CHENIERE ENERGY INC
Form 10-K
February 26, 2010

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

Form 10-K

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

For the fiscal year ended December 31, 2009

OR

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

For the transition period from to

Commission File No. 001-16383

CHENIERE ENERGY, INC.
(Exact name 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 Amex Equities |
| (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 x

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 x

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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 x Non-accelerated filer ¨ Smaller reporting company ¨
(Do not check if a 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 x

The aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $158,000,000 as of June 30, 2009.

57,258,053 shares of the registrant's Common Stock were outstanding as of February 17, 2010.

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 or refinancing or recapitalization 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 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. 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;
- 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. (NYSE Amex Equities: LNG), a Delaware corporation, is a Houston-based energy company primarily engaged in LNG-related businesses. We own and operate the Sabine Pass LNG receiving terminal in Louisiana through our 90.6% ownership interest in and management agreements with Cheniere Energy Partners, L.P. (“Cheniere Partners”) (NYSE Amex Equities: CQP), which is a publicly traded partnership we created in 2007. We also own and operate the Creole Trail Pipeline, which interconnects the Sabine Pass LNG receiving terminal with downstream markets. One of our subsidiaries, Cheniere Marketing, LLC (“Cheniere Marketing”), is marketing LNG and natural gas and is developing a portfolio of contracts to monetize capacity at the Sabine Pass LNG receiving terminal and the Creole Trail Pipeline. We own 30% of the limited partnership interests of Freeport LNG Development, L.P. (“Freeport LNG”), which operates the Freeport LNG receiving terminal. We are also in various stages of developing other LNG receiving terminal and pipeline related projects, which, among other things, will require acceptable commercial arrangements before we make a final investment decision. In addition, we are engaged to a limited extent in oil and natural gas exploration and development activities in the Gulf of Mexico. Unless the context requires otherwise, references to the “Company”, “Cheniere”, “we”, “us” and “our” refer to Cheniere Energy, Inc. and subsidiaries, including our publicly traded subsidiary partnership, Cheniere Partners.

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

In addition to safely maintaining the operations of the Sabine Pass LNG receiving terminal and Creole Trail Pipeline, our primary business strategy is to monetize the 2.0 Bcf/d of regasification capacity at the Sabine Pass LNG receiving terminal held by Cheniere Marketing by entering into long-term TUAs, developing a portfolio of long-term, short-term and spot LNG purchase agreements, and 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.  In addition, our long-term strategy is to develop and construct additional LNG receiving terminals and natural gas pipelines and related infrastructure when market and financial conditions are favorable.

Our ability to successfully execute our business strategies will be impacted by many factors, including the balance of worldwide supply and demand for natural gas and LNG, the relative prices for natural gas in North America and international markets, the willingness of LNG producers and international LNG buyers to invest new capital and secure access to North American natural gas markets on a long-term basis, and access to capital to market our portfolio of natural gas and LNG and to develop and construct future LNG receiving terminal, pipeline and other infrastructure projects.  We believe that North American natural gas prices support long-term profitability for LNG production.  Although we believe that we will have sufficient cash on hand and cash generated from operations to fund our operating expenses and other cash requirements until our long-term debts first become due as early as August 2011 (as lenders of the 2008 Convertible Loans due in 2018 can require prepayment of the loans in August 2011, 2013, and 2015), if there is insufficient demand for our LNG receiving terminal services, our ability to satisfy our long-term debts thereafter will be limited absent a restructuring of our finances, which may include issuing new debt, issuing equity securities, selling assets or a combination thereof. See Item 1A, "Risk Factors."

Corporate Structure

In 2007, we contributed the equity interests in the entity owning the Sabine Pass LNG receiving terminal to Cheniere Partners and completed a public offering of 15,525,000 Cheniere Partners common units. As a result of the public offering, our ownership interest in Cheniere Partners is approximately 90.6%. As of December 31, 2009, we held 135,383,831 subordinated units, 10,891,357 common units and 3,302,045 general partner units of Cheniere Partners. Although results are consolidated for financial reporting, we and Cheniere Partners operate with independent capital structures. As such, cash flow available to us from Cheniere Partners is primarily in the form of cash distributions declared and paid to us on our limited and general partner interests and management fees. We received cash distributions and management fees from Cheniere Partners of $299.6 million, $19.4 million and $10.0 million in the years ended December 31, 2009, 2008 and 2007. These cash distributions from Cheniere Partners were primarily used by Cheniere Marketing to make its TUA payments to the Sabine Pass LNG receiving terminal and to fund operations.

The following diagram depicts our ownership of Cheniere Partners; Sabine Pass LNG, L.P., our majority owned subsidiary ("Sabine Pass"); Freeport LNG; Creole Trail Pipeline, L.P.; and Cheniere Marketing as of December 31, 2009:

Business Segments

Our business activities are conducted by three operating segments for which we provide information in our consolidated financial statements for the years ended December 31, 2009, 2008 and 2007. These three segments are our:

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

For information about our segments' revenues, profits and losses and total assets, see Item 8. Financial Statements and Supplementary Data—Note 25—"Business Segment Information" of our Notes to Consolidated Financial Statements.

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, which during 2009 completed construction of and is currently operating 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, Freeport LNG, located on Quintana Island near Freeport, Texas.

Sabine Pass LNG Receiving Terminal

We have constructed and are operating 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 long-term 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 a regasification capacity of approximately 4.0 Bcf/d (with peak capacity of 4.3 Bcf/d) and aggregate LNG storage capacity of 16.9 Bcf. Construction at the Sabine Pass LNG receiving terminal was substantially completed in the third quarter of 2009. As of December 31, 2009, we had completed construction and attained full operability of the Sabine Pass LNG receiving terminal, and such was accomplished within our budget.

Customers

The entire approximately 4.0 Bcf/d of regasification capacity at the Sabine Pass LNG receiving terminal 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. Capacity reservation fee TUA payments are made by our third-party TUA customers as follows:

- Total Gas and Power North America, Inc. (formally known as 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 that commenced 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 that commenced July 1, 2009. Chevron Corporation has guaranteed Chevron’s obligations under its TUA up to 80% of the fees payable by Chevron.

Our wholly-owned subsidiary, 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 capacity reservation fee payments in the fourth quarter of 2008. Cheniere Marketing is required to make capacity payments aggregating approximately $250 million per year for the period from January 1, 2009 through at least September 30, 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 $20.0 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 reservation 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, if constructed, would be 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. Preliminary site work has 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 approximately 3.3 Bcf/d, four LNG storage tanks with an aggregate LNG storage capacity of approximately 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 1.55 Bcf/d (with peak capacity of 1.75 Bcf/d), one dock, two LNG storage tanks with an aggregate LNG storage capacity of 6.7 Bcf, and a 9.6-mile, 42-inch diameter pipeline through which natural gas is 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 1.15 Bcf/d (with peak capacity of 1.75 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 the years ended December 31, 2009 and 2008, Freeport LNG distributed $15.3 million and $4.8 million to us, respectively.

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 December 17, 2009, there were twelve 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, 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 laws. These laws require that we engage in consultations with appropriate federal and state agencies and that we obtain and maintain applicable 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. Through construction, commissioning and operations, we have been in substantial compliance with all regulations discussed herein.

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 amended the NGA to prohibit market manipulation. The EPAct increased civil and criminal penalties for any violations of the NGA, the Natural Gas Policy Act of 1978 (“NGPA”) and any rules, regulations or orders of the FERC up to $1.0 million per day per violation. In accordance with the EPAct, 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 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 are also 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 are also 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 and 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. Mandatory reporting requirements were promulgated by the EPA and finalized on October 30, 2009. This rule requires mandatory reporting for greenhouse gases from stationary fuel combustion sources. An additional section would have required reporting for all fugitive emissions throughout LNG receiving terminals and would have impacted our reporting requirements; however, this section was deferred in the final rule. 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.

Coastal Zone Management Act (CZMA)

Our LNG receiving terminals are subject to the requirements of the CZMA throughout the construction of facilities located within the coastal zone. The CZMA is administered by the states (in Louisiana by the Department of Natural Resources, in Texas, by the Railroad Commission and the General Land Office). This program is implemented in coordination with the Department of the Army construction permitting process to ensure that impacts to coastal areas are consistent with the intent of the CZMA to manage the coastal areas.

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.

National Historic Preservation Act (NHPA)

Our LNG receiving terminal construction activities are subject to requirements under Section 106 of NHPA. The NHPA requires projects to take into account the effects of their actions on historic properties. These programs are administered by the State Historic Preservation Officer (SHPO). Any areas where ground disturbance will occur are required to be reviewed by the affected SHPOs.

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 new 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

The 153-mile 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.

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 $549 million, before financing costs.

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

Cheniere Marketing and other third parties have entered into interruptible transportation agreements with Creole Trail Pipeline. Firm transportation capacity of 2.0 Bcf/d is available to all qualified shippers, including customers with whom we enter into TUAs for our LNG receiving terminal capacity and who may also desire to enter into agreements for transportation 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

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, Louisiana and Arkansas. The Cheniere Southern Trail Pipeline could supply Florida with natural gas needed to supply the growth that 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 and improving natural gas supply security for Florida and the remainder of the Southeastern U.S.

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. 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 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 interstate and/or intrastate 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 has built 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. In addition, under the NGA, we are not permitted to unduly discriminate or grant undue preference as to our rates or the terms and conditions of service. The FERC has 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, the 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.

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.

In 2009, the U.S. Department of Transportation issued a final rule (known as "Control Room Management Rule") requiring pipeline operators to institute certain control room procedures that address human factors and alarm management. Prior to start-up of the pipeline, Cheniere developed written Control Room Operating Procedures consistent with the then-proposed rule. We are reviewing the manual to assure full compliance with the final rule. We are required to develop the procedures by August 1, 2011 and to implement the procedures by February 1, 2012.

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."

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 engaged in the LNG and natural gas marketing business and is seeking to monetize the 2.0 Bcf/d of regasification capacity at the Sabine Pass LNG receiving terminal which is its principal asset. Cheniere Marketing is seeking to enter into long-term TUAs; 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.

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In 2009, Cheniere Marketing began purchasing, transporting and unloading commercial LNG cargos into the Sabine Pass LNG receiving terminal and has used certain hedging strategies to maximize margins on these cargos. In addition, Cheniere Marketing has continued to enter into various business relationships to facilitate importing commercial LNG cargos.

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. However, our prior business focus was on oil and gas exploration, development and exploitation, and we have retained certain oil and gas 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, 2009, we had interests in 13 active wells, including 3 working interests and 13 overriding royalty interests. Three wells have both a working and overriding royalty interest. There are no plugging and abandonment costs expected in 2010. 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.

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 and Labor Relations

We had 196 full-time employees at February 17, 2010, including 98 employees who directly supported Sabine Pass LNG's operations. We consider our current employee relations to be favorable.

Available Information

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.

We will also make available to any stockholder, without charge, copies of our Annual Report on Form 10-K as filed with the SEC. For copies of this, or any other filing, please contact: Cheniere Energy, Inc., Investor Relations Department, 700 Milam Street, Suite 800, Houston, Texas 77002 or call (713) 562-5000. In addition, the public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers, like us, that file electronically with the SEC.

## 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

Our existing level of cash resources, negative operating cash flow, and debt could cause us to have inadequate liquidity and could materially and adversely affect our business, financial condition and prospects

As of December 31, 2009, we had $88.4 million of cash and cash equivalents and $221.2 million of restricted cash and cash equivalents and we had $3.1 billion of total debt outstanding on a consolidated basis (before debt discounts). Our ability to generate positive cash flow and achieve profitability, so as to enhance our liquidity position in the future and be able to repay or refinance our debt, is subject to a number of risks, including those discussed in these Risk Factors.

We have a significant amount of debt which we may be unable to repay, refinance, or extend on commercially reasonable terms or at all, which could materially and adversely affect our business, financial condition and prospects.

As of December 31, 2009, we had $3.1 billion of total consolidated indebtedness (before debt discounts). Approximately $250 million of our debt plus accrued interest, which is accruing at our option in lieu of cash interest payments at a rate of 12% per year, will mature at the election of the lenders on August 15, 2011, our earliest potential debt maturity date. We do not currently have financial resources, and may not be able to access external financial resources, sufficient to enable us to repay our earliest maturing debt or our subsequently maturing debt. If we are unable to refinance, extend or otherwise satisfy our earliest maturing debt, we may seek to reorganize under the protection of available reorganization statutes, and may make such a determination at a time prior to our earliest potential debt maturity date.

Even if we are able to repay, refinance, or extend our debt, 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, debt issuances, or extensions of debt maturities 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;

- offerings of our equity securities could cause substantial dilution for holders of our common stock and Series B Preferred Stock;

- additional sales of interests in our projects would reduce our interest in future revenues; and

- the prepayment of terminal use fees by, or a business development loan from, prospective customers would reduce future revenues once an LNG receiving terminal commence operations.

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:

- limiting our ability to attract customers;
- limiting our ability to compete with other companies that are not as highly leveraged;
- limiting our flexibility in and ability to plan for or react to changing market conditions in our industry and to economic downturns, and making us more vulnerable than our less leveraged competitors to an industry or economic downturn;
- 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 obtain additional financing to fund our capital expenditures, working capital, acquisitions, debt service requirements or liquidity needs for general business or other purposes; 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.

If we are unsuccessful in operating our business due to our substantial indebtedness or other factors, we may be unable to repay, refinance, or extend our indebtedness on commercially reasonable terms or at all.

We have not been profitable historically, and we have not had positive 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 $161.5 million and $373.0 million (as adjusted) for the years ended December 31, 2009 and 2008, respectively. Additionally, our net cash flow used in operating activities was $97.9 million and $142.1 million for the years ended December 31, 2009 and 2008, respectively.  In the future, we may incur operating losses and experience negative operating cash flow.  We may not be able to reduce costs, increase revenues, or reduce our debt service obligations sufficient to maintain our cash resources which could cause us to have inadequate liquidity to continue our business.

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. 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 respective 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 and 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 wholly owned 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.

Risks Relating to Our LNG Receiving Terminal Business

Operation of the Sabine Pass LNG receiving terminal, and other LNG receiving terminals that we may construct, involves significant risks.

The Sabine Pass LNG receiving terminal faces operational risks, including the following:

- 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.

To maintain the cryogenic readiness of the Sabine Pass LNG receiving terminal or to commission and test our proposed LNG receiving terminals, 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 be maintained in a state of cryogenic readiness for conducting operations and to provide services under our TUAs. Our failure to obtain LNG, LNG vessels, or both, on economical terms, or our inability to finance the purchase of LNG, could provide our TUA customers with the opportunity to interrupt or terminate their payment under their respective TUAs. Any of these occurrences could have a material adverse effect on our business, results of operations, financial condition and prospects.

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.

For our proposed LNG receiving terminals, LNG storage tanks and other equipment 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. We usually include in our construction cost estimates 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.

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 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.

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, or interruption of operations at, the Sabine Pass LNG receiving terminal or related infrastructure, as well as delays or cost increases in construction of our proposed LNG receiving terminals. If there are changes in the global climate, storm frequency and intensity may increase; should it result in rising seas, our coastal operations would be impaired.

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 operations and construction 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 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, and additional approval and permit requirements may be imposed. 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.

We may not be able to enter into satisfactory TUAs with third-party customers for regasification capacity at our proposed LNG receiving terminals, as has been our historical practice. We may change our business strategy regarding 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, and we may experience difficulty attracting additional customers.

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 and adversely affected.

Risks Relating to Our Natural Gas Pipeline Business

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.

Our 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 $1.0 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.

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 are required to maintain 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.

Any reduction in the capacity of, or the allocations to, interconnecting, third-party pipelines could cause a reduction of volumes transported in our 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.

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

We do not own the land on which our pipelines are situated, and we are subject to the possibility of increased costs to retain necessary land use rights. If we were to lose these rights or be required to relocate our pipelines, our business could be materially and adversely affected.

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's business plan may be limited by access to capital and its lack of a credit rating. In addition, Cheniere Energy, Inc. has 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 all of 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 our business, results of operations, financial condition, prospects and liquidity.

We have not yet fully commercialized our LNG receiving capacity at the Sabine Pass LNG receiving terminal

We continue to develop our LNG and natural gas marketing business.  The ability of our LNG and natural gas marketing business to utilize all of our 2.0 Bcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal will depend upon whether we can successfully enter into TUAs for some or all of our reserved capacity, enter into term LNG purchase agreements from our reserved capacity, or purchase spot cargoes. 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, and timing risk associated with the marketing of LNG and natural gas, we use futures, swaps and option contracts traded or cleared on the Intercontinental Exchange (ICE) and NYMEX, or 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.

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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 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 also currently has limited access to third-party sources of financing. Other investment-grade marketing companies have greater financial resources than we do. Our LNG and natural gas marketing business continues to develop and implement its business strategy and may not generate sufficient revenues and cash flows to cover the significant fixed costs of the 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 and 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 internationally and delivered to North America 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 alternative energy sources 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.

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.

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 and 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.

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 Group plc, BP plc, Chevron Corporation, 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.

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 require 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.

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 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 facilities 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 businesses, 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 LNG receiving terminals and pipelines 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 pipelines 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.

There are numerous regulatory approaches currently in effect or being considered to address greenhouse gases, including possible future U.S. treaty commitments, new federal or state legislation that may impose a carbon emissions tax or establish a cap-and-trade program, and regulation by the EPA. 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 the Sabine Pass LNG receiving terminal, this carbon tax may also be imposed on us directly.

