CHENIERE ENERGY INC
Form 10-K
February 27, 2007
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2006

OR

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

For the transition period from to

Commission File No. 001-16383

CHENIERE ENERGY, INC.

(Exact name 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 x 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 x

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

Indicate by check mark 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. (Check one):

Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨

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

The aggregate market value of the registrant s Common Stock held by non-affiliates of the registrant was approximately $1,835,000,000 as of June 30, 2006.

56,027,811 shares of the registrant s Common Stock were outstanding as of February 20, 2007.

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.

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CAUTIONARY STATEMENT

REGARDING FORWARD-LOOKING STATEMENTS

This annual report contains certain statements that are, or may be deemed to be, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, 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 relating to the construction and operation of each of our proposed liquefied natural gas, or LNG, receiving terminals or our proposed pipelines, or expansions or extensions thereof, including statements concerning the completion or expansion thereof by certain dates or at all, the costs related thereto and certain characteristics, including amounts of regasification and storage capacity, the number of storage tanks and docks, pipeline deliverability and the number of pipeline interconnections, if any;
- statements that we expect to receive an order from the Federal Energy Regulatory Commission, or FERC, authorizing us to construct and operate proposed LNG receiving terminals or proposed pipelines by certain dates, or at all;
- statements regarding future levels of domestic natural gas production, supply or consumption; future levels of LNG imports into North America; sales of natural gas in North America; and the transportation, other infrastructure or prices related to natural gas, LNG or other energy sources or hydrocarbon products;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions, whether on the part of Cheniere or at the project level;
- statements regarding any terminal use agreement, 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 LNG regasification capacity that are, or may become, subject to TUAs or other contracts;
- statements regarding counterparties to our TUAs, construction contracts and other contracts;
- statements regarding any business strategy, any business plans or any other plans, forecasts, projections or objectives, 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 legislative, governmental, regulatory, administrative or other public body actions, requirements, permits, investigations, proceedings or decisions;
- statements regarding our anticipated LNG and natural gas marketing activities; and
- any other statements that relate to non-historical or future information.

These forward-looking statements are often identified by the use of terms and phrases such as achieve, anticipate, believe, 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. 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.

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PART I

ITEMS 1. AND 2. *BUSINESS AND PROPERTIES*

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 developing a business to market LNG and natural gas, primarily through our wholly-owned subsidiary, Cheniere Marketing, Inc., or Cheniere Marketing. To a limited extent, we are also engaged 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., which is incorporated in Delaware. 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 http://www.cheniere.com. We provide public access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to these reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC under the Exchange Act. These reports may be accessed free of charge through our internet website. We make our website content available for informational purposes only. The website should not be relied upon for investment purposes, nor is it incorporated by reference into this Form 10-K.

In this annual report, unless the context otherwise requires:

Bcf means billion cubic feet;

Bcf/d means billion cubic feet per day;

cm means cubic meter;

EPC means engineering, procurement and construction;

EPCM means engineering, procurement, construction and management;

IPA means indexed purchase agreement;

LNG means liquefied natural gas;

Mcf means thousand 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.

Our business activities are operated in four reporting segments in our financial statements for the years ended December 31, 2006, 2005 and 2004 as required under Statement of Financial Accounting Standards (SFAS) No. 131, *Disclosures about Segments of an Enterprise and Related Information*:

LNG receiving terminal,

natural gas pipeline,

LNG and natural gas marketing and

oil and gas exploration and development.

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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.

Our Business Strategy

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

- complete the development of our Sabine Pass LNG receiving terminal currently under construction in western Cameron Parish, Louisiana on the Sabine Pass Channel with an aggregate designed regasification capacity of approximately 4 Bcf/d;
- complete the development and construction of our two additional LNG receiving terminals, Corpus Christi LNG and Creole Trail LNG, upon, among other things, achieving acceptable commercial arrangements with an aggregate designed regasification capacity of approximately 6 Bcf/d;
- complete the development and construction of natural gas pipelines and other infrastructure to transport natural gas from our LNG receiving terminals to North American markets;
- develop an LNG and natural gas marketing business, including trading activities, by purchasing LNG under long-term IPAs, purchasing spot LNG on market-based terms, entering into natural gas storage arrangements, buying and selling natural gas in North America and engaging in financial derivative 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 limited oil and gas exploration and development activities generally.

LNG Receiving Terminal Business

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 North America. We have focused our development efforts on the following three LNG receiving terminal projects: Sabine Pass LNG in western Cameron Parish, Louisiana on the Sabine Pass Channel; Corpus Christi LNG near Corpus Christi, Texas; and Creole Trail LNG at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. Although we currently own 100% interests in each of the three LNG receiving terminals, we anticipate that our interest in the Sabine Pass LNG receiving terminal will decrease to approximately 92% upon completion of Cheniere Energy Partners, L.P. s proposed initial public offering. Financing for the Sabine Pass LNG receiving terminal has been obtained and construction commenced in March 2005. 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. In 2003, we formed Sabine Pass LNG, L.P., or Sabine Pass LNG, to own, develop and operate the Sabine Pass LNG receiving terminal. We have entered into leases for three tracts of land comprising 853 acres in Cameron Parish, Louisiana for the project site. Phase 1 of the Sabine Pass LNG receiving terminal was designed, and permitted by the FERC, with an initial regasification capacity of 2.6 Bcf/d and three LNG storage tanks with an aggregate LNG storage capacity of 10.1 Bcf and two unloading docks capable of handling the largest LNG carriers currently being operated or built. In July 2006, Sabine Pass LNG received approval from the FERC to increase the regasification capacity of the Sabine Pass LNG receiving terminal from 2.6 Bcf/d to 4.0 Bcf/d by adding up to three additional LNG storage tanks, additional vaporizers and related facilities. This expansion is referred to as Phase 2.

Phase 1

In March 2005, the FERC issued an order authorizing Sabine Pass LNG to commence construction of Phase 1 of the Sabine Pass LNG receiving terminal, subject to certain ongoing conditions. Construction of the Sabine Pass LNG receiving terminal began in March 2005. During the second quarter of 2008, we expect to complete construction and commissioning of the first two tanks, complete related equipment installation and specified checks and tests, and achieve a sustained revaporized natural gas sendout at a significant rate for a preagreed period of time. Sabine Pass LNG expects to complete construction and commissioning of the third tank and the rest of Phase 1, and to achieve the full 2.6 Bcf/d of Phase 1 regasification capacity, during the third quarter of 2008.

The cost to construct Phase 1 of the Sabine Pass LNG receiving terminal is currently estimated to be approximately $900 million to $950 million, before financing costs, but including the change orders discussed below. In December 2004, Sabine Pass LNG entered into a lump-sum turnkey agreement with Bechtel Corporation, or Bechtel, a major international EPC contractor, which as of February 14, 2007 requires Sabine Pass LNG to pay Bechtel $768.2 million, including change orders agreed to date. Our cost estimates are subject to change due to such items as cost overruns, change orders, delays in construction, increased component and material costs, escalation of labor costs and increased spending to maintain our construction schedules.

Phase 2

In July 2006, Sabine Pass LNG received authorization from the FERC to commence site preparation construction activities for the Phase 2 expansion of the Sabine Pass LNG receiving terminal, subject to certain ongoing conditions. The first stage of the Phase 2 expansion will include the addition of the fourth and fifth LNG storage tanks, additional vaporizers and related facilities, thereby increasing the total regasification capacity of the Sabine Pass LNG receiving terminal to 4.0 Bcf/d. This expansion is referred to as Phase 2 Stage 1. LNG regasification operations relating to the Phase 2 Stage 1 expansion are expected to commence by April 2009. Sabine Pass LNG expects to complete all of Phase 2 Stage 1, including construction and commissioning of the fourth and fifth tanks, and achieve full operability at 4.0 Bcf/d and an aggregate storage capacity of approximately 16.8 Bcf during the third quarter of 2009.

Phase 2 Stage 1 is estimated to cost approximately $500 million to $550 million, before financing costs. Operations relating to the Phase 2 Stage 1 expansion are expected to commence by April 2009, and all of Phase 2 Stage 1 is expected to be completed during the third quarter of 2009.

Construction Agreements

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 pursuant to which Bechtel agreed to provide Sabine Pass LNG with services for the engineering, procurement and construction of the Sabine Pass LNG receiving terminal. Except for certain specified third-party work outlined in the EPC agreement, the work to be performed by Bechtel includes all of the work required to achieve substantial completion and final completion of Phase 1 of the Sabine Pass LNG receiving terminal in accordance with the requirements of the EPC agreement, including achieving specified minimum acceptance criteria and performance guarantees. Sabine Pass LNG issued a notice to proceed 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 December 20, 2008. Final completion must be attained no later than 90 days after achieving substantial completion. 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 contingencies, change orders and other items. As of February 14, 2007, change orders for $121.3 million had been approved, increasing the total contract price to $768.2 million. Bechtel will be entitled to a scheduled bonus of $12 million if on or before April 3, 2008, Bechtel completes construction sufficient to achieve, among other requirements specified in the EPC agreement, a sustained sendout at a significant rate for a preagreed period of time (currently provided to be a rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours). The amount of such scheduled bonus will decrease by a specified amount for each day after April 3, 2008, that Bechtel fails to meet this test, up to a total of 40 days. The specified amount per day is $125,000 for the first 15 days, $300,000 for the next 10 days and $425,000 for the next 15 days. 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.

