail Pipeline, six delivery meter stations were commissioned providing access to eight major interstate and intrastate natural gas pipeline systems.

If we decide to complete construction of the Corpus Christi LNG receiving terminal, we intend to develop the Corpus Christi Pipeline when, among other things, we have entered into acceptable commercial and acceptable financing arrangements.

The Cheniere Southern Trail Pipeline project would interconnect with multiple takeaway pipelines from LNG receiving terminals in southwestern Louisiana and a LNG receiving terminal being developed in Mississippi. The Cheniere Southern Trail Pipeline may also interconnect with multiple onshore pipelines serving conventional basins in the Gulf of Mexico and with new developments transporting natural gas from the unconventional shale plays in Texas and Arkansas. The Cheniere Southern Trail Pipeline could supply Florida with natural gas needed to supply the growth we anticipate in natural gas-fired generation capacity in the state over the next ten to fifteen years. This pipeline would provide LNG suppliers with access to new natural gas markets, while providing alternative access to conventional gas supplies, to improve gas supply security for Florida and the remainder of the Southeastern U.S. The Cheniere Southern Trail Pipeline will be developed once we have entered into acceptable commercial and acceptable financing arrangements.

The Burgos Hub Project involves the construction of an integrated pipeline project that would traverse the United States and Mexico border and includes a related subterranean storage facility in Mexico. We will contemplate making a final investment decision in the Burgos Hub Project upon, among other things, receiving all required authorizations to construct and operate the pipeline and storage facility, and entering into acceptable commercial and acceptable financing arrangements.

LNG and Natural Gas Marketing Business

Our LNG and natural gas marketing business segment is focused on producing long-term, recurring cash flow utilizing its reserved 2.0 Bcf/d of regasification capacity at the Sabine Pass LNG receiving terminal. Our strategy is to remain engaged in the LNG spot market as opportunities arise, and to maintain relationships with key suppliers and market participants that we believe are candidates for entering into long-term LNG cargo sales and/or the purchase of TUA capacity currently reserved by Cheniere Marketing.

To help achieve these goals, we have entered into domestic marketing agreements with various counterparties for the sale of LNG. These agreements provide a framework under which Cheniere Marketing may offer to sell to a counterparty all or a portion of the LNG from each LNG cargo it acquires on delivery to the Sabine Pass LNG receiving terminal, and under which the counterparty will utilize a portion of Cheniere Marketing's TUA capacity for storage and regasification services related to the portion of the LNG cargo that the counterparty purchases.

Oil and Natural Gas Exploration, Development and Exploitation Activities

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 activities in the shallow waters of the Gulf of Mexico. This business has historically required, and will continue to require, an insignificant amount of cash to fund its operations.

Overview of 2008 Events

Our significant accomplishments during 2008, some of which may also impact future years, include the following:

- in February 2008, we announced that we were exploring strategic options for Cheniere to enhance stockholder value, including options to optimize the value of the Sabine Pass LNG receiving terminal and the regasification capacity at the terminal held by Cheniere Marketing under a long-term TUA;
- in April 2008, we commenced a cost savings program in connection with the downsizing of our natural gas marketing business activities, the nearing completion of significant construction activities for both the Sabine Pass LNG receiving terminal and Creole Trail Pipeline and the seeking of alternative arrangements for our time charter interests in two LNG vessels. The cost savings program involved reducing our personnel company-wide by approximately 43%. We recognized losses of $78.7 million from this cost savings program, including the impact of cancelling our LNG vessel charter agreements, with substantially all of these losses having no material effect on our working capital in 2008. As of December 31, 2008, we estimate that we will recognize an additional $0.9 million of such losses in the future;

- in April 2008, construction of Phase 1 of the Creole Trail Pipeline (consisting of 94 miles of natural gas pipeline) was completed and the pipeline was placed into commercial operation;
- in May 2008, we entered into a $95.0 million, 18-month bridge loan (the "Bridge Loan") and received approximately $82.3 million of net proceeds to be held as unrestricted cash and cash equivalents and to be used for general corporate purposes and pipeline capital expenditures. The purpose of the Bridge Loan was to provide incremental funding and liquidity until we entered into a strategic transaction, obtained sufficient revenues from a significant number of imported LNG cargos or consummated an alternative financing transaction;
- in June 2008, Freeport LNG achieved commercial operability, and it began receiving TUA payments from its customers in the second half of 2008;
- in August 2008, Cheniere Common Units Holding, LLC, our wholly-owned subsidiary, closed a $250.0 million senior secured convertible term loan agreement ("2008 Convertible Loans"). Proceeds were used to: repay the Bridge Loan obtained in May 2008; fund a reserve account for payments under Cheniere Marketing's TUA with Sabine Pass LNG; pay expenses incurred in connection with the 2008 Convertible Loans and the consideration of other potential strategic alternatives; and fund working capital and general corporate needs of Cheniere and its subsidiaries;
- in September 2008, Sabine Pass LNG received $145.0 million, net of discount, from the issuance of an additional $183.5 million of Sabine Pass LNG's 7½% Senior Secured Notes due 2016 ("2016 Notes") pursuant to the existing indenture, dated as of November 9, 2006 (the "Sabine Pass Indenture"), under which Sabine Pass LNG had previously issued $1,482.0 million in aggregate principal amount of 2016 Senior Notes and $550.0 million in aggregate principal amount of 7¼% Senior Secured Notes due 2013 ("2013 Notes" and collectively with the 2016 Notes, the "Senior Notes");
- in September 2008, Cheniere Marketing began making its TUA payments to Sabine Pass LNG; and
- in September 2008, the initial 2.6 Bcf/d of sendout capacity and 10.1 Bcf of storage capacity at the Sabine Pass LNG receiving terminal was completed and achieved commercial operability.

We believe that these 2008 activities will provide us with sufficient liquidity to operate our business and pursue our business strategies over the next several years.

Liquidity and Capital Resources

Overview

(in thousands)	Sabine Pass LNG, L.P.	Cheniere Energy Partners, L.P.	Other Cheniere Energy, Inc.	Consolidated Cheniere Energy, Inc.
Cash and cash equivalents	$ —	$ —	$102,192	$102,192
Restricted cash and cash equivalents	362,041	11,928	66,064	440,033
U.S. Treasury securities	—	20,829	—	20,829
Total	$362,041	$32,757	$168,256	$563,054

As of December 31, 2008, we had unrestricted cash and cash equivalents of $102.2 million. In addition, we had restricted cash and cash equivalents of $440.0 million and U.S. Treasury securities of $20.8 million, which were designated for the following purposes: $71.1 million for construction costs of the Sabine Pass LNG receiving terminal; $194.8 million for Sabine Pass LNG's working capital; $96.1 million for interest payments related to the Senior Notes described below; $62.8 million for Cheniere Marketing TUA payments; $32.8 million for cash distributions by Cheniere Partners; and $3.3 million in other restricted cash and cash equivalents.

As described below in further detail by business segment and corporate and other activities, we believe that we have sufficient cash and cash equivalents to operate our business and pursue our business strategies over the next several years.

LNG Receiving Terminal Business

Cheniere Partners

Our ownership interest in the Sabine Pass LNG receiving terminal is held through Cheniere Partners. In 2007, Cheniere Partners completed a public offering of 15,525,000 Cheniere Partners common units. As a result of this public offering, our combined general partner and limited partner ownership interests in Cheniere Partners was reduced to approximately 90.6%. Cheniere Partners owns a 100% interest in Sabine Pass LNG, which is constructing and operating the Sabine Pass LNG receiving terminal.

For each calendar year, Cheniere Partners is expected to make distributions of $1.70 per unit on all outstanding common units, subordinated units and related distributions to its general partner. We anticipate receiving $18.5 million per year out of the total $44.9 million of annual common unit distributions. We anticipate receiving $235.8 million per year from distributions to the subordinated unitholders and general partner, of which we own 100%.

Cheniere Partners relies on the receipt of operating revenues from Sabine Pass LNG's TUAs to fund quarterly cash distributions to us and other unitholders. Sabine Pass LNG is not permitted under the Sabine Pass Indenture to make cash distributions to Cheniere Partners if it does not satisfy a fixed charge coverage ratio test of 2:1, calculated as required in the Sabine Pass Indenture. If the coverage test is not met, we may not receive distributions. As of December 31, 2008, the fixed charge coverage ratio was met and the first distribution was made from Sabine Pass LNG to Cheniere Partners; Cheniere Partners utilized the cash received from Sabine Pass LNG to pay expenses and make distributions to us and its other unitholders.

A distribution reserve account was established from proceeds of Cheniere Partners' initial public offering to pay distributions to the common unitholders and general partner until Cheniere Partners is able to sustain distributions from unrestricted cash, at which time the funds remaining in the account are expected to be returned to us. As of February 15, 2009, there was $32.8 million in the distribution reserve account, which is adequate to fund distributions to the common unitholders and general partner made with respect to each calendar quarter through September 30, 2009. Sabine Pass LNG began making distributions from unrestricted cash in February 2009 and expects to continue making its distributions from its cash balances. We expect that approximately $35 million will be remaining in the distribution reserve account after accounting for interest earned in the account after February 15, 2009, and that approximately $35 million of remaining funds will be distributed to us in August 2009 pursuant to the terms of Cheniere Partners' partnership agreement.

We also expect to receive approximately $19 million of annual management and service fees from Sabine Pass LNG and Cheniere Partners pursuant to existing agreements.

Sabine Pass LNG Receiving Terminal

Our estimated aggregate construction, commissioning and operating cost budget through the achievement of full operability of the Sabine Pass LNG receiving terminal (with approximately 4.0 Bcf/d of total sendout capacity and five LNG storage tanks with approximately 16.8 Bcf of aggregate storage capacity) is approximately $1,559 million, excluding financing costs. Of this amount, approximately $1,416 million of construction and commissioning costs had been incurred as of December 31, 2008. Our remaining construction, commissioning and operating costs are anticipated to be funded from working capital and the $71.1 million of restricted cash and cash equivalents designated for construction. In September 2008, Hurricane Ike and related storm activity, such as windstorms, storm surges and floods, struck the Texas and Louisiana coasts. We experienced minor damage at the Sabine Pass LNG receiving terminal with most of the damage impacting equipment and facilities associated with the 1.4 Bcf/d of sendout capacity and 6.7 Bcf of storage capacity still under construction. Impact to operations and the equipment and facilities associated with the initial 2.6 Bcf/d of sendout capacity and 10.1 Bcf of storage capacity was minimal. We continue to expect to complete construction of the remaining 1.4 Bcf/d of sendout capacity and 6.7 Bcf of storage capacity in the third quarter of 2009.

Estimated costs to repair damage caused by Hurricane Ike are approximately $32 million, of which we believe approximately $22 million will be recoverable from insurance proceeds and other sources. The estimated costs to repair this damage have been factored into the budget estimate above.

The entire 4.0 Bcf/d of regasification capacity that will be available at the Sabine Pass LNG receiving terminal upon completion of construction has been fully reserved under three long-term TUAs, under which Sabine Pass LNG's customers are required to pay fixed monthly fees, whether or not they use the terminal. Because we achieved commercial operability of the Sabine Pass LNG receiving terminal in September 2008, capacity reservation fee TUA payments will begin to be made by our third-party customers as follows:

- Total has reserved approximately 1.0 Bcf/d of regasification capacity and has agreed to make monthly capacity payments to Sabine Pass LNG aggregating approximately $125 million per year for 20 years commencing April 1, 2009. Total, S.A. has guaranteed Total's obligations under its TUA up to $2.5 billion, subject to certain exceptions; and
- Chevron has reserved approximately 1.0 Bcf/d of regasification capacity and has agreed to make monthly capacity payments to Sabine Pass LNG aggregating approximately $125 million per year for 20 years commencing not later than July 1, 2009. Chevron Corporation has guaranteed Chevron's obligations under its TUA up to 80% of the fees payable by Chevron.

In addition, Cheniere Marketing has reserved the remaining 2.0 Bcf/d of regasification capacity, and is entitled to use any capacity not utilized by Total and Chevron. In September 2008, Cheniere Marketing made a capacity reservation fee payment of $15.0 million for October, November and December 2008. In December 2008, Cheniere Marketing made a capacity reservation fee payment of $62.7 million for the first three months of 2009. Cheniere Marketing is required to make monthly capacity payments aggregating approximately $250 million per year for the period from January 1, 2009, through at least the third quarter of 2028. Cheniere has guaranteed Cheniere Marketing's obligations under its TUA.

Under each of these TUAs, Sabine Pass LNG is also entitled to retain 2% of the LNG delivered for the customer's account, which Sabine Pass LNG will use primarily as fuel for revaporation and self-generated power at the Sabine Pass LNG receiving terminal.

Each of Total and Chevron has paid us $20.0 million in nonrefundable advance capacity reservation fees, which will be amortized over a 10-year period as a reduction of each customer's regasification capacity fees payable under its TUA.

Other LNG Receiving Terminals

We have a 30% limited partner interest in Freeport LNG. In March 2008 and May 2008, we received cash call notices from Freeport LNG requesting that we provide further financial support due to higher than expected commissioning and performance testing costs. During 2008, we funded the cash calls and have recorded $4.8 million of additional losses in Freeport LNG. In October 2008, Freeport LNG made its first distribution of $4.8 million to us. We expect to continue to receive distributions from Freeport LNG as they are approved by Freeport LNG's board of directors.

We will contemplate making final investment decisions to complete construction of our Corpus Christi LNG receiving terminal project and to commence construction of our Creole Trail LNG receiving terminal project upon, among other things, entering into acceptable commercial arrangements and entering into acceptable financing arrangements for the applicable project. We do not expect to spend significant funds on these projects until we have entered into acceptable commercial arrangements and acceptable financing arrangements.

Natural Gas Pipeline Business

As of December 31, 2008, Phase 1 of the Creole Trail Pipeline, consisting of 94 miles of natural gas pipeline, had been constructed and placed into commercial operations. Expenditures incurred for the construction of the Creole Trail Pipeline through December 31, 2008 were approximately $553 million, including accrued liabilities. We believe we have sufficient cash and cash equivalents to operate our Creole Trail Pipeline for the next several years.

We will contemplate making a final investment decision to construct Phase 2 of the Creole Trail Pipeline, the Corpus Christi Pipeline, the Cheniere Southern Trail Pipeline and the Burgos Hub Project upon, among other things, receiving all required authorizations to construct and operate the applicable pipeline (and storage facility in the case of Burgos Hub), to the extent not already obtained, and entering into acceptable commercial arrangements and acceptable financing arrangements for the applicable project.

LNG and Natural Gas Marketing Business

In April 2008, we commenced a cost savings program in connection with the downsizing of our natural gas marketing business activities, the nearing completion of significant construction activities for both the Sabine Pass LNG receiving terminal and Creole Trail Pipeline and the seeking of alternative arrangements for our time charter interests in two LNG vessels. We have unwound, terminated or assigned our commitments under our domestic natural gas agreements on terms we believe to be acceptable and have cancelled both of our LNG vessel charters.

We deposited $135.0 million in a TUA reserve account utilizing a portion of the 2008 Convertible Loans that were closed in August 2008. Pursuant to the 2008 Convertible Loans, all funds in the TUA reserve account in excess of three months of Cheniere Marketing's TUA payments can be released to us as unrestricted cash and cash equivalents after we have received three consecutive monthly payments from both Total and Chevron under their respective TUAs, which we believe will occur in August 2009. We believe that we will obtain approximately $66 million from the TUA reserve account as unrestricted cash and cash equivalents in August 2009.

Cheniere Marketing will utilize funds in the TUA reserve account, distributions from Cheniere Partners and operating cash flows to pay its TUA obligation.

Corporate and Other Activities

We are required to maintain a certain level of corporate general and administrative functions to serve our business activities described above. We believe that we have sufficient cash and cash equivalents to fund these business activities over the next several years.

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 activities in the shallow waters of the Gulf of Mexico. We do not anticipate significant cash expenditures related to this activity and expect cash inflows from oil and natural gas production to gradually decrease as our reserves are produced.

Sources and Uses of Cash

The following table summarizes (in thousands) the sources and uses of our cash and cash equivalents for 2008, 2007 and 2006. The table presents capital expenditures on a cash basis; therefore, these amounts differ from the amounts of capital expenditures, including accruals that are referred to elsewhere in this report. Additional discussion of these items follows the table.

	2008	2007	2006
Sources of cash and cash equivalents			
Use of restricted cash and cash equivalents	$ 465,323	$ 527,043	$ —
Proceeds from debt issuance	239,965	400,000	2,415,400
Proceeds from debt issuance—related parties	250,000	—	—
Use of restricted U.S. Treasury securities	16,702	—	—
Sale of common stock	472	3,158	1,953
Proceeds from sale of common units in partnership	—	203,946	—
Proceeds from issuance of common units to minority owners in partnership	—	98,442	—
Other	—	1,048	—
Total sources of cash and cash equivalents	972,462	1,233,637	2,417,353
Uses of cash and cash equivalents			
LNG receiving terminal and pipeline construction-in-process, net	(583,871)	(788,517)	(440,367)
Investment in restricted cash and cash equivalents	(248,767)	—	(1,070,713)
Operating cash flow	(142,145)	(84,291)	(80,426)
Repayment of debt	(95,000)	—	(981,900)
Debt issuance cost	(34,504)	(9,787)	(43,796)
Distributions to minority interest	(26,393)	(13,631)	—
Advances under long-term contracts, net of transfers to construction-in-process	(14,032)	(38,617)	(7,101)
Purchases of LNG for commissioning, net of amounts transferred to LNG receiving terminal construction-in-process	(9,923)	—	—
Purchase of treasury shares	(4,902)	(325,101)	—
Purchases of intangible and fixed assets, net of sales	(2,889)	(41,684)	(10,527)
Oil and gas property additions, net of sales	(564)	—	(3,687)
Investment in U.S. Treasury securities	—	(98,442)	—
Other	(3,810)	—	(8,465)
Total uses of cash and cash equivalents	(1,166,800)	(1,400,070)	(2,646,982)
Net decrease in cash and cash equivalents	(194,338)	(166,433)	(229,629)
Cash and cash equivalents at end of year	$ 102,192	$ 296,530	$ 462,963

Use of restricted cash and cash equivalents

Under the Sabine Pass Indenture, a portion of the proceeds from the Senior Notes was initially required to be used for scheduled interest payments through May 2009 and to fund the cost to complete construction of the Sabine Pass LNG receiving terminal. Due to these restrictions imposed by the Sabine Pass Indenture, the proceeds from the Senior Notes are not presented as cash and cash equivalents. When proceeds from the Senior Notes that have been designated as restricted cash and cash equivalents are used, they are presented as a source of cash and cash equivalents. In 2008 and 2007, the $465.3 million and $527.0 million, respectively, of restricted cash and cash equivalents were used primarily to pay for construction activities at the Sabine Pass LNG receiving terminal.

Proceeds from debt issuance and proceeds from debt issuance—related parties

Our proceeds from the issuance of debt and from the issuance of debt—related parties were $490.0 million, $400.0 million and $2,415.4 million in 2008, 2007 and 2006, respectively. During 2008, we received $95.0 million from borrowings under the Bridge Loan, $250.0 million from borrowings under the 2008 Convertible Loans (considered related party), and $145.0 million, net of discount, from the additional issuance of the 2016 Notes (a portion of which is considered related party borrowings). During 2007, we received $400.0 million from borrowings under the 2007 Term Loan, which was used primarily to repurchase shares of our common stock under the call option acquired in the issuer call spread purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes. During 2006, we received $2,032.0 million in proceeds from the issuance of the Senior Notes and $383.4 million in borrowings under the amended Sabine Pass credit facility.

Use of Restricted U.S. Treasury securities

As mentioned above, through the Cheniere Partners Offering, Cheniere Partners received $98.4 million in net proceeds from the issuance of common units to the public. Cheniere Partners used all of the net proceeds to purchase U.S. Treasury securities to fund a distribution reserve for payment of initial quarterly distributions until Cheniere Partners is able to sustain funding of distributions to its unitholders from unrestricted cash, at which time any remaining cash in the distribution reserve is expected to be returned to us.

Proceeds from sale of common units to minority owners in partnership

In connection with the Cheniere Partners Offering in 2007, we sold to the public a portion of the Cheniere Partners common units held by us through a subsidiary, realizing net proceeds of $203.9 million, which included $39.4 million of net proceeds realized once the underwriters exercised their option to purchase an additional 2,025,000 common units from us. These net proceeds are being used for corporate and general purposes.

Proceeds from issuance of common units in partnership

In connection with the Cheniere Partners Offering in 2007, Cheniere Partners received $98.4 million in net proceeds for the issuance of common units to the public. Cheniere Partners used all of the net proceeds to purchase U.S. Treasury securities to fund a distribution reserve for payment of initial quarterly distributions of $0.425 per common unit, as well as related quarterly distributions to its general partner through the quarterly distributions until Cheniere Partners is able to sustain funding of distributions to its unitholders from unrestricted cash, at which time any remaining cash in the distribution reserve is expected to be returned to us.

LNG receiving terminal and pipeline construction-in-process, net

Capital expenditures for our LNG receiving terminals and pipeline projects were $583.9 million, $788.5 million and $440.4 million in 2008, 2007 and 2006, respectively. The 26% decrease in 2008 resulted primarily from the winding down and completion of the construction of the initial phases of the Sabine Pass LNG receiving terminal and the Creole Trail Pipeline. The 79% increase in 2007 resulted primarily from our continued construction expenditures on the Sabine Pass LNG receiving terminal, which commenced construction in the first quarter of 2005, and the Creole Trail Pipeline, which commenced initial construction in the second quarter of 2007.