There have also been proposals for a mandatory cap and trade program to reduce greenhouse gas emissions. In June 2009, the U.S. House of Representatives passed a comprehensive climate change and energy bill, the American Clean Energy and Security Act, and the U.S. Senate is considering similar legislation that would, among other things, impose a nationwide cap on greenhouse gas emissions and require major sources to obtain “allowances” to meet that cap. In September 2009, the EPA promulgated a rule requiring certain emitters of greenhouse gases to monitor and report their greenhouse gas emissions to the EPA. In addition, in response to the 2007 U.S. Supreme Court ruling in Massachusetts v. EPA that the EPA has authority to regulate carbon dioxide emissions under the Clean Air Act, the EPA has issued and is considering several additional proposals, including one that would require best available control technology for greenhouse gas emissions whenever certain stationary sources are built or significantly modified. In addition, two U.S. federal appeals courts have reinstated lawsuits permitting individuals, state attorneys general and others to pursue claims against major utility, coal, oil and chemical companies on the basis that those companies have created a public nuisance due to their emissions of carbon dioxide. Climate change initiatives and other efforts to reduce greenhouse gas emissions like those described above or otherwise may require additional controls on the operation of our LNG receiving terminals and increased costs to implement and maintain such controls.

Other future legislation and regulations, such as those relating to the transportation and security of LNG imported to the Sabine Pass LNG receiving terminal through the Sabine Pass Channel, could cause additional expenditures, restrictions and delays in our business and to our proposed 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 and operate our 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 and 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 2010 will be dependent upon one facility, the Sabine Pass LNG receiving terminal and related pipeline located in southern Louisiana. Due to our lack of asset and geographic diversification, an adverse development at the Sabine Pass LNG receiving terminal or pipeline, 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.

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 consolidated financial statements.

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 incur impairments to goodwill or long-lived assets.

We review our long-lived assets, including goodwill and other intangible assets, for impairment annually in the fourth quarter or whenever events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. Significant negative industry or economic trends, including a significant decline in the market price of our common stock, reduced estimates of future cash flows for our business segments or disruptions to our business could lead to an impairment charge of our long-lived assets, including goodwill and other intangible assets. Our valuation methodology for assessing impairment requires management to make judgments and assumptions based on historical experience and to rely heavily on projections of future operating performance. Projections of future operating results and cash flows may vary significantly from results. In addition, if our analysis results in an impairment to our goodwill, we may be required to record a charge to earnings in our consolidated financial statements during a period in which such impairment is determined to exist, which may negatively impact our results of operations.

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.

We believe that significantly less than 40% of our assets consist of investment securities. However, if in the future the value of our investment assets, including 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.

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, 2009, 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 FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock has traded on the NYSE Amex Equities 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 Amex Equities, for each quarter during 2008 and 2009.

| | High | Low |
|---|---|---|
| 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 |
| Three Months Ended | | |
| March 31, 2009 | $4.98 | $3.01 |
| June 30, 2009 | 5.19 | 2.71 |
| September 30, 2009 | 3.47 | 2.50 |
| December 31, 2009 | 2.95 | 1.80 |

As of February 17, 2010, we had 57,258,053 million shares of common stock outstanding held by approximately 339 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 twelve months ended December 31, 2009, we purchased 428,728 shares of restricted stock at an average cash price of $2.33 per share related to restricted stock vested during 2009 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, 2009. 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, 2004 and that any dividends were fully reinvested.

| Company / Index | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|
| Cheniere Energy, Inc. | $117 | $91 | $102 | $9 | $8 |
| Russell 2000 Index | $105 | $124 | $122 | $81 | $103 |
| S&P Oil & Gas Exploration & Production | $166 | $174 | $252 | $165 | $234 |

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) | | | | |
|---|---|---|---|---|---|
| | 2009 | 2008 (as adjusted) | 2007 (as adjusted) | 2006 (as adjusted) | 2005(6) (as adjusted) |
| Revenues | $181,126 | $7,144 | $647 | $2,371 | $3,005 |
| LNG terminal and pipeline development expenses | 223 | 10,556 | 34,656 | 12,099 | 22,020 |
| LNG terminal and pipeline operating expenses | 36,857 | 14,522 | — | — | — |
| Exploration costs | — | 128 | 1,116 | 3,138 | 2,839 |
| Depreciation, depletion and amortization | 54,229 | 24,346 | 6,393 | 3,131 | 1,325 |
| General and administrative expenses (1) | 65,830 | 122,678 | 122,046 | 58,012 | 29,145 |
| Restructuring charges (2) | 20 | 78,704 | — | — | — |
| Income (loss) from operations | 23,496 | (244,188) | (163,940) | (75,874) | (52,561) |
| Loss from equity method investments | — | (4,800) | (191) | — | (1,031) |
| Gain on sale of investment in unconsolidated affiliate (3) | — | — | — | — | 20,206 |
| Gain (loss) on early extinguishment of debt (4) | 45,363 | (10,691) | — | (43,159) | — |
| Derivative gain (loss) (5) | 5,277 | 4,652 | — | (20,070) | 837 |
| Interest expense, net | (243,295) | (147,136) | (119,360) | (67,252) | (22,490) |
| Interest income | 1,405 | 20,337 | 82,635 | 49,087 | 17,520 |
| Non-controlling interest | 6,165 | 8,777 | 3,425 | — | 97 |
| Net loss | (161,490) | (372,959) | (196,580) | (159,137) | (34,655) |
| Net loss per share (basic and diluted) (6) | $(3.13) | $(7.87) | $(3.89) | $(2.92) | $(0.65) |
| Weighted average shares outstanding (basic and diluted) (6) | 51,598 | 47,365 | 50,537 | 54,423 | 53,097 |

| | December 31, | | | | |
|---|---|---|---|---|---|
| | 2009 | 2008 (as adjusted) | 2007 (as adjusted) | 2006 (as adjusted) | 2005(6) (as adjusted) |
| Cash and cash equivalents | $88,372 | $102,192 | $296,530 | $462,963 | $692,592 |
| Restricted cash and cash equivalents (current) | 138,309 | 301,550 | 228,085 | 176,827 | 161,561 |
| Working capital | 220,063 | 350,459 | 427,511 | 588,034 | 810,141 |
| Non-current restricted cash and cash equivalents | 82,892 | 138,483 | 478,225 | 1,071,722 | 16,500 |
| Non-current restricted U.S. Treasury securities | — | 20,829 | 63,923 | — | — |
| Property, plant and equipment, net | 2,216,855 | 2,170,158 | 1,645,112 | 748,818 | 280,106 |
| Debt issuances costs, net | 47,043 | 55,688 | 41,449 | 38,422 | 39,317 |

| | | | | | |
|---|---|---|---|---|---|
| Goodwill | 76,819 | 76,844 | 76,844 | 76,844 | 76,844 |
| Total assets | 2,732,622 | 2,920,082 | 2,959,743 | 2,601,365 | 1,286,456 |
| Long-term debt, net of discount | 2,692,740 | 2,750,308 | 2,657,579 | 2,242,209 | 788,857 |
| Long-term debt—related parties, net of discount | 349,135 | 332,054 | — | — | — |
| Long-term deferred revenue | 33,500 | 37,500 | 40,000 | 41,000 | 41,000 |
| Total liabilities | 3,164,749 | 3,194,136 | 2,879,317 | 2,346,450 | 892,963 |
| Total stockholders' equity (deficit) | $(649,732 ) | $(524,216 ) | $(205,249 ) | $254,915 | $393,493 |

(1) General and administrative expenses include $19.2 million, $55.0 million, $56.6 million, $20.2 million and $3.6 million share-based compensation expense recognized in the years ended December 31, 2009, 2008, 2007, 2006 and 2005, respectively.

(2) 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).

(3) 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.

(4) Amount in 2009 relates to gains on the termination of $120.4 million of our Convertible Senior Unsecured Notes. Amount in 2008 relates to losses on the termination of the $95.0 million 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 19—"Long-Term Debt and Long-Term Debt—Related Parties" of our Notes to Consolidated Financial Statements.

(5) 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.
(6) 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.
(7) Amounts reported for the years ended December 31, 2005 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 Significant 2009 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
- Recent Accounting Standards

### Overview of Business

We own and operate the Sabine Pass LNG receiving terminal in Louisiana through our 90.6% ownership interest in and management agreements with Cheniere Energy Partners, L.P. ("Cheniere Partners"), which is a publicly traded partnership we created in 2007. We also own and operate the Creole Trail Pipeline, which interconnects the Sabine Pass LNG receiving terminal with downstream markets. One of our subsidiaries, Cheniere Marketing, LLC ("Cheniere Marketing"), is marketing liquefied natural gas ("LNG") and natural gas and is developing a portfolio of contracts to monetize capacity at the Sabine Pass LNG receiving terminal and the Creole Trail Pipeline. We own 30% of the limited partnership interests of Freeport LNG Development, L.P. ("Freeport LNG"), which operates the Freeport LNG receiving terminal. We are also in various stages of developing other LNG receiving terminal and pipeline related projects, which, among other things, will require commercial justification before we make a final investment decision. In addition, we are engaged to a limited extent in oil and natural gas exploration and development 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, 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 Partners. Cheniere Partners owns a 100% interest in Sabine Pass LNG, L.P. ("Sabine Pass LNG"), which has constructed 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 achieved 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 16.9 Bcf during the third quarter of 2009. Sabine Pass LNG has entered into long-term terminal use agreements (“TUAs”) with Total Gas and Power North America, Inc. (formerly known as Total LNG USA, Inc.) (“Total”), Chevron U.S.A., Inc. (“Chevron”) and Cheniere Marketing for the entire 4.0 Bcf/d of regasification capacity that is now available at the Sabine Pass LNG receiving terminal upon completion of construction.

We will contemplate making final investment decisions to construct the Corpus Christi LNG receiving terminal and 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 a 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, 2009, 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 will be developed once we have entered into acceptable commercial and acceptable financing arrangements. 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 Significant 2009 Events

Our significant accomplishments during 2009, some of which may also impact future years, include the following:

- we completed construction and achieved 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 16.9 Bcf of aggregate storage capacity;

- Sabine Pass LNG received capacity reservation fee payments from Cheniere Marketing, our wholly owned subsidiary, Total and Chevron and successfully unloaded and processed LNG for each customer;

- Cheniere Marketing successfully purchased, transported and unloaded commercial LNG cargos into the Sabine Pass LNG receiving terminal and sold resultant natural gas;

- we reduced debt by exchanging $120.4 million aggregate principal amount of our 2¼% Convertible Senior Unsecured Notes due 2012 (“Convertible Senior Unsecured Notes”) for a combination of $30.0 million cash and cash equivalents and 4.0 million shares of our common stock, reducing our principal amount due in 2012 to $204.6 million, at December 31, 2009; and

- we began receiving limited partner distributions from Freeport LNG.

Liquidity and Capital Resources

Although results are consolidated for financial reporting, Cheniere, Sabine Pass LNG and Cheniere Partners operate with independent capital structures. See “Items 1 and 2. Business and Properties—Corporate Structure.”. Since the inception of both Sabine Pass LNG and Cheniere Partners, the cash needs of each entity have been met with a combination of borrowings, issuance of units and operating cash flows. We expect the cash needs for Sabine Pass LNG and Cheniere Partners over the next 12 months will be met through operating cash flows. With respect to Cheniere, we have historically satisfied cash needs by utilizing existing unrestricted cash, management fees from Sabine Pass LNG and Cheniere Partners, distributions from our investment in Cheniere Partners, distributions from our 30% investment in Freeport LNG and operating cash flows from our pipeline and LNG and natural gas marketing businesses. Below is a table that presents unrestricted and restricted cash for each portion of our capital structure as of December 31, 2009:

| (in thousands) | Sabine Pass LNG, L.P. | Cheniere Energy Partners, L.P. | Other Cheniere Energy, Inc. | Consolidated Cheniere Energy, Inc. |
|---|---|---|---|---|
| Cash and cash equivalents | $ — | $ — | $ 88,372 | $ 88,372 |
| Restricted cash and cash equivalents | 213,537 | 130 | 7,534 | 221,201 |
| Total | $ 213,537 | $ 130 | $ 95,906 | $ 309,573 |

As of December 31, 2009, we had unrestricted cash and cash equivalents of $88.4 million that was available to Cheniere (excluding Cheniere Partners and Sabine Pass LNG). In addition, we had restricted cash and cash equivalents of $221.2 million, which were designated for the following purposes: $117.4 million for Sabine Pass LNG’s working capital; $96.1 million for interest payments related to the Senior Notes described below; and $7.7 million for other restricted purposes. In addition, as of December 31, 2009, we expected to receive in 2010 approximately $50 million as a result of monetizing our LNG inventory and approximately $9 million from margin accounts held by Cheniere Marketing (see discussion regarding LNG and natural gas marketing business below).

We believe that we have sufficient cash, other working capital and cash generated from our operations (excluding the sources and uses of capital by Sabine Pass LNG and Cheniere Partners) to fund Cheniere’s operating expenses and other cash requirements until at least the earliest date when principal payments may be required on our existing indebtedness, which is August 2011. Before such time, we will need to restructure our finances and improve our capital structure, which may be accomplished by entering into long-term TUAs or LNG purchase agreements, refinancing our existing indebtedness, issuing equity or other securities, selling assets or a combination of the foregoing.

Our ability to enhance near-term liquidity and improve our capital structure is dependent on numerous factors, including the availability of credit, the balance of worldwide and domestic supply and demand for natural gas and LNG, and the relative prices for natural gas in North America and international markets. As further described in "Item 1A. Risk Factors" we face numerous financial, market and operational risks in connection with improving our liquidity situation, many of which are beyond our control.

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. 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% (we hold 135,383,831 subordinated units, 10,891,357 common units and 3,302,045 general partner units of Cheniere Partners). Cheniere Partners owns a 100% interest in Sabine Pass LNG, which is operating the Sabine Pass LNG receiving terminal.

For each calendar year, Cheniere Partners is expected to make annual distributions of $1.70 per unit on all outstanding common units, subordinated units and general partner units. 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 on the subordinated and general partner units, of which we own 100%, so long as we, through Cheniere Marketing, make TUA payments to Sabine Pass LNG.

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, as well as other conditions. If the coverage test is not met, we may not receive distributions. The fixed charge coverage ratio test was met for the periods through December 31, 2009, and distributions in the amount of $295.7 million have been made during the year ended 2009, from Sabine Pass LNG to Cheniere Partners. Cheniere Partners utilized the cash received from Sabine Pass LNG to pay expenses and make distributions. Cheniere Partners has made distributions of $280.7 million in the aggregate to us and its other unitholders during the year ended 2009.

A distribution reserve account was established from proceeds of Cheniere Partners' initial public offering to pay distributions to the common unitholders and general partner to the extent unrestricted cash was not sufficient. Sabine Pass LNG began making distributions from unrestricted cash in February 2009. In August 2009, $34.9 million of remaining funds in the distribution reserve account was distributed by Cheniere Partners to us pursuant to the terms of the Cheniere Partners partnership agreement. These distributed funds were included as unrestricted cash and cash equivalents on the December 31, 2009 Consolidated Balance Sheet.

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

Construction at the Sabine Pass LNG receiving terminal was substantially completed in the third quarter of 2009. As of December 31, 2009, we had completed construction and attained 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 16.9 Bcf of aggregate storage capacity), and such was accomplished within our budget.

The entire approximately 4.0 Bcf/d of regasification capacity at the Sabine Pass LNG receiving terminal 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. Capacity reservation fee TUA payments are made by our third-party TUA customers as follows:

- Total Gas and Power North America, Inc. (formerly known as 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 that commenced 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 that commenced July 1, 2009. Chevron Corporation has guaranteed Chevron's obligations under its TUA up to 80% of the fees payable by Chevron.

In addition, our wholly-owned subsidiary, 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 capacity reservation fee payments in the fourth quarter of 2008. Cheniere Marketing is required to make capacity payments aggregating approximately $250 million per year for the period from January 1, 2009 through at least September 30, 2028. Cheniere has guaranteed Cheniere Marketing's obligations under its TUA.

Under each of these TUAs, Sabine Pass LNG is 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 previously paid us $20.0 million in nonrefundable advance capacity reservation fees, which are being amortized over a 10-year period as a reduction of each customer's regasification capacity reservation fees payable under its respective TUA.

Other LNG Receiving Terminals

We have a 30% limited partner interest in Freeport LNG. In the year ended December 31, 2009, Freeport LNG made aggregate distributions to us of $15.3 million. We expect to continue receiving distributions from Freeport LNG as they are approved by the board of directors of Freeport LNG's general partner.

We will contemplate making final investment decisions to construct our Corpus Christi and Creole Trail LNG receiving terminal projects upon, among other things, entering into acceptable commercial and financing arrangements for the applicable project. We do not expect to spend significant funds on these projects in the near-term.

Natural Gas Pipeline Business

As of December 31, 2009, Phase 1 of the Creole Trail Pipeline, consisting of 94 miles of natural gas pipeline, had been constructed and placed into commercial operations. As discussed above, we believe that we have sufficient cash and other working capital to operate Phase 1 of our Creole Trail Pipeline until at least the earliest date when principal payments may be required on our existing indebtedness, which is August 2011.

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 and financing arrangements for the applicable project. We do not expect to spend significant funds on these projects in the near-term.

LNG and Natural Gas Marketing Business

During the twelve months ended December 31, 2009, Cheniere Marketing successfully purchased, transported, and unloaded LNG at the Sabine Pass LNG receiving terminal on a spot basis and entered into derivative contracts to hedge the cash flows from the future sales of this LNG inventory.

The accounting treatment for LNG inventory differs from the treatment for derivative positions such that the economics of Cheniere Marketing's activities are not transparent in the consolidated financial statements until all LNG inventory is sold and derivative positions are settled. Our LNG inventory is recorded as an asset at cost and is subject to lower of cost or market ("LCM") adjustments at the end of each reporting period. The LCM adjustment market price is based on period-end natural gas spot prices, and any gain or loss from a LCM adjustment is recorded in our earnings at the end of each period. Revenue and cost of goods sold are not recognized in our earnings until the regasified LNG is sold. Our unrealized derivatives positions at the end of each period extend into the future to hedge the cash flow from future sales of our LNG inventory. These positions are measured at fair value, and we record the gains and losses from the change in their fair value currently in earnings. Thus, earnings from changes in the fair value of our derivatives may not be offset by losses from LCM adjustments to our LNG inventory because the LCM adjustments that may be made to LNG inventory are based on period-end spot prices that are different from the time periods of the prices used to fair value our derivatives. Any losses from changes in the fair value of our derivatives will not be offset by gains until the regasified LNG is actually sold.