In July 2006, Sabine Pass LNG entered into three construction agreements to facilitate construction of the Phase 2 Stage 1 expansion, as follows:

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

Sabine Pass LNG entered into an EPC LNG tank contract with Zachry Construction Corporation, or Zachry, and Diamond LNG LLC, or Diamond, pursuant to which Zachry and Diamond will furnish all plant, labor, materials, tools, supplies, equipment, transportation, supervision, technical, professional and other services, and perform all operations necessary and required to satisfactorily engineer, procure materials for and construct the two Phase 2 Stage 1 LNG storage tanks. In addition, Sabine Pass LNG has the option (to be elected on or before March 31, 2007) for Zachry and Diamond to engineer, procure and construct a sixth LNG storage tank, with the cost and completion date to be agreed upon if the option is exercised. We do not expect to exercise this option. The tank contract provides that Zachry and Diamond will receive a lump-sum, total fixed price payment for the two Phase 2 Stage 1 tanks of approximately $140.9 million, which is subject to adjustment based on fluctuations in the cost of labor and certain materials, including the steel used in the Phase 2 Stage 1 tanks, and change orders.

Sabine Pass LNG entered into an EPC LNG unit rate soil contract with Remedial Construction Services, L.P., or Recon. Under the soil contract, Recon is required to furnish all plant, labor, materials, tools, supplies, equipment, transportation, supervision, technical, professional and other services, and perform all operations necessary and required to satisfactorily conduct soil remediation and improvement on the Phase 2 Stage 1 site, unless otherwise set forth in the soil contract. Upon issuing a final notice to proceed in August 2006, Sabine Pass LNG paid Recon an initial payment of approximately $2.9 million. The soil contract price is based on unit rates. Payments under the soil contract will be made based on quantities of work performed at unit rates.

Customers

Sabine Pass LNG has entered into three TUAs, through which Total LNG USA, Inc., or Total, Chevron U.S.A., Inc., or Chevron, and Cheniere Marketing have reserved, in the aggregate, the entire approximately 4.0 Bcf/d of LNG regasification capacity that will be available upon completion of Phase 1 and Phase 2 Stage 1

of the Sabine Pass LNG receiving terminal. The Total TUA and the Chevron TUA reserve a combined annual LNG regasification capacity of approximately 2.0 Bcf/d. Phase 1 of the Sabine Pass LNG receiving terminal (2.6 Bcf/d) will be sufficient to cover Sabine Pass LNG s obligations under the Total and Chevron TUAs. Cheniere Marketing has reserved all of the remaining capacity that will be available beyond the Total and Chevron TUA capacity reservations, upon completion of Phase 2 Stage 1, as well as any Phase 1 capacity that is available prior to the commencement of the Total and Chevron TUAs and after Sabine Pass LNG has fulfilled its obligations under the Total and Chevron TUAs.

Total TUA

In September 2004, Sabine Pass LNG entered into a TUA with Total to provide berthing for LNG vessels and for the unloading, storage and regasification of LNG at the Sabine Pass 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 vessels, including the provision of tugboats, (ii) the transportation of natural gas downstream from the Sabine Pass LNG receiving 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%.

Total s fees under the TUA are payable monthly in advance, commencing with the commercial start date of April 1, 2009 (subject to achieving commercial operations completion by that date, and subject to delay by events of *force majeure*) and will continue for a term of 20 years subject to six additional 10-year extension terms. Commercial operations completion will be achieved when the Sabine Pass LNG receiving terminal is ready to be used for its intended purpose to provide the services called for under the Total TUA, with Bechtel as contractor for the Phase 1 EPC agreement having achieved all minimum acceptance requirements under the Phase 1 EPC agreement sufficient to provide the services called for under the Total TUA and contracts with other customers purchasing LNG terminalling services from Sabine Pass LNG similar to the services called for under the Total TUA. Under the Total TUA, Total will 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, which are due on the 25th of the month prior to the month in which Sabine Pass LNG provides services under the Total TUA, are equivalent to payments of $0.28 per MMBtu for capacity and $0.04 per MMBtu (subject to adjustment for inflation) for operating fees, respectively, of reserved monthly LNG receipt capacity. In addition, each month Sabine Pass LNG is entitled to receive a retainage equal to 2% of the LNG delivered for Total s account, which Sabine Pass LNG will use primarily as fuel for revaporization and self-generated power and to cover natural gas unavoidably lost at the facility.

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 Sabine Pass LNG s costs in relation to the services provided or the LNG receiving terminal, Total will bear 40% of such taxes or increased regulatory costs. When LNG regasification capacity exceeds 3.0 Bcf/d, Total will thereafter bear a proportionate share of such taxes or increased regulatory costs, not to exceed 40%. After the Chevron and Total TUAs commence, Sabine Pass LNG expects that Total s proportionate share of such taxes and increased regulatory costs will be 25%. To the extent any ad valorem taxes are imposed and not abated, Sabine Pass LNG 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.

Either party may assign its interests under the TUA to affiliates, and, as permitted by the TUA, Sabine Pass LNG has pledged its interest under the TUA to the collateral trustee of the $550 million of 7 1/4% Senior Secured

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Notes due 2013 and $1,482 million of 7 $^{1}/2$% Senior Secured Notes due 2016, which we refer to as the Sabine Pass LNG notes, issued by Sabine Pass LNG in November 2006 to secure its obligations under the Sabine Pass LNG notes. 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.

An assignment under the TUA will extinguish Total 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 as or better than the guarantor, in the case of Total, or Sabine Pass LNG.

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, and such proceedings are not stayed within 60 days of service.

Either party may terminate the TUA with 30 days written notice if (i) a party has failed to pay when due an amount to the other party 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.

Sabine Pass LNG also entered into an omnibus agreement with Total 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 its affiliates, for capacity of 50 MMcf/d or more, with a term of five years or more, prior to the commercial start date under the TUA, 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.

Chevron TUA

In November 2004, Sabine Pass LNG entered into a TUA with Chevron to provide berthing for LNG vessels and for the unloading, storage and regasification of LNG at the Sabine Pass LNG receiving terminal. Sabine Pass LNG has no obligation to provide certain services such as (i) harbor, mooring and escort services for LNG vessels, including the provision of tugboats, (ii) the transportation of natural gas downstream from the Sabine Pass LNG receiving terminal or the construction of any pipelines to provide such transportation or (iii) the marketing of natural gas. Under the amended TUA, Chevron has reserved 403,945,500 MMBtu of annual LNG receipt capacity, which is equal to approximately 1.0 Bcf/d of regasification capacity, assuming an energy content of 1.085 MMBtu per Mcf and retainage of 2%.

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Although Chevron could select a date as early as February 1, 2009, it is expected that payments of fees under the Chevron TUA will commence on July 1, 2009 (subject to achieving commercial operations completion by that date, and subject to delay caused by events of *force majeure*). Chevron s fees under the Chevron TUA are payable monthly in advance and will continue for a term of 20 years subject to two additional 10-year extensions. Under the Chevron TUA, Chevron is required to pay Sabine Pass LNG a fixed monthly fee for this regasification capacity that consists of (i) a reservation fee of $9.4 million, (ii) an operating fee of $1.3 million 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 receive a retainage equal to 2% of the LNG delivered for Chevron s account, which Sabine Pass LNG will use primarily as fuel for revaporization and self-generated power and to cover natural gas unavoidably lost at the facility. Chevron s payments under the Chevron TUA are due on the 25th of the month prior to the month in which Sabine Pass LNG provides services under the Chevron TUA. Chevron Corporation has guaranteed Chevron 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 Sabine Pass LNG receiving terminal or (ii) enacts any safety or security related regulation which materially increases Sabine Pass LNG s costs in relation to the services provided at the Sabine Pass LNG receiving terminal, Chevron will bear a proportionate share of such taxes or increased regulatory costs, not to exceed 28%. After the Chevron and Total TUAs commence, Sabine Pass LNG expects that Chevron s proportionate share of such taxes and increased regulatory costs will be 25%.

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

Both parties may assign their interests under the TUA to affiliates, and, as permitted by the TUA, Sabine Pass LNG has pledged its interest under the TUA to the collateral trustee of the Sabine Pass LNG notes to secure its obligations under the Sabine Pass LNG notes. In addition, Chevron may make a partial assignment of its total reserved regasification capacity to non-affiliates provided (i) the assignee agrees to be bound by the TUA, (ii) the parent guarantee continues to apply to all assigned obligations, (iii) Chevron 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 extinguish Chevron 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 as or better than the guarantor, in the case of Chevron, or Sabine Pass LNG.