Investment in restricted cash and cash equivalents

Investment in restricted cash and cash equivalents was $248.8 million, zero and $1,070.7 million in 2008, 2007, and 2006, respectively. Investments in restricted cash and cash equivalents are cash and cash equivalents that have been legally restricted to be used for a specific purpose. During 2008, we received $250.0 million from borrowings under the 2008 Convertible Loans and $145.0 million, net of discount, from the additional issuance of the 2016 Notes. Proceeds received from these borrowings were used to fund reserve accounts of $248.8

million, which we classified as restricted cash and cash equivalents. During 2006, the proceeds from the issuance of the Senior Notes were contractually restricted to be used for the construction of our Sabine Pass LNG receiving terminal and for interest payments on the Senior Notes. Due to the contractual constrictions we classified $1,070.7 million as restricted cash and cash equivalents.

Operating cash flow

Net cash used in operations was $142.1 million, $84.3 million and $80.4 million in 2008, 2007 and 2006, respectively. Net cash used in operations in 2006 through 2008 related primarily to the continued development and construction of the Sabine Pass LNG receiving terminal and related activities, including increased employee support costs.

Repayment of debt

In 2008, we repaid borrowings under the Bridge Loan with a portion of the proceeds obtained from the 2008 Convertible Loans. In 2006, we repaid borrowings under the amended Sabine Pass credit facility and Term Loan with a portion of the proceeds obtained from the issuance of the Senior Notes.

Debt issuance costs

Our debt issuance costs were $34.5 million, $9.8 million and $43.8 million in 2008, 2007 and 2006, respectively. The debt issuance costs in 2008 related to the additional issuance of 2016 Notes, the 2008 Convertible Loans and the Bridge Loan. The debt issuance costs in 2007 were primarily related to the 2007 Term Loan. Debt issuance costs in 2006 were primarily related to the amended Sabine Pass credit facility and the Senior Notes.

Distributions to minority interest

During 2008 and 2007, Cheniere Partners distributed $26.4 million and $13.6 million, respectively, to its non-affiliated common unitholders.

Advances under long-term contracts, net of transfer to construction-in-process

We have entered into certain contracts and purchase agreements related to the construction of our Sabine Pass LNG receiving terminal that require us to make payments to fund costs that will be incurred or equipment that will be received in the future. Advances made under long-term contracts on purchase commitments are carried at face value and transferred to property, plant, and equipment as the costs are incurred or equipment is received.

Purchase of treasury shares

Concurrent with the issuance of the Convertible Senior Unsecured Notes, we also entered into hedge transactions in the form of an issuer call spread. During 2007, we exercised the call spread and purchased 9.2 million shares of our common stock for an aggregate purchase price of $325.0 million.

Purchases of intangible and fixed assets, net of sales

Purchases of fixed assets were $2.9 million, $41.7 million and $10.5 million in 2008, 2007 and 2006, respectively. The decrease in 2008 is primarily a result of a decrease in the purchase of intangible and fixed assets due to the winding down of construction activities at the Sabine Pass LNG receiving terminal and Creole Trail Pipeline. The increase in fixed assets from 2006 to 2007 resulted primarily from the expansion of our business to support the Sabine Pass LNG receiving terminal, Creole Trail Pipeline and our natural gas and LNG marketing business.

Debt Agreements

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 2012 to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended (the "Securities Act"). The notes bear interest at a rate of 2.25% per year. Interest on the Convertible Senior Unsecured Notes is payable semi-annually in arrears February 1 and August 1 of each year. The notes are convertible at any time into our common stock under certain circumstances 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. As of December 31, 2008, no holders had elected to convert their notes. 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 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 securities rate plus 50 basis points. The Sabine Pass Indenture governing the notes contains customary reporting requirements.

Sabine Pass LNG Senior Notes

Sabine Pass LNG has issued an aggregate principal amount of $2,215.5 million of Senior Notes consisting of $550.0 million of 7 ¼% Senior Secured Notes due 2013 and $1,665.5 million of 7 ½% Senior Secured Notes due 2016. Interest on the Senior Notes is payable semi-annually in arrears on May 30 and November 30 of each year. The Senior Notes are secured on a first-priority basis by a security interest in all of Sabine Pass LNG's equity interests and substantially all of its operating assets. Under the Sabine Pass Indenture governing the Senior Notes, except for permitted tax distributions, Sabine Pass LNG may not make distributions until certain conditions are satisfied. There must be on deposit in an interest payment account an amount equal to one-sixth of the semi-annual interest payment multiplied by the number of elapsed months since the last semi-annual interest payment. In addition, there must be on deposit in a permanent debt service reserve fund an amount equal to one semi-annual interest payment of $82.4 million. Distributions will be permitted only after satisfaction of the foregoing funding requirements, after satisfying a fixed charge coverage ratio test of 2:1 and after satisfying other conditions specified in the Sabine Pass Indenture.

2007 Term Loan

In May 2007, Cheniere Subsidiary Holdings, LLC, a wholly-owned subsidiary of Cheniere, entered into a $400.0 million credit agreement ("2007 Term Loan"). Borrowings under the 2007 Term Loan generally bear interest at a fixed rate of 9.75% per annum. Interest is calculated on the unpaid principal amount of the 2007 Term Loan outstanding and is payable quarterly in arrears on March 31, September 30, September 30 and December 31 of each year. The 2007 Term Loan will mature on May 31, 2012. The net proceeds from the 2007 Term Loan were $391.7 million and are being used for general corporate purposes, including the repurchase, completed in July 2007, of approximately 9.2 million shares of our outstanding common stock pursuant to the exercise of the call options acquired in the issuer call spread purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes. The 2007 Term Loan is secured by a pledge of our 135,383,831 subordinated units in Cheniere Partners and our equity interests in the entities that own our 30% interest in Freeport LNG.

2008 Convertible Loans

In August 2008, we entered into a credit agreement pursuant to which we obtained $250.0 million in convertible term loans ("2008 Convertible Loans"). The 2008 Convertible Loans will mature in 2018, but the lenders can require prepayment of the loans for thirty days following August 15, 2011, 2013 and 2015, and upon a change of control. The 2008 Convertible Loans bear interest at a fixed rate of 12% per annum, except during the occurrence of an event of default during which time the rate of interest will be 14% per annum. Interest is due semi-annually on the last business day of January and July. At our option, until August 15, 2011, accrued interest may be added to the principal on each semi-annual interest date. The aggregate amount of all accrued interest to August 15, 2011 will be payable upon the maturity date. The 2008 Convertible Loans are secured by Cheniere's rights and fees payable under management services agreements with Sabine Pass LNG and Cheniere Partners, by Cheniere's common units in Cheniere Partners, by the equity and non-real property assets of Cheniere's pipeline entities, by the equity of various other subsidiaries and certain other assets and subsidiary guarantees. The principal amount of $250.0 million may be exchanged for newly-created Series B Convertible Preferred Stock, par value $0.0001 per share ("Series B Preferred Stock"), with voting rights limited to the equivalent of 10,125,000 shares of common stock. The exchange ratio is one share of Series B Preferred Stock for each $5,000 of outstanding borrowings, subject to adjustment. The exchange ratio will be adjusted in the event we make certain distributions of cash, shares or property on our shares of common stock. The aggregate preferred stock is exchangeable into 50 million shares of common stock at a price of $5.00 per share pursuant to a broadly syndicated offering. We are required to file a registration statement to register the Series B Preferred Stock upon demand by the majority of the holders of the Series B Preferred Stock. Such holders also have the right to demand registration of the shares of common stock into which the Series B Preferred Stock is convertible. No portion of any accrued interest is eligible for conversion into Series B Preferred Stock. We placed $135.0 million of the borrowings under the 2008 Convertible Loans into a TUA reserve account to pay the reservation fee and operating fee as defined under Cheniere Marketing's TUA. We utilized $95.0 million of the borrowings under the 2008 Convertible Loans to repay the Bridge Loan. The remaining borrowings were utilized to pay for interest on the Bridge Loan, to pay expenses incurred in connection with the issuance of the 2008 Convertible Loans and consideration of other strategic alternatives and to fund working capital and general corporate needs of Cheniere and its subsidiaries.

One of the lenders is Scorpion Capital Partners LP ("Scorpion"), an affiliate of one of the Company's directors. Scorpion's portion of the 2008 Convertible Loans was $8.5 million and Scorpion did not receive any fees in connection with making the 2008 Convertible Loans.

As long as the 2008 Convertible Loans are exchangeable for shares of Series B Preferred Stock or shares of Series B Preferred Stock remain outstanding, the holders of a majority of the 2008 Convertible Loans and Series B Preferred Stock, acting together, shall have the right to nominate two individuals to the Company's Board of Directors, and together with the Board of Directors, a third nominee, who shall be an independent director.

Issuances of Common Stock

During 2008, 2007 and 2006, we raised $0.5 million, $3.2 million, and $2.0 million, respectively, net of offering costs, from the exercise of stock options and the exchange or exercise of warrants.

During 2008, a total of 145,000 shares of our common stock were issued pursuant to the exercise of stock options, resulting in net cash proceeds of $0.5 million. In addition, in January 2008, 480,000 shares having three-year graded vesting were issued to our employees in the form of non-vested stock awards and 537,000 shares were issued to our executive officers in the form of vested stock awards related to our performance in 2007. In May 2008 and June 2008, as a part of the short-term and long-term retention plans approved by the Compensation Committee, 374,000 shares vesting on December 1, 2008 and 1,525,000 shares having a three-year graded vesting beginning December 31, 2008 were issued to our employees and a consultant in the form of non-vested stock awards. In December 2008, 1,703,000 shares of non-vested stock having a three year graded vesting were issued to employees as an incentive award. During 2008, an additional 272,000 shares having a one-year graded vesting were issued to our directors and 26,000 shares of non-vested stock having three- or four-year graded vestings were issued to employees.

During 2007, we issued a total of 1,717,000 shares of our common stock. A total of 416,000 shares of our common stock were issued pursuant to the exercise of stock options, resulting in net cash proceeds of

$3.2 million. In addition, 273,000 shares were issued in satisfaction of cashless exercises of options to purchase 316,000 shares of common stock. In January 2007, we issued 630,000 shares having three-year graded vesting to our employees and executive officers in the form of non-vested stock awards related to our performance in 2006. In May 2007, we issued 31,000 shares having a one-year graded vesting to our directors. In June 2007 and November 2007, we issued 150,000 shares as retention grants to certain employees vesting 50% on December 1, 2008, 30% on December 1, 2009, and 20% on June 1, 2010. In 2007, we issued an additional 250,000 shares of non-vested stock having three or four-year graded vestings primarily to new employees.

During 2007, we purchased 9,176,000 shares of our common stock for a cash price of $35.42 per share under the call options acquired in the issuer call spread purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes. As of December 31, 2007, these shares had not been cancelled and remained as treasury stock on our Consolidated Balance Sheet. The treasury shares were cancelled during 2008.

During 2006, we issued a total of 711,000 shares of our common stock. A total of 310,000 shares of our common stock were issued pursuant to the exercise of stock options, resulting in net cash proceeds of $2.0 million. In addition, 77,000 shares were issued in satisfaction of cashless exercises of options to purchase 98,000 shares of our common stock. A total of 79,000 shares were issued in 2006 to executive officers in the form of non-vested restricted stock awards related to our performance in 2005, and we issued 241,000 shares of non-vested restricted stock to new employees. We paid federal payroll withholding taxes of $1.0 million in exchange for 26,000 shares of our common stock, which related to common stock previously awarded to officers that vested during 2006. These shares were initially recorded as treasury shares, at cost, but were subsequently retired. In December 2006, 30,000 shares were issued to outside directors in the form of non-vested (restricted) stock awards related to their services provided in 2006.

Contractual Obligations

We are committed to making cash payments in the future on certain of our contracts. Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2008 (in thousands).

	Payments Due for Years Ended December 31,				
	Total	2009	2010-2011	2012-2013	Thereafter
Long-term debt					
Convertible Senior Unsecured Notes (1)	$ 325,000	$ —	$ —	$ 325,000	$ —
2008 Convertible Loans (1)	261,393	—	261,393	—	—
2007 Term Loan (1)	400,000	—	—	400,000	—
Senior Notes, net of discount (1)	2,107,673	—	—	550,000	1,557,673
Senior Notes—related party, net of discount (1)	70,661	—	—	—	70,661
Operating lease obligations (2)(3)	283,867	13,800	27,192	27,702	215,173
Construction and purchase obligations (4)	83,000	80,750	1,500	750	—
Other obligations (5)	20,206	2,873	5,229	4,892	7,212
Total	$3,551,800	$97,423	$295,314	$1,308,344	$1,850,719

(1) A discussion of these obligations can be found at Note 18 of our Notes to Consolidated Financial Statements.

(2) A discussion of these obligations can be found at Note 8 of our Notes to Consolidated Financial Statements.

(3) Minimum lease payments have not been reduced by a minimum sublease rental of $13.7 million due in the future under noncancelable subleases.

(4) A discussion of these obligations can be found at Note 23 of our Notes to Consolidated Financial Statements.

(5) Includes obligations for cooperative endeavor agreements, telecommunication services and software licensing.

In addition, in the ordinary course of business, we maintain letters of credit and have certain cash and cash equivalents restricted in support of certain performance obligations of our subsidiaries. Restricted cash and cash equivalents and U.S. Treasury securities totaled approximately $460.9 million at December 31, 2008. For more information, see Note 7—"Restricted Cash and Cash Equivalents and U.S. Treasury Securities" of our Notes to Consolidated Financial Statements.

Results of Operations

Overall Operations

2008 vs. 2007

Our consolidated net loss was $356.5 million, or $7.53 per share (basic and diluted), in 2008 compared to a net loss of $181.8 million, or $3.60 per share (basic and diluted), in 2007. The increase in the loss was primarily due to restructuring charges, decreased interest income, increased interest expense, net, increased depreciation, depletion and amortization expense ("DD&A"), increased LNG receiving terminal and pipeline operating expense and increased loss on early extinguishment of debt, which were partially offset by decreased LNG receiving terminal and pipeline development expense.

A significant portion of our loss was attributable to the recognition of non-cash, share-based payments accounted for under SFAS No. 123R, which requires all non-cash, share-based compensation, be recognized in the financial statements based on fair value at the date of grant. As a result of our issuance of non-cash, share-based payments to employees, we recorded $55.0 million of non-cash compensation expense in 2008 compared to $56.6 million of non-cash compensation expense in 2007. In addition, we recognized one-time charges of $78.7 million for restructuring charges and $10.7 million for loss on early extinguishment of debt. Not including the impact of these one-time charges in 2008 and the impact of non-cash expense in 2008, our net loss would have been $212.0 million, or $4.48 net loss per common share (basic and diluted).

2007 vs. 2006

Our consolidated net loss was $181.8 million in 2007, a 25% increase over our 2006 net loss, as described below. The increase in the loss was primarily due to our increase in employee headcount in anticipation of commencing operations in early 2008, additional LNG receiving terminal development expenses and an increase in the amount of DD&A recognized in part due to our increase in asset infrastructure being placed in service. In addition, a significant portion of our loss is attributable to the recognition of non-cash, share-based payments accounted for under SFAS No. 123R, *Share-Based Payments*, which requires all non-cash, share-based compensation be recognized in the financial statements based on fair value at the date of grant. As a result of our issuance of non-cash, share-based payments to employees, we recorded $56.6 million of non-cash compensation expense in 2007. Not including the impact of this non-cash expense in 2007, our net loss would have been $125.2 million, or $2.48 net loss per common share—basic and diluted.

Restructuring Charges

During 2008, we incurred $78.7 million of restructuring charges resulting from our cost savings program in connection with the downsizing of our natural gas marketing business activities, nearing completion of significant construction activities for both the Sabine Pass LNG receiving terminal and Creole Trail Pipeline and seeking alternative arrangements for our time charter interests in two LNG vessels (See Note 4—"Restructuring Charges" of our Notes to Consolidated Financial Statements).

Interest Income

2008 vs. 2007

Interest income decreased $62.3 million in 2008 compared to 2007, because of the lower average invested cash balances resulting from the use of cash to pay construction costs and interest payments and lower interest rates.

2007 vs. 2006

Interest income increased $33.5 million in 2007 compared to 2006 because of the higher average invested cash balances resulting from the November 2006 issuance of Senior Notes.

Interest Expense, net

2008 vs. 2007

Interest expense, net of amounts capitalized, increased $26.1 million in 2008 compared to 2007. The increase was caused by the additional borrowing under the Bridge Loan, the 2008 Convertible Loans and the issuance of $183.5 million of additional 2016 Notes during the third quarter of 2008.

2007 vs. 2006

Interest expense, net of amounts capitalized, increased $50.6 million in 2007 compared to 2006. The increase was caused primarily by interest expense recognized on the Senior Notes issued for the construction of the Sabine Pass LNG receiving terminal. In addition, in May 2007, we entered into the 2007 Term Loan which increased our debt and correspondingly increased our interest expense, net of amounts capitalized.

DD&A

2008 vs. 2007

DD&A increased $18.0 million in 2008 compared to 2007. This increase resulted from our having begun depreciating the Sabine Pass LNG receiving terminal's initial 2.6 Bcf/d of regassification capacity and 10.1 Bcf of storage capacity and the Creole Trail Pipeline when they achieved commercial operability in the third and second quarter of 2008, respectively.

LNG Receiving Terminal and Pipeline Operating Expense

2008 vs. 2007

LNG receiving terminal and pipeline operating expenses increased $14.5 million in 2008 compared to 2007 as a result of the Creole Trail Pipeline becoming operational in the second quarter of 2008 and the Sabine Pass LNG receiving terminal achieving commercial operability in September 2008.

Loss on Early Extinguishment of Debt

2008 vs. 2007

Loss on early extinguishment of debt increased $10.7 million in 2008 compared to 2007. The increase was a result of recognizing all unamortized debt issuance costs associated with the $95 million Bridge Loan that was repaid in full using a portion of the borrowings under the 2008 Convertible Loans during the third quarter of 2008.

2007 vs. 2006

In connection with the issuance of the Senior Notes in November 2006, we terminated a Sabine Pass credit facility and term loan. As a result, we recorded a $43.2 million loss on the early extinguishment of debt related to the expensing of debt issuance costs.

LNG Receiving Terminal and Pipeline Development Expense

Our LNG receiving terminal and pipeline development expenses include primarily professional costs 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 and natural gas pipelines.

2008 vs. 2007

LNG receiving terminal and pipeline development expenses decreased $24.1 million in 2008 compared to 2007. The major components of the decrease were an $11.0 million decrease in salaries and benefits, a $4.4 million decrease in public relations and other business development expenditures and a $2.6 million decrease in non-cash compensation expenses. These development expenses along with other $6.1 million individually insignificant development activities decreased in 2008 as a result of the achievement of commercial operability of the initial phase of the Sabine Pass LNG receiving terminal and Phase 1 of the Creole Trail Pipeline and the resulting shift from development activities in 2007 to operating activities in 2008.

2007 vs. 2006

LNG receiving terminal and pipeline development expenses increased $22.6 million in 2007 compared to 2006. Regulatory pipeline asset development expense increased $12.3 million in 2007 as a result of the 2006 recognition as regulatory assets, as prescribed by SFAS No. 71, *Accounting for Effects of Certain Types of Regulations*, amounts that had previously been expensed as pipeline development expenses. The impact of recording these regulatory assets reduced pipeline development expense in 2006 by $12.3 million. Employee salaries and benefits increased $9.7 million in 2007, due to an increase in the average number of employees engaged in LNG receiving terminal and pipeline activities from 68 in 2006 to 138 in 2007. Public relations increased $4.0 million in 2007 due to our participation in Hurricane Rita relief in Johnson Bayou, Louisiana. These increases in development expense were partially offset by a decrease in professional and technical expenses in 2007 as a result of decreased engineering, legal and other technical and professional services directly related to the Corpus Christi and Creole Trail LNG receiving terminals in 2007 as compared to 2006.

Off-Balance Sheet Arrangements

As of December 31, 2008, we had no "off-balance sheet arrangements" that may have a current or future material affect on our consolidated financial position or results of operations.

Inflation and Changing Prices

During 2008, 2007 and 2006, inflation and changing commodity prices have had an impact on our oil and gas revenues but have not significantly impacted our results of operations.

Summary of Critical Accounting Policies and Estimates

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. In preparing our financial statements in conformity with U.S. generally accepted accounting principles ("GAAP"), 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. Additional information about our critical accounting policies is included in Note 2—"Summary of Significant Accounting Policies" of our Notes to Consolidated Financial Statements.

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 obtained. If no lease is obtained, the costs are expensed. Site rental costs and related amortization of capitalized options were 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, *Accounting for Rental Cost Incurred During a Construction Period.*

During the construction periods of our LNG receiving terminals, we capitalize interest and other related debt costs in accordance with Statement of Financial Accounting Standards ("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.

Revenue Recognition

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

Regulated Natural Gas Pipelines

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, *Accounting for the Effects of Certain Types of Regulations*. Accordingly, we have applied the provisions of SFAS No. 71 to the affected pipeline subsidiaries beginning in the second quarter of 2006.

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 that 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 generally accepted accounting principles 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.

Cash Flow Hedges

We have used, and may in the future use, derivative instruments to limit our exposure to variability in expected future cash flows. 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 other comprehensive income, to the extent that the hedge is effective. We assess both at the inception of each hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. On an on-going basis, we monitor the actual dollar offset of the hedges' market values compared to hypothetical cash flow hedges. Any ineffective portion of the cash flow hedges will be reflected in earnings. Ineffectiveness is the amount of gains or losses from derivative instruments that are not offset by corresponding and opposite gains or losses on the expected future transaction.

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. See Note 14—"Goodwill" of our Notes to Consolidated Financial Statements.

Share-Based Compensation Expense

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123R, *Share-Based Payments*, using the modified prospective transition method, and therefore have not restated the results of prior periods. 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 No. 123R using the Black-Scholes-Merton option valuation model. Under the fair value recognition provisions of SFAS No. 123R, we recognize share-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 No. 123R, we accounted for share-based payments under Accounting Principles Board ("APB") Opinion 25, *Accounting for Stock Issued to Employees*, 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 requires the use 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, the expected volatility for the year ended December 31, 2008 used in our fair value model 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 share-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, future share-based compensation expense could be significantly different from what we have recorded in the current period (See Note 21—"Share-Based Compensation" of our Notes to Consolidated Financial Statements).