Management evaluates the performance of its LNG and natural gas marketing business activities differently than the measure calculated and presented in accordance with GAAP in our Consolidated Statement of Operations. Management calculates an Adjusted LNG and natural gas revenue non-GAAP measure to assess the performance of the LNG and natural gas marketing business activities during each period. As our LNG and natural gas marketing business has entered into natural gas swaps that hedge the cash flows from the future sale of LNG inventory, management believes that the presentation of the Adjusted LNG and natural gas revenue non-GAAP measure provides a meaningful indicator of the performance of our LNG and natural gas marketing business activities during the stated period.

The table below shows (in thousands) the differences between the components of both the LNG and natural gas marketing revenue GAAP measure (presented in our Consolidated Statement of Operations) and the Adjusted LNG and natural gas revenue non-GAAP measure:

| | For the Year Ended December 31, 2009 | | | |
|---|---|---|---|---|
| | LNG and natural gas marketing revenue (GAAP measure) | Adjusted LNG and natural gas marketing revenue (Non-GAAP measure) | Difference | |
| Physical natural gas sales | $ 6,146 | $ 6,146 | $ — | |
| Cost of LNG | (3,850) | (38,218) | 34,368 | (a) |
| Realized natural gas derivative gain | 9,635 | 9,635 | — | |
| Unrealized gas derivative loss | (1,029) | (1,029) | — | |
| Inventory lower-of-cost-or-market adjustments | (3,323) | — | (3,323) | (b) |
| Future inventory value | — | 41,261 | (41,261) | (c) |
| Other energy trading activities | 508 | 722 | (214) | |
| LNG and natural gas revenue | $ 8,087 | $ 18,517 | $ (10,430) | |

(a) The cost of LNG GAAP measure takes into consideration only the cost of LNG that was regasified and sold during the year ended December 31, 2009, using the weighed average cost method for LNG inventory. The cost of LNG non-GAAP measure takes into consideration the cost for all of the LNG purchased during the year ended December 31, 2009.

(b) The inventory LCM adjustments GAAP measure represents the inventory write-downs that were recorded during the year ended December 31, 2009, as required by GAAP codification.

(c) The future inventory value non-GAAP measure represents the inventory fair value at December 31, 2009, based on published forward natural gas price curve prices corresponding to the future months when the regasified LNG is planned to be sold.

Based on the LNG and natural gas marketing positions executed during the year ended and in place at December 31, 2009, we expect that future LNG and natural gas marketing revenue GAAP measures will recognize a gain of $10.4 million. However, even with our cash flow hedges in place, a change in the future inventory value may occur to the extent our hedges are not perfectly effective or we change our regasification schedule. Although a change in the future inventory value may occur, we believe that the Adjusted LNG and natural gas marketing revenue non-GAAP measure is a meaningful indicator of performance of our LNG and natural gas marketing business activities during a stated period.

Corporate and Other Activities

We are required to maintain corporate general and administrative functions to serve our business activities described above. As discussed above, we believe that we will have sufficient cash and cash equivalents to fund these functions until our debt begins to mature in August 2011.

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 exploration activities in the shallow waters of the Gulf of Mexico. We do not anticipate significant cash expenditures related to these activities and expect our cash inflows from oil and natural gas production to decrease as 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 the years ended December 31, 2009, 2008 and 2007. 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.

| | 2009 | 2008 (as adjusted) | 2007 (as adjusted) |
|---|---|---|---|
| Sources of cash and cash equivalents | | | |
| Use of restricted cash and cash equivalents | $241,101 | $465,323 | $527,043 |
| Distribution from limited partnership investment in Freeport LNG | 15,300 | — | — |
| Proceeds from debt issuance | — | 239,965 | 400,000 |
| Proceeds from debt issuance—related parties | — | 250,000 | — |
| Use of restricted U.S. Treasury securities | — | 16,702 | — |
| Sale of common stock | — | 472 | 3,158 |
| Proceeds from sale of common units in partnership | — | — | 203,946 |
| Proceeds from issuance of common units to non-controlling owners in partnership | — | — | 98,442 |
| Other | — | — | 1,048 |
| Total sources of cash and cash equivalents | 256,401 | 972,462 | 1,233,637 |
| Uses of cash and cash equivalents | | | |
| LNG receiving terminal and pipeline construction-in-process, net | (112,317) | (583,871) | (788,517) |
| Operating cash flow | (97,857) | (142,145) | (84,291) |
| Repayment of debt | (30,030) | (95,000) | — |
| Distributions to non-controlling interest | (26,392) | (26,393) | (13,631) |
| Purchase of treasury shares | (999) | (4,902) | (325,101) |
| Purchases of intangible and fixed assets, net of sales | (522) | (2,889) | (41,684) |
| Debt issuance cost | (121) | (34,504) | (9,787) |
| Investment in restricted cash and cash equivalents | — | (248,767) | — |
| Advances under long-term contracts, net of transfers to construction-in-process | — | (14,032) | (38,617) |
| Purchases of LNG for commissioning, net of amounts transferred to LNG receiving terminal construction-in-process | — | (9,923) | — |
| Investment in U.S. Treasury securities | — | — | (98,442) |
| Other | (1,983) | (4,374) | — |
| Total uses of cash and cash equivalents | (270,221) | (1,166,800) | (1,400,070) |
| Net decrease in cash and cash equivalents | (13,820) | (194,338) | (166,433) |
| Cash and cash equivalents—beginning of year | 102,192 | 296,530 | 462,963 |
| Cash and cash equivalents—end of year | $88,372 | $102,192 | $296,530 |

Use of restricted cash and cash equivalents

In 2009, 2008 and 2007, the $241.1 million, $465.3 million and $527.0 million, respectively, of restricted cash and cash equivalents were used primarily to pay for scheduled interest payments and construction activities at the Sabine Pass LNG receiving terminal. 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. The decreased use of restricted cash and cash equivalents in 2008 and 2009 primarily resulted from completing construction of the initial sendout capacity of approximately 2.6 Bcf/d and storage capacity of approximately 10.1 Bcf at the Sabine Pass LNG receiving terminal in September 2008. The use of restricted cash and cash equivalents in 2009 primarily resulted from obtaining access to the restricted cash and cash equivalents in the TUA reserve account. Our use compared to 2008 resulted from substantially completing construction of the Sabine Pass LNG receiving terminal during the third quarter of 2009.

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 zero, $490.0 million and $400.0 million in 2009, 2008 and 2007, respectively. During 2008, we received $95.0 million from borrowings under the $95.0 million 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.

Investment In and Use of Restricted U.S. Treasury securities

As described in the "—Proceeds from issuance of common units in partnership" below, we received $98.4 million in 2007 to purchase U.S. Treasury securities to fund a distribution reserve for the payments of initial quarterly distributions until Cheniere Partners was able to sustain funding of distributions to its unitholders from unrestricted cash. In 2008, $16.7 million of U.S. Treasury securities were used to fund the distribution reserve.

Proceeds from sale of common units to non-controlling 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. In 2007, 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 was able to sustain funding of distributions to its unitholders from unrestricted cash in August 2009.

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

Capital expenditures for our LNG receiving terminals and pipeline projects were $112.3 million, $583.9 million and $788.5 million in 2009, 2008 and 2007, respectively. Our capital expenditures decreased in 2009 as a result of the substantial completion of the construction of the Sabine Pass LNG receiving terminal in September 2009. Our capital expenditures decreased in 2008 as a result of the winding down and completion of the construction of the initial phases of the Sabine Pass LNG receiving terminal and the Creole Trail Pipeline.

Investment in restricted cash and cash equivalents

Investment in restricted cash and cash equivalents was zero, $248.8 million and zero in 2009, 2008, and 2007, 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.

Operating cash flow

Net cash used in operations was $97.9 million, $142.1 million and $84.3 million in 2009, 2008 and 2007, respectively. Net cash used in operations in 2007 through 2009 related primarily to the continued development and construction of the Sabine Pass LNG receiving terminal and related activities, including increased employee support costs. In 2009, we received capacity reservation fee payments from Total and Chevron of approximately $158 million.

Repayment of debt

During the second quarter of 2009, we reduced long-term debt by exchanging a combination of $30.0 million cash and cash equivalents and 4.0 million common shares for $120.4 million aggregate principal amount of our Convertible Senior Unsecured Notes. In 2008, we repaid borrowings under the $95.0 million bridge loan with a portion of the proceeds obtained from the 2008 Convertible Loans.

Debt issuance costs

Our debt issuance costs were $0.1 million, $34.5 million and $9.8 million in 2009, 2008 and 2007, respectively. The debt issuance costs in 2008 related to the additional issuance of 2016 Notes, the 2008 Convertible Loans and the $95.0 million bridge loan. The debt issuance costs in 2007 were primarily related to the 2007 Term Loan.

Distributions to non-controlling interest

During 2009, 2008 and 2007, Cheniere Partners distributed $26.4 million, $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 the 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. Advances under long-term contracts were zero, $14.0 million and $38.6 million at December 31, 2009, 2008 and 2007, respectively. The decrease in 2009 compared to 2008 resulted from substantial completion of the construction of the Sabine Pass LNG receiving terminal in September 2009. During 2009, the Sabine Pass LNG receiving terminal received equipment that it had previously advanced payment for under long-term contracts. The decrease in 2008 compared to 2007 was a result of Sabine Pass LNG nearing the completion of the construction of the initial sendout capacity of approximately 2.6 Bcf/d and storage capacity of approximately 10.1 Bcf at the Sabine Pass LNG receiving terminal. During 2008, the Sabine Pass LNG receiving terminal received equipment that it had previously advanced payment for under long-term contracts.

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 $0.5 million, $2.9 million and $41.7 million in 2009, 2008 and 2007, respectively. The decrease in 2009 and 2008 primarily resulted from 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.

Debt Agreements

The following table (in thousands) and the explanatory paragraphs following the table summarize our various debt agreements as of December 31, 2009.

| | Sabine Pass LNG, L.P. | Cheniere Energy Partners, L.P. | Other Cheniere Energy, Inc. | Consolidated Cheniere Energy, Inc. |
|---|---|---|---|---|
| Long-term debt (including related parties) | | | | |
| Senior Notes (including related parties) | $2,215,500 | $— | $— | $ 2,215,500 |

| | | | | |
|---|---|---|---|---|
| 2007 Term Loan | — | — | 400,000 | 400,000 |
| 2008 Convertible Loans (including related parties) | — | — | 293,714 | 293,714 |
| Convertible Senior Unsecured Notes | — | — | 204,630 | 204,630 |
| Total long-term debt | 2,215,500 | — | 898,344 | 3,113,844 |
| | | | | |
| Debt discount (including related parties) | | | | |
| Senior Notes (including related parties) (1) | (32,471) | — | — | (32,471) |
| Convertible Senior Unsecured Notes (2) | — | — | (39,498) | (39,498) |
| Total debt discount | (32,471) | | (39,498) | (71,969) |
| Long-term debt (including related parties), net of discount | $2,183,029 | $— | $858,846 | $ 3,041,875 |

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(1) In September 2008, Sabine Pass LNG issued an additional $183.5 million, par value, of 2016 Notes. The net proceeds from the additional issuance of the 2016 Notes were $145.0 million. The difference between the par value and the net

proceeds is the debt discount, which will be amortized through the maturity of the 2016 Notes.

(2) Effective as of January 1, 2009, we are required to record a debt discount on our Convertible Senior Unsecured Notes. The unamortized discount will be amortized through the maturity of the Convertible Senior Unsecured Notes.

Convertible Senior Unsecured Notes

In July 2005, we consummated a private offering of $325.0 million aggregate principal amount of Convertible Senior Unsecured Notes 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 2¼% per year. Interest on the notes is payable semi-annually in arrears on 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, 2009, 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 indenture governing the notes contains customary reporting requirements.

As discussed in Note 19—"Long-term Debt and Long-term Debt—Related Parties" of our Notes to Consolidated Financial Statements, we adopted on January 1, 2009 an accounting standard that requires issuers of certain convertible debt instruments to separately account for the liability component and the equity component represented by the embedded conversion option in a manner that will reflect that entity's nonconvertible debt borrowing rate when interest costs are recognized in subsequent periods. The fair value of the embedded conversion option at the date of issuance of the Convertible Senior Unsecured Notes was determined to be $134.0 million and has been recorded as a debt discount to the Convertible Senior Unsecured Notes, with a corresponding adjustment to Additional Paid-in Capital. At December 31, 2009, the unamortized debt discount to the Convertible Senior Unsecured Notes was $39.5 million.

During the second quarter of 2009, we reduced debt by exchanging $120.4 million aggregate principal amount of our Convertible Senior Unsecured Notes for a combination of $30.0 million cash and cash equivalents and 4.0 million common shares, reducing our principal amount due in 2012 to $204.6 million, at December 31, 2009. As a result of the exchange, we recognized a gain of $45.4 million that we have reported as gain on early extinguishment of debt in our Consolidated Statements of Operations for the year ended December 31, 2009.

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 7¼% Senior Secured Notes due 2013 and $1,665.5 million of 7½% 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, and there must be on deposit in a permanent debt service reserve fund an amount equal to one semi-annual interest payment of approximately $82 million. Distributions are permitted only after satisfying the foregoing funding requirements, a fixed charge coverage ratio test of 2:1 and 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 9¾% 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 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 on 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 Series B 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 a $95.0 million bridge loan. The remaining borrowings were utilized to pay for interest on the $95.0 million 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.

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. In addition, one of the lenders is Scorpion Capital Partners LP ("Scorpion"), an affiliate of one of the Company's directors. As of December 31, 2009 and 2008, $293.7 million and $261.4 million, were outstanding under the 2008 Convertible Loans and were included on Long-term Debt—Related Party on our Consolidated Balance Sheets, respectively.

Issuances of Common Stock

During 2009, no shares of our common stock were issued pursuant to the exercise of stock options. During 2009, we issued 886 shares of non-vested restricted stock to new and existing employees. We also issued 4.0 million shares of our common stock as part of the consideration used to repurchase a portion of the Convertible Senior Unsecured Notes during the second quarter of 2009.

During 2009 and 2008, we raised zero and $0.5 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.

Contractual Obligations

We are committed to make cash payments in the future pursuant to certain of our contracts. The following table summarizes certain contractual obligations in place as of December 31, 2009 (in thousands).

| | Payments Due for Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | Total | 2010 | 2011-2012 | 2013-2014 | Thereafter |
| Long-term debt (excluding interest) (1) | $3,174,821 | $— | $959,321 | $550,000 | $1,665,500 |
| Operating lease obligations (2)(3) | 326,521 | 13,853 | 28,208 | 28,028 | 256,432 |
| Construction and purchase obligations (4) | 7,408 | 7,408 | — | — | — |
| Other obligations (5) | 20,707 | 3,781 | 7,114 | 4,906 | 4,906 |
| Total | $3,529,457 | $25,042 | $994,643 | $582,934 | $1,926,838 |

(1) Based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2009, our cash payments for interest would be $208.4 million in 2010, $208.4 million in 2011, $183.7 million in 2012, $161.5 million in 2013, $124.9 million in 2014 and $239.5 million for the remaining years for a total of $1,126.4 million. See "Note 19—Long-Term Debt and Long-Term Debt—Related Parties" of our Notes to Consolidated Financial Statements.

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

(3) Minimum lease payments have not been reduced by a minimum sublease rental of $98.9 million due in the future under noncancelable subleases. A discussion of these sublease rental payments can be found at Note 8—"Leases" of our Notes to Consolidated Financial Statements

(4) A discussion of these obligations can be found at Note 24—"Commitments and Contingencies" of our Notes to Consolidated Financial Statements.

(5) Includes obligations for cooperative endeavor agreements, LNG receiving terminal security services, 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 totaled approximately $221.2 million at December 31, 2009. 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

2009 vs. 2008

Our consolidated net loss was $161.5 million, or $3.13 per share (basic and diluted), in 2009 compared to a net loss of $373.0 million, or $7.87 per share (basic and diluted), in 2008. The decrease in the loss was primarily due to increased LNG receiving terminal revenues as a result of the Sabine Pass LNG receiving terminal starting commercial operations during 2009, decreased LNG receiving terminal and pipeline development expense, decreased general and administrative expenses, decreased restructuring charges and the gain from early extinguishment of debt, which were partially offset by increased LNG receiving terminal and pipeline operating expenses, increased depreciation, depletion and amortization expense (“DD&A”), decreased interest income and increased interest expense, net.

A significant portion of our loss was attributable to the recognition of non-cash, share-based payments recognized in the consolidated 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 $19.2 million (12% of net loss) and $55.0 million (15% of net loss) of non-cash compensation expense in 2009 and 2008, respectively. In addition, we recognized one-time items in 2009 of $45.4 million for a gain on early extinguishment of debt. In 2008, we recognized one-time items 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 2009 and 2008 and the impact of non-cash expense in 2009 and 2008, our net loss would have been $187.7 million, or $3.64 net loss per common share (basic and diluted) and $228.6 million, or $4.83 net loss per common share (basic and diluted), respectively.

2008 vs. 2007

Our consolidated net loss was $373.0 million, or $7.87 per share (basic and diluted), in 2009 compared to a net loss of $196.6 million, or $3.89 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 and maintenance 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 recognized in the consolidated 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 (15% of net loss) and $56.6 million (29% on net loss) of non-cash compensation expense in 2008 and 2007, respectively. 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 $228.6 million, or $4.83 net loss per common share (basic and diluted).

LNG Receiving Terminal Revenue

As a result of the completion of the Sabine Pass LNG receiving terminal in 2009, the capacity reservation fee TUA payments began on April 1, 2009 and July 1, 2009 for Total and Chevron, respectively.  In addition to the TUA capacity reservation fee, we recognized $9.3 million of other revenue primarily related to revenues earned from fees charged to customers using our tug boats associated with the Sabine Pass LNG receiving terminal.

