CHENIERE

CONSTRUCTING THE NORTH AMERICAN LNG GATEWAY™

2005 ANNUAL REPORT

2005 HIGHLIGHTS

In 2005, Cheniere became the first company with new LNG terminals under construction in the United States. The following are highlights of the company's activities during the year:

Sabine Pass LNG Terminal

- Commenced construction in March 2005
- Filed an application with FERC seeking authorization to expand send-out capacity to 4.0 Bcf/d

Corpus Christi LNG Terminal

- Acquired BPU LNG, Inc.'s 33.3% interest in the project in February 2005, resulting in Cheniere now holding 100% of the interests in the terminal
- Received FERC authorization to commence initial construction of the terminal in December 2005

Creole Trail LNG Terminal

- Received a Draft Environmental Impact Statement from FERC in December 2005, preliminarily concluding that the proposed project, with appropriate mitigating measures as recommended, would have limited adverse environmental impact

Freeport LNG Terminal – Founder and 30% Limited Partner

- Commenced construction in the first quarter of 2005
- Completed $383 million financing

LNG Marketing

- Initiated the LNG Gateway™ to commercialize Cheniere's LNG receiving terminal capacity

Corporate Financing

- Increased year-end working capital from $306 million in 2004 to $810 million in 2005
- Successfully raised over $1.7 billion in debt financing
- Divested interest in Gryphon Exploration Company in September 2005, resulting in approximately $20 million of net proceeds

Human Resources

- Attracted employees with highly-specialized knowledge in their fields, tripling Cheniere's team to over 130 full time employees

Community Involvement

- Responded within 12 hours of Hurricane Rita to assist Cameron Parish, Louisiana leaders and residents in recovery efforts and implemented an ongoing assistance program

On the cover: Aerial photograph of Sabine Pass LNG receiving terminal construction site

North America's Premier Liquefied Natural Gas Receiving Company

Cheniere Energy, Inc. is developing a platform of three, 100%-owned, onshore liquefied natural gas, or LNG, receiving terminals along the U.S. Gulf Coast. The three terminals will have an aggregate send-out capacity of 9.9 billion cubic feet of natural gas per day. Cheniere plans to leverage its terminal platform by pursuing related LNG business opportunities both upstream and downstream of the terminals.

Cheniere is also the founder of and holds a 30% limited partner interest in a fourth LNG receiving terminal project, participates in an LNG shipping venture, and operates an oil and gas exploration program in the shallow waters of the U.S. Gulf of Mexico.

Cheniere is based in Houston, Texas, with offices in Johnson Bayou, Louisiana, and Paris, France. The company's common stock is listed on the American Stock Exchange under the symbol: **LNG**.

LETTER TO SHAREHOLDERS

March 24, 2006

Dear Shareholders,

Last year our company made a transition from being strictly a project development company to actually having two sites under construction. We can now measure our progress with concrete benchmarks as reflected in pictures of our sites, however that transition necessitated fundamental changes in the structure of the company to accommodate this new phase.

First and foremost, I can report to you that I am extremely well surrounded and supported by exceptionally talented employees. We received two awards for the best project financing of the year, were voted by our peers as the best LNG company of the year, and were the best performer in the universe of companies compiled by the *Wall Street Journal* for both three-year and five-year returns. This is a reflection of the quality of the people who work for Cheniere.

Our business model has not varied much in five years. We are still building liquefied natural gas receiving facilities in locations that for the most part were identified four years ago. As this model was validated, our access to capital has improved. We are now able to contemplate more varied commercial arrangements and start looking at other elements of the LNG value chain. Our core business remains the LNG receiving network, around which a very small company was able to attract capital, customers, and very talented employees.

The foundation for our success is the business itself, the energy business. It is a vital business, at the heart of economic growth, inextricably tied to the well-being of nations and people. It is international and cross-cultural and affects everyone whether they realize it or not. They make movies and write novels about this business, and the business itself remains more fascinating than the fiction around it. If you have any doubt, read The Prize by Daniel Yergin.

The energy business is also a business in deep transformation. This was best captured, oddly enough, by *National Geographic* in its June 2004 article "The End of Cheap Oil." The world is not running out of hydrocarbons, but the costs to extract hydrocarbons and absorb them into the environment are increasing significantly. For a decade and a half, it had been easy to ignore the importance of energy to modern society because hydrocarbons were abundantly available and very inexpensive. At the turn of the millennium, this changed.

We have entered a cycle of dislocation of the energy infrastructure which will have a profound impact on our world. The first stages are already apparent in the dramatic increase in oil prices and the globalization of the natural gas industry. It will alter the balance of economic and political interaction between cultures and nations, sometimes in ways that are evident, and sometimes in ways that are more subtle or unexpected.

Eventually, the world will have to decrease its reliance on hydrocarbons through more efficient exploitation of resources, conservation, or reliance on non-hydrocarbon energy sources. Companies and governments will have to reexamine their business models. Consumers will be confronted with difficult choices.

At Cheniere, we were fortunate to find ourselves at the heart of an early stage of transformation in the whole industry, namely the globalization of natural gas through LNG. This kind of transformation creates unusual opportunities for companies that can adapt quickly. We were able to do so by questioning conventional metrics such as natural gas prices and conventional business models such as the integrated liquefied natural gas chain, and were able to carve out our niche in this context. Remember that the results of the National Petroleum Council studies in 1999 and 2003 were dramatically different. The 1999 study completely missed the looming crisis. The 2003 study recognized it. Our timing could have hardly been better.

It is now clear that traditional business models and relationships are being challenged. International oil companies report record profits but declining production. Producing countries seek to manage their resources more directly. Consumers are increasingly vulnerable to exogenous events such as weather changes. Massive transfers of wealth are occurring with unpredictable political consequences both in consuming and producing countries. In this context new business relationships will emerge. Companies that are well prepared and open-minded will benefit.

We like our platform. We think it provides benefits to both producers and consumers. We will continue to strengthen our relationship with both, and will remain open to flexible business arrangements that benefit all sides.

The energy industry has never been more challenging nor exciting. We are thrilled to be part of it.

Sincerely,
Cheniere Energy, Inc.

Charif Souki
Chairman and CEO

CHENIERE'S INDUSTRY

An Evolving Market

Natural gas currently satisfies more than 24% of worldwide, and 25% of North American primary energy consumption. Natural gas has an advantage over other primary energy sources such as oil and coal because it is clean burning and therefore more environmentally friendly. Its share of the world's energy requirements will continue to increase.

More than 35% of the world's natural gas reserves are located in countries that have low energy consumption and are far from major demand centers. In contrast, supplies close to major markets are facing declines in mature basins. In order for natural gas to be effectively transported by sea, it must be liquefied to condense its volume. Liquefied natural gas, or LNG, is therefore becoming an increasingly significant means of distributing natural gas from remote supply areas to key consuming centers. Investment in liquefaction plants has increased dramatically in the last five years to meet the global need for natural gas. According to the Groupe International des Importateurs de Gaz Naturel Liquéfié, or GIIGNL, as of 2004, there were 69 "trains," or production units, in 12 countries capable of producing approximately 19.2 billion cubic feet per day (Bcf/d) of LNG. LNG production capacity grew by over 20% during the 2000 - 2004 period. Cheniere estimates that liquefaction capacity will more than double by 2010, reaching 41 Bcf/d.

Although LNG has been used commercially in the U.S. since the 1940s, its role was limited to meeting demand peaks caused by seasonal variations. Historically, abundant supplies of domestically sourced, low-cost, piped natural gas kept pace with demand, making the need for LNG imports minimal and sporadic. The era of inexpensive North American natural gas is over. The average wellhead price of natural gas produced in the U.S. has more than doubled in the last five years, indicating a maturing domestic resource base and supporting the economic viability of marginal drilling and imports from distant places.

According to GIIGNL, at the end of 2004, there were four operational LNG receiving terminals in the continental U.S. with an aggregate send-out capacity of 2.8 Bcf/d and the capability to satisfy about 4% of natural gas consumption in North America. LNG imports to the U.S. grew 29% in 2004 versus 2003 levels and reached over 652 Bcf. LNG is expected to play a more pivotal role in satisfying North American natural gas demand as additional receiving capacity becomes available.

Imports can only increase significantly if new LNG receiving capacity is constructed. Former Chairman of the Federal Reserve, Alan Greenspan, stated that greater access to global natural gas reserves is required for North American natural gas markets "to be able to adjust effectively to unexpected shortfalls in domestic supply [and that] access to world natural gas supplies will require a major expansion of LNG terminal import capacity." Ben Bernanke, the current Federal Reserve Chairman, reaffirmed this view in February 2006, when he said, "building LNG terminals is one thing that we can do and we should continue to do to create a more global market for natural gas."

LNG is needed as a reliable source of supply to meet demand and it can be delivered to North America at a competitive price. Cheniere is committed to bringing a new source of natural gas to serve the needs of the North American market.

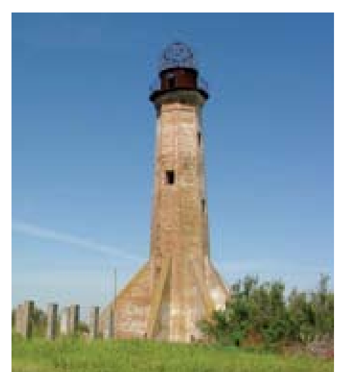
CHENIERE'S APPROACH

Environmentally Sensitive and Community-Friendly

Cheniere is committed to an environmentally sound and community-friendly approach in developing its LNG receiving terminals. Cheniere is making efforts to restore marsh environment and coastline in southwest Louisiana. Cheniere also invests time to develop strong community relationships and believes in the importance of earning a community's trust before asking for its support.

Cheniere has received support for the development of its Sabine Pass and Creole Trail LNG receiving terminals from the Governor of Louisiana, several Louisiana State and Federal legislators, Cameron Parish leaders and various local organizations. Cheniere has received letters in support of the development of its Corpus Christi LNG receiving terminal from the Governor of Texas, the Mayor of Corpus Christi, the Sierra Club and various local organizations.

Cheniere strives to be a good neighbor and a strong corporate citizen in the communities in which it operates. When Hurricane Rita struck the Gulf Coast, communities in Cameron Parish, Louisiana, and Jefferson County, Texas, were devastated. Cheniere responded to help emergency crews and assist in public administrative operations by supplying housing, generators, temporary buildings and furnishings. Cheniere repaired community infrastructure, provided temporary classrooms to substitute for school buildings destroyed in the storm and provided computer equipment and furnishings in order for students to resume classes. Cheniere's support of the community's rebuilding efforts is ongoing.



Top row left to right: *Cheniere sponsors a cross-country cycling team raising funds for M.D. Anderson Cancer Center; Cheniere donates 40 computers to schools in Cameron Parish after Hurricane Rita; Cheniere employees and families gather in Corpus Christi to support local education by riding in the Conquer the Coast bike race.*

Bottom row left to right: *Cheniere donates temporary buildings and furnishings to replace those destroyed by Hurricane Rita; Cheniere employees and friends gather to clean up the historic Sabine Pass Lighthouse in Louisiana.*

CHENIERE'S TERMINAL NETWORK

Optionality, Flexibility, Reliability

Cheniere is developing a network of three onshore LNG receiving terminals and related natural gas pipelines along the U.S. Gulf Coast. Cheniere is among the leading companies in the U.S. strategically pursuing the development of LNG receiving terminals. The company gained an early-mover advantage by identifying sites as early as 1999 and continues to remain at the forefront of U.S. LNG terminal development and construction.

Cheniere's terminal sites are among the best in North America because of their access to all major natural gas markets, existing industrial complexes, substantial local natural gas consumption, support of the local communities, deep water channels and large acreage positions with proximity to open water.

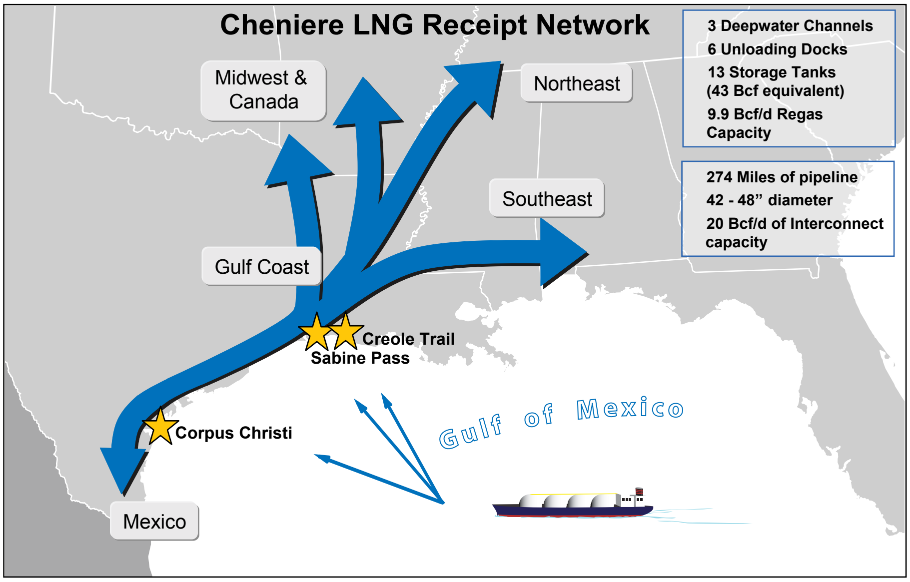
The Sabine Pass, Corpus Christi and Creole Trail LNG receiving facilities are the largest proposed LNG receiving terminals in North America, each with over 600 acres of land under its control and 4.0, 2.6, and 3.3 Bcf/d of send-out capacity, respectively. By operating the terminals as a network, Cheniere expects its customers will benefit from reliability, optionality, and flexibility not possible with single terminal operators. Multiple receiving sites will improve reliability during weather and maintenance interruptions. With three ports, six unloading docks and 13 storage tanks in the network, the company will have multiple options for flexible landing and market optimization.

Cheniere's premier sites, its community focused approach, experienced team and anticipated low construction and operating costs offer the company sustainable competitive advantages in bringing natural gas to the North American market.

Cheniere has commercialized an initial 2 Bcf/d of its receiving network capacity by entering into Terminal Use Agreements, or TUAs, with Total LNG USA, Inc. and Chevron USA, Inc. Cheniere is currently engaged in preliminary discussions with potential customers and other third parties in an effort to secure long-term TUAs with creditworthy anchor tenants. Cheniere seeks to enter into TUAs for an additional 2 Bcf/d of its LNG receiving network capacity.

Cheniere is also engaged in discussions with LNG suppliers to purchase LNG under Indexed Purchase Agreements, or IPAs. These supply agreements will enable Cheniere to sell natural gas to downstream customers, creating direct access between the North American natural gas and global LNG markets.

Cheniere will commercialize the remaining LNG receiving network capacity in a measured fashion, seeking strategic relationships with significant LNG partners.



THE LNG VALUE CHAIN

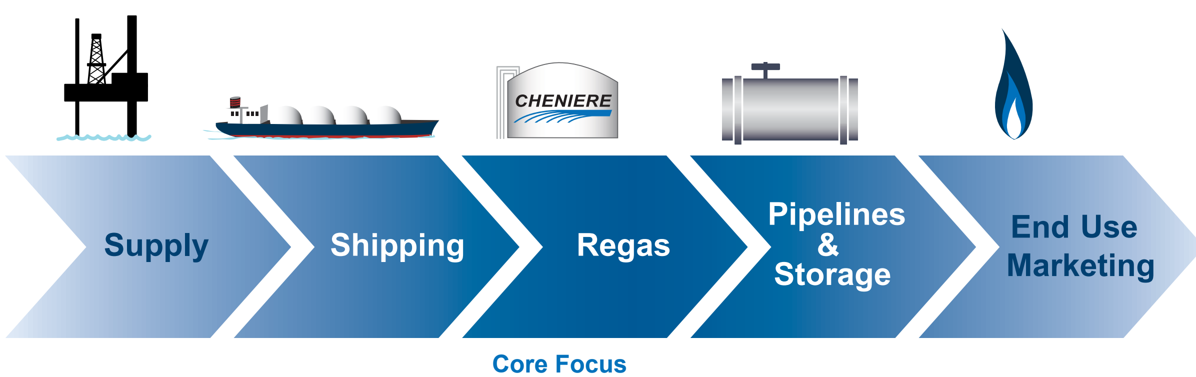
Growing a Competitive Position

Cheniere's regasification terminal network provides a platform for participation in the full LNG value chain. Cheniere plans to leverage its platform by pursuing related LNG business opportunities both upstream and downstream of the terminals.

Cheniere is now considering various midstream opportunities that will enhance its logistical services. Cheniere plans to maximize liquidity for its terminals by constructing natural gas pipelines that interconnect its terminals with the U.S. natural gas pipeline grid. Cheniere formed a wholly-owned subsidiary, Cheniere Pipeline Company, which contracted for engineering, procurement, construction, and construction management with Willbros Engineers, Inc. for a pipeline interconnecting the Sabine Pass LNG terminal with downstream infrastructure. Cheniere Pipeline has also permitted 2.6 Bcf/d of pipeline take-away capacity from the Corpus Christi LNG terminal and has initiated permitting for 3.3 Bcf/d of pipeline take-away capacity from the Creole Trail LNG terminal.

Cheniere also plans to continue participation in LNG shipping. Cheniere holds a minority interest in J & S Cheniere, which chartered an LNG tanker from August 2003 to August 2005 that transported 14 LNG cargoes. J & S Cheniere purchased LNG from international sellers and delivered it and sold it to the U.S. market. J & S Cheniere has also entered into time charters for two new-build LNG tankers, which are expected to be delivered in the fourth quarter of 2007.

To complement its asset infrastructure, Cheniere is developing a marketing competency. Cheniere is currently active in oil and natural gas exploration and development and foresees evaluating possible natural gas reserves development opportunities related to commercialization of its terminal network.



CHENIERE LNG RECEIVING TERMINAL DEVELOPMENT

Constructing the Platform

Cheniere's LNG receiving terminal group is developing three 100%-owned LNG receiving terminals. Sabine Pass LNG is under construction in western Cameron Parish, Louisiana, on the Sabine Pass Channel. Corpus Christi LNG has received final authorization to commence construction in San Patricio County, Texas and is expected to begin site preparation in the second quarter of 2006. Creole Trail LNG is under permitting review and is located at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. In addition, Cheniere owns a 30% limited partner interest in Freeport LNG Development, L.P., which is constructing an LNG receiving terminal on Quintana Island near Freeport, Texas. Upon completion in 2008-2011, these terminals will be capable of sending out 11.4 Bcf/d of natural gas to the U.S. market.

SABINE PASS LNG

Cheniere's 100%-owned limited partnership, Sabine Pass LNG, L.P., is constructing an LNG receiving terminal in western Cameron Parish, Louisiana. Sabine Pass LNG received an order from the Federal Energy Regulatory Commission, or FERC, in December 2004 authorizing construction of the LNG receiving terminal. Construction began in March 2005. Terminal operations are expected to commence in 2008.

Sabine Pass LNG has entered into 20-year TUAs with Total LNG USA, Inc. and Chevron USA, Inc. to provide each with 1.0 Bcf/d of regasification capacity.

Cheniere estimates that the cost of constructing the 2.6 Bcf/d Sabine Pass LNG facility will be approximately $900 million to $950 million, before financing costs. In December 2004, the company entered into a lump-sum turnkey agreement with Bechtel Corporation, a major international EPC contractor. Under this agreement, Bechtel provides engineering, procurement and construction services for the 2.6 Bcf/d Sabine Pass LNG receiving, storage and regasification terminal. In February 2005, HSBC Securities (USA) Inc. and Société Générale arranged $822 million of non-recourse project debt financing to fund a substantial majority of constructing and placing into service the 2.6 Bcf/d Sabine Pass LNG terminal.

Sabine Pass LNG filed an application with FERC seeking authorization to expand the terminal from its initial capacity of 2.6 Bcf/d to approximately 4.0 Bcf/d. Cheniere is negotiating with contractors for the engineering, procurement, and construction of this expansion and expects to begin construction in the second quarter of 2006. The initial stage of the planned expansion of the Sabine Pass project is estimated to cost approximately $500 million to $550 million, before financing costs.

Pile driving at Sabine Pass LNG

Tank 1 construction at Sabine Pass LNG

Sabine Pass LNG artist rendition

Site:	**853 acres**
Accessibility:	**40' channel**
Proximity:	**3.7 nautical miles from coast**
Berths:	**2 docks**
Storage:	**3 tanks (10.1 Bcfe)**
Vaporization:	**2.6 Bcf/d sendout**
In Service:	**2008**
Expansion	
Storage:	**3 tanks (10.1 Bcfe)**
Vaporization:	**1.4 Bcf/d sendout**
In Service:	**2009**

CORPUS CHRISTI LNG

On December 16, 2005, Cheniere's 100%-owned limited partnership, Corpus Christi LNG, L.P., received regulatory approval from FERC to commence initial construction of its LNG receiving terminal near Corpus Christi, Texas. Cheniere is currently developing engineering and design specifications and anticipates engaging a major international EPC contractor to perform the EPC work for the facility. Cheniere expects to begin site preparation and detailed engineering in the second quarter of 2006 and to commence terminal operations in early 2010.

Cheniere estimates that the cost of constructing the 2.6 Bcf/d Corpus Christi LNG facility will be approximately $650 million to $750 million, before financing costs. This estimate is based in part on negotiations with a major international EPC contractor.

Aerial photograph with plot of Corpus Christi LNG overlay

Corpus Christi LNG artist rendition

Site:	**612 acres**
Accessibility:	**45′ channel**
Proximity:	**14.3 nautical miles from coast**
Berths:	**2 docks**
Storage:	**3 tanks (10.1 Bcfe)**
Vaporization:	**2.6 Bcf/d sendout**
In Service:	**2010**

CREOLE TRAIL LNG

Cheniere's 100%-owned limited partnership, Creole Trail LNG, L.P., is seeking regulatory approval to construct a 3.3 Bcf/d LNG receiving terminal. On December 16, 2005, FERC issued the Draft Environmental Impact Statement for the Creole Trail LNG receiving terminal and associated pipeline. FERC preliminarily concluded that the proposed project, with appropriate mitigating measures as recommended, would have limited adverse environmental impact. Cheniere anticipates beginning construction in 2007 and commencing operations in 2011.

The cost of constructing the 3.3 Bcf/d Creole Trail LNG facility is currently estimated at approximately $850 million to $950 million, before financing costs.

Ship simulation at Creole Trail LNG terminal

Creole Trail LNG artist rendition

Site:	**1,463 acres**
Accessibility:	**42′ channel**
Proximity:	**3.0 nautical miles from coast**
Berths:	**2 docks**
Storage:	**4 tanks (13.5 Bcfe)**
Vaporization:	**3.3 Bcf/d sendout**
In Service:	**2011**

FREEPORT LNG — FOUNDER AND 30% LIMITED PARTNER

The Freeport LNG receiving terminal is currently under construction on Quintana Island, near Freeport, Texas. Cheniere developed this project and then sold a 60% interest to the Smith Entities, which subsequently sold a 15% limited partner interest to The Dow Chemical Company, or Dow Chemical. Cheniere also sold a 10% limited partner interest to Contango Oil & Gas Company. Cheniere continues to own a 30% non-operating limited partner interest in Freeport LNG Development, L.P.

In January 2005, FERC authorized Freeport LNG to commence construction of the LNG terminal and natural gas pipeline. Freeport LNG started construction in the first quarter of 2005. The estimated cost to construct the facility is $800 million to $850 million, before financing costs. Terminal operations are expected to commence in 2008.

Capacity for the Freeport LNG terminal is fully subscribed under TUAs for at least 20 years. ConocoPhillips Company, or ConocoPhillips, contracted for 1.0 Bcf/d and Dow Chemical for 500 million cubic feet per day (MMcf/d). ConocoPhillips owns a 50% interest in the general partner entity responsible for managing construction and operations and has agreed to provide a substantial majority of the debt financing for the 1.5 Bcf/d Freeport LNG facility. In December 2005, Freeport LNG announced that it had closed a $383 million private placement of notes which will be used to finance portions of the initial phase and planned expansion of the project.

A filing has been made with FERC for an expansion of the Freeport LNG facility to increase its capacity to 4.0 Bcf/d, add a second dock, and include a third LNG storage tank and underground gas storage. ConocoPhillips exercised its option to acquire additional regasification capacity of 300 MMcf/d in connection with such an expansion. In addition, Freeport LNG announced in January 2005, that it had executed a long-term TUA with MC Global Gas Corporation, or MC Global, a subsidiary of Mitsubishi. Pursuant to the TUA, MC Global has reserved approximately 150 MMcf/d of regasification capacity in the Freeport LNG terminal expansion and has an option to increase its regasification capacity by an additional 100 MMcf/d.


Tank construction at Freeport LNG terminal


Freeport LNG artist rendition

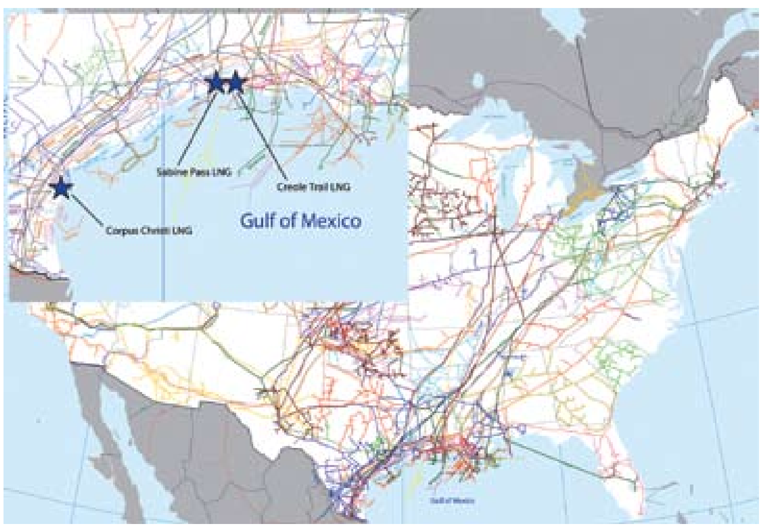
Site:	**233 acres**
Accessibility:	**45’ channel**
Proximity:	**1.0 nautical mile from coast**
Berths:	**1 dock**
Storage:	**2 tanks (6.7 Bcfe)**
Vaporization:	**1.5 Bcf/d sendout**
In Service:	**2008**

CHENIERE NATURAL GAS PIPELINE DEVELOPMENT

Securing Maximum Downstream Liquidity

Cheniere Pipeline Company, or Cheniere Pipeline, a wholly-owned subsidiary of Cheniere Energy, Inc., was formed in 2003 with the objective of developing downstream natural gas pipeline solutions and providing optimal access to North American natural gas markets for Cheniere's LNG receiving terminal network. Development efforts to date have focused primarily on advancing the proposed pipeline projects through the regulatory review and authorization process. As of April 2005, Cheniere Pipeline successfully permitted 40 miles of pipelines to transport 5.2 Bcf/d of natural gas to the North American market. An additional 117 miles of dual 42-inch diameter pipelines are currently in the FERC regulatory review process. Cheniere's pipelines are expected to interconnect with more than 20 Bcf/d of downstream transportation capacity.

Cheniere has entered into an EPC contract for a 16-mile pipeline from the Sabine Pass LNG terminal, which is scheduled to be constructed and operational by the fourth quarter of 2007. Cheniere will consider additional investment in construction of or commitment to short-term or long-term firm or interruptible natural gas pipeline capacity to optimize its market access and maximize liquidity.



CHENIERE LNG AND NATURAL GAS MARKETING

North American LNG Gateway

Cheniere LNG Marketing, Inc., or Cheniere Marketing, a wholly-owned subsidiary of Cheniere Energy, Inc., was formed in 2005 to commercialize Cheniere's LNG receiving terminal capacity not intended for third parties, creating the North American LNG Gateway™. Cheniere Marketing intends to purchase LNG from foreign suppliers, arrange the transportation of LNG to Cheniere's network of LNG terminals, utilize its reserved capacity to revaporize imported LNG, arrange the transportation of revaporized natural gas through affiliate pipelines and other interconnected pipelines, and sell natural gas to buyers in the North American market. Cheniere Marketing also expects to enter into domestic natural gas purchase and sale transactions as part of its marketing activities.

Cheniere plans to leverage the embedded optionality within its asset and contract portfolio to provide a more reliable and higher valued service than any single, tolling-only terminal can provide. Cheniere expects the dynamic deliverability of the LNG Gateway™ will allow for a range of services such as imbalance clearing across multiple pipelines and intra-day load shaping for power generators and local distribution companies.

Cheniere Marketing intends to enter into TUAs with Sabine Pass LNG for 1.5 Bcf/d of regasification capacity at the Sabine Pass LNG receiving terminal and with Corpus Christi LNG for 1.0 Bcf/d of regasification capacity at the Corpus Christi LNG receiving terminal.

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

Form 10-K

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

For the fiscal year ended December 31, 2005

OR

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

For the transition period from to

Commission File 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.)**
717 Texas Avenue, Suite 3100 **Houston, Texas**	**77002**
(Address of principal executive offices)	**(Zip code)**

Registrant's telephone number, including area code: **(713) 659-1361**

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

None

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

Common Stock, $ 0.003 par value	**American Stock Exchange**
(Title of Class)	**(Name of each exchange on which registered)**

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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

The aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $1,508,000,000 as of June 30, 2005.

54,742,805 shares of the registrant's Common Stock were outstanding as of February 28, 2006.

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.
Index to Form 10-K

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, and Section 21E of the Securities Exchange Act of 1934, as amended, or 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 that we expect to commence or complete construction of each of our proposed liquefied natural gas, or LNG, receiving terminals or our proposed pipelines, or any expansions or extensions thereof, by certain dates, or at all;
- statements that we expect to receive Draft Environmental Impact Statements, or DEIS, or Final Environmental Impact Statements, or FEIS, from the Federal Energy Regulatory Commission, or FERC, by certain dates, or at all, or that we expect to receive an order from FERC authorizing us to construct and operate proposed LNG receiving terminals or proposed pipelines by certain dates, or at all;
- statements regarding future levels of domestic or foreign natural gas production or consumption or future levels of LNG imports into North America or sales of natural gas in North America, regardless of the source of such information, or the transportation or other infrastructure or prices related to natural gas, LNG or other hydrocarbon products;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions, whether on the part of Cheniere or at the project level, including financing arrangements for which we may have received commitment letters;
- statements relating to the construction of our proposed LNG receiving terminals and our proposed pipelines, including statements concerning the engagement of any engineering, procurement and construction, or EPC, contractor and the anticipated terms and provisions of any agreement with an EPC contractor, and anticipated costs related thereto;
- statements regarding any terminal use agreement, or TUA, or other agreement to be entered into or performed substantially in the future, including any cash distributions and revenues anticipated to be received and the anticipated timing thereof, and statements regarding the amounts of total regasification capacity that is, or may become subject to, TUAs or other contracts;
- statements that our proposed LNG receiving terminals and pipelines, when completed, will have certain characteristics, including amounts of regasification and storage capacities, a number of storage tanks and docks, pipeline deliverability and the number of pipeline interconnections, if any;
- statements regarding possible expansions of the currently projected size of any of our proposed LNG receiving terminals;
- statements regarding our business strategy, our business plans or any other plans, forecasts or objectives, any or all of which are subject to change;
- statements regarding any Securities and Exchange Commission, or SEC, or other governmental or regulatory inquiry or investigation;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding our anticipated LNG and natural gas marketing activities; and
- any other statements that relate to non-historical or future information.

These forward-looking statements are often identified by the use of terms and phrases such as "achieve," "anticipate," "believe," "estimate," "expect," "forecast," "plan," "project," "propose," "strategy" and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve assumptions, risks and uncertainties, and these expectations may prove to be incorrect. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this 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" beginning on page 35 of this annual report. 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. Other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

PART I

ITEMS 1. AND 2. *BUSINESS AND PROPERTIES*

General

Cheniere Energy, Inc., a Delaware corporation, is a Houston-based company engaged, through its subsidiaries, in the energy business generally. As used in this annual report, the terms "we", "us" and "our" refer to Cheniere Energy, Inc. and its subsidiaries. We are currently engaged primarily in the business of developing and constructing, and then owning and operating, a network of three onshore LNG receiving terminals, and related natural gas pipelines, along the Gulf Coast of the United States. We are also engaged, to a limited extent, in oil and natural gas exploration and development activities in the Gulf of Mexico.

Our common stock has been publicly traded since July 3, 1996 under the name Cheniere Energy, Inc. Our common stock is traded on the American Stock Exchange under the symbol LNG. Our principal executive offices are located at 717 Texas Avenue, Suite 3100, Houston, Texas 77002, and our telephone number is (713) 659-1361. Our internet address is 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 SEC under the Exchange Act. These reports may be accessed free of charge through our internet website (located at www.cheniere.com), where we provide a link to the SEC's website (at www.sec.gov). 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.

In this annual report, unless the context otherwise requires:

- *Bcf* means billion cubic feet;
- *Bcf/d* means billion cubic feet per day;
- *Bcfe* means billion cubic feet of natural gas equivalent, using the ratio of six Mcf of natural gas to one barrel (or 42 United States gallons of liquid volume) of crude oil, condensate and natural gas liquids;
- *cm* means cubic meter;
- *EPC* means engineering, procurement and construction;
- *IPA* means indexed purchase agreement;
- *LNG* means liquefied natural gas;
- *Mcf* means thousand cubic feet;
- *MMcf* means million cubic feet;
- *MMcf/d* means million cubic feet per day;

- *MMBtu* means million British thermal units;
- *Tcf* means trillion cubic feet; and
- *TUA* means terminal use agreement.

General Development of Our Business

We were originally incorporated in Delaware in 1996 under the name Cheniere Energy Operating Co. for the purpose of engaging in the oil and gas exploration business, initially on the Louisiana Gulf Coast. In 1996, we underwent a reorganization with a publicly-held corporation, pursuant to which we became a publicly-held corporation and changed our name to Cheniere Energy, Inc. In 1999, we began developing our LNG receiving terminal business.

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

- complete the development and construction of our three onshore U.S. Gulf Coast LNG receiving terminals with an aggregate designed regasification capacity of approximately 10 Bcf/d, subject to further expansion;
- secure an additional 2 Bcf/d of long-term arrangements under TUAs with creditworthy "anchor tenants," resulting in approximately 4 Bcf/d of our total existing and future regasification capacity, thus providing for an expected stream of contracted cash flows as terminals become operational;
- secure long-term indexed purchase agreements, or IPAs, for approximately 3 Bcf/d through the purchase of LNG from foreign suppliers and the sale of revaporized natural gas into North American markets, utilizing our planned regasification capacity;
- reserve approximately 3 Bcf/d of regasification capacity for future short-term or spot market opportunities and terminal operations requirements;
- grow our LNG receiving terminal business by expanding our existing projects and potentially pursuing development of additional LNG receiving terminals on the U.S. Gulf Coast and elsewhere;
- develop natural gas pipelines and other infrastructure to transport natural gas from our LNG receiving terminals to North American markets;
- to complement our LNG receiving terminal business, develop our LNG and natural gas marketing business by entering into domestic natural gas purchase and sale transactions;
- pursue other energy business initiatives, including participating in projects that own or are developing foreign natural gas reserves that could be converted into LNG and investing in LNG shipping businesses; and
- engage in additional oil and gas exploration, development, production, transportation and processing activities generally.

Within the context of this long-term strategy, our immediate focus is on our LNG receiving terminals being developed in western Cameron Parish, Louisiana on the Sabine Pass Channel and near Corpus Christi, Texas. We have allocated 2.5 Bcf/d of regasification capacity within these two terminals to our marketing affiliate (1.5 Bcf/d at Sabine Pass and 1.0 Bcf/d at Corpus Christi) to enable it to pursue approximately 200 LNG cargoes annually for its *LNG Gateway*™ program. In April 2006, we anticipate offering the remaining regasification capacity in Sabine Pass (500 MMcf/d) to potential TUA customers through a formal request-for-proposal process. As we see the market develop for regasification capacity, we will introduce from time to time additional capacity at our Corpus Christi LNG receiving terminal through the same request-for-proposal process.

We anticipate reserving the regasification capacity at our Creole Trail LNG receiving terminal for strategic relationships.

We operate four business activities:

- LNG receiving terminal development,
- natural gas pipeline development,
- LNG and natural gas marketing, and
- oil and gas exploration and development.

At this stage in our development, our operations are divided into two reporting segments in our financial statements for the years ended December 31, 2005, 2004 and 2003 as required under Statement of Financial Accounting Standards (SFAS) No. 131, "*Disclosures about Segments of an Enterprise and Related Information*": LNG Receiving Terminal Development and Oil and Gas Exploration and Development.

LNG Receiving Terminal Development Business

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 economically justify the use of LNG. LNG is transported using large oceangoing tankers specifically constructed for this purpose. LNG receiving terminals offload LNG from tankers, 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.

LNG is a well-established, global source of natural gas for electric generation, heating and industrial applications. According to the Groupe International des Importateurs de Gaz Naturel Liquifié, or GIIGNL, as of the end of 2004, there were 69 liquefaction plants in 12 countries capable of producing 19.2 Bcf/d and 47 receiving terminals in 13 countries capable of receiving and regasifying LNG.

North America has the largest interconnected natural gas market in the world, consuming approximately 75.7 Bcf/d in 2004, according to BP Statistical Review. Currently, there are only four onshore LNG receiving terminals in North America (excluding Puerto Rico) with a combined sustainable sendout capacity of natural gas of approximately 2.8 Bcf/d, according to GIIGNL. This regasification capacity represents about 4% of total North American current natural gas consumption. By contrast, Japan imports all of its natural gas as LNG, according to BP Statistical Review.

LNG's contribution to the North American market has historically been minimal, due mainly to an abundant supply of domestically sourced, low cost natural gas. The Energy Information Administration has reported, however, that the average wellhead price of natural gas produced in the United States has more than doubled in the last five years, an indication of a declining domestic resource base. The need to increase US regasification capacity and LNG imports to supplement natural gas supplies has been recognized in recent years. Indicative of this, the Former Chairman of the Federal Reserve testified before Congress that North America needs "to be able to adjust effectively to unexpected shortfalls in domestic supply [and that] access to world natural gas supplies will require a major expansion of LNG terminal import capacity." His successor, Ben Bernanke, said in February 2006 that "building LNG terminals is one thing that we can do and we should continue to do to create a more global market for natural gas." Also in February 2006, President Bush said that "we've got to make sure that we've got enough natural gas to meet our home heating and industrial needs. And one of the best ways to secure supply is to expand our ability to receive liquefied natural gas."

We believe that LNG is needed as a reliable source of supply to meet demand and that LNG can be delivered to North America at a competitive price. We also believe that global LNG supplies will be more than ample.

We began developing our LNG receiving terminal business in 1999 and, since then, have been among the first companies to secure sites and commence development of new LNG receiving terminals in the United States. We have focused our development efforts on three, 100% owned LNG receiving terminal projects at the following locations: Sabine Pass LNG in western Cameron Parish, Louisiana on the Sabine Pass Channel; Corpus Christi LNG near Corpus Christi, Texas; and Creole Trail LNG at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. In addition, we own a 30% interest in a fourth project, Freeport LNG, located on Quintana Island near Freeport, Texas. We retained this interest following the sale of 70% of our interest in 2003 to finance our other activities.

Our LNG Receiving Terminals

Sabine Pass LNG

Development

We are developing the Sabine Pass LNG receiving terminal in western Cameron Parish, Louisiana, on the Sabine Pass Channel. We formed Sabine Pass LNG, L.P., or Sabine Pass LNG, to develop the terminal. We have entered into leases for three tracts of land comprising 853 acres in Cameron Parish, Louisiana for the project site. The initial phase, or Phase 1, of the Sabine Pass LNG receiving terminal was designed with an initial regasification capacity of 2.6 Bcf/d and three LNG storage tanks with an aggregate LNG storage capacity of 10.1 Bcfe, along with two unloading docks capable of handling 87,000 cm to 250,000 cm LNG shipping vessels. In July 2005, we made a filing with FERC seeking approval to increase the regasification capacity of the Sabine Pass LNG receiving terminal up to 4.0 Bcf/d and to add up to three additional LNG storage tanks and related facilities, which is referred to as Phase 2.

Phase 1

In March 2005, FERC issued an order authorizing Sabine Pass LNG to commence construction of Phase 1 of the Sabine Pass LNG receiving terminal. Construction began in March 2005, and we expect to commence terminal operations in 2008. In order to commence operations of Phase 1 (which is not dependent on completion of Phase 2), Sabine Pass LNG will be required to satisfy certain conditions specified by FERC.

The cost to construct Phase 1 of the Sabine Pass LNG facility is currently estimated at approximately $900 million to $950 million, before financing costs, but including the change orders discussed below. In December 2004, we entered into a lump-sum turnkey agreement with Bechtel Corporation, or Bechtel, a major international EPC contractor, which currently requires us to pay Bechtel approximately $712 million. Our cost estimate is subject to change due to such items as cost overruns, change orders, changes in commodity prices (particularly steel), escalation of labor costs and additional funds which may be expended to maintain our construction schedule, as described below.

In August 2005, construction at Phase 1 of our Sabine Pass LNG receiving terminal site was temporarily suspended in connection with Hurricane Katrina, as a precautionary measure. In September 2005, 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. No significant damage occurred to the site, equipment or materials as a result of either of these hurricanes. Construction activities were remobilized at the site and returned to pre-hurricane levels by mid-November 2005. Recent assessments from Bechtel and certain subcontractors of the hurricanes' impact indicate that, due to their residual effects, the primary impediment to our overall construction plan continues to be a shortage of available skilled labor, with likely delay of the anticipated construction schedule in the absence of remedial action. As a result, we are currently in negotiations with Bechtel and certain subcontractors concerning additional activities and expenditures in order, among other things, to attract sufficient skilled labor to mitigate potential schedule delays and still provide a reasonable opportunity to attain the initial target bonus date of April 3, 2008 (the date originally anticipated for completion of construction sufficient to achieve a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours and that, if attained, would entitle Bechtel to a scheduled $12 million bonus). As part of these negotiations, we have agreed in principle to defer the date by which substantial completion of the entire project is required to be accomplished under the EPC contract from September 3 to December 20, 2008. In the absence of substantial completion by such date, Bechtel would be obligated to pay us certain liquidated damages as provided under the terms of the EPC contract. We expect that the above-described arrangement will not exceed $50 million, although such amount is subject to change, requires approval of the lenders under our Sabine Pass Credit Facility (as described below under "—Funding") and requires that a change order be agreed upon with Bechtel.