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, development and exploitation activities in the U.S. Gulf of Mexico. We determined that, in light of our level of exploration, development and exploitation activities in 2005, the successful efforts method of accounting provided a better matching of expenses to the period in which oil and gas production was realized. As a result, we determined 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, 2006 and 2005 was to reduce the balance of our net investment in oil and gas properties and retained earnings at those dates by $18.0 million and $18.2 million, respectively. The change in accounting method resulted in a decrease in the net loss of $0.3 million and an increase in the net loss of $0.3 million for 2006 and 2005, respectively, and had no impact on earnings per share (basic and diluted) for these respective periods. The change in method of accounting had no impact on cash or working capital.

Recently Issued Accounting Standards Not Yet Adopted

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51*, which establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS No. 160 is effective for fiscal years beginning October 1, 2009. In conjunction with our public offering of 15,525,000 of our common units in Cheniere Partners, we sold a portion of our Cheniere Partners common units to the public, realizing net proceeds of $203.9 million. Due to the subordinated distribution rights on our subordinated units, we have recorded those proceeds as a minority interest. As a result of the adoption of SFAS No. 160 on January 1, 2009, when our subordinated units in Cheniere Partners are converted to common units we are no longer able to elect an accounting policy of recording this gain through earnings, but will recognize the $203.9 million suspended gain directly in equity. In addition, our minority interest will be presented within the Stockholders equity section of our consolidated balance sheet, separate from the parent's equity.

On January 1, 2008, we adopted SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—including an amendment of FASB Statement No. 115*. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option) with changes in fair value reported in earnings. Cheniere already records derivative contracts at fair value in accordance with SFAS No. 133, *Accounting for Derivative*

Instruments and Hedging Activities, as amended. The adoption of SFAS No. 159 had no impact on our financial position, results of operations and cash flow as management did not elect the fair value option for any financial instruments or other assets and liabilities.

On January 1, 2008, we adopted SFAS No. 157, *Fair Value Measurements* as it relates to financial assets and financial liabilities. In February 2008, the FASB issued FASB Staff Position ("FSP") No. FAS 157-2, *Effective Date of FASB Statement No. 157,* which delayed the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on at least an annual basis, until January 1, 2009 for calendar year-end entities. The adoption of SFAS No. 157 did not have a material impact on our financial position, results of operations and cash flow.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 13.* SFAS No. 161 requires enhanced disclosures about an entity's derivative and hedging activities, including (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133, and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. This standard becomes effective for us on January 1, 2009. Earlier adoption of SFAS No. 161 and, separately, comparative disclosures for earlier periods at initial adoption are encouraged. As SFAS No. 161 only requires enhanced disclosures, this standard will have no impact on our financial position, results of operations and cash flow.

In April 2008, the FASB issued FSP SFAS No. 142-3, *Determination of the Useful Life of Intangible Assets.* This FSP amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142, *Goodwill and Other Intangible Assets.* The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141R, and other GAAP. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early adoption is prohibited. We do not expect the adoption of SFAS FSP No. 142-3 to have a material impact on our financial position, results of operations and cash flow.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles.* SFAS No. 162 identifies the sources of accounting principles and the framework for selecting principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP in the United States. This statement will be effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board's amendments to AU section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles.* We do not expect the adoption of SFAS No. 162 to have a material impact on our financial position, results of operations and cash flow.

In May 2008, the FASB issued FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement).* This FSP clarifies that convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) are not addressed by paragraph 12 of APB Opinion No. 14, *Accounting for Convertible Debt and Debt issued with Stock Purchase Warrants.* Additionally, this FSP specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We do not anticipate that this new FSP will have any material impact upon our financial position, results of operations and cash flow.

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

Cash Investments

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.

Marketing and Trading Commodity Price Risk

Our derivative positions as of December 31, 2008 primarily consisted of exchange cleared NYMEX natural gas swaps entered into to hedge the exposure to variability in expected future cash flows related to commissioning and cool down cargoes purchased in the second quarter of 2008 that are being sold as part of the testing phase of the commissioning process. As of December 31, 2008, we had entered into a total of 782,500 MMBtu of NYMEX natural gas swaps through June 2009 for which we will receive fixed prices of $5.35 to $8.62 per MMBtu. At December 31, 2008, the value of the derivatives was an asset of $1.2 million.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

INDEX TO FINANCIAL STATEMENTS

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MANAGEMENT'S REPORTS TO THE STOCKHOLDERS OF CHENIERE ENERGY, INC.

Management's Report on Internal Control Over Financial Reporting

As management, we are responsible for establishing and maintaining adequate internal control over financial reporting for Cheniere Energy, Inc. and its subsidiaries ("Cheniere"). In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act of 2002, we have conducted an assessment, including testing using the criteria in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Cheniere's system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Based on our assessment, we have concluded that Cheniere maintained effective internal control over financial reporting as of December 31, 2008, based on criteria in *Internal Control—Integrated Framework* issued by the COSO.

Management's Certifications

The certifications of Cheniere's Chief Executive Officer and Chief Financial Officer required by the Sarbanes-Oxley Act of 2002 have been included as Exhibits 31 and 32 in Cheniere's Form 10-K.

CHENIERE ENERGY, INC.

By: /s/ CHARIF SOUKI
Charif Souki
Chief Executive Officer and President

By: /s/ DON A. TURKLESON
Don A. Turkleson
Senior Vice President
and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
Cheniere Energy, Inc.

We have audited the accompanying consolidated balance sheets of Cheniere Energy, Inc. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders' (deficit) equity, and cash flows for each of the two years in the period ended December 31, 2008. Our audit also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Cheniere Energy, Inc. and subsidiaries at December 31, 2008 and 2007, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Cheniere Energy, Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 26, 2009 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

ERNST & YOUNG LLP

Houston, Texas
February 26, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
Cheniere Energy, Inc.

We have audited Cheniere Energy, Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Cheniere Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Cheniere Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Cheniere Energy, Inc. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders' (deficit) equity, and cash flows for each of the two years in the period ended December 31, 2008 and our report dated February 26, 2009 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
ERNST & YOUNG LLP

Houston, Texas
February 26, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Stockholders of Cheniere Energy, Inc.:

We have audited the accompanying consolidated statements of operations, stockholders' equity and cash flows of Cheniere Energy, Inc. and subsidiaries (the "Company") for the year ended December 31, 2006. In connection with our audit of the consolidated financial statements, we also have audited financial statement schedule I. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated results of their operations and their cash flows for the year ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, the Company changed its method of accounting for investments in oil and gas properties. As also discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, the Company changed its method of accounting for stock-based compensation.

/s/ UHY LLP

UHY LLP

Houston, Texas
February 27, 2007 except for
financial statement schedule I as to which the
date is February 26, 2008

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET
(in thousands, except share data)

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 102,192	$ 296,530
Restricted cash and cash equivalents	301,550	228,085
Accounts and interest receivable	3,630	48,786
Prepaid expenses and other	9,220	27,211
Total current assets	416,592	600,612
NON-CURRENT RESTRICTED CASH AND CASH EQUIVALENTS	138,483	478,225
NON-CURRENT RESTRICTED U.S. TREASURY SECURITIES	20,829	63,923
PROPERTY, PLANT AND EQUIPMENT, NET	2,170,158	1,645,112
DEBT ISSUANCE COSTS, NET	57,676	44,005
GOODWILL	76,844	76,844
INTANGIBLE LNG ASSETS	6,106	20,402
LNG HELD FOR COMMISSIONING	9,923	—
ADVANCES UNDER LONG-TERM CONTRACTS	10,705	28,497
OTHER	14,754	4,679
Total assets	$2,922,070	$2,962,299
LIABILITIES AND STOCKHOLDERS' DEFICIT		
CURRENT LIABILITIES		
Accounts payable	$ 1,220	$ 6,620
Accrued liabilities	61,883	164,917
Other	3,030	1,564
Total current liabilities	66,133	173,101
LONG-TERM DEBT, NET OF DISCOUNT	2,832,673	2,757,000
LONG-TERM DEBT—RELATED PARTIES	332,054	—
MINORITY INTEREST	250,162	285,675
DEFERRED REVENUE	37,500	40,000
OTHER NON-CURRENT LIABILITIES	8,141	8,637
COMMITMENTS AND CONTINGENCIES	—	—
STOCKHOLDERS' DEFICIT		
Preferred stock, $.0001 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, $.003 par value Authorized: 120,000,000 shares at both December 31, 2008 and 2007 Issued and outstanding: 52,297,109 and 47,730,869 shares at December 31, 2008 and 2007, respectively	157	143
Treasury stock: 179,000 and 9,192,000 shares at December 31, 2008 and 2007, respectively, at cost	(496)	(325,039)
Additional paid-in-capital	181,289	451,705
Accumulated deficit	(785,389)	(428,918)
Accumulated other comprehensive loss	(154)	(5)
Total stockholders' deficit	(604,593)	(302,114)
Total liabilities and stockholders' deficit	$2,922,070	$2,962,299

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2008	2007	2006
Revenues			
Oil and gas sales	$ 4,215	$ 5,376	$ 2,310
Marketing and trading gain (loss)	2,914	(4,729)	61
Pipeline revenue	15	—	—
Total revenues	7,144	647	2,371
Operating costs and expenses			
LNG receiving terminal and pipeline development expense	10,556	34,656	12,099
LNG receiving terminal and pipeline operating expense	14,522	—	—
Exploration costs	128	1,116	3,138
Oil and gas production costs	398	358	237
Impairment of fixed assets	—	18	1,628
Depreciation, depletion and amortization	24,346	6,393	3,131
General and administrative expenses	122,678	122,046	58,012
Restructuring charges	78,704	—	—
Total operating costs and expenses	251,332	164,587	78,245
Loss from operations	(244,188)	(163,940)	(75,874)
Loss from equity method investments	(4,800)	(191)	—
Loss on early extinguishment of debt	(10,691)	—	(43,159)
Derivative gain (loss)	4,652	—	(20,070)
Interest expense, net	(130,648)	(104,557)	(53,968)
Interest income	20,337	82,635	49,087
Other income	90	851	176
Loss before income taxes and minority interest	(365,248)	(185,202)	(143,808)
Income tax provision	—	—	(2,045)
Loss before minority interest	(365,248)	(185,202)	(145,853)
Minority interest	8,777	3,425	—
Net loss	$(356,471)	$(181,777)	$(145,853)
Net loss per common share—basic and diluted	$ (7.53)	$ (3.60)	$ (2.68)
Weighted average number of common shares outstanding—basic and diluted	47,365	50,537	54,423

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' (DEFICIT) EQUITY
(in thousands)

	Common Stock		Treasury Stock		Additional Stock Capital	Deferred Compensation	Accumulated Deficit	Accumulated Other Comprehensive Loss	Total Shareholders' (Deficit) Equity
	Shares	Amount	Shares	Amount					
Balance—December 31, 2005	54,521	$164	—	—	$ 375,551	$(9,684)	$(101,288)	$ 3,798	$ 268,541
Issuances of stock	386	1	—	—	1,995	—	—	—	1,996
Issuances of restricted stock	350	1	—	—	(1)	—	—	—	—
Forfeitures of restricted stock	(18)	—	18	—	—	—	—	—	—
Reversal of deferred compensation	—	—	—	—	(9,684)	9,684	—	—	—
Stock-based compensation	—	—	—	—	23,371	—	—	—	23,371
Treasury stock acquired	(26)	—	26	976	(976)	—	—	—	—
Treasury stock retired	—	—	(44)	(976)	—	—	—	—	(976)
Comprehensive loss:	—	—	—	—	—	—	—	—	—
Interest rate swaps	—	—	—	—	—	—	—	(3,798)	(3,798)
Foreign currency translation	—	—	—	—	—	—	—	(34)	(34)
Net loss	—	—	—	—	—	—	(145,853)	—	(145,853)
Balance—December 31, 2006	55,213	166	—	—	390,256	—	(247,141)	(34)	143,247
Issuances of stock	688	2	—	—	3,155	—	—	—	3,157
Issuances of restricted stock	1,029	2	—	—	(2)	—	—	—	—
Forfeitures of restricted stock	(20)	—	20	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	58,331	—	—	—	58,331
Treasury stock acquired	(9,179)	(27)	9,179	(325,101)	27	—	—	—	(325,101)
Treasury stock retired	—	—	(7)	62	(62)	—	—	—	—
Comprehensive loss:	—	—	—	—	—	—	—	—	—
Foreign currency translation	—	—	—	—	—	—	—	29	29
Net loss	—	—	—	—	—	—	(181,777)	—	(181,777)
Balance—December 31, 2007	47,731	143	9,192	(325,039)	451,705	—	(428,918)	(5)	(302,114)
Issuances of stock	145	—	—	—	472	—	—	—	472
Issuances of restricted stock	4,910	15	—	—	(15)	—	—	—	—
Forfeitures of restricted stock	(172)	—	172	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	58,571	—	—	—	58,571
Treasury stock acquired	(317)	(1)	317	(4,901)	—	—	—	—	(4,902)
Treasury stock retired	—	—	(9,502)	329,444	(329,444)	—	—	—	—
Comprehensive gain (loss):	—	—	—	—	—	—	—	—	—
Foreign currency translation	—	—	—	—	—	—	—	(149)	(149)
Net loss	—	—	—	—	—	—	(356,471)	—	(356,471)
Balance—December 31, 2008	52,297	157	179	(496)	181,289	—	(785,389)	(154)	(604,593)

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$(356,471)	$(181,777)	$ (145,853)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	24,346	6,393	3,131
Impairment of unproved properties and dry hole expense	—	785	2,089
Amortization of debt issuance costs	9,947	6,320	3,958
Non-cash compensation	55,030	56,638	21,768
Non-cash restructuring charges	17,669	—	—
Use of restricted cash and cash equivalents	94,610	103,043	—
Restricted interest income on restricted cash and cash equivalents	(18,495)	(53,327)	—
Loss on early extinguishment of debt	10,716	—	37,136
Minority interest	(8,777)	(3,425)	—
Other	8,082	230	1,797
Changes in operating assets and liabilities:			
Accounts and interest receivable	45,157	(41,654)	(5,842)
Regulatory assets	—	—	(12,343)
Accounts payable and accrued liabilities	(42,066)	42,007	13,210
Prepaid expenses and other	18,107	(19,524)	523
NET CASH USED IN OPERATING ACTIVITIES	(142,145)	(84,291)	(80,426)
CASH FLOWS FROM INVESTING ACTIVITIES:			
LNG terminal and pipeline construction-in-process, net	(583,871)	(788,517)	(440,367)
Use of (investment in) restricted cash and cash equivalents	465,323	526,318	(1,070,713)
Use of (investment in) restricted U.S. Treasury securities	16,702	(98,442)	—
Purchases of LNG commissioning, net of amounts transferred to LNG terminal construction-in-process	(9,923)	—	—
Purchases of intangible and fixed assets, net of sales	(2,889)	(41,684)	(10,527)
Oil and gas property, net of sales	(564)	17	(3,687)
Advances under long-term contracts, net of transfers to construction-in-progress	(14,032)	(38,617)	(7,101)
Other	(3,808)	1,031	(7,533)
NET CASH USED IN INVESTING ACTIVITIES	(133,062)	(439,894)	(1,539,928)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from debt issuance	239,965	—	2,032,000
Proceeds from debt issuance—related parties	250,000	—	—
Proceeds from sale of common units in partnership	—	203,946	—
Proceeds from issuance of common units to minority owners in partnership	—	98,442	—
Distributions to minority interest	(26,393)	(13,631)	—
Proceeds from 2007 term loan	—	400,000	—
Repayment of term loan	—	—	(598,500)
Repayment of debt	(95,000)	—	—
Borrowing under Sabine Pass credit facility	—	—	383,400
Repayment of Sabine Pass credit facility	—	—	(383,400)
Debt issuance cost	(34,504)	(9,787)	(43,796)
Purchase of treasury shares	(4,902)	(325,101)	—
Investment in restricted cash and cash equivalents	(248,767)	—	—
Other	470	3,883	1,021
NET CASH PROVIDED BY FINANCING ACTIVITIES	80,869	357,752	1,390,725
NET DECREASE IN CASH AND CASH EQUIVALENTS	(194,338)	(166,433)	(229,629)
CASH AND CASH EQUIVALENTS—BEGINNING OF PERIOD	296,530	462,963	692,592
CASH AND CASH EQUIVALENTS—END OF PERIOD	$ 102,192	$ 296,530	$ 462,963

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

NOTE 1—ORGANIZATION AND NATURE OF OPERATIONS

Cheniere Energy, Inc., a Delaware corporation, is a Houston-based company engaged, through its subsidiaries, in the energy business generally, including our publicly traded subsidiary partnership, Cheniere Energy Partners, L.P. ("Cheniere Partners"). As used in these Notes to Consolidated Financial Statements, the terms "Cheniere", "we", "us" and "our" refer to Cheniere Energy, Inc. and its subsidiaries. We are currently engaged primarily in the business of developing and constructing, and then owning and operating, a network of three onshore liquefied natural gas ("LNG") receiving terminals and natural gas pipelines, and we are developing a business to market LNG and natural gas primarily through our wholly-owned subsidiary, Cheniere Marketing, LLC. ("Cheniere Marketing"), formerly Cheniere Marketing, Inc. To a limited extent, we continue to be engaged in oil and natural gas exploration, development and exploitation activities in the Gulf of Mexico.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Our Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in the United States of America. The consolidated financial statements include the accounts of Cheniere Energy, Inc. and its majority-owned subsidiaries. We also hold ownership interests in entities that are accounted for under the equity method of accounting. All significant intercompany accounts and transactions have been eliminated in consolidation.

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 obtained. If no lease is obtained, the costs are expensed. Site rental costs and related amortization of capitalized options were 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, *Accounting for Rental Cost Incurred During a Construction Period.*

During the construction periods of our LNG receiving terminals, we capitalize interest and other related debt costs in accordance with Statement of Financial Accounting Standards ("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 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 certain of our pipeline systems to be constructed have met the criteria set forth in SFAS No. 71, *Accounting for the Effects of Certain Types of Regulations. Accordingly, we began applying the provisions of SFAS No. 71 to the affected pipeline subsidiaries in the second quarter of 2006.*

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 the accounting principles generally accepted in the United States of America ("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 regasification capacity fees are recognized as revenue over the term of the respective terminal use agreement ("TUA"). Advance payments of capacity reservation fees are initially deferred.

Revenues from the sale of oil and gas production are recognized upon passage of title, net of royalty interests. When sales volumes differ from our entitled share, an underproduced or overproduced imbalance occurs. To the extent an overproduced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability. At December 31, 2008 and 2007, we had no gas imbalances.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Expenditures for construction activities, major renewals and betterments are capitalized, while expenditures for maintenance and repairs and general and administrative activities are charged to expense as incurred. Interest costs incurred on debt obtained for the construction of property, plant and equipment are capitalized as construction-in-process over the construction period or related debt term, whichever is shorter. Once placed into service, the LNG terminal construction-in-process costs are depreciated using the straight-line depreciation method. Depreciation of computer and office equipment, computer software, leasehold improvements and vehicles is computed using the straight-line method over the estimated useful lives of the assets, which range from two to ten years. Upon retirement or other disposition of property, plant and equipment, the cost and related accumulated depreciation are removed from the account, and the resulting gains or losses are recorded in operations.

In accordance with SFAS No. 144, management reviews property, plant and equipment for impairment periodically and whenever events or changes in circumstances have indicated that the carrying amount of property, plant and equipment might not be recoverable. We have recorded impairments related to fixed assets of zero, $18,000 and $1.6 million for 2008, 2007 and 2006.

Income Taxes

Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes on temporary differences between the tax basis of assets and liabilities and their reported amounts in the consolidated financial statements. Deferred tax assets and liabilities are included in the consolidated financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled as prescribed in SFAS No. 109, *Accounting for Income Taxes*. As changes in tax laws or rates are enacted, deferred tax assets and liabilities are adjusted through the current period's provision for income taxes. A valuation allowance is provided for deferred tax assets if it is more likely than not that such asset will not be realizable.

Cash Flow Hedges

We have used, and may in the future use, derivative instruments to limit our exposure to variability in expected future cash flows. 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 other comprehensive income, to the extent that the hedge is effective. We assess both at the inception of each hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. On an on-going basis we monitor the actual dollar offset of the hedges' market values compared to hypothetical cash flow hedges. Any ineffective portion of the cash flow hedges will be reflected in earnings. Ineffectiveness is the amount of gains or losses from derivative instruments that are not offset by corresponding and opposite gains or losses on the expected future transaction.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make certain estimates and assumptions that affect the amounts reported in the consolidated financial statements and the accompanying notes. Actual results could differ from the estimates and assumptions used.

Items subject to estimates and assumptions include, but are not limited to, the carrying amount of property, plant and equipment, and goodwill; valuation allowances for income tax assets; and the fair value of share-based payments. Actual results could differ significantly from those estimates.

Cash Equivalents

We classify all investments with original maturities of three months or less as cash equivalents. Our investments are primarily in commercial paper and are made in accordance with corporate policy, which, among other things, stipulates minimum acceptable credit ratings of commercial paper issuers.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, restricted cash and cash equivalents, restricted certificates of deposit, accounts receivable, and accounts payable approximate fair value because of the short maturity of those instruments. We use available market data and valuation methodologies to estimate the fair value of debt.

Concentration of Credit Risk

Financial instruments that potentially subject us to a concentration of credit risk consist principally of cash and cash equivalents and restricted cash. We maintain cash balances at financial institutions, which may at times be in excess of federally insured levels. We have not incurred losses related to these balances to date.

We have entered into certain long-term TUAs with unaffiliated third parties for regasification capacity at our Sabine Pass LNG receiving terminal. We are dependent on the respective counterparties' creditworthiness and their willingness to perform under their respective TUAs. We have mitigated this credit risk by securing TUAs for a significant portion of our regasification capacity with creditworthy third-party customers with a minimum Standard & Poor's rating of AA.