Chevron 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 s actions, if Sabine Pass LNG:

- fails to deliver at least 191,625,000 MMBtu of Chevron s total natural gas nominations in a 12-month period;
- fails entirely to receive 15 cargoes or more nominated by Chevron over a period of 90 days; or
- fails to unload, or notify Chevron that Sabine Pass LNG would be unable to unload, 50 cargoes or more scheduled for delivery by Chevron for a 12-month period.

Sabine Pass LNG may terminate the TUA if the parent guarantee ceases to be in full force and effect or if Chevron or its parent guarantor, Chevron Corporation, 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 to the other party 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 Marketing TUA

In November 2006, Sabine Pass LNG entered into an amended and restated TUA with Cheniere Marketing, a wholly-owned subsidiary of Cheniere, to provide berthing for LNG vessels and for the unloading, storage and regasification of LNG at the Sabine Pass LNG receiving terminal. Sabine Pass LNG has no obligation to provide Cheniere Marketing with certain services such as (i) harbor, mooring and escort services for LNG vessels, including the provision of tugboats, (ii) the transportation of natural gas downstream from the Sabine Pass LNG receiving terminal or the construction of any pipelines to provide such transportation or (iii) the marketing of natural gas. Under the Cheniere Marketing TUA, Cheniere Marketing will pay fees to Sabine Pass LNG based on 781,830,000 MMBtu of stipulated maximum annual LNG reception quantity, which is equivalent to approximately 2.0 Bcf/d of regasification capacity assuming an energy content of 1.05 MMBtu per Mcf and retainage of 2%. The stipulated maximum LNG reception quantity allocated to Cheniere Marketing is reduced to the extent that the Sabine Pass LNG receiving terminal is unable to provide services up to such amount as a result of the timing of start dates under existing customer agreements (including the Total and Chevron TUAs) or delays in commencing commercial operation of the Phase 2 Stage 1 expansion of the Sabine Pass LNG receiving terminal; however, the fees to be paid by Cheniere Marketing under the Cheniere Marketing TUA will not be accordingly adjusted.

Cheniere Marketing s fees under the Cheniere Marketing TUA are payable monthly in advance commencing on the commercial start date (which will be the later of January 1, 2008 or the date when commercial operations completion is achieved), and will continue for a term of 20 years subject to four additional 10-year extension terms. Commercial operations completion will be achieved when the Sabine Pass LNG receiving terminal is ready to be used for its intended purpose to provide the services called for under the Cheniere Marketing TUA, with Bechtel as contractor for the Phase 1 EPC agreement having achieved all minimum acceptance requirements under the Phase 1 EPC agreement sufficient to provide the services called for under the Cheniere Marketing TUA. Under the Cheniere Marketing TUA, Cheniere Marketing 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 times 1/12 of the stipulated maximum annual LNG reception quantity; (ii) an operating fee of $0.04 per MMBtu times 1/12 of the stipulated maximum annual LNG reception quantity, which operating fee is adjusted annually for changes in the U.S. Consumer Price Index (All Urban Consumers); and (iii) certain other taxes and regulatory costs. Notwithstanding the foregoing, Cheniere Marketing is required to pay a flat fee of $5 million per month from the commercial start date under the Cheniere Marketing TUA through December 31, 2008. Cheniere Marketing s payments under the Cheniere Marketing TUA are due on the 25th of the month prior to the month in which Sabine Pass LNG provides services under the Cheniere Marketing TUA. In addition, each month, Sabine Pass LNG is entitled to receive a retainage equal to 2% of the LNG delivered for Cheniere Marketing s account, which Sabine Pass LNG will use primarily as fuel for revaporization and self-generated power and to cover natural gas unavoidably lost at the facility. All of Cheniere Marketing s obligations during the initial 20-year term of the TUA are supported by an irrevocable guaranty in favor of Sabine Pass LNG by Cheniere.

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 Cheniere Marketing TUA, or the Sabine Pass LNG receiving terminal or (ii) enacts any safety or security related regulation which materially increases Sabine Pass LNG s costs in relation to the services provided at the Sabine Pass LNG receiving terminal, Cheniere Marketing will bear such taxes or increased regulatory costs at a rate proportional to its percentage of the right to use of the Sabine Pass LNG receiving terminal s total capacity. After the Chevron and Total TUAs commence, Sabine Pass LNG expects that Cheniere Marketing s proportionate share of such taxes and increased regulatory costs will be 50%.

Both Sabine Pass LNG and Cheniere Marketing may assign their respective interests under the Cheniere Marketing TUA to affiliates, as long as such assignment is not made prior to the first business day following the

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Cheniere Marketing TUA s commercial start date. As permitted by the Cheniere Marketing TUA, Sabine Pass LNG has pledged its interest under the Cheniere Marketing TUA to the collateral trustee under the Sabine Pass LNG notes to secure its obligations under the Sabine Pass LNG notes. In addition, Cheniere Marketing may make a partial assignment of its total reserved regasification capacity (but not its rights to excess capacity described below) to non-affiliates provided that (i) the assignee agrees to be bound by the Cheniere Marketing TUA, (ii) Cheniere Marketing continues to be liable for all payments due under the Cheniere Marketing TUA and (iii) Cheniere Marketing and the assignee designate a representative and jointly exercise all rights under the Cheniere Marketing TUA.

An assignment under the Cheniere Marketing TUA will terminate Cheniere Marketing s obligations only if (i) the assignment constitutes all of Cheniere Marketing s rights and obligations, (ii) the assignee agrees to assume all obligations of the assignor from inception of the Cheniere Marketing TUA and (iii) the assignee demonstrates creditworthiness at the time of the assignment that is reasonably acceptable to Sabine Pass LNG (and including credit standards that will be deemed acceptable).

Cheniere Marketing may terminate the Cheniere Marketing 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 Cheniere Marketing s actions, if Sabine Pass LNG:

- fails to deliver at least 201,972,750 MMBtu of Cheniere Marketing s total natural gas nominations in a 12 month period;
- fails entirely to receive at least 17 cargoes nominated by Cheniere Marketing over a period of 90 consecutive days; or
- fails to unload 53 cargoes or more scheduled for delivery by Cheniere Marketing for a 12-month period.

Sabine Pass LNG may terminate the Cheniere Marketing TUA if Cheniere Marketing commences bankruptcy, reorganization or liquidation proceedings, or has such proceedings commenced against it, and such proceedings are not stayed within 60 days of service.

Either party may terminate the Cheniere Marketing TUA with 30 days written notice if (i) a party has failed to pay when due an amount owed to the other party 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 Cheniere Marketing TUA.

The Cheniere Marketing TUA is designed to work in tandem with the Total TUA and the Chevron TUA and states that no provision of the Cheniere Marketing TUA shall be effective if and to the extent that it expressly conflicts with a provision of the Total TUA or the Chevron TUA. Any excess capacity at the Sabine Pass LNG receiving terminal that Sabine Pass LNG is not contractually obligated to make available to any other customer, and any capacity that any other customer elects not to use, may be used exclusively by Cheniere Marketing without any additional charge or fee except for 2% retainage and port charges in respect of vessels entering or leaving the Sabine Pass LNG receiving terminal. This excess capacity may be available from time to time, including at completion of Phase 1 and the outset of commercial operation of the Sabine Pass LNG receiving terminal, which is the date on which the Sabine Pass LNG receiving terminal is projected to have capacity of 2.6 Bcf/d.

The Cheniere Marketing TUA provides that, at Cheniere Marketing s request, Sabine Pass LNG must construct a sixth LNG storage tank with a working capacity of approximately 160,000 cubic meters of LNG for the benefit of Cheniere Marketing as soon as possible but not later than four years after notification from Cheniere Marketing. Sabine Pass LNG s obligation to construct the additional LNG storage tank will be subject to its receipt of all FERC and other required governmental permits and approvals and obtaining financing that it considers reasonably acceptable in form and content.

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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. The Corpus Christi LNG receiving terminal was designed, and permitted by the FERC, with a regasification capacity of 2.6 Bcf/d, three LNG storage tanks with an aggregate LNG storage capacity of 10.1 Bcf and two unloading docks capable of handling the largest LNG carriers currently being operated or built. We estimate that the cost to construct the Corpus Christi LNG receiving terminal 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 and is subject to change.

In December 2005, the FERC issued an order authorizing Corpus Christi LNG to commence initial construction of the Corpus Christi LNG receiving terminal, subject to satisfaction of certain conditions specified by the FERC. In order to accelerate the timing of developing the Corpus Christi LNG receiving terminal, Corpus Christi LNG elected in April 2006 to commence preliminary site work and entered into an engineering, procurement and construction services agreement for preliminary work with La Quinta LNG Partners, L.P., or La Quinta. La Quinta is a limited partnership whose general partners are Zachry and AMEC E&C Services, Inc. Under the terms of the agreement, La Quinta has provided Corpus Christi LNG with certain preliminary design, engineering, construction and site preparation work on a reimbursable basis in connection with the Corpus Christi LNG receiving terminal. Such preliminary site work commenced during the second quarter of 2006 and has been substantially completed. We anticipate that payments to be made by Corpus Christi LNG to La Quinta for work performed under the agreement will not exceed $35 million. We will contemplate making a final investment decision to complete construction of the Corpus Christi LNG receiving terminal upon, among other things, achieving acceptable commercial arrangements.