Phase 2

Phase 2 of our Sabine Pass LNG facility may be constructed in stages. It is expected that the initial stage will consist of two LNG storage tanks, additional vaporizers and related facilities to increase the total regasification capacity to 4.0 Bcf/d. This stage is estimated to cost approximately $500 million to $550 million, before financing costs. In a subsequent stage still under evaluation, we may add a sixth LNG storage tank and related facilities. We currently anticipate that Phase 2 will be constructed under a reimbursable engineering, procurement, construction and management agreement currently under negotiation with Bechtel pursuant to which Bechtel would manage, on behalf of Sabine Pass LNG, the construction activities of other contractors under agreements currently being negotiated between Sabine Pass LNG and those contractors. Our cost estimate is subject to change due to such items as cost overruns, change orders, changes in commodity prices (particularly steel) and escalating labor costs.

Subject to our receipt of the required regulatory governmental approvals, including FERC approval, and acceptable funding arrangements, which may include existing cash balances, proceeds from debt or equity offerings, or a combination thereof, we anticipate beginning construction of the first stage of Phase 2 during the second quarter of 2006. Assuming we achieve this schedule, we anticipate that Phase 2 operations would commence in 2009. In order to commence such operations, we will be required to satisfy certain conditions specified by FERC.

Customers

Total TUA

In September 2004, Sabine Pass LNG entered into a TUA with Total LNG USA, Inc., or Total, to provide berthing for LNG tankers and for the unloading, storage and regasification of LNG at the LNG receiving terminal. Sabine Pass LNG has no obligation to provide Total with certain services such as (i) harbor, mooring and escort services for LNG tankers, including the provision of tugboats, (ii) the transportation of natural gas downstream from the LNG terminal or the construction of any pipelines to provide such transportation or (iii) the marketing of natural gas.

Under the TUA, Total has reserved 390,915,000 MMBtu of annual LNG receipt capacity, which is equivalent to approximately 1.0 Bcf/d of regasification capacity, assuming an energy content of 1.05 MMBtu per Mcf and retainage of 2%. The Total TUA is scheduled to commence no later than April 2009, subject to substantial completion, runs for an initial term of 20 years and is subject to six additional 10-year extensions. Beginning on the commercial start date of the Sabine Pass LNG facility, Total has agreed to pay a monthly fixed capacity reservation fee of $9.1 million; a monthly operating fee of $1.3 million, which is adjusted annually for changes in the U.S. Consumer Price Index (All Urban Consumers); and certain other incremental costs and governmental authority taxes and costs. These monthly payment amounts are equivalent to payments of $0.28 per MMBtu for capacity and $0.04 per MMBtu for operating fees, respectively, of reserved monthly LNG receipt capacity. In addition, each month Sabine Pass LNG is entitled to retain 2% of the LNG delivered for Total's account for use as fuel at the facility. Total's obligations under the TUA are supported by an irrevocable guarantee, for an amount up to $2.5 billion, in favor of Sabine Pass LNG by Total S.A.

If any governmental authority (i) imposes any taxes on Sabine Pass LNG (excluding taxes on revenue or income) with respect to the services provided under the TUA, or the LNG receiving terminal or (ii) enacts any safety or security related regulation which materially increases the costs of Sabine Pass LNG in relation to the services provided or the LNG receiving terminal, Total will bear such taxes or increased regulatory costs at the rate of 40%, subject to adjustment if the LNG regasification facilities are expanded. To the extent any ad valorem taxes are imposed and not abated, we will reimburse Total for up to one-half of such amount not to exceed $3.9 million per year.

Sabine Pass LNG is obligated to pay liquidated damages to Total in the event of certain types of docking and unloading delays.

Both Sabine Pass LNG and Total may assign their interests under the TUA to affiliates, and, as permitted by the TUA and discussed below under "—Funding," Sabine Pass LNG has pledged its interest under the TUA to lenders to secure indebtedness incurred to finance the construction and term financing of the LNG receiving terminal. In addition, Total may make a partial assignment of its total reserved regasification capacity to nonaffiliates provided that (i) the assignee agrees to be bound by the TUA, (ii) the parent guarantee continues to apply to all assigned obligations and (iii) Total and the assignee designate a representative and jointly exercise all rights under the TUA.

Total may terminate the TUA if:

- Sabine Pass LNG has declared *force majeure* with respect to a period that has extended, or is projected to extend, for 18 months; or
- for reasons not excused by *force majeure* or Total's actions, if Sabine Pass LNG:
    - fails to deliver at least 191,625,000 MMBtu of Total's total natural gas nominations in a 12-month period;
    - fails entirely to receive at least 15 cargoes nominated by Total over a period of 90 consecutive days; or
    - fails to unload 50 cargoes or more scheduled for delivery by Total for a 12-month period.

Sabine Pass LNG may terminate the TUA if:

- the parent guarantee ceases to be in full force and effect;
- for a period exceeding 15 days, two of the parent guarantor's credit ratings fall below investment grade; or
- the parent guarantor commences bankruptcy or liquidation proceedings, or has such proceedings commenced against it.

Either party may terminate the TUA with 30 days written notice if (i) a party has failed to pay when due an amount owed that causes its cumulative delinquency to exceed three times the monthly capacity reservation fee, (ii) the cumulative delinquency has not been paid within 60 days of such notice and (iii) the other party has subsequently given 30 days' written notice to terminate the TUA.

In November 2004, Total exercised its option to proceed with the transaction by delivering to Sabine Pass LNG an advance capacity reservation fee payment of $10 million and a guarantee by its parent entity, Total S.A., of certain Total obligations under the TUA. Because Total elected to proceed with the transaction and Bechtel accepted the final notice to proceed, or NTP, an additional advance capacity reservation fee payment of $10 million was paid by Total to Sabine Pass LNG in April 2005.

Cheniere, Sabine Pass LNG and Total also entered into an omnibus agreement in September 2004, under which the TUA remains subject to certain conditions. Under the omnibus agreement, if Sabine Pass LNG enters into a new TUA with a third party, other than our affiliates, for capacity of 50 MMcf/d or more, with a term of five years or more, prior to the commercial start date of the terminal, Total will have the option, exercisable within 30 days of the receipt of notice of such transaction, to adopt the pricing terms contained in such new TUA for the remainder of the term of the Total TUA. In addition, the omnibus agreement provided Total with an option to increase its reserved capacity in the event that either party provided notice of a plan to expand the Sabine Pass LNG facility. During 2005, we provided such notice to Total and its option expired.

Chevron USA TUA

In November 2004, Sabine Pass LNG entered into a TUA with Chevron USA, Inc., or Chevron USA, pursuant to which Sabine Pass LNG is obligated to provide berthing for LNG tankers and for the unloading, storage and regasification of LNG at the LNG receiving terminal. Sabine Pass LNG has no obligation to provide certain services such as (i) harbor, mooring and escort services for LNG tankers, including the provision of tugboats, (ii) the transportation of natural gas downstream from the LNG terminal or the construction of any pipelines to provide such transportation or (iii) the marketing of natural gas.

In December 2005, Chevron USA exercised its option under its omnibus agreement to increase its regasification capacity by 300 MMcf/d for a total of 1.0 Bcf/d and paid Sabine Pass LNG an additional $3 million advance capacity reservation fee. As a result of Chevron USA exercising its option, the TUA is being amended to reflect such increased reservation of regasification capacity. Under the TUA, before the amendment described above, Chevron USA had reserved 282,761,850 MMBtu of annual LNG receipt capacity, which is equivalent to approximately 700 MMcf/d of regasification capacity, assuming an energy content of 1.085 MMBtu per Mcf and retainage of 2%.

The Chevron USA TUA commences between February 2009 and July 2009, subject to substantial completion, runs for an initial term of 20 years and is subject to two additional 10-year extensions. Beginning on the commercial start date of the Sabine Pass LNG facility, Chevron USA is required to pay Sabine Pass LNG a fixed monthly fee for this regasification capacity that is comprised of (i) a reservation fee of $0.28 per MMBtu of one-twelfth of the reserved annual LNG receipt capacity, (ii) an operating fee of $0.04 per MMBtu of one-twelfth of the reserved annual LNG receipt capacity and (iii) certain taxes and regulatory costs. The operating fee is adjusted annually for changes in the U.S. Consumer Price Index (All Urban Consumers). In addition, each month Sabine Pass LNG is entitled to retain 2% of the LNG delivered for Chevron USA's account for use as fuel at the facility. Chevron Corporation, or Chevron, will be required to guarantee Chevron USA's payment obligations under the TUA, up to a maximum of 80% of the fees payable under the TUA.

If any governmental authority (i) imposes any taxes on Sabine Pass LNG (excluding taxes on revenue or income) with respect to the services provided under the TUA, or the LNG receiving terminal or (ii) enacts any safety or security related regulation which materially increases the costs of Sabine Pass LNG in relation to the services provided at the LNG receiving terminal, Chevron USA will bear a proportionate share of such taxes or increased regulatory costs equal to 28%, subject to adjustment for Chevron USA's exercise of its capacity option in December 2005.

Sabine Pass LNG is obligated to pay liquidated damages to Chevron USA in the event of certain types of docking and unloading delays.

Both Sabine Pass LNG and Chevron USA may assign their interests under the TUA to affiliates, and, as permitted by the TUA and discussed below under "—Funding," Sabine Pass LNG has pledged its interest under the TUA to lenders to secure indebtedness incurred to finance the construction and term financing of the LNG receiving terminal. In addition, Chevron USA may make a partial assignment of its total reserved regasification capacity to nonaffiliates provided (i) the assignee agrees to be bound by the TUA, (ii) the parent guarantee continues to apply to all assigned obligations, (iii) Chevron USA remains liable for payments owed and (iv) the respective responsibilities of the parties under the TUA are not increased or decreased.

An assignment under the TUA will terminate Chevron USA's or Sabine Pass LNG's obligations only if (i) the assignment constitutes all of such party's rights and obligations under the TUA, (ii) the assignee agrees to be bound by the TUA and (iii) the assignee demonstrates creditworthiness at the time of the assignment that is the same or better than the guarantor, in the case of Chevron USA, or Sabine Pass LNG, in its case.

Chevron USA may terminate the TUA if Sabine Pass LNG has declared *force majeure* with respect to a period that has extended, or is projected to extend, for 18 months, or for reasons not excused by *force majeure* or Chevron USA's actions, if Sabine Pass LNG:

- fails to deliver at least 141,380,925 MMBtu of Chevron USA's total natural gas nominations in a 12-month period;
- fails entirely to receive 12 cargoes or more nominated by Chevron USA over a period of 90 days; or
- fails to unload, or notifies Chevron USA that it would be unable to unload, 37 cargoes or more scheduled for delivery by Chevron USA for a 12-month period.

The foregoing amounts are subject to adjustment in connection with the pending amendment of the TUA as a result of Chevron USA's December 2005 exercise of its capacity option.

Sabine Pass LNG may terminate the TUA if the parent guarantee ceases to be in full force and effect or if the parent guarantor or Chevron USA commences bankruptcy, insolvency or liquidation proceedings, or has such proceedings commenced against it, that are not stayed within 60 days.

Either party may terminate the TUA with 30 days written notice if (i) a party has failed to pay when due an amount owed that causes its cumulative delinquency to exceed three times the monthly capacity reservation fee, (ii) the cumulative delinquency has not been paid within 60 days after issuance of a delinquency notice and (iii) the other party has subsequently given 30 days written notice to terminate the TUA.

Cheniere, Sabine Pass LNG and Chevron USA simultaneously entered into an omnibus agreement, under which Chevron USA agreed to make advance capacity reservation fee payments. Under the omnibus agreement, Chevron USA exercised an option in December 2005, at the same fee, to increase its reserved capacity to 1.0 Bcf/d. As a result, a total of $20 million of advance capacity reservation fee payments were paid to Sabine Pass LNG by Chevron USA under the omnibus agreement. In addition, the omnibus agreement provided Chevron USA with an option to increase its reserved capacity in the event that either party provided notice of a plan to expand the Sabine Pass LNG facility. During 2005, we provided such notice to Chevron USA and its option expired.

Cheniere LNG Marketing

Cheniere LNG Marketing, Inc., or Cheniere Marketing, our wholly-owned subsidiary, intends to enter into a TUA with Sabine Pass LNG for 1.5 Bcf/d of regasification capacity at our Sabine Pass LNG receiving terminal, which capacity will be reduced to 600 MMcf/d in the event that both the Total TUA and the Chevron USA TUA commence prior to the completion of Phase 2 of our Sabine Pass LNG facility. See "—LNG and Natural Gas Marketing Business" for a discussion of our regasification capacity expected to be utilized by Cheniere Marketing.

Proposed Capacity Offering

Sabine Pass LNG intends to conduct a formal request-for-proposal process with unaffiliated third parties for up to 500 MMcf/d of regasification capacity at the Sabine Pass LNG receiving terminal. This process is expected to commence in April 2006 and will be subject to prior commitment to qualified third parties. We expect the request-for-proposal period to conclude in the second quarter of 2006; however, we may not be able to obtain any TUAs on terms acceptable to us, or at all.

EPC Agreement

In December 2004, Sabine Pass LNG entered into a lump-sum turnkey EPC agreement with Bechtel for the construction of Phase 1 of the Sabine Pass LNG receiving terminal. Under the EPC agreement, Bechtel agreed to provide Sabine Pass LNG with services for the engineering, procurement and construction of the Sabine Pass LNG receiving, storage and regasification terminal. Except for certain specified third-party work specified in the EPC agreement, the work to be performed by Bechtel includes all of the work required to achieve substantial completion and final completion of the Sabine Pass LNG receiving terminal in accordance with the requirements of the EPC agreement, including achieving specified minimum acceptance criteria and performance guarantees. Bechtel is obligated to perform its work in accordance with good engineering and construction practices and applicable laws, codes and standards.

Sabine Pass LNG issued a limited notice to proceed, or LNTP, in December 2004 and a final notice to proceed, or NTP, in early April 2005, which required Bechtel to commence all other aspects of the work under the EPC agreement. Bechtel must achieve substantial completion in accordance with the requirements of the EPC agreement on or before September 3, 2008. Final completion must be attained no later than 90 days after achieving substantial completion.

Until substantial completion under the terms of the EPC agreement, Sabine Pass LNG has certain rights to request change orders, and Bechtel has the right to request change orders up to and after substantial completion in the event of specified occurrences, including, among other things:

- a *force majeure* event;
- a suspension of work ordered by Sabine Pass LNG;
- certain acts and omissions by Sabine Pass LNG (including failure to fulfill obligations), but, in each case, only where such act or omission adversely affects Bechtel's costs of the performance of work, its ability to perform the work in accordance with the project schedule or its ability to perform any material obligation under the EPC agreement; and
- certain changes in law, but only where such delay adversely affects Bechtel's costs of the performance of the work, its ability to perform the work in accordance with the project schedule or its ability to perform any material obligation under the EPC agreement.

Sabine Pass LNG agreed to pay to Bechtel a contract price of $646.9 million plus certain reimbursable costs for the work under the EPC agreement. This contract price is subject to adjustment for changes in certain commodity prices, contingencies, change orders and other items. Payments under the EPC agreement will be made in accordance with the payment schedule set forth in the EPC agreement. The contract price and payment schedule, including milestones, may be amended only by change order. Bechtel will be liable to Sabine Pass LNG for certain delays in achieving substantial completion, minimum acceptance criteria and performance guarantees. Bechtel will be entitled to a scheduled bonus of $12 million, or a lesser amount in certain cases, if on or before April 3, 2008, Bechtel completes construction sufficient to achieve, among other requirements specified in the EPC agreement, a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours. Bechtel will be entitled to receive an additional bonus of $67,000 per day (up to a maximum of $6 million) for each day that commercial operation is achieved prior to April 1, 2008. As of February 28, 2006, change orders for $64.8 million had been approved, increasing the total contract price to $711.8 million. We anticipate additional change orders intended to mitigate ongoing effects of the 2005 hurricanes that would increase the contract price by an amount not expected to exceed $50 million. We expect to submit any such change orders to our lenders by May 3, 2006 for approval under the Sabine Pass Credit Facility described below under "—Funding".

Bechtel warrants in the EPC agreement that:

- the equipment required for the Sabine Pass LNG receiving terminal will be new and of good quality;
- the work and the equipment will meet the requirements of the EPC agreement, including good engineering and construction practices and applicable laws, codes and standards; and
- the work and the equipment will be free from encumbrances to title.

Until 18 months after substantial completion, Bechtel will be liable to promptly correct any work that is found defective.

In the event of an uncured default by Bechtel, Sabine Pass LNG may terminate the EPC agreement and take any of the following actions:

- take possession of the facility, equipment, construction equipment, work product and books and records;
- take assignment of certain subcontracts; and
- complete the work.

Following such a termination, if the cost to reach final completion exceeded the unpaid balance of the contract price, Bechtel would be liable for the difference. If the cost to reach final completion were less than the unpaid balance of the contract price, the difference would be payable to Bechtel.

Sabine Pass LNG also has the right to terminate the EPC agreement for convenience. In the event of any such termination for convenience, Bechtel would be paid:

- the portion of the contract price for the work performed prior to termination, less that portion of the contract price paid previously;
- actual reasonable cancellation charges owed by Bechtel to subcontractors (if Sabine Pass LNG does not take assignment of such subcontracts);
- actual costs associated with demobilization charges; and
- lost profits, except in certain cases, equal to 10% of the contract price less a portion of the advance payment related to the NTP.

Sabine Pass LNG may, upon a 30-day written notice to Bechtel, suspend the work under the EPC agreement. In the event of such suspension for a period exceeding 90 consecutive days or 120 aggregate days, other than any suspension due to an event of *force majeure* or the fault or negligence of Bechtel or its subcontractors, Bechtel would be permitted to terminate the EPC agreement subject to giving a 14 days' notice. In the event of such a termination, Bechtel would be entitled to the compensation described above in relation to termination for convenience. If Sabine Pass LNG suspends work under the EPC agreement, Bechtel could be entitled to a change order to recover the reasonable costs of the suspension, including demobilization and remobilization costs. Bechtel may also suspend or terminate the EPC agreement upon the occurrence of certain other events, including *force majeure* and uncured defaults of Sabine Pass LNG such as:

- failure to pay any undisputed amounts;
- failure to comply materially with material obligations under the EPC agreement; and
- insolvency.

Under the EPC agreement, if Bechtel experiences a *force majeure* event, it could be entitled to an extension of the date by which substantial completion is to be accomplished and an extension of the date by which it could earn the $12 million bonus. If any *force majeure* delay lasts at least 30 days, Bechtel would be entitled to an adjustment of the contract price under the EPC agreement to compensate it for its standby expenses, up to a limit of $3.8 million in the aggregate. A *force majeure* event generally occurs if any act or event occurs that:

- prevents or delays the affected party's performance of its obligations in accordance with the terms of the EPC agreement;
- is beyond the reasonable control of the affected party, not due to its fault or negligence; and
- could not have been prevented or avoided by the affected party through the exercise of due diligence.

Bechtel has claimed events of *force majeure* arising out of three hurricanes that made landfall along the U.S. Gulf Coast in 2005. Sabine Pass LNG is currently in negotiations with Bechtel and certain subcontractors concerning additional activities and expenditures in order, among other things, to attract sufficient skilled labor to mitigate potential schedule delays and provide a reasonable opportunity for Bechtel to attain the initial target bonus date of April 3, 2008 (the date originally anticipated for completion of construction sufficient to achieve a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours and that, if attained, would entitle Bechtel to a scheduled $12 million bonus). As part of these negotiations, we have agreed in principle to defer the date by which substantial completion of the entire project is required to be accomplished under the EPC contract from September 3 to December 20, 2008. In the absence of substantial completion by such date, Bechtel would be obligated to pay us certain liquidated damages as provided under the terms of the contract. We expect that the above-described arrangement will not exceed $50 million, although such amount is subject to change, requires approval of the lenders under our Sabine Pass Credit Facility (as described below under "—Funding") and requires that a change order be agreed upon with Bechtel.

Operation

In February 2005, Sabine Pass LNG entered into an Operation and Maintenance Agreement, or O&M Agreement, with Cheniere LNG O&M Services, L.P., or Cheniere O&M, a wholly-owned subsidiary of Cheniere. Pursuant to the O&M Agreement, Cheniere O&M has agreed to provide all necessary services required to operate and maintain the Sabine Pass LNG receiving terminal. The O&M Agreement will remain in effect until 20 years after substantial completion of the facility. Prior to substantial completion of the project, Sabine Pass LNG is required to reimburse Cheniere O&M for its operating expenses and pay a fixed monthly fee of $95,000 (indexed for inflation). The fixed monthly fee will increase to $130,000 (indexed for inflation) upon substantial completion of the facility, and Cheniere O&M will thereafter in certain circumstances be entitled to a bonus equal to 50% of the salary component of labor costs.

In February 2005, Sabine Pass LNG also entered into a Management Services Agreement, or MSA, with Sabine Pass LNG-GP, Inc., or Sabine Pass GP, its general partner and a wholly-owned subsidiary of Cheniere. Pursuant to the MSA, Sabine Pass LNG appointed Sabine Pass GP to manage the business of Sabine Pass LNG, excluding those matters provided under the O&M Agreement. The MSA terminates 20 years after the commercial start date set forth in the Total TUA. Prior to substantial completion of construction of the Sabine Pass LNG receiving facility, Sabine Pass LNG is required to pay Sabine Pass GP a monthly fixed fee of $340,000; thereafter, the monthly fixed fee will increase to $520,000 (indexed for inflation).

Funding

In February 2005, Sabine Pass LNG entered into an $822 million credit facility, or Sabine Pass Credit Facility, with an initial syndicate of 47 financial institutions. Société Générale serves as the administrative agent and HSBC Bank USA, National Association, or HSBC, serves as collateral agent. The Sabine Pass Credit Facility will be used to fund a substantial majority of the costs of constructing and placing into operation Phase 1 of the Sabine Pass LNG receiving terminal. Unless Sabine Pass LNG decides to terminate availability earlier, the Sabine Pass Credit Facility will be available until no later than April 1, 2009, after which time any unutilized portion of the Sabine Pass Credit Facility will be permanently canceled. Before Sabine Pass LNG could make an initial borrowing under the Sabine Pass Credit Facility, it was required to provide evidence that it had received equity contributions in amounts sufficient to fund $233.7 million of the project costs. As of December 31, 2005, the $233.7 million equity contributions had been funded and, as a result, we began drawing under the Sabine Pass Credit Facility in January 2006. As of February 28, 2006, $58.5 million had been drawn under the Sabine Pass Credit Facility. In addition, we made a $37.4 million subordinated loan to Sabine Pass LNG in late 2005.

Borrowings under the Sabine Pass Credit Facility bear interest at a variable rate equal to LIBOR plus the applicable margin. The applicable margin varies from 1.25% to 1.625% during the term of the Sabine Pass Credit Facility. The Sabine Pass Credit Facility provides for a commitment fee of 0.50% per annum on the daily committed, undrawn portion of the Sabine Pass Credit Facility. Administrative fees must also be paid annually to the administrative agent and the collateral agent. The principal of loans made under the Sabine Pass Credit Facility must be repaid in semi-annual installments commencing six months after the later of (i) the date that substantial completion of the project occurs under the EPC agreement and (ii) the commercial start date under the Total TUA. Sabine Pass LNG may specify an earlier date to commence repayment upon satisfaction of certain conditions. In any event, payments under the Sabine Pass Credit Facility must commence no later than October 1, 2009, and all obligations under the Sabine Pass Credit Facility mature and must be fully repaid by February 25, 2015.

The Sabine Pass Credit Facility contains customary conditions precedent to the initial borrowing and any subsequent borrowings, as well as customary affirmative and negative covenants. Sabine Pass LNG has obtained, and may in the future seek, consents, waivers and amendments to the Sabine Pass Credit Facility documents. The obligations of Sabine Pass LNG under the Sabine Pass Credit Facility are secured by all of Sabine Pass LNG's personal property, including the Total and Chevron USA TUAs and the partnership interests in Sabine Pass LNG.

In connection with the closing of the Sabine Pass Credit Facility, Sabine Pass LNG entered into swap agreements with HSBC and Société Générale. Under the terms of the swap agreements, Sabine Pass LNG will be able to hedge against rising interest rates, to a certain extent, with respect to its drawings under the Sabine Pass Credit Facility up to a maximum amount of $700 million. The swap agreements have the effect of fixing the LIBOR component of the interest rate payable under the Sabine Pass Credit Facility with respect to hedged drawings under the Sabine Pass Credit Facility up to a maximum of $700 million at 4.49% from July 25, 2005 to March 25, 2009 and at 4.98% from March 26, 2009 through March 25, 2012. The final termination date of the swap agreements will be March 25, 2012.

We are currently evaluating funding alternatives for the construction of Phase 2 of the Sabine Pass LNG facility, which may include existing cash balances, proceeds from debt or equity offerings, or a combination thereof.

Corpus Christi LNG

Development

We are also developing the Corpus Christi LNG receiving terminal near Corpus Christi, Texas. We formed Corpus Christi LNG, L.P., or Corpus Christi LNG, in May 2003 to develop the terminal. We contributed our technical expertise and know-how, and all of the work in progress related to the Corpus Christi project, in exchange for a 66.7% limited partner interest in Corpus Christi LNG. A third party, BPU LNG, Inc., or BPU LNG, contributed approximately 212 acres of land and committed to contribute cash to fund the first $4.5 million of Corpus Christi LNG project expenses, in exchange for its 33.3% limited partner interest. Corpus Christi LNG also obtained related easements and other rights to an additional 400 acres. In January 2004, BPU LNG entered into an option agreement with Corpus Christi LNG to acquire 100 MMcf/d of regasification capacity at the terminal, which was subsequently assigned to its sole stockholder, BPU Associates, LLC. In February 2005, we acquired BPU LNG's 33.3% limited partner interest in exchange for two million restricted shares of Cheniere common stock, which were subsequently registered for resale.

The Corpus Christi LNG receiving terminal is designed with regasification capacity of 2.6 Bcf/d, two docks and three LNG storage tanks with an aggregate LNG storage capacity of 10.1 Bcfe. The facility will have two unloading docks, which can handle 87,000 cm to 250,000 cm LNG shipping vessels. The total cost to construct this facility is currently estimated at approximately $650 million to $750 million, before financing costs. This estimate is based in part on our negotiations with a major international EPC contractor. Our cost estimate is subject to change due to such items as cost overruns, change orders, changes in commodity prices (particularly steel) and escalating labor costs. BPU LNG was required to fund 100% of the first $4.5 million of Corpus Christi LNG's expenditures, which amount was funded as of March 31, 2004. From that date until February 8, 2005, when we acquired BPU LNG's 33.3% interest, we funded 66.7% of the expenditures of Corpus Christi LNG, with BPU LNG funding the balance. Since February 8, 2005, BPU LNG has not been required to fund any expenditures, and as the sole owner of Corpus Christi LNG, we are now required to fund 100% of the expenditures.

In December 2005, 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 FERC. We are negotiating and anticipate entering into an arrangement with a major international EPC contractor for the Corpus Christi LNG receiving terminal. We expect to begin site preparation and detailed engineering work in the second quarter of 2006 and to commence operations at the Corpus Christi LNG receiving terminal in early 2010.

Customers

Cheniere Marketing intends to enter into a TUA with Corpus Christi LNG for 1.0 Bcf/d of regasification capacity at that terminal. See "—LNG and Natural Gas Marketing Business" for a discussion of our regasification capacity expected to be utilized by Cheniere Marketing.

Corpus Christi LNG intends to conduct a formal request-for-proposal process with unaffiliated third parties for up to 1.0 Bcf/d of regasification capacity at the Corpus Christi LNG receiving terminal. This process, a time for which has not been established, will be subject to prior commitment to qualified third parties. However, we may not be able to obtain any TUAs on terms acceptable to us, or at all.

Funding

We currently expect to fund the project costs for our Corpus Christi LNG receiving terminal using financing similar to that used for our Sabine Pass LNG facility, proceeds from debt or equity offerings, existing cash or a combination thereof.

Creole Trail LNG

Development

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., or Creole Trail LNG, in December 2004 to develop the terminal. We have options to lease tracts of land comprising 1,463 acres in Cameron Parish, Louisiana for the project site.

The Creole Trail LNG receiving terminal is anticipated to be designed with regasification capacity of 3.3 Bcf/d, two docks and four LNG storage tanks with an aggregate LNG storage capacity of 13.5 Bcfe. The facility will have two unloading docks, which can handle 87,000 cm to 250,000 cm LNG shipping vessels. The cost to construct the Creole Trail facility is currently estimated at approximately $850 million to $950 million, before financing costs. Our cost estimate is preliminary and is subject to change.

In May 2005, we filed on application with FERC to obtain an order to site, construct and operate the facility. In December 2005, FERC issued the DEIS for our Creole Trail facility, preliminarily concluding that the facility, with appropriate mitigating measures as recommended, would have limited adverse environmental impact. Once we obtain FERC authorization, we expect to begin construction in 2007 after obtaining financing and entering into an EPC agreement. Based on this schedule, we expect to commence terminal operations in 2011.

Customers

We have not entered into any contracts for the regasification capacity at our proposed Creole Trail LNG receiving terminal. We anticipate reserving the regasification capacity at our Creole Trail LNG receiving terminal for strategic relationships. We may not be able to obtain any TUAs on terms acceptable to us, or at all. We currently intend that a portion of the regasification capacity not committed to unaffiliated third parties will be contracted to Cheniere Marketing. See "—LNG and Natural Gas Marketing Business" for a discussion of our regasification capacity expected to be utilized by Cheniere Marketing.

Funding

We currently expect to fund the costs of the Creole Trail LNG terminal project using financing similar to that used for our Sabine Pass LNG facility, proceeds from future debt or equity offerings, existing cash or a combination thereof.

Other Sites

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

Other LNG Interests—Freeport LNG

Development

In 2001, we initiated development of an LNG receiving facility on Quintana Island near Freeport, Texas. In 2003, we contributed to Freeport LNG Development, L.P., or Freeport LNG, all of our interest in the Freeport site and project in exchange for a 40% limited partner interest in Freeport LNG and $6.7 million of cash payments. We subsequently sold a 10% limited partner interest in Freeport LNG to an affiliate of Contango Oil & Gas Company. As a result of the sale, we own a 30% limited partner interest in Freeport LNG. As a limited partner in Freeport LNG, we must rely largely on the general partner to successfully implement Freeport LNG's business plans.

The Freeport LNG receiving terminal is being developed on land leased from Port Freeport. The initial phase of the project includes regasification capacity of 1.5 Bcf/d, one dock, two LNG storage tanks with an aggregate LNG storage capacity of 6.7 Bcfe, and a 9.4-mile, 42-inch diameter pipeline through which natural gas will be transported to a customer redelivery point at Stratton Ridge, Texas, which is a major point of interconnection with the Texas intrastate gas pipeline grid. We have been advised by Freeport LNG that it has entered into a lump-sum turnkey contract for its receiving terminal, and that the estimated cost to construct the terminal and associated facilities (before the proposed expansion discussed below) is approximately $800 million to $850 million, before financing costs. We believe that this cost estimate is subject to change due to such items as cost overruns and change orders under the EPC agreement.

In January 2005, FERC authorized Freeport LNG to commence construction of the LNG receiving terminal and natural gas pipeline. Construction began in the first quarter of 2005, and we expect that terminal operations will commence in early 2008. In order to commence operations, Freeport LNG will be required to satisfy certain conditions specified by FERC.

Freeport LNG has filed an application seeking an additional order from FERC to authorize the construction of an expansion that would increase the regasification capacity from its currently permitted 1.5 Bcf/d LNG receiving terminal to approximately 4.0 Bcf/d. In addition to increased regasification capacity, the proposed expansion includes a second dock, a third LNG storage tank and 7.5 Bcf of underground salt cavern gas storage. The development, construction and operation of the Freeport LNG facility, as well as the anticipated financial consequences for us as a limited partner in Freeport LNG, will change as a result of any such expansion.

TUA Customers

Freeport LNG has entered into TUAs with three customers: The Dow Chemical Company, or Dow, ConocoPhillips Company, or ConocoPhillips, and MC Global Gas Corporation, or MC Global, a wholly-owned subsidiary of Mitsubishi Corporation. Under the TUAs, Freeport LNG is obligated to provide berthing for LNG tankers and for the unloading, storage and regasification of LNG at its receiving terminal. In addition, Freeport LNG will provide for the transportation and delivery of natural gas through the facility's 9.4-mile pipeline to Stratton Ridge, Texas for interconnection with downstream pipelines.

In March 2004, Dow entered into a long-term TUA with Freeport LNG, pursuant to which Dow has reserved 195,275,000 MMBtu of annual LNG receipt capacity under the TUA, which is equivalent to approximately 500 MMcf/d of regasification capacity. The Dow TUA commences between April 2007 and March 2008 (subject to extensions), runs for an initial term of 20 years and is subject to three 10-year extensions. Dow is required to pay Freeport LNG a monthly reservation fee for this regasification capacity, which is subject to reduction under certain circumstances. In addition, each month Freeport LNG is entitled to retain a percentage of Dow's share of LNG to be used as fuel at the facility. Dow is also required to pay a portion of power and other operating costs.

In July 2004, ConocoPhillips and Freeport LNG entered into a long-term TUA, pursuant to which ConocoPhillips has reserved 390,550,000 MMBtu of annual LNG receipt capacity, which is equivalent to approximately 1.0 Bcf/d of regasification capacity. In addition, ConocoPhillips has exercised its option to reserve approximately 300 MMcf/d of regasification capacity with respect to the additional capacity resulting from the proposed expansion. The ConocoPhillips TUA commences between April 2007 and March 2008 (subject to extensions), runs for an initial term until February 2033 and is subject to six 10-year extensions. ConocoPhillips is required to pay Freeport LNG a monthly reservation fee for this regasification capacity, which is subject to reduction under certain circumstances. In addition, each month Freeport LNG is entitled to retain ConocoPhillips' allocable share of LNG used as fuel at the facility and its allocable portion of all other actual losses. ConocoPhillips is also required to pay on a monthly basis its allocable portion of power and other operating costs.

In January 2005, Freeport LNG announced that it had executed a 17-year TUA with MC Global. Pursuant to the TUA, MC Global has reserved approximately 150 MMcf/d of regasification capacity in the Freeport LNG terminal and has an option to increase its total regasification capacity by an additional 100 MMcf/d, to a total of 250 MMcf/d.

Funding

In July 2004, Freeport LNG entered into a credit agreement with ConocoPhillips for ConocoPhillips to provide a substantial majority of the debt financing for the initial phase of the project. In December 2005, Freeport LNG announced that it had closed a $383 million private placement of notes, which will be used to fund the remaining portion of the initial phase of the project, a portion of the cost of expanding the LNG receiving terminal and the development of 7.5 Bcf of underground salt cavern gas storage. As a result of such financing being obtained, we do not anticipate that any capital calls will be made upon the limited partners of Freeport LNG in the foreseeable future.

To the extent that the funding provided by ConocoPhillips and the private placement notes is insufficient or not available to meet the capital expenditures or working capital requirements of Freeport LNG, the general partner of Freeport LNG may obtain such additional funding from various funding sources. 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 with capital contributions by the limited partners. We received capital calls, and made capital contributions, in the amount of approximately $2.1 million in 2005. No capital calls are currently outstanding, and in view of the closing of the Freeport LNG financing described above, we do not anticipate any in the foreseeable future. However, in the event of any 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 any future Freeport LNG capital calls on a case-by-case basis and to fund additional capital contributions that we elect to make using cash on hand and funds raised through the issuance of Cheniere equity or debt securities or other Cheniere borrowings.

The general partner of Freeport LNG is also authorized to do all things necessary to obtain debt and equity financing in connection with any expansion of the facility. Any equity financing obtained for such expansion will dilute the ownership interests of the limited partners on a pro rata basis. However, we and the other limited partners have preemptive rights that allow any limited partner to maintain its percentage ownership interest in Freeport LNG.

Competition

The volume of natural gas supply additions required to meet U.S. consumption needs is a function of not only demand growth but also the decline in the underlying production base. In North America, this natural decline has been accelerating over the last decade, significantly increasing the need to bring on new supplies. According to a 2003 report by The National Petroleum Council, the natural gas production from existing wells in the United States in 1991 declined 17%, or 9.0 Bcf/d, by 1992. In contrast, data from IHS Energy shows that natural gas production from existing wells in 2004 declined 28%, or 17 Bcf/d, by 2005.

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

- existing producing basins in the United States, Canada and Mexico;
- frontier basins 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 natural gas could be met by alternative energy forms, including coal, hydroelectric, oil, wind, solar and nuclear energy. LNG will face competition from each of these energy sources.

We compete with other companies to be among the first to construct LNG receiving terminals in economically desirable locations. According to FERC, there are currently over 40 LNG receiving terminals actively proposed to be constructed in the United States, although we anticipate that only four new terminals will be constructed in the United States by 2010. In addition, one shipboard regasification facility has commenced operations, and companies are pursuing other offshore terminals and shipboard regasification facilities to import LNG into U.S. markets.

BP Statistical Review has reported that, as of December 31, 2004, there was 6,333 Tcf of proved natural gas reserves worldwide, and we believe that LNG has the potential to be a significant new source of lower cost supply to North America. We will compete with other importers of LNG at existing and proposed North American LNG receiving terminals. As of December 31, 2005, there were four onshore LNG receiving terminals operating in North America, which will compete with any terminals that we develop. We believe that all of the capacity at these four existing onshore United States terminals is committed to customers under long-term arrangements. As of December 31, 2005, there were 44 LNG receiving terminals in 12 countries, and we will compete with these and other proposed LNG receiving terminals worldwide to be the most economical delivery point for LNG production for both long-term contracted and spot volumes.

Governmental Regulation

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

FERC

In order to site, construct and operate our proposed LNG receiving terminals, we must receive and maintain authorization from FERC under Section 3 of the Natural Gas Act of 1938, or NGA. The FERC permitting process includes:

- public notice and public meetings;
- data gathering and analysis at FERC's request;
- issuance of a Draft Environmental Impact Statement by FERC;
- public meetings;
- issuance of a Final Environmental Impact Statement by FERC; and
- FERC order authorizing construction.

In addition, orders from FERC authorizing construction of an LNG receiving terminal are typically subject to specified conditions that must be satisfied prior to commencement of construction.

Other Federal Governmental Permits, Approvals and Consultations

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

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

Energy Policy Act of 2005

In 2005, the Energy Policy Act of 2005, or EPAct, was signed into law. The EPAct contains numerous provisions relevant to the natural gas industry and to interstate pipelines. The EPAct includes several provisions which amend the NGA. The primary provisions of interest to our proposed interstate pipelines focus on two areas: infrastructure development, and market manipulation and enforcement. Regarding infrastructure development, the EPAct states that FERC has exclusive authority to approve or deny an application for the siting, construction, expansion or operation of an LNG receiving terminal. The EPAct also provides for market-based rates for new storage facilities placed into service after August 8, 2005, even if the storage provider has market power if FERC determines that market-based rates are in the public interest and necessary to encourage the construction of the storage capacity and customers are adequately protected from the exercise of market power. Regarding market manipulation and enforcement, the EPAct amends the NGA to prohibit market manipulation. The EPAct also amends the NGA and the NGPA to increase civil and criminal penalties. FERC has initiated a rulemaking proceeding regarding market-based storage rates. In addition, FERC issued a Final Rule effective January 26, 2006 regarding market manipulation, which makes it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to 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. This Final Rule works together with FERC's enhanced penalty authority to provide increased oversight of the natural gas marketplace.

Environmental Matters

Our LNG operations are subject to various federal, state and local laws and regulations relating to the protection of the environment. In some cases, these laws and regulations require us to obtain governmental authorizations before we may conduct certain activities or may require us to limit certain activities in order to protect endangered or threatened species or sensitive areas. These environmental laws may impose substantial penalties for noncompliance and substantial liabilities for pollution. As with the industry generally, compliance with these laws increases our overall cost of business. While these laws affect our capital expenditures and earnings, we believe that these regulations do not affect our competitive position in the industry because our competitors are similarly affected by these laws. Environmental regulations have historically been subject to frequent change. Consequently, we are unable to predict the future costs or other future impacts of environmental regulations on our future operations.

The federal Comprehensive Environmental Response, Compensation and Liability Act, or 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 for:

- the costs of cleaning up the hazardous substances that have been released into the environment;
- damages to natural resources; and
- the costs of certain health studies.

In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances. Although CERCLA currently excludes petroleum, natural gas, natural gas liquids and liquefied natural gas from its definition of "hazardous substances," this exemption may be limited or modified by the United States Congress in the future.

Our operations are subject to the federal Clean Air Act, or CAA, and comparable state and local laws. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The Environmental Protection Agency, or EPA, and states have been developing regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining permits and approvals addressing other air emission-related issues. We do not believe, however, that our operations will be materially adversely affected by any such requirements.

Certain persons have expressed concerns that air emissions from our Sabine Pass LNG project located in Cameron Parish, Louisiana, which are allowed under our existing permits, will adversely impact regional air quality in southeastern Texas so as to trigger future federal sanctions for that area under the Clean Air Act. While we have no reason to believe that any formal challenge will be made regarding our existing permits under the Clean Air Act, there can be no assurance that challenges will not be pursued or that, if pursued, they would not result in costs or conditions that could have a material adverse effect on our business and operations.

Our operations are also subject to the federal Clean Water Act, or CWA, and analogous state and local laws. Pursuant to certain requirements of the CWA, the EPA has adopted regulations concerning discharges of 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. In addition, our operations, including construction of LNG receiving terminals, in areas deemed to be wetlands, or which otherwise involve discharges of dredged or fill material into navigable waters of the United States, may be subject to Army Corps of Engineers permitting requirements.

The federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes govern the disposal of "hazardous wastes." In the event any hazardous wastes are generated in connection with our LNG operations, we may be subject to regulatory requirements affecting the handling, transportation, storage and disposal of such wastes.

Our operations may be restricted by requirements under the Environmental Species Act, or ESA, which seeks to ensure that human activities do not jeopardize endangered or threatened animal, fish and plant species nor destroy or modify their critical habitats.

Natural Gas Pipeline Development Business

We formed Cheniere Pipeline Company, a wholly-owned subsidiary, to develop natural gas pipelines that will provide optimal access to North American natural gas markets for customers of our Sabine Pass, Corpus Christi and Creole Trail LNG receiving terminals. Development efforts to date have focused primarily on advancing our pipeline projects through the regulatory review and authorization process. As these development efforts have progressed, our focus has expanded to also include the construction and operation of our proposed natural gas pipelines. Our pipeline systems will connect with multiple pipelines that provide a means of delivering revaporized natural gas from our LNG receiving terminals to various North American natural gas markets. Our ultimate decisions regarding pipeline connections to our facilities will depend upon future events, including, in particular, customer preferences and general market demand for natural gas from a particular LNG receiving terminal.