Goodwill

As further described in Note 14—"Goodwill", we account for goodwill in accordance with the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*. Under the provisions of that statement, we are required to perform an annual review of goodwill for impairment. This review is required to be done at the reporting unit level, which we have determined to be our LNG receiving terminals business, which is a component of our LNG receiving terminal development business segment. We perform the annual review for possible impairment in the fourth calendar quarter of each year. If an event or change in circumstances indicates the fair value of a reporting unit may be below its carrying value, an impairment test would be performed sooner than the annual review date.

Debt Issuance Costs

Debt issuance costs consist primarily of arrangement fees, professional fees, legal fees and printing costs. These costs are capitalized and are being amortized to interest expense over the term of the related debt facility.

Share-Based Compensation Expense

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123R, *Share-Based Payments*, using the modified prospective transition method, and therefore have not restated the results of prior periods. 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 No. 123R using the Black-Scholes-Merton option valuation model. Under the fair value recognition provisions of SFAS No. 123R, we recognize share-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 No. 123R, we accounted for share-based payments under Accounting Principles Board ("APB") Opinion 25, *Accounting for Stock Issued to Employees*, 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 requires the use 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, the expected volatility for 2008 used in our fair value model 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 share-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, future share-based compensation expense could be significantly different from what we have recorded in the current period (See Note 21—"Share-Based Compensation" for further discussion on share-based compensation).

Net Loss Per Share

Net loss per share ("EPS") is computed in accordance with the requirements of SFAS No. 128, *Earnings Per Share*. Basic EPS excludes dilution and is computed by dividing net income (loss) by the weighted average number of common shares outstanding during the period. Diluted EPS reflects potential dilution and is computed by dividing net income by the weighted average number of common shares outstanding during the period increased by the number of additional common shares that would have been outstanding if the potential common shares had been issued. Basic and diluted EPS for all periods presented are the same since the effect of our options, warrants and unvested stock is anti-dilutive to our net loss per share under SFAS No. 128. Stock options, warrants and unvested stock representing securities that could potentially dilute basic EPS in the future that were not included in the diluted computation because they would have been anti-dilutive for the years 2008, 2007 and 2006, were 4.9 million, 5.8 million and 5.7 million, respectively. In addition, common shares of 59.2 million on a weighted average basis, issuable upon conversion of the 2008 Convertible Loans and the Convertible Senior Unsecured Notes (described in Note 18—"Long-Term Debt and Long-Term Debt—Related Parties"), were not included in the computation of diluted net loss per share for 2008, 2007 and 2006, because the computation of diluted net loss per share utilizing the "if-converted" method would be anti-dilutive. No adjustments were made to reported net loss in the computation of EPS.

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 determined that, in light of our current level of exploration and development activities, the successful efforts method of accounting provides was better matching of expenses to the period in which oil and gas production was realized. As a result, we determined that the change in accounting method 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, 2006 was to reduce the balance of our net investment in oil and gas properties and retained earnings at that date by $18.0 million. The change in accounting method for the year ended December 31, 2006 resulted in a decrease in the net loss of $15.0 million. The cumulative effect of the change in accounting method increased earnings per share (basic and diluted) $0.3 million for the year ended December 31, 2006, but had no impact on earnings per share (basic and diluted) for the year ended December 31, 2006. The change in method of accounting had no impact on cash or working capital.

Asset Retirement Obligations

We account for the retirement of our tangible long-lived assets in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 requires us to record the fair value of a liability for legal obligations associated with the retirement of tangible long-lived assets and a corresponding increase in the carrying amount of the related long-lived assets. Subsequently, the asset retirement costs included in the carrying amount of the related asset are allocated to expense based on the useful life of the applicable asset.

New Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51*, which establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS No. 160 is effective for fiscal years beginning October 1, 2009. In conjunction with our public offering of 15,525,000 of our common units in Cheniere Partners, we sold a portion of our Cheniere Partners common units to the public, realizing net proceeds of $203.9 million. Due to the subordinated distribution rights on our subordinated units, we have recorded those proceeds as a minority interest. As a result of the adoption of SFAS No. 160 on January 1, 2009, when our subordinated units in Cheniere Partners are converted to common units we are no longer able to elect an accounting policy of recording this gain through earnings, but will recognize the $203.9 million suspended gain directly in equity. In addition, our minority interest will be presented within the Stockholders equity section of our consolidated balance sheet, separate from the parent's equity.

On January 1, 2008, we adopted SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—including an amendment of FASB Statement No. 115* ("SFAS No. 159"). SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option) with changes in fair value reported in earnings. Cheniere already records derivative contracts at fair value in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended* ("SFAS No. 133"). The adoption of SFAS No. 159 had no impact on our financial position, results of operations and cash flow as management did not elect the fair value option for any financial instruments or other assets and liabilities.

On January 1, 2008, we adopted SFAS No. 157, *Fair Value Measurements* ("SFAS No. 157") as it relates to financial assets and financial liabilities. In February 2008, the FASB issued FSP No. FAS 157-2, *Effective Date of FASB Statement No. 157*, which delayed the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on at least an annual basis, until January 1, 2009 for calendar year-end entities. The adoption of SFAS No. 157 did not have a material impact on our financial position, results of operations or cash flow.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133* ("SFAS No. 161"). SFAS No. 161 requires enhanced disclosures about an entity's derivative and hedging activities, including (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133, and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. This standard becomes effective for us on January 1, 2009. Earlier adoption of SFAS No. 161 and, separately, comparative disclosures for earlier periods at initial adoption are encouraged. As SFAS No. 161 only requires enhanced disclosures, this standard will have no impact on our financial position, results of operations or cash flow.

In April 2008, the FASB issued FASB Staff Position ("FSP") SFAS No. 142-3, *Determination of the Useful Life of Intangible Assets*. This FSP amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142, *Goodwill and Other Intangible Assets*. The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141R, and other GAAP. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early adoption is prohibited. We do not expect the adoption of SFAS FSP No. 142-3 to have a material impact on our financial position, results of operations or cash flow.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*. SFAS No. 162 identifies the sources of accounting principles and the framework for selecting principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP in the United States. This statement will be effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board's amendments to AU section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles*. We do not expect the adoption of SFAS No. 162 to have a material impact on our financial position, results of operations or cash flow.

In May 2008, the FASB issued FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)*. This FSP clarifies that convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) are not addressed by paragraph 12 of APB Opinion No. 14, *Accounting for Convertible Debt and Debt issued with Stock Purchase Warrants*. Additionally, this FSP specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We do not anticipate that this new FSP will have any material impact upon our financial position, results of operations or cash flow.

NOTE 3—INITIAL PUBLIC OFFERING OF CHENIERE ENERGY PARTNERS, L.P.

On March 26, 2007, Cheniere Partners and Cheniere LNG Holdings, LLC ("Holdings"), our wholly-owned subsidiary, completed an initial public offering of 13,500,000 Cheniere Partners common units (the "Cheniere Partners Offering"). Cheniere Partners is a Delaware limited partnership formed by us to develop, own and operate the Sabine Pass LNG receiving terminal. Upon the closing of the Cheniere Partners Offering, the following transactions occurred:

- Holdings contributed its ownership interests in the entities that directly or indirectly own the Sabine Pass LNG receiving terminal to Cheniere Energy Investments, LLC, a wholly-owned subsidiary of Cheniere Partners;
- Cheniere Partners issued 21,362,193 common units, 135,383,831 subordinated units, 3,302,045 general partner units (representing a 2% general partner interest) and certain general partner incentive distribution rights to wholly-owned subsidiaries of Cheniere;
- Cheniere Partners issued 5,054,164 common units to the public and received net proceeds of $98.4 million; and
- Holdings initially sold 8,445,836 common units to the public and received net proceeds of $164.5 million, after which Cheniere and the public owned 89.8% and 8.2% limited partner interests in Cheniere Partners, respectively. Holdings also granted the underwriters an option to purchase an additional 2,025,000 of its Cheniere Partners common units to cover over-allotments in connection with the Cheniere Partners Offering.

Cheniere Partners used all of the net proceeds of $98.4 million it received from the sale of its common units to purchase U.S. Treasury securities to fund a distribution reserve for payment of initial quarterly distributions of $0.425 per common unit, as well as related quarterly distributions to its general partner, until Cheniere Partners is able to sustain funding of distributions to its unitholders from unrestricted cash, at which time any remaining cash in the distribution reserve is expected to be returned to us.

On April 16, 2007, the underwriters of the Cheniere Partners Offering exercised their over-allotment option to purchase 2,025,000 additional common units, which resulted in net proceeds of approximately $39.4 million to Holdings as the selling unitholder.

The net proceeds of $164.5 million from the initial sale of the common units by Holdings and the net proceeds of $39.4 million that it received from the subsequent exercise of the underwriters' option to purchase additional common units from Holdings are not assets of Cheniere Partners, and therefore, are unrestricted as to our use and are available for corporate and general business purposes.

As of December 31, 2008, our combined general partner and limited partner ownership interest in Cheniere Partners was approximately 90.6%. As of such date, we held 135,383,831 subordinated units, 10,891,357 common units and 3,302,045 general partner units of Cheniere Partners. During the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the initial quarterly distribution plus any arrearages on the initial quarterly distribution from prior quarters. Our subordinated units do not accrue arrearages. The subordination period generally will end if:

- Cheniere Partners has earned and paid at least $0.425 on each outstanding common unit, subordinated unit and general partner unit for each of the three consecutive, non-overlapping four-quarter periods ending on or after June 30, 2010; or

- Cheniere Partners has earned and paid at least $0.638 (150% of the initial quarterly distribution) on each outstanding common unit, subordinated unit and general partner unit for any four consecutive quarters ending on or after June 30, 2008.

The portion of the common units held by the public is presented as a minority interest on our Consolidated Balance Sheet. Losses attributable to the minority interest are presented separately on our Consolidated Statement of Operations based upon the minority interest's share of Cheniere Partners' losses calculated in accordance with Cheniere Partners' partnership agreement.

NOTE 4—RESTRUCTURING CHARGES

In the second quarter of 2008, we announced a cost savings program in connection with the downsizing of our natural gas marketing business activities, the nearing completion of significant construction activities for both the Sabine Pass LNG receiving terminal and Creole Trail Pipeline and the seeking of alternative arrangements for our time charter interest in two LNG vessels. In connection with this program, we recognized $78.7 million in restructuring charges in 2008, in accordance with SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities,* and have presented the financial impact as restructuring charges on the Consolidated Statements of Operations.

Below is a reconciliation of the total restructuring charges expected to be recognized and charged to expense over the restructuring period to the amount of expected restructuring charges at December 31, 2008 (in thousands):

	Severance Costs	Facility Costs	Marketing Costs	Total
Estimated restructuring charges (at inception of program)	$12,400	$ —	$ 69,400	$ 81,800
Adjustment to estimated restructuring charges as of December 31, 2008	(6,071)	2,583	1,292	(2,196)
Total estimated restructuring charges at December 31, 2008	6,329	2,583	70,692	79,604
Restructuring charges recognized as of December 31, 2008	(5,429)	(2,583)	(70,692)	(78,704)
Estimated restructuring charges to be recognized in the future	$ 900	$ —	$ —	$ 900

NOTE 5—MINORITY INTEREST

We have consolidated certain joint ventures and partnerships because we have a controlling interest in these ventures. Therefore, the entities' financial statements are consolidated in our consolidated financial statements and the other entities equity is recorded as minority interest. The following table sets forth the components of our minority interest balance attributable to third-party investors' interest (in thousands):

Net proceeds from Cheniere Partners' issuance of common units (1)	$ 98,442
Net proceeds from Holdings' sale of Cheniere Partners common units (2)	203,946
Distributions to Cheniere Partners' minority interest	(40,023)
Minority interest share of loss of Cheniere Partners	(12,203)
Minority interest at December 31, 2008	$250,162

(1) Through the Cheniere Partners Offering, Cheniere Partners received $98.4 million in net proceeds from the issuance of its common units to the public. Securities and Exchange Commission ("SEC") Staff Accounting

Bulletin ("SAB") No. 51, Accounting for Sales of Stock by a Subsidiary, provided guidance on accounting by the parent for issuances of a subsidiary's common equity to unaffiliated parties. Under SAB No. 51, a company was able to elect an accounting policy of recording a gain or loss on the sale of common equity of a subsidiary equal to the amount of proceeds received in excess of the carrying value of the parent's investment. SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51, establishes new accounting and reporting standards for the noncontrolling interest in a subsidiary. As a result of the adoption of SFAS No. 160 on January 1, 2009, when our subordinated units in Cheniere Partners are converted to common units we will recognize the $98.4 million suspended gain directly in equity. In addition, our minority interest will be presented within the stockholders equity section of our consolidated balance sheet, separate from the parent's equity.

(2) In conjunction with the Cheniere Partners Offering, Holdings sold a portion of the Cheniere Partners common units held by it to the public, realizing proceeds net of offering costs of $203.9 million, which included $39.4 million of net proceeds realized once the underwriters exercised their option to purchase an additional 2,025,000 common units from Holdings. Due to the subordinated distribution rights on our subordinated units, we have recorded those proceeds as a minority interest. As a result of the adoption of SFAS No. 160 on January 1, 2009, when our subordinated units in Cheniere Partners are converted to common units we will recognize the $203.9 million suspended gain directly in equity. In addition, our minority interest will be presented within the stockholders equity section of our consolidated balance sheet, separate from our equity.

NOTE 6—TREASURY STOCK

During the second half of 2007, we purchased 9.2 million shares of our common stock through the exercise of call options acquired in the issuer call spread purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes (See Note 18—"Long-Term Debt and Long-Term Debt—Related Parties"). These purchases completed the acquisition of our common stock under the call option, bringing our total stock purchased under the issuer call spread to 9.2 million shares with an aggregate purchase price of approximately $325.0 million. These shares were held as treasury stock at December 31, 2007. During 2008, we retired 9.5 million shares of treasury stock, which brings the shares held in treasury at December 31, 2008 to 0.2 million shares.

NOTE 7—RESTRICTED CASH AND CASH EQUIVALENTS AND U.S. TREASURY SECURITIES

Restricted cash and cash equivalents and U.S. Treasury securities are composed of cash that has been contractually restricted as to usage or withdrawal, as follows:

Sabine Pass LNG Receiving Terminal Construction Reserve

In November 2006, Sabine Pass LNG, L.P., our wholly-owned subsidiary ("Sabine Pass LNG"), consummated a private offering of an aggregate principal amount of $2,032.0 million of Senior Secured Notes consisting of $550.0 million of 7 1/4% Senior Secured Notes due 2013 (the "2013 Notes") and $1,482.0 million of 7 1/2% Senior Secured Notes due 2016 (the "2016 Notes" and collectively with the 2013 Notes, the "Senior Notes") (See Note 18—"Long-Term Debt and Long-Term Debt—Related Parties"). In September 2008, Sabine Pass LNG issued an additional $183.5 million, before discount, of 2016 Notes whose terms were identical to the previously outstanding 2016 Notes. The additional issuance and the previously outstanding 2016 Notes are treated as a single series of notes under the indenture governing the Senior Notes ("Sabine Pass Indenture"). Under the terms and conditions of the Senior Notes, we were required to fund a cash reserve account for approximately $987 million to pay the remaining costs to complete the Sabine Pass LNG receiving terminal. The cash accounts are controlled by a collateral trustee, and therefore, are shown as restricted cash and cash equivalents on our Consolidated Balance Sheet. As of December 31, 2008 and 2007, $27.4 million and $40.2 million related to accrued construction costs had been classified as part of current restricted cash and cash equivalents, and $43.7 million and $380.2 million related to remaining construction costs had been classified as a non-current asset on our Consolidated Balance Sheet, respectively.

Senior Notes Debt Service Reserve

As described above, Sabine Pass LNG consummated private offerings of an aggregate principal amount of $2,215.5 million Senior Notes (See Note 18—"Long-Term Debt and Long-Term Debt—Related Parties"). Under the terms and conditions of the Senior Notes, we were required to fund a cash reserve account with $335.0 million related to future interest payments on the Senior Notes through May 2009. The cash accounts are controlled by a collateral trustee, and therefore, are shown as restricted cash and cash equivalents on our Consolidated Balance Sheet. As of December 31, 2008 and 2007, $13.7 million and $151.0 million related to the payment of interest due within twelve months had been classified as part of current restricted cash, and $82.4 million and $61.8 million related to the remaining payments of interest had been classified as non-current restricted cash, respectively.

Cheniere Partners Distribution Reserve

At the closing of the Cheniere Partners Offering, Cheniere Partners funded a distribution reserve of $98.4 million, which was invested in U.S. Treasury securities (See Note 3—"Initial Public Offering of Cheniere Energy Partners, L.P."). The distribution reserve, including interest earned thereon, is available to pay quarterly distributions of $0.425 per common unit for all common units, as well as related distributions to Cheniere Partners' general partner, through the distribution made in respect of the quarter ending September 30, 2009. The U.S. Treasury securities were acquired at a discount from their maturity values equal to an average of approximately 4.87% per year. As of December 31, 2008, we classified the $20.8 million balance of U.S. Treasury securities as Non-Current Restricted U.S. Treasury Securities on our Consolidated Balance Sheet, as these securities had original maturities greater than three months.

TUA Reserve

Under the terms and conditions of the 2008 Convertible Loans described below in Note 18—"Long-Term Debt and Long-Term Debt—Related Parties", we were required to fund a reserve account with $135.0 million to pay Cheniere Marketing's TUA obligations to Sabine Pass LNG and as additional collateral for the 2008 Convertible Loans. The cash account is controlled by a collateral trustee, and therefore, is shown as restricted cash and cash equivalents on our Consolidated Balance Sheet. In September 2008 and December 2008, Cheniere Marketing utilized $15.0 million and $62.7 million, respectively, of this TUA reserve to pay its fourth quarter 2008 and first quarter 2009 TUA obligations to Sabine Pass LNG. As of December 31, 2008, we classified the remaining $62.8 million as part of current restricted cash on our Consolidated Balance Sheet.

Other Restricted Cash and Cash Equivalents

As of December 31, 2008 and 2007, $197.7 million and $36.9 million related to various other contractual restrictions had been classified as part of current restricted cash and cash equivalents, and $12.4 million and $36.2 million had been classified as a non-current asset on our Consolidated Balance Sheet, respectively.

NOTE 8—LEASES

Future Annual Minimum Lease Payments

Future annual minimum lease payments are as follows (in thousands):

Years Ending December 31,	Operating Leases (2)
2009	$ 13,800
2010	13,658
2011	13,534
2012	13,703
2013	13,999
Thereafter (1)(2)	215,173
Total	$283,867

(1) Includes certain lease option renewals as they were reasonably assured, as defined in SFAS No. 13, *Accounting for Leases.*

(2) Future annual minimum lease payments do not include $6.3 million expected to be recovered through sublease agreements for our Texas Avenue office lease in Houston, Texas, and $7.4 million expected to be recovered for our Pennzoil office lease.

Tug Boat Agreements

Sabine Pass TUG Services, LLC, our wholly owned subsidiary, entered into a Marine Services Agreement (the "Tug Agreement") for the use of tug boats and marine services for the Sabine Pass LNG receiving terminal. The term of the Tug Agreement commenced in January 2008 for a period of 10 years, with an option to renew two additional, consecutive terms of five years each. In accordance with Emerging Issues Task Force ("EITF") 01-08, *Determining Whether an Arrangement Contains a Lease*, we have determined that the Tug Agreement contains a lease for the tugs specified in the Tug Agreement. In addition, we have concluded that the tug boat lease contained in the Tug Agreement is an operating lease as defined in SFAS No. 13, and as such, the equipment component of the Tug Agreement will be charged to expense over the term of the Tug Agreement as it becomes payable.

LNG Site Leases

Our obligations under LNG site options are renewable on an annual or semiannual basis. We may terminate our obligations at any time by electing not to renew or by exercising the options.

In January 2005, we exercised our options and entered into three land leases for the site of the Sabine Pass LNG receiving terminal. The leases have an initial term of 30 years, with options to renew for six 10-year extensions with similar terms as the initial term. In February 2005, two of the three leases were amended, thereby increasing the total acreage under lease to 853 acres and increasing the annual lease payments to $1.5 million. The annual lease payments will be adjusted for inflation based on a consumer price index, as defined in the lease agreements, every five years. We recognized $1.5 million of site lease expense on our Consolidated Statement of Operations for 2008 and 2007.

NOTE 9—ADVANCES UNDER LONG-TERM CONTRACTS

We have entered into certain engineering, procurement and construction ("EPC") contracts and purchase agreements related to the construction of our Sabine Pass LNG receiving terminal that require us to make payments to fund costs that will be incurred or equipment that will be received in the future. Advances made under long-term contracts on purchase commitments are carried at face value and transferred to property, plant and equipment as the costs are incurred or equipment is received. As of December 31, 2008 and 2007, our advances under long-term contracts were $10.7 million and $28.5 million, respectively.

NOTE 10—PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consists of LNG terminal construction-in-process expenditures, LNG site and related costs, investments in oil and gas properties, and fixed assets, as follows (in thousands):

	December 31,	
	2008	2007
LNG TERMINAL COSTS		
LNG receiving terminal plant	$ 927,298	$ —
LNG receiving terminal construction-in-process	643,340	1,169,695
LNG site and related costs, net	2,579	1,991
Accumulated depreciation	(7,813)	
Total LNG receiving terminal costs	$1,565,404	$1,171,686
NATURAL GAS PIPELINE COSTS		
Natural gas pipeline plant	$ 562,893	$ —
Natural gas pipeline construction-in-process	7,937	425,038
Pipeline right-of-ways	18,221	15,751
Accumulated depreciation	(8,454)	
Total natural gas pipeline costs	$ 580,597	$ 440,789
OIL AND GAS PROPERTIES, successful efforts method		
Proved	$ 3,439	$ 2,526
Unproved	—	—
Accumulated depreciation, depletion and amortization	(1,043)	(653)
Total oil and gas properties, net	$ 2,396	$ 1,873
FIXED ASSETS		
Computers and office equipment	$ 5,693	$ 8,195
Furniture and fixtures	5,315	5,008
Computer software	12,128	12,268
Leasehold improvements	9,208	11,247
Projects-in-process	—	2,147
Other	1,254	1,072
Accumulated depreciation	(11,837)	(9,173)
Total fixed assets, net	$ 21,761	$ 30,764
PROPERTY, PLANT AND EQUIPMENT, net	$2,170,158	$1,645,112

LNG Terminal Costs

Costs associated with the construction of the Sabine Pass LNG receiving terminal have been capitalized as construction-in-process since the date the project satisfied our criteria for capitalization. For 2008 and 2007, we capitalized $80.7 million and $66.2 million of interest expense related to the construction of the Sabine Pass LNG receiving terminal, respectively. In March 2006, our Corpus Christi LNG receiving terminal satisfied the criteria for capitalization. Accordingly, costs associated with the initial site work for the Corpus Christi LNG receiving terminal have been capitalized. For the years ended December 31, 2008 and 2007, we capitalized $0.6 million and $2.1 million, respectively, of interest expense related to this construction project.