Customers

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

Creole Trail LNG

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 was designed, and permitted by the FERC, with a regasification capacity of 3.3 Bcf/d, four LNG storage tanks with an aggregate LNG storage capacity of 13.5 Bcf and two unloading docks capable of handling the largest LNG carriers currently being operated or built. We estimate that the cost to construct the Creole Trail LNG receiving terminal will be approximately $850 million to $950 million, before financing costs. Our cost estimate is preliminary and is subject to change.

In June 2006, the FERC authorized Creole Trail LNG to site, construct and operate the Creole Trail LNG receiving terminal. We will contemplate making a final investment decision to commence construction of the Creole Trail LNG receiving terminal upon, among other things, achieving acceptable commercial arrangements.

Customers

We have not entered into any contracts for the regasification capacity at our proposed Creole Trail LNG receiving terminal.

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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

We own a 30% limited partner interest in Freeport LNG Development, L.P., or Freeport LNG, which is developing an LNG receiving facility on Quintana Island near Freeport, Texas. The first 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 Bcf, and a 9.4-mile, 42-inch diameter pipeline through which natural gas will be transported to customer redelivery points at Stratton Ridge, Texas. We expect that the first phase of the Freeport LNG receiving terminal project will commence operations in the first half of 2008. The proposed second phase of the project includes additional regasification capacity of 2.5 Bcf/d, a second dock, a third LNG storage tank with capacity of 3.3 Bcf and 7.5 Bcf of underground salt cavern gas storage. The FERC has authorized Freeport LNG to commence construction of the proposed second phase of the project.

Freeport LNG has entered into TUAs with three customers: The Dow Chemical Company for approximately 500 MMcf/d of regasification capacity; ConocoPhillips Company for approximately 1.0 Bcf/d of regasification capacity in the first phase and approximately 300 MMcf/d of additional regasification capacity in the proposed second phase; and MC Global Gas Corporation, a wholly-owned subsidiary of Mitsubishi Corporation, for approximately 150 MMcf/d of regasification capacity in the proposed second phase and an option to reserve approximately 100 MMcf/d of additional regasification capacity in the second phase. We believe that Freeport LNG has obtained sufficient financing to fund the first phase of the project and a portion of the proposed second phase; as a result, we do not anticipate that any capital calls will be made upon the limited partners of Freeport LNG in the foreseeable future.

Competition

New supplies to meet North America s natural gas demand 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 energy currently met by natural gas could alternatively be met by other energy forms such as coal, hydroelectric, oil, wind, solar and nuclear energy. LNG will face competition from each of these energy sources.

We compete with other companies to be among the first to construct LNG receiving terminals in economically desirable locations. According to the FERC, as of December 18, 2006, there were six existing LNG receiving terminals in North America, including one offshore facility for receiving LNG regasified aboard specialized LNG vessels, as well as 44 new LNG receiving terminals or expansions approved or proposed to be constructed in the U.S., of which six are under construction. To the extent not already fully contracted, and if and when we have to replace any TUAs, we will compete with these existing and proposed North American LNG receiving terminals and their customers. In addition, as of December 31, 2005, there were 51 LNG receiving terminals in 15 countries and other proposed LNG receiving terminals worldwide with which we will compete to be the most economical delivery point for LNG production for both long-term contracted and spot volumes.

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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 that we engage in consultations with certain federal and state agencies and that we obtain certain permits and other authorizations before commencement of construction and operation of LNG receiving terminals. This regulatory burden increases the cost of constructing and operating the LNG receiving terminals, and failure to comply with such laws could result in substantial penalties.

FERC

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

- initial public notice and public meetings;
- data gathering and analysis at the FERC s request;
- issuance of a Draft Environmental Impact Statement by the FERC;
- additional public meetings, as warranted;
- issuance of a Final Environmental Impact Statement by the FERC; and
- the FERC order authorizing construction.

In addition, orders from the FERC authorizing construction of an LNG receiving terminal are typically subject to specified conditions that must be satisfied throughout the construction, commissioning and operation of terminals. Those conditions require us to:

- appoint third-party environmental inspectors to monitor compliance with the FERC s conditions;
- submit any material changes to the design or construction of the facility for FERC approval;
- submit an implementation plan for compliance with the FERC-ordered mitigation measures;
- submit monthly construction reports and weekly environmental reports detailing construction progress and ongoing compliance efforts;

- comply with U.S. Fish and Wildlife Service guidelines regarding lighting;
- file a Coastal Zone Management Plan consistency determination;
- limit construction activities to comply with noise limits and regulations and file a noise survey; and
- file plans regarding the installation, implementation and operation of various safety measures and comply with those plans.

In addition, throughout the life of our LNG receiving terminals, they will be subject to regular reporting requirements to the FERC and the Department of Transportation regarding the operation and maintenance of the facilities.

Other Federal Governmental Permits, Approvals and Consultations

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

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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 operations focus on two areas: infrastructure development, and market manipulation and enforcement. Regarding infrastructure development, the EPAct states that the FERC has exclusive authority to approve or deny an application for the siting, construction, expansion or operation of an LNG receiving terminal. Regarding market manipulation and enforcement, the EPAct amends the NGA to prohibit market manipulation. The EPAct also amends the NGA and the Natural Gas Policy Act of 1978, or NGPA, to increase civil and criminal penalties for any violations of the NGA, NGPA and any rules, regulations or orders of the FERC up to $1 million per day per violation. In addition, the 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 the FERC s jurisdiction, to defraud, make an untrue statement or omit a material fact or engage in any practice, act or course of business that operates or would operate as a fraud. This final rule works together with the FERC s enhanced penalty authority to provide increased oversight of the natural gas marketplace.

Environmental Regulation

Our LNG receiving terminal operations are subject to various federal, state and local laws and regulations relating to the protection of the environment. In some cases, these laws and regulations require us to obtain governmental permits and authorizations before we may conduct certain activities. These environmental laws and regulations may impose substantial penalties for noncompliance and substantial liabilities for pollution. Many of these laws and regulations restrict or prohibit the types, quantities and concentration of substances that can be released into the environment and can lead to substantial liabilities for non-compliance or for pollution or releases of hazardous substances, materials or compounds or otherwise 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 substantial civil and criminal fines and penalties. As with the industry generally, our operations will entail risks in these areas, and compliance with these laws and regulations increases our overall cost of business. While these laws and regulations affect our capital expenditures and earnings, we believe that these laws and regulations do not affect our competitive position in the industry because our competitors are similarly affected. Environmental laws and regulations have historically been subject to frequent revision and reinterpretation. Consequently, we are unable to predict the future costs or other future impacts of environmental regulations on our future operations.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)

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

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Clean Air Act (CAA)

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

Certain persons have expressed concerns that air emissions from the Sabine Pass LNG receiving terminal, which are allowed under Sabine Pass LNG s existing permits, could adversely impact regional air quality in southeastern Texas so as to trigger future federal sanctions for that area under the CAA. While we have no reason to believe that any formal challenge will be made regarding Sabine Pass LNG s existing permits under the CAA, such challenges may be pursued and, if pursued, may result in costs or conditions that could have a material adverse effect on our business and operations.

Clean Water Act (CWA)

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

Resource Conservation and Recovery Act (RCRA)

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

Endangered Species Act

Our operations and planned construction activities may also be restricted by requirements under the Endangered Species Act, 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 Business

We formed Grand Cheniere Pipeline, LLC, a wholly-owned subsidiary, to develop natural gas pipelines that will provide access to North American natural gas markets for customers of our Sabine Pass, Corpus Christi and Creole Trail LNG receiving terminals. Our pipeline systems will connect with multiple interstate 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, L.P., a wholly-owned subsidiary of Cheniere, to develop a 16-mile, 42-inch diameter interstate natural gas pipeline that is designed to transport 2.6 Bcf/d of regasified LNG, connecting from the Sabine Pass LNG receiving terminal and running easterly along a corridor that will allow for interconnection points with existing interstate and intrastate natural gas pipelines in southwest Louisiana, including interstate pipelines operated by Natural Gas Pipeline Company of America,

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Transcontinental Gas Pipe Line Corporation, Tennessee Gas Pipeline Company, Florida Gas Transmission and Bridgeline Holdings, L.P. We expect to install interconnects with these existing pipelines, which will initially allow 1.6 Bcf/d of natural gas to be transported. We will be able to transport additional natural gas from the Sabine Pass LNG receiving terminal upon completion of Phase 1 of the Creole Trail Pipeline, as discussed below, or upon installation of additional interconnected capacity with these existing pipelines.