Our Proposed Pipelines

Sabine Pass Pipeline

We formed Cheniere Sabine Pass Pipeline Company, a wholly-owned subsidiary of Cheniere, to develop, construct, own and operate the natural gas pipeline servicing our Sabine Pass LNG receiving terminal. FERC issued an order in December 2004 authorizing construction, subject to specified conditions that must be satisfied, of our proposed 16-mile, 42-inch diameter natural gas pipeline connection to our Sabine Pass LNG receiving terminal. This interstate pipeline is designed to transport 2.6 Bcf/d of regasified LNG from the site of our Sabine Pass LNG facility, running easterly along a corridor that will allow for interconnection points with existing interstate and intrastate natural gas pipelines in southwest Louisiana, including pipelines operated by Natural Gas Pipeline Company of America, Transcontinental Gas Pipeline Corporation, Tennessee Gas Pipeline Company, Florida Gas Transmission and Bridgeline Holdings, L.P. We believe that these existing pipelines are currently capable of transporting approximately 3.8 Bcf/d.

Preliminary engineering, survey and easement acquisition is in progress. Subject to FERC approval of the implementation plan for construction of our Sabine Pass pipeline, we anticipate beginning construction in early 2007. We anticipate commencing operations of the pipeline in the fourth quarter of 2007.

We estimate that the total cost to construct the Sabine Pass pipeline, including certain work not included in the EPC pipeline contract, such as interconnection with third-party pipelines, will be approximately $90 million. Our total cost estimate is preliminary and subject to change due to such items as cost overruns, change orders, changes in commodity prices (particularly steel) and escalating labor costs.

EPC Pipeline Contract

On February 21, 2006, Cheniere Sabine Pass Pipeline Company entered into an EPC pipeline contract with Willbros Engineers, Inc., or Willbros. Under the EPC pipeline contract, which is effective as of February 1, 2006, Willbros will provide Cheniere Sabine Pass Pipeline Company with services for the management, engineering, material procurement, construction and construction management of the Sabine Pass pipeline. Cheniere Sabine Pass Pipeline Company entered into the EPC pipeline contract sufficiently in advance of commencement of physical construction of the pipeline in order to perform detailed engineering and procure materials.

The work to be performed by Willbros includes all management, engineering, procurement, construction and construction management for the Sabine Pass pipeline, including providing all equipment, materials, supplies, labor, workmanship, apparatus, machinery, tools, structures, inspection, manufacture, fabrication, installation, design, delivery, transportation, storage and any incidental work reasonably inferable as required and necessary to complete the Sabine Pass pipeline in accordance with applicable law, applicable codes and standards and all other provisions of the EPC pipeline contract. In addition, Willbros will provide reasonable assistance to Cheniere Sabine Pass Pipeline Company in its efforts to obtain required rights of way, access roads, pipe yards, ware yards and all other land rights or property interests necessary for construction.

The work to be performed by Willbros is based upon and must comply with the preliminary engineering developed by Cheniere Sabine Pass Pipeline Company's other consultants and contractors and the certificate issued by FERC authorizing, among other things, the construction of the Sabine Pass pipeline.

Willbros may not commence work related to ware yard preparation and material receipt earlier than January 1, 2007 and may not commence work related to the construction of the Sabine Pass pipeline earlier than April 1, 2007. Willbros must achieve mechanical completion of the Sabine Pass pipeline no later than September 30, 2007, except as adjusted by change order. At any time upon written notice, either party has the right to request change orders.

Cheniere Sabine Pass Pipeline Company will pay to Willbros a contract price not to exceed $67.7 million, subject to additions and deductions by any change order as provided in the EPC pipeline contract, excluding Louisiana sales and use taxes applicable to permanent materials and equipment to be incorporated into the Sabine Pass pipeline, which Cheniere Sabine Pass Pipeline Company is obligated to reimburse in accordance with the EPC pipeline contract.

Payments under the EPC pipeline contract will be made in accordance with the payment schedule set forth in the EPC pipeline contract.

Willbros warrants that the work and each component thereof will be:

- new, complete, fit for the purposes specified in the EPC pipeline contract and of suitable grade for the intended function and use;
- in accordance with all of the requirements of the EPC pipeline contract, including in accordance with good engineering and construction practices, applicable law and applicable codes and standards;
- free from encumbrances to title; and
- free from defects in design, material and workmanship and otherwise conform to the standards and requirements contained in the specifications and elsewhere in the EPC pipeline contract.

Except with respect to materials or equipment procured by Willbros from a third-party vendor, if within 12 months after start-up any work is found to be defective, Willbros will be obligated to immediately and on an expedited basis correct any such defective work. With respect to materials or equipment procured by Willbros from a third-party vendor, Willbros' liability during the 12 months after start-up for such materials and equipment will be limited to "passing through" to Cheniere Sabine Pass Pipeline Company the benefits of any warranties Willbros receives from the applicable vendor.

In the event of an uncured default by Willbros, Cheniere Sabine Pass Pipeline Company may terminate for default Willbros' performance of all or part of the work. In the case of termination for default, Cheniere Sabine Pass Pipeline Company may complete the work by whatever method it deems expedient, including:

- taking possession, for the purposes of completing the work, of all Willbros equipment and materials, and/or
- taking assignment of any or all subcontracts or purchase orders for the construction of the Sabine Pass pipeline.

Following such a termination, Willbros will not be entitled to receive any further payment until the work is fully completed and accepted by Cheniere Sabine Pass Pipeline Company, and Willbros will be liable to

Cheniere Sabine Pass Pipeline Company for all costs, damages, losses and expenses (including all attorneys' fees, consultant fees and litigation or arbitration expenses) incurred by Cheniere Sabine Pass Pipeline Company in completing the work, including all liquidated damages to the extent payable pursuant to the EPC pipeline contract.

Cheniere Sabine Pass Pipeline Company also has the right to terminate the EPC pipeline contract. In the event of any such termination for convenience, Willbros would be paid:

- the reasonable value of the work satisfactorily performed prior to termination (the basis of payment being based on the terms of the EPC pipeline contract, less previous payments, if any, paid to Willbros under the EPC pipeline contract), plus
- reasonable direct close-out costs, but in no event will Willbros be entitled to receive any amount for unabsorbed overhead, contingency or anticipatory profit.

Cheniere Sabine Pass Pipeline Company may at any time, whether or not for cause, suspend performance of the work, or any part thereof, by a change order specifying the work to be suspended and the effective date of such suspension. Except when such suspension ordered by Cheniere Sabine Pass Pipeline Company is the result of or due to the fault or negligence of Willbros or any subcontractor or vendor, Willbros will be entitled to the reasonable costs (including actual, but not unabsorbed, overhead, contingency, risk and reasonable profit) of such suspension incurred during the suspension period, including demobilization and remobilization costs and costs incurred for Willbros personnel and for Willbros equipment, at specified standby rates and a time extension to the preparation and material receipt commencement date, the construction commencement date or the scheduled mechanical completion date if and to the extent permitted under the EPC pipeline contract.

If the commencement, prosecution or completion of any work is delayed by a *force majeure* event, then Willbros may be entitled to an extension to the scheduled mechanical completion date. If such delay or prevention occurs for a continuous period of at least 5 days in any 30 day period, Willbros would be entitled to an adjustment of the contract price under the EPC pipeline contract to reimburse it for its standby expenses, up to a limit of $1.5 million in the aggregate. A *force majeure* event generally occurs if any act or event occurs that:

- renders impossible or impracticable the affected party's performance of its obligations under the EPC pipeline contract;
- is beyond the reasonable control of the affected party and not due to its fault or negligence; and
- could not have been prevented or avoided by the affected party through the exercise of due diligence.

The obligation of either party to pay money under or pursuant to the EPC pipeline contract will not be excused by reason of a *force majeure* event.

Corpus Christi Pipeline

We formed Cheniere Corpus Christi Pipeline Company, a wholly-owned subsidiary of Cheniere, to develop, construct, own and operate the natural gas pipeline servicing our Corpus Christi LNG receiving terminal. FERC issued an order in April 2005 authorizing construction, subject to specified conditions that must be satisfied, of our proposed 24-mile, 48-inch diameter natural gas pipeline. This interstate pipeline is designed to transport 2.6 Bcf/d of regasified LNG from the site of our proposed Corpus Christi LNG receiving terminal, running northwesterly along a corridor that will allow for interconnection points with interstate and intrastate natural gas transmission pipelines in South Texas, including existing pipelines operated by Texas Eastern Transmission Corporation, Gulf South Pipeline Company, L.P., Gulf Terra Intrastate, L.P. (Channel), Kinder Morgan Tejas Pipeline, L.P., Crosstex CCNG Marketing, Ltd., Transcontinental Gas Pipeline Corporation, Tennessee Gas Pipeline Company and Natural Gas Pipeline Company of America. We believe these existing pipelines are currently capable of transporting approximately 4.6 Bcf/d. Construction contracts for the Corpus Christi pipeline have not been negotiated.

Creole Trail Pipelines

We formed Cheniere Creole Trail Pipeline Company, a wholly-owned subsidiary of Cheniere, to develop, construct, own and operate the natural gas pipelines servicing our Creole Trail LNG receiving terminal. In connection with the FERC application for our Creole Trail LNG receiving terminal, we have sought approval to construct dual 117-mile, 42-inch diameter natural gas pipelines. These interstate pipelines are designed to transport 3.3 Bcf/d of regasified LNG from the site of our proposed Creole Trail LNG receiving terminal, running north/northeasterly along a corridor through six Louisiana parishes and terminating near Rayne, Louisiana. The Creole Trail pipelines are anticipated to be designed with potential interconnections to existing interstate and intrastate natural gas pipelines in southwestern Louisiana operated by ANR Pipeline Company, Bridgeline Holdings, L.P., Sabine Pipeline Company, Targa Louisiana Intrastate L.L.C., Gulf South Pipeline Company, L.P., Transcontinental Gas Pipeline Corporation, Trunkline Gas Pipeline Company, Texas Eastern Transmission Corporation, Tennessee Gas Pipeline, Florida Gas Transmission Company, Columbia Gulf Transmission Company and Cypress Gas Pipeline, L.L.C. We believe that these existing pipelines are currently capable of transporting approximately 12.0 Bcf/d. Construction contracts for the Creole Trail pipeline have not been negotiated.

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 from a particular LNG receiving terminal.

Funding

We estimate that approximately $800 million to $1 billion of total capital expenditures will be required to construct our three proposed pipelines. We currently expect to fund the costs of our proposed pipelines from our existing cash balances, project financing, proceeds from future debt or equity offerings, or a combination thereof.

Customers

We offered our pipeline capacity to potential customers through a formal request-for-proposal process, and we awarded our marketing affiliate all of the capacity in our proposed Sabine Pass and Corpus Christi pipelines. Cheniere Marketing has entered into binding precedent agreements for transportation services on each of these pipelines at the maximum tariff rate for the transport and sale of revaporized natural gas that it derives from its own imported LNG or LNG that it purchases from other importers for sale into North American markets. See "—LNG and Natural Gas Marketing Business" below. Transportation precedent agreements have not been executed for our Creole Trail pipelines. Cheniere Marketing's capacity rights and obligations under the transportation precedent agreements are fully assignable, and we anticipate that unaffiliated customers with whom we enter into TUAs for our LNG receiving terminals will also desire to enter into agreements for the transportation of revaporized gas on our proposed pipelines. Furthermore, we expect that other unaffiliated third-party shippers of domestic natural gas may desire transportation services in our pipelines on at least an interruptible basis.

Competition

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

Our pipelines will face competition from other intrastate and/or interstate pipelines that connect with our LNG receiving terminals. In particular, our Sabine Pass pipeline will compete with the proposed Kinder Morgan

Louisiana Pipeline owned by Kinder Morgan Energy Partners, L.P., or Kinder Morgan. Kinder Morgan has announced that it is building a 3.2 Bcf/d take-away pipeline system from our Sabine Pass LNG receiving terminal. The Kinder Morgan Louisiana Pipeline will consist of two segments: a 137-mile, 2 Bcf/d pipeline extending to Evangeline Parish, Louisiana, and interconnecting with 11 interstate pipelines as well as a series of intrastate pipes; and a one-mile, 1.2 Bcf/d pipeline interconnecting with the Natural Gas Pipeline Co. of America system near our Sabine Pass LNG receiving terminal. Total and Chevron USA have both announced agreements with Kinder Morgan securing 100% of the initial capacity on the Kinder Morgan Louisiana Pipeline for 20 years.

Governmental Regulation

Interstate Natural Gas Pipelines

Under the NGA, FERC regulates the transportation of natural gas in interstate commerce. Under FERC's regulations, "transportation" service includes natural gas storage service. In general, FERC's authority to regulate pipelines and the services they provide includes:

- rates and charges for natural gas transportation and related services;
- the certification and construction of new facilities;
- the extension and abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and
- various other matters.

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

The natural gas industry historically has been heavily regulated. FERC regulates the transportation rates and terms and conditions of service of interstate natural gas pipelines. See "—Rates" below. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, FERC may not continue this approach.

Our Sabine Pass, Corpus Christi and Creole Trail pipelines will be interstate natural gas pipelines, which will connect our LNG facilities directly to the interstate natural gas pipeline grid. To the extent that we construct and operate interstate natural gas pipelines, we must obtain authorization pursuant to Section 7 of the NGA to construct and operate these pipeline facilities and the rates that we charge will be subject to FERC's regulation under NGA Section 4 as well as to FERC's open access and tariff requirements. FERC's exercise of jurisdiction over interstate gas pipelines is substantially broader than its exercise of jurisdiction over LNG terminals and would continue as long as these pipelines are operated in interstate commerce.

Pipeline Safety

Louisiana and Texas administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968, as amended, or the 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, or PSIA, which is administered by the U.S. Department of Transportation Office of Pipeline Safety, or OPS, governs the areas of testing, education, training and communication. The PSIA requires pipeline companies to perform 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 Department of Transportation issued a Final Rule that became effective January 14, 2004, requiring pipeline operators to develop integrity management programs for gas transportation pipelines. The Final Rule requires pipeline operators to perform ongoing assessments of pipeline integrity; identify and characterize applicable threats to pipeline segments that could impact a high consequence area; improve data collection, integration and analysis; repair and remediate the pipeline, as necessary; and implement preventive and mitigation actions. This rule incorporates the requirements of the PSIA.

Energy Policy Act of 2005

The EPAct contains numerous provisions relevant to the natural gas industry and to interstate pipelines. See "—LNG Receiving Terminal Development Business—Governmental Regulation—Energy Policy Act of 2005."

Rates

Under the NGA, rates charged for the interstate transportation of natural gas must be just and reasonable and non-discriminatory. Amounts collected by the pipeline in excess of just and reasonable rates are subject to refund with interest. Beginning in the mid-1980s, FERC initiated a number of regulatory changes intended to create a more competitive environment in the natural gas marketplace. Among the most important of these changes were:

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

On November 25, 2003, FERC issued a series of orders adopting revised Standards of Conduct (Order No. 2004) that apply uniformly to interstate natural gas pipelines. In light of the changing structure of the energy industry, these Standards of Conduct govern relationships between regulated interstate natural gas pipelines and all of their energy affiliates. These new 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. The rule is designed to prevent interstate natural gas pipelines from giving an undue preference to any of their energy affiliates and to ensure that transmission is provided on a nondiscriminatory basis. Order No. 2004 requires interstate pipelines to operate independently from their energy affiliates, prohibits interstate pipelines from providing non-public transportation or shipper information to their energy affiliates, and prohibits interstate pipelines from favoring their energy affiliates in providing service. Our interstate natural gas pipelines will be required to comply with these Standards of Conduct.

Environmental Matters

Our pipeline business will be 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 Development Business—Environmental Matters" above.

LNG and Natural Gas Marketing Business

Our LNG and natural gas marketing business is in its early stages of development. We have formed Cheniere Marketing to utilize the portion of our planned LNG receiving terminal regasification capacity that we intend not to allocate to third parties but rather to reserve for use by Cheniere Marketing. Cheniere Marketing anticipates entering into IPAs for approximately 3.0 Bcf/d for LNG purchased from foreign suppliers and then selling revaporized natural gas into North American markets. We intend to purchase LNG from foreign suppliers, arrange the transportation of LNG to our network of LNG receiving terminals, utilize Cheniere Marketing's reserved revaporization capacity at our terminals to revaporize imported LNG, arrange the transportation of revaporized natural gas through our pipelines and other interconnected pipelines, and sell natural gas to buyers in the North American market. We also expect to enter into domestic natural gas purchase and sale transactions as part of our marketing activities.

To complement our LNG receiving terminal business, we anticipate engaging in the foregoing commercial activities, which may include the use of derivative transactions, to manage or hedge exposure to price, volume, timing, location, quality and credit risk associated with the marketing of LNG and natural gas. We are currently developing risk management policies, procedures and systems to assist us in controlling and managing our proposed marketing activities. We expect that we will need to hire additional employees in connection with the development of our marketing business.

Concurrently with making any commitments to purchase LNG as described above, we expect that Cheniere Marketing would enter into substantially corresponding agreements for the sale of the revaporized gas into the North American market. Although we are actively seeking foreign sources of LNG and domestic buyers of revaporized natural gas for such potential LNG supplies, we currently have no agreements for either, and we may not be able to obtain any such agreements on terms acceptable to us, or at all. We anticipate that credit support may be required by certain counterparties to any of the above-referenced transactions, including derivatives, which may subject us to additional funding requirements.

Customers

Sabine Pass LNG and Corpus Christi LNG

Cheniere Marketing intends to enter into a TUA with Sabine Pass LNG for 1.5 Bcf/d of regasification capacity at our Sabine Pass LNG receiving terminal, which capacity is expected to be reduced to 600 MMcf/d in the event that both the Total TUA and the Chevron USA TUA commence prior to the completion of Phase 2 of our Sabine Pass LNG facility. In addition, Cheniere Marketing intends to enter into a TUA with Corpus Christi LNG for 1.0 Bcf/d of regasification capacity at our Corpus Christi LNG receiving terminal.

Competition

Our LNG purchase efforts will compete with the following for supplies of LNG:

- 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; and
- oil and gas producers who sell or control LNG derived from their international oil and gas properties.

In addition, there will be competition for suitable tankers available to transport LNG to North American markets from foreign sources, which will impact our access to LNG supplies and the cost of LNG delivered to the U.S. Gulf Coast.

Our natural gas marketing business will compete with the following for the sale of natural gas:

- 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 gas for the geographic area in which their affiliated distributor operates;
- aggregators who gather small volumes 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; and
- brokers who act as facilitators, bringing buyers and sellers of natural gas together.

J & S Cheniere

We hold a minority interest in J & S Cheniere S.A., or J & S Cheniere. The majority interest in J & S Cheniere is held by J & S Energy Holding B.V., or J & S Holding, a Netherlands corporation affiliated with J & S Trading Company, Ltd., an international petroleum trading and marketing company. Pursuant to a shareholders agreement, we identify and assist with LNG-related business opportunities that we determine are appropriate for J & S Cheniere. We are not required to offer any particular business opportunities or funding to J & S Cheniere. All financing of these business opportunities will be provided by J & S Holding should it determine that a business opportunity is appropriate for J & S Cheniere. However, J & S Holding is not required to fund any particular business opportunity. The shareholders agreement gives us the right to purchase additional shares up to a maximum of 50% of the outstanding shares of J & S Cheniere. The shareholders agreement also provides J & S Holding the right to acquire all of our J & S Cheniere shares in the event that we experience a change in control (defined in the shareholders agreement to include a change in a majority of our board, the acquisition of more than 40% of our outstanding common stock other than as approved by our board of directors and a merger or consolidation that results in 50% or less of the surviving entity's voting securities being owned by the holders of our voting securities immediately prior to such transaction).

As its initial LNG business opportunity, in August 2003, J & S Cheniere chartered its first LNG tanker, the 130,000 cm-capacity Tenaga Empat. The vessel was operated under a transportation agreement and on a spot charter basis until August 2005.

In August 2004, J & S Cheniere executed a time charter for its second LNG tanker for up to 10 years with Kawasaki Kisen Kaisha, Ltd., or K-Line, to charter a new build, 145,000 cm-capacity LNG tanker being constructed by Kawasaki Shipbuilding Corporation. The tanker is expected to be delivered in the fourth quarter of 2007.

In August 2004, J & S Cheniere also executed a time charter agreement for up to 10 years for its third LNG tanker with a joint venture company established by K-Line, Shoei Kisen Kaisha, Ltd. and others. The new build, 154,200 cm-capacity LNG tanker is being constructed by Imabari Shipbuilding Co., Ltd. and is expected to be delivered in the fourth quarter of 2007.

J & S Cheniere entered into an agreement with us in December 2003 under which J & S Cheniere has an option to enter into a TUA reserving up to 200 MMcf/d of capacity at each of our Sabine Pass LNG and Corpus Christi LNG facilities. Following execution of the option agreement, an option fee of $1 million was paid to us in January 2004 by J & S Cheniere. J & S Cheniere may exercise the option as to each facility by entering into a TUA no later than 60 days after receipt of written notification by us that such facility has been approved by FERC and all other approvals and permits have been received which are necessary to begin construction of the facility. The option agreement provides that any such TUA will provide for: (i) a fee per MMBtu delivered equal to 8% of the then current price of natural gas at Henry Hub (instead of a capacity reservation fee payable whether or not it uses the terminal); (ii) an initial five-year term, with up to three additional five-year renewal periods upon payment of a $1 million fee for each renewal; and (iii) a minimum of two LNG vessel deliveries per month at the facility. The terms of the TUA contemplated by the J & S Cheniere option agreement have not been negotiated or finalized. We anticipate that definitive arrangements with J & S Cheniere may involve different terms and transaction structures than were contemplated when the option agreement was entered into in December 2003.

We have recently commenced discussions to renegotiate our existing arrangements with, and to increase our ownership interest to as much as 49% in, J & S Cheniere. The related investment is expected to be approximately $25 million.

Governmental Regulation

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. Our sales of natural gas will be affected by the availability, terms and cost of pipeline transportation. As noted above, under "—Natural Gas Pipeline Development Business—Governmental Regulation," the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting interstate natural gas transmission These initiatives may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our proposed natural gas marketing operations. We do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with whom we anticipate competing.

Oil and Gas Exploration and Development Business

Although our focus is primarily on development of LNG-related businesses, we continue to be involved to a limited extent in oil and gas exploration, development and exploitation, and in exploitation of our existing 3D seismic database through prospect generation. We have historically focused on evaluating and generating drilling prospects using a regional and integrated approach with a large seismic database as a platform. We expect that our oil and gas exploration activities will continue in the Gulf of Mexico, through active interpretation of our seismic data and generation of prospects, through participation in the drilling of wells, and through farm-out arrangements and back-in interests (a reversionary interest in oil and gas leases reserved by us) whereby the capital costs of such activities are borne primarily by industry partners. Cheniere will, from time to time, invest in drilling a share of these prospects. Our current oil and gas exploration and development activities are focused on two areas:

- the Cameron Project, which covers an area of approximately 230 square miles extending roughly three to five miles on either side of the westernmost 28 miles of Louisiana coastline; and
- the Offshore Texas Project Area, which covers approximately 6,800 square miles in the shallow waters offshore Texas and the West Cameron Area of offshore Louisiana.

Our officers and technical staff have extensive experience both onshore and offshore in the Gulf Coast and believe that we are well-positioned to evaluate, explore and develop properties in these areas. From time to time, we may pursue opportunities in other geographic locations as well.

Cameron Project Seismic Exploration Program

We were formed in 1996 to fund the acquisition of a proprietary seismic database along the transition zone (the area approximately three to five miles on either side of the Gulf of Mexico shore line) in Cameron Parish, Louisiana. Under the terms of an exploration agreement with an industry partner, we paid for certain seismic costs in the amount of approximately $16.5 million and acquired a 50% ownership interest in the seismic data covering the Cameron project, among other interests that have subsequently expired or terminated. After the termination of the exploration agreement, we purchased our partner's 50% interest in the seismic data for $500,000 and sold all of the seismic data to a seismic marketing company for $3.3 million. We now retain a license to all of the seismic data for use in our exploration program. We are also entitled to receive at no additional cost any subsequent reprocessing of the data, which may be performed by the seismic marketing company.

In 1999, we licensed 8,800 square miles of seismic data from Fairfield Industries covering a portion of the Offshore Louisiana Area, and made a commitment to fund the reprocessing of the entire 8,800-square-mile seismic database. In 2000, we entered into an agreement with Warburg, Pincus Equity Partners, L.P., a global private equity fund based in New York, to fund exploration and development in the Offshore Louisiana Area through a then newly formed private corporation, Gryphon Exploration Company, or Gryphon. In September 2005, Gryphon was sold, which resulted in net proceeds to us of $20.2 million.

Seismic Exploration Program in Offshore Texas Project Area

In 2000, we acquired two licenses to an aggregate of approximately 1,900 square miles of seismic data from Seitel Data Ltd., a division of Seitel Inc. In October 2000, we exercised our option to expand the agreement with Seitel Data Ltd. to cover an additional 1,900 square miles of seismic data. Together, the licenses acquired from Seitel represent coverage of over 433 Outer Continental Shelf blocks in the shallow waters offshore Texas and Louisiana in the Gulf of Mexico. In 2001, we sold to Gryphon for $3.5 million one of our two licenses to the Seitel 3D seismic data. We retain one license to the Seitel 3D seismic data.

In 2000, we also negotiated a Master Data Users Agreement with a Houston-based firm, Jebco Seismic L.P., to acquire 3,000 square miles (333 blocks) of seismic data in both state and federal waters offshore Texas, bringing our total data set in the shallow waters offshore Texas and Louisiana to approximately 6,800 square miles of seismic coverage. As of December 31, 2003, we had received reprocessed data for the 3,000 square miles of seismic data in the Jebco data set and the 3,800 square miles of seismic data in the Seitel data set, representing all of the reprocessing to be done in the Offshore Texas Project Area. In 2001, we sold to Gryphon for $3.5 million one of our two licenses to the Jebco 3D seismic data covering an additional 3,000 square miles. We retain one license to the Jebco 3D seismic data.

Our exploration team generated and captured 24 prospects during 2003, 2004 and 2005 and sold interests in 23 of the prospects to industry partners, retaining various overriding royalty interests and working interests ranging from an overriding royalty interest (a share of the hydrocarbons produced from an oil and gas property, free of the expense of production) of 3.358% up to 5.0% to a carried working interest (an agreement whereby we retain an interest in a well but bear none or only a portion of the cost of drilling the initial well) of approximately up to 24% and a cost-bearing working interest of up to 25%. Fourteen of the prospects sold during 2003, 2004 and 2005 have been drilled by our industry partners, and we expect that several of the remaining prospects sold during that period will be drilled by our industry partners during 2006. However, we do not serve as operator of any of these prospects, and our partners in the prospects are not contractually obligated to drill them.

Drilling Activities

During 2003 and 2004, we did not participate directly in the drilling of any wells; in 2005, we participated directly in the drilling of two wells. Our industry partners drilled nine wells, two wells and three wells in 2003, 2004 and 2005, respectively, on prospects that we generated. During 2003, seven of the nine wells were productive; during 2004, both wells were productive; and during 2005, one well was productive. At December 31, 2005, we had a 20% working interest in one well and overriding royalty interests (ranging from 0.63% to 5.0%) in nine other productive wells.

Production and Sales

The following table presents certain information with respect to our oil and natural gas production, average sales prices received and average production costs during 2003, 2004 and 2005. In April 2002, we sold our interests in the Redfish and Stingray wells on West Cameron Block 49, representing all of our directly-owned producing properties at the time.

	Year Ended December 31,		
	2005	2004	2003
Production:			
Oil (Bbl)	2,167	1,362	17
Gas (Mcf)	396,284	328,677	123,392
Gas equivalents (Mcfe)	409,286	336,849	123,494
Average sales prices:			
Oil (per Bbl)	$ 48.64	$ 36.69	$ 20.66
Gas (per Mcf)	$ 7.32	$ 5.93	$ 5.33
Selected data per Mcfe:			
Average sales price	$ 7.34	$ 5.93	$ 5.32
Production costs(1)	$ 0.58	$ 0.35	$ —
Oil and gas depreciation, depletion and amortization excluding impairments	$ 5.90	$ 2.48	$ 0.98

(1) No production costs were recorded in 2003, as we owned non-cost bearing overriding royalty interests in wells located in offshore federal waters not subject to state production taxes.

Acreage and Wells

The following table sets forth certain information with respect to our developed and undeveloped leased acreage as of December 31, 2005.

	Developed Acres		Undeveloped Acres(1)	
	Gross	Net	Gross	Net
Offshore Louisiana	—	—	10,000	513
Offshore Texas	640	128	40,426	12,148
Total	640	128	50,426	12,661

(1) We have 421 net lease acres expiring in 2006.

At December 31, 2005, we had working interests in one gross (0.2 net) producing gas well; we had overriding royalty interests in nine producing gas wells.

Drilling Activities

All of our drilling activities are conducted through arrangements with independent contractors. We own no drilling equipment. At December 31, 2005, we had a net working interest of 20% in one exploratory gas well.

Oil and Gas Reserves

All of the information herein regarding estimates of our proved reserves, related future net revenues and PV-10 as of December 31, 2005 is taken from the report generated by Sharp Petroleum Engineering, Inc., our independent petroleum engineer, in accordance with the rules and regulations of the SEC. The independent engineer's estimates were based upon a review of production histories and other geologic, economic, ownership and engineering data that we provided.

	December 31, 2005 Proved Reserves			
	Oil (Bbl)	Gas (Mcf)	Mcfe	PV-10(1)
Offshore Texas	147	145,179	146,061	$ 737,642
Offshore Louisiana	1,166	245,508	252,504	$2,007,249
Proved Reserves	1,313	390,687	398,565	$2,744,891
Proved Developed Reserves	1,313	390,687	398,565	$2,744,891

(1) The PV-10 amount (present value of estimated pre-tax future net revenues discounted at 10%) is calculated using year-end prices of $53.72 per barrel of oil and $8.90 per Mcf of gas.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and future amounts and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Estimates of proved undeveloped reserves are inherently less certain than estimates of proved developed reserves. The quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures, geologic success and future oil and gas sales prices may all differ from those assumed in these estimates. In addition, our reserves may be subject to downward or upward revision based upon production history, purchases or sales of properties, results of future development, prevailing oil and gas prices and other factors. Therefore, the present value shown above should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties.

In accordance with SEC guidelines, the estimates of future net revenues from our proved reserves and the present value thereof are made using oil and gas sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including, in the case of gas contracts, the use of fixed and determinable contractual price escalations. We may receive amounts different than the estimates for a number of reasons, including changes in prices. See Supplemental Information to Consolidated Financial Statements. Estimates of our proved oil and gas reserves were not filed with or included in reports to any other federal authority or agency other than the SEC during the fiscal year ended December 31, 2005.

Business Strategy

Our objective in the Exploration and Development business is to expand the net value of our assets by building an oil and gas reserve base in a cost-efficient manner, through exploitation of our seismic database to facilitate identifying drilling prospects.

Seismic Data

We have acquired the following two significant seismic database assets:

- a license to a 228-square-mile seismic program covering the transition zone in Cameron Parish, and
- a license to a 6,800-square-mile seismic database comprising several seismic surveys in the shallow waters offshore Texas and Louisiana.

The offshore Texas database has been available previously to the industry and was processed using a technique called dip move out, or DMO. We acquired the DMO data and underwrote the reprocessing of the data utilizing another technology known as prestack time migration, or PSTM. Both DMO and PSTM are processing techniques which improve seismic data quality to more accurately image subsurface features and delineate hydrocarbon accumulations. Of the two techniques, PSTM is more advanced and technically accurate. The regional PSTM data is the technology tool which management believes gives us a competitive advantage.

Analysis and Methodology

We have developed a prospect generation infrastructure capable of detailed analyses of large volumes of seismic, geological and engineering data. We employ a rigorous methodology which includes:

- the detailed analyses of existing fields to identify geological and geophysical attributes for use as analogs;
- regional trend mapping to extend prolific plays into under-explored areas;
- the use of workstation interpretation techniques to rapidly identify prospects with attributes similar to those identified in the analog fields;
- the integration of seismic interpretation, well control, structure, stratigraphy, timing, sourcing factors, and production data to quantify prospect potential; and
- the integration of the above sciences with experience and conservative economic evaluation to focus the exploration program on highly commercial projects.

By conducting a thorough analysis of the data and strict adherence to the methodology, we believe that we can reduce the risk of dry holes and achieve significant growth, while maintaining a competitive cost of exploration and development.

Experience

We have built a technical and management team that is experienced in the Gulf of Mexico and in various technical specialties required for our exploration program. The technical staff averages over 30 years of experience exploring for oil and gas in the Gulf Coast. We believe that this experienced team allows us to be very productive in the generation and acquisition of prospects.

Competition and Markets

The availability of a ready market for and the price of any hydrocarbons that we produce will depend on many factors beyond our control, including the extent of domestic production and imports of foreign oil, the marketing of competitive fuels, the proximity and capacity of natural gas pipelines, the availability of transportation and other market facilities, the demand for hydrocarbons, the political conditions in international oil-producing regions, the effect of federal and state regulation of allowable rates of production, taxation, the conduct of drilling operations and federal regulation of natural gas. In the past, as a result of excess deliverability of natural gas, many pipeline companies curtailed the amount of natural gas taken from producing wells, shut in some producing wells, significantly reduced gas taken under existing contracts, refused to make payments under applicable take-or-pay provisions and have not contracted for gas available from some newly completed wells.

In addition, the restructuring of the natural gas pipeline industry has eliminated the gas purchasing activity of traditional interstate gas transmission pipeline buyers. Producers of natural gas, therefore, have been required to develop new markets among gas marketing companies, end-users of natural gas and local distribution companies. All of these factors, together with economic factors in the marketing area, generally may affect the supply and/or demand for oil and gas and thus the prices available for sales of oil and gas.

Competition in the industry is intense, particularly with respect to the acquisition of producing properties and proved undeveloped acreage. We compete with the major oil companies and other independent producers of varying sizes, all of which are engaged in the exploration, development and acquisition of producing and non-producing properties.

Governmental Regulation

Our oil and gas exploration, development and related operations are subject to extensive federal, state and local statutes, rules, regulations and other laws. Failure to comply with such laws can result in substantial penalties. The regulatory burden on the oil and gas industry increases our cost of doing business and affects our profitability.

MMS Regulations

We conduct certain activities on federal oil and gas leases which the Minerals Management Service, or MMS, administers. The MMS grants leases through competitive bidding. These leases contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to The Outer Continental Shelf Lands Act, or OCSLA. For example, for offshore operations, we must comply with the following MMS requirements:

- obtain MMS approval of exploration plans prior to the commencement of exploration operations;
- obtain MMS approval of development and production plans prior to the commencement of such operations;
- obtain an MMS permit prior to the commencement of drilling (in addition to permits which may be required from other agencies, such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency);
- comply with stringent MMS engineering and construction specifications applicable to offshore production facilities located on the Outer Continental Shelf, or OCS;
- comply with MMS prohibitions or restrictions on the flaring or venting of natural gas, liquid hydrocarbons and oil; and
- comply with MMS regulations governing the plugging and abandonment of wells located offshore and the removal of all production facilities.

Bonding and Financial Responsibility Requirements

In connection with our ownership or operation of oil and gas leases, we are required by governmental agencies, including the MMS, to obtain bonding or otherwise demonstrate financial responsibility at varying levels. These bonds may cover such obligations as plugging and abandonment of wells, removal and closure of related exploration and production facilities, and pollution liabilities. The costs of such bonding and financial responsibility requirements can be substantial, and we may not be able to obtain such bonds and/or otherwise demonstrate financial responsibility in all cases.

Regulation of Production

Our oil and gas production operations are subject to state conservation laws and regulations, including:

- laws relating to the unitization or pooling of oil and gas properties;
- laws establishing the maximum rates of production from wells;
- laws regulating the spacing of wells;
- laws regulating the plugging and abandonment of wells; and
- laws which otherwise regulate the operation of, and production from, both oil and gas wells.

Such laws may restrict the rate at which the wells in which we have an interest may produce oil or gas, with the result that the amount or timing of our revenues could be adversely affected.

Environmental Matters

Our oil and gas exploration, development and related operations are subject to the same federal, state and local laws and regulations relating to the protection of the environment that are applicable to our LNG operations. See "—LNG Receiving Terminal Development Business—Governmental Regulation—Environmental Matters" above. In addition, our oil and gas exploration, development and related operations are subject to the following regulations.

The disposal of wastes containing Naturally Occurring Radioactive Material, which are commonly generated during oil and gas production, is regulated under state law. Typically, wastes containing naturally occurring radioactive material can be managed on site or disposed of at facilities licensed to receive such waste at costs that are not expected to be material.

The federal Oil Pollution Act of 1990, or OPA, requires owners and operators of facilities that could be the source of an oil spill into waters of the United States (a term defined to include rivers, creeks, wetlands and coastal waters) to adopt and implement plans and procedures to prevent any such oil spill. OPA also requires affected facility owners and operators to demonstrate that they have at least $35 million in financial resources to pay the costs of cleaning up an oil spill and to compensate any parties damaged by an oil spill. Such financial assurances may be increased to as much as $150 million if a formal assessment indicates such an increase is warranted.

Financial Information About Segments

During the last three fiscal years, all of our revenues have resulted from our oil and gas exploration and development activities. For information about our segments' revenues, profits and losses and total assets, see Note 23 to our Consolidated Financial Statements.

Subsidiaries

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

Employees

We had 130 full-time employees as of February 28, 2006.

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 and prospects.

Risks Relating to Our Financial Matters

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

From our inception, we have generally incurred operating losses, and we will likely continue to incur operating losses and experience negative operating cash flow for at least the next two years. We have not yet started the construction of two of our three planned LNG receiving terminals or our pipelines. We do not anticipate that our LNG receiving operations or our three pipelines will generate positive operating cash flow until at least one of our planned LNG receiving terminals is built, which we expect will not be until 2008 at the earliest. Although we may commence operations at our LNG receiving terminals, revenues under any particular TUA may not commence for up to one year or more after operations at the related facility commence. We will continue to incur significant capital and operating expenditures while we develop our planned LNG receiving terminals and pipelines. We do not anticipate that our current oil and gas exploration activities, which are limited in scope, or advance sales of regasification capacity at our planned LNG receiving terminals will generate sufficient funds to cover these expenditures. As a result, we expect to continue to have operating losses and negative operating cash flow on a quarterly and an annual basis for at least the next two years.

Any delays beyond the expected development periods for our planned LNG receiving terminals or pipelines would prolong, and could increase the level of, our operating losses and negative operating cash flow. Our future liquidity may also be affected by (i) the timing of construction financing availability in relation to the incurrence of construction costs and other outflows and (ii) the anticipated timing of receipt of cash flow under TUAs and other sales of capacity in relation to the incurrence of projected project operating expenses. However, many factors (including factors beyond our control) could result in a disparity between liquidity sources and cash needs, including factors such as construction delays and breaches of agreements. Our ability to generate positive operating cash flow and achieve profitability in the future is dependent on our ability to successfully complete our LNG development projects and market the capacity of our facilities, and our ability to do so is subject to a number of risks, including those discussed below.

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

As of December 31, 2005, we had $693 million in cash and cash equivalents, exclusive of $177 million in restricted cash. We currently estimate that the cost of completing our three LNG receiving terminals will be approximately $3.0 billion, before financing costs, and the cost of constructing our three proposed pipelines will be approximately $800 million to $1 billion. Our cost estimate is subject to change due to such items as cost overruns, change orders under existing or future EPC agreements, changes in commodity prices (particularly steel), escalating labor costs and additional funds that may need to be expanded to maintain construction schedules. In addition, the development of our marketing business will require the expenditure of funds before any revenues are received. To fund these development projects, we will have to draw on our Sabine Pass Credit Facility and pursue a variety of additional sources of funding, including most, if not all, of the following:

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

Our ability to obtain these types of financing will depend, in part, on factors beyond our control, such as the status of various capital and industry markets at the time financing is sought and such markets' view of our industry and prospects at such time. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, if at all, even if our development projects are otherwise proceeding on schedule. In addition, our ability to obtain some types of financing may be dependent upon our ability to obtain other types of financing. For example, project-level debt financing is typically contingent upon a significant equity capital contribution from the project sponsor. As a result, even if we are able to identify potential project-level lenders, we may still have to obtain another form of external financing for us to fund an equity capital contribution to the project subsidiary. Any project-level debt financing will also typically be conditioned upon our prior receipt of commitments for a portion of projected regasification capacity under long-term TUAs, and our ability to fund the projects will likely be subject to the achievement of additional milestones in our project financing. A failure to obtain financing at any point in the development process could cause us to delay or fail to complete our business plan, which could cause our business to be unsuccessful.

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

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

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

The actual construction costs of our proposed LNG receiving terminals and pipelines may be significantly higher than our current estimates, which are before financing costs.

We do not have any prior experience in constructing LNG receiving terminals or pipelines, and no LNG receiving terminal has been constructed in the United States in over 25 years. As construction progresses, we may decide or be forced to submit change orders to our EPC contractors that could result in longer construction periods and higher construction costs. Similarly, we may encounter significant cost overruns during some phases of the construction process. In addition, under any agreement with an EPC contractor, we expect to retain the commodity price risk for nickel and various types of steel used in the construction process. As a result, any significant change orders, cost overruns or increases in the commodity price of nickel or steel could have a material adverse effect on our business, results of operations, financial condition and prospects.

Risks Relating to Our LNG Receiving Terminal Development Business

The construction of our planned LNG receiving terminals is subject to a number of development risks, which could cause cost overruns and delays or prevent completion of one or more of our LNG development projects.

Key factors that may affect the timing of, and our ability to complete, our LNG development projects include, but are not limited to:

- the issuance and/or continued availability of necessary permits, licenses and approvals from FERC, other governmental agencies and third parties as are required to construct and operate the facilities;
- the availability of sufficient debt financing and equity financing, both on the part of Cheniere and at the project level;
- our ability to obtain satisfactory long-term TUAs with "anchor tenant" customers for a portion of the capacity at each proposed LNG receiving terminal and for these customers to perform under those TUAs during the terms thereof and to maintain their creditworthiness;
- our ability to enter into a satisfactory agreement with an EPC contractor for each facility and to maintain good relationships with these contractors, and the ability of those EPC contractors to perform their obligations under EPC agreements and to maintain their creditworthiness;
- site development difficulties, including change orders, cost overruns, construction delays and changes in commodity prices (particularly steel);
- unanticipated changes in domestic and international market demand for natural gas or the supply of LNG, which will depend, in part, on supplies of, and prices for, alternative energy sources;
- competition with other domestic and international LNG receiving terminals;
- commercial arrangements for pipelines and related equipment to transport natural gas from each LNG receiving terminal;
- local and general economic conditions;
- catastrophes, such as explosions, fires and product spills;
- resistance in the local community to the development of LNG receiving terminals;
- labor disputes; and
- weather conditions, such as hurricanes.