We began depreciating equipment and facilities associated with the initial 2.6 Bcf/d of sendout capacity and 10.1 Bcf of storage capacity of the Sabine Pass LNG receiving terminal when they were ready for use in the third quarter of 2008. The Sabine Pass LNG receiving terminal is depreciated using the straight-line depreciation method applied to groups of LNG receiving terminal assets with varying useful lives. The identifiable components of the Sabine Pass LNG receiving terminal with similar estimated useful lives have a depreciable range between 10 and 50 years.

Natural Gas Pipeline Costs

Our 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 our pipelines have met the criteria set forth in SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*. For the years ended December 31, 2008 and 2007, we capitalized $17.0 million and $15.1 million, respectively, of AFUDC to our natural gas pipeline projects.

Fixed Assets

Our fixed assets are recorded at cost and are depreciated on a straight-line method based on estimated lives of the individual assets or groups of assets. Depreciation expense related to our property, plant and equipment totaled $24.3 million and $5.7 million for the years ended December 31, 2008 and 2007, respectively.

Asset Retirement Costs

Our asset retirement obligations relate primarily to the retirement of certain LNG receiving terminal and natural gas pipeline assets and obligations related to right-of-way agreements. In accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*, we determined that due to an indeterminate life of such assets, the fair value of the retirement obligation is not reasonably estimable. A liability for such asset retirement obligation will be recorded when a fair value is determinable.

NOTE 11—INTANGIBLE ASSETS

The fair values, net book values and estimated useful lives of our intangible assets as of December 31, 2008 and 2007 are presented in the following tables (in thousands).

	As of December 31, 2008			
	Fair value	Amortization Period	Accumulated Amortization	Net Book Value
Amortizable intangible assets	$ 1,637	5 years	$ —	$ 1,637
Intangible assets not subject to amortization	4,469	—	—	4,469
Total	$ 6,106		$ —	$ 6,106

	As of December 31, 2007			
	Fair value	Amortization Period	Accumulated Amortization	Net Book Value
Amortizable intangible assets	$14,228	5 years	$ —	$14,228
Intangible assets not subject to amortization	6,174	—	—	6,174
Total	$20,402		$ —	$20,402

Amortizable Intangible Assets

We assigned $1.6 million and $14.2 million to intangible assets acquired either individually or with a group of assets that are subject to amortization as of December 31, 2008 and 2007, respectively. The weighted average amortization period for these assets is 5 years. For 2008 and 2007, we had not recognized amortization expense.

Intangible Assets Not Subject to Amortization

We assigned $4.5 million and $6.2 million to intangible assets acquired either individually or with a group of assets that are not subject to amortization as of December 31, 2008 and 2007, respectively.

NOTE 12—DEBT ISSUANCE COSTS

We have incurred debt issuance costs in connection with our long-term debt. These costs are capitalized and are being amortized over the term of the related debt. As of December 31, 2008, we had capitalized $57.7 million of costs directly associated with the arrangement of debt financing, net of accumulated amortization, as follows (in thousands):

Long-term Debt	Debt Issuance Costs	Amortization Period	Accumulated Amortization	Net Costs
2013 Senior Notes	$ 9,353	7 years	$ (2,903)	$ 6,450
2016 Senior Notes	30,035	10 years	(5,737)	24,298
2007 Term Loan	8,450	5 years	(2,673)	5,777
2008 Convertible Loans	16,927	10 years	(599)	16,328
Convertible Senior Unsecured Notes	9,542	7 years	(4,721)	4,821
Marketing Credit Facility	614	1 year	(612)	2
	$74,921		$(17,245)	$57,676

Scheduled amortization of these debt issuance costs for the next five years is estimated to be $43.7 million.

NOTE 13—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. As of December 31, 2008 and 2007, we had unrecorded cumulative suspended losses of $27.2 million and $19.8 million, respectively, related to our investment in Freeport LNG as the basis in this investment had been reduced to zero. In March 2008 and May 2008, we received cash call notices from Freeport LNG requesting that we provide further financial support due to higher than expected commissioning and performance testing costs. During 2008, we funded the cash calls and recorded $4.8 million of additional losses in Freeport LNG. In addition, Freeport LNG distributed $4.8 million to us in October 2008.

We recorded $4.8 million for 2008, and zero for 2007 and 2006 related to net losses of Freeport LNG.

The financial position of Freeport LNG at December 31, 2008 and 2007 and the results of Freeport LNG's operations for the years ended December 31, 2008, 2007 and 2006 are summarized as follows (in thousands):

	December 31,	
	2008	2007
Current assets	$ 72,834	$ 120,580
Property, plant and equipment, net	887,388	1,590
Construction-in-process	62,768	863,977
Other assets	31,608	46,316
Total assets	$1,054,598	$1,032,463
Current liabilities	$ 61,317	$ 34,477
Notes payable, net of current maturities	1,090,086	1,063,984
Deferred revenue and other deferred credits	15,401	5,478
Partners' capital	(112,206)	(71,476)
Total liabilities and partners' capital	$1,054,598	$1,032,463

	Year ended December 31,		
	2008	2007	2006
Revenue	$116,359	$ —	$ —
Loss from continuing operations	(7,890)	(16,677)	(16,631)
Net loss	(40,730)	(22,542)	(30,162)
Cheniere's 30% share of loss from equity method investment (1)	$ (12,219)	$ (6,763)	$ (9,049)

(1) During 2008, 2007 and 2006, we did not record $12.2 million, $6.8 million and $9.0 million of the net losses for such periods, respectively, as the basis in this investment had been reduced to zero and because we did not guarantee any obligations and had not been committed to provide any further financial support since December 2005, other than $4.8 million in cash calls which we received and funded in 2008.

NOTE 14—GOODWILL

In February 2005, we acquired the minority interest in Corpus Christi LNG, L.P. ("Corpus Christi LNG"), through the acquisition of BPU LNG, Inc. ("BPU"), in exchange for 2 million restricted shares of our common stock. BPU held as its sole asset the 33.3% limited partner interest in Corpus Christi LNG. As a result of this transaction, we own 100% of the limited partner interests in Corpus Christi LNG. This transaction was accounted for using the purchase method of accounting as prescribed by SFAS No. 141, *Accounting for Business Combinations*, and was valued at $77.2 million, including direct transaction costs. Of this amount, $76.8 million has been recorded as goodwill and will be accounted for in accordance with SFAS No. 142. The goodwill is the difference between the deemed value of the shares conveyed and the historical carrying value of the minority interest under GAAP plus direct transaction costs. For the calculation of federal income taxes, none of this goodwill amount will be deductible.

We performed annual goodwill impairment reviews in the fourth quarters of 2008 and 2007. These impairment reviews consisted of comparing the carrying value, including goodwill, of the reporting unit under review to the estimated fair value of the reporting unit. Had the carrying value exceeded the estimated fair value of the reporting unit, an impairment of the reporting unit would have been recognized, resulting in an impairment charge to earnings. A reporting unit is defined as a business segment or component of a business segment that has similar economic characteristics. For our impairment reviews, we have designated our LNG receiving terminal business as the reporting unit under review due to similar economic characteristics. Our reviews indicated that no impairment of goodwill was necessary.

NOTE 15—DERIVATIVE INSTRUMENTS

Interest Rate Derivative Instruments

In connection with the closing of the original Sabine Pass credit facility in February 2005 ("the Sabine Pass Credit Facility"), we entered into swap agreements ("Sabine Swaps"). Under the terms of the Sabine Swaps, we were able to hedge against rising interest rates, to a certain extent, with respect to drawings under the Sabine Pass Credit Facility, up to a maximum amount of $700 million. The Sabine Swaps had 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 million 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 was March 25, 2012.

The Sabine Pass Credit Facility was amended and restated in July 2006, increasing the amount available to Sabine Pass LNG from $822 million to $1.5 billion. In connection with the closing of the amended Sabine Pass Credit Facility in July 2006, we entered into additional interest rate swap agreements (the "Amended Sabine Swaps" and collectively with the Sabine Swaps, the "Swaps"). The Swaps had 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 $600 million term loan (the "Term Loan") on August 31, 2005, Holdings entered into interest rate swap agreements ("Term Loan Swaps") to hedge against rising interest rates. Under the terms of the Term Loan Swaps, Holdings hedged an initial notional amount of $600 million. The notional amount declined in accordance with anticipated principal payments under the Term Loan. The Term Loan Swaps had 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 was September 30, 2010.

In conjunction with the termination of the amended Sabine Pass Credit Facility and the Term Loan in November 2006, we terminated the Swaps and the Term Loan Swaps, and recognized a loss of $20.1 million. In accordance with EITF 00-9, *Classification of a Gain or Loss from a Hedge of Debt That Is Extinguished*, the loss recognized as the result of early termination of the Swaps and the Term Loan Swaps is presented on our Consolidated Statement of Operations as a derivative loss.

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 determined that the Swaps and the Term Loan Swaps qualified as cash flow hedges within the meaning of SFAS No. 133 and designated them as such. We assessed both at the inception of each of the Swaps and the Term Loan Swaps and on an on-going basis, whether the Swaps and the Term Loan Swaps that were used in our hedging transactions were highly effective in offsetting changes in cash flows of the hedged items. At inception, we determined the hedging relationship of the Swaps and the Term Loan Swaps and the underlying debt to be highly effective. On an on-going basis, we monitored the actual dollar offset of the market values of the Swaps and the Term Loan Swaps compared to hypothetical cash flow hedges. Any ineffective portion of the cash flow hedges was reflected in earnings. We continued to assess the hedge effectiveness of the Swaps and the Term Loan Swaps on a quarterly basis in accordance with the provisions of SFAS No. 133 until they were terminated in November 2006. Ineffectiveness is the amount of gains or losses from derivative instruments which are not offset by corresponding and opposite gains or losses on the expected future transaction.

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 accumulated other comprehensive income ("AOCI") and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. In our case, the impact on earnings was a reduction of interest expense of zero, zero and $7.2 million for 2008, 2007 and 2006, respectively. The ineffective portion of the gain or loss on the derivative instruments, if any, must be recognized currently in earnings. If the forecasted transaction is no longer probable of occurring, the associated gain or loss recorded in AOCI is recognized currently in earnings. For 2008 and 2007, we have recognized a net derivative gain of $4.7 million and zero, respectively.

NOTE 16—ACCRUED LIABILITIES

As of December 31, 2008 and 2007, accrued liabilities consisted of the following (in thousands):

	December 31,	
	2008	2007
LNG terminal construction costs	$26,768	$ 39,574
Accrued interest expense and related fees	17,305	16,159
Pipeline construction costs	5,102	47,266
Natural gas purchases	—	40,607
Payroll	8,717	16,143
Other accrued liabilities	3,991	5,168
Accrued liabilities	$61,883	$164,917

NOTE 17—DEFERRED REVENUE

As of December 31, 2008 and 2007, we had recorded $2.5 million and zero, respectively, as current deferred revenue and $37.5 million and $40.0 million, respectively, as non-current deferred revenue related to advance capacity reservation fee payments.

In November 2004, Total LNG USA, Inc. ("Total") paid Sabine Pass LNG a nonrefundable advance capacity reservation fee of $10.0 million in connection with the reservation of approximately 1.0 Bcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal. An additional advance capacity reservation fee payment of $10.0 million was paid by Total to Sabine Pass LNG in April 2005. The advance capacity reservation fee payments will be amortized over a 10-year period after operations commence as a reduction of Total's regasification capacity fee under its TUA. As a result, we recorded the advance capacity reservation fee payments that we received, although non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

In November 2004, we entered into a TUA to provide Chevron U.S.A., Inc. ("Chevron") with approximately 0.7 Bcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal. In December 2005, Chevron exercised its option to increase its reserved capacity by approximately 0.3 Bcf/d to approximately 1.0 Bcf/d and paid Sabine Pass LNG an additional $3.0 million advance capacity reservation fee. As of

December 31, 2008, Chevron USA had made advance capacity reservation fee payments to Sabine Pass LNG totaling $20.0 million. These capacity reservation fee payments will be amortized over a 10-year period as a reduction of Chevron's regasification capacity fee under its TUA. As a result, we recorded the advance capacity reservation payments that we received, although non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

NOTE 18—LONG-TERM DEBT AND LONG-TERM DEBT—RELATED PARTIES

As of December 31, 2008 and 2007, our long-term debt consisted of the following (in thousands):

	December 31,	
	2008	2007
Long-term debt, net of discount:		
Senior Notes, net of discount	$2,107,673	$2,032,000
Convertible Senior Unsecured Notes	325,000	325,000
2007 Term Loan	400,000	400,000
Total long-term debt, net of discount	2,832,673	2,757,000
Long-term debt— related parties:		
Senior Notes—related party, net of discount	70,661	—
2008 Convertible Loans	261,393	—
Total long-term debt—related party, net of discount	332,054	—
Total long-term debt and long-term debt—related party, net of discount	$3,164,727	$2,757,000

Below is a schedule of future principal payments that we are obligated to make on our outstanding long-term debt at December 31, 2008 (in thousands):

	Payments Due for the Years Ended December 31,				
	Total	2009	2010 to 2011	2012 to 2013	Thereafter
Long-term debt:					
Senior Notes, net of discount	$2,107,673	$ —	$ —	$ 550,000	$1,557,673
Convertible Senior Unsecured Notes	325,000	—	—	325,000	—
2007 Term Loan	400,000	—	—	400,000	—
Long-term debt—related parties:					
Senior Notes—related party, net of discount	70,661	—	—	—	70,661
2008 Convertible Loans	261,393	—	261,393	—	—
Total long-term debt and long-term debt—related parties	$3,164,727	$ —	$261,393	$1,275,000	$1,628,334

Sabine Pass LNG Senior Notes

In November 2006, Sabine Pass LNG issued an aggregate principal amount of $2,032.0 million of Senior Notes, consisting of $550.0 million of the 2013 Notes and $1,482.0 million of the 2016 Notes. In September 2008, Sabine Pass LNG issued an additional $183.5 million, before discount, of 2016 Notes whose terms were identical to the previously outstanding 2016 Notes. The net proceeds from the additional issuance of the 2016

Notes were $145.0 million. One of the lenders of the additional issuance of the 2016 Notes is GSO Capital Partners, L.P. ("GSO"), an affiliate of two members of Cheniere's board of directors. GSO did not receive any fees in connection with making the additional issuance of 2016 Notes. The additional issuance and the previously outstanding 2016 Notes are treated as a single series of notes under the Sabine Pass Indenture. Sabine Pass LNG placed $100.0 million of the $145.0 million of net proceeds from the additional issuance of the 2016 Notes into a construction account to pay construction expenses of cost overruns related to the construction, cool down, commissioning and completion of the Sabine Pass LNG receiving terminal. In addition, Sabine Pass LNG placed $40.8 million of the remaining net proceeds into an account in accordance with the cash waterfall requirements of the security deposit agreement, which are used by Sabine Pass LNG for working capital and other general business purposes.

Sabine Pass LNG placed $335.0 million of net proceeds from the original issuance of the Senior Notes in a reserve account to fund scheduled interest payments on the original Senior Notes. Interest on the Senior Notes is payable semi-annually in arrears on May 30 and November 30 of each year. The Senior Notes are secured on a first-priority basis by a security interest in all of Sabine Pass LNG's equity interests and substantially all of its operating assets. Under the Sabine Pass Indenture, except for permitted tax distributions, Sabine Pass LNG may not make distributions until certain conditions are satisfied. There must be on deposit in an interest payment account an amount equal to one-sixth of the semi-annual interest payment multiplied by the number of elapsed months since the last semi-annual interest payment. In addition, there must be on deposit in a permanent debt service reserve fund an amount equal to one semi-annual interest payment of approximately $82.4 million. Distributions will be permitted only after satisfaction of the foregoing funding requirements, after satisfying a fixed charge coverage ratio test of 2:1 and after satisfying other conditions specified in the Sabine Pass Indenture.

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 2012 to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended ("Securities Act"). The notes bear interest at a rate of 2.25% per year. The notes are convertible at any time into our common stock under certain circumstances at an initial conversion rate of 28.2326 shares per $1,000 principal amount of the notes, which is equal to a conversion price of approximately $35.42 per share. As of December 31, 2008, no holders had elected to convert their notes.

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 securities rate plus 50 basis points. The Sabine Pass Indenture governing the notes contains customary reporting requirements.

2007 Term Loan

In May 2007, Cheniere Subsidiary Holdings, LLC ("Cheniere Subsidiary"), a wholly-owned subsidiary of Cheniere, entered into a $400.0 million credit agreement ("2007 Term Loan"). Borrowings under the 2007 Term Loan generally bear interest at a fixed rate of 9.75% per annum. Interest is calculated on the unpaid principal amount of the 2007 Term Loan outstanding and is payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year. The 2007 Term Loan will mature on May 31, 2012. The net proceeds of $391.7 million from the 2007 Term Loan are being used for general corporate purposes, including our repurchase, completed during 2007, of approximately 9.2 million shares of our outstanding common stock pursuant to the exercise of the call options acquired in the issuer call spread purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes. The 2007 Term Loan is secured by a pledge of our 135,383,831 subordinated units in Cheniere Partners and our equity interests in the entities that own our 30% interest in Freeport LNG.

2008 Convertible Loans

In August 2008, we entered into a credit agreement pursuant to which we obtained $250.0 million in convertible term loans ("2008 Convertible Loans"). The 2008 Convertible Loans will mature in 2018, but the lenders can require prepayment of the loan for thirty days following August 15, 2011, 2013 and 2015, and upon a change of control. The 2008 Convertible Loans bear interest at a fixed rate of 12% per annum, except during the occurrence of an event of default during which time the rate of interest will be 14% per annum. Interest is due semi-annually on the last business day of January and July. At our option, until August 15, 2011, accrued interest may be added to the principal on each semi-annual interest date. The aggregate amount of all accrued interest to August 15, 2011 will be payable upon the maturity date. The 2008 Convertible Loans are secured by Cheniere's rights and fees payable under management services agreements with Sabine Pass LNG and Cheniere Partners, by Cheniere's common units in Cheniere Partners, by the equity and non-real property assets of Cheniere's pipeline entities, by the equity of various other subsidiaries and certain other assets and subsidiary guarantees. The principal amount of $250.0 million may be exchanged for newly-created Series B Convertible Preferred Stock, par value $0.0001 per share ("Series B Preferred Stock") with voting rights limited to the equivalent of 10,125,000 shares of common stock. The exchange ratio is one share of Series B Preferred Stock for each $5,000 of outstanding borrowings, subject to adjustment. The aggregate preferred stock is exchangeable into 50 million shares of common stock at a price of $5.00 per share pursuant to a broadly syndicated offering. No portion of any accrued interest is eligible for conversion into Series B Preferred Stock. We placed $135.0 million of the borrowings under the 2008 Convertible Loans into a TUA reserve account to pay the reservation fee and operating fee as defined under Cheniere Marketing's TUA. We utilized $95.0 million of the borrowings under the 2008 Convertible Loans to repay the Bridge Loan. The remaining borrowings were utilized to pay for interest on the Bridge Loan, to pay expenses incurred in connection with the issuance of the 2008 Convertible Loans and consideration of other strategic alternatives and to fund working capital and general corporate needs of Cheniere and its subsidiaries.

One of the lenders is Scorpion Capital Partners LP ("Scorpion"), an affiliate of one of the Cheniere's directors. Scorpion's portion of the 2008 Convertible Loans was $8.5 million and Scorpion did not receive any fees in connection with making the 2008 Convertible Loans.

As long as the 2008 Convertible Loans are exchangeable for shares of Series B Preferred Stock or shares of Series B Preferred Stock remain outstanding, the holders of a majority of the 2008 Convertible Loans and Series B Preferred Stock, acting together, shall have the right to nominate two individuals to the Company's Board, and together with the Board, a third nominee, who shall be an independent director.

Bridge Loan

In May 2008, Cheniere Common Units Holding, LLC ("Cheniere Common Units Holding"), a newly formed wholly-owned subsidiary of Cheniere, entered into the Bridge Loan pursuant to which the lenders agreed to make a term loan of $95.0 million to Cheniere Common Units Holding. We received approximately $82.3 million of net proceeds. This loan was repaid in the third quarter of 2008 using a portion of the proceeds from the 2008 Convertible Loans.

NOTE 19—FINANCIAL INSTRUMENTS

We entered into financial derivatives to hedge the exposure to variability in expected future cash flows attributable to the future sale of natural gas from our LNG commissioning cargoes ("LNG commissioning cargo derivatives"). The net cost (LNG commissioning cargo purchase price less natural gas sales proceeds) of our LNG commissioning cargoes is capitalized on our Consolidated Balance Sheet as it is directly related to the LNG receiving terminal construction and is incurred to place the LNG receiving terminal in usable condition. However, changes in the fair value of our LNG commissioning cargo derivatives are reported in earnings because they are not able to be designated as a qualifying hedge in accordance with FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities.