LNG and Natural Gas Marketing Revenue

Operating results from marketing and trading activities are presented on a net basis on our Consolidated Statement of Operations. Marketing and trading revenues represent the margin earned on the purchase and transportation costs of LNG and subsequent sales of natural gas to third parties. Our marketing and trading revenues also include pretax derivative gains/losses and inventory lower-of-cost-or-market adjustments, if any.  See table below (in thousands) for itemized comparison of each major type of energy trading and risk management activity:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| Physical natural gas sales, net of costs | $2,296 | $943 | $52 |
| Inventory lower-of-cost-or-market write-downs | (3,323) | — | — |
| Gain (loss) from derivatives | 8,606 | (1,435) | (4,391) |
| Other energy trading activities | 508 | 3,406 | (390) |
| Total LNG and Natural Gas Marketing Revenue | $8,087 | $2,914 | $(4,729) |

2009 vs. 2008

LNG and natural gas marketing revenues increased $5.2 million, from $2.9 million in 2008 to a $8.1 million in 2009. The $8.1 million in 2009 primarily resulted from $8.6 million in derivative gains and $2.3 million of net revenue from physical sales of regasified LNG, which was offset by a $3.3 million inventory write-down.  The increase in natural gas marketing and trading revenue is primarily a result of the different marketing and trading activities we were engaged in during 2009 compared to 2008.  Prior to the downsizing of our natural gas marketing business in April 2008, we had entered into various commercial transactions that were unwound, terminated or assigned in 2008. The $2.9 million gain in 2008 primarily resulted from revenue from short-term TUA option transactions.  During 2009, we began purchasing, transporting and unloading commercial LNG cargos into the Sabine Pass LNG receiving terminal and used certain hedging strategies to maximize margins on these cargos.

2008 vs. 2007

LNG and natural gas marketing revenues increased $7.6 million, from a $4.7 million loss in 2007 to a $2.9 million gain in 2008. The $2.9 million gain in 2008 primarily resulted from revenue from short-term TUA option transactions, which was partially offset by losses on our derivative positions entered into prior to our corporate restructuring in April 2008.

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.

2009 vs. 2008

LNG receiving terminal and pipeline development expenses decreased $10.3 million in 2009 compared to 2008. The decrease resulted from less development activities at the Sabine Pass LNG receiving terminal than in 2008. The 2009 costs primarily related to continued site maintenance costs incurred on the Corpus Christi and Creole Trail LNG receiving terminals.

2008 vs. 2007

LNG receiving terminal and pipeline development expenses decreased $24.1 million in 2008 compared to 2007. These development expenses 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.

LNG Receiving Terminal and Pipeline Operating Expense

Our LNG receiving terminal and pipeline operating expenses include costs incurred to operate the Sabine Pass LNG receiving terminal and the Creole Trail Pipeline.

2009 vs. 2008

Operating and maintenance expense increased $22.4 million, from $14.5 million in 2008 to $36.9 million in 2009. This $22.4 million increase primarily resulted from the achievement of commercial operability of the initial 2.6 Bcf/d of sendout capacity and 10.1 Bcf of storage capacity of the Sabine Pass LNG receiving terminal in the third quarter of 2008 and the substantial completion of construction and 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 16.9 Bcf of aggregate storage capacity in the third quarter of 2009.

2008 vs. 2007

Operating and maintenance expense increased $14.5 million, from zero in 2007 to $14.5 million in 2008. This $14.5 million increase primarily resulted from the initial 2.6 Bcf/d of regassification capacity and the 10.1 Bcf of storage capacity achieving commercial operability in September 2008 and also included costs to repair damage caused by Hurricane Ike.

Depreciation, Depletion and Amortization (“DD&A”)

2009 vs. 2008

DD&A increased $29.9 million, from $24.3 million in 2008 to $54.2 million in 2009. This increase is primarily related to beginning deprecation on the costs 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 that was placed into service in the third quarter of 2008. In addition, depreciation expense increased in 2009 as a result of the substantial completion of construction and 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 16.9 Bcf of aggregate storage capacity in the third quarter of 2009.

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.

General and Administrative Expense ("G&A")

Our G&A expenses include costs that are incurred directly related to operating the Sabine Pass LNG receiving terminal and Creole Trail Pipeline.

2009 vs. 2008

The $56.8 million reduction in G&A expense from 2008 to 2009 primarily resulted from a reduction in salaries and benefits incurred in 2009 associated with our 2008 cost savings program and the allocation of salaries and benefits to operating costs as a result of the achievement of commercial operability of the Sabine Pass LNG receiving terminal in September 2008.

Restructuring Charges

During 2009 and 2008, we incurred less than $0.1 million and $78.7 million of restructuring charges, respectively, resulting from our cost savings program in connection with downsizing 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 2—"Summary of Significant Accounting Policies" of our Notes to Consolidated Financial Statements).

Gain/(Loss) on Early Extinguishment of Debt

2009 vs. 2008

Gain/(Loss) on early extinguishment of debt increased $56.1 million, from a $10.7 million loss in 2008 to a $45.4 million gain in 2009. During the second quarter of 2009, we reduced debt by exchanging $120.4 million aggregate principal amount of our Convertible Senior Unsecured Notes for a combination of $30.0 million cash and cash equivalents and 4.0 million common shares, reducing our principal amount due in 2012 to $204.6 million. As a result of the exchange, we recognized a gain of $45.4 million that was reported as a gain on early extinguishment of debt.

2008 vs. 2007

Gain/(Loss) on early extinguishment of debt decreased $10.7 million in 2008 compared to 2007. The decrease resulted from 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.

Interest Income

2009 vs. 2008

Interest income decreased $18.9 million in 2009 compared to 2008, because of the lower average invested cash balances resulting from the use of cash to pay construction costs and interest payments, as well as lower interest rates.

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, as well as lower interest rates.

Interest Expense, net

2009 vs. 2008

Interest expense, net of amounts capitalized, increased $96.2 million, from $147.1 million in 2008 to $243.3 million in 2009. The increase in interest expense was caused by additional debt issuances during the third quarter of 2008 and a decrease in capitalized interest as a result of placing in service the initial phase of the Sabine Pass LNG receiving terminal and Creole Trail Pipeline in the third quarter of 2008 and second quarter of 2008, respectively.

2008 vs. 2007

Interest expense, net of amounts capitalized, increased $27.8 million in 2008 compared to 2007. The increase was caused by the additional borrowing under the $95.0 million bridge loan, the 2008 Convertible Loans and the issuance of $183.5 million of additional 2016 Notes during the third quarter of 2008.

Off-Balance Sheet Arrangements

As of December 31, 2009, 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 2009, 2008 and 2007, 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 apply the accounting rules to the specific set of circumstances existing in our business. In preparing our consolidated financial statements in conformity with GAAP, we endeavor to comply properly with all applicable rules on or before their adoption, and we believe that the proper implementation and consistent application of the accounting rules are critical. However, not all situations are specifically addressed in the accounting literature. In these cases, we must use our best judgment to adopt a policy for accounting for these situations. We accomplish this by analogizing to similar situations and the accounting guidance governing them.

Accounting for LNG Activities

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

Generally, costs that are capitalized prior to a project meeting the criteria otherwise necessary for capitalization include: land and lease option costs that are capitalized as property, plant and equipment and certain permits that 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.

We capitalize interest and other related debt costs during the construction period of our LNG receiving terminal. 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 reservation fees are recognized as revenue over the term of the respective TUAs. Advance capacity reservation fees are initially deferred and amortized over a 10-year period as a reduction of a customer's regasification capacity reservation fees payable under its TUA. The retained 2% of LNG delivered for each customer's account at the Sabine Pass LNG receiving terminal is recognized as revenues as Sabine Pass LNG performs the services set forth in each customer's TUA.

Use of Estimates

The preparation of consolidated 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.

Estimates used in the assessment of impairment of our long-lived assets, including goodwill, are the most significant of our estimates. There are numerous uncertainties inherent in estimating future cash flows of assets or business segments. The accuracy of any cash flow estimate is a function of judgment used in determining the amount of cash flows generated. As a result, cash flows may be different from the cash flows that we use to assess impairment of our assets. Management reviews its estimates of cash flows on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. Significant negative industry or economic trends, including a significant decline in the market price of our common stock, reduced estimates of future cash flows for our business segments or disruptions to our business could lead to an impairment charge of our long-lived assets, including goodwill and other intangible assets. Our valuation methodology for assessing impairment requires management to make judgments and assumptions based on historical experience and to rely heavily on projections of future operating performance. Projections of future operating results and cash flows may vary significantly from results. In addition, if our analysis results in an impairment of our long-lived assets, including goodwill, we may be required to record a charge to earnings in our consolidated financial statements during a period in which such impairment is determined to exist, which may negatively impact our results of operations.

Other items subject to estimates and assumptions include asset retirement obligations, valuation allowances for net deferred tax assets, valuations of derivative instruments, valuations of noncash compensation and collectability of accounts receivable and other assets.

As future events and their effects cannot be determined accurately, actual results could differ significantly from our estimates.

LNG and Natural Gas Marketing

We have determined that our LNG and natural gas marketing business activities are energy trading and risk management activities for trading purposes and have elected to present these activities on a net basis on our Consolidated Statement of Operations. Marketing and trading revenues represent the margin earned on the purchase and transportation of LNG purchases and subsequent sales of natural gas to third parties. These energy trading and risk management activities include, but are not limited to: purchase of LNG and natural gas, transportation contracts, and derivatives. Below is a brief description of our accounting treatment of each type of energy trading and risk management activity and how we account for it:

Purchase of LNG and natural gas

The purchase value of LNG or natural gas inventory is recorded as an asset on our Consolidated Balance Sheet at the cost to acquire the product. Our inventory is subject to LCM adjustment each quarter. Recoveries of losses resulting from interim period LCM adjustments are made due to market price recoveries on the same inventory in the same fiscal year and are recognized as gains in later interim periods with such gains not exceeding previously recognized losses. Any adjustment to our inventory is recorded on a net basis as LNG and natural gas marketing revenue on our Consolidated Statement of Operations.

Transportation contracts

We enter into transportation contracts with respect to the transport of LNG or natural gas to a specific location for storage or sale. Transportation costs that are incurred during the purchase of LNG or natural gas are capitalized as part of the acquisition costs of the product. Transportation costs incurred to sell LNG or natural gas are recorded on a net basis as LNG and natural gas marketing revenue on our Consolidated Statement of Operations.

Derivatives

We use derivative instruments from time to time to hedge the cash flow variability of our commodity trading activities. We have disclosed certain information regarding these derivative positions, including the fair value of our derivative positions, in Note 20—"Financial Instruments" of our Notes to Consolidated Financial Statements. We record changes in the fair value of our derivative positions in our LNG and natural gas marketing revenue on our Consolidated Statement of Operations based on the value for which the derivative instrument could be exchanged between willing parties. To date, all of our derivative positions fair value determinations have been made by management using quoted prices in active markets for identical instruments. The ultimate fair value of our derivative instruments is uncertain, and we believe that it is possible that a change in the estimated fair value will occur in the near future as commodity prices change.

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. The economic effects of regulation can result in a regulated company recording as assets those costs that have been or are expected to be approved for recovery from customers, or recording as liabilities those amounts that are expected to be required to be returned to customers, in a rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, we record assets and liabilities that result from the regulated rate-making process that may not be recorded under GAAP for non-regulated entities. We continually assess whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Based on this continual assessment, we believe the existing regulatory assets are probable of recovery. These regulatory assets and liabilities are primarily classified in the Consolidated Balance Sheets as Other Assets and Other Liabilities. We periodically evaluate their applicability under GAAP, and consider factors such as regulatory changes and the effect of competition. If cost-based regulation ends or competition increases, we may have to reduce our asset balances to reflect a market basis less than cost and write-off the associated regulatory assets and liabilities.

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. Cash flow hedge transactions hedge the exposure to variability in expected future cash flows. In the case of cash flow hedges, the hedged item (the underlying risk) is generally unrecognized (i.e., not recorded on the consolidated 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, U.S. GAAP requires that the fair value of a derivative instrument designated as a cash flow hedge to 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 represents the excess of cost over fair value of the assets of businesses acquired. It is evaluated annually for impairment by first comparing our management's estimate of the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in the amount of the excess. We had goodwill of approximately $76.8 million at December 31, 2009 and 2008, attributable to our LNG receiving terminal segment.

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. As discussed above regarding our use of estimates, our judgments and assumptions are inherent in our management's estimate of future cash flows used to determine the estimate of the reporting unit's fair value. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements.

Share-Based Compensation Expense

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, using the Black-Scholes-Merton option valuation model. 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.

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, 2009 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 22—“Share-Based Compensation” of our Notes to Consolidated Financial Statements).

Recent Accounting Standards

In April 2009, the Financial Accounting Standards Board (“FASB”) issued a staff position providing additional guidance on factors to consider in estimating fair value when there has been a significant decrease in market activity for a financial asset. The guidance was effective for interim and annual periods ending after June 15, 2009. The implementation of this standard did not have a material impact on our financial position, results of operations or cash flow.

In April 2009, the FASB issued a staff position requiring fair value disclosures in both interim as well as annual financial statements in order to provide more timely information about the effects of current market conditions on financial instruments. The guidance is effective for interim and annual periods ending after June 15, 2009. The implementation of this standard did not have a material impact on our financial position, results of operations or cash flow.

In May 2009, the FASB issued new requirements for reporting subsequent events. These requirements set forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements, and disclosures that an entity should make about events or transactions that occurred after the balance sheet date. Disclosure of the date through which an entity has evaluated subsequent events and the basis for that date is also required. This disclosure should alert all users of financial statements that an entity has not evaluated subsequent events after the date set forth in the financial statements being presented. The Company started adhering to these requirements in the second quarter of 2009.

In June 2009, the FASB issued an amendment to the accounting and disclosure requirements for the consolidation of variable interest entities. The guidance affects the overall consolidation analysis and requires enhanced disclosures on involvement with variable interest entities. The guidance is effective for fiscal years beginning after November 15, 2009. We do not expect the adoption of this amendment to have a material impact on our financial position, results of operations or cash flow.

In June 2009, the FASB issued SFAS No. 168, FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles. SFAS No. 168 establishes the FASB Accounting Standards Codification (the “Codification”) as the single source of authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. SFAS No. 168 and the Codification are effective for financial statements issued for interim and annual periods ending after September 15, 2009. As of July 1, 2009, the Codification supersedes all existing non-SEC accounting and reporting standards. We adopted this statement for the period ended September 30, 2009. The adoption of this statement did not have an impact on our financial position, results of operations or 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

Through Cheniere Marketing, from time to time we will enter into natural gas and foreign currency derivatives to hedge the exposure of future cash flows associated with the LNG that we hold. We use value at risk ("VaR") and other methodologies for market risk measurement and control purposes. The VaR is calculated using the Monte Carlo simulation method. At December 31, 2009 and 2008, the one-day VaR with a 95% confidence interval on our derivative positions was less than $0.1 million, respectively.

Our derivative positions as of December 31, 2009 primarily consisted of exchange cleared NYMEX natural gas swaps entered into to hedge the exposure to variability in expected future cash flows related to the sale of commercial LNG and excess LNG purchased for commissioning at the Sabine Pass LNG receiving terminal. As of December 31, 2009, we had entered into a total of 7,465,000 MMBtu of NYMEX natural gas swaps through January 2011 for which we will receive fixed prices of $4.903 to $7.151 per MMBtu. At December 31, 2009, the value of the derivatives was a liability of $0.9 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

CHENIERE ENERGY, INC. AND SUBSIDIARIES

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 and, even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation.

Based on our assessment, we have concluded that Cheniere maintained effective internal control over financial reporting as of December 31, 2009, based on criteria in Internal Control—Integrated Framework issued by the COSO.

Cheniere's independent auditors, Ernst & Young LLP, have issued an audit report on Cheniere's internal control over financial reporting

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 | By: | /s/ Meg A. Gentle |
| | Charif Souki | | Meg A. Gentle |
| | Chief Executive Officer and President | | Senior Vice President and Chief Financial Officer |

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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, 2009 and 2008, and the related consolidated statements of operations, stockholders' (deficit) equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits 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 audits.

We conducted our audits 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 provide 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, 2009 and 2008, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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.

As described in Note 2 of the consolidated financial statements, on January 1, 2009, Cheniere Energy, Inc. adopted an accounting standard requiring issuers of certain convertible debt instruments to separately account for the liability component and the equity component represented by the embedded conversion option. Also on January 1, 2009, Cheniere Energy, Inc. adopted an accounting standard on accounting and reporting for non-controlling interest. Both accounting standards were adopted on a retrospective basis resulting in revision of the December 31, 2008 balance sheet.