Delays in the construction of an LNG receiving terminal beyond the estimated development periods, as well as cost overruns, could increase the cost of completion beyond the amounts currently estimated in our capital budget, which could require us to obtain additional sources of financing to fund our operations until the LNG receiving terminal is developed (which could cause further delays). Any delay in completion of the LNG receiving terminals may also cause a delay in the receipt of revenues projected from operation of the facilities or cause a loss of our TUA customers in the event of significant delays. Delays could also erode our competitive advantage of being one of the first companies to develop new LNG receiving terminals. As a result, any significant construction delay, whatever the cause, could have a material adverse effect on our business, results of operations, financial condition and prospects.

Failure to obtain and maintain approvals and permits from governmental and regulatory agencies with respect to the development of our LNG receiving terminal business would have a detrimental effect on us and our LNG projects.

The design, construction and operation of LNG receiving terminals are all highly regulated activities. FERC approval under Section 3 of the NGA, as well as several other material governmental and regulatory approvals and permits, is required in order to construct and operate our proposed LNG receiving terminals. Although we have obtained NGA Section 3 authorization to construct and operate our Sabine Pass and Corpus Christi LNG receiving terminals, we have not yet received an NGA Section 3 FERC order authorizing construction of our Creole Trail project. We also have not obtained several other material governmental and regulatory approvals and permits required in order to construct and operate our proposed LNG receiving terminals. We have no control over the outcome of the review and approval process. We do not know whether or when any such approvals or permits can be obtained, or whether or not any existing or potential interventions or other actions by third parties will 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.

We face competition in the LNG receiving terminal development business from competitors with far greater resources and the potential for overcapacity in the LNG receiving terminal marketplace.

Many companies are considering the development of infrastructure in the domestic LNG market, including, without limitation, major oil and gas companies such as ExxonMobil, ConocoPhillips, Royal Dutch/Shell and Chevron. Other energy companies such as Sempra, Tractebel, McMoRan Exploration, Occidental Petroleum, AES, Excelerate Energy and other public and private companies have also proposed developing LNG receiving facilities, both onshore and offshore. Almost all of our competitors have longer operating histories, more development experience, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources than we do. The superior resources that these competitors have available to deploy could allow them to surpass us in terms of the status of their LNG receiving terminal development projects. Among other things, these competitors may not have to rely on external financing.

Industry analysts have predicted that if all of the proposed LNG receiving terminals in North America that have been announced by developers were actually built, there would likely be substantial excess capacity for such terminals in the future. Accordingly, there is a substantial risk that slower-paced LNG receiving terminal development projects may never be completed. Any perception in the LNG receiving terminal marketplace that we may be unable to complete our proposed LNG receiving terminals, because competing projects are further along in their development or otherwise, could have a material adverse effect on our business, results of operations, financial condition and prospects.

In addition, our proposed LNG receiving terminals will likely continue to face competition when and if they are completed, including competition from North American sources of natural gas and onshore, offshore and shipboard LNG regasification facilities. Our proposed Sabine Pass, Corpus Christi and Creole Trail LNG receiving terminals will also compete with the Freeport LNG receiving terminal in which we own a 30% interest. If the number of LNG receiving terminals built outstrips demand for natural gas from those terminals, the excess capacity will likely lead to a decrease in the prices that we will be able to obtain for uncommitted amounts of our regasification services. Because of the substantial likelihood that we will have significant debt service obligations, any such price decreases would impact us more severely than our competitors with greater financial resources. Accordingly, potential overcapacity in the LNG receiving terminal marketplace, or a significant decline in natural gas prices, could have a material adverse effect on our business, results of operations, financial condition and prospects.

Cyclical changes in the demand for LNG regasification capacity may result in reduced operating revenues and may cause operating losses in the future.

The economics of LNG terminal and marketing operations 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:

- significant additions in regasification capacity, whether through LNG receiving terminal construction or expansion, take several years to become operational and are therefore necessarily based upon estimates of future demand for natural gas;

- when demand for natural gas increases, competition to build new LNG regasification capacity may heighten because new capacity may be more profitable, with a lower marginal cost of production;
- when LNG regasification capacity significantly increases, the competition for the receipt and regasification of LNG increases;
- under-supplies at the foreign supply source of LNG also increase competition among LNG terminals and may cause LNG receiving terminal operators to compete aggressively on price in order to maximize capacity utilization;
- when demand for LNG receiving capacity decreases, the high fixed cost structure of capital-intensive LNG receiving terminals causes producers and transporters of natural gas to compete aggressively on price in order to maximize capacity utilization;
- substantial increases in the receiving capacity of LNG receiving terminals will substantially increase the potential supply of natural gas to U.S. markets, which could substantially amplify the downswings related to the over-supply of available natural gas;
- supplies of, and prices for, alternative energy sources such as coal, oil, nuclear, hydroelectric, wind and solar energy cause changes in the demand for natural gas;
- as competition in natural gas is focused on price, being a low-cost supplier is critical to profitability. This would favor the construction of larger LNG receiving facilities, which maximize economies of scale, but also could cause an increase in capacity that can outstrip the existing growth in demand for natural gas; and
- cyclical trends in general business and economic conditions cause changes in the demand for natural gas.

The increases and decreases in the available supply of natural gas as a result of changes in available LNG receiving capacity available could materially adversely affect our business, results of operations, financial condition and prospects.

We may have difficulty obtaining enough customers for regasification capacity at our proposed LNG receiving terminals to implement and complete our business plan. We may change our business strategy as to how and when we market our capacity.

Our current marketing strategy calls for us to enter into long-term TUAs covering approximately 4 Bcf/d of our total existing and future regasification capacity at our LNG receiving terminals, including a commitment to pay capacity reservation fees, prior to the commencement of construction of each facility. 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 project-level financing for each LNG receiving facility may be contingent on our ability to enter into long-term TUAs covering approximately 4 Bcf/d of regasification capacity in advance of the commencement of construction. In addition, we anticipate that we will be able to rely on these capacity reservation fee payments to cover a portion of operating costs prior to commencement of operations at our proposed LNG receiving terminals. As of the date of this filing, we do not have any TUAs in place for either our proposed Corpus Christi facility or our proposed Creole Trail facility nor do we have any contracts in place for the use of our pipelines.

We may experience difficulty attracting additional customers because we are a small, developing company with no operating history in the LNG business. In order to succeed, we must convince additional potential customers, among other things, that we will be able to secure adequate financing for the construction of the LNG receiving terminal sites and natural gas pipelines that we are developing and that they will be approved by appropriate governmental agencies. We may also change our marketing strategy due to our inability to enter into TUAs prior to construction and our view regarding future prices, demand and supply of natural gas and regasification capacity. If these marketing efforts are not successful, our business, results of operations, financial condition and prospects could be materially adversely affected.

Failure of imported LNG to become a competitive source of energy in the United States could have a detrimental effect on our ability to implement and complete our business plan.

In the United States, due mainly to an abundant supply of natural gas, imported LNG has not historically been a major energy source. Our business plan is based on the belief that LNG can be produced and delivered to the United States 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 would further increase the available supply of natural gas at a lower cost than LNG. In addition to natural gas, LNG also competes with other sources of energy, including coal, oil, nuclear, hydroelectric, wind and solar energy. As a result, LNG may not become a competitive source of energy in the United States. The failure of LNG to become a competitive supply alternative to domestic natural gas, oil and other import alternatives could have a material adverse effect on our business, results of operations, financial condition and prospects.

The inability to import LNG into the United States due to, among other things, governmental regulation or potential instability in countries that supply natural gas, could materially adversely affect our business plans and results of operations.

Upon completion of the LNG receiving terminals, our business will be dependent upon the ability of our third-party customers and Cheniere Marketing to import LNG supplies into the United States. Political instability in foreign countries that have supplies of natural gas, or strained relations between such countries and the United States, may impede the willingness or ability of LNG suppliers in such countries to export LNG to the United States. Such foreign suppliers may also be able to negotiate more favorable prices with other LNG customers around the world than with us and other customers in the United States, thereby reducing the supply of LNG available to be imported into the United States market. In addition, we believe that the existing fleet of tankers that is available to transport LNG is inadequate, and the failure to expand LNG tanker capacity would impede both our and our customers' ability to import LNG into the United States. Any significant impediment to the ability to import LNG into the United States could have a material adverse affect on our business, results of operations, financial condition and prospects.

Decreases in the price of natural gas in North America could harm our ability to develop our proposed LNG receiving terminals and market the sale of natural gas.

The development of domestic LNG receiving terminals is based on assumptions about the future price of natural gas and the availability of imported LNG. The willingness of potential customers to contract for regasification capacity would be negatively impacted and, once facilities are in operation, LNG throughput volumes would likely decline if the price of natural gas in North America is, or is forecasted to be, lower than the cost to produce and deliver LNG to North American markets. Any significant decline in the price of natural gas could cause the cost of natural gas produced from imported LNG to be higher than domestically produced natural gas. As a result, any significant decline in the price of natural gas could have a material adverse effect on our business, results of operations, financial condition and prospects.

Natural gas prices have been, and are likely to continue to be, volatile and subject to wide fluctuations in response to any of the following factors:

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

Our TUAs are subject to termination by our contractual counterparties under certain circumstances, and we are generally dependent on the performance of those counterparties under the TUAs.

Sabine Pass LNG has entered into long-term TUAs with subsidiaries of Total S.A. and Chevron. Each of the TUAs contains various termination rights. For example, Total may terminate its TUA with Sabine Pass LNG if Sabine Pass LNG fails to deliver a specified amount of natural gas nominations or fails to receive or unload a specified number of cargoes. In addition, in the case of each of our TUAs, we are dependent on the respective counterparties' creditworthiness and their continued willingness to perform their obligations under the TUAs. If any of these counterparties fails to perform its obligations under its respective TUA, our business, results of operations, financial condition and prospects could be materially adversely affected, even if we were to be ultimately successful in seeking damages from that counterparty for a breach of the TUA.

The construction of our proposed LNG receiving terminals will be dependent on performance by, and our relationship with, the contractors that we engage at each facility.

Sabine Pass LNG entered into an EPC agreement in December 2004 with Bechtel. We also plan to enter into contracts with a major international EPC contractor for the construction of our proposed Corpus Christi and Creole Trail LNG receiving terminals. The success of our LNG receiving terminal development projects is highly dependent on our ability to enter into acceptable contracts with reputable EPC contractors and other contractors performing portions of the construction on our projects and for such contractors to perform their obligations under the contracts, including completing the projects on a timely basis. However, we may not be able to enter into acceptable contracts for the construction of Phase 2 of our Sabine Pass LNG receiving terminal or our proposed Corpus Christi or Creole Trail LNG receiving terminals. Other than with respect to Phase 1 of our Sabine Pass LNG receiving terminal, we have no prior experience working with any EPC contractor, including Bechtel, or other construction contractor. We may encounter unexpected delays or problems in connection with the construction of any of our proposed LNG receiving terminals. In addition, any EPC agreement could be terminated by an EPC contractor under certain circumstances prior to completion of construction. For example, see the description of the termination provisions of the EPC agreement with Bechtel under "—LNG Receiving Terminal Development Business—Our LNG Receiving Terminals—Sabine Pass LNG—EPC Agreement" above. If our relationship with any initial EPC contractor fails for any reason, we would be forced to engage a substitute contractor, which would likely result in a significant delay in our development schedule and could have a material adverse effect on our business, results of operations, financial condition and prospects.

Risks Relating to Our Pipeline Development Business

Expanding our business by constructing pipelines subjects us to risks.

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

Failure to obtain and maintain approvals and permits from governmental and regulatory agencies with respect to the development of our pipelines would have a detrimental effect on us and our LNG 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, is required in order to construct and operate our proposed pipelines. We have obtained authorization from FERC pursuant to Section 7(c) of the NGA to construct and operate our Sabine Pass and Corpus Christi pipelines, subject to certain conditions. However, we have not yet received authorization from FERC to construct and operate our Creole Trail pipelines. We also have not obtained several other material governmental and regulatory approvals and permits required in order to construct and operate our proposed pipelines. 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 proposed pipelines will be subject to FERC rate-making, which could have an adverse impact on our ability to recover the full cost of operating our pipelines, including a reasonable return.

Our FERC tariffs will 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. 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 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 recently enacted Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation.

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

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

We will depend upon third-party pipelines and other facilities that will provide delivery options to and from our proposed 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 temporary or permanent interruption at any key pipeline interconnect which caused a material reduction in volumes transported on our proposed pipelines could have a material adverse effect on our business, results of operations and financial condition.

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

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

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

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

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

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

Because our proposed pipelines will be dependent upon a few customers, including an affiliate, for a significant portion of the revenues anticipated to be generated by our pipeline business, our business may be materially and adversely affected if we lose any one of these customers.

We do not currently have any third-party customers for our pipelines. We anticipate that customers with whom we enter into TUAs for our LNG receiving terminals will enter into agreements for the transportation of revaporized gas on our proposed pipelines. However, the number of such customers is anticipated to be limited, and we anticipate being substantially dependent on them for a significant percentage of the revenues generated by our pipeline business. In addition, the largest customer of our proposed pipelines is anticipated to be our affiliate, Cheniere Marketing. The loss of any of these customers, a decline in their creditworthiness or a substantial reduction in their shipments on our proposed pipelines, could have a material adverse effect on our business, results of operations and financial condition.

Risks Relating to Our LNG and Natural Gas Marketing Business

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

We have just recently begun developing our LNG and natural gas marketing business. To date, the business has only a few employees, has generated no revenues and has no operating history upon which you can evaluate our business strategy or the future prospects of the business. The ability of our LNG and natural gas marketing business to generate revenues in the future will depend upon whether we can successfully develop and implement our business strategy and make the transition from a development stage business to an operating business. We may encounter many expenses, delays, problems and difficulties that we have not anticipated and for which we have not planned in developing and operating our LNG and natural gas marketing business.

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

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

- expected supply is less than the amount hedged;
- the counterparty to the hedging contract defaults on its contractual obligations; or

- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

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

If we do not attract and retain qualified personnel for our developing LNG and natural gas marketing business, our operations could be adversely affected.

Our success in developing and operating an LNG and natural gas marketing business will be, in part, dependent upon the number and quality of personnel that we can hire and our ability to maintain good relationships with them. We anticipate that we will need to hire additional employees to conduct our natural gas marketing activities. If we are unable to retain qualified employees and then successfully maintain good relationships them, our results of operations may be adversely affected.

Other risks related to our LNG receiving terminal development business could have similar adverse effects on our marketing business.

Some of the risks described above under "—Risks Relating to Our LNG Receiving Terminal Development Business" could have an adverse impact on our marketing business, including those set forth under the following headings:

- "Cyclical changes in the demand for LNG regasification capacity may result in reduced operating revenues and may cause operating losses in the future;"
- "Failure of imported LNG to become a competitive source of energy in the United States could have a detrimental effect on our ability to implement and complete our business plan;"
- "The inability to import LNG into the United States due to, among other things, governmental regulation or potential instability in countries that supply natural gas, could materially adversely affect our business plans and results of operations;" and
- "Decreases in the price of natural gas in North America could harm our ability to develop our proposed LNG receiving terminals and market the sale of natural gas."

Risks Relating to Our Oil and Gas Exploration and Development Business

We are subject to significant exploration risks, including the risk that we may not be able to find or produce enough oil and gas to generate any profits.

Our exploration activities involve significant risks, including the risk that we may not be able to find or produce enough oil and gas to generate any profits. The wells we drill may not discover any oil or gas. Furthermore, there is no way to know in advance of drilling and testing whether any prospect will yield oil or gas in sufficient quantities to make money for us. In addition, we are highly dependent on seismic activity and the related application of new technology as a primary exploration methodology. This methodology, however, requires greater pre-drilling expenditures than traditional drilling strategies. Even when fully used and properly interpreted, 3D seismic data can only assist us in identifying subsurface reservoirs and hydrocarbon indicators, and will not allow us to determine conclusively if hydrocarbons will in fact be present and recoverable. If our exploration efforts are unsuccessful, our business, results of operations, financial condition and prospects could be materially adversely affected.

We may not be able to acquire the oil and gas leases we need to sustain profitable operations.

In order to engage in oil and gas exploration in the areas covered by our 3D seismic data, we must first acquire rights to conduct exploration and recovery activities on such properties. We may not be successful in acquiring farm-outs (agreements whereby the owner of lease interests grants to a third party the right to earn an assignment of an interest in the lease, typically by drilling one or more wells), seismic permits, lease options, leases or other rights to explore for or recover oil and gas. Both the U.S. Department of the Interior and the States of Texas and Louisiana award oil and gas leases on a competitive bidding basis. Non-governmental owners of the onshore mineral interests within the area covered by our exploration program are not obligated to lease their mineral rights to us except where we have already obtained lease options. In addition, other major and independent oil and gas companies with financial resources significantly greater than ours may bid against us for the purchase of oil and gas leases. If we are unsuccessful in acquiring these leases, permits, options and other interests, the area covered by our 3D seismic data that could be explored through drilling will be significantly reduced, and our business, results of operations, financial condition and prospects could be materially adversely effected.

If we are unable to obtain satisfactory turnkey contracts, we may have to assume additional risks and expenses when drilling wells.

We anticipate that any wells drilled in which we have an interest will be drilled by established industry contractors under turnkey contracts that limit our financial and legal exposure. Under a turnkey drilling contract, a negotiated price is agreed upon and the money placed in escrow. The contractor then assumes all of the risk and expense, including any cost overruns, of drilling a well to contract depth and completing any agreed upon evaluation of the wellbore. Upon performance of all these items, the escrowed money is released to the contractor.

Circumstances may arise, however, where a turnkey contract is not economically beneficial to us or is otherwise unobtainable from proven industry contractors. In such instances, we may decide to drill wells on a day-rate basis. Under a day-rate drilling contract, the operator pays an agreed sum for each day of drilling required to reach contract depth. All risk and expense of drilling a well to total depths lies with the operator in day-rate contracts. The drilling of such test wells would subject us to the usual drilling hazards such as cratering, explosions, uncontrollable flows of oil, gas or well fluids, fires, pollution and other environmental risks. We would also be liable for any cost overruns attributable to drilling problems that otherwise would have been covered by a turnkey contract. These liabilities, if incurred, could have a materially adverse effect on our business, results of operations, financial condition and prospects.

If we are unsuccessful at marketing our oil and gas at commercially acceptable prices, our profitability will decline.

Our ability to market oil and gas at commercially acceptable prices depends on, among other factors, the following:

- the availability and capacity of gathering systems and pipelines;
- federal and state regulation of production and transportation;
- changes in supply and demand; and
- general economic conditions.

Our inability to respond appropriately to changes in these factors could have a material adverse effect on our business, results of operations, financial condition and prospects.

Shortage of rigs, equipment, supplies or personnel may restrict our operations.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, demand for, and wage rates of, qualified drilling rig crews rises with increases in the number of active rigs in service. Shortages of drilling rigs, equipment or supplies could delay or restrict our exploration and development operations, which in turn could have a material adverse effect on our business, results of operations, financial condition and prospects.

We depend on industry partners and could be seriously harmed if they do not perform satisfactorily, which is usually not within our control.

Because our oil and gas exploration and development business has few employees and limited operating revenues, we are and will continue to be largely dependent on industry partners for the success of our oil and gas exploration projects. We could be seriously harmed if we fail to attract industry partners to participate in the drilling of prospects which we identify or if our industry partners do not perform satisfactorily on projects that affect us. We often have and will continue to have no control over factors that would influence the performance of our partners.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and future net cash flows.

Numerous uncertainties, including those beyond our control, are inherent in estimating quantities of proved oil and gas reserves. Information included herein for 2005 relating to estimates of our proved reserves is based on reports prepared by Sharp Petroleum Engineering, Inc. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows may vary considerably from the actual results because of a number of variable factors and assumptions involved. These include:

- historical production from the area compared with production from other producing areas;
- the effects of regulation by governmental agencies;
- future oil and gas prices;
- operating costs;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

Therefore, the estimates of the quantities of oil and gas and the expected future net cash flows computed by different engineers or by the same engineers (but at different times) may vary significantly. The actual production, revenues and expenditures related to our reserves may vary materially from the engineers' estimates. In addition, we may make changes to our estimates of reserves and future net cash flows. These changes may be based on the following factors:

- production history;
- results of future development;
- oil and gas prices;
- performance of counterparties under agreements to which we are a party; and
- operating and development costs.

Do not interpret the PV-10 values included in this Form 10-K as the current market value of our properties' estimated oil and gas reserves. According to the SEC, the PV-10 is generally based on prices and costs as of the date of the estimate. In contrast, the actual future prices and costs may be materially higher or lower. Actual future net cash flows may also be affected by the following factors:

- the amount and timing of actual production;
- the supply of, and demand for, oil and gas;

- the curtailment or increases in consumption by natural gas purchasers; and
- the changes in governmental regulations or taxation.

The timing in producing and the costs incurred in developing and producing oil and gas will affect the timing of actual future net cash flows from proved reserves. Ultimately, the timing will affect the actual present value of oil and gas. In addition, the SEC requires that we apply a 10% discount factor in calculating PV-10 for reporting purposes. This is not necessarily the most appropriate discount factor to apply because it does not take into account the interest rates in effect, the risks associated with us and our properties, or the oil and gas industry in general.

Because of our lack of diversification, factors harming the oil and gas industry in general, including downturns in prices for oil and gas, would be especially harmful to us.

We are an independent energy company and are not actively engaged in any other industry. Our revenues and results of operation are substantially dependent on the oil and gas industry in general and the prevailing prices for oil and gas in particular. Circumstances that harm the oil and gas industry in general will have an especially harmful effect on us. Oil and gas prices have been and are likely to continue to be volatile and subject to wide fluctuations in response to any of the following factors:

- relatively minor changes in the supply of and demand for oil and gas;
- political conditions in international oil producing regions;
- the extent of domestic production and importation of oil in relevant markets;
- the level of consumer demand;
- weather conditions;
- the competitive position of oil or gas as a source of energy as compared with other energy sources;
- the refining capacity of oil purchasers; and
- the effect of federal and state regulation on the production, transportation and sale of oil and gas.

It is likely that adverse changes in the oil and gas market or the regulatory environment would have an adverse effect on our business, results of operations, financial condition and prospects, including our ability to develop and implement our LNG project and to obtain capital from lending institutions, industry participants, private or public investors or other sources.

Risks Relating to Our Business in General

We are currently a small, developing company with limited operating history in the businesses that we are developing. Our business plans are contingent on our ability to manage successfully our anticipated expansion and transition to operating these businesses.

As of February 28, 2006, we had 130 full-time employees, who, for the most part, are focused on the pre-construction stages of the development of our three proposed LNG receiving terminals. As we begin construction of the LNG receiving terminals, we will have to hire new onsite employees to manage the construction of each facility. Before our proposed LNG receiving terminals commence operations, we will have to hire an entire staff to operate each facility. We have no experience in the construction or operation of LNG receiving terminals or pipelines or the marketing of LNG or natural gas, and, as a result, we will be forced to rely to a significant extent on the new employees we hire to perform these functions. During 2006, we anticipate hiring approximately 110 employees. As our operations expand, we will also have to expand our administrative staff. If we are not able to successfully manage the expansion of our business, our business, results of operation, financial condition and prospects could be materially adversely affected.

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 use to greater and unanticipated risks.

We have little or no prior experience in some of the downstream opportunities that we are pursuing, such as natural gas pipeline development or natural gas marketing. We also have limited experience in some of the upstream opportunities that we are pursuing, such as investment in LNG shipping businesses and oil and gas exploration, development and transportation. Similarly, we have little or no prior experience in other upstream opportunities that we are pursuing, such as securing foreign LNG supply arrangements and developing foreign natural gas reserves that could be converted into LNG and imported into either domestic or international markets. We may not be successful in our efforts to pursue any or all of these initiatives. If we are successful in pursuing one or more of these downstream or upstream opportunities, we will likely incur greater risks than we expect to incur in our LNG receiving terminal business, and some of those risks we will not be able to anticipate.

We depend on key personnel, and we could be seriously harmed if we lost their services.

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 agreements 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. In addition, our future success will depend in part on our ability to attract and retain additional qualified personnel.

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

The construction and operation of our proposed LNG receiving terminals and pipelines will be subject to the inherent risks normally 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 a significant delay in the timing of commencement of operations and/or in damage to or destruction of our facilities or damage to persons and property. In addition, our operations face possible risks associated with acts of aggression or terrorism on our facilities and the facilities and tankers of third parties on which our operations are dependent.

In accordance with customary industry practices, we intend to maintain insurance against some, but not all, of these risks and losses. We may not be able to maintain insurance (as our project lenders may require) 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 and prospects.

Existing and future United States governmental regulation, taxation and price controls could seriously harm us.

Our LNG receiving terminal and pipeline businesses are subject to extensive federal, state and local laws and regulations that regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Failure to comply with such rules and regulations can result in substantial penalties and may harm us. Present, as well as future, legislation and regulations could cause additional expenditures, restrictions and delays in our business, the extent of which cannot be predicted and which may require us to limit substantially, delay or cease operations in some circumstances.

The construction and operation of our LNG receiving terminals and pipelines are subject to issuance of necessary permits, licenses, consultations and approvals from numerous federal agencies, including from FERC under Section 3 of the NGA. The costs that we incur to obtain and maintain FERC and other governmental approvals authorizing us to commence construction of our proposed LNG receiving terminals and pipelines and to comply with the ongoing regulation of the operation and maintenance of such terminals and pipelines could have a material adverse effect on our business, results of operations, financial condition and prospects. In addition, delay in the receipt of, or modification or other regulatory action with respect to, FERC or other required governmental authorization could cause substantial delays in the commencement of construction or operations of our LNG receiving terminals or pipelines, increased costs or even result in the cessation of operations. Any interstate pipeline transmission system connected to our LNG receiving terminals, as will be the case with each of our LNG receiving terminals, is subject to FERC regulation under Section 7 of the NGA. Such regulation may restrict the ability of our customers to transport gas to and from our terminals, which could have a material adverse effect on our business, results of operations, financial condition and prospects. FERC has in the past regulated the prices at which natural gas could be sold. Federal reenactment of price controls or increased regulation of the transport of natural gas could have a material adverse effect on our business, results of operations, financial condition and prospects.

Our LNG receiving terminal and pipeline development businesses are also subject to extensive federal, state and local laws and regulations governing the discharge of natural gas, hazardous substances, materials and other compounds into the environment or otherwise relating to environmental protection. These laws and regulations may restrict or prohibit the types, quantities and concentration of substances that can be released into the environment and impose substantial liabilities for pollution or releases of hazardous substances, materials or compounds or impose conditions that require additional costs or changes in operations that could have a material adverse effect on our business, results of operations, financial condition and prospects. Failure to comply with these laws and regulations may also result in civil and criminal fines and penalties. Moreover, state and federal environmental laws and regulations may become more stringent.

Federal laws and regulations such as CERCLA, the CAA, the OPA and the CWA, and analogous state laws have regularly imposed increasingly strict requirements for water and air pollution control, hazardous waste and materials management and strict financial responsibility and remedial response obligations. The cost of complying with such environmental legislation could have a material adverse effect on our business, results of operations, financial condition and prospects.

Existing environmental laws and regulations may be revised or reinterpreted or new laws and regulations may be adopted or become applicable to us. Revised, reinterpreted or additional laws and regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, results of operations, financial condition and prospects.

Some of our economic value is derived from our ownership of minority interests in entities over which we exercise no day-to-day control.

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

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

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

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

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

Terrorist attacks or sustained military campaigns may adversely impact our business.

The terrorist attacks that took place in the United States on September 11, 2001 were unprecedented events that have created many economic and political uncertainties, some of which may materially adversely impact our business. The continued threat of terrorism and the impact of military and other action will likely lead to continued volatility in prices for natural gas and could affect the markets for the operations of our LNG customers on which we will be dependent, as well as lead to increased costs incurred by us in implementing security measures against such threats. Furthermore, the United States government has issued public warnings that indicate that pipelines and other energy assets might be specific targets of terrorist organizations. These potential targets might include our assets. The continuation of these developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations, financial condition and prospects.

Hurricanes Katrina and Rita, or future similar storms, could have a material adverse effect on our business, financial condition and results of operations.

In August and September of 2005, Hurricanes Katrina and Rita and related storm activity, such as windstorms, storm surges, floods and tornadoes, caused extensive and catastrophic physical damage in and to coastal and inland areas located in the Gulf Coast region of the United States (parts of Texas, Louisiana, Mississippi and Alabama) and certain other parts of the southeastern United States. Construction at our Sabine Pass 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.

Bechtel has claimed events of *force majeure* arising out of three hurricanes in 2005 along the U.S. Gulf Coast. Sabine Pass LNG is currently in negotiations with Bechtel and certain subcontractors concerning additional activities and expenditures in order, among other things, to attract sufficient skilled labor to mitigate potential schedule delays and provide a reasonable opportunity for Bechtel to attain the initial target bonus date of April 3, 2008 (the date originally anticipated for completion of construction sufficient to achieve a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours and that, if attained, would entitle Bechtel to a scheduled $12 million bonus). As part of these negotiations, we have agreed in principle to defer the date by which substantial completion of the entire project is required to be accomplished under the EPC contract from September 3 to December 20, 2008. In the absence of substantial completion by such date, Bechtel would be obligated to pay us certain liquidated damages as provided under the terms of the contract. We expect that the above-described arrangement will not exceed $50 million, although such amount is subject to change, requires approval of the lenders under our Sabine Pass Credit Facility and requires that a change order be agreed upon with Bechtel. These storms and their collateral effects, mainly labor availability, could result in additional delays or cost increases for construction of our Sabine Pass LNG receiving terminal.

Future similar storms and related storm activity and collateral effects could result in damage to, delays or cost increases in construction of, or interruption of operations at, our planned LNG receiving terminals or related pipelines.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

ITEM 3. *LEGAL PROCEEDINGS*

We are, and may in the future be, involved as a party to various legal proceedings, which are incidental to the ordinary course of business. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of these matters. In the opinion of management and legal counsel, as of December 31, 2005, 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.

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

Neither Cheniere, nor any entity required to be consolidated with Cheniere for purposes of this annual report, has been required to pay a penalty to the Internal Revenue Service for failing to make disclosures required with respect to certain transactions that have been identified by the Internal Revenue Service as abusive or that have a significant tax avoidance.

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

None.

PART II

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

Our common stock has traded on the American Stock Exchange under the symbol LNG since March 24, 2003. The table below presents the high and low daily closing sales prices of the common stock, as reported by the American Stock Exchange, for each quarter during 2004 and 2005.

	High	Low
Three Months Ended		
March 31, 2004	$ 9.54	$ 5.55
June 30, 2004	10.42	5.53
September 30, 2004	10.42	8.12
December 31, 2004	32.35	10.06
Three Months Ended		
March 31, 2005	$39.46	$30.98
June 30, 2005	34.95	26.00
September 30, 2005	41.86	31.38
December 31, 2005	42.73	34.74

The above historical share prices have been adjusted to reflect our two-for-one stock split that occurred on April 22, 2005.

As of February 28, 2006, we had 54.7 million shares of common stock outstanding held by approximately 8,500 beneficial 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 credit agreements, as well as other factors the board of directors deems relevant.

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)				
	2005	**2004**	**2003**	**2002**	**2001**
Revenues	$ 3,005	$ 1,998	$ 658	$ 239	$ 2,373
LNG terminal development expenses (1)	22,020	17,166	6,705	1,557	1,789
Depreciation, depletion and amortization	3,702	1,324	429	369	1,244
Ceiling test write-down	—	—	—	—	5,126
General and administrative expenses	29,145	12,476	2,542	1,918	2,504
Loss from operations	(52,099)	(29,085)	(9,018)	(3,695)	(8,710)
Equity in net loss of affiliate (2)	—	—	—	(2,185)	(2,974)
Gain on sale of investment in unconsolidated affiliate (2)	20,206	—	—	—	—
Equity in net loss of limited partnership (3)	(1,031)	(1,346)	(4,471)	—	—
Gain on sale of LNG assets	—	—	4,760	—	—
Reimbursement from limited partnership investment	—	2,500	—	—	—
Interest expense	(17,373)	—	—	—	—
Interest income	17,520	501	3	8	19
Minority interest (4)	97	2,862	3,015	—	—
Income tax benefit	2,045	—	—	—	—
Net loss	(29,798)	(24,568)	(5,288)	(5,632)	(11,665)
Net loss per share (basic and diluted) (5)	$ (0.56)	$ (0.63)	$ (0.18)	$ (0.21)	$ (0.45)
Weighted average shares outstanding (basic and diluted) (5)	53,097	38,895	29,543	26,595	26,071

	December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Cash and cash equivalents	$ 692,592	$308,443	$ 1,258	$ 590	$ 611
Restricted cash and cash equivalents	160,885	—	—	—	—
Working capital	810,141	305,752	155	(1,413)	(530)
Property, plant and equipment, net	298,083	20,880	20,024	19,211	19,932
Debt issuances costs, net	43,008	1,302	—	—	—
Goodwill	76,844	—	—	—	—
Total assets	1,308,124	333,567	24,591	21,059	25,024
Long-term debt	917,500	—	—	—	—
Total liabilities	980,606	5,628	4,332	3,262	1,874
Deferred revenue	41,000	23,000	1,000	—	—
Total stockholders' equity	286,518	304,601	19,139	17,797	23,149

(1) The year ended 2002 includes $1.7 million in recoveries of general and administrative expenses reimbursable under the term of an agreement related to our sale of the Freeport LNG site, which closed in February 2003. See Note 8 to our Consolidated Financial Statements.

(2) Effective January 1, 2003, we began accounting for this investment in Gryphon using the cost method of accounting. The amounts listed for 2002 and 2001 represent our equity in the net loss of Gryphon under the equity method of accounting. In 2005, Gryphon was sold to Woodside Energy (USA), generating net cash proceeds and a gain to Cheniere of $20.2 million. See Note 22 to our Consolidated Financial Statements.

(3) Represents our equity in the net loss of Freeport LNG. See Note 8 to our Consolidated Financial Statements.

(4) Represents minority interest in the net loss of Corpus Christi LNG. See Note 13 to our Consolidated Financial Statements.

(5) Net loss per share and weighted average shares outstanding have been restated to reflect a two-for-one split that occurred on April 22, 2005.

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

General

We are engaged primarily in the business of developing and constructing, and then owning and operating, a network of three onshore LNG receiving terminals, and related natural gas pipelines, along the Gulf Coast of the United States. We are also engaged, to a limited extent, in oil and natural gas exploration and development activities in the Gulf of Mexico. We operate four business activities: LNG receiving terminal development, natural gas pipeline development, LNG and natural gas marketing and oil and gas exploration and development. At this stage in our development, our operations are divided into two reporting segments in our financial statements: LNG Receiving Terminal Development and Oil and Gas Exploration and Development.

LNG Receiving Terminal Development Business

We have focused our development efforts on three, 100% owned LNG receiving terminal projects at the following locations: Sabine Pass LNG in western Cameron Parish, Louisiana on the Sabine Pass Channel; Corpus Christi LNG near Corpus Christi, Texas; and Creole Trail LNG at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. In addition, we own a 30% interest in a fourth project, Freeport LNG, located on Quintana Island near Freeport, Texas. Our three terminals have an aggregate designed regasification capacity of approximately 10 Bcf/d, subject to expansion. We have entered into long-term TUAs with Total and Chevron USA for an aggregate of 2 Bcf/d of the available regasification capacity, and we anticipate retaining a portion of regasification capacity for our own use.

Construction of Phase 1 of our Sabine Pass LNG receiving terminal commenced in March 2005, and we anticipate commencing operations at the terminal in 2008. Construction of the Corpus Christi and Creole Trail LNG receiving terminals is anticipated to commence in 2006 and 2007, respectively, and we anticipate commencing operations at the facilities in 2010 and 2011, respectively.

Natural Gas Pipeline Development Business

We anticipate developing natural gas pipelines from each of our three LNG receiving terminals to provide optimal access to North American natural gas markets. Development efforts to date have focused primarily on advancing our pipeline projects through the regulatory review and authorization process. Recently, our development efforts have also included the construction and operation of our proposed natural gas pipelines. We anticipate commencing construction of our Sabine Pass pipeline in early 2007 and that it will be operational in the fourth quarter of 2007.

LNG and Natural Gas Marketing Business

Our LNG and natural gas marketing business is in its early stages of development. Utilizing a portion of our planned LNG receiving terminal regasification capacity that we intend to reserve for use by Cheniere Marketing at our three LNG receiving terminals, we intend to purchase LNG from foreign suppliers, arrange transportation of LNG to our network of LNG receiving terminals, arrange the transportation of revaporized natural gas through our pipelines and other interconnected pipelines and sell natural gas to buyers in the North American market. In addition, we also expect to enter into domestic natural gas purchase and sale transactions as part of our marketing activities.

Oil and Gas Exploration and Development Business

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

Liquidity and Capital Resources

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

We currently estimate that the cost of completing our three LNG receiving terminals will be approximately $3.0 billion, before financing costs. In addition, we expect that capital expenditures of approximately $800 million to $1 billion will be required to construct our three proposed pipelines.

As of December 31, 2005, we had working capital of $810.1 million. While we believe that we have adequate financial resources available to us through 2006, we must augment our existing sources of cash with significant additional funds in order to carry out our long-term business plan. We currently expect that our capital requirements will be financed in part through cash on hand, issuances of project-level debt, equity or a combination of the two and in part with net proceeds of debt or equity securities issued by Cheniere or other Cheniere borrowings.

Our LNG Receiving Terminals

Sabine Pass LNG

We currently estimate that the cost of constructing Phase 1 of the Sabine Pass LNG facility will be approximately $900 million to $950 million, before financing costs, which will be funded as described below. Phase 2 of the Sabine Pass LNG facility may be constructed in stages. The first stage is estimated to cost approximately $500 million to $550 million, before financing costs. We are currently evaluating funding alternatives for the first stage of construction of Phase 2 of the Sabine Pass LNG facility, which may include existing cash balances, proceeds from debt or equity offerings, or a combination thereof. The second stage of constructing Phase 2 of the Sabine Pass LNG facility is still under evaluation.

Sabine Pass Credit Facility

In February 2005, Sabine Pass LNG entered into the $822 million Sabine Pass Credit Facility with an initial syndicate of 47 financial institutions. Société Générale serves as the administrative agent and HSBC serves as collateral agent. The Sabine Pass Credit Facility will be used to fund a substantial majority of the costs of constructing and placing into operation Phase 1 of the Sabine Pass LNG receiving terminal. Unless Sabine Pass LNG decides to terminate availability earlier, the Sabine Pass Credit Facility will be available until no later than April 1, 2009, after which time any unutilized portion of the Sabine Pass Credit Facility will be permanently canceled. Before Sabine Pass LNG could make an initial borrowing under the Sabine Pass Credit Facility, it was required to provide evidence that it had received equity contributions in amounts sufficient to fund $233.7 million of the project costs. As of December 31, 2005, the $233.7 million equity contributions had been funded and, as a result, we began drawing under the Sabine Pass Credit Facility in January 2006. As of February 28, 2006, $58.5 million had been drawn under the Sabine Pass Credit Facility. In addition, we made a $37.4 million subordinated loan to Sabine Pass LNG in late 2005.

Borrowings under the Sabine Pass Credit Facility bear interest at a variable rate equal to LIBOR plus the applicable margin. The applicable margin varies from 1.25% to 1.625% during the term of the Sabine Pass Credit Facility. The Sabine Pass Credit Facility provides for a commitment fee of 0.50% per annum on the daily committed, undrawn portion of the Sabine Pass Credit Facility. Administrative fees must also be paid annually to the agent and the collateral agent. The principal of loans made under the Sabine Pass Credit Facility must be repaid in semi-annual installments commencing six months after the later of (i) the date that substantial completion of the project occurs under the EPC agreement and (ii) the commercial start date under the Total TUA. Sabine Pass LNG may specify an earlier date to commence repayment upon satisfaction of certain conditions. In any event, payments under the Sabine Pass Credit Facility must commence no later than October 1, 2009, and all obligations under the Sabine Pass Credit Facility mature and must be fully repaid by February 25, 2015.

Under the terms and conditions of the Sabine Pass Credit Facility, all cash held by Sabine Pass LNG is controlled by the collateral agent. These funds can only be released by the collateral agent upon receipt of satisfactory documentation that the Sabine Pass LNG project costs are bona fide expenditures and are permitted under the terms of the Sabine Pass Credit Facility. The Sabine Pass Credit Facility does not permit Sabine Pass LNG to hold any cash, or cash equivalents, outside of the accounts established under the agreement. Because these cash accounts are controlled by the collateral agent, the Sabine Pass LNG cash balance of $8.9 million held in these accounts as of December 31, 2005 is classified as restricted on our balance sheet.

The Sabine Pass Credit Facility contains customary conditions precedent to the initial borrowing and any subsequent borrowings, as well as customary affirmative and negative covenants. Sabine Pass LNG has obtained, and may in the future seek, consents, waivers and amendments to the Sabine Pass Credit Facility documents. The obligations of Sabine Pass LNG under the Sabine Pass Credit Facility are secured by all of Sabine Pass LNG's personal property, including the Total and Chevron USA TUAs and the partnership interests in Sabine Pass LNG.

In connection with the closing of the Sabine Pass Credit Facility, Sabine Pass LNG entered into swap agreements with HSBC and Société Générale. Under the terms of the swap agreements, Sabine Pass LNG will be able to hedge against rising interest rates, to a certain extent, with respect to its drawings under the Sabine Pass Credit Facility up to a maximum amount of $700 million. The swap agreements have the effect of fixing the LIBOR component of the interest rate payable under the Sabine Pass Credit Facility with respect to hedged drawings under the Sabine Pass Credit Facility up to a maximum of $700 million at 4.49% from July 25, 2005 to March 25, 2009 and at 4.98% from March 26, 2009 through March 25, 2012. The final termination date of the swap agreements will be March 25, 2012.

EPC Agreement

Sabine Pass LNG issued an NTP in early April 2005, which required Bechtel to commence all other aspects of the work under the EPC agreement. Sabine Pass LNG agreed to pay to Bechtel a contract price of $646.9 million plus certain reimbursable costs for the work under the EPC agreement. This contract price is subject to adjustment for changes in certain commodity prices, contingencies, change orders and other items. Payments under the EPC agreement will be made in accordance with the payment schedule set forth in the EPC agreement. The contract price and payment schedule, including milestones, may be amended only by change order. Bechtel will be liable to Sabine Pass LNG for certain delays in achieving substantial completion, minimum acceptance criteria and performance guarantees. Bechtel will be entitled to a scheduled bonus of $12 million, or a lesser amount in certain cases, if on or before April 3, 2008, Bechtel completes construction sufficient to achieve, among other requirements specified in the EPC agreement, a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours. Bechtel will be entitled to receive an additional bonus of $67,000 per day (up to a maximum of $6 million) for each day that commercial operation is achieved prior to April 1, 2008. As of February 28, 2006, change orders for $64.8 million were approved, thereby increasing the total contract price to $711.8 million. We anticipate additional change orders intended to mitigate ongoing effects of the 2005 hurricanes that would increase the contract price by an amount not expected to exceed $50 million. We expect to submit any such change orders to our lenders by May 3, 2006 for approval under the Sabine Pass Credit Facility.