The FERC issued an order in December 2004 authorizing us to construct, own and operate the Sabine Pass Pipeline, subject to specified conditions that must be satisfied. Preliminary engineering, survey and easement acquisition is nearing completion on the Sabine Pass Pipeline. In February 2006, Cheniere Sabine Pass Pipeline, L.P. entered into an EPC pipeline contract with Willbros Engineers, Inc. for the management, engineering, material procurement, construction and construction management of the Sabine Pass Pipeline. We anticipate commencing construction of the Sabine Pass Pipeline in the second quarter of 2007 with construction completed and the pipeline available for commercial operations in the fourth quarter of 2007.

We estimate that the cost to construct the Sabine Pass Pipeline will be approximately $100 million, before financing costs. This estimate is subject to change due to such items as cost overruns, change orders, delays in construction, increased component and material costs and escalation of labor costs.

Creole Trail Pipeline

We formed Cheniere Creole Trail Pipeline, L.P., a wholly-owned subsidiary of Cheniere, or CCTP, to develop a 137-mile, 42-inch diameter interstate natural gas pipeline. The Creole Trail Pipeline is being constructed in two phases. Phase 1 consists of approximately 78 miles of natural gas pipeline interconnecting with the Sabine Pass Pipeline, running east to the site of the Creole Trail LNG receiving terminal and then north and northeast along a corridor that will allow for interconnection points with existing interstate and intrastate natural gas pipelines in southwest Louisiana, which we believe are currently capable of transporting approximately 4.4 Bcf/d. Phase 2 of the Creole Trail Pipeline consists of approximately 59 miles of natural gas pipeline running from the terminus of Phase 1 east to a terminus near Rayne, Louisiana, along a corridor that will allow for interconnection points with existing interstate and intrastate natural gas pipelines, which we believe are currently capable of transporting approximately 7.2 Bcf/d.

The FERC has issued orders authorizing us to construct, own and operate the Creole Trail Pipeline. These authorizations are subject to specified conditions that must be satisfied. CCTP filed an application with the FERC in November 2006 to amend the order received in June 2006 by modifying the planned dual pipeline to be a single pipeline. In December 2006, the FERC issued an order approving the application and partially vacated the previously authorized capacity, thereby reducing the pipeline to a single pipeline capable of transporting 2.0 Bcf/d. Should market demand for transportation service on the Creole Trail Pipeline increase as a result of the Creole Trail LNG receiving terminal commencing commercial operations, CCTP will seek additional FERC authorization at that time to modify its receipt pattern or to increase its pipeline capacity as necessary to satisfy such demand. Once the Creole Trail LNG receiving terminal becomes operational, the flow of gas on the Creole Trail Pipeline may be modified, with volumes moving both west and north/northeast from the Creole Trail LNG receiving terminal, to accommodate the full sendout requirements of the Creole Trail LNG receiving terminal. The increase in pressure resulting from operation of the Creole Trail LNG receiving terminal, in conjunction with the modified receipt pattern, will enable CCTP to transport up to 3.3 Bcf/d on a long-term basis. Alternatively, CCTP may seek additional FERC authorization to modify the Creole Trail Pipeline via extension, looping or compression addition as dictated by evolving market requirements.

CCTP has issued purchase orders to ILVA, S.p.A. and CPW America Co. for the purchase of all of the pipe needed to construct both Phase 1 and Phase 2 of the Creole Trail Pipeline. In the first quarter of 2007, CCTP entered into construction agreements with Sunland Construction, Inc. and Sheehan Pipe Line Construction Company to construct Phase 1 of the Creole Trail Pipeline. A construction contract is currently under negotiation

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for approximately 18 miles of Phase 1 of the Creole Trail Pipeline. We anticipate that construction of Phase 1 of the Creole Trail Pipeline will commence in the second quarter of 2007 and that Phase 1 operations will commence in the second quarter of 2008. Construction contracts for Phase 2 of the Creole Trail Pipeline have not been negotiated.

The total anticipated cost to construct Phase 1 and Phase 2 of the Creole Trail Pipeline is approximately $400 million to $450 million and $200 million to $250 million, respectively, before financing costs. Our cost estimates are subject to change due to such items as cost overruns, change orders, delays in construction, increased component and material costs and escalation of labor costs.

Corpus Christi Pipeline

We formed Cheniere Corpus Christi Pipeline, L.P., a wholly-owned subsidiary of Cheniere, to develop a 24-mile, 42-inch interstate natural gas pipeline that is designed to transport 2.6 Bcf/d of regasified LNG, connecting from the Corpus Christi LNG receiving terminal and 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 Pipe Line 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.

The FERC issued an order in April 2005 authorizing us to construct, own and operate the Corpus Christi Pipeline, subject to specified conditions that must be satisfied. Construction contracts for the Corpus Christi 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.

Customers

We offered our pipeline capacity to potential customers through a formal request-for-proposal process, and awarded our marketing affiliate all of the capacity in each of our proposed 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. 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 desire to also 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 pipelines will 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, the FERC s continuing efforts to increase competition in the natural gas industry are increasing the natural gas transportation options of a pipeline s traditional customers.

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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 and Creole Trail 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 the Sabine Pass LNG receiving terminal. The Kinder Morgan Louisiana Pipeline will consist of two segments: a 137-mile, 2.0 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 the Sabine Pass LNG receiving terminal. Total and Chevron 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, the FERC regulates the transportation of natural gas in interstate commerce. Under the FERC s regulations, transportation service includes natural gas storage service. In general, the FERC s authority to regulate pipelines and the services that they provide includes:

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

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

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

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

Order No. 436 (1985), which requires open-access, nondiscriminatory transportation of natural gas;

Order No. 497 (1988), which set forth new standards and guidelines imposing certain constraints on the interaction between interstate natural gas pipelines and their marketing affiliates and imposing certain disclosure requirements regarding that interaction;

Order No. 636 (1992), which required interstate natural gas pipelines that perform open-access transportation under blanket certificates to unbundle or separate their traditional merchant sales services from their transportation and storage services and to provide comparable transportation and storage services with respect to all natural gas supplies whether purchased from the pipeline or from other merchants such as marketers or producers. Order No. 636 also permitted pipeline customers to

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release all or part of their firm transportation capacity to third parties. Order 636 has been affirmed in all material respects upon judicial review; and

Order No. 637 (2000), which, among other things, required pipelines to implement imbalance management services; restricted the ability of pipelines to impose penalties for imbalances, overruns and non-compliance with operational flow orders; and implemented new pipeline reporting requirements.

In November 2003, the FERC issued a series of orders adopting revised Standards of Conduct (Order No. 2004) that apply uniformly to interstate natural gas pipelines. These Standards of Conduct were designed to govern relationships between the pipeline and any energy affiliate, rather than governing conduct between the pipeline and its marketing affiliate. However, in 2006, Order No. 2004, as applied to natural gas pipelines, was vacated by a federal court, and the FERC issued an interim rule which expressly states that the Standards of Conduct do not govern the relationship between natural gas pipelines and its energy affiliates. Shortly thereafter, the FERC issued a notice of proposed rulemaking, which, among other things, requests comments as to whether the interim rule should be made permanent. The comment period will last approximately two months after which time the FERC will issue a final rule.

Our Sabine Pass Pipeline, Corpus Christi Pipeline and Creole Trail Pipeline will be interstate natural gas pipelines, which will connect our LNG receiving terminals 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 the FERC s regulation under Section 4 of the NGA. Our interstate pipelines will also be subject to the FERC s open access requirements. The FERC s exercise of jurisdiction over interstate natural gas pipelines is substantially broader than its exercise of jurisdiction over LNG receiving 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 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 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 not unduly discriminatory. Amounts collected by the pipeline that the FERC finds unlawful are subject to refund with interest.

Environmental Regulation

Our natural gas 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 Business Governmental Regulation Environmental Regulation above.

LNG and Natural Gas Marketing Business

We are in the early stages of developing our LNG and natural gas marketing business. Cheniere Marketing has entered into a TUA with each of the Sabine Pass and Corpus Christi LNG receiving terminals. Cheniere Marketing anticipates entering into long-term agreements for the purchase of LNG 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 revaporization capacity at our LNG receiving 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. Alternatively, we may purchase LNG from foreign suppliers and sell the LNG to foreign purchasers if more favorable economic conditions exist in those markets. In order to develop our marketing capability, we are engaging in domestic natural gas purchase and sale, transportation and storage transactions as part of our initial activities.