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, 2009, 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 25, 2010 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
ERNST & YOUNG LLP

Houston, Texas
February 25, 2010

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited Cheniere Energy, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2009, 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. and subsidiaries' 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. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, 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, 2009 and 2008, and the related consolidated statements of operations, stockholders' (deficit) equity, and cash flows for each of the three years in the period ended December 31, 2009 and our reported dated 25, February 2010 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
ERNST & YOUNG LLP

Houston, Texas
February 25, 2010

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET
(in thousands, except share data)

| | December 31, 2009 | December 31, 2008 (as adjusted) |
|---|---|---|
| ASSETS | | |
| CURRENT ASSETS | | |
| Cash and cash equivalents | $88,372 | $102,192 |
| Restricted cash and cash equivalents | 138,309 | 301,550 |
| Accounts and interest receivable | 9,899 | 3,630 |
| LNG inventory | 32,602 | — |
| Prepaid expenses and other | 17,093 | 9,220 |
| Total current assets | 286,275 | 416,592 |
| | | |
| NON-CURRENT RESTRICTED CASH AND CASH EQUIVALENTS | 82,892 | 138,483 |
| NON-CURRENT RESTRICTED U.S. TREASURY SECURITIES | — | 20,829 |
| PROPERTY, PLANT AND EQUIPMENT, NET | 2,216,855 | 2,170,158 |
| DEBT ISSUANCE COSTS, NET | 47,043 | 55,688 |
| GOODWILL | 76,819 | 76,844 |
| INTANGIBLE LNG ASSETS | 6,088 | 6,106 |
| LNG HELD FOR COMMISSIONING | — | 9,923 |
| ADVANCES UNDER LONG-TERM CONTRACTS | 1,021 | 10,705 |
| OTHER | 15,629 | 14,754 |
| Total assets | $2,732,622 | $2,920,082 |
| | | |
| LIABILITIES AND STOCKHOLDERS' DEFICIT | | |
| CURRENT LIABILITIES | | |
| Accounts payable | $426 | $1,220 |
| Accrued liabilities | 38,425 | 61,883 |
| Deferred revenue | 26,456 | 2,500 |
| Other | 905 | 530 |
| Total current liabilities | 66,212 | 66,133 |
| | | |
| LONG-TERM DEBT, NET OF DISCOUNT | 2,692,740 | 2,750,308 |
| LONG-TERM DEBT—RELATED PARTIES | 349,135 | 332,054 |
| DEFERRED REVENUE | 33,500 | 37,500 |
| OTHER NON-CURRENT LIABILITIES | 23,162 | 8,141 |
| | | |
| COMMITMENTS AND CONTINGENCIES | — | — |
| | | |
| STOCKHOLDERS' DEFICIT | | |
| Preferred stock, $.0001 par value, 5,000,000 shares authorized, none issued | — | — |
| Common stock, $.003 par value | | |
| Authorized: 240,000,000 and 120,000,000 shares at December 31, 2009 and 2008 | | |
| Issued and outstanding: 56,651,000 and 52,297,000 shares at December 31, 2009 and 2008, respectively | 170 | 157 |

| | | |
|---|---|---|
| Treasury stock: 697,000 and 179,000 shares at December 31, 2009 and 2008, respectively, at cost | (1,494 ) | (496 ) |
| Additional paid-in-capital | 336,971 | 300,033 |
| Accumulated deficit | (985,246 ) | (823,756 ) |
| Accumulated other comprehensive loss | (133 ) | (154 ) |
| Total stockholders' deficit | (649,732 ) | (524,216 ) |
| NON-CONTROLLING INTEREST | 217,605 | 250,162 |
| Total deficit | (432,127 ) | (274,054 ) |
| Total liabilities and deficit | $2,732,622 | $2,920,082 |

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

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

| | Year Ended December 31, 2009 | 2008 (as adjusted) | 2007 (as adjusted) |
|---|---|---|---|
| Revenues | | | |
| LNG receiving terminal revenue | $ 170,071 | $— | $— |
| Oil and gas sales | 2,866 | 4,215 | 5,376 |
| Marketing and trading gain (loss) | 8,087 | 2,914 | (4,729 ) |
| Pipeline revenue | 102 | 15 | — |
| Total revenues | 181,126 | 7,144 | 647 |
| | | | |
| Operating costs and expenses | | | |
| LNG receiving terminal and pipeline development expense | 223 | 10,556 | 34,656 |
| LNG receiving terminal and pipeline operating expense | 36,857 | 14,522 | — |
| Exploration costs | — | 128 | 1,116 |
| Oil and gas production costs | 471 | 398 | 358 |
| Impairment of fixed assets | — | — | 18 |
| Depreciation, depletion and amortization | 54,229 | 24,346 | 6,393 |
| General and administrative expenses | 65,830 | 122,678 | 122,046 |
| Restructuring charges | 20 | 78,704 | — |
| Total operating costs and expenses | 157,630 | 251,332 | 164,587 |
| | | | |
| Income (loss) from operations | 23,496 | (244,188 ) | (163,940 ) |
| Loss from equity method investments | — | (4,800 ) | (191 ) |
| Gain/(loss) on early extinguishment of debt | 45,363 | (10,691 ) | — |
| Derivative gain | 5,277 | 4,652 | — |
| Interest expense, net | (243,295 ) | (147,136 ) | (119,360 ) |
| Interest income | 1,405 | 20,337 | 82,635 |
| Other income | 99 | 90 | 851 |
| Loss before income taxes and non-controlling interest | (167,655 ) | (381,736 ) | (200,005 ) |
| | | | |
| Income tax provision | — | — | — |
| Loss before non-controlling interest | (167,655 ) | (381,736 ) | (200,205 ) |
| | | | |
| Non-controlling interest | 6,165 | 8,777 | 3,425 |
| Net loss | $ (161,490 ) | $ (372,959 ) | $ (196,580 ) |
| | | | |
| Net loss per common share—basic and diluted | $ (3.13 ) | $ (7.87 ) | $ (3.89 ) |
| Weighted average number of common shares outstanding—basic and diluted | 51,598 | 47,365 | 50,537 |

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

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

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

| | Common Stock Shares | Common Stock Amount | Treasury Stock Shares | Treasury Stock Amount | Additional Paid-in Capital | Accumulated Deficit | Accumulated Other Comprehensive Loss | Non-controlling Interest | Tota Equi (Defic |
|---|---|---|---|---|---|---|---|---|---|
| Balance—December 31, 2006 | 55,213 | $ 166 | —$ | —$ | 390,256 | $ (247,141) | $ (34) | $ —$ | 143,2 |
| Cumulative effect of accounting change | — | — | — | — | 118,744 | (7,076) | | | 111,6 |
| Balance—December 31, 2006 (as adjusted) | 55,213 | 166 | — | — | 509,000 | (254,217) | (34) | — | 254,9 |
| Issuances of stock | 688 | 2 | — | — | 3,155 | — | — | — | 3,1 |
| Issuances of restricted stock | 1,029 | 2 | — | — | (2) | — | — | — | |
| Forfeitures of restricted stock | (20) | — | 20 | — | — | — | — | — | |
| Stock-based compensation | — | — | — | — | 58,331 | — | — | — | 58,3 |
| Treasury stock acquired | (9,179) | (27) | 9,179 | (325,101) | 27 | — | — | — | (325,1 |
| Treasury stock retired | — | — | (7) | 62 | (62) | — | — | — | |
| Comprehensive loss: Foreign currency translation | — | — | — | — | — | — | 29 | — | |
| Net proceeds from non-controlling interest | — | — | — | — | — | — | — | 302,731 | 302,7 |
| Loss attributable to non-controlling interest | — | — | — | — | — | — | — | (3,425) | (3,4 |
| Distribution to non-controlling interest | — | — | — | — | — | — | — | (13,631) | (13,6 |
| Net loss (as adjusted) | — | — | — | — | — | (196,580) | — | — | (196,5 |
| Balance—December 31, 2007 | 47,731 | 143 | 9,192 | (325,039) | 570,449 | (450,797) | (5) | 285,675 | 80,4 |
| Issuances of stock | 145 | — | — | — | 472 | — | — | — | 4 |
| | 4,910 | 15 | — | — | (15) | — | — | — | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Issuances of restricted stock | | | | | | | | | |
| Forfeitures of restricted stock | (172) | — | 172 | — | — | — | — | — | |
| Stock-based compensation | — | — | — | — | 58,571 | — | — | — | 58,5 |
| Treasury stock acquired | (317) | (1) | 317 | (4,901) | — | — | — | — | (4,9 |
| Treasury stock retired | — | — | (9,502) | 329,444 | (329,444) | — | — | — | |
| Comprehensive gain (loss): Foreign currency translation | — | — | — | — | — | — | (149) | — | ( |
| Loss attributable to non-controlling interest | — | — | — | — | — | — | — | (9,120) | (9,1 |
| Distribution to non-controlling interest | — | — | — | — | — | — | — | (26,393) | (26,3 |
| Net loss (as adjusted) | — | — | — | — | — | (372,959) | — | — | (372,9 |
| Balance—December 31, 2008 | 52,297 | 157 | 179 | (496) | 300,033 | (823,756) | (154) | 250,162 | (274,0 |
| Issuances of stock | 3,985 | 12 | — | — | 16,212 | — | — | — | 16,2 |
| Issuances of restricted stock | 886 | 3 | — | — | (3) | — | — | — | |
| Forfeitures of restricted stock | (89) | — | 89 | — | — | — | — | — | |
| Stock-based compensation | — | — | — | — | 20,728 | — | — | — | 20,7 |
| Treasury stock acquired | (428) | (2) | 429 | (998) | 1 | — | — | — | (9 |
| Comprehensive loss: Foreign currency translation | — | — | — | — | — | — | 21 | — | |
| Loss attributable to non-controlling interest | — | — | — | — | — | — | — | (6,165) | (6,1 |
| Distribution to non-controlling interest | — | — | — | — | — | — | — | (26,392) | (26,3 |
| Net loss | — | — | — | — | — | (161,490) | — | — | (161,4 |
| Balance—December 31, 2009 | $ 56,651 | 170 | $ 697 | (1,494)$ | 336,971 $ | (985,246) $ | (133)$ | 217,605 $ | (432, |

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

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS
(in thousands)

| | Year Ended December 31, 2009 | 2008 (as adjusted) | 2007 (as adjusted) |
|---|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | |
| Net loss | $(161,490) | $(372,959) | $(196,580) |
| Adjustments to reconcile net loss to net cash used in operating activities: | | | |
| Depreciation, depletion and amortization | 54,229 | 24,346 | 6,393 |
| (Gain)/loss on early extinguishment of debt | (45,363) | 10,716 | — |
| Non-cash interest expense on 2008 Convertible Loans | 32,321 | 11,393 | — |
| Amortization of debt issuance and discount costs | 27,549 | 26,435 | 21,123 |
| Non-cash compensation | 19,204 | 55,030 | 56,638 |
| Non-cash inventory write-downs | 3,516 | — | — |
| Non-controlling interest | (6,165) | (8,777) | (3,425) |
| Restricted interest income on restricted cash and cash equivalents | (2,794) | (18,495) | (53,327) |
| Use of restricted cash and cash equivalents | 1,353 | 94,610 | 103,043 |
| Non-cash restructuring charges | 415 | 17,669 | — |
| Other | 2,232 | (3,311) | 1,015 |
| Changes in operating assets and liabilities: | | | |
| Accounts and interest receivable | (1,343) | 45,157 | (41,654) |
| Accounts payable and accrued liabilities | 253 | (42,066) | 42,007 |
| LNG inventory | (32,628) | — | — |
| Deferred revenue | 19,956 | — | — |
| Prepaid expenses and other | (9,102) | 18,107 | (19,524) |
| NET CASH USED IN OPERATING ACTIVITIES | (97,857) | (142,145) | (84,291) |
| | | | |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | |
| LNG terminal and pipeline construction-in-process, net | (112,317) | (583,871) | (788,517) |
| Use of restricted cash and cash equivalents | 110,399 | 465,323 | 526,318 |
| Distributions from limited partnership investment | 15,300 | — | — |
| Purchases of intangible and fixed assets, net of sales | (522) | (2,889) | (41,684) |
| Oil and gas property, net of sales | (474) | (564) | 17 |
| 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) | — |
| Advances under long-term contracts, net of transfers to construction-in-process | — | (14,032) | (38,617) |
| Other | (402) | (3,808) | 1,031 |
| NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES | 11,984 | (133,062) | (439,894) |
| | | | |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | |
| Use of (investment in) restricted cash and cash equivalents | 130,702 | (248,767) | 725 |
| Repayment of debt | (30,030) | (95,000) | — |
| Distributions to non-controlling interest | (26,392) | (26,393) | (13,631) |
| Purchase of treasury shares | (999) | (4,902) | (325,101) |

| | | | |
|---|---|---|---|
| Debt issuance cost | (121) | (34,504) | (9,787) |
| Proceeds from debt issuance | — | 239,965 | — |
| 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 non-controlling owners in partnership | — | — | 98,442 |
| Proceeds from 2007 term loan | — | — | 400,000 |
| Other | (1,107) | 470 | 3,158 |
| NET CASH PROVIDED BY FINANCING ACTIVITIES | 72,053 | 80,869 | 357,752 |
| | | | |
| NET DECREASE IN CASH AND CASH EQUIVALENTS | (13,820) | (194,338) | (166,433) |
| CASH AND CASH EQUIVALENTS—BEGINNING OF PERIOD | 102,192 | 296,530 | 462,963 |
| CASH AND CASH EQUIVALENTS—END OF PERIOD | $88,372 | $102,192 | $296,530 |

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

## NOTE 1—ORGANIZATION AND NATURE OF OPERATIONS

Cheniere Energy, Inc., a Delaware corporation, is a Houston-based energy company primarily engaged in LNG-related businesses. We own and operate the Sabine Pass LNG receiving terminal in Louisiana through our 90.6% ownership interest in and management agreements with Cheniere Energy Partners, L.P. ("Cheniere Partners"), which is a publicly traded partnership we created in 2007. We also own and operate the Creole Trail Pipeline, which interconnects the Sabine Pass LNG receiving terminal with downstream markets. One of our subsidiaries, Cheniere Marketing, LLC ("Cheniere Marketing"), is marketing LNG and natural gas and is developing a portfolio of long-term and short-term contracts to monetize capacity at the Sabine Pass LNG receiving terminal and the Creole Trail Pipeline. We own 30% of the limited partnership interests of Freeport LNG Development, L.P. ("Freeport LNG"), which operates the Freeport LNG receiving terminal. We are also in various stages of developing other LNG receiving terminal and pipeline related projects, which, among other things, will require commercial justification before we make a final investment decision. In addition, we are engaged to a limited extent in oil and natural gas exploration and development activities in the Gulf of Mexico. Unless the context requires otherwise, references to the "Company", "Cheniere", "we", "us" and "our" refer to Cheniere Energy, Inc. and its subsidiaries, including our publicly trad subsidiary partnership, Cheniere Partners.

We have evaluated subsequent events through February 25, 2010.

## 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.

Certain reclassifications have been made to conform prior period information to the current presentation. The reclassifications had no effect on our overall consolidated financial position, results of operations or cash flows.

### Liquidity

As of December 31, 2009, we had unrestricted cash and cash equivalents of $88.4 million that was available to Cheniere (excluding Cheniere Partners and Sabine Pass LNG). In addition, we had restricted cash and cash equivalents of $221.2 million, which were designated for the following purposes: $117.4 million for Sabine Pass LNG's working capital; $96.1 million for interest payments related to the Senior Notes described below; and $7.7 million for other restricted purposes. We believe that we have sufficient cash, other working capital and cash generated from our operations to fund our operating expenses and other cash requirements until at least the earliest date when principal payments may be required on our existing indebtedness, which is August 2011. Before such time, we will need to restructure our finances and improve our capital structure, which may be accomplished by entering into long-term TUAs or LNG purchase agreements, refinancing our existing indebtedness, issuing equity or other securities, selling assets or a combination of the foregoing.

Our ability to enhance near-term liquidity and improve our capital structure is dependent on numerous factors, including the availability of credit, the balance of worldwide and domestic supply and demand for natural gas and LNG, and the relative prices for natural gas in North America and international markets. We face numerous financial, market and operational risks in connection with improving our liquidity situation, many of which are beyond our control.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Recent Accounting Developments

Effective January 1, 2009, we adopted an accounting standard that requires the presentation of non-controlling interests (previously shown as minority interest) as a component of equity on our Consolidated Balance Sheets and Consolidated Statement of Equity (Deficit). The adoption of this accounting standard did not have any other material impact on our financial position, results of operations or cash flow.

Effective January 1, 2009, we adopted an accounting standard that requires issuers of certain convertible debt instruments to separately account for the liability component and the equity component represented by the embedded conversion option in a manner that will reflect that entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. Upon settlement, the entity shall allocate consideration transferred and transaction costs incurred to the extinguishment of the liability component and the reacquisition of the equity component. We adopted this accounting standard January 1, 2009 and applied it retrospectively to all periods presented.

Our 2¼% Convertible Senior Unsecured Notes due 2012 ("Convertible Senior Unsecured Notes") are impacted by this change. The fair value of the embedded conversion option at the date of issuance was determined to be $134.0 million and has been recorded as a debt discount to the Convertible Senior Unsecured Notes, with a corresponding adjustment to Additional Paid-in Capital. This debt discount is being amortized over the term of the underlying Convertible Senior Unsecured Notes.

As a result of the adoption, adjustments have been made to the consolidated financial statements of prior periods. The following table summarizes the incremental effect of the adoption on our Consolidated Statements of Operations and per-share amounts for the years ended December 31, 2008 and 2007 (in thousands, except per share amounts):

| | Year Ended December 31, 2008 | | | Years Ended December 31, 2007 | | |
|---|---|---|---|---|---|---|
| | Prior to adoption | Effect of adoption | As adjusted | Prior to adoption | Effect of adoption | As adjusted |
| Increase: | | | | | | |
| Interest expense, net | $ (130,648) | $ (16,488) | $ (147,136) | $ (104,557) | $ (14,803) | $ (119,360) |
| Net loss | (356,471) | (16,488) | (372,959) | (181,777) | (14,803) | (196,580) |
| | | | | | | |
| Basic and diluted net loss per share | $ (7.53) | $ (0.34) | $ (7.87) | $ (3.60) | $ (0.29) | $ (3.89) |

The incremental effect of the adoption on our Consolidated Balance Sheet as of December 31, 2008 is presented as follows (in thousands):

| | December 31, 2008 | | |
|---|---|---|---|
| | Prior to adoption | Effect of adoption | As adjusted |
| Increase/(decrease): | | | |
| Debt issuance costs | $ 57,676 | $ (1,988) | $ 55,688 |
| Long-term debt, net of discount | 2,832,673 | (82,365) | 2,750,308 |
| Additional paid-in capital | 181,289 | 118,744 | 300,033 |

| | | | |
|---|---|---|---|
| Accumulated deficit | (785,389) | (38,367) | (823,756) |

Debt issuance costs decreased $2.0 million, representing the cumulative adjustment caused by a portion of debt issuance costs being reclassified to additional paid-in capital.