Bechtel has claimed events of *force majeure* arising out of three hurricanes in 2005 along the U.S. Gulf Coast. Sabine Pass LNG is currently in negotiations with Bechtel and certain subcontractors concerning additional activities and expenditures in order, among other things, to attract sufficient skilled labor to mitigate potential schedule delays and provide a reasonable opportunity for Bechtel to attain the initial target bonus date of April 3, 2008. As part of these negotiations, we have agreed in principle to defer the date by which substantial completion of the entire project is required to be accomplished under the EPC contract from September 3 to December 20, 2008. In the absence of substantial completion by such date, Bechtel would be obligated to pay us certain liquidated damages as provided under the terms of the contract. We expect that the above-described arrangement will not exceed $50 million, although such amount is subject to change, requires approval of the lenders under our Sabine Pass Credit Facility and requires that a change order be agreed upon with Bechtel.

Customer TUAs

Total has paid Sabine Pass LNG nonrefundable advance capacity reservation fees of $20 million in the aggregate ($10 million in each of 2004 and 2005) in connection with the reservation under a 20-year TUA (with extension options) of approximately 1.0 Bcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal. These capacity reservation fee payments will be amortized over a 10-year period as a reduction of Total's regasification capacity fee under the TUA.

Chevron USA has paid Sabine Pass LNG nonrefundable advance capacity reservation fees of $20 million in the aggregate ($12 million in 2004 and $8 million in 2005) in connection with the reservation under a 20-year TUA (with extension options) of approximately 1.0 Bcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal, taking into account the option exercised by Chevron USA in December 2005. These capacity reservation fee payments will be amortized over a 10-year period as a reduction of Chevron USA's regasification capacity tariff under the TUA.

Corpus Christi LNG

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

BPU LNG was required to fund 100% of the first $4.5 million of Corpus Christi LNG's expenditures, which amount was funded as of March 31, 2004. From that date until February 8, 2005, when we acquired BPU LNG's 33.3% interest, we funded 66.7% of the expenditures of Corpus Christi LNG, with BPU LNG funding the balance. Since February 8, 2005, BPU LNG has not been required to fund any expenditures, and as the sole owner of Corpus Christi LNG, we are now required to fund 100% of expenditures.

We expect to begin site preparation and detailed engineering work in the second quarter of 2006 and to commence operations at the Corpus Christi LNG receiving terminal in early 2010.

We currently expect to fund the project costs for our Corpus Christi LNG receiving terminal from cash balances, project financing similar to that used for our Sabine Pass LNG facility, proceeds from debt or equity offerings, or a combination thereof. If these types of financing are not available, we will be required to seek alternative sources of financing, which may not be available on acceptable terms, if at all.

Creole Trail LNG

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

Other LNG Interests

We have a 30% limited partner interest in Freeport LNG. Under the limited partnership agreement of Freeport LNG, development expenses of the Freeport LNG project and other Freeport LNG cash needs generally are to be funded out of Freeport LNG's own cash flows, borrowings or other sources, and, up to a pre-agreed total amount, with capital contributions by the limited partners. In July 2004, Freeport LNG entered into a credit agreement with ConocoPhillips to provide a substantial majority of the debt financing. We received capital calls, and made capital contributions, in the amount of approximately $2.1 million in 2005. In December 2005, Freeport LNG announced that it had closed a $383 million private placement of notes, which will be used to fund the remaining portion of the initial phase of the project, a portion of the cost of expanding the LNG receiving terminal and the development of 7.5 Bcf of underground salt cavern gas storage. As a result of such financing being obtained, we do not anticipate that any capital calls will be made upon the limited partners of Freeport LNG in the foreseeable future.

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

Our Proposed Pipelines

We estimate that approximately $800 million to $1 billion of total capital expenditures will be required to construct our three proposed pipelines. We currently expect to fund the costs of our three proposed pipelines from our existing cash balances, project financing, proceeds from future debt or equity offerings, or a combination thereof.

On February 21, 2006, Cheniere Sabine Pass Pipeline Company entered into an EPC pipeline contract with Willbros. Under the EPC pipeline contract, which is effective as of February 1, 2006, Willbros will provide Cheniere Sabine Pass Pipeline Company with services for the management, engineering, material procurement, construction and construction management of the Sabine Pass pipeline. Cheniere Sabine Pass Pipeline Company entered into the EPC pipeline contract sufficiently in advance of commencement of physical construction of the pipeline in order to perform detailed engineering and procure materials. This EPC pipeline contract, among other things, provides for a guaranteed maximum price of approximately $67.7 million, subject to adjustment under certain circumstances, as provided in the contract. We estimate that the total cost to construct the pipeline, including certain work not included in the EPC pipeline contract, such as interconnection with third-party pipelines, will be approximately $90 million. Our total cost estimate is preliminary and subject to change due to such items as cost overruns, change orders, changes in commodity prices (particularly steel) and escalation of labor costs. Construction contracts for the Corpus Christi and Creole Trail pipelines have not been negotiated.

Our Marketing Business

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

Other Capital Resources

Convertible Senior Unsecured Notes

In July 2005, we consummated a private offering of $325 million aggregate principal amount of Convertible Senior Unsecured Notes due August 1, 2012 to qualified institutional buyers pursuant to Rule 144A under the Securities Act. The notes bear interest at a rate of 2.25% per year. The notes are convertible into our common stock pursuant to the terms of the indenture governing the notes at an initial conversion rate of 28.2326 per $1,000 principal amount of the notes, which is equal to a conversion price of approximately $35.42 per share. We may redeem some or all of the notes on or before August 1, 2012, for cash equal to 100% of the principal plus any accrued and unpaid interest if in the previous 10 trading days the volume-weighted average price of our common stock exceeds $53.13, subject to adjustment, for at least five consecutive trading days. In the event of such a redemption, we will make an additional payment equal to the present value of all remaining scheduled interest payments through August 1, 2012, discounted at the U.S. Treasury rate plus 50 basis points. The indenture governing the notes contains customary reporting requirements.

Concurrent with the issuance of the Convertible Senior Unsecured Notes, we also entered into hedge transactions in the form of an issuer call spread (consisting of a purchase and a sale of call options on our common stock) with an affiliate of the initial purchaser of the notes, having a term of two years and a net cost to us of $75.7 million. These hedge transactions are expected to offset potential dilution from conversion of the notes up to a market price of $70.00 per share. The net cost of the hedge transactions will be recorded as a reduction to Additional Paid-in-Capital in accordance with the guidance of EITF Issue 00-19, *Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company's Own Stock*. Net proceeds from the offering were $239.8 million, after deducting the cost of the hedge transactions, the underwriting discount and related fees. As of December 31, 2005, no holders had elected to convert their notes.

We currently intend to use the net proceeds from the Convertible Senior Unsecured Notes offering primarily for the following purposes: (i) to fund Phase 2 of the Sabine Pass LNG receiving terminal, development and construction of the Corpus Christi and/or Creole Trail LNG receiving terminals and pipelines, (ii) to pay debt service obligations and/or (iii) for general corporate purposes.

Term Loan

In August 2005, Cheniere LNG Holdings, LLC, or Cheniere LNG Holdings, a wholly-owned subsidiary of Cheniere, entered into a $600 million term loan, or Term Loan, with Credit Suisse. The Term Loan interest rate equals LIBOR plus a 2.75% margin and terminates on August 30, 2012. In connection with the closing, Cheniere LNG Holdings entered into swap agreements with Credit Suisse to hedge the LIBOR interest rate component of the Term Loan. The blended rate of the swap agreements on the Term Loan results in an annual fixed interest rate of 7.25% (including the 2.75% margin) for the first five years (See Note 10 to our Consolidated Financial Statements). On December 30, 2005, Cheniere LNG Holdings made the first required quarterly principal payment of $1.5 million. Quarterly principal payments of $1.5 million are required through June 30, 2012, and a final principal payment of $559.5 million is required on August 30, 2012. The Term Loan contains customary affirmative and negative covenants. The obligations of Cheniere LNG Holdings are secured by its 100% equity interest in Sabine Pass LNG and its 30% limited partner equity interest in Freeport LNG.

Under the conditions of the Term Loan, Cheniere LNG Holdings was required to fund from the loan proceeds a total of $216.2 million into two collateral accounts. These funds are restricted and to be disbursed only for the payment of interest and principal due under the Term Loan, reimbursement of certain expenses, and funding of additional capital contributions to Sabine Pass LNG as required under the Sabine Pass Credit Facility. Because these accounts are controlled by Credit Suisse, the collateral agent, our cash and cash equivalent undisbursed balance of $168.5 million held in these accounts as of December 31, 2005 is classified as restricted on our consolidated balance sheet. Of this amount, $16.5 million is classified as non-current due to the timing of certain required debt amortization payments.

We currently intend to use the remaining proceeds from the Term Loan primarily for the following purposes: (i) to fund requirements in excess of amounts available under the Sabine Pass Credit Facility for the construction of the Sabine Pass LNG receiving terminal, (ii) to pay specified Term Loan debt service obligations and certain other expenses, (iii) to fund Phase 2 of the Sabine Pass LNG receiving terminal, (iv) to fund the development and construction of the Corpus Christi and/or Creole Trail LNG receiving terminals and pipelines and/or (v) for general corporate purposes.

Short-Term Liquidity Needs

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

- cash balances;
- drawings under the Sabine Pass Credit Facility;
- issuances of Cheniere debt and equity securities, including issuances of common stock pursuant to exercises by the holders of existing options;
- LNG receiving terminal capacity reservation fees;
- collection of receivables; and
- sales of prospects generated by our oil and gas exploration and development business.

Historical Cash Flows

Net cash used in operations increased to $18.4 million in 2005 compared to $661,000 in 2004. This $17.7 million increase was primarily due to continued development of our LNG receiving terminals and related pipelines and increased costs to support such activities.

Net cash used in investing activities was $406.1 million during 2005 compared to net cash provided by investing activities of $1.2 million in 2004. During 2005, we funded $177.4 million related to restricted cash balances as required by the Term Loan and the Sabine Pass Credit Facility. We also advanced $8.1 million to the Sabine Pass LNG EPC contractor (net of $24.2 million applied against invoices and transferred to construction-in-progress related to the Sabine Pass LNG receiving terminal). We recorded $229.7 million to construction-in-progress related to Phase 1 of the Sabine Pass LNG facility. The remaining cash used in investing activities during 2005 was used primarily for the purchase of fixed assets, advances to Freeport LNG, and oil and gas property additions. These uses were partially offset by $20.2 million in proceeds received from the sale of our interest in Gryphon and $1.2 million received from the sale of interests in oil and gas prospects. During 2004, cash provided by investing activities of $1.2 million included a reimbursement from our limited partnership investment, proceeds from the sale of a limited partnership interest, and sales of our interests in oil and gas prospects, partially offset by oil and gas property and fixed asset additions.

Net cash provided by financing activities was $808.7 million during 2005 compared to $306.7 million in 2004. During 2005, we received proceeds from the issuance of our Convertible Senior Unsecured Notes and completion of the Term Loan in the amounts of $249.3 million (net of $75.7 million for the issuer call spread) and $600 million, respectively. In addition, we received $3.0 million in proceeds from the exercise of stock options and warrants. These proceeds were partially offset by $42.1 million in debt issuance costs related to the Sabine Pass Credit Facility, the Convertible Senior Unsecured Notes and the Term Loan. During 2004, we received proceeds from our $300.0 million public equity offering of common stock in December 2004 (before related offering costs of $14.1 million). In addition, we received $20.9 million from a private sale of our common stock (before offering costs of $965,000) and exercises of warrants and stock options. We also received $3.1 million in partnership contributions in 2004 made by the minority owner in Corpus Christi LNG. Cash flows from financing activities in 2004 were partially offset by the repayment of a $1.0 million note payable.

Due to the factors described above, our cash and cash equivalents increased to $692.6 million as of December 31, 2005 compared to $308.4 million at December 31, 2004, and our working capital increased to $810.1 million as of December 31, 2005 compared to $305.8 million at December 31, 2004.

Issuances of Common Stock

From our inception until August 2005, the primary source of financing for our operating expenses, investments in our exploration program and investments in our development of LNG receiving terminals was the sale of our equity securities. During 2005 and 2004, we raised $3 million and $305.9 million, respectively, net of offering costs, from the exchange or exercise of warrants, the exercise of stock options, a public equity offering of common stock and the sale of Cheniere common stock to accredited investors pursuant to Regulation D.

In February 2005, our stockholders approved an increase in Cheniere's authorized common stock from 40 million to 120 million shares. On April 22, 2005, we issued 26,789,242 shares of our common stock in a two-for-one stock split. The stock split entitled all stockholders of record at the close of business on April 8, 2005 to receive one additional share of common stock for each share held on that date. All per share amounts and outstanding and weighted share amounts included in this annual report on Form 10-K have been restated to give effect to the two-for-one stock split.

In February 2005, we acquired the 33.3% minority interest in Corpus Christi LNG through the acquisition of BPU LNG in exchange for 2 million restricted shares of our common stock valued at $77 million plus direct transaction costs.

In December 2005, 160,151 shares were issued to employees and outside directors in the form of non-vested (restricted) stock awards related to our performance in 2005. We recorded $6.2 million of deferred compensation as a reduction to stockholders' equity. In 2005, we also issued 15,000 shares of non-vested stock to certain employees. As a result, we recorded $498,000 of deferred compensation as a reduction of stockholders' equity. During 2005, we recorded $3.5 million (before capitalization of $145,000 as oil and gas property costs) in total non-cash compensation expense related to the amortization of deferred compensation.

During 2005, a total of 864,000 shares of our common stock were issued pursuant to the exercise of stock options, resulting in net cash proceeds of $2.5 million. A total of 433,000 shares of common stock were also issued pursuant to the exercise of warrants, resulting in net cash proceeds of $520,000. In addition, 97,000 shares were issued in satisfaction of cashless exercises of warrants to purchase 100,000 shares of common stock, and 33,000 shares were issued in satisfaction of cashless exercises of options to purchase 34,000 shares of common stock.

We issued a total of 17.9 million shares of common stock in 2004. In January 2004, we issued 2.2 million shares of common stock in a private placement under Regulation D to twelve accredited investors for total consideration of $14.9 million. We paid a 6.5% sales commission totaling $965,000, resulting in $13.9 million of net proceeds received from the offering. In February 2004, 766,000 shares were issued to employees and outside directors in the form of vested stock and non-vested stock awards related to our performance in 2003. This included 322,000 shares of stock for which we recorded $2.4 million in non-cash compensation expense, and 444,000 shares of non-vested stock for which we recorded $3.3 million in deferred compensation as a reduction in stockholders' equity. In November 2004, 236,000 shares were issued to employees and outside directors in the form of non-vested stock awards related to our performance in 2004. We recorded $4.9 million of deferred compensation as a reduction to stockholders' equity. In December 2004, we issued 10 million shares of common stock in connection with a public offering, for which we received net proceeds of $285.9 million. Throughout 2004, we issued a total of 1.8 million shares pursuant to the exercise of warrants, resulting in net cash proceeds of $3.4 million. We also issued 2.4 million shares pursuant to the exercise of stock options, resulting in net proceeds of $2.7 million and 553,000 shares in satisfaction of cashless exercises of stock options and warrants to purchase 390,000 and 250,000 shares, respectively.

We issued a total of 6.4 million shares of common stock in 2003. In April 2003, we issued 1.5 million shares of common stock pursuant to a contingent contractual obligation related to Cheniere's 2001 acquisition of an option to lease the Freeport LNG receiving terminal site. In May 2003, we issued 1.6 million shares of common stock to seventeen investors in a private placement made pursuant to Regulation D. The purchase price of the shares included cash of $1.2 million and the surrender of existing warrants to purchase 1.6 million shares of our common stock. Offering expenses relating to the private placement were $57,000. In August 2003, we issued 757,000 shares pursuant to a cashless exercise of warrants to purchase 1.4 million shares. Throughout 2003, we issued a total of 2.2 million shares pursuant to the exercise of warrants, resulting in net cash proceeds of $2.9 million. We also issued 375,000 shares pursuant to the exercise of stock options, resulting in proceeds of $292,000.

Contractual Obligations

We are committed to making cash payments in the future on certain of our contracts. We have no off-balance sheet debt or other such unrecorded obligations, and we have not guaranteed the debt of any other party. Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2005 (in thousands).

	Payments Due for Years Ending December 31,				
	Total	2006	2007-2008	2009-2010	Thereafter
Term Loan (1)	$598,500	$6,000	$12,000	$12,000	$568,500
Convertible Senior Unsecured Notes (1)	325,000	—	—	—	325,000
Operating Leases (2)	50,486	2,024	4,903	4,861	38,698
Other Obligations (3)	692	496	166	30	—
Total	$974,678	$8,520	$17,069	$16,891	$932,198

(1) A discussion of these obligations can be found at Note 14 to our Consolidated Financial Statements.

(2) A discussion of these obligations can be found at Note 21 to our Consolidated Financial Statements.

(3) Includes obligations for telecommunication services and software licensing.

Lease Commitments and Other Obligations

We currently have lease commitments for approximately 56,000 square feet of office space in downtown Houston, Texas. In October 2003, we entered into a lease agreement for office space having a term which runs from December 2003 through April 2014. Beginning in April 2004, our monthly lease rental for this space is $21,000 and escalates to $24,000 beginning in February 2009 through the remaining term of the lease. We have an option to renew the lease for an additional five years at the then-current market rate. In May 2004, we amended our office lease agreement to increase our rentable square footage (the "Expansion Space"). The lease term for the Expansion Space runs from September 2004 through August 2009. Our monthly lease rental for the Expansion Space is $14,000 beginning in June 2005. We have the option, subject and subordinate to another tenants' renewal option, to renew the lease for an additional five years. In March 2005, we further amended our office lease to increase our rentable square footage to include an additional floor on the premises. The lease term for the additional floor runs from May 2005 through January 2014. We have an option to renew the lease for an additional five years at the then-current market rate as part of the renewal of our original lease space. Under the amended lease, there are no monthly lease payments for the additional floor from May 2005 through April 2007, after which time the lease payments range from approximately $30,000 to $39,000 per month through January 2014. We have prepaid $201,000 in rent related to 2013 and have included such amount in Other Assets on the consolidated balance sheet as of December 31, 2005.

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 our Sabine Pass LNG receiving terminal site. The leases have an initial term of 30 years, with options to renew for six 10-year extensions. 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. For 2005, these payments have been capitalized as part of the construction cost of the Sabine Pass LNG receiving terminal; however, beginning in January 2006, these lease payments have been expensed as required by Financial Accounting Standards Board, or FASB, Staff Position, or FSP, 13-1, *Accounting for Rental Costs Incurred During Construction*.

Restricted Certificate of Deposit and Letter of Credit

Under the terms of our office lease, we are required to post a standby letter of credit in favor of the lessor. The initial amount of the letter of credit was increased from $865,000 to $1.1 million in April 2004 related to the expansion of our office space; and the amount will be reduced by approximately $225,000 per annum over a five-year period. This letter of credit was initially established under the terms of our bank line of credit at that time.

Upon the termination of our bank line of credit in June 2004, we purchased a certificate of deposit in the amount of $1.1 million and entered into a pledge agreement in favor of the commercial bank that had previously issued the standby letter of credit for $1.1 million. In October 2004 and 2005, both the letter of credit and certificate of deposit were amended to decrease the face amounts by approximately $225,000 to $898,000 and $674,000, respectively. The renewed letter of credit and the certificate of deposit both mature on November 30, 2005. Under the terms of the pledge agreement, the commercial bank was assigned a security interest in the certificate of deposit as collateral for the letter of credit. As a result, the certificate of deposit plus $2,000 of accrued interest is classified as restricted on our balance sheet at December 31, 2005.

Off-Balance Sheet Arrangements

As of December 31, 2005, 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

During 2003, 2004 and 2005, inflation and changing commodity prices have had an impact on our revenues but have not significantly impacted our results of operations. However, we have experienced escalated steel prices relating to the construction of our LNG receiving terminals and labor costs in connection with the collateral effects of the 2005 hurricanes.

Prior Bank Line of Credit

In June 2004, we terminated our $5 million line of credit with a commercial bank. This facility was originally established in July 2003 with a borrowing base of $2 million. During 2003, we borrowed $1 million under the facility to acquire oil and gas leases, which we subsequently repaid in January 2004.

Short-Term Promissory Notes

In February 2003, we executed a promissory note payable in the amount of $225,000. The proceeds of the note were used to pay certain costs related to our 3-D seismic database. In July 2003, we repaid the note payable.

Results of Operations—Comparison of the Fiscal Years Ended December 31, 2005 and 2004

Overview—Our financial results for the year ended December 31, 2005 reflect a net loss of $29.8 million, or $0.56 per share (basic and diluted), compared to a net loss of $24.6 million, or $0.63 per share (basic and diluted), in 2004.

The major factors contributing to our net loss of $29.8 million in 2005 were LNG receiving terminal development expenses of $22.0 million and general and administrative expenses of $29.1 million, which were significantly offset by the $20.2 million gain on the sale of our investment in Gryphon. Absent the gain on the sale of our investment in Gryphon, we would have reported a net loss of $50.0 million, or $0.94 per share (basic and diluted), for 2005. The major factors contributing to our $24.6 million net loss in 2004 were LNG receiving terminal development expenses of $17.2 million and general and administrative expenses of $12.5 million, which were partially offset by a $2.9 million minority interest in the operations of Corpus Christi LNG and by a $2.5 million reimbursement from our limited partner investment in Freeport LNG.

LNG Receiving Terminal Development and Related Pipeline Activities—LNG receiving terminal development expenses increased $4.8 million, or 28%, to $22.0 million in 2005 compared to $17.2 million in 2004. Our development expenses primarily included professional fees associated with front-end engineering and design work, obtaining orders from FERC authorizing construction of our facilities and other required permitting for our planned LNG receiving terminals, their related natural gas pipelines as well as other initiatives that complement the development of our LNG receiving terminal business. Expenses of our LNG employees involved in development activities are also included. Beginning in the first quarter of 2005, costs related to the construction of Phase 1 of our Sabine Pass LNG receiving terminal have been capitalized.

LNG receiving terminal development expenses for 2005 totaled $7.1 million and were mainly attributable to our Creole Trail LNG and Corpus Christi LNG terminal projects and Phase 2 of the Sabine Pass LNG project. In 2005, we incurred $6.4 million in LNG pipeline development expenses primarily related to our Sabine Pass LNG and Creole Trail LNG projects. In addition, we incurred $8.5 million in other LNG receiving terminal development expenses, including $7.3 million in LNG employee-related costs. Our LNG staff increased from an average of 14 employees in 2004 to an average of 25 employees in 2005 as a result of the expansion of our business. LNG employee-related costs for 2005 included cash bonus costs of $1.7 million related to 2005 company performance and non-cash compensation of $1.2 million related to the amortization of deferred compensation associated with non-vested stock.

In 2004, we recorded $5.8 million in terminal development expenses related to the Corpus Christi LNG receiving terminal. This amount was partially offset by $2.9 million related to the minority interest of our 33.3% limited partner. Substantially all expenditures incurred through March 31, 2004 were the obligation of the minority owner, as the minority owner was required to fund 100% of the first $4.5 million of project expenditures. As project expenditures had reached $4.5 million by March 31, 2004, the minority owner began sharing all subsequent project expenditures based on its 33.3% limited partner interest. During 2004, we also incurred direct receiving terminal development expenses of $6.4 million related to Phase 1 of our Sabine Pass LNG receiving terminal and $375,000 related to our Creole Trail LNG receiving terminal, in each of which we own 100% of the projects. In addition, during 2004, we incurred $4.8 million in LNG employee-related costs. LNG employee-related costs for 2004 also included cash bonuses of $2.0 million and non-cash compensation of $928,000 (which included stock awards and amortization of deferred compensation associated with non-vested stock awards).

In 2005, our 30% equity share of the net loss of Freeport LNG resulted in a reported net loss of $1 million. In contrast, in 2004, our 30% equity share of the net loss of Freeport LNG was $1.3 million, including $278,000 of loss that was suspended as of December 31, 2003 (see Note 8 to our Consolidated Financial Statements).

In January 2004, we received the final $2.5 million payment from Freeport LNG pursuant to the terms of the agreement related to our February 2003 disposition of LNG assets in exchange for cash and a limited partner interest in Freeport LNG. Because our investment basis in Freeport LNG had been previously reduced to zero, the $2.5 million payment was recorded as a reimbursement from limited partnership investment in our consolidated statement of operations during the first quarter of 2004.

General and Administrative Expenses—General and administrative, or G&A, expenses increased $16.7 million, or 134%, to $29.1 million in 2005 compared to $12.5 million in 2004. The increase in G&A resulted primarily from the expansion of our business (including increases in corporate staff from an average of 14 employees in 2004 to an average of 47 employees in 2005). Corporate employee-related costs for 2005 included cash bonuses of $4.3 million and non-cash compensation of $2.2 million related to the amortization of deferred compensation associated with non-vested stock awards. Corporate employee-related costs for 2004 included cash bonuses of $2.2 million and non-cash compensation of $2.7 million (which included stock awards and amortization of deferred compensation associated with non-vested stock awards). We capitalize as oil and gas property costs that portion of G&A expenses directly related to our exploration and development activities. We capitalized $927,000 in 2005 compared to $1.6 million in 2004.

Depreciation, Depletion and Amortization Expenses—Depreciation, Depletion and Amortization, or DD&A, expenses increased $2.4 million, or 180%, to $3.7 million in 2005 from $1.3 million in 2004. The increase included $1.6 million in higher oil and gas DD&A as a result of an increase in our DD&A rate from $2.48 per Mcfe to $5.90 per Mcfe and the higher production volumes discussed below. Other DD&A also increased by $797,000 primarily as a result of higher depreciation expense associated with the acquisition of furniture, fixtures and equipment and office space leasehold improvements associated with the expansion of our business.

Derivative gain, net—During 2005, we recorded a net derivative gain of $837,000 attributable to the ineffective portion of our interest rate swaps.

Interest Expense—Interest expense, net of capitalization, was $17.4 million in 2005 compared to zero in 2004. This increase was attributable to the issuance of our Convertible Senior Unsecured Notes and completion of the Term Loan during the third quarter of 2005. Capitalized interest of $6.1 million in 2005 was primarily related to the amortization of debt issuance cost and commitment fees associated with the Sabine Pass Credit Facility.

Interest Income—Interest income increased to $17.5 million in 2005 from $501,000 in 2004 as a result of an increase in our cash and cash equivalent balances attributable primarily to our common stock offering in December 2004 and the issuance of our Convertible Senior Unsecured Notes and completion of the Term Loan in the third quarter of 2005.

Gain on Sale of Investment in Unconsolidated Affiliate—On August 31, 2005, Gryphon was sold for $283 million, plus assumption of $14 million of net debt in a merger with Woodside Energy (USA). We received net cash proceeds of $20.2 million for our interest, and since our investment balance was zero, we recognized a gain in 2005 equal to the net cash proceeds amount.

Oil and Gas Activities—Oil and gas revenues increased by $1.0 million, or 50%, to $3.0 million in 2005 from $2.0 million in 2004 as a result of a 22% increase in production volumes (409,000 Mcfe in 2005 compared with 337,000 Mcfe in 2004) and a 24% increase in average natural gas prices to $7.34 per Mcf in 2005 from $5.93 per Mcf in 2004. We produced from an average of 10 wells in both 2005 and 2004. Oil and gas production costs increased 102% to $237,000 in 2005 compared to $117,000 in 2004. This increase was primarily due to higher production taxes attributable to the higher production volumes and commodity prices during 2005.

Income Tax Benefit—A tax benefit of $2.0 million was recognized in 2005 relating to the portion of the change in our tax asset valuation account that is allocable to the deferred income tax on items reported in other comprehensive income on derivative instruments in accordance with Statement of Financial Accounting Standards, or SFAS, No. 109, *Accounting for Income Taxes*, and EITF *Abstracts*, Topic D-32.

Results of Operations—Comparison of the Fiscal Years Ended December 31, 2004 and 2003

Overview—Our financial results for the year ended December 31, 2004 reflected a net loss of $24.6 million, or $0.63 per share (basic and diluted), compared to a net loss of $5.3 million, or $0.18 per share (basic and diluted), in 2003.

The major factors contributing to our net loss during 2004 were: LNG receiving terminal development expenses of $17.2 million (which were partially offset by a $2.9 million minority interest in the operations of

Corpus Christi LNG) and general and administrative expenses of $12.5 million. These factors were partially offset by a $2.5 million reimbursement from our limited partnership investment in Freeport LNG.

LNG Receiving Terminal Development and Related Pipeline Activities—LNG receiving terminal development expenses were 156% higher in 2004 ($17.2 million) than in 2003 ($6.7 million). Because we have been in the preliminary stage of developing our LNG receiving terminals through December 31, 2004, substantially all of the costs to such date related to such activities were expensed. These costs primarily included professional fees associated with front-end engineering and design work, obtaining an order from FERC authorizing construction of our terminals and other required permitting for Phase 1 of the Sabine Pass LNG, Corpus Christi LNG and Creole Trail LNG receiving terminals and their related natural gas pipelines. The expenses of our LNG employees directly involved in the development of our LNG receiving terminals are also included. LNG receiving terminal development expenses were significantly higher in 2004 because we accelerated, beginning in the third quarter of 2003, the schedule of LNG receiving terminal development for Phase 1 of our Sabine Pass LNG receiving terminal as well as our Corpus Christi LNG receiving terminal. We accelerated the development of our Creole Trail LNG receiving terminal in the fourth quarter of 2004.

In 2004, we recorded $5.8 million in terminal development expenses related to the Corpus Christi LNG receiving terminal. This amount was partially offset by $2.9 million related to the minority interest of our 33.3% limited partner. Substantially all expenditures incurred through March 31, 2004 were the obligation of the minority owner, as the minority owner was required to fund 100% of the first $4.5 million of project expenditures. As project expenditures had reached $4.5 million by March 31, 2004, the minority owner began sharing all subsequent project expenditures based on its 33.3% limited partner interest. Also during 2004, we incurred direct receiving terminal development expenses of $6.4 million related to Phase 1 of our Sabine Pass LNG receiving terminal and $375,000 related to our Creole Trail LNG receiving terminal, in each of which we own 100% of the projects. In addition, during 2004, we incurred $4.8 million in LNG employee-related costs. In connection with the expansion of our LNG receiving terminal business, our employee costs increased, as we expanded our LNG staff from four employees during 2003 to an average of 15 employees during 2004. LNG employee-related costs for 2004 also included cash bonuses of $2 million and non-cash compensation of $928,000 (which included stock and non-vested stock awards) related to our 2003 and 2004 company performance.

In 2003, we incurred $6.7 million in LNG receiving terminal development expenses. Of this amount, $3 million related to development costs for the Corpus Christi LNG project. However, these costs were entirely offset by the minority interest of our 33.3% limited partner as discussed above. Also during 2003, we incurred $3.7 million primarily for development expenses related to Phase 1 of our Sabine Pass LNG project and LNG employee-related costs.

In February 2003, our Freeport LNG receiving terminal project was acquired by Freeport LNG, from whom we retained a 40% limited partnership interest and received payments totaling $5 million over time. In connection with the sale of LNG assets to Freeport LNG, we reported a gain of $4.8 million. We also sold a 10% interest in Freeport LNG in March 2003 for $2.3 million, resulting in a gain of $423,000. During 2003, we received payments totaling $2.5 million from Freeport LNG, plus $1.7 million in reimbursement of project costs, which were recorded as a reduction to our investment in the partnership. In addition, during 2003 we recorded our equity share ($4.5 million) related to the 2003 loss incurred by Freeport LNG, which reduced our investment basis to zero as of December 31, 2003. In January 2004, we received the final $2.5 million payment from Freeport LNG. Because our investment basis in Freeport LNG had been reduced to zero, the payment was recorded as a reimbursement from limited partnership investment in our consolidated statement of operations for 2004.

In 2004, our 30% equity share of the net loss from Freeport LNG was $1.3 million, including $278,000 of loss that was suspended as of December 31, 2003 (see Note 8 to our Consolidated Financial Statements). This compares to our equity share of the loss of $4.5 million for 2003. The significant improvement between periods for Freeport LNG was a result of Freeport LNG's receipt of a non-refundable fee of $10 million from ConocoPhillips in January 2004.

General and Administrative Expenses—G&A expenses increased $9.9 million, or 391%, to $12.5 million in 2004 compared to $2.5 million in 2003. The increase in G&A resulted primarily from the expansion of our business (including increases in average corporate staff from an average of 5 employees in 2003 to an average of 16 employees in 2004). Corporate employee-related costs for 2004 also included cash bonuses of $2.2 million and non-cash compensation of $2.7 million (which included stock and non-vested stock awards) related to our 2003 and 2004 company performance. We capitalize as oil and gas property costs that portion of G&A expenses directly related to our exploration and development activities. We capitalized $1.6 million in 2004 compared to $976,000 in 2003.

Depreciation, Depletion and Amortization Expenses—DD&A expenses increased $895,000, or 209%, to $1.3 million in 2004 from $429,000 in 2003. The increase primarily resulted from higher oil and gas DD&A as a result of an increase in our DD&A rate from $0.98 per Mcfe to $2.48 per Mcfe and higher production volumes discussed below. DD&A also increased as a result of more depreciation expense resulting from the acquisition of furniture, fixtures and equipment associated with the expansion of our business.

Interest Income—Interest income increased to $501,000 in 2004 from $3,000 in 2003 primarily because of an increase in our cash balance resulting from our $300 million public equity offering of our common stock in December 2004 (before related offering costs of $14.1 million). In addition, we received $22 million in advance regasification capacity payments in November and December of 2004 and raised $20 million in net cash proceeds related to a private placement of our common stock and exercises of options and warrants to purchase our common stock during 2004.

Oil and Gas Activities—Oil and gas revenues increased by $1.3 million, or 204%, to $2 million in 2004 from $658,000 in 2003 as a result of a 173% increase in production volumes (336,849 Mcfe in 2004 compared with 123,494 Mcfe in 2003) and an 11% increase in average natural gas prices to $5.93 per Mcf in 2004 from $5.33 per Mcf in 2003. We produced from an average of 10 wells in 2004 as compared with an average of 7 wells in 2003. We incurred little or no production cost in 2003 and 2004 because all of our revenues were generated from non-cost bearing overriding royalty interests, or ORRI, until December 2004. The small amount of production costs in 2004 is attributable to our share of production taxes on two producing wells located in Texas state waters and operating costs attributable to a well converted from an ORRI to a working interest at payout in December 2004.

Other Matters

Critical Accounting Estimates and Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment, to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption, and believe 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

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 natural gas pipelines.

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

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

Revenue Recognition

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

Full Cost Method of Accounting

We follow the full cost method of accounting for our oil and gas properties. Under this method, all productive and non-productive exploration and development costs incurred for the purpose of finding oil and gas reserves are capitalized. Such capitalized costs include lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, together with internal costs directly attributable to property acquisition, exploration and development activities.

The costs of our oil and gas properties, including the estimated future costs to develop proved reserves and the carrying amounts of any asset retirement obligations, are depreciated using a composite unit-of-production rate based on estimates of proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, then the amount of the impairment is added to the capitalized costs to be amortized. Net capitalized costs are limited to a capitalization ceiling, calculated on a quarterly basis as the aggregate of the present value, discounted at 10%, of estimated future net revenues from proved reserves (based on current economic and operating conditions), but excluding asset retirement obligations, plus the lower of cost or fair market value of unproved properties, less related income tax effects.

Our allocation of seismic exploration costs between proved and unproved properties involves an estimate of the total reserves to be discovered through our exploration program. This estimate includes a number of assumptions that we have incorporated into a three-year plan. Such factors include an estimate of the number of exploration prospects generated, prospect reserve potential, success ratios and ownership interests. We transfer unproved properties to proved properties based on a ratio of proved reserves discovered at a point in time to the estimate of total reserves to be discovered in our exploration program. The carrying value of unproved properties is evaluated for possible impairment by comparing it to the estimated future net cash flows associated with the estimated total reserves to be discovered in our exploration program. To the extent that the carrying value of unproved properties is greater than the estimated future net revenue, any excess is transferred to proved properties. It is reasonably possible, based on the results obtained from future drilling and prospect generation, that revisions to this estimate of total reserves to be discovered could affect our capitalization ceiling.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved oil and gas reserves.

We account for the retirement of our tangible long-lived assets in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 requires us to record the fair value of a liability for legal obligations associated with the retirement of tangible long-lived assets and a corresponding increase in the carrying amount of the related long-lived assets. Subsequently, the asset retirement costs included in the carrying amount of the related asset are allocated to expense using the unit-of-production method used to depreciate oil and gas properties under the full cost method of accounting.

Oil and Gas Reserves

The process of estimating quantities of proved reserves is inherently uncertain, and our reserve data are only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and crude oil that cannot be measured in an exact manner. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgment of the persons preparing the estimate. At least annually, our reserves are estimated by an independent petroleum engineer.

Because these estimates depend on many assumptions, all of which may substantially differ from actual results, reserve estimates may be different from the quantities of natural gas and crude oil that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

The present value of future net cash flows does not necessarily represent the current market value of our estimated proved natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

Our rate of recording DD&A is dependent upon our estimate of proved reserves. If the estimate of proved reserves declines, the rate at which we record DD&A expense increases thereby reducing net income. Such a decline may result from lower market prices, which may make it uneconomical to drill for and produce higher cost fields.

Cash Flow Hedges

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

Goodwill

Goodwill is accounted for in accordance with SFAS No. 142, *Goodwill and Other Intangible Assets*. We perform an annual goodwill impairment review in the fourth quarter of each year, although we may perform a goodwill impairment review more frequently whenever events or circumstances indicate that the carrying value may not be recoverable. See Note 9 to our Consolidated Financial Statements.

New Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment*, that addresses the accounting for share-based payment transactions in which a company receives employee services in exchange for equity instruments of the company, such as stock options and non-vested stock. SFAS No. 123R eliminates the ability to account for share-based compensation transactions using APB Opinion No. 25 and requires instead that such transactions be accounted for using a fair value-based method. From inception through December 31, 2005, we have accounted for stock-based compensation using the intrinsic value method pursuant to APB Opinion No. 25. SFAS No. 123R requires that all stock-based payments to employees, including grants of employee stock options and non-vested stock, be recognized as compensation expense in the financial statements based on their fair values (intrinsic value in the case of non-vested stock) at the time such awards are granted. SFAS No. 123R is effective January 1, 2006 for companies with fiscal years ending December 31. Accordingly, we will begin reporting the results of SFAS No. 123R on our operations in the quarter ending March 31, 2006. We are adopting the new standard using the modified-prospective transition method. The adoption of the new standard will have a significant future impact on our results of operations, but will have no impact on our cash flows. Had we adopted SFAS No. 123R in prior periods, the effects of that standard on net income and earnings per share would have been approximately the same as the effects of SFAS No. 123 presented in the Stock-Based Compensation pro forma disclosure included in Note 2 of our Consolidated Financial Statements.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections—A Replacement of APB Opinion No. 20 and FASB Statement No. 3*. SFAS No. 154 changes the requirements for accounting and reporting on a change in accounting principle, while carrying forward the guidance in APB Opinion No. 20, *Accounting Changes* and FASB Statement No. 3, *Reporting Accounting Changes in Interim Financial Statements*, with respect to accounting for changes in estimates, changes in the reporting entity and the correction of errors. APB Opinion No. 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change, the cumulative effect of changing to the new accounting principle. SFAS No. 154 requires retrospective application to prior periods' financial statements for voluntary changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The impact of SFAS No. 154 will depend on the accounting change that may occur in a future period.

In October 2005, the FASB issued FSP 13-1 to address the accounting for rental costs associated with operating leases that are incurred during a construction period. FSP 13-1 requires rental costs associated with ground or building operating leases that are incurred during a construction period to be recognized as rental expense. FSP 13-1 is effective in fiscal years beginning after December 15, 2005. Accordingly, we will adopt the new standard in the quarter ending March 31, 2006. As of December 31, 2005, we have capitalized $1.5 million in rental expenses related to our Sabine Pass LNG terminal site lease.

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

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

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

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

Interest Rates

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

In connection with the closing of the Sabine Pass Credit Facility in February 2005, we entered into interest rate swap agreements to hedge against increases in floating interest rates with respect to draws, up to a maximum of $700 million under this facility. No debt was outstanding under this facility at December 31, 2005.

At December 31, 2005, we had $923.5 million of debt outstanding. Of this amount, our $325 million of Convertible Senior Unsecured Notes bore a fixed interest rate of 2.25%. The Term Loan, totaling $598.5 million, bore interest at floating rates; however, concurrent with the closing of the Term Loan, we entered into interest rate swaps with respect to this loan. (See Note 10 to our Consolidated Financial Statements)

The following table summarizes the fair market values of our existing interest rate swap agreements as of December 31, 2005 (in thousands):

Variable to Fixed Swaps

Maturity Date	Notional Principal Amount	Fixed Interest Rate (Pay)	Weighted Average Interest Rate	Fair Market Value (1)
January through December 2006	$ 4,958,050	3.75% - 4.49%	US $ LIBOR BBA	$ 5,841
January through December 2007	9,086,074	3.75% - 4.49%	US $ LIBOR BBA	7,033
January through December 2008	10,638,516	3.98% - 4.49%	US $ LIBOR BBA	2,724
January through December 2009	5,113,000	4.49% - 5.98%	US $ LIBOR BBA	(5,382)
January through December 2010	2,942,260	4.98% - 5.98%	US $ LIBOR BBA	(3,600)
January through December 2011	1,331,700	4.98%	US $ LIBOR BBA	(619)
January through December 2012	650,100	4.98%	US $ LIBOR BBA	(373)
	$34,719,700			$ 5,624

(1) The fair market value is based upon a marked-to-market calculation utilizing an extrapolation of third-party mid-market LIBOR rate quotes at December 30, 2005.

ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

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

Based on our assessment, we have concluded that Cheniere maintained effective internal control over financial reporting as of December 31, 2005, based on criteria in *Internal Control—Integrated Framework* issued by the COSO. Our assessment of the effectiveness of Cheniere's internal control over financial reporting as of December 31, 2005, has been audited by UHY Mann Frankfort Stein & Lipp CPAs, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

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/ DON A. TURKLESON
Charif Souki	**Don A. Turkleson**
Chief Executive Officer	**Senior Vice President and Chief Financial Officer**

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Cheniere Energy, Inc. and subsidiaries, or the Company, as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2005. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We did not audit the financial statements of Freeport LNG Development, L.P., or Freeport LNG, an investment which, as discussed in Note 8 to the consolidated financial statements, is accounted for by the equity method of accounting. The investment in Freeport LNG was zero and $(1,071,000) as of December 31, 2005 and 2004, respectively, and the equity in its net loss was $1,031,000, $1,346,000 and $4,471,000, respectively, for each of the three years in the period ended December 31, 2005. The financial statements of Freeport LNG were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Freeport LNG, are based solely on the report of the other auditors.