Effective January 1, 2008, we adopted SFAS No. 157, Fair Value Measurements, and SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115*. As a result of the adoption, we elected not to measure any additional financial assets or liabilities at fair value, other than those which were recorded at fair value prior to adoption.

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The financial assets and liabilities at December 31, 2008, measured at fair value on a recurring basis, are summarized below (in thousands):

	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value at December 31, 2008
Derivative assets	$1,230	$—	$—	$1,230
Total assets at fair value	$1,230	$—	$—	$1,230

Trading derivatives relate to positions held by Cheniere Marketing and include exchange-traded derivative contracts and over-the-counter derivative contracts. Other derivatives reflect positions held by Cheniere Marketing on behalf of Sabine Pass LNG related to natural gas swaps entered into to hedge the cash flows from the sale of excess LNG purchased for commissioning.

SFAS No. 107, *Disclosures about Fair Value of Financial Instruments*, requires the disclosure of the estimated fair value of financial instruments including those financial instruments for which the SFAS No. 159 fair value option was not elected. The carrying amounts reported on the Consolidated Balance Sheets for cash and cash equivalents, restricted cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to their short-term nature. The carrying amounts of the fair values of financial instruments for which SFAS No. 159 was not elected are as follows:

Financial Instruments (in thousands):

	December 31, 2008		December 31, 2007	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
2013 Notes (1)	$ 550,000	$ 412,500	$ 550,000	$ 525,250
2016 Notes, net of discount (1)	1,628,334	1,204,967	1,482,000	1,404,195
2.25% Convertible Senior Unsecured Notes (2)	325,000	50,375	325,000	338,611
2007 Term Loan (3)	400,000	400,000	400,000	400,000
2008 Convertible Loans (4)	261,393	261,393	—	—
Restricted U.S. Treasury securities (5)	20,829	22,901	63,923	66,984

(1) The fair value of the Senior Notes, net of discount, is based on quotations obtained from broker-dealers who made markets in these and similar instruments as of December 31, 2008 and December 31, 2007, as applicable.
(2) The fair value of our Convertible Senior Unsecured Notes is based on the closing trading prices on December 31, 2008 and December 31, 2007, as applicable.
(3) The 2007 Term Loan bears interest at a fixed rate; therefore, the estimated fair value is expected to vary with changes in market interest rates. At December 31, 2008 and December 31, 2007, the fair value of the debt instrument was stated at its carrying amount due to it being a non-trading instrument with no liquid market.
(4) The 2008 Convertible Loans bear interest at a fixed rate; therefore, the estimated fair value is expected to vary with changes in market interest rates. At December 31, 2008, the fair value of the debt instrument was stated at its carrying amount due to it being a non-trading instrument with no liquid market.
(5) The fair value of our restricted U.S. Treasury securities is based on quotations obtained from broker-dealers who made markets in these and similar instruments as of December 31, 2008 and December 31, 2007, as applicable.

NOTE 20—INCOME TAXES

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

	Year Ended December 31,		
	2008	2007	2006
Current federal income tax expense	$ —	$ —	$ —
Deferred federal income tax (provision) benefit	—	—	(2,045)
Total income tax (provision) benefit	$ —	$ —	$(2,045)

From our inception, we have reported net operating losses for both financial reporting purposes and for federal, international and state income tax reporting purposes. Accordingly, we are not presently a taxpayer and have not recorded a net liability for federal, international or state income taxes in any of the years included in the accompanying financial statements. Our Consolidated Statement of Operations for the year ended December 31, 2006 included a deferred income tax provision of $2.0 million. The deferred income tax provision was recorded in accordance with the guidance in paragraph 140 of SFAS No. 109 and EITF Abstracts, Topic D-32 which requires items reported in accumulated other comprehensive income ("AOCI") to be stated separately from the tax benefits associated with a loss from continuing operations. In our specific situation, the circumstance relates to after-tax Other Comprehensive Income ("OCI") of $3.8 million (consisting of pre-tax OCI income of $5.8 net of the related deferred federal income tax expense of $2.0 million) that was recorded for the year ended December 31, 2005 related to our Swaps and Term Loan Swaps.

The reconciliation of the federal statutory income tax rate to our effective income tax rate follows:

	Year Ended December 31,		
	2008	2007	2006
U.S. statutory tax rate	35.0%	35.0%	35.0%
Non-deductible executive share-based compensation expense	— %	— %	(2.0)%
Deferred tax asset valuation reserve	(35.5)%	(35.0)%	(35.0)%
State income tax expense (net of federal benefit)	— %	— %	— %
All other	0.5%	— %	— %
Effective tax rate as reported	— %	— %	(2.0)%

Deferred tax assets and liabilities reflect the net tax effect of temporary differences between the carrying amount of assets and liabilities for financial reporting purposes and amounts used for income tax purposes. Significant components of our deferred tax assets and liabilities at December 31, 2008 and 2007 are as follows (in thousands):

	Year Ended December 31, 2008	Year Ended December 31, 2007
Deferred tax assets		
Net operating loss carryforwards	$137,235	$ 38,560
Investment in limited partnership	81,429	90,600
Stock award compensation expense	31,317	21,199
Capital loss carryforward	21,909	—
Start-up costs and construction-in-process associated with LNG, pipeline and marketing activities	8,861	8,051
Oil and gas properties and fixed assets	2,500	2,137
Unrealized mark-to-market gains and losses	—	178
	$283,251	$160,725

	Year Ended December 31, 2008	Year Ended December 31, 2007
Deferred tax Liabilities		
Pipeline tax depreciation	$ (2,478)	$ —
Other items—deductible for tax	(4,000)	(1,318)
	(6,478)	(1,318)
Net deferred tax assets	276,773	159,407
Less: tax asset valuation allowance	(276,773)	(159,407)
	$ —	$ —

FIN No. 48

In July 2006, the FASB issued 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 de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition rules. The Company adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, on January 1, 2007. On the date of adoption, we determined that all of the material tax positions taken in our income tax returns previously filed and tax positions to be taken in our future income tax returns with respect to items originating before January 1, 2007 met the more likely-than-not recognition threshold prescribed by FIN No. 48.

During 2007, we recognized $54.4 million of deferred tax benefits for tax positions related to the accelerated recovery of a substantial portion of the costs of the Sabine Pass LNG receiving terminal for which the ultimate deductibility was highly certain, but for which there was some uncertainty corresponding to the timing of the related prior, current and future year tax deductions. During the first quarter of 2008, based on discussions with representatives from the relevant taxing authorities, we determined that the deferred tax benefits associated with the accelerated depreciation deductions would not be available in 2007. Therefore, during the first quarter of 2008 we reduced the amount of the deferred tax benefits recognized in 2007 by $54.4 million and reduced our FIN No. 48 liability by the same amount. At December 31, 2008, we had $22.2 million of unrecognized federal income tax benefits that pertain to tax positions taken in the current and prior years for which there is still some uncertainty as to the timing of the corresponding tax deductions, but which the ultimate deductibility is highly certain. Under SFAS No. 109, the timing of the corresponding tax deductions will not affect our annual reported effective income tax rate in any of the prior, current or future financial reporting periods, but could result in the acceleration of tax payments for a prior reporting period. Adjustments to our federal taxable income in prior tax reporting periods would largely be offset by our available net operating loss ("NOL") carryovers, and therefore, the potential underpayment of tax, interest and penalties have not been accrued with respect to this liability.

It is not likely that the amount of our unrecognized tax benefits will decrease significantly within the next twelve months. To date, the adoption of FIN No. 48 has had no impact on our financial position, results of operations or cash flows. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands):

Balance as January 1, 2008	$ 70,530
Additions based on tax positions related to current year	6,801
Additions for tax positions of prior years	—
Reductions for tax positions of prior years	(55,144)
Settlements	—
Balance at December 31, 2008	$ 22,187

During the first quarter of 2008, we resolved the uncertainty related to the tax positions associated with the timing of the current and future tax deductions for a substantial portion of our 2007 capital costs. Therefore, we reduced the deferred tax benefits that were recognized in 2007 by $54.4 million which caused us to reduce our FIN No. 48 liability in the first quarter of 2008 by an equal amount. As discussed above, we have not previously recorded a liability for international, federal or state income taxes and therefore we have not been subject to any penalties or interest expense related to any income tax liabilities. In future reporting periods, if any interest or penalties are imposed in connection with an income tax liability, we expect to include both of these items in the our income tax provision.

Our federal consolidated income tax returns filed to date have not been audited by the Internal Revenue Service; we have not been notified of any pending federal, state or international income tax audits. We have not entered into any agreements with any taxing authorities to extend the period of time in which they may assert or assess additional income tax, penalties or interest. However, because we are presently in an NOL carryover position and have been since our inception, under the applicable Internal Revenue Service ("IRS") guidelines, in the event of an audit, our available federal NOL carryover amount is subject to adjustment until the normal three-year federal statute of limitations closes for the year in which the NOL is fully utilized. The Texas Comptroller's Office recently completed an audit of Cheniere's Texas franchise tax returns for the three-year period ended December 31, 2004; the Louisiana Department of Revenue recently completed an income and franchise audit of Cheniere and one of our wholly-owned affiliates for the two-year period ended December 31, 2003. We expect that all of our significant operating affiliates will be audited by the States of Texas and Louisiana for annual tax reporting periods ended on or after December 31, 2004. To date, all of the state-level income tax audits have been settled favorably and without changes. None of our foreign affiliates have been audited by any foreign taxing authorities and none have been notified of any pending income tax audits.

At December 31, 2008, our NOL carryforward for financial and tax reporting purposes were $392.1 million and $510.6 million, respectively. Our tax NOL carryforward exceeds our financial NOL carryforward because our financial NOL carryforward does not include $63.4 million of deductions related to our uncertain tax positions as discussed above, and $55.1 million of share-based compensation deductions as provided for in SFAS No. 123R. Both amounts have been included in our tax NOL carryforward amount. The full amount of the deferred tax benefit attributable to our financial NOL has been included in our deferred tax asset valuation allowance.

As discussed in Note 21—"Share-Based Compensation", we adopted SFAS No. 123R effective January 1, 2006. For companies like Cheniere that have NOL carryforwards, SFAS No. 123R affects the manner in which share-based compensation tax deductions are treated for financial reporting purposes. We may claim share-based compensation deductions in our federal corporate income tax returns in an amount equal to the related income that is included in our employees' reported federal taxable income subject to any other applicable limitations. Under SFAS No. 123R, tax benefits generated in 2006 and subsequent reporting periods related to the excess of tax deductible share-based compensation over the amount recognized for financial accounting purposes may not be recorded to additional paid-in-capital ("APIC") for financial reporting purposes until the share-based compensation deductions actually reduce our cash income tax liability. Any tax benefits attributable to these deductions will not be recorded to APIC for financial reporting purposes until such time as all existing and future NOL carryforwards have been fully utilized.

Our federal NOL carryforwards are subject to expiration starting in 2011 extending through 2028. In addition to the normal NOL expiration rules, Internal Revenue Code ("IRC") Section 382 imposes additional limitations on a corporation's ability to utilize its NOL carryforwards in the tax years following an "ownership change." For this purpose, an ownership change results from stock transactions that increase the ownership of certain existing and new stockholders in the corporation by more than 50 percentage points during a three preceding year testing period. The minimum annual NOL utilization limitation amount is determined first by multiplying the company's market capitalization value on the ownership change date by the applicable federal interest rate that generally ranges between three and five percent. The amount of the limitation may, under certain circumstances, be increased to reflect both recognized and deemed recognized "built-in gains" that occur, or are deemed to occur, during the five-year period immediately following the ownership change. Any unused annual limitation may be carried over to later years. Several ownership changes in our stock have occurred between 1998 and 2007 that subjected our NOL carryforwards that existed in those years to the annual NOL utilization limitations provided for in Section 382. However, the annual NOL utilization limitations applicable to these ownership changes have not had a material impact on our ability to utilize the NOL carryforwards generated in prior years.

During the second quarter of 2008, largely due to the increased level of trading activity in our shares, we experienced an ownership change that will subject approximately $300 million of our existing tax NOL carryforwards to the annual NOL utilization limitations under Section 382. However, we do not believe that the applicable NOL utilization limitations will significantly affect our ability to fully utilize our existing tax NOL carryforwards after consideration of the additional limitation created by deemed recognition of built-in gains in the five-year period following this change.

At December 31, 2008, we also have a capital loss carryforward of $62.6 million that may be carried forward for up to five years. The capital loss carryforward represents the portion of our 2008 restructuring charges that represent capital losses for federal income tax reporting purposes. This carryforward may only be used to reduce future year gains derived from the sale or exchange of investments or other capital assets. The portion of our capital loss carryover that is not utilized within the five-year carryforward period is subject to expiration. The full amount of the deferred tax benefit attributable to our capital loss carryforward has been included in our deferred tax asset valuation allowance.

In accordance with SFAS No. 109, a valuation allowance equal to our net deferred tax asset balance has been established due to the uncertainty of realizing the tax benefits related to our net operating loss carryforwards, our capital loss carryforward and our other deferred tax assets. The change in the deferred tax asset valuation allowance was $117.4 million and $62.9 million for the years ended December 31, 2008 and 2007, respectively.

NOTE 21—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"). Effective January 1, 2006, we adopted SFAS No. 123R (revised 2004), *Share-Based Payment*, which revised SFAS No. 123 and superseded Accounting Principles Bulletin ("APB") No. 25. No adjustments to prior periods were made as a result of adopting SFAS No. 123R. 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.

For the years ended December 31, 2008, 2007 and 2006 the total share-based compensation expense recognized in our net loss (net of capitalization) was $55.0 million, $56.6 million and $21.8 million, respectively. As required by SFAS No. 123R, the effect of a change in estimated forfeitures is recognized through a cumulative adjustment included in share-based compensation cost in the period of change in estimate. We consider many factors when estimating expected forfeitures, including types of awards, employee class and historical experience. For the years ended December 31, 2008 and 2007, the cumulative adjustment recognized in our compensation expense was $14.5 million and $4.8 million, respectively. For the years ended December 31, 2008, 2007 and 2006, the total share-based compensation cost capitalized as part of the cost of capital assets was $2.4 million, $1.7 million and $1.6 million, respectively.

The impact of adopting SFAS No. 123R on our results of operations for the year ended December 31, 2006 was an increase in expenses of $17.3 million, 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 $0.32.

The total unrecognized compensation cost at December 31, 2008 relating to non-vested share-based compensation arrangements granted under the 1997 Plan and 2003 Plan, before any capitalization, was $20.9 million. That cost is expected to be recognized over 4.0 years, with a weighted average period of 1.08 years.

Tax deductions are generally available to us in an amount equal to the share-based compensation income included in the taxable income of our employees, to the extent our corporate-level tax deductions are not otherwise limited by Section 162(m) of the IRC. As previously discussed in Note 20—"Income Taxes", SFAS

No. 123R specifically provides that tax benefits associated with share-based payments to employees may not be recognized unless or until the corresponding tax deductions have reduced current taxes payable. As a result of our cumulative NOL carryovers and resulting valuation allowance, the tax benefits associated with deductions related to share-based payments to employees will not be recognized for financial reporting purposes until such time as all existing and future NOLs have been utilized.

The adoption of SFAS No. 123R had no effect on our 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 $0.5 million, $3.2 million and $2.0 million in the years ended December 31, 2008, 2007 and 2006, respectively.

Phantom Stock

In May 2007, the Company established the 2007 Incentive Compensation Plan ("2007 Plan") and the 2008-2010 Incentive Compensation Plan ("2008-2010 Plan") covering executive officers and other key employees for the performance periods of 2007, 2008, 2009 and 2010. A total of 537,000 and 1,794,000 shares of phantom stock were granted under the 2007 Plan and 2008-2010 Plans, respectively, payable in shares of our common stock upon achievement of stock price hurdles established by the plans. Using a Monte Carlo simulation, fair values were calculated for the performance periods 2008, 2009 and 2010, respectively and a projected earnings date was also forecasted on which the stock price hurdle would be achieved for the award related to each performance period. The fair value of the award for each performance period was to be amortized as compensation expense ratably from the date of plan approval to the date expected to be earned. In January 2008, 537,000 of shares of our common stock were issued as the stock price hurdle for the 2007 Plan was achieved. During the fourth quarter of 2008, certain executives and key employees forfeited 1,041,000 shares of their 2008—2010 phantom shares with no concurrent consideration. In connection with the cancellation of the phantom shares, a total of $5.1 million of unrecognized compensation cost was recognized.

Stock Options

We estimate the fair value of stock options under SFAS No. 123R at the date of grant using a Black-Scholes valuation model, which is consistent with the valuation technique we previously utilized to value stock options for the footnote disclosures required under SFAS No. 123. The risk-free rate is based on the U.S. Treasury securities yield curve in effect at the time of grant. The expected term (estimated period of time outstanding) of stock options granted is based on the "simplified" method of estimating the expected term for "plain vanilla" stock options allowed by SAB No. 107, *Valuation of Share-based Payment Agreements for Public Companies*, and varies based on the vesting period and contractual term of the stock option. Expected volatility for stock options granted is based on an equally weighted average of the implied volatility of exchange traded stock 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 stock option's expected life. We have not declared dividends on our common stock. We did not issue any options to purchase shares of our common stock during year ended December 31, 2008.

During 2005 and 2006, retention stock options were granted to executives and key employees as a future incentive for employment. The retention grants included vesting periods beginning in 2009 through 2012 as well as exercise prices ranging from $36.25 to $90.00. During the fourth quarter of 2008, certain executives and key employees forfeited 2,000,000 shares of their out-of-the-money option retention grants with no concurrent consideration. In connection with the cancellation of the phantom shares, a total of $19.6 million of unrecognized compensation expense was recorded.

During 2007, we issued options to purchase 20,000 shares of our common stock under the 2003 Plan to employees 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.

During 2006, we issued options to purchase 501,000 shares of our common stock under the 2003 Plan. This included options to purchase 131,000 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 of Directors 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; fully vested options to purchase a total of 50,000 shares granted to two 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 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.

The table below provides a summary of option activity under the combined plans as of December 31, 2008:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
	(in thousands)			(in thousands)
Outstanding at January 1, 2008	4,442	$38.84		
Granted	—	—		
Exercised	(155)	4.29		
Forfeited or Expired	(3,081)	44.44		
Outstanding at December 31, 2008	1,206	$28.96	4.57	$ —
Exercisable at December 31, 2008	1,070	$27.94	4.30	$ —

The weighted average grant-date fair value of options granted during the years ended December 31, 2008, 2007 and 2006 was zero, $19.44 and $23.07, respectively. The total intrinsic value of options exercised during the years ended December 31, 2008, 2007 and 2006 was $1.0 million, $19.3 million and $12.0 million, respectively.

Effective March 28, 2007, 69 employee stock option grants were amended to provide for acceleration of vesting upon termination under certain circumstances, within one year of a change of control event, or upon the death or disability of the stock option holder. This amendment did not have an impact on our assessment of stock options ultimately expected to vest, and, therefore, resulted in no change in their valuation of our forfeiture assumptions.

Stock and Non-Vested Stock

We have granted stock and non-vested (restricted) stock to employees, executive officers, outside directors and consultants under the 2003 Plan. Under SFAS No. 123R, grants of non-vested stock are 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 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 ($9.7 million 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 2008, 479,802 shares having three-year graded vesting were issued to our employees in the form of non-vested stock awards and 537,000 shares were issued to our executive officers in the form of vested stock awards related to our performance in 2007. In May 2008 and June 2008, as a part of the short-term and long-term retention plans approved by the Compensation Committee, 374,000 shares vesting on December 1, 2008 and 1,525,000 shares having a three-year graded vesting beginning December 31, 2008 were issued to our employees and a consultant in the form of non-vested stock awards. In December 2008, 1,702,600 non-vested stock having a three year graded vesting were issued to employees as an incentive award. During 2008, an additional 272,000 shares having a one-year graded vesting were issued to our directors and 26,000 shares of non-vested stock having three- or four-year graded vestings were issued to employees.

In January 2007, 630,000 shares having three-year graded vesting were issued to our employees and executive officers in the form of non-vested stock awards related to our performance in 2006. In May 2007, 31,000 shares having a one-year graded vesting were issued to our directors. In June 2007 and November 2007, 150,000 shares were issued as retention grants to certain employees vesting 50% on December 1, 2008, 30% on December 1, 2009, and 20% on June 1, 2010. In 2007, an additional 250,000 shares of non-vested stock having three or four-year graded vestings were issued primarily to new employees.

On May 25, 2007, the Compensation Committee of our Board of Directors approved a bonus plan covering substantially all employees not otherwise included in the 2007 Plan. This plan provided covered employees the ability to earn bonuses based on the achievement of established annual performance goals as well as a stock price appreciation goal. The fair value of the grants was recalculated at each balance sheet date until the total number of restricted shares was granted in January 2008. Because of the existence of the stock price appreciation goal, which was a market condition, the restricted stock was not eligible for amortization under the straight-line method, and each vesting tranche is being amortized separately.

During 2006, 30,000 and 79,000 shares having three-year graded vesting were issued to our directors and certain of our executive officers, respectively. During the year ended December 31, 2006, a total of 241,000 shares of stock having four-year graded vesting were issued primarily to new employees.

The table below provides a summary of the status of our non-vested shares under the 2003 Plan as of December 31, 2008, (in thousands except for per share information):

	Non Vested Shares	Weighted Average Grant Date Fair Value Per Share
Non-vested at January 1, 2008	1,355	$32.74
Granted	4,916	9.40
Vested	(2,375)	11.07
Forfeited	(172)	19.51
Non-vested at December 31, 2008	3,724	$ 3.46

The weighted average grant-date fair values of non-vested stock granted during the years ended December 31, 2008, 2007 and 2006 were $9.40, $31.99 and $35.60, respectively. The total grant-date fair values of shares vested during the years ended December 31, 2008, 2007 and 2006 were $6.8 million, $7.8 million and $5.4 million, respectively.