The cumulative effect of the change in accounting principles was a net loss of $7.1 million, recorded as an adjustment to our accumulated deficit as of January 1, 2007, from the retrospective increase in interest expense through December 31, 2006.

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 and lease option costs that are capitalized as property, plant and equipment and certain permits that 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.

We capitalize interest and other related debt costs during the construction period of our LNG receiving terminals. 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

The Sabine Pass LNG receiving terminal LNG regasification capacity reservation fees are recognized as revenue over the term of the respective terminal use agreement ("TUA"). Advance payments of capacity reservation fees are initially deferred and recognized as revenue and are being amortized over a 10-year period as a reduction of each customer's regasification capacity reservation fees payable under its TUA. The retained 2% of LNG delivered for each customer's account at the Sabine Pass LNG receiving terminal is recognized as revenues as Sabine Pass LNG performs the services set forth in each customer's TUA.

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, 2009 and 2008, we had no gas imbalances.

LNG and Natural Gas Marketing

We have determined that our LNG and natural gas marketing business activities are energy trading and risk management activities for trading purposes and have elected to present these activities on a net basis on our Consolidated Statement of Operations. Marketing and trading revenues represent the margin earned on the purchase and transportation of LNG purchases and subsequent sales of natural gas to third parties. These energy trading and risk management activities include, but are not limited to: purchase of LNG and natural gas, transportation contracts, and derivatives. Below is a brief description of our accounting treatment of each type of energy trading and risk management activity and how we account for it:

Purchase of LNG and natural gas

The purchase value of LNG or natural gas inventory is recorded as an asset on our Consolidated Balance Sheet at the cost to acquire the product. Our inventory is subject to lower-of-cost-or-market adjustment each quarter. Recoveries of losses resulting from interim period LCM adjustments are made due to market price recoveries on the same inventory in the same fiscal year and are recognized as gains in later interim periods with such gains not exceeding previously recognized losses. Any adjustment to our inventory is recorded on a net basis as LNG and natural gas marketing revenue on our Consolidated Statement of Operations.

Transportation contracts

We enter into transportation contracts with respect to the transport of LNG or natural gas to a specific location for storage or sale. Transportation costs that are incurred during the purchase of LNG or natural gas are capitalized as part of the acquisition costs of the product. Transportation costs incurred to sell LNG or natural gas are recorded on a net basis as LNG and natural gas marketing revenue on our Consolidated Statement of Operations.

Derivatives

We use derivative instruments from time to time to hedge the cash flow variability of our commodity trading activities. We have disclosed certain information regarding these derivative positions, including the fair value of our derivative positions, in Note 20—"Financial Instruments" of our Notes to Consolidated Financial Statements. We record changes in the fair value of our derivative positions in our LNG and natural gas marketing revenue on our Consolidated Statement of Operations based on the value for which the derivative instrument could be exchanged between willing parties. To date, all of our derivative positions fair value determinations have been made by management using quoted prices in active markets for identical instruments. The ultimate fair value of our derivative instruments is uncertain, and we believe that it is possible that a change in the estimated fair value will occur in the near future as commodity prices change.

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. The economic effects of regulation can result in a regulated company recording as assets those costs that have been or are expected to be approved for recovery from customers, or recording as liabilities those amounts that are expected to be required to be returned to customers, in a rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, we record assets and liabilities that result from the regulated rate-making process that may not be recorded under GAAP for non-regulated entities. We continually assess whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Based on this continual assessment, we believe the existing regulatory assets are probable of recovery. These regulatory assets and liabilities are primarily classified in the Consolidated Balance Sheets as Other Assets and Other Liabilities. We periodically evaluate their applicability under GAAP, and consider factors such as regulatory changes and the effect of competition. If cost-based regulation ends or competition increases, we may have to reduce our asset balances to reflect a market basis less than cost and write-off the associated regulatory assets and liabilities.

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.

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. 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. We began depreciating equipment and facilities associated with the remaining 1.4 Bcf/d of sendout capacity and 6.8 Bcf of storage capacity of the Sabine Pass LNG receiving terminal when they were ready for use in the third quarter of 2009. 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 15 and 50 years. 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.

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 no significant impairments related to fixed assets for 2009, 2008 or 2007.

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 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. Cash flow hedge transactions hedge the exposure to variability in expected future cash flows. In the case of cash flow hedges, the hedged item (the underlying risk) is generally unrecognized (i.e., not recorded on the consolidated 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, U.S. GAAP 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 consolidated 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.

Estimates used in the assessment of impairment of our long-lived assets, including goodwill, are the most significant of our estimates. There are numerous uncertainties inherent in estimating future cash flows of assets or business segments. The accuracy of any cash flow estimate is a function of judgment used in determining the amount of cash flows generated. As a result, cash flows may be different from the cash flows that we use to assess impairment of our assets. Management reviews its estimates of cash flows on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. Significant negative industry or economic trends, including a significant decline in the market price of our common stock, reduced estimates of future cash flows for our business segments or disruptions to our business could lead to an impairment charge of our long-lived assets, including goodwill and other intangible assets. Our valuation methodology for assessing impairment requires management to make judgments and assumptions based on historical experience and to rely heavily on projections of future operating performance. Projections of future operating results and cash flows may vary significantly from results. In addition, if our analysis results in an impairment of our long-lived assets, including goodwill, we may be required to record a charge to earnings in our consolidated financial statements during a period in which such impairment is determined to exist, which may negatively impact our results of operations.

Other items subject to estimates and assumptions include asset retirement obligations, valuation allowances for net deferred tax assets, valuation of derivative instruments, valuations of noncash compensation and collectability of accounts receivable and other assets.

As future events and their effects cannot be determined accurately, actual results could differ significantly from our 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

Goodwill represents the excess of cost over fair value of the assets of businesses acquired. It is evaluated annually for impairment by first comparing our management's estimate of the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit's goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in the amount of the excess. We had goodwill of approximately $76.8 million at December 31, 2009 and 2088, attributable to our LNG receiving terminal segment.

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. As discussed above regarding our use of estimates, our judgments and assumptions are inherent in our management's estimate of future cash flows used to determine the estimate of the reporting unit's fair value. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements.

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

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, using the Black-Scholes-Merton option valuation model. 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.

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, 2009 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 22—"Share-Based Compensation" of our Notes to Consolidated Financial Statements).

Net Loss Per Share

Net loss per share ("EPS") is computed in accordance with US GAAP. 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. 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 2009, 2008 and 2007, were $9.0 million, $4.9 million and $5.8 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 19—"Long-Term Debt and Long-Term Debt—Related Parties"), were not included in the computation of diluted net loss per share for 2009, 2008 and 2007, 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.

Asset Retirement Obligations

We recognize asset retirement obligations ("AROs") for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and for conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within our control. The fair value of a liability for an ARO is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset. Our recognition of asset retirement obligations is described below:

Natural Gas Pipeline

Currently, the Creole Trail natural gas pipeline is our only constructed and operating natural gas pipeline. We believe that it is not feasible to predict when the natural gas transportation services provided by the Creole Trail natural gas pipeline will no longer be utilized. In addition, our right-of-way agreements associated with the Creole Trail natural gas pipeline have no stipulated termination dates. Therefore, we have concluded that due to advanced technology associated with current natural gas pipelines and our intent to operate the Creole Trail natural gas pipeline as long as supply and demand for natural gas exists in the United States, we have not recorded an ARO associated with the Creole Trail natural gas pipeline.

LNG Receiving Terminal

Currently, the Sabine Pass LNG receiving terminal is our only constructed and operating LNG receiving terminal. Based on the real property lease agreement at the Sabine Pass LNG receiving terminal, at the expiration of the term of the lease we are required to surrender the LNG receiving terminal in good working order and repair, with normal wear and tear and casualty expected. Our property lease agreement at the Sabine Pass LNG receiving terminal has a term of up to 90 years including renewal options. Due to the language in the real property lease agreement, we have determined that the cost to surrender the LNG receiving terminal in the required condition will be minimal, and therefore have not recorded an ARO associated with the Sabine Pass LNG receiving terminal.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Recent Accounting Standards Not Yet Adopted

In June 2009, the FASB issued an amendment to the accounting and disclosure requirements for the consolidation of variable interest entities. The guidance affects the overall consolidation analysis and requires enhanced disclosures on involvement with variable interest entities. The guidance is effective for fiscal years beginning after November 15, 2009. We do not expect the adoption of this amendment to have a material impact on 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.

As of December 31, 2009, 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.

The portion of the common units held by the public is presented as a non-controlling interest on our Consolidated Balance Sheet. Losses attributable to the non-controlling interest are presented separately on our Consolidated Statement of Operations based upon the non-controlling 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 and have presented the financial impact as restructuring charges on the Consolidated Statements of Operations.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

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, 2009 (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) |
| Restructuring charges recognized as of December 31, 2008 | (5,429) | (2,583) | (70,692) | (78,704) |
| Estimated restructuring charges as of December 31, 2008 | 900 | — | — | 900 |
| | | | | |
| Adjustment to estimated restructuring charges as of December 31, 2009 | (880) | — | — | (880) |
| Restructuring charges recognized as of December 31, 2009 | (20) | — | — | (20) |
| Estimated restructuring charges as of December 31, 2009 | $— | $— | $— | $— |

NOTE 5—NON-CONTROLLING 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 entities' other equity is recorded as a non-controlling interest. The following table sets forth the components of our non-controlling 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' non-controlling interest | | (66,415) |
| Non-controlling interest share of loss of Cheniere Partners | | (18,368) |
| Non-controlling interest at December 31, 2009 | $ | 217,605 |

(1) In March and April 2007, we and Cheniere Energy Partners, L.P. ("Cheniere Partners") completed a public offering of 15,525,000 Cheniere Partners common units ("Cheniere Partners Offering"). Through the Cheniere Partners Offering, Cheniere Partners received $98.4 million in net proceeds from the issuance of its common units to the public. Prior to January 1, 2009, 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. Effective January 1, 2009, the sale of common equity of a subsidiary will be accounted for as an equity transaction.

(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 non-controlling interest.

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 19—"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.

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

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Sabine Pass LNG Receiving Terminal Construction Reserve

In November 2006, Sabine Pass LNG, L.P. (“Sabine Pass LNG”) issued an aggregate principal amount of $2,032.0 million of Senior Secured Notes consisting of $550.0 million of 7¼% Senior Secured Notes due 2013 (the “2013 Notes”) and $1,482.0 million of 7½% Senior Secured Notes due 2016 (the “2016 Notes” and collectively with the 2013 Notes, the “Senior 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 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”) (See Note 19—“Long-Term Debt and Long-Term Debt—Related Parties”). Under the term and conditions of the Senior Notes, Sabine Pass LNG was required to fund a cash reserve account for approximately $987 million to pay the remaining costs to complete construction of 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 Sheets. As of December 31, 2009, the Sabine Pass LNG receiving terminal construction reserve account balance was zero. As of December 31, 2008, the Sabine Pass LNG receiving terminal construction reserve account balance was $71.1 million, of which $27.4 million of the construction reserve account related to accrued construction costs that had been classified as part of current restricted cash and cash equivalents, and $43.7 million of the construction reserve account related to remaining construction costs had been classified as a non-current asset on our Consolidated Balance Sheets.

Senior Notes Debt Service Reserve

As described above, Sabine Pass LNG consummated private offerings of an aggregate principal amount of $2,215.5 million of Senior Notes (See Note 19—“Long-Term Debt and Long-Term Debt—Related Parties”). 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, and 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 are permitted only after satisfying the foregoing funding requirements, a fixed charge coverage ratio test of 2:1 and other conditions specified in the Sabine Pass Indenture. As of December 31, 2009 and 2008, we classified $13.7 million as current restricted cash and cash equivalents for the payment of interest due within twelve months. As of December 31, 2009 and 2008, we classified the permanent debt service reserve fund of $82.4 million as non-current restricted cash and cash equivalents. These cash accounts are controlled by a collateral trustee, and therefore, are shown as restricted cash and cash equivalents on our Consolidated Balance Sheets.

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 5—“Non-Controlling Interest”). The distribution reserve, including interest earned thereon, was available to be used 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 ended June 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 provided under the Cheniere Partners partnership agreement, any amount remaining in the distribution reserve was to be distributed to us. Cheniere Partners received sufficient cash from Sabine Pass LNG to make distributions to all of its unitholders without withdrawing certain funds from the distribution reserve account. Cheniere Partners therefore distributed $34.9 million to us from the distribution reserve account in August 2009.

As of December 31, 2009 and 2008, we classified $0.1 million and zero as current restricted cash and cash equivalents that may be utilized to pay quarterly distributions. As of December 31, 2009 and 2008, we classified zero and $12.0 million as non-current restricted cash that may be utilized to pay quarterly distributions, respectively. In addition, as of December 31, 2009 and 2008, we classified zero and $20.8 million as non-current restricted U.S. Treasury securities on our Consolidated Balance Sheets that may be utilized to pay quarterly distributions, 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 19—"Long-Term Debt and Long-Term Debt—Related Parties", we were required to fund a reserve account with $135.0 million to pay obligations of Cheniere Marketing under its Terminal Use Agreement ("TUA") with Sabine Pass LNG and as additional collateral for the 2008 Convertible Loans. We

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

continue to fund this account using quarterly distributions received from distributions on Cheniere's common, subordinated and general partner units in Cheniere Partners. The cash account is controlled by a collateral trustee, and therefore, is shown as restricted cash and cash equivalents on our Consolidated Balance Sheets. In June 2009, through an amendment of the 2008 Convertible Loans, we moved $65.2 million out of the TUA reserve account into an unrestricted cash and cash equivalent account. In addition, we made Cheniere Marketing's December 2009 TUA payment in the amount of $62.7 million to Sabine Pass LNG from this account, leaving the balance of the TUA reserve account at zero as of December 31, 2009. As of December 31, 2008, we classified $62.8 million as part of current restricted cash and cash equivalents on our Consolidated Balance Sheets because these funds were held by Sabine Pass LNG.

Other Restricted Cash and Cash Equivalents

As of December 31, 2009 and 2008, $124.4 million and $197.7 million, respectively, of cash and cash equivalents was primarily related to cash and cash equivalents held by Sabine Pass LNG and Cheniere Partners that is considered restricted to Cheniere.  In addition, due to various other contractual restrictions, $0.5 million had been classified as non-current restricted cash and cash equivalents on our Consolidated Balance Sheets, respectively.

## NOTE 8—LEASES

### Future Annual Minimum Lease Payments

Future annual minimum lease payments, excluding inflationary adjustments, are as follows (in thousands):

| Years Ending December 31, | | Operating Leases (2) (3) |
|---|---|---|
| 2010 | $ | 13,853 |
| 2011 | | 13,936 |
| 2012 | | 14,272 |
| 2013 | | 14,724 |
| 2014 | | 13,304 |
| Thereafter (1)(2) | | 256,432 |
| Total | $ | 326,521 |

(1) Includes certain lease option renewals as they were reasonably assured.

(2) Future annual minimum lease payments do not include $86.4 million of future sublease payments we will receive from our two third-party TUA customers that effectively offsets two-thirds of our lease payment obligation, as discussed below.  Future annual minimum lease payments also do not include $4.8 million expected to be recovered through sublease agreements for our Texas Avenue office lease in Houston, Texas, and $7.7 million expected to be recovered for our Pennzoil office lease.

(3) Lease payments for our tug boat lease represent third-party tug boat lease payment obligations and do not take into account the payments we receive from our third-party TUA customers that effectively offset two-thirds of our lease payment obligation, as discussed below.

Tug Boat Agreements

Sabine Pass Tug Services, LLC (“Tug Services”), 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 accounting literature on how to determine 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, 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.

In the second quarter of 2009, Tug Services entered into a Tug Sharing Agreement with Sabine Pass LNG's three TUA customers to provide their LNG cargo vessels with tug boat and marine services at the Sabine Pass LNG receiving terminal and effectively offset the cost of the tug boat lease. The Tug Sharing Agreement provides for each of our customers to pay Tug Services an annual service fee.

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 in each of 2009 and 2008.

## NOTE 9—ADVANCES UNDER LONG-TERM CONTRACTS

We entered into certain engineering, procurement and construction ("EPC") contracts and purchase agreements related to the construction of the 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, 2009 and 2008, our advances under long-term contracts were $1.0 million and $10.7 million, respectively.

## NOTE 10—LNG HELD FOR COMMISSIONING

LNG purchased for commissioning activities is recorded at cost and classified as a non-current asset on our Consolidated Balance Sheets as LNG held for commissioning. As the LNG held for commissioning is used to cool down the LNG receiving terminal and establish LNG heel in the LNG receiving terminal, we capitalize the portion used. The LNG used in the commissioning process is capitalized net of amounts received from the sale of natural gas.

As of September 30, 2009, commissioning activities and construction of the Sabine Pass LNG receiving terminal were substantially complete; therefore, we no longer needed the remaining LNG held for commissioning. We had 1,115,000 MMBtu of LNG Held for Commissioning remaining at September 30, 2009 which was reclassified to current assets as $3.5 million of LNG inventory, representing the market value of LNG inventory that we have retained for operations.

At December 31, 2008, we had $9.9 million recorded as LNG held for commissioning on our Consolidated Balance Sheets.