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 audits 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, based on our audits and the report of other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Cheniere Energy, Inc. and subsidiaries at December 31, 2005 and 2004, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Cheniere Energy, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 10, 2006 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

/s/ UHY MANN FRANKFORT STEIN & LIPP CPAs, LLP

UHY MANN FRANKFORT STEIN & LIPP CPAs, LLP

Houston, Texas
March 10, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting appearing on page 73, that Cheniere Energy, Inc. and subsidiaries, or the Company, maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, 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, management's assessment that Cheniere Energy, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework* issued by COSO. Also, in our opinion, Cheniere Energy, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by COSO.

We have also 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, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2005, and our report dated March 10, 2006 expressed an unqualified opinion on those consolidated financial statements.

/s/ UHY MANN FRANKFORT STEIN & LIPP CPAs, LLP

UHY MANN FRANKFORT STEIN & LIPP CPAs, LLP

Houston, Texas
March 10, 2006

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET
(in thousands, except share data)

	December 31, 2005	December 31, 2004
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 692,592	$308,443
Restricted Cash and Cash Equivalents	160,885	—
Restricted Certificate of Deposit	676	900
Advances to EPC Contractor	8,087	—
Accounts Receivable	2,912	1,374
Derivative Assets	5,468	—
Prepaid Expenses	843	564
Total Current Assets	871,463	311,281
NON-CURRENT RESTRICTED CASH AND CASH EQUIVALENTS	16,500	—
PROPERTY, PLANT AND EQUIPMENT, NET	298,083	20,880
DEBT ISSUANCE COSTS, NET	43,008	1,302
INVESTMENT IN LIMITED PARTNERSHIP	—	—
GOODWILL	76,844	—
LONG-TERM DERIVATIVE ASSETS	1,837	—
INTANGIBLE LNG ASSETS	93	88
OTHER	296	16
Total Assets	$1,308,124	$333,567
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	$ 778	$ 1,262
Accrued Liabilities	54,544	3,196
Accrued Losses on Investment in Limited Partnership	—	1,071
Current Portion of Long-Term Debt	6,000	—
Total Current Liabilities	61,322	5,529
LONG-TERM DEBT	917,500	—
DEFERRED REVENUE	41,000	23,000
LONG-TERM DERIVATIVE LIABILITIES	1,682	—
LONG-TERM ASSET RETIREMENT OBLIGATION	102	99
MINORITY INTEREST	—	338
COMMITMENTS AND CONTINGENCIES	—	—
STOCKHOLDERS' EQUITY		
Preferred Stock, $.0001 par value Authorized: 5,000,000 shares Issued and Outstanding: none	—	—
Common Stock, $.003 par value Authorized: 120,000,000 and 40,000,000 shares at December 31, 2005 and December 31, 2004, respectively Issued and Outstanding: 54,521,131 and 50,918,582 shares at December 31, 2005 and December 31, 2004, respectively	164	153
Additional Paid-in-Capital	375,551	364,504
Deferred Compensation	(9,684)	(6,543)
Accumulated Deficit	(83,311)	(53,513)
Accumulated Other Comprehensive Income	3,798	—
Total Stockholders' Equity	286,518	304,601
Total Liabilities and Stockholders' Equity	$1,308,124	$333,567

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

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

	Year Ended December 31, 2005	2004	2003
Revenues			
Oil and Gas Sales	$ 3,005	$ 1,998	$ 658
Total Revenues	3,005	1,998	658
Operating Costs and Expenses			
LNG Receiving Terminal Development Expenses	22,020	17,166	6,705
Oil and Gas Production Costs	237	117	—
Depreciation, Depletion and Amortization	3,702	1,324	429
General and Administrative Expenses	29,145	12,476	2,542
Total Operating Costs and Expenses	55,104	31,083	9,676
Loss from Operations	(52,099)	(29,085)	(9,018)
Gain on Sale of Investment in Unconsolidated Affiliate	20,206	—	—
Equity in Net Loss of Limited Partnership	(1,031)	(1,346)	(4,471)
Gain on Sale of LNG Assets	—	—	4,760
Gain on Sale of Limited Partnership Interest	—	—	423
Reimbursement from Limited Partnership Investment	—	2,500	—
Derivative Gain	837	—	—
Interest Expense	(17,373)	—	—
Interest Income	17,520	501	3
Loss Before Income Taxes and Minority Interest	(31,940)	(27,430)	(8,303)
Income Tax Benefit	2,045	—	—
Loss Before Minority Interest	(29,895)	(27,430)	(8,303)
Minority Interest	97	2,862	3,015
Net Loss	$(29,798)	$(24,568)	$ (5,288)
Net Loss Per Common Share—Basic and Diluted	$ (0.56)	$ (0.63)	$ (0.18)
Weighted Average Number of Common Shares Outstanding—Basic and Diluted	53,097	38,895	29,543

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(in thousands)

	Common Stock		Additional Paid-In Capital	Deferred Compensation	Accumulated Deficit	Accumulated Other Comprehensive Income	Total Stockholders' Equity
	Shares	Amount					
Balance—December 31, 2002	26,594	$ 80	$ 41,374	$ —	$(23,657)	$ —	$ 17,797
Issuances of Stock	6,382	19	5,723	—	—	—	5,742
Issuances of Warrants	—	—	945	—	—	—	945
Expenses Related to Offerings	—	—	(57)	—	—	—	(57)
Net Loss	—	—	—	—	(5,288)	—	(5,288)
Balance—December 31, 2003	32,976	$ 99	$ 47,985	—	$(28,945)	$ —	$ 19,139
Issuances of Stock	17,263	52	323,295	—	—	—	323,347
Issuances of Restricted Stock	680	2	8,274	(8,276)	—	—	—
Amortization of Deferred Compensation	—	—	—	1,733	—	—	1,733
Expenses Related to Offerings	—	—	(15,050)	—	—	—	(15,050)
Net Loss	—	—	—	—	(24,568)	—	(24,568)
Balance—December 31, 2004	50,919	$153	$364,504	$(6,543)	$(53,513)	$ —	$304,601
Issuances of Stock	3,427	10	80,115	—	—	—	80,125
Issuances of Restricted Stock	175	1	6,662	(6,663)	—	—	—
Amortization of Deferred Compensation	—	—	—	3,522	—	—	3,522
Expenses Related to Offerings	—	—	(27)	—	—	—	(27)
Purchase of Issuer Call Spread	—	—	(75,703)	—	—	—	(75,703)
Comprehensive Gain on Interest Rate Swaps, net of income taxes	—	—	—	—	—	3,798	3,798
Net Loss	—	—	—	—	(29,798)	—	(29,798)
Balance—December 31, 2005	54,521	$164	$375,551	$(9,684)	$(83,311)	$3,798	$286,518

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Loss	$ (29,798)	$ (24,568)	$(5,288)
Adjustments to Reconcile Net Loss to Net Cash Used In Operating Activities:			
Depreciation, Depletion and Amortization	3,702	1,324	429
Non-Cash Compensation	3,438	3,618	—
Gain on Sale of Investment in Unconsolidated Affiliate	(20,206)	—	—
Deferred Tax Benefit	(2,045)	—	—
Reimbursement from Limited Partnership Investment	—	(2,500)	—
Equity in Net Loss of Limited Partnership	1,031	1,346	4,471
Gain on Sale of LNG Assets	—	—	(4,760)
Gain on Sale of Limited Partnership Interest	—	—	(423)
Minority Interest	(97)	(2,862)	(3,015)
Non-Cash Derivative Gain	(871)	—	—
Other	1,857	(18)	(4)
Changes in Operating Assets and Liabilities			
Accounts Receivable—Affiliates	—	1,000	—
Other Accounts Receivable	(320)	(890)	230
Prepaid Expenses	(280)	(257)	(483)
Deferred Revenue	18,000	22,000	—
Accounts Payable and Accrued Liabilities	7,195	1,146	1,284
NET CASH USED IN OPERATING ACTIVITIES	(18,394)	(661)	(7,559)
CASH FLOWS FROM INVESTING ACTIVITIES:			
LNG Terminal Construction-In-Progress	(229,705)	—	—
Investment in Restricted Cash and Cash Equivalents	(177,385)	—	—
Advance to EPC Contractor, net of transfers to Construction- In-Progress	(8,087)	—	—
Purchases of Fixed Assets	(5,811)	(915)	(341)
Investment in Limited Partnership	(2,102)	(275)	
Oil and Gas Property Additions	(3,861)	(2,025)	(2,514)
Proceeds from Sale of Investment in Unconsolidated Affiliate	20,206	—	—
Reimbursement from Limited Partnership Investment	—	2,500	—
Sale of LNG Assets	—	—	1,873
Sale of Interest in Oil and Gas Prospects	1,235	2,381	392
Other	(639)	(481)	620
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	(406,149)	1,185	30
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from Issuances of Notes Payable	—	—	1,225
Issuance of Convertible Senior Unsecured Notes	325,000	—	—
Proceeds from Term Loan	600,000	—	—
Repayment of Term Loan	(1,500)	—	—
Purchase of Issuer Call Spread	(75,703)	—	—
Debt Issuance Costs	(42,124)	(1,302)	—
Sale of Common Stock	2,972	320,933	4,429
Offering Costs	(27)	(15,050)	(57)
Repayment of Note Payable	—	(1,000)	(225)
Partnership Contributions by Minority Owner	74	3,080	2,825
NET CASH PROVIDED BY FINANCING ACTIVITIES	808,692	306,661	8,197
NET INCREASE IN CASH AND CASH EQUIVALENTS	384,149	307,185	668
CASH AND CASH EQUIVALENTS—BEGINNING OF YEAR	308,443	1,258	590
CASH AND CASH EQUIVALENTS—END OF YEAR	$ 692,592	$308,443	$ 1,258

The accompanying notes are an integral part of these 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 company engaged, through its subsidiaries, in the energy business generally. As used in these Notes to Consolidated Financial Statements, the terms "we", "us" and "our" refer to Cheniere Energy, Inc. and its subsidiaries. We are currently engaged primarily in the business of developing and constructing, and then owning and operating, a network of three onshore LNG receiving terminals, and related natural gas pipelines, along the Gulf Coast of the United States. We are also engaged, to a limited extent, in oil and natural gas exploration and development activities in the Gulf of Mexico.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

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 and cost methods of accounting. All significant intercompany accounts and transactions have been eliminated in consolidation. Certain items in the prior year financial statements have been reclassified to conform with the 2005 presentation.

All references to issued and outstanding shares, weighted average shares, and per share amounts in the accompanying consolidated financial statements have been retroactively adjusted to reflect our two-for-one stock split that occurred on April 22, 2005.

Accounting for LNG Activities

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 natural gas pipelines.

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

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

Full Cost Method of Accounting

We follow the full cost method of accounting for our oil and gas properties. Under this method, all productive and nonproductive exploration and development costs incurred for the purpose of finding oil and gas reserves are capitalized. Such capitalized costs include lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, together with internal costs directly attributable to property acquisition, exploration and development activities. We capitalized general and administrative expenses, totaling $927,000, $1,569,000 and $976,000 for the years 2005, 2004 and 2003, respectively.

The costs of our oil and gas properties, including the estimated future costs to develop proved reserves and the carrying amounts of any asset retirement obligations, are depreciated using a composite unit-of-production rate based on estimates of proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, then the amount of the impairment is added to the capitalized costs being amortized. Net capitalized costs are limited to a capitalization ceiling, calculated on a quarterly basis as the aggregate of the present value, discounted at 10%, of estimated future net revenues from proved reserves (based on current economic and operating conditions), but excluding asset retirement obligations, plus the lower of cost or fair market value of unproved properties, less related income tax effects.

Our allocation of seismic exploration costs between proved and unproved properties involves an estimate of the total reserves to be discovered through our exploration program. This estimate includes a number of assumptions that we have incorporated into a three-year plan. Such factors include an estimate of the number of exploration prospects generated, prospect reserve potential, success ratios and ownership interests. We transfer seismic exploration costs to proved properties based on a ratio of proved reserves discovered at a point in time to the estimate of total reserves to be discovered in our exploration program. The carrying value of unproved properties is evaluated for possible impairment by comparing it to the estimated future net cash flows associated with the estimated total reserves to be discovered in our exploration program. To the extent that the carrying value of unproved properties is greater than the estimated future net revenue, any excess is transferred to proved properties. It is reasonably possible, based on the results obtained from future drilling and prospect generation, that revisions to this estimate of total reserves to be discovered could affect our capitalization ceiling.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved oil and gas reserves.

We account for the retirement of our tangible long-lived assets in accordance with SFAS No. 143, "*Accounting for Asset Retirement Obligations*". SFAS No. 143 requires us to record the fair value of a liability for legal obligations associated with the retirement of tangible long-lived assets and a corresponding increase in the carrying amount of the related long-lived assets. Subsequently, the asset retirement costs included in the carrying amount of the related asset are allocated to expense using the unit-of-production method used to depreciate oil and gas properties under the full cost method of accounting.

On January 1, 2003, the date of adoption of SFAS No. 143, we had no legal obligations associated with the retirement of any long-lived assets, as all of our oil and gas property interests were non-cost bearing overriding royalty interests, or ORRI. In 2004, we converted an ORRI to a working interest at well payout. As a result, we recorded $97,000, the present value of the expected abandonment cost of the well and related equipment, as a long-term asset retirement obligation and a corresponding amount to proved oil and gas properties. Accretion expense for 2005 and 2004 was $3,000 and $2,000, respectively, and was included in depreciation, depletion and amortization expense. The resulting long-term asset retirement obligation was $102,000 at December 31, 2005.

Revenue Recognition

LNG regasification capacity fees are recognized as revenue over the term of the respective terminal use agreement, or TUA. Advance capacity reservation fees are initially deferred.

Revenues from the sale of oil and gas production are recognized upon passage of title, net of royalty interests. When sales volumes differ from our entitled share, an under produced 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, 2005 and 2004, we had no gas imbalances.

Fixed Assets

Fixed assets are recorded at cost. Repairs and maintenance costs are charged to operations as incurred. Depreciation is computed using the straight-line method over estimated useful lives of the assets, which range from two to ten years. Upon retirement or other disposition of fixed assets, the cost and related accumulated depreciation are removed from the account and the resulting gains or losses are recorded.

Offering Costs

Offering costs consist primarily of underwriter's fees, placement fees, professional fees, legal fees and printing costs. These costs are charged against the related proceeds from the sale of common stock in the periods in which they occur or charged to expense in the event of a terminated offering.

Income Taxes

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

Cash Flow Hedges

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

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires that we make 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. Depletion of oil and gas properties is determined using estimates of proved oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves. Similarly, total reserves to be discovered through our exploration program are subject to numerous uncertainties including estimates of future recoverable reserves and commodity price outlook. Other estimates which may impact our financial statements include the fair value of our interest rate derivatives and estimates used in determining the effectiveness of derivatives designated as hedges.

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.

Commodity Price Risk

We produce and sell natural gas, crude oil and condensate. As a result, our financial results can be affected as these commodity prices fluctuate widely in response to changing market forces. We had not entered into any commodity hedging transactions as of December 31, 2005.

Concentration of Credit Risk

All of our revenues are attributable to properties operated by three companies. These companies sell our share of production for us, pay the associated severance taxes, and remit the balance to us. Our products are commodities and have a readily available market for sale.

We maintain funds in bank accounts that exceed the limit insured by the Federal Deposit Insurance Corporation, or FDIC. Accounts are guaranteed by the FDIC up to $100,000. The risk of loss attributable to these uninsured balances is mitigated by depositing funds only in commercial banks with minimum Standard & Poor's and Moody's Investor Service ratings of A and Aa3, respectively. We have not experienced any losses in such accounts.

We have entered into certain long-term TUAs with unaffiliated third parties for regasification capacity at our proposed 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 with creditworthy third-party customers with a minimum Standard & Poor's rating of AA.

Goodwill

As further described in Note 9—"Goodwill", we account for goodwill in accordance with the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*. Under the provisions of that statement, we are required to perform an annual review of goodwill for impairment. This review is required to be done at the reporting unit level, which we have determined to be our LNG receiving terminals business, which is a component of our LNG receiving terminal development business segment. We perform the annual review for possible impairment in the fourth calendar quarter of each year. If an event or change in circumstances indicate the fair value of a reporting unit may be below its carrying value, an impairment test would be performed sooner than the annual review date.

Debt Issuance Costs

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

Stock-Based Compensation

SFAS No. 123, *Accounting for Stock-Based Compensation*, encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation—Transition and Disclosure—an amendment of SFAS No. 123*, to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. The statement also amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used on reported results.

We have chosen to continue to account for stock-based compensation issued to employees using the intrinsic value method prescribed in Accounting Principles Board, or APB, Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the quoted market price of our stock at the date of the grant over the amount an employee must pay to acquire the stock. We grant options at or above the market price of its common stock at the date of each grant.

The fair value of options is calculated using the Black-Scholes option-pricing model. Had we adopted the fair value method of accounting for stock-based compensation, compensation expense would have been higher, and net loss attributable to common stockholders would have increased for the periods presented. No change in cash flows would occur. The effects of applying SFAS No. 123 in this pro forma disclosure are not indicative of future amounts.

	Year Ended December 31,		
	2005	2004	2003
	(in thousands, except per share amounts)		
Net loss as reported	$(29,798)	$(24,568)	$(5,288)
Add: Stock-based employee compensation included in net loss	61	—	—
Deduct:			
Total stock-based employee compensation expense determined under fair value method for all awards, net of related income tax	(13,045)	(2,206)	(967)
Pro forma net loss	$(42,782)	$(26,774)	$(6,255)
Net loss per share			
Basic and diluted—as reported	$ (0.56)	$ (0.63)	$ (0.18)
Basic and diluted—pro forma	$ (0.81)	$ (0.69)	$ (0.21)

From our inception, we have recorded annual net operating losses for both financial reporting purposes and for federal and state income tax reporting purposes. Accordingly, we are not presently a taxpayer, and therefore there is no tax effect on stock-based employee compensation expense.

The weighted average fair value of warrants and options granted as employee compensation during 2005, 2004 and 2003 was $20.16, $5.82 and $0.72, respectively. The fair values were determined using the Black-Scholes option-pricing model with the following weighted average assumptions, and a forfeiture rate that is assumed to be negligible:

	Year Ended December 31,		
	2005	2004	2003
Dividend yield	0.0%	0.0%	0.0%
Weighted average volatility	96.3%	95.9%	107.5%
Risk-free interest rate	4.2%	3.4%	3.0%
Expected lives of options	6.4 years	4.0 years	4.0 years

Net Loss Per Share

Net loss per share, or EPS, is computed in accordance with the requirements of SFAS No. 128, *Earnings Per Share*. Basic EPS excludes dilution and is computed by dividing net income (loss) by the weighted average number of common shares outstanding during the period. Diluted EPS reflects potential dilution and is computed by dividing net income by the weighted average number of common shares outstanding during the period increased by the number of additional common shares that would have been outstanding if the potential common shares had been issued. Basic and diluted EPS for all periods presented are the same since the effect of our options and warrants is anti-dilutive to our net loss per share under SFAS No. 128. Stock options, warrants and unvested stock representing securities that could potentially dilute basic EPS in the future that were not included in the diluted computation because they would have been anti-dilutive for the years 2005, 2004 and 2003 were 5,680,000, 3,133,000 and 6,519,000 respectively. In addition, common shares of 3,972,000 on a weighted average basis, issuable upon conversion of the Convertible Senior Unsecured Notes (described in Note 14—"Long-Term Debt"), were not included in the computation of diluted net loss per share for 2005 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.

We entered into an issuer call spread (an instrument that combines the purchase and sale of call options on our common stock) to offset the potential dilution from conversion of our Convertible Senior Unsecured Notes. Purchased call options are always excluded from the calculation of diluted earning per share because they are anti-dilutive. SFAS No. 128 requires that we include the sold call options in the calculation of diluted earnings per share using the treasury stock method whenever the average market price of our common shares exceeds the strike price of the call options. The strike price of the sold call options is $70 per share, which is greater than the average market price of our common stock for 2005; thus, the sold call options were not included in the calculation of diluted earning per share. The total number of shares that could potentially be included under the sold call options is 9,176,000.

New Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment*, that addresses the accounting for share-based payment transactions in which a company receives employee services in exchange for equity instruments of the company, such as stock options and non-vested stock. SFAS No. 123R eliminates the ability to account for share-based compensation transactions using APB Opinion No. 25 and requires instead that such transactions be accounted for using a fair value-based method. From inception through December 31, 2005, we have accounted for stock-based compensation using the intrinsic method pursuant to APB Opinion No. 25. SFAS No. 123R requires that all stock-based payments to employees, including grants of employee stock options and non-vested stock, be recognized as compensation expense in the financial statements based on their fair values (intrinsic valued in the case of restricted stock) at the time such awards are granted. SFAS No. 123R is effective January 1, 2006 for companies with fiscal years ending December 31. Accordingly, we will begin reporting the results of SFAS No. 123R on our operations in the quarter ending March 31, 2006. We are adopting the new standard using the modified-prospective transition method. The adoption of the new standard will have a significant future impact on our results of operations, but will have no impact on our future cash flows. Had we adopted SFAS No. 123R in prior periods, the effects of that standard on net income and earnings per share would have been approximately the same as the effects of SFAS No. 123 shown in the Stock-Based Compensation proforma disclosure presented previously.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections—A Replacement of APB Opinion No. 20 and FASB Statement No. 3*. SFAS No. 154 changes the requirements for accounting and reporting on a change in accounting principle, while carrying forward the guidance in APB Opinion No. 20, *Accounting Changes* and FASB Statement No. 3, *Reporting Accounting Changes in Interim Financial Statements*, with respect to accounting for changes in estimates, changes in the reporting entity and the correction of errors. APB Opinion No. 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change, the cumulative effect of changing to the new accounting principle. SFAS No. 154 requires retrospective application to prior periods' financial statements for voluntary changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The impact of SFAS No. 154 will depend on an accounting change that may occur in a future period.

In October 2005, the FASB issued FSP 13-1, *Accounting for Rental Costs Incurred During a Construction Period*, to address the accounting for rental costs associated with operating leases that are incurred during a construction period. FSP 13-1 requires rental costs associated with ground or building operating leases that are incurred during a construction period to be recognized as rental expense. FSP 13-1 is effective in fiscal years beginning after December 15, 2005. Accordingly, we will adopt the new standard in the quarter ending March 31, 2006. As of December 31, 2005, we have capitalized $1,501,000 in rental costs related to our Sabine Pass LNG receiving terminal site lease. We began expensing these rental costs effective January 1, 2006.

NOTE 3—RESTRICTED CASH AND CASH EQUIVALENTS

In February 2005, Sabine Pass LNG, L.P., our wholly-owned subsidiary, or Sabine Pass LNG, entered into an $822,000,000 credit facility, or the Sabine Pass Credit Facility, with an initial syndicate of 47 financial institutions. Société Générale serves as the administrative agent and HSBC Bank USA, National Association, or HSBC, serves as collateral agent. Under the terms and conditions of the Sabine Pass Credit Facility, all cash held by Sabine Pass LNG is controlled by the collateral agent. These funds can only be released by the collateral agent upon receipt of satisfactory documentation that the Sabine Pass LNG Phase 1 project costs are bona fide expenditures and are permitted under the terms of the Sabine Pass Credit Facility. The Sabine Pass Credit Facility does not permit Sabine Pass LNG to hold any cash, or cash equivalents, outside of the accounts established under the agreement. Because these cash accounts are controlled by the collateral agent, the Sabine Pass LNG cash balance of $8,871,000 held in these accounts as of December 31, 2005 is classified as restricted on our balance sheet.

In August 2005, Cheniere LNG Holdings, LLC, our wholly-owned subsidiary, or Cheniere LNG Holdings, entered into a $600,000,000 Senior Secured Term Loan, or the Term Loan, with Credit Suisse, Cayman Islands

Branch, or Credit Suisse, who also serves as collateral agent and administrative agent. Under the conditions of the Term Loan, Cheniere LNG Holdings was required to fund from the loan proceeds a total of $216,200,000 into two collateral accounts: $181,000,000 into a debt service reserve collateral account and $35,200,000 into a capital contribution reserve collateral account. These funds are restricted to the payment of interest and principal due under the Term Loan, reimbursement of certain expenses, and funding of additional capital contributions to Sabine Pass LNG as required under the Sabine Pass Credit Facility. As of December 31, 2005, all additional capital contributions contemplated by the Term Loan have been funded to Sabine Pass LNG. Because the accounts are controlled by the collateral agent, our cash and cash equivalent balance of $168,514,000 held in these accounts as of December 31, 2005 is classified as restricted on our consolidated balance sheet. Of this amount, $16,500,000 is classified as non-current due to the timing of certain required debt amortization payments.

NOTE 4—RESTRICTED CERTIFICATE OF DEPOSIT AND LETTER OF CREDIT

Under the terms of our office lease, we are required to post a standby letter of credit in favor of the lessor. The initial amount of the letter of credit was increased from $865,000 to $1,123,000 in April 2004, which related to the expansion of our office space; and the amount will be reduced by approximately $225,000 per annum over a five-year period. This letter of credit was initially established under the terms of our bank line of credit in effect at that time.

Upon the termination of our bank line of credit in June 2004, we purchased a certificate of deposit in the amount of $1,123,000 and entered into a pledge agreement in favor of the commercial bank that had previously issued the standby letter of credit for $1,123,000. In October 2004 and 2005, both the letter of credit and certificate of deposit were amended to decrease the face amounts by approximately $225,000 to $898,000 and $674,000, respectively. The current letter of credit and the certificate of deposit both mature on November 30, 2006. Under the terms of the pledge agreement, the commercial bank was assigned a security interest in the certificate of deposit as collateral for the letter of credit. As a result, the certificate of deposit plus $2,000 of accrued interest is classified as restricted on our balance sheet at December 31, 2005.

NOTE 5—ADVANCES TO EPC CONTRACTOR

In December 2004, Sabine Pass LNG entered into a lump-sum turnkey EPC contract with Bechtel Corporation, or Bechtel, to construct the initial phase, or Phase 1, of the Sabine Pass LNG receiving terminal. Under the EPC contract, we were required to make a 5% advance payment to Bechtel upon issuance of the final notice to proceed, or NTP, related to the construction of Phase 1. A payment of $32,347,000 was made to Bechtel in March 2005 when the NTP was issued and that amount was classified on our consolidated balance sheet as a current asset. In accordance with the payment schedule included in the EPC contract, $2,696,000 per month is being reclassified to construction-in-progress over a twelve-month period. As of December 31, 2005, the remaining balance of the advance was $8,087,000.

NOTE 6—PROPERTY, PLANT AND EQUIPMENT

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

	December 31,	
	2005	2004
LNG TERMINAL COSTS		
LNG terminal construction-in-progress	$271,142	$ —
LNG site and related costs, net	1,249	786
Total LNG Terminal Costs	272,391	786
OIL AND GAS PROPERTIES, full cost method		
Proved	5,787	3,339
Unproved	17,216	16,688
Accumulated depreciation, depletion and amortization	(3,386)	(971)
Total Oil and Gas Properties, net	19,617	19,056
FIXED ASSETS		
Computers and office equipment	3,611	905
Furniture and fixtures	1,145	523
Computer software	1,640	334
Leasehold improvements	1,757	100
Other	26	—
Accumulated depreciation	(2,104)	(824)
Total Fixed Assets, net	6,075	1,038
PROPERTY, PLANT AND EQUIPMENT, net	$298,083	$20,880

In February 2005, Phase 1 of our Sabine Pass LNG project satisfied the criteria for capitalization. Accordingly, costs associated with the construction of Phase 1 of our Sabine Pass LNG project have been capitalized as construction-in-progress since that time.

We have made investments in acquiring, processing and reprocessing our seismic databases covering a 6,800-square-mile project area offshore Texas and Louisiana and a 228-square-mile project area onshore and offshore Louisiana. The costs of these projects become subject to amortization on a ratable basis as the oil and gas reserves expected to be recovered from the projects are discovered. We began drilling prospects identified within our seismic databases in 1999. We did not participate directly in drilling any wells during the period from 2001 through 2004, but we retained overriding royalty interests in wells drilled by others on prospects we generated during such period; however, in 2005, we participated directly in the drilling of two wells.

Depreciation, depletion and amortization of oil and gas property costs totaled $2,415,000, $835,000 and $121,000 for the years ended December 31, 2005, 2004 and 2003, respectively. Depreciation, depletion and amortization per equivalent Mcf (using an Mcf-to-barrel conversion factor of 6 to 1) was $5.90, $2.48 and $0.98 for the years ended December 31, 2005, 2004 and 2003, respectively.

Depreciation expense related to our fixed assets totaled $1,284,000, $410,000 and $165,000 for the years ended December 31, 2005, 2004 and 2003, respectively.

NOTE 7—DEBT ISSUANCE COSTS

As of December 31, 2005, we have capitalized $43,008,000 of costs directly associated with the arrangement of debt financing, net of accumulated amortization, as follows:

Debt Facility	Debt Issuance Costs	Amortization Period (1)	Accumulated Amortization	Net Costs
Sabine Pass Credit Facility (2)	$20,176,000	10 years	$(1,679,000)	$18,497,000
Convertible Senior Unsecured Notes (3)	9,542,000	7 years	(589,000)	8,953,000
Term Loan (4)	16,083,000	7 years	(761,000)	15,322,000
Other	236,000	—	—	236,000
	$46,037,000		$(3,029,000)	$43,008,000

(1) Debt issuance costs are amortized over the term of the related debt facility.

(2) Although no borrowings were outstanding as of December 31, 2005, the amortization of the debt issuance cost is recorded to interest expense and subsequently capitalized as construction-in-progress during the construction period of the Sabine Pass LNG receiving terminal. For the year ended December 31, 2005, the amount amortized and capitalized was $1,679,000.

(3) For the year ended December 31, 2005, the amount amortized to interest expense was $589,000.

(4) For the year ended December 31, 2005, the amount amortized to interest expense was $761,000.

Scheduled amortization of these debt issuance costs for each of the next five years is estimated at $5,693,000.

NOTE 8—INVESTMENT IN LIMITED PARTNERSHIP

In August 2002, we entered into an agreement with entities controlled by Michael S. Smith, or Smith entities, to sell a 60% interest in the Freeport site and project. On February 27, 2003, we sold our interest in the site and project to Freeport LNG Development, L.P., or Freeport LNG, in which we held a 40% limited partner interest. Smith entities held the general partner interest and remaining 60% limited partner interest in Freeport LNG. We recovered $1,740,000 in costs that we had incurred on the project and received an additional $5,000,000 ($2,500,000 during 2003 and $2,500,000 in January 2004) from Freeport LNG. For the funding of Freeport LNG project development costs, Smith entities also committed to contribute up to $9,000,000 and to allocate available proceeds from any sales of options or capacity reservations and/or proceeds from loans related to capacity reservations to these costs. In connection with the closing, we issued warrants to Smith entities to purchase 1,400,000 shares of our common stock at a price of $1.25 per share, exercisable for a period of 10 years.

We accounted for the transfer of the site and planned LNG receiving terminal to Freeport LNG in accordance with Emerging Issues Task Force, or EITF, Issue No. 01-2, *Interpretations of APB Opinion No. 29*. Accordingly, in 2003 we recorded a $4,760,000 gain on sale of LNG assets to the extent of the 60% interest not retained.

Effective March 1, 2003, we sold a 10% limited partner interest in Freeport LNG to an affiliate of Contango Oil & Gas Company, or Contango, for $2,333,000 payable over time, including the cancellation of our $750,000 short-term note payable. We also issued warrants to Contango to purchase 600,000 shares of our common stock at a price of $1.25 per share, exercisable for a period of 10 years. As a result of the sale, we now hold a 30% limited partner interest in Freeport LNG. In December 2004, a subsidiary of The Dow Chemical Company, or Dow, acquired a 15% limited partner interest in Freeport LNG from one of the Smith entities, thereby reducing its limited partner interest from 60% to 45%.

We account for our 30% limited partnership investment in Freeport LNG using the equity method of accounting. During 2003, we received installment payments totaling $2,500,000 from Freeport LNG, which amounts were recorded as a reduction to the basis of our investment in the partnership. In addition, we recorded $4,471,000 related to our 30% equity share of the 2003 net loss of Freeport LNG. This non-cash loss reduced the basis of our investment in Freeport LNG to zero, and as a result, we did not record $278,000, or the 2003 Suspended Loss, of our equity share of the loss of the partnership as of December 31, 2003 because we did not guarantee any obligations of Freeport LNG and had not committed to provide additional financial support to Freeport LNG at that time.

In January 2004, we received the final $2,500,000 payment from Freeport LNG. As our investment basis in Freeport LNG had been reduced to zero as of December 31, 2003, the payment was recorded as a reimbursement from limited partnership investment in our consolidated statement of operations.

During 2004, we recorded $1,346,000 related to our 30% equity share of the 2004 net loss of Freeport LNG, including the 2003 Suspended Loss. This $1,346,000 non-cash loss reduced our investment basis to zero and resulted in our recording accrued losses on investment in limited partnership of $1,071,000 as of December 31, 2004. We accrued this liability, as we intended to provide additional financial support through the payment of outstanding capital call notices as of December 31, 2004. This additional financial support was provided in 2005 as a portion of the capital call payments discussed below.

During 2005, we paid $2,102,000 of capital call contributions to Freeport LNG. In addition, we recognized an equity loss in the amount of $1,031,000 relating to the net loss of Freeport LNG. Our total 30% equity share of the 2005 net loss of Freeport LNG was $4,999,000 of which $3,968,000 was suspended, or the 2005 Suspended Loss. In December 2005, Freeport LNG announced that it had closed a $383,000,000 private placement of notes, which would be used to fund the remaining portion of the initial phase of the project, a portion of the cost of expanding the LNG receiving terminal and development of underground salt cavern gas storage. Accordingly, we do not currently have the obligation or intent to fund our suspended losses in the foreseeable future. As a result, as of December 31, 2005, the basis of our equity investment in Freeport LNG was zero, and we did not have any accrued losses.

The financial position of Freeport LNG at December 31, 2005 and 2004 and the results of Freeport LNG's operations for the years ended December 31, 2005, 2004 and 2003 are summarized as follows (in thousands):

	December 31,	
	2005	2004
Current assets	$380,615	$38,106
Construction-in-progress	246,351	9,728
Fixed assets, net, and other assets	9,309	592
Total assets	$636,275	$48,426
Current liabilities	$ 53,533	$ 5,676
Notes payable	595,766	48,041
Deferred revenue and other deferred credits	5,748	3,500
Partners' capital	(18,772)	(8,791)
Total liabilities and partners' capital	$636,275	$48,426

	Year Ended December 31,		
	2005	2004	2003
Revenue	$ —	$10,000	$ —
Loss from continuing operations	(16,238)	(3,569)	(14,940)
Net loss	(16,663)	(3,561)	(14,940)
Cheniere's equity in loss from limited partnership (adjusted for suspended losses)	$ (1,031)	$ (1,346)	$ (4,471)

NOTE 9—GOODWILL

In February 2005, we acquired the minority interest of Corpus Christi LNG, L.P., or Corpus Christi LNG, through the acquisition of BPU LNG, Inc., or BPU, in exchange for 2,000,000 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 now own 100% of the limited partner interest in Corpus Christi LNG. This transaction was accounted for using the purchase method of accounting as prescribed by SFAS No. 141, *Accounting for Business Combinations*, and was valued at $77,246,000, including direct transaction costs. Of this amount, $76,844,000 has been recorded as goodwill and will be accounted for in accordance with SFAS No. 142. The goodwill is the difference between the deemed value of the shares conveyed and the historical carrying value of the minority interest under generally accepted accounting principles plus direct transaction costs. For the calculation of federal income taxes, none of this goodwill amount will be deductible.

We performed an annual goodwill impairment review in the fourth quarter of 2005. A goodwill impairment review consists of comparing the carrying value, including goodwill, of the reporting unit under review, to the estimated fair value of the reporting unit. To the extent that the carrying value exceeds the estimated fair value of the reporting unit, an impairment of the reporting unit would occur 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 review, we have designated our LNG receiving terminal business as the reporting unit under review due to similar economic characteristics. Our review indicated that no impairment of goodwill was necessary.

Because BPU's sole asset was the 33.3% limited partner interest in Corpus Christi LNG, which was consolidated in our financial statements, we do not believe that pro forma financial statements would provide any additional benefit to an investor in our common stock. As a result, we have not prepared pro forma financial statements related to the transaction.

NOTE 10—DERIVATIVE INSTRUMENTS

Interest Rate Derivative Instruments

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

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

Accounting for Hedges

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

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

SFAS No. 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income, or OCI, and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. In our case, the impact on earnings is reflected in interest expense. The ineffective portion of the gain or loss on the derivative instrument, if any, must be recognized currently in earnings. For the year ended December 31, 2005, we have recognized net derivative gains of $837,000 into earnings. If the forecasted transaction is no longer probable of occurring, the associated gain or loss recorded in OCI is recognized currently in earnings.

Summary of Derivative Values

The following table reflects the amounts that are recorded as assets and liabilities at December 31, 2005 for our derivative instruments (in thousands):

	Interest Rate Derivative Instruments
Current derivative assets	$5,468
Derivative receivables (1)	1,175
Long-term derivative assets	1,837
Total derivative assets	8,480
Current derivative liabilities	—
Derivative payables (2)	84
Long-term derivative liabilities	1,682
Total derivative liabilities	1,766
Net derivative assets	$6,714

(1) Included in Accounts Receivable on the Consolidated Balance Sheet.

(2) Included in Accrued Liabilities on the Consolidated Balance Sheet.

Below is a reconciliation of our net derivative assets to our accumulated other comprehensive income at December 31, 2005 (in thousands):

Net derivative assets	$ 6,714
Net derivative gains recognized into earnings	(837)
Other comprehensive income reclassified to interest expense	(15)
Cash settled derivative losses during the period	(19)
Accumulated other comprehensive income, before income taxes	5,843
Income taxes on accumulated other comprehensive income	(2,045)
Accumulated other comprehensive income, after income taxes	$ 3,798

For the year ended December 31, 2005, we settled derivative contracts that resulted in $391,000 of net realized derivative gains. The maximum length of time over which we have hedged our exposure to the variability in future cash flows for forecasted transactions is seven years under the Swaps. As of December 31, 2005, $6,259,000 of accumulated net deferred gains on the Swaps, currently included in other comprehensive income, are expected to be reclassified to earnings during the next twelve months, assuming no change in the LIBOR forward curves at December 31, 2005. The actual amounts that will be reclassified will likely vary based on the probability that interest rates will, in fact, change. Therefore, management is unable to predict what the actual reclassification from OCI to earnings (positive or negative) will be for the next twelve months.

NOTE 11—ACCRUED LIABILITIES

Accrued liabilities consist of the following (in thousands):

	December 31,	
	2005	2004
LNG terminal construction costs	$39,728	$ —
Accrued interest expense and related fees	4,937	—
Debt issuance costs	3,083	—
Payroll	2,460	—
LNG terminal development expenses	1,534	1,611
Professional and legal services	1,043	342
Insurance expense	41	488
Other accrued liabilities	1,718	755
Accrued liabilities	$54,544	$3,196

NOTE 12—DEFERRED REVENUE

In December 2003, we entered into a shareholders agreement whereby we became a minority owner of J & S Cheniere S.A., a Switzerland joint-stock company, or J & S Cheniere. The majority owner is J & S Energy Holding B.V., or J & S Holding, a Netherlands corporation affiliated with J & S Trading Company, Ltd., an international petroleum trading and marketing company. J & S Cheniere was formed for the purpose of buying, selling, transporting and trading LNG. Pursuant to the shareholders agreement, we identify and assist with LNG-related business opportunities that we determine are appropriate for J & S Cheniere. We are not required to offer any particular business opportunities or funding to J & S Cheniere. We have no board of director representation nor do we participate in the day-to-day management of J & S Cheniere. All financing of the business opportunities will be provided by J & S Holding should it determine that a business opportunity is appropriate for J & S Cheniere. However, J & S Holding is not required to fund any particular business opportunity. We account for this investment using the cost method of accounting. At December 31, 2005, Cheniere's investment basis was $16,000.

Also in December 2003, we entered into an option agreement with J & S Cheniere under which J & S Cheniere has an option to enter into a TUA reserving up to 200 MMcf/d of capacity at each of our Sabine Pass and Corpus Christi LNG facilities. We were paid $1,000,000 in January 2004 following execution of the option agreement by J & S Cheniere in January 2004. The terms of the TUA contemplated by the J & S Cheniere option agreement have not been negotiated or finalized. We anticipate that definitive arrangements with J & S Cheniere may involve different terms and transaction structures than were contemplated when the option agreement was entered into in December 2003. Although non-refundable, we have recorded the option fee as deferred revenue.

In November 2004, Total LNG USA, Inc., or Total, paid Sabine Pass LNG a nonrefundable advance capacity reservation fee of $10,000,000 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 $10,000,000 was paid by Total to Sabine Pass LNG in April 2005. The advance capacity reservation fee payments will be amortized over a 10-year period after operations commence as a reduction of Total's regasification capacity fee under its TUA. As a result, we record the advance capacity reservation payments that we receive, although non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

Also in November 2004, we entered into a TUA to provide Chevron USA, Inc., or Chevron USA, with approximately 700 MMcf/d of LNG regasification capacity at our Sabine Pass LNG receiving terminal. In December 2005, Chevron USA exercised its option to increase its reserved capacity by approximately 300 MMcf/d to approximately 1.0 Bcf/d and paid Sabine Pass LNG an additional $3,000,000 advance capacity reservation fee. As of December 31, 2005, Chevron USA has made advance capacity reservation fee payments to Sabine Pass LNG totaling $20,000,000, with $12,000,000 paid in 2004 and $8,000,000 paid in 2005. These capacity reservation fee payments will be amortized over a 10-year period as a reduction of Chevron USA's regasification capacity fee under the TUA. As a result, we record the advance capacity reservation payments that we receive, although non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

As of December 31, 2005 and 2004, we had recorded $41,000,000 and $23,000,000, respectively, as deferred revenue related to option and advance capacity reservation fee payments.

NOTE 13—MINORITY INTEREST IN LIMITED PARTNERSHIP

In May 2003, we formed a limited partnership, Corpus Christi LNG, L.P., or Corpus Christi LNG, to develop an LNG receiving terminal near Corpus Christi, Texas. Under the terms of the limited partnership agreement, we contributed our technical expertise and know-how, and all of the work in progress related to the Corpus Christi project, in exchange for a 66.7% limited partner interest in Corpus Christi LNG.