Share-based Plan Descriptions and Information

Our 1997 Plan provided for the issuance of stock options to purchase up to 5.0 million 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 11.0 million 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 share-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, bonus stock and phantom shares. In general, stock options granted to employees as hiring incentives were granted at the money with 10-year terms and graded vesting over four years. Retention grants made to employees have provided for exercise prices at or in excess of the stock price on the grant date, 10-year terms and graded vesting over three years. Restricted stock that has been granted as a hiring incentive vests over three or four years on a graded basis, while restricted stock granted from a bonus pool generally vests over three years. Shares issued under the 2003 Plan are generally newly issued shares.

401(k) Plan

In 2005, we established a defined contribution pension plan ("401(k) Plan"). The 401(k) Plan allows eligible employees to contribute up to 100% of their compensation up to the IRS maximum. We match each employee's salary deferrals (contributions) up to six percent of compensation and may make additional contributions at our discretion. Effective January 1, 2007, employees are immediately vested in the contributions made by us. Our contributions to the 401(k) Plan were $2.3 million, $1.8 million and $0.9 million for the years ended December 31, 2008, 2007, and 2006, respectively. We have made no discretionary contributions to the 401(k) Plan to date.

NOTE 22—COMPREHENSIVE LOSS

The following table is a reconciliation of our net loss to our comprehensive loss for the periods shown (in thousands):

	Years Ended December 31,		
	2008	2007	2006
Net loss	$(356,471)	$(181,777)	$(145,853)
Other comprehensive (loss) income items:			
Cash flow hedges, net of income tax	—	—	(3,798)
Foreign currency translation	(149)	29	(34)
Comprehensive loss	$(356,620)	$(181,748)	$(149,685)

NOTE 23—COMMITMENTS AND CONTINGENCIES

LNG Terminal Commitments and Contingencies

Obligations under LNG TUAs

Sabine Pass LNG has entered into third-party TUAs with Total and Chevron to provide berthing for LNG vessels and for the unloading, storage and regasification of LNG at the Sabine Pass LNG receiving terminal.

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 December 2005, Freeport LNG announced that it had closed a $383.0 million private placement of notes, which would be used to fund the remaining portion of the initial phase of the project, a portion of the cost of expanding the LNG receiving terminal and development of underground salt cavern gas storage. We do not anticipate that any capital calls will be made upon the limited partners of Freeport LNG in the foreseeable future. Capital calls may be made upon us and the other limited partners in Freeport LNG and 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 or funds raised through the issuance of Cheniere equity or debt securities or other Cheniere borrowings.

Under a settlement agreement dated as of June 14, 2001, we agreed to pay a royalty, which we refer to as the Crest Royalty. This Crest Royalty is calculated based on the volume of natural gas processed through covered LNG facilities. The Freeport LNG and Sabine Pass LNG receiving terminals are covered facilities. The Crest Royalty is subject to a maximum of approximately $11.0 million per production year at throughput of approximately 1.0 Bcf/d and a minimum of $2.0 million. The Crest Royalty will be payable after natural gas is first processed on a commercial basis by a covered LNG receiving terminal. That has not occurred at the Sabine Pass LNG facility, and we are advised that it has not occurred at the Freeport LNG receiving terminal. We do not know when or at which LNG receiving terminal the first commercial processing will occur. Freeport LNG has assumed the obligation to pay the Crest Royalty for natural gas processed at Freeport LNG's receiving terminal. We are advised that Freeport LNG has entered into long-term TUAs, with each of ConocoPhillips Company ("ConocoPhillips"); the Dow Chemical Company ("Dow") and a subsidiary of Mitsubishi Corporation ("Mitsubishi"), for an aggregate of approximately 1.55 Bcf/d of terminal throughput capacity. The ConocoPhillips TUA is for approximately 0.9 Bcf/d. The Dow TUA is for approximately 0.5 Bcf/d; and the Mitsubishi TUA is for approximately 0.15 Bcf/d.

In March 2008 and May 2008, we received cash call notices from Freeport LNG requesting that we provide further financial support due to higher than expected commissioning and performance testing costs. During 2008, we funded the cash calls and have recorded $4.8 million of additional losses in Freeport LNG. In addition, Freeport LNG distributed $4.8 million to us in October 2008.

LNG Terminal EPC Agreements

In July 2006, Sabine Pass LNG entered into an engineering, procurement, construction and management ("EPCM") Agreement with Bechtel for engineering, procurement, construction and management of construction services in connection with our 1.4 Bcf/d expansion at the Sabine Pass LNG receiving terminal. 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 the expansion. As of December 31, 2008, we are committed to make cash payments of approximately $56.5 million in the future pursuant to this contract.

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 LNG storage tanks in connection with the 1.4 Bcf/d expansion. 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. As of December 31, 2008, we are committed to make cash payments of approximately $23.5 million in the future pursuant to this contract.

Restricted Net Assets

At December 31, 2008, our restricted net assets of consolidated subsidiaries were approximately $250.2 million.

Other Commitments

In the ordinary course of business, we have issued surety bonds related to our offshore oil and gas operations and entered into certain multi-year licensing and service agreements, none of which are considered material to our financial position.

Legal Proceedings

We may in the future 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 December 31, 2008 and 2007, there were no threatened or pending legal matters that would have a material impact on our consolidated results of operations, financial position or cash flows.

NOTE 24—BUSINESS SEGMENT INFORMATION

We have three operating business segments: LNG receiving terminal business, natural gas pipeline business and LNG and natural gas marketing business. These operating 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 business segment is in various stages of developing three LNG receiving terminal projects along the U.S. Gulf Coast at the following locations: Sabine Pass LNG, approximately 90.6% owned (at December 31, 2008), in western Cameron Parish, Louisiana on the Sabine Pass Channel; Corpus Christi LNG, 100% owned, near Corpus Christi, Texas; and Creole Trail LNG, 100% owned, 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 business segment is in various stages of developing natural gas pipelines to provide access to North American natural gas markets.

Our LNG and natural gas marketing business segment is seeking to develop a portfolio of long-term, short-term, and spot LNG purchase agreements, and will focus on entering into business relationships for the domestic marketing of natural gas that is imported by Cheniere Marketing as LNG to the Sabine Pass LNG receiving terminal.

	Segments				
	LNG Receiving Terminal	Natural Gas Pipeline	LNG & Natural Gas Marketing	Corporate and Other (1)	Total Consolidation
			(in thousands)		
As of or for the Year Ended December 31, 2008					
Revenues	$ 15,000	$ 1,025	$ (12,086)	$ 3,205	$ 7,144
Depreciation, depletion and amortization	8,337	8,398	1,599	6,012	24,346
Non-cash compensation	3,500	833	11,629	39,068	55,030
Loss from operations	(26,111)	(14,846)	(109,880)	(93,351)	(244,188)
Interest expense, net	(74,825)	(22,674)	(2,057)	(31,092)	(130,648)
Interest income	14,619	—	1,624	4,094	20,337
Goodwill	76,844	—	—	—	76,844
Total assets	2,191,671	590,995	136,138	3,266	2,922,070
Expenditures for additions to long-lived assets	$ 401,751	$148,132	$ 527	$ 2,375	$ 552,785
As of or for the Year Ended December 31, 2007					
Revenues	$ —	$ —	$ (4,729)	$ 5,376	$ 647
Depreciation, depletion and amortization	235	—	891	5,267	6,393
Non-cash compensation	4,937	2,019	13,617	37,758	58,331
Loss from operations	(37,390)	(4,835)	(39,356)	(82,359)	(163,940)
Interest expense, net	(69,419)	(4)	(502)	(34,632)	(104,557)
Interest income	52,273	—	2,476	27,886	82,635
Goodwill	76,844	—	—	—	76,844
Total assets	2,041,894	443,421	157,601	319,383	2,962,299
Expenditures for additions to long-lived assets	$ 488,373	$393,159	$ 5,294	$ 13,141	$ 899,967
As of or for the Year Ended December 31, 2006					
Revenues	$ —	$ —	$ 61	$ 2,310	$ 2,371
Depreciation, depletion and amortization	137	—	107	2,887	3,131
Non-cash compensation expense	5,726	603	1,265	14,174	21,768
Loss from operations (2)	(28,392)	8,255	(6,915)	(48,822)	(75,874)
Loss on early extinguishment of debt (3)	(43,159)	—	—	—	(43,159)
Derivative loss (3)	(20,070)	—	—	—	(20,070)
Interest expense	(35,990)	(256)	—	(17,722)	(53,968)
Interest income	15,871	—	208	33,008	49,087
Income tax provision	—	—	—	(2,045)	(2,045)
Goodwill	76,844	—	—	—	76,844
Total assets	1,975,666	49,223	44,499	535,099	2,604,487
Expenditures for additions to long-lived assets	$ 413,338	$ 47,749	$ 3,594	$ 9,214	$ 473,895

(1) Includes corporate activities, oil and gas exploration, development and exploitation activities and certain intercompany eliminations. Our oil and gas exploration, development and exploitation operating activities have been included in the corporate and other column due to the lack of a material impact that these activities have on our financial statements. Prior periods were restated to include oil and gas exploration, development and exploitation activities within corporate and other.

(2) Natural gas pipeline income from operations for the year ended December 31, 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 from operations would have been a net loss of $4.1 million for the year ended December 31, 2006.

(3) Primarily represents recognized losses on the termination of the Sabine Pass Credit Facility and the Term Loan in November 2006. See Note 18—"Long-Term Debt and Long-Term Debt—Related Parties."

NOTE 26—SUPPLEMENTAL CASH FLOW INFORMATION AND DISCLOSURES OF NON-CASH TRANSACTIONS

The following table provides supplemental disclosure of cash flow information (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Cash paid during the year for interest, net of amounts capitalized	$110,695	$106,640	$43,253
Construction-in-process and debt issuance additions funded with accrued liabilities	$ 28,448	$112,824	$26,436

During 2007, 688,249 shares of common stock were issued in satisfaction of cashless exercises of options to purchase 731,670 shares of common stock.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
SUMMARIZED QUARTERLY FINANCIAL DATA
(unaudited)

Quarterly Financial Data—(in thousands, except per share amounts)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year ended December 31, 2008:					
Revenues	$ 1,477	$ 914	$ 4,100	$ 653	$ 7,144
Loss from operations	(38,365)	(103,467)	(39,145)	(63,211)	(244,188)
Net loss	(49,911)	(132,333)	(67,443)	(106,784)	(356,471)
Net loss per share—basic and diluted	$ (1.06)	$ (2.81)	$ (1.42)	$ (2.23)	$ (7.53)
Year ended December 31, 2007:					
Revenues	$ (1,256)	$ 872	$ 394	$ 637	$ 647
Loss from operations	(29,772)	(40,224)	(47,274)	(46,670)	(163,940)
Net loss	(34,556)	(41,119)	(53,454)	(52,648)	(181,777)
Net loss per share—basic and diluted	$ (0.63)	$ (0.76)	$ (1.14)	$ (1.14)	$ (3.60)

ITEM 9. *CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE*

None.

ITEM 9A. *CONTROLS AND PROCEDURES*

Evaluation of Disclosure Controls and Procedures

Based on their evaluation as of the end of the fiscal year ended December 31, 2008, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

During the most recent fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Our Management Report on Internal Control Over Financial Reporting is included in the Financial Statements on page 57 and is incorporated herein by reference.

ITEM 9B. *OTHER INFORMATION*

None.

PART III

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required by Items 10 through 14 of Part III of this Report is incorporated by reference from Cheniere's definitive proxy statement, which is to be filed pursuant to Regulation 14A within 120 days after the end of Cheniere's fiscal year ended December 31, 2008.

PART IV

ITEM 15. *EXHIBITS AND FINANCIAL STATEMENT SCHEDULES*

(a) Financial Statements, Schedules and Exhibits

(1) Financial Statements—Cheniere Energy, Inc. and Subsidiaries:

Management's Reports to the Stockholders of Cheniere Energy, Inc. 57
Reports of Independent Registered Public Accounting Firm—Ernst & Young LLP 58
Report of Independent Registered Public Accounting Firm—UHY LLP 60
Consolidated Balance Sheet 61
Consolidated Statement of Operations 62
Consolidated Statement of Stockholders' (Deficit) Equity 63
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Supplemental Information to Consolidated Financial Statements—Summarized Quarterly Financial Data 101

(2) Financial Statement Schedules:

Schedule I—Condensed Parent Company Financial Statements for the years ended December 31, 2008, 2007 and 2006 114

(3) Exhibits:

Exhibit No.	Description
2.1*	Seismic Data Purchase Agreement, dated June 21, 2000 between Seitel Data Ltd. and the Company. (Incorporated by reference to Exhibit 10.39 to the Company's Quarterly Report on Form 10-Q (SEC File No. 000-09092), filed on August 11, 2000)
2.2*	Settlement and Purchase Agreement, dated and effective as of June 14, 2001 by and between the Company, CXY Corporation, Crest Energy, L.L.C., Crest Investment Company and Freeport LNG Terminal, LLC, and two related letter agreements each dated February 27, 2003. (Incorporated by reference to Exhibit 10.36 to Cheniere Energy Partner, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on January 25, 2007)
2.3*	Agreement and Plan of Merger, dated February 8, 2005, by and among Cheniere LNG, Inc., Cheniere Acquisition, LLC, BPU Associates, LLC and BPU LNG, Inc. (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on February 8, 2005)
2.4*	Share Purchase Agreement, dated December 7, 2007, between Mercuria Energy Holding B.V. and Cheniere LNG Services, Inc. (Incorporated by reference to Exhibit 10.94 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2008)
3.1*	Restated Certificate of Incorporation of the Company. (Incorporated by reference to Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2004 (SEC File No. 001-16383), filed on August 10, 2004)
3.2*	Certificate of Amendment of Restated Certificate of Incorporation of the Company. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on February 8, 2005)
3.3*	Amended and Restated By-laws of the Company. (Incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-8 (SEC File No. 333-112379), filed on January 20, 2004)
3.4*	Amendment No. 1 to Amended and Restated By-laws of the Company. (Incorporated by reference to Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 6, 2005)
3.5*	Amendment No. 2, dated September 6, 2007, to the Amended and Restated By-Laws of Cheniere Energy, Inc. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on September 12, 2007)
4.1*	Specimen Common Stock Certificate of the Company. (Incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1 (SEC File No. 333-10905), filed on August 27, 1996)
4.2*	Certificate of Designation of Series A Junior Participating Preferred Stock. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (SEC File No. 001 16383), filed on October 14, 2004)
4.3*	Rights Agreement by and between the Company and U.S. Stock Transfer Corp., as Rights Agent, dated as of October 14, 2004. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on October 14, 2004)

Exhibit No.	Description
4.4*	First Amendment to Rights Agreement by and between the Company and U.S. Stock Transfer Corp., as Rights Agent, dated January 24, 2005. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 24, 2005)
4.5*	Second Amendment to Rights Agreement by and between Cheniere Energy, Inc. and Computershare Trust Company, N.A. (formerly U.S. Stock Transfer Corp.), as Rights Agent, dated as of October 24, 2008 (filed herewith). (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on October 24, 2008)
4.6*	Certificate of Designations of Series B Preferred Stock of Cheniere Energy, Inc. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 18, 2008)
4.7*	Form of Series B Preferred Stock Certificate of Cheniere Energy, Inc. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 18, 2008)
4.8*	Indenture, dated as of July 27, 2005, between the Company, as issuer, and The Bank of New York, as trustee. (Incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on July 27, 2005)
4.9*	Indenture, dated as of November 9, 2006, between Sabine Pass LNG, L.P., as issuer, and The Bank of New York, as trustee. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
4.10*	Form of 7.25% Senior Secured Note due 2013 (Included as Exhibit A1 to Exhibit 4.9 above)
4.11*	Form of 7.50% Senior Secured Note due 2016 (Included as Exhibit A1 to Exhibit 4.9 above)
10.1*	LNG Terminal Use Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.2*	Amendment of LNG Terminal Use Agreement, dated January 24, 2005, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.40 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on March 10, 2005)
10.3*	Omnibus Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.4*	Guaranty, dated as of November 9, 2004, by Total S.A. in favor of Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001 16383), filed on November 15, 2004)
10.5*	LNG Terminal Use Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.6*	Amendment to LNG Terminal Use Agreement, dated December 1, 2005, by and between Chevron U.S.A., Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.28 to Sabine Pass LNG, L.P.'s Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006)
10.7*	Omnibus Agreement, dated November 8, 2004, between Chevron U.S.A., Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)

Exhibit No.	Description
10.8*	Guaranty Agreement, dated as of December 15, 2004, from ChevronTexaco Corporation to Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.12 to Sabine Pass LNG, L.P.'s Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006)
10.9*	Amended and Restated Terminal Use Agreement, dated November 9, 2006, by and between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.10*	Amendment of LNG Terminal Use Agreement, dated June 25, 2007, by and between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 26, 2007)
10.11*	Cooperative Endeavor Agreement & Payment in Lieu of Tax Agreement, dated October 23, 2007 (amending the Amended and Restated Terminal Use Agreement, dated November 9, 2006, by and between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P.). (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 6, 2007)
10.12*	LNG Lease Agreement, dated June 24, 2008, between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 11, 2008)
10.13*	Guarantee Agreement, dated as of November 9, 2006, by the Company. (Incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.14*	Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 20, 2004)
10.15*	Change Orders 1 through 27 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.15 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005 (SEC File No. 001-16383), filed on March 13, 2006)
10.16*	Change Orders 28, 29 and 31 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 5, 2006)
10.17*	Change Orders 30, 32 and 33 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 4, 2006)
10.18*	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. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 6, 2006)
10.19*	Change Order 39 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.34 to Cheniere Energy Partners, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on December 21, 2006)

Exhibit No.	Description
10.20*	Change Order 40 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 11, 2006, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.31 of Sabine Pass LNG, L.P.'s Registration Statement on Form S-4/A (SEC File No. 333-138916), filed on January 10, 2007)
10.21*	Change Order 41 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 11, 2006, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.36 to Cheniere Energy Partners, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on January 25, 2007)
10.22*	Change Order 42 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated January 18, 2007, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2007)
10.23*	Change Order 43 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.34 to Sabine Pass LNG, L.P.'s Registration Statement on Form S-4 (SEC File No. 333-138916), filed on April 3, 2007)
10.24*	Change Orders 44 and 45 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 8, 2007)
10.25*	Change Orders 46, 47, 48 and 49 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 8, 2007)
10.26*	Change Order 50 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 6, 2007)
10.27*	Change Orders 51 and 52 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.26 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2008)
10.28*	Change Orders No. 53 through 56 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 9, 2008)
10.29*	Change Orders 57 and 58 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement, dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 11, 2008)
10.30	Change Order 59 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement, dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation.

Exhibit No.	Description
10.31*	Amendment to Agreement, dated September 3, 2008, for modification for transfer of risk of loss and modification of certain other obligations between Owner and Contractor under the Lump Sum Turnkey Agreement for Engineering, Procurement and Construction of the Sabine Pass LNG Receiving, Storage and Regasification Terminal by and between Sabine Pass LNG, L.P. and Bechtel Corporation, dated December 18, 2004. (Incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 7, 2008)
10.32*	Engineering, Procurement and Construction Services Agreement for Preliminary Work, dated April 13, 2006, between Corpus Christi LNG, LLC and La Quinta LNG Partners, LP. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 5, 2006)
10.33*	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. (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 4, 2006)
10.34*	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. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 6, 2007)
10.35*	Change Orders 2 and 3 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. (Incorporated by reference to Exhibit 10.38 to Sabine Pass LNG, L.P.'s Registration Statement on Form S-4 (SEC File No. 333-138916), filed on June 11, 2007)
10.36*	Change Order 4 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. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 8, 2007)
10.37*	Change Orders 5, 6, 7 and 8 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. (Incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2008)
10.38*	Change Order 10 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. (Incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 7, 2008)
10.39*	Engineer, Procure and Construct (EPC) LNG Tank Contract, dated July 21, 2006, between Sabine Pass LNG, L.P., Zachry Construction Corporation and Diamond LNG LLC. (Incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 4, 2006)

Exhibit No.	Description
10.40*	Change Order 1, 2 and 3 to Engineer, Procure and Construct (EPC) LNG Tank Contract, dated July 21, 2006, between Sabine Pass LNG, L.P., Zachry Construction Corporation and Diamond LNG LLC. (Incorporated by reference to Exhibit 10.37 to Sabine Pass LNG, L.P.'s Registration Statement on Form S-4 (SEC File No. 333-138916), filed on June 11, 2007)
10.41	Change Order 4 to Engineer, Procure and Construct (EPC) LNG Tank Contract, dated July 21, 2006, between Sabine Pass LNG, L.P., Zachry Construction Corporation and Diamond LNG LLC.
10.42*	Engineer, Procure and Construct (EPC) LNG Unit Rate Soil Contract, dated July 21, 2006, between Sabine Pass LNG, L.P. and Remedial Construction Services, L.P. (Incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 4, 2006)
10.43*	Change Order 5 to Engineer, Procure and Construct (EPC) LNG Unit Rate Soil Contract, dated July 21, 2006, between Sabine Pass LNG, L.P. and Remedial Construction Services, L.P. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 8, 2007)
10.44*	Change Order 6 to Engineer, Procure and Construct (EPC) LNG Unit Rate Soil Contract, dated July 21, 2006, between Sabine Pass LNG, L.P. and Remedial Construction Services, L.P. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 6, 2007)
10.45*	Change Order 7 to Engineer, Procure and Construct (EPC) LNG Unit Rate Soil Contract, dated July 21, 2006, between Sabine Pass LNG, L.P. and Remedial Construction Services, L.P. (Incorporated by reference to Exhibit 10.42 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2008)
10.46*	Change Order 8 to Engineer, Procure and Construct (EPC) LNG Unit Rate Soil Contract, dated July 21, 2006, between Sabine Pass LNG, L.P. and Remedial Construction Services, L.P. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 9, 2008)
10.47*	Notice of Commitment, dated May 31, 2007. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.48*	Collateral Trust Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., The Bank of New York, as collateral trustee, Sabine Pass LNG-GP, Inc. and Sabine Pass LNG-LP, LLC. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.49*	Amended and Restated Parity Lien Security Agreement, dated November 9, 2006, by and between Sabine Pass LNG, L.P. and The Bank of New York, as collateral trustee. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.50*	Third Amended and Restated Multiple Indebtedness Mortgage, Assignment of Rents and Leases and Security Agreement, dated November 9, 2006, between the Sabine Pass LNG, L.P. and The Bank of New York, as collateral trustee. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.51*	Amended and Restated Parity Lien Pledge Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., Sabine Pass LNG-GP, Inc., Sabine Pass LNG-LP, LLC and The Bank of New York, as collateral trustee. (Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)