To engage in the foregoing commercial activities, Cheniere Marketing has entered into, or intends to enter into, various commercial transactions. These transactions include master natural gas sales contracts, generally using contracts promulgated by the North American Energy Standards Board, or the NAESB contracts; short-term natural gas transportation contracts with various domestic transporters, including parking and loan agreements; financial derivatives agreements, generally using ISDA form contracts promulgated by the International Swap Dealers Association; and futures brokerage and clearing agreements with Calyon Financial and Man Financial, Inc. Our marketing activities will also include the use of derivative transactions in order to take market positions or manage and hedge exposure to price, volume, timing, location, quality and credit risk associated with the marketing of LNG and natural gas. We have developed risk management policies, procedures and systems, which are reviewed regularly, to assist us in controlling and managing our marketing activities.

We have committed $40 million initially to our marketing and trading activities, in addition to overhead costs and natural gas storage charges. We expect that our LNG and natural gas marketing business will have additional capital requirements as its activities expand, which we plan to provide from our available cash or secure from third parties. Lack of access to capital resources could limit the activities of our LNG and natural gas marketing business in the future.

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 (other than the PPM Energy agreement discussed below and the NAESB contracts), and we may not be able to obtain any such long-term agreements on terms acceptable to us, or at all. Credit support will be required by certain counterparties to the above-referenced transactions, including derivatives, which may subject us to additional funding requirements.

Capacity Agreements

In 2006, Cheniere Marketing entered into TUAs for 2.0 Bcf/d and 1.0 Bcf/d of regasification capacity at the Sabine Pass and Corpus Christi LNG receiving terminals, respectively. See LNG Receiving Terminal Business Our LNG Receiving Terminals Sabine Pass LNG Customers Cheniere Marketing for a more detailed description of the TUA for the regasification capacity at the Sabine Pass LNG receiving terminal.

We have also entered into a ten-year natural gas storage contract, commencing on April 1, 2008, for natural gas storage services of up to a maximum of 3.0 Bcf at a storage facility in Michigan.

Cheniere Marketing has entered into binding precedent agreements for transportation services on each of the Sabine Pass Pipeline, Creole Trail Pipeline and Corpus Christi Pipeline 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. 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 desire to also enter into agreements for the transportation of revaporized gas on our proposed pipelines.

Customers

In April 2006, Cheniere Marketing entered into a gas purchase agreement with PPM Energy, Inc., or PPM, which is a U.S. subsidiary of Scottish Power plc, a developer and operator of renewable energy in both the United Kingdom and the U.S. Pursuant to the gas purchase agreement, Cheniere Marketing has the right to sell to PPM up to 600,000 MMBtu of natural gas per day and has agreed to initially allocate a portion of the LNG that it procures under a long-term LNG supply agreement to PPM. PPM will be allocated 40% of the first 100,000 MMBtu per day achieved under an LNG supply agreement and 20% after a delivery quantity of 100,000 MMBtu has been achieved. PPM has agreed to buy the natural gas from Cheniere Marketing at a price equal to the sum of (a) 96% of the NYMEX Henry Hub natural gas futures contract price for a delivery month, plus (b) $0.10 per MMBtu. The gas purchase agreement runs for an initial term of 10 years beginning two months after the later to occur of commencement of commercial operations at the Sabine Pass LNG receiving terminal, commencement of commercial operation of the Creole Trail Pipeline with firm service provided to certain principal pipelines, and commencement of commercial delivery of natural gas from the Sabine Pass LNG receiving terminal to the Creole Trail Pipeline. The agreement will extend for a five-year period following the initial term and for a second five-year period following the first extension term unless either party provides written notice of termination to the other party at least 120 days prior to the expiration of the then-current term. Either party may terminate the gas purchase agreement if the initial term has not commenced by June 30, 2010 or Cheniere Marketing has not elected to deliver gas to PPM by October 31, 2010. The parties have various other early termination rights.

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.

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 natural 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, which was formed to engage in LNG transportation and trading through the utilization and management of charters for two new LNG tankers. 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).

In August 2004, J & S Cheniere executed a time charter for an 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 an 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 second quarter of 2008.

J & S Cheniere entered into an agreement with Cheniere LNG, Inc. 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 receiving terminals. Following execution of the option agreement, J & S Cheniere paid us an option fee of $1 million. J & S Cheniere may exercise the option as to each LNG receiving terminal by entering into a TUA no later than 60 days after receipt of written notification by us that such LNG receiving terminal has been approved by the FERC and all other approvals and permits have been received which are necessary to begin construction of the terminal. 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. In November 2006, Cheniere Marketing entered into a letter agreement with Cheniere LNG, Inc. and Sabine Pass LNG pursuant to which Cheniere Marketing has agreed to relinquish up to 200 Mmcf/d of its regasification capacity (and proportionately reduce its fixed monthly fee) under the Cheniere Marketing TUA if required to allow Sabine Pass LNG to satisfy its obligations under a potential TUA with J & S Cheniere.

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Governmental Regulation

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

The EPAct contains provisions intended to prohibit the manipulation of the natural gas markets and to increase the ability of the FERC to enforce and promote compliance with the statutes, orders, rules and regulations that the FERC administers. In 2005, the EPAct amended the NGA to add an anti-manipulation provision. To implement this provision of the EPAct, the FERC issued a final rule in 2006 that makes it unlawful for any entity, in connection with the purchase or sale of natural gas, or the purchase or sale of transportation service under the FERC s jurisdiction, to (1) use or employ any devise, scheme or artifice to defraud; (2) make any untrue statements of a material fact, or omit to state a material fact needed in order to make a statement not misleading; or (3) engage in any act, practice or course of business that operates or would operate as a fraud or deceit upon any entity.

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

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. Our historical oil and gas exploration activities have existed 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. Our current oil and gas exploration and development activities have been 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.

Prospects

Our exploration team generated, captured, sold or caused to be drilled 11 prospects during 2004, 2005 and 2006. We retained interests in the form of overriding royalty interests (a share of the hydrocarbons produced from an oil and gas property, free of the expense of production) and backin working interests (an agreement whereby we retain a reversion right to a working interest in a well at payout but bear none of the cost of drilling the initial well). Our overriding royalty interests range from 0.63% up to 5.0%, and backin working interests range from 15.0% up to 20.0%. We also participated in the drilling of wells with cost-bearing working interests of 5.0% up to 25.0%. In the wells where we participated with a cost-bearing working interest, we also retained an overriding royalty interest prior to payout and a backin working interest after payout. All 11 of the above-mentioned prospects were drilled by our industry partners.

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Drilling Activities

During 2004, we did not participate directly in the drilling of any wells; in 2005, we participated directly in the drilling of two wells; and in 2006, we participated directly in the drilling of four wells. Our industry partners drilled two wells, three wells and six wells in 2004, 2005 and 2006, respectively, on prospects that we generated. During 2004, both wells were discoveries; during 2005, one well was a discovery; and during 2006, four wells were discoveries. For the discoveries drilled in the years 2004 through 2006, four of the wells are producing and three are temporarily suspended awaiting development.

At December 31, 2006, we had working interests of 5.0% to 25.0% in four wells and overriding royalty interests (ranging from 0.63% to 5.0%) in sixteen other wells. Of the 20 wells in which we had an interest as of December 31, 2006, three were temporarily suspended awaiting development, nine were productive and eight were shut in waiting for plugging and abandonment. Of the eight wells waiting for plugging, seven were wells in which we had only an overriding royalty interest and therefore, we have no liability for abandonment costs.

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 2004, 2005 and 2006.

	Year Ended December 31,		
	2006	2005	2004
Production:			
Oil (Bbl)	3,295	2,167	1,362
Gas (Mcf)	319,112	396,284	328,677
Gas equivalents (Mcfe)	338,882	409,286	336,849
Average sales prices:			
Oil (per Bbl)	$ 61.97	$ 48.64	$ 36.69
Gas (per Mcf)	$ 6.60	$ 7.32	$ 5.93
Selected data per Mcfe:			
Average sales price	$ 6.82	$ 7.34	$ 5.93
Production costs	$ 0.70	$ 0.58	$ 0.35
Oil and gas depreciation, depletion and amortization excluding impairments (1)	$ 0.61	$ 0.09	$ 0.06

(1) Amounts reported for the years ended December 31, 2005 and 2004 have been adjusted to reflect the change in our method of accounting for investments in oil and gas properties from the full cost method to the successful efforts method.

Acreage

The following table sets forth certain information with respect to our developed and undeveloped leased acreage as of December 31, 2006.

	Developed Acres		Undeveloped Acres (1)	
	Gross	Net	Gross	Net
Louisiana				
Texas	960	240	35,630	10,958
Total	960	240	35,630	10,958

(1) We do not have any lease acres expiring in 2007.

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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, 2006 is taken from the report generated by Sharp Petroleum Engineering, Inc., an 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, 2006			
	Proved Reserves			
	Oil (Bbl)	Gas (Mcf)	Mcfe	PV-10 (1)
Offshore Texas	22,431	1,575,094	1,709,680	$ 5,425,171
Offshore Louisiana	1,252	160,927	168,439	$ 736,929
Proved Reserves	23,683	1,736,021	1,878,119	$ 6,162,100
Proved Developed Reserves	23,683	1,736,021	1,878,119	$ 6,162,100

(1) The PV-10 amount (present value of estimated pre-tax future net revenues discounted at 10%) is calculated using year-end prices of $56.83 per barrel of oil and $5.04 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. 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, 2006.