Substantially all Corpus Christi LNG expenditures incurred through March 31, 2004 were the obligation of the minority owner, since the minority owner was required to fund 100% of the first $4,500,000 of partnership expenditures. Because partnership expenditures had reached $4,500,000 as of March 31, 2004, the minority owner began sharing all subsequent expenditures based on its 33.3% limited partner interest.

In February 2005, we acquired the minority interest of Corpus Christi LNG through the acquisition of BPU. As a result of this transaction, we now own 100% of the limited partner interest of Corpus Christi LNG and are required to fund 100% of expenditures incurred after such date. We also manage the project as the general partner through one of our wholly-owned subsidiaries.

For the years ended December 31, 2005, 2004 and 2003, our consolidated statement of operations includes $97,000, $2,862,000 and $3,015,000, respectively, related to the minority interest of Corpus Christi LNG.

NOTE 14—LONG-TERM DEBT

As of December 31, 2005 and 2004, our long-term debt is comprised of the following (in thousands):

	December 31, 2005	December 31, 2004
Sabine Pass Credit Facility	$ —	$—
Convertible Senior Unsecured Notes	325,000	—
Term Loan	598,500	—
	923,500	—
Less: Current Portion—Term Loan	(6,000)	—
Total Long-Term Debt	$917,500	$—

Below is a schedule of future principal payments that we are obligated to make based on our outstanding long-term debt at December 31, 2005 (in thousands):

	Payments Due for Years Ended December 31,						
	Total	2006	2007	2008	2009	2010	Thereafter
Term Loan	$598,500	$6,000	$6,000	$6,000	$6,000	$6,000	$568,500
Convertible Senior Unsecured Notes	325,000	—	—	—	—	—	325,000
Total	$923,500	$6,000	$6,000	$6,000	$6,000	$6,000	$893,500

Sabine Pass Credit Facility

In February 2005, Sabine Pass LNG entered into the $822,000,000 Sabine Pass Credit Facility with an initial syndicate of 47 financial institutions. Société Générale serves as the administrative agent and HSBC serves as collateral agent. The Sabine Pass Credit Facility will be used to fund a substantial majority of the costs of constructing and placing into operation Phase 1 of our Sabine Pass LNG receiving terminal. Unless Sabine Pass LNG decides to terminate availability earlier, the Sabine Pass Credit Facility will be available until no later than April 1, 2009, after which time any unutilized portion of the Sabine Pass Credit Facility will be permanently canceled. Before Sabine Pass LNG could make an initial borrowing under the Sabine Pass Credit Facility, it was required to provide evidence that it had received equity contributions in an amount sufficient to fund $233,715,000 of the project costs. As of December 31, 2005, the $233,715,000 in equity contributions had been funded. At December 31, 2005, there were no borrowings outstanding; however, as of February 28, 2006, $58,500,000 had been drawn under the Sabine Pass Credit Facility.

Borrowings under the Sabine Pass Credit Facility bear interest at a variable rate equal to LIBOR plus the applicable margin. The applicable margin varies from 1.25% to 1.625% during the term of the Sabine Pass Credit Facility. The Sabine Pass Credit Facility provides for a commitment fee of 0.50% per annum on the daily committed, undrawn portion of the facility. Annual administrative fees must also be paid to the administrative and collateral agents. The principal of loans made under the Sabine Pass Credit Facility must be repaid in semi-annual installments commencing six months after the later of (i) the date that substantial completion of the project occurs under the EPC agreement and (ii) the commercial start date under the Total TUA. Sabine Pass LNG may specify an earlier date to commence repayment upon satisfaction of certain conditions. In any event, payments under the Sabine Pass Credit Facility must commence no later than October 1, 2009, and all obligations under the Sabine Pass Credit Facility mature and must be fully repaid by February 25, 2015.

The Sabine Pass Credit Facility contains customary conditions precedent to the initial borrowing and any subsequent borrowings, as well as customary affirmative and negative covenants. We were in compliance, in all material respects, with these covenants at December 31, 2005. Sabine Pass LNG has obtained, and may in the future seek, consents, waivers and amendments to the Sabine Pass Credit Facility documents. The obligations of Sabine Pass LNG under the Sabine Pass Credit Facility are secured by all of Sabine Pass LNG's personal property, including the Total and Chevron USA TUAs and the partnership interests in Sabine Pass LNG.

In connection with the closing of the Sabine Pass Credit Facility, Sabine Pass LNG entered into the Sabine Swaps with HSBC and Société Générale. Under the terms of the Sabine Swaps, Sabine Pass LNG will be able to hedge against rising interest rates, to a certain extent, with respect to its drawings under the Sabine Pass Credit Facility, up to a maximum amount of $700,000,000. The Sabine Swaps have the effect of fixing the LIBOR component of the interest rate payable under the Sabine Pass Credit Facility with respect to hedged drawings under the Sabine Pass Credit Facility, up to a maximum of $700,000,000 at 4.49% from July 25, 2005 to March 25, 2009, and at 4.98% from March 26, 2009 through March 25, 2012. The final termination date of the Sabine Swaps will be March 25, 2012.

During the construction period, all interest costs, including amortization of related debt issuance costs and commitment fees, will be capitalized as part of the total cost of Phase 1 of our Sabine Pass LNG receiving terminal. As of December 31, 2005, $5,323,000 in commitment fees and amortization of debt issuance costs have been capitalized and included in LNG terminal construction-in-progress.

Convertible Senior Unsecured Notes

In July 2005, we consummated a private offering of $325,000,000 aggregate principal amount of Convertible Senior Unsecured Notes due August 1, 2012 to qualified institutional buyers pursuant to Rule 144A under the Securities Act. The notes bear interest at a rate of 2.25% per year. The notes are convertible into our common stock pursuant to the terms of the indenture governing the notes at an initial conversion rate of 28.2326 per $1,000 principal amount of the notes, which is equal to a conversion price of approximately $35.42 per share. We may redeem some or all of the notes on or before August 1, 2012, for cash equal to 100% of the principal plus any accrued and unpaid interest if in the previous 10 trading days the volume-weighted average price of our common stock exceeds $53.13, subject to adjustment, for at least five consecutive trading days. In the event of such a redemption, we will make an additional payment equal to the present value of all remaining scheduled interest payments through August 1, 2012, discounted at the U.S. Treasury rate plus 50 basis points. The indenture governing the notes contains customary reporting requirements.

Concurrent with the issuance of the Convertible Senior Unsecured Notes, we also entered into hedge transactions in the form of an issuer call spread (consisting of a purchase and a sale of call options on our common stock) with an affiliate of the initial purchaser of the notes, having a term of two years, and a net cost to us of $75,703,000. These hedge transactions are expected to offset potential dilution from conversion of the notes up to a market price of $70.00 per share. The net cost of the hedge transactions is recorded as a reduction to Additional Paid-in-Capital in accordance with the guidance of the Emerging Issues Task Force, or EITF, Issue

00-19, *Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company's Own Stock*. Net proceeds from the offering were $239,786,000, after deducting the cost of the hedge transactions, the underwriting discount and related fees. As of December 31, 2005, no holders had elected to convert their notes. Total interest expense recognized for the year ended December 31, 2005 was $3,741,000 before interest capitalization of $170,000.

Term Loan

In August 2005, Cheniere LNG Holdings entered into the $600,000,000 Term Loan with Credit Suisse. The Term Loan interest rate equals LIBOR plus a 2.75% margin and terminates on August 30, 2012. In connection with the closing, Cheniere LNG Holdings entered into the Term Loan Swaps with Credit Suisse to hedge the LIBOR interest rate component of the Term Loan. The blended rate of the Term Loan Swaps on the Term Loan results in an annual fixed interest rate of 7.25% (including the 2.75% margin) for the first five years (See Note 10—"Derivative Instruments"). On December 30, 2005, Cheniere LNG Holdings made the first required quarterly principal payment of $1,500,000. Quarterly principal payments of $1,500,000 are required through June 30, 2012, and a final principal payment of $559,500,000 is required on August 30, 2012. As discussed in Note 3—"Restricted Cash and Cash Equivalents", a portion of the loan proceeds is controlled by Credit Suisse and is restricted to its use.

At December 31, 2005, principal repayments on the Term Loan of $6,000,000 are due within the next 12 months and are classified on the balance sheet as a current liability on the Term Loan. Interest expense for the year ended December 31, 2005 was $14,405,000 before interest capitalization of $603,000. The Term Loan contains customary affirmative and negative covenants. We were in compliance, in all material respects, with these covenants at December 31, 2005. The obligations of Cheniere LNG Holdings are secured by its 100% equity interest in Sabine Pass LNG and its 30% limited partner equity interest in Freeport LNG.

Note Payable

In January 2004, we repaid the $1,000,000 outstanding balance under a line of credit with a commercial bank. The line of credit was terminated in June 2004.

NOTE 15—FINANCIAL INSTRUMENTS

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

Long-Term Debt (in thousands):

	December 31, 2005	
	Carrying Amount	**Estimated Fair Value**
Term Loan due 2012 (1)	$598,500	$598,500
2.25% Convertible Senior Unsecured Notes due 2012 (2)	325,000	392,031
Sabine Pass Credit Facility (3)	—	—
	$923,500	$990,531

(1) The Term Loan bears interest based on a floating rate; therefore, the estimated fair value is deemed to equal the carrying amount of these notes.
(2) The fair value of our Convertible Senior Unsecured Notes is based on a closing trading price as of December 30, 2005.
(3) The Sabine Pass Credit Facility will bear interest based on a floating rate. No debt was outstanding under this facility at December 31, 2005.

NOTE 16—INCOME TAXES

From our inception, we have reported net operating losses for both financial reporting purposes and for federal and state income tax reporting purposes. Accordingly, we are not presently a taxpayer and have not recorded a net liability for federal or state income taxes in any of the years included in the accompanying financial statements. Our consolidated statement of operations for the years ended December 31, 2005, 2004 and 2003 includes deferred income tax benefits of $2,045,000, $-0- and $-0-, respectively. The deferred income tax benefit recorded for the year ended December 31, 2005 has been provided for in accordance with the guidance in paragraph 140 of SFAS No. 109 and EITF Abstracts, Topic D-32 which, in certain circumstances, requires items reported in OCI to be considered in the determination of the amount of tax benefit when a net operating loss occurs. In our situation, the specific circumstance relates to OCI of $5,843,000 recorded as of December 31, 2005 related to our interest rate swaps (See Note 10—"Derivative Instruments" and Note 19—"Other Comprehensive Loss" for additional discussions). The deferred tax benefit included in our 2005 consolidated statement of operations represents the portion of the change in our tax asset valuation account that is allocable to the deferred income tax on items reported in other comprehensive income in our 2005 consolidated statement of stockholders' equity.

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

	Year Ended December 31,		
	2005	2004	2003
Current federal income tax expense	$ —	$ —	$ —
Deferred federal income tax benefit	2,045	—	—
Total income tax benefit.	$2,045	$ —	$ —

Deferred tax assets and liabilities reflect the net tax effect of temporary differences between the carrying amount of assets and liabilities for financial reporting purposes and amounts used for income tax purposes. Significant components of our deferred tax assets and liabilities at December 31, 2005 and 2004 are as follows (in thousands):

	December 31,	
	2005	2004
Deferred tax assets		
NOL carryforwards	$19,310	$16,944
Advance payments—terminal use agreements	14,000	8,140
Start-up costs and construction-in-progress associated with LNG projects	11,594	6,223
Investment in limited partnership	1,755	1,250
Investment in unconsolidated affiliate	—	1,553
	46,659	34,110

	December 31, 2005	December 31, 2004
Deferred tax liabilities		
Oil and gas properties and fixed assets	4,099	4,828
Stock grant compensation expense	270	237
Unrealized gain on hedging transactions	1,968	—
	6,337	5,065
Net deferred tax assets	40,322	29,045
Less: tax asset valuation allowance	(40,322)	(29,045)
	$ —	$ —

The change in the deferred tax asset valuation allowance was $11,277,000 and $17,475,000 during the years ended December 31, 2005 and 2004, respectively.

At December 31, 2005, we had net operating loss, or NOL, carryforwards for federal income tax reporting purposes of approximately $55,172,000. In accordance with SFAS No. 109, a valuation allowance equal to our net deferred tax asset balance has been established due to the uncertainty of realizing the tax benefits related to our NOL carryforwards and other deferred tax assets.

NOL carryforwards expire starting in 2012 extending through 2025. Certain of our NOLs which were previously subject to annual utilization limitations under the Internal Revenue Code Section 382 change of ownership regulations are now available for utilization due to annual increases in the allowed NOL utilization amounts provided for in Section 382. The NOL carryforward amounts presented in the table above include approximately $11,664,000 and $8,323,000 for the years ended December 31, 2005 and 2004, respectively, of excess tax benefits related to the exercise of non-qualified employee stock options and vested stock awards. The full amount of the related tax benefit is included in our deferred tax asset valuation allowance.

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

	Year Ended December 31, 2005	2004	2003
U.S. statutory tax rate	35 %	35 %	35 %
Excess tax benefits related to exercise of non-qualified employee stock options and vested stock awards (1)	12 %	37 %	12 %
Deferred tax asset valuation reserve (2)	(36)%	(69)%	(51)%
State income tax expense (net of federal benefit) (3)	(5)%	2 %	2 %
All other	0 %	(5)%	2 %
Effective tax rate as reported	6 %	0 %	0 %

(1) As of December 31, 2005, we have elected to account for stock-based compensation in accordance with APB Opinion No. 25 (see Note 2—"Summary of Significant Accounting Policies—Stock-Based Compensation"). For federal income tax reporting purposes, we are generally allowed to claim federal income tax deductions based on the fair market value of the underlying securities on the vest date for vested stock awards and on the date of exercise for stock options. Because the stock-based compensation expense that is required to be included in our reported annual operating losses is significantly less than the amounts

that have been included in our employees' taxable incomes, the associated excess tax benefits reduce our reported effective tax rates. As discussed above, to date, approximately $11,664,000 of deferred excess tax benefits related to the exercise of non-qualified employee stock options and vested stock awards are included in our NOL carryforward amount.

(2) As discussed above, in accordance with SFAS No. 109, a valuation allowance equal to our net deferred tax asset balance has been established due to the uncertainty of realizing the federal and state deferred tax benefits related to our NOL carryforwards and other deferred tax assets.

(3) SFAS No. 109 requires us to measure our deferred income tax assets and liabilities separately for each tax jurisdiction that imposes an income tax on our operations (principally federal and state income taxes). In prior reporting periods, our reported effective tax rate included an additional 2% for certain deferred state income tax benefits related to our Texas and Louisiana exploration and development operations. We are not expecting to realize such state income tax benefits; therefore, our 2005 reported effective tax rate includes an adjustment to eliminate the related deferred state income tax benefits.

NOTE 17—WARRANTS

As of December 31, 2005, there were no outstanding warrants for the purchase of our common stock. Warrants we issued did not confer upon the holders thereof any voting or other rights of a stockholder of Cheniere. Warrants were granted in connection with certain of our debt or equity financings and as compensation for services. In instances where warrants were granted in connection with financings, such warrants were valued based on the estimated fair market value of the stock at the date of issuance. Where warrants were issued for services, fair value was calculated using the Black-Scholes pricing model. Information related to our warrants is summarized in the following table:

	Year Ended December 31,		
	2005	2004	2003
Outstanding at beginning of period	533,334	2,599,166	5,187,042
Warrants issued	—	—	3,432,500
Warrants exercised	(530,234)	(2,043,844)	(2,164,186)
Warrants canceled	(3,100)	(21,988)	(3,856,190)
Outstanding at end of period	—	533,334	2,599,166
Weighted average exercise price of warrants outstanding	$ —	$ 1.21	$ 1.65
Weighted average remaining contractual life of warrants outstanding	N/A	6.0 years	5.5 years

In September 2005, we issued 96,900 shares of common stock in exchange for the surrender of warrants to purchase 100,000 shares of common stock in a cashless transaction based on the then-current market price of $40.33. The warrants were exercisable at $1.25 per share.

In separate cashless transactions, in October 2004, we issued 57,724 and 57,366 shares of common stock in exchange for the surrender of warrants to purchase 62,500 and 62,500 shares of common stock based on the then-current price of $11.45 and $10.65 per share, respectively. The warrants were exercisable at $0.875 per share.

In August 2004, we issued 112,922 shares of common stock in exchange for the surrender of warrants to purchase 125,000 shares in a cashless transaction based on the then-current market price of $9.055 per share. The warrants were exercisable at $0.875 per share.

In August 2003, we issued 756,616 shares of common stock in exchange for the surrender of warrants to purchase 1,400,000 shares in a cashless transaction based on the then-current market price of $2.72 per share. The warrants were exercisable at $1.25 per share.

In April 2003, we issued warrants to purchase 500,000 shares of common stock at $1.25 per share to our Chief Executive Officer as a signing bonus. At the time of issue, the current market price was $0.90 per share. The warrants vested one year from the date of issue and were exercised in September 2004.

In February 2003, in connection with the sale of a 60% interest in our Freeport LNG project, we issued warrants valued at $540,000 to purchase 1,400,000 shares of our common stock. We also issued warrants to purchase 482,500 shares of common stock to a former employee of Cheniere and the current President and Chief Operating Officer of Freeport LNG, in replacement of his options to purchase 482,500 shares of common stock. The number and exercise prices of the warrants were the same as the options replaced and ranged from $0.53 to $6.00 per share. Warrants to purchase 450,000 shares of common stock and valued at $174,000 were issued to LNG consultants for services previously performed. In connection with the sale of a 10% interest in the limited partnership, we issued warrants valued at $242,000 to purchase 600,000 shares of common stock to the purchaser.

NOTE 18—EMPLOYEE BENEFITS

Stock-Based Compensation

In 1997, we established the Cheniere Energy, Inc. 1997 Stock Option Plan, as amended, or the Option Plan, which allowed for the issuance of options to purchase up to 5,000,000 shares of our common stock. Options on 5,000,000 shares of our common stock had been granted and were outstanding or had been exercised as of December 31, 2005. The term of options granted under the Option Plan is generally five years. Vesting varies, but generally occurs over three or four years, in increments of 33% or 25%, respectively, on each anniversary of the grant date. All options granted under the Option Plan have exercise prices equal to or greater than fair market value at the date of grant.

In 2004, our stockholders approved the Cheniere Energy, Inc. 2003 Stock Incentive Plan, as amended, or the 2003 Stock Incentive Plan, which allowed for the issuance of non-qualified or incentive stock options, purchased stock, stock (bonus stock), non-vested (restricted) stock, stock appreciation rights, phantom stock and other stock-based performance awards. It initially authorized the issuance of options to purchase common stock or awards of common stock up to 2,000,000 shares. On February 8, 2005, the shareholders approved an amendment to the 2003 Stock Incentive Plan increasing the number of shares of common stock authorized for issuance under the plan from 2,000,000 to 8,000,000. Through December 31, 2005, a total of 5,335,771 shares have been issued or reserved for issuance under the 2003 Stock Incentive Plan.

In 2004, stock grants of 322,000 shares, non-vested stock grants of 680,352 shares, and non-qualified stock option grants of 735,000 shares (net of forfeitures) were made to employees and directors from the 2003 Stock Incentive Plan. In February 2004, we issued stock and non-vested stock under the 2003 Stock Incentive Plan related to our performance in 2003. This included $2,415,000 of non-cash compensation expense related to the issuance of 322,000 shares, which shares were fully vested on the date of grant; and $3,330,000 of deferred compensation as a reduction to stockholders' equity, related to the issuance of 444,000 shares of non-vested stock, which vests on each of the first and second anniversaries of the grant date. In November 2004, we recorded $4,946,000 of deferred compensation as a reduction to stockholders' equity related to 236,352 shares of non-vested stock that were issued to employees and directors related to our performance in 2004. One-third of the shares vest on each of the first, second and third anniversaries of the grant date. The non-qualified stock option grants of 735,000 shares were made to new employees throughout the course of 2004.

In 2005, non-vested stock and non-qualified stock option grants of 175,151 and 3,423,296 shares (net of forfeitures), respectively, were made to employees and directors from the 2003 Stock Incentive Plan. In March 2005, non-qualified stock option grants to purchase 2,200,000 shares of common stock, or Retention Grants, were made to certain executive officers and key employees to provide an incentive for them to remain employed while the company executes critical aspects of its business plan. The Retention Grants have exercise prices at or significantly above the market price on the date of issuance and vest in one-third increments in March 2009, 2010 and 2011. In December 2005, we recorded $6,166,000 of deferred compensation as a reduction to stockholders' equity for the issuance of 160,151 shares of non-vested stock to employees and directors related to our performance in 2005. One-third of the shares vest on each of the first, second and third anniversaries of the grant date. Also in 2005, we recorded $498,000 of deferred compensation as a reduction of stockholders' equity in connection 15,000 shares of non-vested stock issued to employees. One-fourth of the shares vest on each of the first, second, third and fourth anniversaries of the effective dates. Non-qualified stock options for the purchase of 1,223,296 shares of common stock (net of forfeitures) were granted to new employees throughout 2005 and have exercise prices equal to fair market value at the date of grant. One-fourth of the option shares vest on each of the first, second, third and fourth anniversaries of the grant date.

Deferred compensation related to non-vested stock grants is amortized on a straight-line basis over the vesting period. During 2004, we recorded $4,148,000 (before capitalization of $529,000 as oil and gas property costs) in non-cash compensation expense, of which $2,415,000 related to stock awards and $1,733,000 related to amortization of deferred compensation associated with non-vested stock awards. During 2005, we recorded $3,522,000 (before capitalization of $145,000 as oil and gas property costs) in total non-cash compensation expense related to amortization of deferred compensation associated with non-vested stock awards. At December 31, 2005, the balance of non-cash deferred compensation remaining to be amortized was $9,684,000.

A summary of the status of our stock options is presented below:

	Year Ended December 31,		
	2005	2004	2003
Options outstanding at beginning of period	2,599,264	3,920,000	3,967,222
Options granted at an exercise price of $0.46 to $2.31 per share	—	—	980,000
Options granted at an exercise price of $7.40 to $11.26 per share	—	1,380,000	—
Options granted at an exercise price of $26.51 to 29.94 per share	699,800	—	—
Options granted at an exercise price of $30.00 to $36.60 per share	1,942,296	110,000	—
Options granted at an exercise price of $37.05 to $42.73 per share	320,700	—	—
Options granted at an exercise price of $60.00 per share	400,000	—	—
Options granted at an exercise price of $90.00 per share	100,000	—	—
Options exercised	(897,164)	(2,696,012)	(375,000)
Options converted to warrants	—	—	(482,500)
Options surrendered in cashless exercises, cancelled, or expired	(40,084)	(114,724)	(169,722)
Options outstanding at end of period	5,124,812	2,599,264	3,920,000
Options exercisable at end of period	486,559	444,266	2,323,960
Weighted average exercise price of options outstanding	$ 28.67	$ 5.94	$ 1.11
Weighted average exercise price of options exercisable	$ 7.43	$ 1.98	$ 1.25
Weighted average fair value of options granted during the period	$ 20.16	$ 5.81	$ 0.80
Weighted average remaining contractual life of options outstanding	7.1 years	3.7 years	2.9 years

The following table summarizes information about fixed options outstanding at December 31, 2005:

	Options Outstanding		Options Exercisable
Exercise Prices	Number Outstanding	Weighted Average Years Remaining Contractual Life	Number Outstanding
$ 0.46 to $2.31 per share	465,660	2.3	198,997
$ 7.40 to $11.26 per share	1,125,856	3.2	245,894
$26.51 to $29.94 per share	695,800	9.3	—
$30.00 to $36.60 per share	2,030,796	8.8	36,668
$37.05 to $42.73 per share	306,700	9.2	5,000
$60.00 per share	400,000	9.2	—
$90.00 per share	100,000	9.2	—
	5,124,812	7.1	486,559

401(k) Plan

In 2005, we established a defined contribution pension plan, or the 401(k) Plan. The 401(k) Plan allows eligible employees to contribute up to 100% of their compensation up to the Internal Revenues Service maximum. We match each employee's salary deferrals (contributions) up to six percent of compensation and may make additional contributions at our discretion. Our contributions to the 401(k) Plan were $517,000 for the year ended December 31, 2005. No discretionary contributions were made by us to the 401(k) Plan in 2005.

NOTE 19—OTHER COMPREHENSIVE LOSS

The following table is a reconciliation of our Net Loss to our Comprehensive Loss for the periods shown (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Net Loss	$(29,798)	$(24,568)	$(5,288)
Other Comprehensive Income items:			
Cash Flow Hedges, net of income taxes	3,798	—	—
Comprehensive Loss	$(26,000)	$(24,568)	$(5,288)

NOTE 20—RELATED PARTY TRANSACTIONS

From time to time, officers and employees may charter aircraft for company business travel. We entered into a letter agreement, or charter letter, with an unrelated third-party entity, Western Airways, Inc., or Western, that specifies the terms under which it would provide for charter of a Challenger 600 aircraft. One of the Challenger 600 aircraft which may be provided by Western for such services is owned by Bramblebush, LLC, or the LLC. The LLC is owned and/or controlled by our Chairman and Chief Executive Officer, Charif Souki. Our Code of Business Conduct and Ethics prohibits potential conflicts of interest. Upon the recommendation of our Audit Committee, which determined that the terms of the charter letter are fair and in our best interest, our Board of Directors unanimously approved the terms of the charter letter in May 2005 and granted an exception under our Code of Business Conduct and Ethics in order to permit us to charter the Challenger 600 aircraft. For the year ended December 31, 2005, we incurred $798,000 related to the charter of the Challenger 600 aircraft owned by the LLC.

In conjunction with our private placement of equity in January 2004, placement fees were paid to T. R. Winston & Company, Inc., a company in which the son of Charif Souki, Cheniere's Chairman and Chief Executive Officer, is employed. Placement fees to T. R. Winston for such placement totaled $965,000.

In December 2003, we entered into a shareholders agreement whereby we acquired a minority interest in J & S Cheniere. One of the directors of J & S Cheniere is the brother of Charif Souki. We also entered into an option agreement with J & S Cheniere providing for a $1,000,000 payment to us from J & S Cheniere for the option to acquire regasification capacity at our Sabine Pass and Corpus Christi LNG receiving terminals.

We have made office space available for use by Keith F. Carney, a non-management director. The pro rata amount of office lease expense related to that space was $3,000, $3,000 and $4,000 in 2005, 2004 and 2003, respectively.

NOTE 21—COMMITMENTS AND CONTINGENCIES

Lease Commitments

Future Annual Minimum Lease Payments

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

Year Ending December 31,	Operating Leases
2006	$ 2,024
2007	2,380
2008	2,523
2009	2,449
2010	2,412
Thereafter	38,698
Total	$50,486

Office Leases

In October 2003, we entered into a lease agreement for new office space with a term which runs from December 2003 through April 2014. Beginning in April 2004, our monthly lease rental is $21,000 and escalates to $24,000 beginning in February 2009 through the remaining term of the lease. We have an option to renew the lease for an additional five years at the then-current market rate. In May 2004, we amended our office lease agreement to increase our rentable square footage, or the Expansion Space. The lease term for the Expansion Space runs from September 2004 through August 2009. Our monthly lease rental for the Expansion Space is $14,000 beginning in June 2005. We have the option, subject and subordinate to another tenants' renewal option, to renew the lease for an additional five years at a rate specified in this amendment. In March 2005, we amended our office lease to increase our rentable square footage to include an additional floor on the premises. The lease term for the additional floor runs from May 2005 through January 2014. We have an option to renew the lease for an additional five years at the then-current market rate as part of the renewal of our original lease space. Under the amended lease, there are no monthly lease payments for the additional floor from May 2005 through April 2007, after which time the lease payments range from approximately $30,000 to $39,000 per month through January 2014. We have prepaid $201,000 in rent related to 2013 and have included such amount in Other Assets on the consolidated balance sheet as of December 31, 2005. We are also responsible for our proportionate share of the building operating expenses. In connection with the lease, we have issued a letter of credit in favor of the landlord in the amount of $674,000. The letter of credit amount decreases by approximately $225,000 each October for the next three years. In addition, the lease creates a lien on all property that we place on the premises as a security interest for payment of amounts due under the terms of the lease.

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 our Sabine Pass LNG receiving terminal site. The leases have an initial term of 30 years, with options to renew for six 10-year extensions. 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 $1,501,000. For 2005, these payments have been capitalized as part of the construction cost of the Sabine Pass LNG receiving terminal; however, beginning in 2006, these lease payments will be expensed as required by FSP 13-1.

Our total rental expense for the years ended December 31, 2005, 2004 and 2003 was $727,000, $445,000 and $128,000, respectively.

LNG Commitments

Obligations under LNG TUAs

Sabine Pass LNG has entered into TUAs with Total and Chevron USA to provide berthing for LNG tankers and for the unloading, storage and regasification of LNG at our Sabine Pass LNG receiving terminal.

LNG Option Agreements

We entered into an agreement with J & S Cheniere under which J & S Cheniere has an option to enter into a TUA reserving up to 200 MMcf/d of capacity at each of our Sabine Pass and Corpus Christi LNG facilities. Following execution of the option agreement, $1,000,000 was paid by J & S Cheniere to us in January 2004. The terms of the TUA contemplated by the J & S Cheniere option agreement have not been negotiated or finalized. We anticipate that definitive arrangements with J & S Cheniere may involve different terms and transaction structures than were contemplated when the option agreement was entered into in December 2003. Although non-refundable, we have recorded the option fee as deferred revenue.

In January 2004, Corpus Christi LNG, L.P. entered into an option agreement with BPU to provide 100 MMcf/d of regasification capacity at our Corpus Christi LNG receiving terminal. The option agreement was subsequently assigned by BPU to its sole stockholder, BPU Associates, LLC.

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 received capital calls, and made capital contributions, in the amount of approximately $2,102,000 in 2005. In December 2005, Freeport LNG announced that it had closed a $383,000,000 private placement of notes, which would be used to fund the remaining portion of the initial phase of the project, a portion of the cost of expanding the LNG receiving terminal and development of underground salt cavern gas storage. As a result of such financing being obtained, we do not anticipate that any capital calls will be made upon the limited partners of Freeport LNG in the foreseeable future. Additional 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.

In connection with the acquisition of the option to lease the Freeport LNG receiving terminal site in June 2001, we issued 1,000,000 shares of common stock valued at $1,150,000, or $1.15 per share, the closing price of our common stock on the date of the transaction, to the seller of the lease option. We also committed to issue an additional 1,500,000 shares of our common stock to the seller of the lease option in April 2003, for which we received no additional consideration. These shares were issued in April 2003 at a value of $1,312,500, or $0.875 per share, the closing price of our common stock on the date of issuance. The seller of the lease option also obtained the right to receive a royalty payment on the gross quantities of gas processed at LNG terminals that we own. The royalty is generally calculated based on $0.03 per Mcf of gas processed, subject to a minimum royalty of $2,000,000 per year and a maximum royalty of $10,950,000 per year after production begins. In 2002, a long-term lease was secured by Freeport LNG, and at the closing of the sale of our interests in the site and project, Freeport LNG assumed the obligation to pay the royalty with respect to gas processed and produced at the Freeport LNG facility.

EPC Agreement

In December 2004, we entered into a lump-sum turnkey EPC agreement with Bechtel pursuant to which Bechtel is providing services for the engineering, procurement and construction of Phase 1 of our Sabine Pass LNG receiving terminal. In December 2004, a limited notice to proceed, or LNTP, was issued and accepted by Bechtel, at which time Bechtel was required to promptly commence performance of certain off-site engineering and preparatory work under the EPC agreement. In early April 2005, a final NTP was issued, and Bechtel commenced all other aspects of work under the EPC agreement.

Sabine Pass LNG agreed to pay Bechtel a contract price of $646,936,000 plus certain reimbursable costs. This contract price is subject to adjustment for changes in certain commodity prices, contingencies, change orders and other items. Payments under the EPC agreement will be made in accordance with the payment schedule set forth in the EPC agreement. The contract price and payment schedule, including milestones, may be amended only by change order. Bechtel will be liable to Sabine Pass LNG for certain delays in achieving substantial completion, minimum acceptance criteria and performance guarantees. Bechtel will be entitled to a scheduled bonus of $12,000,000, or a lesser amount in certain cases, if on or before April 3, 2008, Bechtel completes construction sufficient to achieve, among other requirements specified in the EPC agreement, a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours. Bechtel will be entitled to receive an additional bonus of up to $67,000 per day (up to a maximum of $6,000,000) for each day that commercial operation is achieved prior to April 1, 2008. As of February 28, 2006, change orders for $64,845,000 had been approved, increasing the total contract price to $711,781,000. We anticipate additional change orders intended to mitigate ongoing effects of the 2005 hurricanes that would increase the contract price by an amount not expected to exceed $50,000,000. We expect to submit any such change orders to our lenders by May 3, 2006 for approval under the Sabine Pass Credit Facility.

In July 2005, we executed a letter of intent with a potential EPC contractor to negotiate an EPC contract for construction of our Corpus Christi LNG terminal. Subject to certain terms and conditions, in the event that we did not execute an EPC contract with this contractor on or before January 31, 2006, we were obligated to pay the contractor a fee of $1,000,000. On October 10, 2005, we entered into a Memorandum of Understanding, or MOU, with the same potential EPC contractor to negotiate the terms of an EPC contract for each of the Corpus Christi and Creole Trail LNG receiving terminals. Under the terms of the MOU, the $1,000,000 fee was cancelled and replaced by a $500,000 termination fee, payable, with certain exceptions, if we elect to terminate the MOU or if we fail to agree on the terms of an EPC contract for at least one of the terminals by April 30, 2007.

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 are, and may in the future be, involved as a party to various legal proceedings, which are incidental to the ordinary course of business. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of these matters. In the opinion of management and legal counsel, as of December 31, 2005, 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.

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

NOTE 22—GAIN ON SALE OF INVESTMENT IN UNCONSOLIDATED AFFILIATE

In October 2000, Cheniere and Warburg, Pincus Energy Partners, L.P. formed Gryphon Exploration Company, or Gryphon, to fund an oil and gas exploration program in the Gulf of Mexico. Since January 1, 2003, our investment (effective 9.3% ownership) in Gryphon has been accounted for under the cost method of accounting, and our investment basis was zero. On August 31, 2005, Gryphon was sold for $283,000,000, plus assumption of $14,000,000 of net debt in a merger with Woodside Energy (USA). The transaction generated net cash proceeds of $20,206,000 to us, and since our investment balance was zero at the closing of this transaction, we recognized a gain in our consolidated statement of operations for the year ended December 31, 2005 equal to the net cash proceeds amount.

NOTE 23—BUSINESS SEGMENT INFORMATION

Our business activities are conducted within two principal operating segments: LNG receiving terminal development, and oil and gas exploration and development. These segments operate independently.

Our LNG receiving terminal development segment is in various stages of developing three, 100% owned LNG receiving terminal projects along the U.S. Gulf Coast at the following locations: Sabine Pass LNG in western Cameron Parish, Louisiana on the Sabine Pass Channel; Corpus Christi LNG near Corpus Christi, Texas; and Creole Trail LNG at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. In addition, we own a 30% minority interest in a fourth project, Freeport LNG, located on Quintana Island near Freeport, Texas. Our related natural gas pipeline development activities and other initiatives that complement the development of our LNG receiving terminal business are also presently included in the segment.

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

	Segments				
	LNG Receiving Terminal	Oil & Gas Exploration and Development	Total	Corporate and Other (1)	Total Consolidated
			(in thousands)		
As of or for the Year Ended December 31, 2005:					
Revenues	$ —	$ 3,005	$ 3,005	$ —	$ 3,005
Depreciation, depletion and amortization	55	2,435	2,490	1,212	3,702
Non-cash compensation expense	1,235	182	1,417	2,021	3,438
Loss from operations	(29,122)	(1,204)	(30,326)	(21,773)	(52,099)
Equity in net loss of equity method investee (2)	(1,031)	—	(1,031)	—	(1,031)
Gain on sale of investment in unconsolidated affiliate (3)	—	20,206	20,206	—	20,206
Derivative gain	837	—	837	—	837
Interest expense	13,826	—	13,826	3,547	17,373
Interest income	2,645	—	2,645	14,875	17,520
Income tax benefit	2,045	—	2,045	—	2,045
Goodwill	76,844	—	76,844	—	76,844
Total assets	783,837	20,305	804,142	503,982	1,308,124
Expenditures for additions to long-lived assets	271,879	4,211	276,090	6,095	282,185
As of or for the Year Ended December 31, 2004:					
Revenues	$ —	$ 1,998	$ 1,998	$ —	$ 1,998
Depreciation, depletion and amortization	78	868	946	378	1,324
Income (loss) from operations	(17,245)	17	(17,228)	(11,857)	(29,085)
Equity in net loss of equity method investee (4)	(1,346)	—	(1,346)	—	(1,346)
Reimbursement from limited partnership investment (5)	2,500	—	2,500	—	2,500
Total assets	24,355	19,931	44,286	289,281	333,567
Expenditures for additions to long-lived assets	460	2,676	3,136	868	4,004
As of or for the Year Ended December 31, 2003:					
Revenues	$ —	$ 658	$ 658	$ —	$ 658
Depreciation, depletion and amortization	142	192	334	95	429
Income (loss) from operations	(6,847)	466	(6,381)	(2,637)	(9,018)
Equity in net loss of equity method investee (6)	(4,471)	—	(4,471)	—	(4,471)
Gain on sale of LNG assets (7)	4,760	—	4,760	—	4,760
Gain on sale of limited partnership interest (8)	423	—	423	—	423
Total assets	2,953	20,219	23,172	1,419	24,591
Expenditures for additions to long-lived assets	—	2,554	2,554	533	3,087

(1) Includes corporate activities and certain intercompany eliminations.
(2) Represents equity in net loss of our investment in Freeport LNG, excluding the 2005 Suspended Loss of $3,968,000. Our investment basis is zero at December 31, 2005.
(3) Represents gain on sale of our interest in Gryphon Exploration Company. See Note 22—"Gain on Sale of Investment in Unconsolidated Affiliate".
(4) Represents equity in net loss of our investment in Freeport LNG for 2004 totaling $1,068,000 plus the 2003 Suspended Loss of $278,000.
(5) In January 2004, we received the final $2,500,000 payment due from Freeport LNG. See Note 8—"Investment in Limited Partnership".
(6) Represents equity in net loss of our investment in Freeport LNG, excluding the 2003 Suspended Loss of $278,000. Our investment basis was reduced to zero as of December 31, 2003.
(7) In February 2003, we sold a 60% interest in our Freeport LNG terminal project to Freeport LNG. A gain of $4,760,000 was recognized on the sale. See Note 8—"Investment in Limited Partnership".
(8) In March 2003, we sold a 10% limited partner interest in Freeport LNG to a third party and recognized a gain of $423,000. See Note 8—"Investment in Limited Partnership".

NOTE 24—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,		
	2005	2004	2003
Cash paid during the year for:			
Interest, net of $2,669 capitalized	$12,792	$ 4	$ 41
Income taxes	$ —	$ —	$ —

In 2005, non-vested stock grants of 175,151 shares were made to employees and outside directors under the 2003 Stock Incentive Plan. We recorded $6,663,000 to common stock and additional paid-in-capital, offset by a corresponding amount of deferred compensation to stockholders' equity. During 2005, we recorded $3,583,000 (before capitalization of $145,000 as oil and gas property costs) in total non-cash compensation expense. As of December 31, 2005, the balance of non-cash deferred compensation was $9,684,000.

In 2005, 129,842 shares of our common stock were issued in satisfaction of cashless exercises of stock options and warrants to purchase 33,868 and 100,000 shares, respectively.

In February 2005, we acquired the 33.3% minority interest in Corpus Christi LNG through the acquisition of BPU in exchange for 2,000,000 restricted shares of our common stock valued at $77,090,000.

In 2004, we recorded $97,000, the present value of the expected abandonment cost of a well in which we hold a working interest, and its related equipment, as a long-term asset retirement obligation. A corresponding amount was recorded to proved oil and gas properties. Non-cash accretion expense for 2005 and 2004 was $3,000 and $2,000, respectively, and was included in depreciation, depletion and amortization expense.

In December 2003, the minority interest owner of Corpus Christi LNG contributed two tracts of land valued at $311,000 to be used for the LNG terminal site.

In August 2003, we issued 756,616 shares of common stock in exchange for the surrender of warrants to purchase 1,400,000 shares in a cashless transaction.

In April 2003, pursuant to a contingent contractual obligation related to our 2001 acquisition of an option to lease the Freeport LNG terminal site, we issued 1,500,000 shares of our common stock, valued at $1,312,000 on the date of issuance, to satisfy a closing requirement related to the February 2003 sale of a 60% interest in our Freeport LNG project

In February 2003, in connection with the sale of a 60% interest in the Freeport LNG site and project, we issued warrants valued at $540,000 to purchase 1,400,000 shares of common stock. As a result of the closing of the Freeport transaction, we issued warrants valued at $174,000 to purchase 450,000 shares of common stock to LNG consultants for services previously performed for us. In connection with the sale of a 10% interest in Freeport LNG, we issued warrants valued at $242,000 to purchase 600,000 shares of common stock to the purchaser, and the purchaser canceled the $750,000 note previously payable by us. These transactions are described in more detail in Note 8—“Investment in Limited Partnership”.

NOTE 25—SUBSEQUENT EVENTS

At December 31, 2005, there were no borrowings outstanding under the Sabine Pass Credit Facility; however, as of February 28, 2006, $58,500,000 had been drawn under the Sabine Pass Credit Facility.

On January 3, 2006, 78,671 shares, valued at $37.71 per share, were granted to executive officers in the form of non-vested (restricted) stock awards relating to our performance in 2005.

During January and February 2006, we issued 141,003 shares of common stock pursuant to the exercise of stock options at an average price of $7.37 generating proceeds of $1,039,000.

On February 21, 2006, Cheniere Sabine Pass Pipeline Company, our wholly-owned subsidiary, entered into an EPC pipeline contract with Willbros Engineering, Inc., or Willbros. Under the EPC pipeline contract, Willbros will provide Cheniere Sabine Pass Pipeline Company with services for the management, engineering, material procurement, construction and construction management of the Sabine Pass pipeline. Sabine Pass Pipeline Company will pay to Willbros a contract price not to exceed $67,700,000 subject to additions and deductions by any change order as provided in the EPC pipeline contract, excluding certain Louisiana sales and use taxes, which Cheniere Sabine pass Pipeline Company is obligated to reimburse. Cheniere Sabine Pass Pipeline Company entered into the EPC pipeline contract sufficiently in advance of commencement of physical construction of the pipeline in order to perform detailed engineering and procure materials.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
OIL AND GAS RESERVES AND RELATED FINANCIAL DATA
(unaudited)

Costs Incurred in Oil and Gas Producing Activities

Presented below are costs incurred in oil and gas property acquisition, exploration and development activities (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Acquisition of properties			
Proved properties	$ —	$ —	$ —
Unproved properties	1,530	318	937
Exploration costs	2,681	2,261	1,577
Development costs	—	—	—
Subtotal	$4,211	$2,579	$2,514
Asset retirement costs	—	97	—
Total	$4,211	$2,676	$2,514

Included in the costs incurred for the years ended December 31, 2005, 2004 and 2003 was $927,000, $1,573,000 and $1,064,000, respectively, of capitalized general and administrative expenses, capitalized interest expense and capitalized debt discount directly related to property acquisition, exploration and development.