## NOTE 11—LNG INVENTORY

LNG inventory is recorded at cost and is subject to the lower of cost or market adjustments at the end of each period. Inventory cost is determined using the average cost method. Recoveries of losses resulting from interim period LCM adjustments are made due to market price recoveries on the same inventory in the same fiscal year and are recognized as gains in later interim periods with such gains not exceeding previously recognized losses. As of December 31, 2009, we had 7,778,000 MMBtu of LNG inventory recorded at $32.6 million on our Consolidated Balance Sheet. As of December 31, 2008, we had no LNG inventory on our Consolidated Balance Sheet. We purchased 9,127,000 MMBtu of LNG inventory during the year ended December 31, 2009. In addition, we reclassified 1,115,000 MMBtu of LNG held for commissioning to LNG inventory in September 2009 as described in Note 10—"LNG Held for Commissioning." We have entered into natural gas swaps and forward foreign exchange contracts to hedge the exposure to variability in expected future cash flows related to the sale of the majority of our LNG inventory (see Note 20—"Financial Instruments"). During the year ended December 31, 2009, we incurred losses of $3.3 million related to lower of cost or market adjustments that are presented net within Marketing and trading revenue in our Consolidated Statement of Operations.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

NOTE 12—PROPERTY, PLANT AND EQUIPMENT

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

| | December 31, 2009 | December 31, 2008 |
|---|---|---|
| LNG TERMINAL COSTS | | |
| LNG receiving terminal | $1,637,542 | $927,298 |
| LNG receiving terminal construction-in-process | 37,120 | 643,340 |
| LNG site and related costs, net | 2,994 | 2,579 |
| Accumulated depreciation | (40,200) | (7,813) |
| Total LNG receiving terminal costs | $1,637,456 | $1,565,404 |
| | | |
| NATURAL GAS PIPELINE COSTS | | |
| Natural gas pipeline | $564,213 | $562,893 |
| Natural gas pipeline construction-in-process | 1,995 | 7,937 |
| Pipeline right-of-ways | 18,455 | 18,221 |
| Accumulated depreciation | (23,004) | (8,454) |
| Total natural gas pipeline costs | $561,659 | $580,597 |
| | | |
| OIL AND GAS PROPERTIES, successful efforts method | | |
| Proved | $3,565 | $3,439 |
| Accumulated depreciation, depletion and amortization | (1,787) | (1,043) |
| Total oil and gas properties, net | $1,778 | $2,396 |
| | | |
| FIXED ASSETS | | |
| Computers and office equipment | $5,799 | $5,693 |
| Furniture and fixtures | 5,291 | 5,315 |
| Computer software | 12,284 | 12,128 |
| Leasehold improvements | 9,258 | 9,208 |
| Other | 1,488 | 1,254 |
| Accumulated depreciation | (18,158) | (11,837) |
| Total fixed assets, net | $15,962 | $21,761 |
| | | |
| PROPERTY, PLANT AND EQUIPMENT, NET | $2,216,855 | $2,170,158 |

LNG Terminal Costs

As of December 31, 2009, the Sabine Pass LNG receiving terminal had been placed into service, and all costs associated with the construction of the Sabine Pass LNG receiving terminal are presented in the table above as LNG receiving terminal. For 2009 and 2008, we capitalized $26.1 million and $80.7 million of interest expense related to the construction of the Sabine Pass LNG receiving terminal, respectively.

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. We began depreciating equipment and facilities associated with the remaining 1.4 Bcf/d of sendout capacity and 6.8 Bcf of storage capacity of the Sabine Pass LNG receiving terminal when they were ready for use in the third quarter of 2009. 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 15 and 50 years, as follows:

| Components | Useful life (yrs) |
| --- | --- |
| LNG storage tanks | 50 |
| Marine berth, electrical, facility and roads | 35 |
| Regasification processing equipment (recondensers, vaporization, and vents) | 30 |
| Sendout pumps | 20 |
| Other | 15-30 |

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

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. As of December 31, 2009, $34.0 million of costs associated with the initial site work for the Corpus Christi LNG receiving terminal were capitalized as LNG receiving terminal construction-in-process (including capitalized interest related to this construction project for the years ended December 31, 2009 and 2008, of zero and $0.6 million, respectively). As noted in Note 2—"Summary of Significant Accounting Policies," 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. At December 31, 2009, management determined that the $34.0 million of costs capitalized were more likely than not recoverable in the future. Management's assessment is based on certain estimates and assumptions used to determine if impairment is warranted. If the estimates and assumptions used are determined to be different in the future, the amount capitalized may be subject to impairment.

Natural Gas Pipeline Costs

Our 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. The economic effects of regulation can result in a regulated company recording as assets those costs that have been or are expected to be approved for recovery from customers, or recording as liabilities those amounts that are expected to be required to be returned to customers, in a rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, we record assets and liabilities that result from the regulated rate-making process that may not be recorded under GAAP for non-regulated entities. We continually assess whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Based on this continual assessment, we believe the existing regulatory assets are probable of recovery. These regulatory assets and liabilities are primarily classified in the Consolidated Balance Sheets as Other Assets and Other Liabilities. We periodically evaluate their applicability under GAAP, and consider factors such as regulatory changes and the effect of competition. If cost-based regulation ends or competition increases, we may have to reduce our asset balances to reflect a market basis less than cost and write-off the associated regulatory assets and liabilities.

For the years ended December 31, 2009 and 2008, we capitalized zero and $17.0 million, respectively, of Allowance for Funds Used During Construction ("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 $54.2 million, $24.3 million and $5.7 million for the years ended December 31, 2009, 2008 and 2007, respectively.

## NOTE 13—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, 2009, we had capitalized $47 million of costs directly associated with the arrangement of debt financing, net of accumulated amortization, as follows (in thousands):

| Long-term Debt | Amortization Period | Net Costs |
|---|---|---|

| | Debt Issuance Costs | | Accumulated Amortization | |
|---|---|---|---|---|
| 2013 Senior Notes | $9,353 | 7 years | $ (3,993 ) | $5,360 |
| 2016 Senior Notes | 30,057 | 10 years | (8,465 ) | 21,592 |
| 2007 Term Loan | 8,450 | 5 years | (4,364 ) | 4,086 |
| 2008 Convertible Loans | 16,942 | 10 years | (2,295 ) | 14,647 |
| Convertible Senior Unsecured Notes | 6,613 | 7 years | (5,315 ) | 1,298 |
| Marketing Credit Facility | 60 | 1 year | — | 60 |
| | $71,475 | | $ (24,432 ) | $47,043 |

Scheduled amortization of these debt issuance costs for the next five years is estimated to be $40.5 million.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

## NOTE 14—INVESTMENT IN LIMITED PARTNERSHIP

We account for our 30% limited partnership investment in Freeport LNG using the equity method of accounting. As of December 31, 2009 and 2008, we had unrecorded cumulative suspended losses of $10.9 million and $27.2 million, respectively, related to our investment in Freeport LNG, as the basis in this investment had been reduced to zero.

During 2009, Freeport LNG distributed $15.3 million to us.

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 suspended losses in Freeport LNG. In addition, Freeport LNG distributed $4.8 million to us in October 2008.

The financial position of Freeport LNG at December 31, 2009 and December 31, 2008 and the results of Freeport LNG's operations for the years ended December 31, 2009 and 2008 are summarized as follows (in thousands):

| | December 31, | |
|---|---|---|
| | 2009 | 2008 |
| Current assets | $113,387 | $72,834 |
| Property, plant and equipment, net | 861,386 | 887,388 |
| Construction-in-process | 71,544 | 62,768 |
| Other assets | 37,596 | 31,608 |
| Total assets | $1,083,913 | $1,054,598 |
| | | |
| Current liabilities | $86,677 | $61,317 |
| Notes payable, net of current maturities | 1,089,494 | 1,090,086 |
| Deferred revenue and other deferred credits | 16,563 | 15,401 |
| Partners' capital | (108,821) | (112,206) |
| Total liabilities and partners' capital | $1,083,913 | $1,054,598 |

| | Year ended December 31, | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| Revenue | $229,522 | $116,359 | $— |
| Income (loss) from continuing operations | 134,468 | (7,890) | (16,677) |
| Net income (loss) | 54,385 | (40,730) | (22,542) |
| Cheniere's 30% share of income (loss) from equity method investment (1) | $16,316 | $(12,219) | $(6,763) |

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(1) During 2009, 2008 and 2007, we did not record $16.3 million, $12.2 million and $6.8 million of the net income (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 15—GOODWILL

In February 2005, we acquired the non-controlling 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 and was valued at $77.2 million, including direct transaction costs. Of this amount, $76.8 million has been recorded as goodwill. The goodwill is the difference between the deemed value of the shares conveyed and the historical carrying value of the non-controlling 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 2009 and 2008. 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 16—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 $700.0 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 $700.0 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 $822.0 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 $600.0 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 $600.0 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

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 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 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.

The effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument is 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 for 2009, 2008 and 2007, 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 2009 and 2008, we recognized a net derivative gain of $5.3 million and $4.7 million, respectively.

## NOTE 17—ACCRUED LIABILITIES

As of December 31, 2009 and 2008, accrued liabilities consisted of the following (in thousands):

| | December 31, | |
|---|---|---|
| | 2009 | 2008 |
| Accrued interest expense and related fees | $16,179 | $17,305 |
| Payroll | 11,118 | 8,717 |
| LNG terminal construction costs | 10,335 | 26,768 |
| Pipeline construction costs | 22 | 5,102 |
| Other accrued liabilities | 771 | 3,991 |
| Accrued liabilities | $38,425 | $61,883 |

## NOTE 18—DEFERRED REVENUE

As of December 31, 2009 and 2008, we had recorded $26.5 million and $2.5 million, respectively, as current deferred revenue and $33.5 million and $37.5 million, respectively, as non-current deferred revenue related to advance capacity reservation fee payments.

In November 2004, Total Gas and Power North America, Inc. (formerly known as 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 are being amortized as a reduction of Total’s regasification capacity fee under its TUA over a 10-year period beginning with the commencement of its TUA on April 1, 2009. As a result, we recorded the advance capacity reservation fee payments that Sabine Pass LNG received, although non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

In November 2004, Sabine Pass LNG 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, making advance capacity reservation fee payments to Sabine Pass LNG totaling $20.0 million. The advance capacity reservation fee payments are being amortized as a reduction of Chevron’s regasification capacity reservation fee under its TUA over a 10-year period beginning with the commencement of its TUA on July 1, 2009. As a result, we recorded the advance capacity reservation fee payments that Sabine Pass LNG received, although non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

## NOTE 19—LONG-TERM DEBT AND LONG-TERM DEBT—RELATED PARTIES

As of December 31, 2009 and 2008, our long-term debt consisted of the following (in thousands):

| | December 31, 2009 | December 31, 2008 (as adjusted) |
|---|---|---|
| Long-term debt (including related parties): | | |
| Senior Notes (including related parties) | $2,215,500 | $2,215,500 |
| 2007 Term Loan | 400,000 | 400,000 |
| 2008 Convertible Loans (including related parties) | 293,714 | 261,393 |
| Convertible Senior Unsecured Notes | 204,630 | 325,000 |
| Total long-term debt | 3,113,844 | 3,201,893 |
| Debt discount: | | |
| Senior Notes (including related parties) | (32,471) | (37,166) |
| Convertible Senior Unsecured Notes | (39,498) | (82,365) |
| Total debt discount | (71,969) | (119,531) |
| Long-term debt (including related parties), net of discount | $3,041,875 | $3,082,362 |

Below is a schedule of future principal payments that we are obligated to make on our outstanding long-term debt at December 31, 2009 (in thousands):

| | Total | Payments Due for the Years Ended December 31, 2010 | 2011 to 2012 | 2013 to 2014 | Thereafter |
|---|---|---|---|---|---|
| Long-term debt (including related parties): | | | | | |
| Senior Notes | $ 2,215,500 | $ — | $ — | $ 550,000 | $ 1,665,500 |
| 2007 Term Loan | 400,000 | — | 400,000 | — | — |
| 2008 Convertible Loans | 354,691 | — | 354,691 | — | — |
| Convertible Senior Unsecured Notes | 204,630 | — | 204,630 | — | — |
| Total long-term debt (including related parties) | $ 3,174,821 | $ — | $ 959,321 | $ 550,000 | $ 1,665,500 |

### 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 received from the additional issuance of the 2016 Notes were $145.0 million. One of the lenders making a portion of the loans evidenced by the additional 2016 Notes was GSO Capital Partners, L.P. (“GSO”), an affiliate of two members of Cheniere’s board of directors. GSO, a related party, did not receive any fees in connection with 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 that Sabine Pass LNG entered into in connection with the Senior Notes, which are used by Sabine Pass LNG for working capital and other general business purposes.

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, and 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 are permitted only after satisfying the foregoing funding requirements, a fixed charge coverage ratio test of 2:1 and other conditions specified in the Sabine Pass Indenture. During the years ended December 31, 2009 and 2008, Sabine Pass LNG made distributions of $295.7 million and zero, respectively, after satisfying all the applicable conditions in the Sabine Pass Indenture.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

As of December 31, 2009 and 2008, we classified $72.9 million and $70.7 million, respectively, as part of Long-Term Debt—Related Party on our Consolidated Balance Sheets because related parties held these portions of this debt.

Convertible Senior Unsecured Notes

In July 2005, we consummated a private offering of $325.0 million aggregate principal amount of Convertible Senior Unsecured Notes 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 2¼% 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, 2009, no holders had elected to convert their notes at the conversion rate.

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 indenture governing the notes contains customary reporting requirements.

As discussed in Note 2—"Summary of Significant Accounting Policies", we adopted on January 1, 2009 an accounting standard that requires issuers of certain convertible debt instruments to separately account for the liability component and the equity component represented by the embedded conversion option in a manner that will reflect that entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. The following table summarizes the liability component of the Convertible Senior Unsecured Notes (in thousands):

| | December 31, 2009 | December 31, 2008 (As adjusted) |
|---|---|---|
| Principal amount | $ 204,630 | $ 325,000 |
| Unamortized discount | (39,498) | (82,365) |
| Net carry amount | $ 165,132 | $ 242,635 |

The unamortized discount is being amortized through the August 2012 maturity of the Convertible Senior Unsecured Notes. Interest expense for the Convertible Senior Unsecured Notes, including the debt discount amortization for the year ended December 31, 2009 and 2008 was $21.3 million and $25.2 million, respectively. The effective interest rate as of December 31, 2009 was 10.9% for the Convertible Senior Unsecured Notes.

During the second quarter of 2009, we reduced debt by exchanging $120.4 million aggregate principal amount of our Convertible Senior Unsecured Notes for a combination of $30.0 million cash and cash equivalents and 4.0 million shares of common stock, reducing our principal amount due in 2012 to $204.6 million at December 31, 2009. As a result of the exchange, we recognized a gain of $45.4 million that we have reported as gain on early extinguishment of debt in our Consolidated Statements of Operations for the year ended December 31, 2009.

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 9¾% 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 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 30 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 a reservation fee and operating fee under Cheniere Marketing's TUA. We utilized $95.0 million of the borrowings under the 2008 Convertible Loans to repay a $95.0 million bridge loan. The remaining borrowings were utilized to pay for interest on the $95.0 million 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.

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. In addition, one of the lenders is Scorpion Capital Partners LP ("Scorpion"), an affiliate of one of the Company's directors. As of December 31, 2009 and 2008, $276.2 million and $261.4 million, respectively, were outstanding under the 2008 Convertible Loans and were included in Long-term Debt—Related Party on our Consolidated Balance Sheets.

## NOTE 20—FINANCIAL INSTRUMENTS

We entered into financial derivatives to hedge the exposure to variability in expected future cash flows and currency fluctuations attributable to the future sale of natural gas from our LNG commissioning cargoes ("LNG commissioning cargo derivatives") and for the future sale of natural gas that is purchased by Cheniere Marketing ("commercial LNG derivatives"). Commercial LNG is recorded at cost as LNG inventory on our Consolidated Balance Sheets and is subject to the lower of cost or market adjustments at the end of each period. Prior to September 30, 2009, the net cost of our LNG commissioning cargoes (LNG commissioning cargo purchase price less natural gas sales proceeds) was capitalized on our Consolidated Balance Sheets as it directly related to the LNG receiving terminal construction and was incurred to place the LNG receiving terminal in usable condition. However, changes in the fair value of our commercial LNG and LNG commissioning cargoes derivatives are reported in earnings because they do not meet the criteria to be designated as a hedging instrument that is required to qualify for cash flow hedge accounting.

Effective January 1, 2008, we adopted accounting standards that establish a framework for measuring fair value and expanded disclosures about fair value measurements, which permitted entities to choose to measure many financial instruments and certain other items at fair value. 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 fair value of our commodity futures contracts are based on inputs that are quoted prices in active markets for identical assets or liabilities, resulting in Level 1 categorization of such measurements. The following table (in thousands) sets forth, by level within the fair value hierarchy, the fair value of our financial assets and liabilities at December 31, 2009:

| | Quoted Prices in Active Markets for Identical Instruments (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total Carrying Value |
|---|---|---|---|---|
| Derivatives liability | $ 905 | — | — | $ 905 |

Derivatives liability reflects the fair value of natural gas swaps entered into to hedge the cash flows from the sale of LNG inventory.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The estimated fair value of financial instruments, including those financial instruments for which the fair value option was not elected are set forth in the table below. The carrying amounts reported on our Consolidated Balance Sheets for cash and cash equivalents, restricted cash and cash equivalents, accounts receivable, interest receivables, and accounts payable approximate fair value due to their short-term nature.

Financial Instruments (in thousands):

| | December 31, 2009 | | December 31, 2008 | |
|---|---|---|---|---|
| | Carrying Amount | Estimated Fair Value | Carrying Amount (As adjusted) | Estimated Fair Value (As adjusted) |
| 2013 Notes (1) | $ 550,000 | $ 503,250 | $ 550,000 | $ 412,500 |
| 2016 Notes, net of discount (1) | 1,633,029 | 1,371,744 | 1,628,334 | 1,204,967 |
| Convertible Senior Unsecured Notes, net of discount (2) | 165,132 | 95,777 | 242,635 | 37,608 |
| 2007 Term Loan (3) | 400,000 | 384,640 | 400,000 | 242,447 |
| 2008 Convertible Loans (3) | 293,714 | 299,001 | 261,393 | 119,491 |
| Restricted U.S. Treasury securities (4) | — | — | 20,829 | 22,901 |

(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, 2009 and 2008, as applicable.

(2) The fair value of our Convertible Senior Unsecured Notes is based on the closing trading prices on December 31, 2009 and 2008, as applicable.