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;

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- 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; and
- 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 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.

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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 Regulation

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 Business Governmental Regulation Environmental Regulation 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 U.S. (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, substantially 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 24 of our Notes to Consolidated Financial Statements.

Subsidiaries

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

Employees

We had 256 full-time employees as of February 1, 2007.

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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 through 2008. 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 third-party 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.

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, 2006, we had $463.0 million in cash and cash equivalents, exclusive of $1.2 billion 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 estimates are subject to change due to such items as cost overruns, change orders, delays in construction, increased component and material costs, escalation of labor costs, and increased spending to maintain the construction schedules. In addition, the development of our marketing business will require significant credit support funding. To fund all of these development projects, we will have to pursue a variety of sources of funding besides those that we currently have committed or planned, including most, if not all, of the following:

debt and/or equity financing at the project level;

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

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.

Our substantial indebtedness could adversely affect our ability to operate our business.

As of December 31, 2006, we had approximately $2.4 billion of indebtedness. Our substantial indebtedness could have important consequences, including:

- limiting our ability to obtain additional financing to fund our capital expenditures, working capital, acquisitions, debt service requirements or liquidity needs for general business or other purposes;

- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service debt, including indebtedness that we may incur in the future;

- limiting our ability to compete with other companies who are not as highly leveraged;

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- limiting our ability to react to changing market conditions in our industry and in our customers industries and to economic downturns;
- limiting our flexibility in planning for, or reacting to, changes in our business and future business opportunities;
- making us more vulnerable than a less leveraged company to a downturn in our business or in the economy;
- limiting our ability to attract customers; and
- resulting in a material adverse effect on our business, results of operations and financial condition if we are unable to service our indebtedness or obtain additional financing, as needed.

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

Our ability to satisfy our obligations will depend upon our future operating performance. Prevailing economic conditions and financial, business and other factors, many of which are beyond our control, will affect our ability to make payments on our debt obligations. If we are not able to generate sufficient cash from operations to meet our other obligations, we may need to refinance all or a portion of our indebtedness on or before maturity. We may not be able to refinance any of our indebtedness on commercially reasonable terms or at all.

We may experience cost overruns and delays in the completion of our proposed LNG receiving terminals and pipelines as well as difficulties in obtaining funding for any additional costs, which could have a material adverse effect on our results of operations.

Our construction costs for our proposed LNG receiving terminals and pipelines may be significantly higher than our current estimates as a result of cost overruns, change orders under existing or future construction contracts, increased component and material costs, escalating labor costs, limited availability of labor, delays in construction and increased spending to maintain construction schedules. As of February 14, 2007, change orders for $121.3 million had been approved under the Phase 1 EPC agreement with Bechtel for the Sabine Pass LNG receiving terminal. We do not have any prior experience in constructing LNG receiving terminals, and no LNG receiving terminal has been constructed and placed in service in the United States in almost 25 years, as a result of which there are limited benchmarks against which to compare our estimates.

Furthermore, in order to cover not only increased costs but also the cost of a sixth LNG storage tank that we may be required to construct at the Sabine Pass LNG receiving terminal if requested by Cheniere Marketing under its TUA, we may need to obtain additional funding. If we fail to obtain sufficient funding, our business plan could fail. Our ability to obtain debt or equity financing that may be needed to provide additional funding to cover increased costs will depend, in part, on factors beyond our control, such as the status of various capital and industry markets at the time financing is sought. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, if at all. Even if we are able to obtain financing, we may have to accept terms that are disadvantageous to us or that may have a material adverse effect on our current or future business, results of operations, financial condition and prospects.

Risks Relating to Our LNG Receiving Terminal Business

Our inability to timely construct and commission our LNG receiving terminals would prevent us from commencing operations when anticipated and would delay or prevent us from realizing anticipated cash flows.

We are currently constructing the Sabine Pass LNG receiving terminal. We may not complete Phase 1 or Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal, and our other LNG receiving terminals, in a timely manner, or at all, due to numerous factors, some of which are beyond our control. Factors that could adversely affect our planned completion include:

- failure by Bechtel or the other contractors to fulfill their obligations under their construction contracts, or disagreements with them over their contractual obligations;
- our failure to enter into satisfactory additional agreements with contractors for the rest of Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal;
- shortages of materials or delays in delivery of materials;
- cost overruns and difficulty in obtaining sufficient debt or equity financing to pay for such additional costs;
- difficulties or delays in obtaining LNG for commissioning activities necessary to achieve commercial operability of the LNG receiving terminals;
- failure to obtain all necessary governmental and third-party permits, licenses and approvals for the construction and operation of the LNG receiving terminals;
- weather conditions, such as hurricanes, and other catastrophes, such as explosions, fires, floods and accidents;
- difficulties in attracting a sufficient skilled and unskilled workforce, increases in the level of labor costs and the existence of any labor disputes;
- resistance in the local community to the development of the LNG receiving terminals due to safety, environmental or security concerns; and
- local and general economic and infrastructure conditions.

Our inability to timely complete the Sabine Pass LNG receiving terminal and our other LNG receiving terminals, including as a result of any of the foregoing factors, could prevent us from commencing operations when anticipated, which could delay payments under the TUAs. As a result, we may not receive our anticipated cash flows on time or at all.

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

We have no experience constructing LNG receiving terminals and limited experience working with EPC contractors, including Bechtel, and with other construction contractors. Timely and cost-effective completion of our proposed LNG receiving terminals in compliance with agreed specifications is central to our business strategy and is highly dependent on our contractors performance under their agreements with us. Our contractors ability to perform successfully under their contracts is dependent on a number of factors, including their ability to:

design and engineer our proposed LNG receiving terminals to operate in accordance with specifications;

engage and retain third-party subcontractors and procure equipment and supplies;

respond to difficulties such as equipment failure, delivery delays, schedule changes and failure to perform by subcontractors, some of which are beyond their control;

attract, develop and retain skilled personnel, including engineers;

post required construction bonds and comply with the terms thereof;

manage the construction process generally, including coordinating with other contractors and regulatory agencies; and

maintain their own financial condition, including adequate working capital.

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These risks are heightened for Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal, which is still in the contracting phase. A substantial number of contracts, such as for performing portions of or supplying materials for Phase 2 Stage 1, remain to be negotiated for Phase 2 Stage 1, and we may be unable to reach satisfactory arrangements for these contracts. As a result, the scope, design, timing and cost for Phase 2 Stage 1 construction are not as well defined as they are for Phase 1 of the Sabine Pass LNG receiving terminal, and therefore the risk of delays, cost overruns or non-completion is greater for Phase 2 Stage 1 than for Phase 1.

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

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

To commission our LNG receiving terminals, we must purchase and process LNG. We have not previously purchased or processed any LNG.

Our LNG receiving terminals must undergo a commissioning process for their storage tanks and other equipment before commencement of commercial operation. The commissioning process will require a substantial quantity of LNG as well as access to adequate LNG tankers to deliver the LNG.

Our construction cost estimates do not include the costs of acquiring this LNG (other than a minor portion we refer to as heel LNG) at our LNG receiving terminals, which we have projected will be approximately $157.5 million for the Sabine Pass LNG receiving terminal. Our actual cost to obtain LNG for the commissioning process could exceed our estimates, and the overrun could be significant.

We face several principal risks associated with this required purchase of LNG, including the following:

- we may be unable to enter into a contract for the purchase of the LNG needed for commissioning and may be unable to obtain tankers to deliver such LNG on terms reasonably acceptable to us or at all;

- we will bear the commodity price risk associated with purchasing the LNG, holding it in inventory for a period of time and selling the regasified LNG; and

- we may be unable to obtain financing for the purchase and shipment of the LNG on terms that are reasonably acceptable to us or at all.

Our failure to obtain LNG, tankers or both, or its inability to finance the purchase of LNG needed for commissioning, would impede commencement of commercial operation at our LNG receiving terminals, which could delay the date on which our TUA customers are required to begin making payments to us. This delay in payments could have a material adverse effect on our business, results of operations, financial condition and prospects.

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

The design, construction and operation of LNG receiving terminals are all highly regulated activities. The FERC s approval under Section 3 of the NGA, as well as several other material governmental and regulatory approvals and permits, are required in order to construct and operate our proposed LNG receiving terminals. Although we have obtained NGA Section 3 authorization to construct and operate our LNG receiving terminals, such authorization is subject to ongoing conditions imposed by the FERC. 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, including several under the Clean Air Act and the Clean Water Act from the U.S. Army Corps of Engineers and the Louisiana Department of Environmental Quality. We have no control over the 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. 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.