Capitalized Costs Related to Oil and Gas Producing Activities

The following table presents total capitalized costs of proved and unproved properties and accumulated depreciation, depletion and amortization related to oil and gas producing operations (in thousands):

	December 31,	
	2005	2004
Proved properties	$ 5,787	$ 3,339
Unproved properties	17,216	16,688
	23,003	20,027
Accumulated depreciation, depletion and amortization	(3,386)	(971)
	$19,617	$19,056

Costs Not Being Amortized

Presented below is a summary of oil and gas property costs not being amortized at December 31, 2005, by the year in which such costs were incurred. Such costs include capitalized interest of $169,000. The majority of the evaluation activities are expected to be completed within three years.

	Cumulative Balance at December 31, 2005	Costs incurred for the year ended December 31,			
		2005	2004	2003	2002 and earlier
		(in thousands)			
Acquisition costs	$ 1,322	$ 991	$291	$ 18	$ 22
Exploration costs	15,894	1,473	336	1,035	13,050
Development costs	—	—	—	—	—
Total	$17,216	$2,464	$627	$1,053	$13,072

Results of Operations from Oil and Gas Producing Activities

The results of operations from oil and gas producing activities are as follows (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Revenues	$ 3,005	$1,998	$ 658
Production costs	(237)	(117)	—
Depreciation, depletion and amortization (1)	(2,418)	(837)	(122)
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$ 350	$1,044	$ 536

(1) Includes $3,000 and $2,000 of asset retirement accretion expense in 2005 and 2004, respectively.

Reserve Quantities

Estimates of our proved reserves and the related standardized measure of discounted future net cash flow information are based on the reports generated by our independent petroleum engineers, Sharp Petroleum Engineering, Inc., in accordance with the rules and regulations of the SEC. The independent engineers' estimates were based upon a review of production histories and other geologic, economic, ownership and engineering data provided by us. These estimates represent our interest in the reserves associated with our properties. All of our oil and gas reserves are located within the United States or its territorial waters.

Our estimates of proved reserves and proved developed reserves of oil and gas as of December 31, 2005, 2004 and 2003 and the changes in our proved reserves are as follows:

	2005		2004		2003	
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
Proved reserves:						
Beginning of year	3,021	919,120	5,123	912,779	3,980	1,333,000
Revisions of prior estimates	459	(132,149)	(738)	(159,303)	(3,830)	(1,093,920)
Production	(2,167)	(396,284)	(1,364)	(328,676)	(17)	(123,392)
Sale of reserves in place	—	—	—	—	—	—
Extensions, discoveries and other additions	—	—	—	494,320	4,990	797,091
End of year	1,313	390,687	3,021	919,120	5,123	912,779
Proved developed reserves:						
Beginning of year	3,021	919,120	3,024	759,095	1,606	503,000
End of year	1,313	390,687	3,021	919,120	3,024	759,095

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and future amounts and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

Estimates of proved undeveloped reserves are inherently less certain than estimates of proved developed reserves. The quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures, geologic success and future oil and gas sales prices may all differ from those assumed in these estimates. In addition, our reserves may be subject to downward or upward revision based upon production history, purchases or sales of properties, results of future development, prevailing oil and gas prices and other factors.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows was calculated by applying year-end prices (adjusted for location and quality differentials) to estimated future production, less future expenditures (based on year-end costs) to be incurred in developing and producing our proved reserves and the estimated effect of future income taxes based on the current tax law. The resulting future net cash flows were discounted using a rate of 10% per annum.

From our inception, we have recorded annual net operating losses for both financial reporting purposes and for federal and state income tax reporting purposes. Accordingly, we are not presently a taxpayer, and therefore there is no tax effect on future net cash flow amounts.

The standardized measure of discounted future net cash flow amounts contained in the following tabulation does not purport to represent the fair market value of oil and gas properties. No value has been given to unproved properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs. Future realization of oil and gas prices over the remaining reserve lives may vary significantly from current prices. In addition, the method of valuation utilized, based on year-end prices and costs and the use of a 10% discount rate, is not necessarily appropriate for determining fair value.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves is as follows (in thousands):

	December 31,		
	2005	2004	2003
Future gross revenues	$3,548	$5,666	$5,231
Less—future costs:			
Production	(212)	(570)	(134)
Development and abandonment	(80)	(80)	—
Income taxes	—	—	—
Future net cash flows	3,256	5,016	5,097
Less—10% annual discount for estimated timing of cash flows	(511)	(868)	(819)
Standardized measure of discounted future net cash flows	$2,745	$4,148	$4,278

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS OIL AND GAS RESERVES AND RELATED FINANCIAL DATA—(Continued)

(unaudited)

The following table summarizes the principal sources of change in the standardized measure of discounted future net cash flows (in thousands, except for prices):

	Year Ended December 31,		
	2005	2004	2003
Standardized measure—beginning of period	$ 4,148	$ 4,278	$ 5,131
Sales of oil and gas produced, net of production costs	(2,768)	(1,881)	(657)
Extensions, discoveries and other additions	—	1,849	3,692
Revisions to previous quantity estimates, timing and other	58	(698)	(4,945)
Net changes in prices and production costs	971	268	727
Sale of reserves in place	—	—	—
Development costs incurred	—	—	—
Changes in estimated development costs	—	—	—
Net changes in income taxes	—	—	—
Accretion of discount	336	332	330
Standardized measure—end of period	$ 2,745	$ 4,148	$ 4,278
Current prices at year-end, used in standardized measure			
Oil (per Bbl)	$ 53.72	$ 38.10	$ 31.00
Gas (per Mcf)	$ 8.90	$ 6.04	$ 5.63

We may receive amounts different from those incorporated into the standardized measure of discounted cash flow for a number of reasons, including changes in prices. Therefore, the present value shown above should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

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

Quarterly Financial Data—(in thousands)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year ended December 31, 2005:					
Revenues	$ 737	$ 689	$ 729	$ 850	$ 3,005
Gross profit (1)	334	368	320	(672)	350
Loss from operations	(10,261)	(10,823)	(10,681)	(20,334)	(52,099)
Net income (loss) (2)	(9,215)	(9,837)	7,678	(18,424)	(29,798)
Net income (loss) per share—basic and diluted	$ (0.18)	$ (0.18)	$ 0.14	$ (0.34)	$ (0.56)
Year ended December 31, 2004:					
Revenues	$ 332	$ 335	$ 465	$ 866	$ 1,998
Gross profit (1)	247	243	346	177	1,013
Loss from operations	(7,218)	(7,327)	(5,505)	(9,035)	(29,085)
Net loss (3)	(1,075)	(8,053)	(5,639)	(9,801)	(24,568)
Net loss per share—basic and diluted	$ (0.03)	$ (0.22)	$ (0.15)	$ (0.23)	$ (0.63)

(1) Revenues less production costs and oil and gas depreciation, depletion and amortization.

(2) The third quarter of 2005 includes $20,206,000 gain on sale of our investment in Gryphon Exploration Company. See Note 22—“Gain on Sale of Investment in Unconsolidated Affiliate”.

(3) The first quarter of 2004 includes a $2,500,000 gain recognized on receipt of the final $2,500,000 payment from Freeport LNG. See Note 8—“Investment in Limited Partnership”.

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, 2005, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

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

Management Report on Internal Control Over Financial Reporting

Our Management Report on Internal Control Over Financial Reporting is included in the Financial Statements on page 73 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 involving the election of directors, which is to be filed pursuant to Regulation 14A within 120 days after the end of Cheniere's fiscal year ended December 31, 2005.

PART IV

ITEM 15. *EXHIBITS AND FINANCIAL STATEMENT SCHEDULES*

(a) Financial Statements, Schedules and Exhibits

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

The financial statements of Freeport LNG Development, L.P. for the period from December 1, 2002 to December 31, 2005, for which Cheniere used the equity method of accounting, have been filed as part of this report on Form 10-K. (See Item 15(c))

(2) Financial Statement Schedules

All consolidated financial statement schedules have been omitted because they are not required, are not applicable, or the required information has been included elsewhere within this Form 10-K.

(3) Exhibits

Exhibit No.	Description
1.1*	Underwriting Agreement, dated as of December 2, 2004, by and among Cheniere Energy, Inc. (the "Company") and the Underwriters named on Schedule I thereto. (Incorporated by reference to Exhibit 1.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 6, 2004)
1.2*	Purchase Agreement, dated as of July 22, 2005, between Cheniere Energy, Inc. and Credit Suisse First Boston LLC. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on July 27, 2005)
2.1*	Seismic Data Purchase Agreement, dated June 21, 2000 between Seitel Data Ltd. and the Company. (Incorporated by reference to Exhibit 10.39 of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2000 (SEC File No. 000-09092), filed on August 11, 2000)
2.2*	Settlement and Purchase Agreement, dated and effective as of June 14, 2001 by and between the Company, CXY Corporation, Crest Energy, L.L.C., Crest Investment Company and Freeport LNG Terminal, LLC. (Incorporated by reference to Exhibit 10.10 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 (SEC File No. 001-16383), filed on April 1, 2002)
2.3*	Agreement and Plan of Merger, dated February 8, 2005, by and among Cheniere LNG, Inc., Cheniere Acquisition, LLC, BPU Associates, LLC and BPU LNG, Inc. (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on February 8, 2005)
3.1*	Restated Certificate of Incorporation of the Company. (Incorporated by reference to Exhibit 4.1 of 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 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on February 8, 2005)
3.3*	Amended and Restated By-laws of the Company. (Incorporated by reference to Exhibit 4.3 of the Company's Registration Statement on Form S-8 (SEC File No. 333-112379), filed on January 20, 2004)
3.4*	Amendment No. 1 to Amended and Restated By-laws of the Company. (Incorporated by reference to Exhibit 3.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 (SEC File No. 001-16383), filed on May 6, 2005)
4.1*	Specimen Common Stock Certificate of the Company. (Incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1 (SEC File No. 333-10905), filed on August 27, 1996)

Exhibit No.	Description
4.2*	Certificate of Designation of Series A Junior Participating Preferred Stock. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on October 14, 2004)
4.3*	Rights Agreement by and between the Company and U.S. Stock Transfer Corp., as Rights Agent, dated as of October 14, 2004. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on October 14, 2004)
4.4*	First Amendment to Rights Agreement by and between the Company and U.S. Stock Transfer Corp., as Rights Agent, dated January 24, 2005. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 24, 2005)
4.5*	Piggy-Back Registration Rights Agreement, dated February 8, 2005, by and between the Company and BPU Associates, LLC. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on February 8, 2005)
4.6*	Registration Rights Agreement, dated as of July 27, 2005, between Cheniere Energy, Inc. and Credit Suisse First Boston LLC. (Incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on July 27, 2005)
4.7*	Indenture, dated as of July 27, 2005, between Cheniere Energy, Inc., as issuer, and The Bank of New York, as trustee. (Incorporated by reference to Exhibit 4.3 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on July 27, 2005)
10.1*†	Cheniere Energy, Inc. Amended and Restated 1997 Stock Option Plan. (Incorporated by reference to Exhibit 10.14 of the Company's Quarterly on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 000-16383), filed on November 4, 2005)
10.2*†	Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.14 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)
10.3 †	Addendum to Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan
10.4*†	Form of Non-Qualified Stock Option Grant (four-year vesting) under the Cheniere Energy, Inc. 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.10 to the Company' Annual Report on Form 10-K (SEC File No. 001-16383), filed on March 10, 2005)
10.5*†	Form of Non-Qualified Stock Option Grant (three-year vesting) under the Cheniere Energy, Inc. 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.11 to the Company' Annual Report on Form 10-K (SEC File No. 001-16383), filed on March 10, 2005)
10.6*†	Form of Restricted Stock Grant under the Cheniere Energy, Inc. 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.12 to the Company' Annual Report on Form 10-K (SEC File No. 001-16383), filed on March 10, 2005)
10.7*†	Form of Cancellation and Grant of Non-Qualified Stock Options (three-year vesting) under the Cheniere Energy, Inc. 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 2, 2005)
10.8*	LNG Terminal Use Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.9*	Amendment of LNG Terminal Use Agreement, dated January 24, 2005, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.40 to the Company' Annual Report on Form 10-K (SEC File No. 001-16383), filed on March 10, 2005)

Exhibit No.	Description
10.10*	Omnibus Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.11*	Guaranty, dated as of November 9, 2004, by Total S.A. in favor of Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.12*	LNG Terminal Use Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.13*	Omnibus Agreement, dated November 8, 2004, between Chevron U.S.A., Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.14*	Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 20, 2004)
10.15	Change Orders 1 through 27 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation
10.16*	Credit Agreement, dated February 25, 2005, among Sabine Pass LNG, L.P., Société Générale, HSBC Bank USA, National Association and the Lenders named thereto. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.17*	Consent and Waiver No. 1 to Credit Agreement, dated as of April 4, 2005, among Sabine Pass LNG, L.P., Société Générale and HSBC Bank USA, National Association (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 (SEC File No. 001-16383), filed on May 6, 2005)
10.18*	Consent and Waiver No. 2 to Credit Agreement, dated as of May 5, 2005, among Sabine Pass LNG, L.P., Société Générale and HSBC Bank USA, National Association. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 (SEC File No. 001-16383), filed on August 5, 2005)
10.19*	Consent and Waiver No. 3 to Credit Agreement, dated as of April 25, 2005, among Sabine Pass LNG, L.P., Société Générale and HSBC Bank USA, National Association. (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 (SEC File No. 001-16383), filed on August 5, 2005)
10.20*	Consent and Waiver No. 4 to Credit Agreement, dated as of May 31, 2005, among Sabine Pass LNG, L.P., Société Générale and HSBC Bank USA, National Association. (Incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 (SEC File No. 001-16383), filed on August 5, 2005)
10.21*	Consent and Waiver No. 5 to Credit Agreement, dated as of July 5, 2005, among Sabine Pass LNG, L.P., Société Générale and HSBC Bank USA, National Association. (Incorporated by reference to Exhibit 10.10 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)
10.22*	Consent and Waiver No. 6 to Credit Agreement, dated as of July 27, 2005, among Sabine Pass LNG, L.P., Société Générale and HSBC Bank USA, National Association. (Incorporated by reference to Exhibit 10.11 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)

Exhibit No.	Description
10.23*	Consent and Waiver No. 7 to Credit Agreement, dated as of August 29, 2005, among Sabine Pass LNG, L.P., Société Générale and HSBC Bank USA, National Association. (Incorporated by reference to Exhibit 10.12 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)
10.24	Consent and Waiver No. 8 to Credit Agreement, dated as of November 28, 2005, among Sabine Pass LNG, L.P., Société Générale and HSBC Bank USA, National Association
10.25	Consent and Waiver No. 9 to Credit Agreement, dated as of January 23, 2006, among Sabine Pass LNG, L.P., Société Générale and HSBC Bank USA, National Association
10.26	Consent and Waiver No. 10 to Credit Agreement, dated as of February 17, 2006, among Sabine Pass LNG, L.P., Société Générale and HSBC Bank USA, National Association
10.27*	Security Agreement, dated February 25, 2005, among Sabine Pass LNG, L.P., Société Générale, and HSBC Bank USA, National Association. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.28*	Pledge Agreement, dated February 25, 2005, among Sabine Pass LNG-LP, LLC, Sabine Pass LNG-GP, Inc., Société Générale, Sabine Pass LNG, L.P. and HSBC Bank USA, National Association. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.29*	Collateral Agency Agreement, dated February 25, 2005, among Sabine Pass LNG, L.P., HSBC Bank USA, National Association and Société Générale. (Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.30*	Operation and Maintenance Agreement, dated February 25, 2005, between Sabine Pass LNG, L.P. and Cheniere LNG O&M Services, L.P. (Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.31*	Management Services Agreement, dated February 25, 2005, between Sabine Pass LNG-GP, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.32*	International Swap Dealers Association, Inc. Master Agreement and Schedules, dated February 25, 2005, between HSBC Bank USA, National Association and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.33*	Confirmation, dated February 25, 2005, effective July 25, 2005, between HSBC Bank USA, National Association and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.34*	Confirmation, dated February 25, 2005, effective March 25, 2009, between HSBC Bank USA, National Association and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.35*	International Swap Dealers Association, Inc. Master Agreement and Schedules, dated February 25, 2005, between Société Générale, New York, and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.10 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.36*	Confirmation, dated February 25, 2005, effective July 25, 2005, between Société Générale, New York, and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.11 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)

Exhibit No.	Description
10.37*	Confirmation, dated February 25, 2005, effective March 25, 2009, between Société Générale, New York, and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.12 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.38*	Secured Party Addition Agreement, dated February 25, 2005, executed by HSBC Bank, National Association. (Incorporated by reference to Exhibit 10.13 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.39*	Secured Party Addition Agreement, dated February 25, 2005, executed by Société Générale. (Incorporated by reference to Exhibit 10.14 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.40*	Confirmation, dated July 22, 2005, between Cheniere Energy, Inc. and Credit Suisse First Boston International. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on July 22, 2005)
10.41*	Credit Agreement, dated August 31, 2005, among Cheniere LNG Holdings, LLC, the initial lenders named therein, and Credit Suisse, Cayman Islands Branch. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)
10.42*	Security Agreement, dated August 31, 2005, from Cheniere LNG Holdings, LLC to Credit Suisse, Cayman Islands Branch. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)
10.43*	Pledge Agreement, dated August 31, 2005, from Cheniere LNG-LP Interests, LLC to Credit Suisse, Cayman Islands Branch. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)
10.44*	Control Agreement, dated August 31, 2005, from Cheniere LNG Holdings, LLC, to Credit Suisse, Cayman Islands Branch, and The Bank of New York. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)
10.45*	Novation Confirmation (#9233022), dated September 6, 2005, among Credit Suisse First Boston International, Cheniere Energy, Inc. and Cheniere LNG Holdings, LLC. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)
10.46*	Novation Confirmation (#9233023), dated August 31, 2005, among Credit Suisse First Boston International, Cheniere Energy, Inc. and Cheniere LNG Holdings, LLC. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)
10.47*	Novation Confirmation (#9233025), dated August 31, 2005, among Credit Suisse First Boston International, Cheniere Energy, Inc. and Cheniere LNG Holdings, LLC. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)
10.48*	Novation Confirmation (#9233026), dated August 31, 2005, among Credit Suisse First Boston International, Cheniere Energy, Inc. and Cheniere LNG Holdings, LLC. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)

Exhibit No.	Description
10.49*	Novation Confirmation (#9233027), dated August 31, 2005, among Credit Suisse First Boston International, Cheniere Energy, Inc. and Cheniere LNG Holdings, LLC. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005 (SEC File No. 001-16383), filed on November 4, 2005)
10.50	International Swap Dealers Association, Inc. Master Agreement and Schedule, dated December 23, 2005, between Credit Suisse First Boston International and Cheniere LNG Holdings, LLC
10.51*†	Summary of Compensation to Non-Employee Directors. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 14, 2005)
10.52*†	Summary of Compensation for Executive Officers. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 5, 2006)
10.53	Agreement for Engineering, Procurement and Construction Services, dated February 21, 2006, between Cheniere Sabine Pass Pipeline Company and Willbros Engineers, Inc.
21	Subsidiaries of Cheniere Energy, Inc.
23.1	Consent of UHY Mann Frankfort Stein & Lipp CPAs, LLP
23.2	Consent of Hein & Associates LLP
23.3	Consent of Sharp Petroleum Engineering, Inc.
31.1	Certification by Chief Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
31.2	Certification by Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
32.1	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Incorporated by reference
† Management contract or compensatory plan or arrangement

(c) Freeport LNG Development, L.P. Financial Statements, for which Cheniere used the equity method of accounting for the period from December 1, 2002 to December 31, 2005, are filed as a part of this report beginning on page 124.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHENIERE ENERGY, INC.
(Registrant)

By: /s/ CHARIF SOUKI

Charif Souki
Chief Executive Officer and Chairman of the Board

Date: March 10, 2006

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

Signature	Title	Date
/s/ CHARIF SOUKI **Charif Souki**	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	March 10, 2006
/s/ WALTER L. WILLIAMS **Walter L. Williams**	Vice Chairman of the Board and Director	March 10, 2006
/s/ DON A. TURKLESON **Don A. Turkleson**	Senior Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)	March 10, 2006
/s/ CRAIG K. TOWNSEND **Craig K. Townsend**	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 10, 2006
/s/ NUNO BRANDOLINI **Nuno Brandolini**	Director	March 10, 2006
/s/ KEITH F. CARNEY **Keith F. Carney**	Director	March 10, 2006
/s/ PAUL J. HOENMANS **Paul J. Hoenmans**	Director	March 10, 2006
/s/ DAVID B. KILPATRICK **David B. Kilpatrick**	Director	March 10, 2006
/s/ J. ROBINSON WEST **J. Robinson West**	Director	March 10, 2006

INDEX TO FINANCIAL STATEMENTS

Freeport LNG Development, L.P. Audited Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of
Freeport LNG Development, L.P., a Limited Partnership
Houston, Texas

We have audited the accompanying consolidated balance sheets of Freeport LNG Development, L.P., a Delaware limited partnership (a development stage limited partnership) and subsidiaries, as of December 31, 2005 and 2004, and the related consolidated statements of operations, changes in partners' capital (deficit) and cash flows for the years ending December 31, 2005, 2004 and 2003, and for the period from inception (December 1, 2002) through December 31, 2005. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements 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 audits 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Freeport LNG Development, L.P. and subsidiaries, as of December 31, 2005 and 2004, and the results of their operations and their cash flows for the years ending December 31, 2005, 2004 and 2003, and for the period from inception (December 1, 2002) through December 31, 2005 in conformity with accounting principles generally accepted in the United States of America.

/s/ HEIN & ASSOCIATES LLP

Hein & Associates LLP

Dallas, Texas
February 16, 2006

FREEPORT LNG DEVELOPMENT, L.P.
(A DEVELOPMENT STAGE LIMITED PARTNERSHIP)

CONSOLIDATED BALANCE SHEETS

	Years Ended December 31, 2005	2004
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,000	$ 58,000
Cash restricted for construction, current general operations and other specified activities	379,341,000	37,866,000
Prepaid expenses	1,265,000	182,000
Total current assets	380,615,000	38,106,000
Office Equipment and Leasehold Improvements, net	1,614,000	144,000
Construction in Progress	246,351,000	9,728,000
Note Payable Offering Cost	6,959,000	—
Other Assets	736,000	448,000
Total Assets	$636,275,000	$48,426,000
LIABILITIES AND PARTNERS' CAPITAL (DEFICIT)		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 53,533,000	$ 5,676,000
Total current liabilities	53,533,000	5,676,000
Notes Payable	595,766,000	48,041,000
Deferred Revenue and Other Deferred Credits	5,748,000	3,500,000
Commitments and Contingency (Notes 3 and 7)		
Partners' Capital (Deficit), including deficit accumulated during the development stage of $36,056,000 and $19,393,000, respectively	(18,772,000)	(8,791,000)
Total Liabilities and Partners' Capital (Deficit)	$636,275,000	$48,426,000

See accompanying notes to these consolidated financial statements.

FREEPORT LNG DEVELOPMENT, L.P.
(A DEVELOPMENT STAGE LIMITED PARTNERSHIP)

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31,			For the Period of Inception (December 1, 2002) through December 31,
	2005	2004	2003	2005
Revenues	$ —	$10,000,000	$ —	$ 10,000,000
Expenses:				
Facility site rental and other site costs	4,798,000	820,000	573,000	6,191,000
Personnel and related costs	3,379,000	2,326,000	2,193,000	8,111,000
Engineering	139,000	2,394,000	2,419,000	5,200,000
Environmental and special studies	2,053,000	791,000	1,063,000	4,129,000
Purchase of limited partners pre-construction cost	—	—	5,000,000	5,000,000
Professional services	4,751,000	5,934,000	3,068,000	13,837,000
Other general and administrative costs	1,118,000	1,304,000	624,000	3,171,000
Total expenses	16,238,000	13,569,000	14,940,000	45,639,000
Operating Income (Loss)	(16,238,000)	(3,569,000)	(14,940,000)	(35,639,000)
Other Income (Expense):				
Interest income	612,000	8,000	—	620,000
Interest expense	(1,037,000)	—	—	(1,037,000)
Net Loss	$(16,663,000)	$ (3,561,000)	$(14,940,000)	$(36,056,000)

See accompanying notes to these consolidated financial statements.

FREEPORT LNG DEVELOPMENT, L.P.
(A DEVELOPMENT STAGE LIMITED PARTNERSHIP)

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL (DEFICIT)

	General Partner	Limited Partners	Accumulated Deficit	Total Partners' Capital (Deficit)
Balances, at Inception (December 1, 2002)	$—	$ —	$ —	$ —
Net loss	—	—	(892,000)	(892,000)
Balances, at December 31, 2002	—	—	(892,000)	(892,000)
Capital contributions	—	10,390,000	—	10,390,000
Net loss	—	—	(14,940,000)	(14,940,000)
Balances, at December 31, 2003	—	10,390,000	(15,832,000)	(5,442,000)
Contributions	—	6,152,000	—	6,152,000
Withdrawals	—	(5,940,000)	—	(5,940,000)
Net loss	—	—	(3,561,000)	(3,561,000)
Balances, at December 31, 2004	—	10,602,000	(19,393,000)	(8,791,000)
Contributions	—	6,682,000	—	6,682,000
Net loss	—	—	(16,663,000)	(16,663,000)
Balances, at December 31, 2005	$—	$17,284,000	$(36,056,000)	$(18,772,000)

See accompanying notes to these consolidated financial statements.

FREEPORT LNG DEVELOPMENT, L.P.
(A DEVELOPMENT STAGE LIMITED PARTNERSHIP)

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,			For the Period from Inception (December 1, 2002) through
	2005	2004	2003	2005
Operating Activities:				
Net loss	$ (16,663,000)	$ (3,561,000)	$(14,940,000)	$ (36,056,000)
Adjustments to reconcile net loss to net cash used in operating activities:				
Depreciation	179,000	27,000	15,000	221,000
Changes in assets and liabilities:				
Prepaids and other assets	(1,084,000)	36,000	(218,000)	(1,264,000)
Accounts payable and accrued liabilities	3,278,000	(1,398,000)	2,494,000	5,261,000
Due to limited partners	—	(2,501,000)	2,501,000	—
Deferred revenue	2,244,000	3,500,000	—	5,749,000
Net cash used in operating activities	(12,046,000)	(3,897,000)	(10,148,000)	(26,089,000)
Investing Activities:				
Purchase of property, equipment, and other assets	(1,649,000)	(469,000)	(165,000)	(2,284,000)
Construction in progress, net of increase in accounts payable related to construction in process	(191,290,000)	(6,040,000)	—	(197,330,000)
Net cash used in investing activities	(192,939,000)	(6,509,000)	(165,000)	(199,614,000)
Financing Activities:				
Note proceeds	383,000,000	—	—	383,000,000
Loan proceeds from COP	163,688,000	48,041,000	—	211,729,000
Contributions from partners	6,682,000	6,152,000	10,390,000	23,223,000
Payment of note offering cost	(6,959,000)	—	—	(6,959,000)
Withdrawals by partners	—	(5,940,000)	—	(5,940,000)
Net cash provided by financing activities	546,411,000	48,253,000	10,390,000	605,053,000
Net Increase in Cash and Cash Equivalents	341,426,000	37,847,000	77,000	379,350,000
Cash, Cash Equivalents and Restricted Cash, at beginning of period	37,924,000	77,000	—	—
Cash, Cash Equivalents and Restricted Cash, at end of period	$ 379,350,000	$37,924,000	$ 77,000	$ 379,350,000

See accompanying notes to these consolidated financial statements.

FREEPORT LNG DEVELOPMENT, L.P.
(A DEVELOPMENT STAGE LIMITED PARTNERSHIP)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES:

Business Activity—Freeport LNG Development, L.P. (the "Partnership") is in the process of developing, building and commercializing a liquefied natural gas (LNG) receiving and regasification facility on Quintana Island, near Freeport, Texas (the "Facility"). After construction is completed, the Partnership will own and operate the Facility. During 2004, FLNG Land, Inc. (Land), a wholly owned subsidiary, was formed to facilitate Phase 1 land related transactions. During 2005, Freeport LNG Expansion, L.P. and FLNG Storage, L.P., both wholly owned subsidiaries, were formed for the purpose of exploring adding additional capacity to the Facility (Phase 2) and exploring adding an underground storage facility (Storage). Also during 2005, FLNG Land II, Inc. (Land II), a wholly owned subsidiary, was formed to facilitate Phase 2 land related transactions.

Principles of Consolidation—The consolidated financial statements include the accounts of Freeport LNG Development, L.P. and its 100% owned subsidiaries. All intercompany accounts and transactions are eliminated in the consolidation.

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

Cash and Cash Equivalents—The Partnership considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

Cash received from advances on the note payable to ConocoPhillips (COP) can only be used for construction and regular operations and cannot be used to fund any additional expansion studies or be used to pay expenses that were incurred prior to when the Partnership obtained Federal Energy Regulatory Commission ("FERC") approval for the construction of Phase 1 of the Facility.

Cash received from the notes payable to institutional investors is restricted and can only be used for additional Phase 1 costs, expansion studies or expansion construction, storage construction, and certain other disbursements.

Property, Plant and Equipment—Property, plant and equipment are stated at cost. Depreciation is computed using the straight-line method over the estimated useful lives of the assets for financial reporting purposes. Expenditures for major renewals and betterments that extend the useful lives are capitalized. Expenditures for normal maintenance and repairs are expensed as incurred. When assets are sold or abandoned, the cost of the assets sold or abandoned and the related accumulated depreciation will be eliminated from the accounts, and any gains or losses will be charged or credited to other income (expense) of the respective period. The estimated useful lives by classification are as follows:

Office Equipment	5 years
Leasehold Improvements	15 years

Construction in Progress—Construction in progress through December 31, 2005 relates to engineering, land, acquisition, title work, and other direct costs related to Phase 1 construction of the Facility, which were incurred after the Partnership obtained FERC approval and closed on the related construction loan, and physical assets added to Phase 1 during the construction that were needed in order to allow a potential Phase 2 expansion to be built at a later time.

Revenue Recognition—Revenues will be recognized for terminal use fees as they are earned from the regasification process. Revenue from capacity reservations are generally deferred.

The Partnership also recognized revenue from a transaction in 2004 when it provided engineering and design studies to ConocoPhillips. In connection with this sale, the Partnership also agreed to reserve a specific amount of capacity for ConocoPhillips.

Concentrations of Credit Risk and Other Concentrations—Although held in nationally recognized financial institutions, substantially all of the Partnership's cash balances are in excess of the FDIC insurance limits. As discussed in Note 4, ConocoPhillips has significant involvement with the Partnership.

Income Taxes—The Partnership files its Federal income tax return as a partnership under the Internal Revenue Code. In lieu of corporate income taxes, the partners of the Partnership are taxed on their proportionate share of the Partnership's taxable income. Accordingly, no provision or liability has been recognized for federal income tax purposes for those periods, as taxes are the responsibility of the individual partners of the Partnership.

Income taxes are provided for the Partnership's subsidiaries that are C-Corporations in accordance with Statement of Financial Accounting Standards No. 109 "Accounting for Income Taxes". A deferred tax asset or liability is recorded for all temporary differences between income for financial statement purposes and income for tax purposes as well as operating loss carry forwards. Deferred tax expense (or benefit) results from the net change during the year of deferred tax assets and liabilities.

The net deferred tax assets for these subsidiaries were approximately $1,020,000 and $130,000 at December 31, 2005 and 2004, respectively before the valuation allowance. The net deferred tax asset has been reduced to zero in both periods after consideration of the valuation allowance. A valuation allowance is recorded when, in the opinion of management, it is likely that some portion of the deferred tax asset will not be realized. Deferred taxes are adjusted for the effects of changes in tax laws and rates. No income taxes were paid in 2003, 2004 or 2005.

2. DEVELOPMENT STAGE OPERATIONS:

The Partnership was formed December 1, 2002. Through June 2004, operations were devoted to preconstruction costs such as obtaining approvals from FERC, obtaining the appropriate leases and permits, completing the engineering and environmental studies necessary for further development of the Facility, and obtaining financing to construct the Facility.

In June 2004, the Partnership obtained FERC approval for the Facility subject to satisfaction of certain conditions. The conditions were satisfied and FERC issued approval to begin construction in January 2005. Construction began on January 17, 2005. The construction of Phase 1 is expected to be completed in the first quarter of 2008.

The Partnership is also pursuing research and development for possible expansion of the Facility, the construction of an underground storage facility, and other opportunities.

3. LIQUIDITY AND CONTINUED OPERATIONS:

The Partnership will ultimately need to complete construction of the Facility and operate it profitably. There is significant construction which needs to be completed, and start up of Phase 1 of the Facility is expected in 2008.

Notwithstanding the foregoing, the Partnership believes it will continue as a going-concern based on favorable results related to the engineering studies, having secured all permits and government approvals required for Phase 1, the strong financial backing of its partners and future customers, its success in commercializing the expected available capacity, and its current financing obtained from ConocoPhillips and institutional investors.

4. AGREEMENT WITH CONOCOPHILLIPS:

The Partnership's general partner ("Freeport LNG GP Inc." or "Freeport GP"), and ConocoPhillips have executed an omnibus agreement. This agreement governs several transactions among the entities. The agreement was modified in the fourth quarter of 2005. The agreement, among other things, governs the following:

- ConocoPhillips agreed to pay the Partnership $10,000,000 for specific engineering and design studies, which occurred in January 2004. The Partnership recorded the payment as revenue in 2004.
- ConocoPhillips agreed to loan a substantial majority of the Facility's anticipated construction costs, including interest during the construction phase. The debt service under this loan will be fully serviced by the ConocoPhillips Terminal Use Agreement ("TUA"). The Partnership made loan draws of approximately $202,000,000 against this construction loan and expects to make additional loan draws in excess of $400,000,000 prior to completion of construction of the Facility. Additional draws were made against the loan subsequent to December 31, 2005.
- ConocoPhillips purchased 50% of the stock of Freeport LNG GP for $9,000,000 from the principal investor of Freeport LNG GP. After the purchase of the stock, ConocoPhillips and the principal investor of Freeport LNG GP each appointed three persons to a board which manages the construction and will manage operation of the Facility.
- ConocoPhillips agreed to a TUA which will govern the terms under which LNG is processed and will reserve a specified capacity.

5. DEFERRED REVENUE:

The Partnership received $3,500,000 from ConocoPhillips in 2004 and $1,500,000 from MC Global Gas Corporation in 2005 to reserve specific capacities that are expected to be available if the Partnership completes a potential Phase 2 expansion of the plant. This revenue will not be recognized unless a Phase 2 expansion is completed. The Partnership is still researching the feasibility of Phase 2, and at this time, it is uncertain when, or if, Phase 2 construction or operations will begin.

6. NOTES PAYABLE:

ConocoPhillips—The Partnership has entered into an agreement with ConocoPhillips to provide financing to construct the Facility. ConocoPhillips has agreed to finance the first $460,000,000 of construction cost, including $10,000,000 in support of any channel widening efforts undertaken by the Brazos River Harbor Navigation District (the "Port"), and has agreed to provide financing up to 50% of any additional supplemental costs incurred. The Partnership has drawn approximately $202,000,000 as of December 31, 2005. The interest rate on the note is 8%. Interest totaling $9,368,000 and $420,000 at December 31, 2005 and 2004, respectively, has been capitalized and all interest has been accrued and is included in notes payable as of December 31, 2005. Repayments on this loan will not begin until the Facility is constructed and operating. The loan is collateralized by all of the Phase 1 assets of the Partnership.

Institutional Investors—In December 2005 the Partnership completed a $383,000,000 private placement of notes payable. The purchasers were institutional investors. The notes bear an interest rate of 6.5%, which is subject to up to two 50 basis point upward adjustments, based on the creditworthiness of the customers. All interest on the notes was accrued at December 31, 2005. The notes begin amortizing in 2010, with final payment due in December 2015. The use of the proceeds is restricted for the remaining 50% of any additional Phase 1 supplemental costs (as described with ConocoPhillips above) and for certain other expansion, development or operational activities. In conjunction with the note placement, the Partnership capitalized approximately $6,959,000 of note offering costs, which are being amortized over the term of the notes. Amortization expense for 2005 was not material. The loan is collateralized by the Dow Terminal Use Agreement, by the underground storage assets, if constructed, of the Partnership and by a second lien on all Phase 1 assets of the Partnership.

7. COMMITMENTS:

The Partnership has entered into lease agreements with the Port for the lease of the land on which the Facility will be constructed and areas around the Facility. The leases will terminate in 2033, with six options to renew the leases for an additional 10 years for each option. The lease agreements require $2,300,000 in payments each year. The lease payments will also increase based on increases in the Consumer Price Index (“CPI”) from year to year.

Additionally, the leases provide that the Partnership will guarantee thru-put fees of $1,250,000 per year (subject to increase for the CPI index) to be received by the Dock Facilities operated by the Port from carriers shipping LNG to the Facility. This guarantee is expected to begin in 2008.

The Partnership has entered into a lease agreement in 2005 with Pinto Energy Partners, L.P. for the lease of land on which a storage facility may be constructed. The lease will terminate in 2033, with six options to renew for an additional 10 years for each option. Base rent is $250,000 until March 1, 2010. If construction of the storage facility has not begun prior to March 1, 2010, base rent will increase to $750,000 until construction begins. Based on the projected beginning of construction and the projected completion date, base rent will increase between $400,000 and $1,400,000. If the storage facility is completed (beginning no earlier than March 1, 2010), rent will increase to $2,000,000 per year. All amounts due under the lease are subject to annual adjustments based on the CPI. The Partnership also can make a one time payment of $2,500,000 between March 1, 2010 and April 30, 2010 to terminate the lease (adjusted for CPI), if construction has not started.

The Partnership office lease has a base rent of $194,000 per year with an estimated additional rent of $130,000 which will be adjusted by the landlord each calendar year. Additional rent is to reimburse taxes and expenses incurred by the landlord which the Partnership is obligated to pay based on the terms of the lease. The term of the lease is 100 months beginning on July 1, 2005.

The following table presents the future minimum lease payments due under the leases and ignoring any increases related to the CPI index, the thru-put guarantee, or increases based on construction of the storage facility:

	Land	Land-Storage	Office
2006	$ 2,300,000	$ 250,000	$ 324,000
2007	2,300,000	250,000	324,000
2008	2,300,000	250,000	324,000
2009	2,300,000	250,000	324,000
2010	2,300,000	250,000	324,000
Thereafter	50,600,000	17,000,000	974,000
	$62,100,000	$18,250,000	$2,594,000

Rent expense and related costs were $2,652,000, $820,000 and $573,000 for the years ended December 31, 2005, 2004 and 2003, respectively.

Employment Agreements—The Partnership has employment agreements with six key managers of the Partnership. The agreements define target annual variable compensation levels, vesting in profits participation, and define the duration of the employment obligation. The Partnership has accrued and, subsequent to December 31, 2005, paid all annual variable compensation obligations due under these agreements. The initial employment term has expired for a portion of the six employment agreements and the related employees are now "at will" employees with no Partnership obligation other than those associated with vested profits participation, if any. Because the Facility has not begun operation, the profits participation obligation, if any, cannot be determined. A maximum remaining salary obligation of not more than $300,000 remains under the portion of the agreements for which the initial term has not expired.

Related Parties—In December 2004, the Partnership entered into a consulting agreement with an affiliate of the principal investor of Freeport LNG GP to provide for chief executive officer services. The agreement requires yearly payments of $500,000 and reimbursement for travel and other expenses. In 2005 the Partnership expensed $500,000 for the consulting services and $635,000 for reimbursement of travel and other expenses.

Capacity Reservations—One of the Partnership's limited partners, Freeport LNG Investments LLLP, has entered into an agreement whereby it borrowed $5,000,000 from The Dow Chemical Company ("Dow"). In connection with this agreement, Freeport LNG Investments LLLP invested the proceeds of the loan as a capital contribution to the Partnership and the Partnership agreed to reserve a stipulated capacity at the Facility for Dow. The Dow Capacity Reservation and the ConocoPhillips TUA are expected to fully reserve substantially all of the Facility's anticipated Phase 1 capacity.

Turn-key Construction Contact—The Partnership has a turn-key construction contract for Phase 1 and for certain work that will facilitate expansion of the Facility with a fixed price of $577,798,000**,** which includes all change orders agreed to through December 31, 2005. It is reasonably possible that additional change orders will be executed, increasing the cost of the Facility.

Phase 2—The Partnership is evaluating the possibility of expanding the vaporization capacity of the Facility and evaluating the feasibility of constructing and operating an underground natural gas storage facility near Stratton Ridge, Texas. In May 2005 the Partnership filed an application with FERC to expand the permitted capacity of the plant to a total capacity of 4.0 BCFD. Approval is pending review by FERC. In conjunction with the possible expansion, the Partnership has submitted applications for permits from other governing agencies including the Texas Commission on Environmental Quality, the U.S Army Corp of Engineers, and the U.S Coast Guard. Subsequent to December 31, 2005, the Texas Railroad Commission has approved construction of the underground storage facility. The feasibility of both the expansion of the Facility and construction of an underground storage facility are ongoing.

8. OFFICE EQUIPMENT AND LEASEHOLD IMPROVEMENTS:

Property and equipment consists of:

	Years Ended December 31, 2005	2004
Office equipment	$ 440,000	$142,000
Leasehold improvements	1,395,000	44,000
Property and equipment	1,835,000	186,000
Less: accumulated depreciation	(221,000)	(42,000)
Total property and equipment, net	$1,614,000	$144,000

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES:

Accounts payable and accrued liabilities consist of the following:

	Years Ended December 31, 2005	2004
Employee bonuses	$ 572,000	$ 489,000
Engineering and study costs	1,069,000	275,000
Professional fees	1,730,000	644,000
Investment banking advisor fees	14,000	117,000
Construction related costs	49,308,000	3,688,000
Other accrued liabilities and payables	840,000	463,000
Total accounts payable and accrued liabilities	$53,533,000	$5,676,000

10. SUBSEQUENT EVENT:

Subsequent to December 31, 2005, the Partnership continued to construct Phase 1 and continued to borrow funds from ConocoPhillips. Additional research and development expenditures were made subsequent to December 31, 2005 for development activities on the possible Phase 2 expansion and possible storage facility.