(3) The 2007 Term Loan and 2008 Convertible Loans are closely held by few holders and purchases and sales are infrequent and are conducted on a bilateral basis without price discovery by us. These loans are not rated and have unique covenants and collateral packages such that comparisons to other instruments would be imprecise. Moreover, the 2008 Convertible Loans are convertible into shares of Cheniere common stock. Nonetheless, we have provided an estimate of the fair value of these loans as of December 31, 2009 and 2008 based on an index of the yield to maturity of CCC rated debt of other companies in the energy sector.

(4) 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 2009, as applicable.

## NOTE 21—INCOME TAXES

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| Current federal income tax expense | $— | $— | $— |
| Deferred federal income tax (provision) benefit | — | — | — |
| Total income tax (provision) benefit | $— | $— | $— |

From our inception, we have reported net operating losses (“NOLs”) 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 consolidated financial statements.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

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

| | Year Ended December 31, 2009 | 2008 | 2007 |
|---|---|---|---|
| U.S. statutory tax rate | 35.0 % | 35.0 % | 35.0 % |
| Deferred tax asset valuation reserve | (42.6) % | (39.1) % | (38.4) % |
| State tax benefit | 7.1 % | 3.7 % | 3.8 % |
| All other | 0.5 % | 0.4 % | (0.4) % |
| Effective tax rate as reported | — % | — % | — % |

Significant components of our deferred tax assets and liabilities at December 31, 2009 and 2008 are as follows (in thousands):

| | Year Ended December 31, 2009 | 2008 (As Adjusted) (1) |
|---|---|---|
| Deferred tax assets | | |
| Net operating loss carryforward (2) | $265,717 | $184,588 |
| Investment in limited partnership | 53,056 | 81,429 |
| Stock award compensation expense | 35,835 | 31,317 |
| Start-up costs and construction-in-process associated with LNG, pipeline and marketing activities | 8,861 | 8,861 |
| Oil and gas properties and fixed assets | 2,382 | 2,500 |
| Other | 12,208 | — |
| Total deferred tax assets | $378,059 | $308,695 |
| | | |
| Deferred tax liabilities | | |
| Pipeline tax depreciation | $(23,286) | $(2,478) |
| Other | (15,420) | (32,827) |
| Total deferred tax liabilities | $(38,706) | $(35,305) |
| | | |
| Net deferred tax assets | $339,353 | $273,390 |
| Less: tax asset valuation allowance (3) | (339,353) | (273,390) |
| | $— | $— |

(1) We have made certain changes in the classification and presentation of certain gross deferred tax assets and liabilities which had a corresponding change in the valuation allowance. The net deferred tax assets and liabilities have not changed.

(2) The December 31, 2009 NOL carryforward is composed of approximately $229 million federal NOL carryforward and approximately $37 million state NOL carryforward. If the NOL carryforward is not utilized it will begin to expire between 2011 and 2029.

(3) 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 NOL carryforward and other deferred tax assets. The change in the deferred tax asset valuation allowance was $66.0 million and $117.4 million for the years ended December 31, 2009 and 2008, respectively. The change in the 2009 valuation allowance from 2008 includes a $2.8 million decrease for expiring, cancelled, and exercised options that were formerly offset by a full valuation allowance.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Changes in the balance of unrecognized tax benefits excluding tax, interest and penalties are as follows (in thousands):

| | |
|---|---|
| Balance as January 1, 2009 | $22,187 |
| Reductions for tax positions of prior years | (310) |
| Balance at December 31, 2009 | $21,877 |

At December 31, 2009, we had $21.9 million of unrecognized federal income tax benefits that pertain to tax positions taken in the prior years for which there is uncertainty as to the timing of the corresponding tax deductions, but which the ultimate deductibility is highly certain. 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 NOL carryforward, 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.

Internal Revenue Code (“I.R.C.”) 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 the previous three year testing period. The minimum annual NOL utilization limitation amount is determined by multiplying the company’s market capitalization value on the ownership change date by the applicable federal interest rate. 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. 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 fourth quarter of 2008, largely due to the increased level of trading activity in our shares, we experienced an ownership change within Section 382 that will subject approximately $600 million of our existing tax NOL carryforwards to the annual NOL utilization limitations. The applicable Section 382 limitation may affect our ability to fully utilize our existing tax NOL carryforwards. Our ability to fully utilize our existing tax NOL carryforwards is dependent on increasing the recognition of built-in gains in the five-year period following the above-referenced ownership change.

## NOTE 22—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”). We recognize our share-based payments to employees in the consolidated 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.

For the years ended December 31, 2009, 2008 and 2007, the total share-based compensation expense recognized in our net loss (net of capitalization) was $19.2 million, $55.0 million and $56.6 million, respectively. 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, 2009, 2008 and 2007, the cumulative adjustment recognized in our compensation expense was $1.0 million, $14.5 million, and $4.8 million respectively. For the years ended December 31, 2009, 2008 and 2007, the total share-based compensation cost capitalized as part of the cost of capital assets was $1.1 million, $2.4 million and $1.7 million, respectively.

The total unrecognized compensation cost at December 31, 2009 relating to non-vested share-based compensation arrangements granted under the 1997 Plan and 2003 Plan, before any capitalization, was $24.9 million. That cost is expected to be recognized over 3.75 years, with a weighted average period of 0.92 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 21—"Income Taxes", 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.

We received total proceeds from the exercise of stock options of zero, $0.5 million and $3.2 million in the years ended December 31, 2009, 2008 and 2007, respectively.

Phantom Stock

On February 25, 2009, the Compensation Committee made phantom stock grants of 5,545,000 shares pursuant to our 2003 Plan to all Cheniere executives, designated employees and one consultant. On June 12, 2009, the Compensation Committee made additional phantom stock grants of 800,000 shares to our Chief Executive Officer pursuant to the approval from our stockholders to increase the maximum number of shares granted to any one individual under our 2003 Plan during a calendar year from 1.0 million shares to 3.0 million shares. The shares were awarded under a time based plan and a performance based plan. The time based plan includes 1,565,000 shares and provides for a three-year graded vesting schedule. One-third of the compensation, or 522,000 shares, vested on December 15, 2009. The remaining two-thirds will vest equally on December 15, 2010 and 2011. The performance based plan includes 4,780,000 shares and divides each grant into three equal parts providing incentive compensation based on separate vesting terms. Vested shares of phantom stock will be settled in cash or in shares of common stock, as determined by the Compensation Committee. In June 2009, we obtained approval from our shareholders to increase the number of shares of common stock available for issuance under our 2003 Plan from 11.0 million common shares to 21.0 million common shares, which provided the required number of common shares needed to satisfy vested phantom stock. We transferred the fair valued compensation liability associated with these phantom grants into additional paid-in capital. Using a Monte Carlo simulation, fair values were calculated as of June 12, 2009 for the time and performance based plans. For the year ended December 31, 2009, a total of $5.9 million was recognized as compensation expense relating to time and performance based phantom stock grants. We will account for these phantom grants similar to restricted stock as we intend to settle and historically have settled these types of instruments with common shares. The total unrecognized compensation cost at December 31, 2009 relating to non-vested phantom stock, before any capitalization, was $13.7 million and is expected to be recognized over 2.0 years, with a weighted average period of 1.12 years.

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 through 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. 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 forfeitures of the phantom shares, a total of $5.1 million of unrecognized compensation cost was recognized. Subsequently, on February 19, 2009, the Compensation Committee of our Board of Directors (the "Compensation Committee") cancelled the 2008–2010 Phantom Incentive Compensation Plan (the "Incentive Plan").

Stock Options

We estimate the fair value of stock options at the date of grant using a Black-Scholes valuation model. 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, 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, 2009.

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.  These options were granted during 2005 and 2006 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. In connection with the cancellation of the phantom shares, a total of $19.6 million of unrecognized compensation expense was recorded.

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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.

The table below provides a summary of option activity under the combined plans as of December 31, 2009:

| | Options (in thousands) | Weighted Average Exercise Price | Weighted Average Remaining Contractual Term | Aggregate Intrinsic Value (in thousands) |
|---|---|---|---|---|
| Outstanding at January 1, 2009 | 1,206 | $ 28.96 | | |
| Granted | — | — | | |
| Exercised | — | — | | |
| Forfeited or Expired | (323) | 36.07 | | |
| Outstanding at December 31, 2009 | 883 | $ 26.36 | 4.94 | $ — |
| Exercisable at December 31, 2009 | 860 | $ 26.00 | 4.90 | $ — |

The weighted average grant-date fair value of options granted during the years ended December 31, 2009, 2008 and 2007 was zero, zero and $19.44, respectively. The total intrinsic value of options exercised during the years ended December 31, 2009, 2008 and 2007 was zero, $1.0 million and $19.3 million, respectively.

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. Grants of non-vested stock are accounted for on an intrinsic value basis. 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.

For the years ended December 31, 2009, 2008 and 2007, we issued 522,000 shares, 537,000 shares and zero, respectively, of performance vested stock awards to our executives and certain officers.

For the years ended December 31, 2009, 2008 and 2007, we issued 325,000 shares, 4,379,000 shares and 1,061,000 shares, respectively, of non-vested stock awards to our employees, executives, directors and a consultant as performance, retention, service and new hire awards. A majority of the awards were issued with a one, three or four-year graded vesting period. A certain group of 2007 retention grants received a vesting schedule of 50% on December 1, 2008, 30% on December 1, 2009 and 20% on June 1, 2010.

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.

The table below provides a summary of the status of our non-vested shares under the 2003 Plan as of December 31, 2009 (in thousands except for per share information):

| | Non Vested Shares | Weighted Average Grant Date Fair Value Per Share |
|---|---|---|
| Non-vested at January 1, 2009 | 3,724 | $3.46 |
| Granted | 847 | — |
| Vested | (2,176) | 3.07 |
| Forfeited | (88) | 4.48 |
| Non-vested at December 31, 2009 | 2,307 | $2.52 |

The weighted average grant-date fair values of non-vested stock granted during the years ended December 31, 2009, 2008 and

2007 were zero, $9.40 and $31.99, respectively. The total grant-date fair values of shares vested during the years ended December 31, 2009, 2008 and 2007 were $5.4 million, $6.8 million and $7.8 million, respectively.

Share-based Plan Descriptions and Information

Our 1997 Plan provides 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.

In June 2009, we obtained approval from our stockholders to increase the number of shares of common stock available for issuance under our 2003 Plan from 11.0 million shares to 21.0 million shares. 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, restricted stock units and phantom 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 $1.4 million, $2.3 million and $1.8 million for the years ended December 31, 2009, 2008, and 2007, respectively. We have made no discretionary contributions to the 401(k) Plan to date.

NOTE 23—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, | | |
|---|---|---|---|
| | 2009 | 2008 (as adjusted) | 2007 (as adjusted) |
| Net loss | $(161,490) | $(372,959) | $(196,580) |
| Other comprehensive (loss) income item: | | | |
| Foreign currency translation | 21 | (149) | 29 |
| Comprehensive loss | $(161,469) | $(373,108) | $(196,551) |

NOTE 24—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. 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

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. Freeport LNG has assumed the obligation to pay the Crest Royalty for natural gas processed at Freeport LNG's receiving terminal. 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 first production year began in April 2009.

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.

LNG Terminal EPC Agreements

In July 2006, Sabine Pass LNG entered into an engineering, procurement, construction and management ("EPCM") agreement with Bechtel Corporation ("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 initial terms of the EPCM agreement, Bechtel was paid on a cost reimbursable basis, plus a fixed fee in the initial amount of $18.5 million. A discretionary bonus was paid to Bechtel at Sabine Pass LNG's sole discretion upon completion of the expansion. As of December 31, 2009, we were committed to make cash payments of approximately $2.6 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 were made upon final completion.

Restricted Net Assets

At December 31, 2009, our restricted net assets of consolidated subsidiaries were approximately ($477) 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, as of December 31, 2009, 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 25—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 consists of the operational Sabine Pass LNG receiving terminal, approximately 90.6% owned (at December 31, 2009) in western Cameron Parish, Louisiana on the Sabine Pass Channel and two other LNG receiving terminals that are in various stages of development at the following locations: 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 consists of the Creole Trail Pipeline, consisting of 94 miles of natural gas pipeline

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

connecting the Sabine Pass LNG receiving terminal to numerous interconnections points with existing interstate natural gas pipelines in southwest Louisiana, and other natural gas pipelines in various stages of development 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 focuses 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.

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

| | | | Segments | | |
|---|---|---|---|---|---|
| | LNG Receiving Terminal | Natural Gas Pipeline | LNG & Natural Gas Marketing | Corporate and Other (1) | Total Consolidation |
| As of or for the Year Ended December 31, 2009 | | | | | |
| Revenues | $170,071 | $102 | $8,087 | $2,866 | $ 181,126 |
| Intersegment revenues (losses) (2) (3) (4) (5) | 252,928 | 932 | (249,196 ) | (4,664 ) | — |
| Depreciation, depletion and amortization | 33,203 | 14,731 | 1,505 | 4,790 | 54,229 |
| Non-cash compensation | 1,300 | 583 | 5,661 | 11,652 | 19,196 |
| Income (loss) from operations | 333,710 | (21,453 ) | (260,514 ) | (28,247 ) | 23,496 |
| Interest expense, net | (157,057 ) | (44,912 ) | — | (41,326 ) | (243,295 ) |
| Interest income | 1,056 | 4 | 202 | 143 | 1,405 |
| Goodwill | 76,819 | — | — | — | 76,819 |
| Total assets | 2,013,618 | 569,626 | 147,164 | 2,214 | 2,732,622 |
| Expenditures for additions to long-lived assets | $106,628 | $(4,376 ) | $1,081 | $(539 ) | $ 102,794 |
| As of or for the Year Ended December 31, 2008 (as adjusted) | | | | | |
| Revenues | $— | $15 | $2,914 | $4,215 | $ 7,144 |
| Intersegment revenues (losses) (2) (3) (4) (5) | 15,000 | 1,010 | (15,000 ) | (1,010 ) | — |
| 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 ) | (47,580 ) | (147,136 ) |
| Interest income | 14,619 | — | 1,624 | 4,094 | 20,337 |
| Goodwill | 76,844 | — | — | — | 76,844 |
| Total assets | 2,191,671 | 590,995 | 136,138 | 1,278 | 2,920,082 |
| 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 (as adjusted) | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 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) | (49,435) | (119,360) |
| Interest income | 52,273 | — | 2,476 | 27,886 | 82,635 |
| Goodwill | 76,844 | — | — | — | 76,844 |
| Total assets | 2,041,894 | 443,421 | 157,601 | 316,827 | 2,959,743 |
| Expenditures for additions to long-lived assets | $488,373 | $393,159 | $5,294 | $13,141 | $ 899,967 |

(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 consolidated financial statements. Prior periods were restated to include oil and gas exploration, development and exploitation activities within corporate and other.

(2) Intersegment revenues related to our LNG receiving terminal segment are primarily from TUA capacity reservation fee revenues of $250.2 million and $15.0 million and tug revenues that were received from our LNG and natural gas marketing segment for

the years ended December 31, 2009 and 2008, respectively. These LNG receiving terminal segment intersegment revenues are eliminated with intersegment expenses in our Consolidated Statement of Operations.

(3) Intersegment revenues related to our natural gas pipeline segment are primarily from transportation fees charged by our natural gas pipeline segment to our LNG receiving terminal and LNG and natural gas marketing segments to transport natural gas that was regasified at the Sabine Pass LNG receiving terminal. These natural gas pipeline segment intersegment revenues are eliminated with intersegment expenses in our Consolidated Statement of Operations.

(4) Intersegment losses related to our LNG and natural gas marketing segment are primarily from TUA capacity reservation fee expenses of $250.2 million and $15.0 million and tug costs that were incurred from our LNG receiving terminal segment for the years ended December 31, 2009 and 2008, respectively. The costs of the LNG and natural gas marketing segment TUA capacity reservation fee expenses are classified as marketing trading gain (loss) as it is considered a capacity contract related to our energy trading and risk management activities. These LNG and natural gas marketing segment intersegment revenues are eliminated with intersegment expenses in our Consolidated Statement of Operations.

(5) Intersegment losses related to corporate and other are from various transactions between our LNG receiving terminal, natural gas pipeline and LNG and natural gas marketing segments in which revenue recorded by one operating segment is eliminated with a non-revenue line item (i.e. operating expense or is capitalized) by the other operating segment.

## 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, | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| Cash paid during the year for interest, net of amounts capitalized | $90,702 | $110,695 | $106,640 |
| Construction-in-process and debt issuance additions funded with accrued liabilities | 3,424 | 28,448 | 112,824 |

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.

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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 ended December 31, 2009: | | | | |
| Revenues | $1,235 | $37,959 | $56,332 | $85,600 |
| Income (loss) from operations | (37,398) | 323 | 18,254 | 42,317 |
| Net loss | (82,742) | (13,051) | (42,497) | (23,200) |
| Net loss per share—basic and diluted | $(1.70) | $(0.25) | $(0.80) | $(0.44) |
| Year ended December 31, 2008: | | | | |
| Revenues | $1,477 | $914 | $4,100 | $653 |
| Loss from operations | (38,365) | (103,467) | (39,145) | (63,211) |
| Net loss (as adjusted) | (53,693) | (136,543) | (71,619) | (111,104) |
| Net loss per share—basic and diluted (as adjusted) | $(1.14) | $(2.90) | $(1.51) | $(2.32) |

## 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, 2009, 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 (i) accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and (ii) 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 Consolidated Financial Statements on page 48 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, 2009.

# PART IV

## ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements, Schedules and Exhibits

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

(3) Exhibits:

| Exhibit No. | Description |
|---|---|
| 2.1* | 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) |
| 2.2* | 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) |
| 3.1* | Restated Certificate of Incorporation of the Company. (Incorporated by reference to Exhibit 3.1 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* | Certificate of Amendment of Restated Certificate of Incorporation of the Company. (Incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-8 (SEC File No. 333-160017), filed on June 16, 2009) |
| 3.4* | 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 30, 2004) |
| 3.5* | 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) |
| 3.6* | 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 |