Exhibit No.	Description
10.52*	Security Deposit Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., The Bank of New York, as collateral trustee, and The Bank of New York, as depositary agent. (Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.53*	Credit Agreement, dated as of May 31, 2007, among Cheniere Subsidiary Holdings, LLC, Perry Capital, L.L.C., the several lenders from time to time parties thereto, and The Bank of New York, as Administrative Agent. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.54*	Guarantee and Pledge Agreement, dated as of May 31, 2007, by Cheniere Energy, Inc., Cheniere LNG Holdings, LLC, Cheniere FLNG-GP, LLC, and Cheniere Subsidiary Holdings, LLC in favor of The Bank of New York, as Administrative Agent. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.55*	Credit Agreement dated as of September 14, 2007, among Cheniere Marketing, Inc., the lenders party thereto and BNP Paribas, as administrative agent for the lenders. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on September 20, 2007)
10.56*	Security Agreement dated as of September 14, 2007, between Cheniere Marketing, Inc. and BNP Paribas, as collateral trustee. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.57*	Collateral Trust Agreement dated as of September 14, 2007, between Cheniere Marketing, Inc. and BNP Paribas, as collateral trustee. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.58*	Credit Agreement, dated May 5, 2008, among Cheniere Common Units Holding, LLC, the lenders party thereto and Credit Suisse, Cayman Islands Branch. (Incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 9, 2008)
10.59*	Pledge Agreement, dated May 5, 2008, among Cheniere Common Units Holding, LLC, Cheniere LNG Holdings, LLC, Cheniere Pipeline GP Interests, LLC, Grand Cheniere Pipeline, LLC and Credit Suisse, Cayman Islands Branch. (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 9, 2008)
10.60*	Security Agreement, dated May 5, 2008, between Cheniere Common Units Holding, LLC and Credit Suisse, Cayman Islands Branch. (Incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 9, 2008)
10.61*	Non-Recourse Guaranty, dated May 5, 2008, by Cheniere Energy, Inc. in favor of Credit Suisse. (Incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 9, 2008)
10.62*	Credit Agreement dated August 15, 2008, by and among Cheniere Common Units Holding, LLC the other Loan Parties (as defined therein), The Bank of New York Mellon, as administrative agent and collateral agent and the Lenders (as defined therein). (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 18, 2008)
10.63	First Amendment to Credit Agreement, dated September 15, 2008, among Cheniere Common Units Holding, LLC, the other Loan Parties (as defined therein), The Bank of New York Mellon, as administrative agent and collateral agent and the Lenders (as defined therein)

Exhibit No.	Description
10.64	Second Amendment to Credit Agreement, First Amendment to Guarantee and Collateral Agreement (Crest Entities) and First Amendment to Guarantee and Collateral Agreement (Non-Crest Entities), dated December 31, 2008, by Cheniere Common Units Holding, LLC, the loan parties, the guarantors and the grantors signatory thereto, the lenders signatory thereto and The Bank of New York Mellon, as administrative agent and as collateral agent
10.65*	Guarantee and Collateral Agreement (Crest Entities), dated August 15, 2008, made by the entities party thereto in favor of The Bank of New York Mellon, as collateral agent. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 18, 2008)
10.66*	Guarantee and Collateral Agreement (Non-Crest Entities), dated August 15, 2008, by Cheniere Common Units Holding, LLC and the other entities party thereto in favor of The Bank of New York Mellon, as collateral agent. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 18, 2008)
10.67	Waiver to Credit Agreement and Guarantee and Collateral Agreement (Non-Crest Entities), dated December 13, 2008, among Cheniere Common Units Holding, LLC, Cheniere Midstream Holdings, Inc., Cheniere LNG Services, Inc., GSO Special Situations Fund LP, GSO Credit Opportunities Fund (Helios), L.P., GSO Special Situations Overseas Master Fund Ltd., Blackstone Distressed Securities Fund L.P., Scorpion Capital Partners LP and The Bank of New York Mellon, as collateral agent and administrative agent
10.68	Second Amendment to Guarantee and Collateral Agreements, dated December 31, 2008, by Cheniere Midstream Holdings, Inc., Sabine Pass Tug Services, LLC, Cheniere LNG, Inc., Cheniere LNG Terminals, Inc., Cheniere Marketing, LLC, the Lenders signatory thereto and The Bank of New York Mellon, as collateral agent
10.69*	Security Deposit Agreement, dated August 15, 2008, by and among Cheniere LNG Holdings, LLC and The Bank of New York Mellon, as collateral agent and depositary agent. (Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 18, 2008)
10.70*	Investors' Agreement, dated August 15, 2008, by and between Cheniere Energy, Inc., Cheniere Common Units Holding, LLC and the investors named therein. (Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 18, 2008)
10.71	First Amendment to Investors' Agreement, dated November 11, 2008, among Cheniere Energy, Inc., Cheniere Common Units Holding, LLC, GSO Special Situations Fund LP, GSO Origination Funding Partners LP, Blackstone Distressed Securities Fund L.P., GSO COF Facility LLC, and Scorpion Capital Partners LP
10.72*	Gas Purchase and Sale Agreement, dated April 4, 2006, between Cheniere LNG Marketing, Inc. and PPM Energy, Inc. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 5, 2006)
10.73*	Master Ex-Ship LNG Sales Agreement, dated April 26, 2007, between Cheniere Marketing, Inc. and Gaz de France International Trading S.A.S., including Letter Agreement, dated April 26, 2007, and Specific Order No. 1, dated April 26, 2007. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 8, 2007)
10.74*	GDF Transatlantic Option Agreement, dated April 26, 2007, between Cheniere Marketing, Inc. and Gaz de France International Trading S.A.S. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 8, 2007)

Exhibit No.	Description
10.75*†	Cheniere Energy, Inc. Amended and Restated 1997 Stock Option Plan. (Incorporated by reference to Exhibit 10.14 to the Company's Quarterly on Form 10-Q (SEC File No. 000-16383), filed on November 4, 2005)
10.76*†	Form of Amendment to Nonqualified Stock Option Agreement under the Cheniere Energy, Inc. Amended and Restated 1997 Stock Option Plan pursuant to the Nonqualified Stock Option Agreement. (Incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 7, 2008)
10.77*†	Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.14 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 4, 2005)
10.78*†	Addendum to Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005 (SEC File No. 001-16383), filed on March 13, 2006)
10.79*†	Amendment No. 1 to Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 4.10 to the Company's Registration Statement on Form S-8 (SEC File No. 333-134886), filed on June 9, 2006)
10.80*†	Amendment No. 2 to Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.84 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2007)
10.81*†	Amendment No. 3 to Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit A to the Company's Proxy Statement (SEC File No. 001-16383), filed on April 23, 2008)
10.82*†	Form of Non-Qualified Stock Option Grant for Employees and Consultants (three-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.2 to the Company' Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007)
10.83*†	Form of Non-Qualified Stock Option Grant for Employees and Consultants (four-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.3 to the Company' Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007)
10.84*†	Form of Non-Qualified Stock Option Grant for Non-Employee Directors under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.4 to the Company' Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007)
10.85*†	Form of Amendment to Non-Qualified Stock Option Grant under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.7 to the Company' Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 7, 2008)
10.86*†	Form of Restricted Stock Grant (three-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.5 to the Company' Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007)
10.87*†	Form of Restricted Stock Grant (four-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.6 to the Company' Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007)

Exhibit No.	Description
10.88*†	Form of Restricted Stock Agreement for Non-Employee Directors. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.89*†	Form of Cancellation and Grant of Non-Qualified Stock Options (three-year vesting) under the Cheniere Energy, Inc. 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 2, 2005)
10.90*†	Form of Amendment to Non-Qualified Stock Option Agreement. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on April 3, 2007)
10.91*†	Form of French Stock Option Grant for Employees and Consultants (four-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.91 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2007)
10.92*†	Form of French Restricted Shares Grant for Employees, Consultants and Non-Employee Directors (three-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.92 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2007)
10.93*†	Form of French Restricted Shares Grant for Employees, Consultants and Non-Employee Directors (four-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.93 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2007)
10.94†	Indefinite Term Employment Agreement, dated February 20, 2006, between Cheniere International, Inc. and Jean Abiteboul; Letter Agreement, dated February 23, 2006, between Cheniere Energy, Inc. and Jean Abiteboul; Amendment to a Contract of Employment, dated March 20, 2007, between Cheniere LNG Services SARL and Jean Abiteboul; and Amendment to Indefinite Term Contract of Employment, dated January 18, 2008, between Cheniere LNG Services and Jean Abiteboul
10.95†	Summary of Compensation for Executive Officers.
10.96*†	Summary of Compensation to Non-Employee Directors. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 19, 2008)
10.97*†	Summary of 2007 Performance Bonus Plan. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on April 5, 2007)
10.98*†	Summary of Terms for Cheniere Energy, Inc. Incentive Compensation Plan for Executive Committee Members and Other Key Employees. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.99*†	Cheniere Energy, Inc. 2008 Short-Term Retention Plan. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 14, 2008)
10.100*†	Form of Cheniere Energy, Inc. 2008 Short-Term Retention Plan Restricted Stock Grant. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 14, 2008)
10.101*†	Cheniere Energy, Inc. 2008 Long-Term Retention Plan. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 14, 2008)

Exhibit No.	Description
10.102*†	Form of Cheniere Energy, Inc. 2008 Long-Term Retention Plan Restricted Stock Grant. (Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 14, 2008)
10.103*†	Cheniere Energy, Inc. 2008 Change of Control Cash Payment Plan. (Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 14, 2008)
10.104*†	Form of Change of Control Agreement. (Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 14, 2008)
10.105*†	Form of Release and Separation Agreement. (Incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 14, 2008)
10.106*†	Form of Restricted Stock Grant for Senior Vice President and General Counsel. (Incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 14, 2008)
10.107*†	Form of Indemnification Agreement for directors of Cheniere Energy, Inc. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 19, 2008)
10.108*†	Form of 2009 Phantom Stock Grant (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on February 27, 2009)
21.1	Subsidiaries of Cheniere Energy, Inc.
23.1	Consent of Ernst & Young LLP
23.2	Consent of UHY LLP
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

* Incorporated by reference

† Management contract or compensatory plan or arrangement

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT— CHENIERE ENERGY, INC.

CONDENSED BALANCE SHEET
(in thousands)

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 9,152	$ 46,945
Prepaid expenses and other	20	238
Total current assets	9,172	47,183
DEBT RECEIVABLE—AFFILIATES	615,571	581,358
OTHER	4,821	6,198
Total assets	$ 629,564	$ 634,739
LIABILITIES AND STOCKHOLDERS' (DEFICIT) EQUITY		
CURRENT LIABILITIES	3,080	3,075
LONG-TERM DEBT	325,000	325,000
LONG-TERM DEBT—AFFILIATE	401,308	391,708
INVESTMENT IN AND EQUITY IN LOSSES OF AFFILIATES	504,769	217,070
COMMITMENTS AND CONTINGENCIES	—	—
STOCKHOLDERS' (DEFICIT) EQUITY	(604,593)	(302,114)
Total liabilities and stockholders' equity	$ 629,564	$ 634,739

See accompanying notes to condensed financial statements.

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT— CHENIERE ENERGY, INC.

CONDENSED STATEMENT OF OPERATIONS
(in thousands)

	Year Ended December 31,		
	2008	**2007**	**2006**
Revenues			
Total revenues	$ —	$ —	$ —
Operating costs and expenses	170	60	3,494
Loss from operations	(170)	(60)	(3,494)
Interest expense, net	(8,698)	(8,698)	(8,676)
Interest income	988	3,336	—
Interest income—affiliates	40,363	34,213	34,213
Interest expense—affiliates	(44,341)	(22,496)	—
Equity losses of affiliates	(344,613)	(188,082)	(167,896)
Other income	—	10	—
Income tax (provision) benefit	—	—	—
Net loss	$(356,471)	$(181,777)	$(145,853)

See accompanying notes to condensed financial statements.

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT— CHENIERE ENERGY, INC.

CONDENSED STATEMENT OF CASH FLOWS (in thousands)

	Year Ended December 31,		
	2008	2007	2006
NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES	$(45,848)	$ (28,604)	$ 4,218
CASH FLOWS FROM INVESTING ACTIVITIES:			
Return of capital from (capital contributions to) affiliates	1,508	4,223	(6,856)
Other	—	184	4
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	1,508	4,407	(6,852)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings from long-term debt	9,600	391,708	—
Purchase of treasury shares	—	(325,062)	2
Issuance of long-term debt—affiliate	—	—	—
Purchase of issuer call spread	—	—	—
Sale of common stock	472	3,155	1,995
Amortization of debt issuance costs	1,377	1,377	1,614
Issuance of restricted stock	(15)	—	—
Other	(4,887)	(37)	(977)
NET CASH PROVIDED BY FINANCING ACTIVITIES	6,547	71,141	2,634
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(37,793)	46,944	—
CASH AND CASH EQUIVALENTS—BEGINNING OF YEAR	46,945	1	1
CASH AND CASH EQUIVALENTS—END OF YEAR	$ 9,152	$ 46,945	$ 1

SUPPLEMENTAL CASH FLOW INFORMATION AND DISCLOSURES OF NON-CASH TRANSACTIONS

	Year Ended December 31,		
	2008	2007	2006
		(in thousands)	
Non-cash capital contributions (1)	$344,613	$188,082	$145,853

(1) Amounts represent equity losses of affiliates not funded by Cheniere.

See accompanying notes to condensed financial statements.

NOTE 1—Summary of Significant Accounting Policies

The condensed financial statements represent the financial information required by Securities and Exchange Commission Regulation S-X 5-04 for Cheniere Energy, Inc ("Cheniere").

In the condensed financial statements, Cheniere's investments in affiliates are presented under the equity method of accounting. Under this method, the assets and liabilities of affiliates are not consolidated. The investments in net assets of the affiliates are recorded in the balance sheets. The loss from operations of the affiliates is reported on a net basis as equity in net losses of affiliates.

A substantial amount of Cheniere's operating, investing, and financing activities are conducted by its affiliates. The condensed financial statements should be read in conjunction with Cheniere's consolidated financial statements.

NOTE 2—Debt

As of December 31, 2008 and 2007, our long-term debt consisted of the following (in thousands):

	December 31,	
	2008	2007
Convertible Senior Unsecured Notes	$325,000	$325,000
Long-Term Note—Affiliate	401,308	391,708
Total Long-Term Debt	$726,308	$716,708

Below is a schedule of future principal payments that we are obligated to make on our outstanding long-term debt at December 31, 2008 (in thousands):

	Payments Due for Years Ended December 31,				
	Total	2009	2010 to 2011	2012 to 2013	Thereafter
Convertible Senior Unsecured Notes	$325,000	$ —	$ —	$325,000	$ —
Long-Term Note-Affiliate	401,308	—	—	—	401,308
Total	$726,308	$ —	$ —	$325,000	$401,308

Long-Term Note-Affiliate

In May 2007, we entered into a $391.7 million long-term note ("Long-Term Note-Affiliate") with Cheniere Subsidiary Holdings, LLC ("Cheniere Subsidiary"), a newly formed wholly-owned subsidiary of Cheniere. Cheniere Subsidiary received the $391.7 million net proceeds from a $400 million credit agreement entered into in May 2007. Borrowings under the Long-Term Note-Affiliate bear interest equal to the terms of Cheniere Subsidiary's credit agreement at a fixed rate of 9.75% per annum. Interest is calculated on the unpaid principal amount of the Long-Term Note-Affiliate outstanding and is payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year. The Long-Term Note-Affiliate will mature on May 31, 2012. The $391.7 million proceeds from the Long-Term Note-Affiliate were used for general corporate purposes, including our repurchase, completed during 2007, of approximately 9.2 million shares of our outstanding common stock pursuant to the exercise of the call options acquired in the issuer call spread purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes.

NOTE 3—GUARANTEES

Guarantees on Behalf of Cheniere Marketing, LLC

TUA Agreement

Cheniere Marketing, LLC, ("Cheniere Marketing"), formerly Cheniere Marketing, Inc., a wholly owned subsidiary of Cheniere, has a 20-year, firm commitment Terminal Use Agreement ("TUA") with Sabine Pass LNG, L.P. for regasification capacity at the Sabine Pass LNG receiving terminal. Cheniere Marketing must make the full contracted amount of capacity reservation fee payments under its TUA whether or not it uses any of its reserved capacity. In September 2008, Cheniere Marketing made a capacity reservation fee payment of $15 million for October, November and December of 2008. In December 2008, Cheniere Marketing made a capacity reservation fee payment of $62.7 million for the first three months of 2009. Cheniere Marketing is required to make monthly capacity reservation fee payments aggregating approximately $250 million per year for the period from January 1, 2009, through at least the third quarter of 2028. Cheniere has guaranteed Cheniere Marketing's obligations under its TUA

Marketing and Trading Guarantees

Our LNG and natural gas marketing business segment is pursuing a two-front commercial strategy focused on producing long-term recurring cash flow by capitalizing on Cheniere Marketing's reserved 2.0 Bcf/fd of regasification capacity at the Sabine Pass LNG receiving terminal. Our strategy is to remain engaged in the LNG spot market as opportunities arise, and to maintain relationships with key suppliers and market participants that we believe are candidates for entering into long term LNG cargo sales and/or the purchase of TUA capacity currently reserved by Cheniere Marketing. Many of Cheniere Marketing's natural gas purchase, sale, transportation and shipping agreements have been guaranteed by Cheniere. These contracts that have been guaranteed by Cheniere have a $18.1 million maximum potential of future payments and various expiration dates. The carrying amount of the liability related to these guaranteed contracts was zero as of December 31, 2008.

Guarantee on behalf of Sabine Pass Tug Services, LLC

In November 2006, Sabine Pass Tug Services, LLC ("Sabine Pass Tug Services") entered into a marine services agreement for three tugs with Alpha Marine Services, LLC ("Alpha Marine Services"). The initial term of the marine services agreement ends on the tenth anniversary of the service date, with Sabine Pass Tug Services having the option for two additional extension terms of five years each. This contract has been guaranteed by Cheniere for up to $5.0 million.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities 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.
(Registrant)

By: /s/ CHARIF SOUKI
Charif Souki
Chief Executive Officer, President and Chairman of the Board

Date: February 26, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ CHARIF SOUKI **Charif Souki**	Chief Executive Officer, President & Chairman of the Board (Principal Executive Officer)	February 26, 2009
/s/ DON A. TURKLESON **Don A. Turkleson**	Senior Vice President & Chief Financial Officer	February 26, 2009
/s/ JERRY D. SMITH **Jerry D. Smith**	Vice President and Chief Accounting Officer	February 26, 2009
/s/ VICKY A. BAILEY **Vicky A. Bailey**	Director	February 26, 2009
/s/ NUNO BRANDOLINI **Nuno Brandolini**	Director	February 26, 2009
/s/ KEITH F. CARNEY **Keith F. Carney**	Director	February 26, 2009
/s/ JOHN DEUTCH **John Deutch**	Director	February 26, 2009
/s/ PAUL J. HOENMANS **Paul J. Hoenmans**	Director	February 26, 2009
/s/ DAVID B. KILPATRICK **David B. Kilpatrick**	Director	February 26, 2009
/s/ JASON NEW **Jason New**	Director	February 26, 2009
/s/ D. DWIGHT SCOTT **D. Dwight Scott**	Director	February 26, 2009
/s/ J. ROBINSON WEST **J. Robinson West**	Director	February 26, 2009
/s/ WALTER L. WILLIAMS **Walter L. Williams**	Director	February 26, 2009

CORPORATE INFORMATION

Board of Directors

Vicky A. Bailey
President
Anderson Stratton
International, LLC

Nuno Brandolini
Chairman of the Board &
Chief Executive Officer
Scorpion Holdings, Inc.

Keith F. Carney
Lead Director

John M. Deutch
Institute Professor
Massachusetts Institute of
Technology

Paul J. Hoenmans
Retired Executive Vice
President
Mobil Oil Corporation

David B. Kilpatrick
President
Kilpatrick Energy Group

Jason New
Senior Managing Director
of The Blackstone Group

Donald (Dwight) Scott
Senior Managing Director
of The Blackstone Group

Charif Souki
Chairman of the Board,
Chief Executive Officer
and President

J. Robinson West
Chairman of the Board
PFC Energy

Walter L. Williams
Director , Cheniere Energy

Corporate Officers

Charif Souki
Chairman of the Board,
Chief Executive Officer
& President

Jean Abiteboul
Senior Vice President,
International

Meg A. Gentle
Senior Vice President &
Chief Financial Officer

R. Keith Teague
Senior Vice President,
Asset Group

H. Davis Thames
Senior Vice President,
Marketing

Don Turkleson
Senior Vice President

K. Scott Abshire
Vice President & Chief
Information Officer

E. Darron Granger
Vice President,
Engineering & Construction

Graham A. McArthur
Vice President & Treasurer

Albert Nahas
Vice President,
Government Affairs

Tim A. Neumann
Vice President &
General Counsel

Patricia A. Outtrim
Vice President, Government
& Regulatory Affairs

Katie L. Pipkin
Vice President,
Investor Relations

Ann E. Raden
Vice President, Human
Resources & Administration

Jerry Smith
Vice President & Chief
Accounting Officer

George Tiblier
Vice President, Tax

Anne V. Vaughan
Assistant General Counsel
& Corporate Secretary

Michael A. Wortley
Vice President,
Strategic Planning

Contacts & Advisors

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Independent Accountants
Ernst & Young, LLP
Houston, Texas

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