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

If we are successful in completing our LNG receiving terminals, we will still face risks associated with operating the facilities. These risks will include, but will not be limited to, the following:

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

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

Our three existing TUAs for regasification capacity at the Sabine Pass LNG receiving terminal provide for an in-kind deduction of 2% of the LNG delivered to the Sabine Pass LNG receiving terminal, which will be used primarily as fuel for revaporization and self-generated power and to cover natural gas unavoidably lost at the facility. There is a risk that this 2% in-kind deduction will be insufficient for these needs and that we will have to purchase additional natural gas from third parties. We have no arrangements in place to obtain any such natural gas and will bear the risk of changing prices with respect to additional natural gas that we may need to purchase for fuel.

The inability to import LNG into the United States could materially adversely affect our customers and our business plans and results of operations if we have to replace TUAs that terminate or expire.

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

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around the world than with customers in the United States, thereby reducing the supply of LNG available to be imported into the United States market. Any significant impediment to the ability to import LNG into the United States could have a material adverse affect on our customers and on our business, results of operations, financial condition and prospects. In addition, the quality of LNG available for importation may not meet the quality specifications of our pipelines or the pipelines interconnected with or downstream of our proposed LNG receiving terminals.

Failure of sufficient LNG liquefaction capacity to be constructed worldwide could adversely affect the performance by our customers of their obligations under the TUAs and could reduce our operating revenue and cause us operating losses.

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

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

If sufficient LNG liquefaction capacity is not constructed, our customers may find it difficult to obtain sufficient utilization of their capacity at our LNG receiving terminals to support their obligations under their TUAs.

A shortage of LNG tankers worldwide could adversely affect our and our potential customers ability to import LNG into North America, which could inhibit our growth and cause us operating losses.

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 our ability and the ability of potential customers to import LNG into North America. The construction and delivery of additional LNG vessels requires significant capital, and the availability of the vessels could be delayed to our detriment because of:

- an inadequate number of shipyards constructing LNG vessels and a backlog of orders at these shipyards;
- political or economic disturbances in the countries where the vessels are being constructed;

changes in governmental regulations or maritime self-regulatory organizations;

work stoppages or other labor disturbances at the shipyards;

bankruptcy or other financial crisis of shipbuilders;

quality or engineering problems;

weather interference or a catastrophic event, such as a major earthquake, tsunami or fire; and

shortages of or delays in the receipt of necessary construction materials.

Failure of imported LNG to become a competitive source of energy in North America could adversely affect our ability to enter into TUAs with customers and our ability to import LNG into North America, which could inhibit our growth and cause us operating losses.

In North America, due mainly to an abundant supply of natural gas, imported LNG has not historically been a major energy source. Our business plan is based, in part, on the belief that LNG can be produced and delivered at a lower cost than the cost to produce some domestic supplies of natural gas, or other alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas may be discovered in North America, which 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 North America. The failure of LNG to become a competitive supply alternative to domestic natural gas, oil and other import alternatives could adversely affect our ability to enter into TUAs with customers at the proposed Creole Trail LNG receiving terminal or the proposed Corpus Christi LNG receiving terminal and could impede the ability of Cheniere Marketing to import LNG into North America, which could reduce our operating revenues and cause us operating losses. In addition, other continents have a longer history of importing LNG and, due to their geographic proximity to LNG producers and limited domestic natural gas supplies, may be willing and able to pay more for LNG, thereby eliminating the supply of LNG available in North American markets. The failure of LNG to become a competitive supply alternative may impede our ability to obtain customers for regasified LNG, which may inhibit our growth and cause us operating losses.

Decreases in the price of natural gas could lead to reduced development of LNG projects worldwide, which could adversely affect our ability to enter into TUAs and natural gas sale contracts with customers, which could inhibit our growth and cause us operating losses.

The development of domestic LNG receiving terminals and LNG projects generally is based on assumptions about the future price of natural gas and the availability of imported LNG. Natural gas prices have been, and are likely to continue to be, volatile and subject to wide fluctuations in response to 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 compared with other energy sources; and
- the effect of federal and state regulation on the production, transportation and sale of natural gas.

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 forecast 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, we and our potential customers may not be able to procure supplies of LNG or customers for regasified LNG, which may inhibit our growth and cause us operating losses.

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Cyclical changes in the demand for LNG regasification capacity may adversely affect our ability to enter into TUAs and natural gas sale contracts with customers, which could inhibit our growth and cause us operating losses.

The economics of LNG terminal 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 in North America, Europe, Asia and other markets, which could divert LNG from our proposed LNG receiving terminals;
- reduced demand for natural gas, which could suppress demand for LNG;
- increased natural gas production deliverable by pipelines, which could suppress demand for LNG;
- insufficient LNG production worldwide, which may limit the LNG traded worldwide;
- cost improvements that allow competitors to offer LNG regasification services at reduced prices;
- insufficient LNG tanker supplies, which may limit the ability to import LNG;
- changes in supplies of, and prices for, alternative energy sources such as coal, oil, nuclear, hydroelectric, wind and solar energy, which may reduce the demand for natural gas; and
- cyclical trends in general business and economic conditions that cause changes in the demand for natural gas.

These changes in the economics of LNG terminal operations could materially adversely affect our and our customers ability to procure supplies of LNG to be imported into North America and to procure customers for regasified LNG at economical prices, or at all. If and when our TUAs terminate or expire, unfavorable economic conditions that affect our customers could, in turn, for similar reasons, reduce our operating revenues and cause us operating losses.

We may experience increased labor costs, and the unavailability of skilled workers or our failure to retain key personnel could hurt the ability to construct and operate our proposed LNG receiving terminals.

Companies in our industry, including us, are dependent upon the available labor pool of skilled employees. We compete with other energy companies and other employers to attract and retain qualified personnel with the technical skills and experience required to construct our proposed LNG receiving terminals and, upon commencement of commercial operation, to provide our customers with the highest quality service. A shortage in the labor pool of skilled workers or other general inflationary pressures or changes in applicable laws and regulations could make it more difficult to attract and retain personnel and could require an increase in the wage and benefits packages that we offer, thereby increasing our operating costs. For example, in the aftermaths of Hurricanes Katrina and Rita, Bechtel and certain subcontractors temporarily experienced a shortage of available skilled labor necessary to meet the requirements of the Sabine Pass LNG receiving terminal Phase 1 construction plan. As a result, we agreed to change orders with Bechtel concerning additional activities and expenditures to mitigate the hurricanes effects on the completion of Phase 1 of the Sabine Pass LNG receiving terminal. Any increase in our operating costs could materially adversely affect our business, results of operations, financial condition and prospects.

We may face competition in the LNG receiving terminal business from competitors with far greater resources, as well as potential overcapacity in the LNG receiving terminal marketplace.

Many companies are considering or pursuing the development of infrastructure in the domestic LNG market, including major oil and natural gas companies such as Chevron Corporation, ConocoPhillips, ExxonMobil, Royal Dutch/Shell and Total. Other energy companies such as AES, Dominion, El Paso

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Corporation, Excelerate Energy, McMoRan Exploration, Occidental Petroleum, Sempra, Suez and other public and private companies have also proposed developing or expanding LNG receiving facilities in North America, both onshore and offshore. Almost all of these competitors have longer operating histories, more development experience, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources and access to LNG supply than we do. The superior resources that these competitors have available for deployment could allow them to compete successfully against us.

Industry analysts have predicted that if a substantial number 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 available from such terminals in the future. 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 LNG receiving terminals will also compete with the Freeport LNG receiving terminal that is currently under construction and in which we own a 30% minority interest. If the number of LNG receiving terminals built outstrips demand for natural gas from those terminals, the excess capacity could have a material adverse effect on 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 for a portion of the 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 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 third-party TUAs in place for either our proposed Corpus Christi LNG receiving terminal or our proposed Creole Trail LNG receiving terminal, nor do we have any third-party 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 with additional customers 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.

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 Total, Chevron and Cheniere Marketing. Each of the TUAs contains various termination rights. For example, each counterparty may terminate its TUA if the Sabine Pass LNG receiving terminal experiences a force majeure delay for longer than 18 months, fails to deliver a specified amount of natural gas redelivery nominations or fails to receive or unload a specified number of LNG cargoes. We may not be able to replace these TUAs on desirable terms, or at all, if they are terminated. In the case of each of these TUAs, we are dependent on the respective counterparty s continued willingness and ability

to perform its 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 ultimately successful in seeking damages from that counterparty or its guarantor for a breach of the TUA.

Risks Relating to Our Pipeline 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, at the budgeted cost or at all. For instance, if we build a new pipeline, the construction may occur over an extended period of time, and we will not receive any revenues until the pipeline has been completed and customers pay for transportation service on the pipeline. Moreover, we may construct pipelines to capture anticipated future growth in a region in which such growth does not materialize. As a result, our pipelines may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. 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 also have not obtained several other material governmental and regulatory approvals and permits required in order to construct and operate our proposed pipelines, including several under the Clean Air Act and the Clean Water Act from the U.S. Army Corps of Engineers and the Louisiana Department of Environmental Quality. We have no control over the timing of the review and approval process nor can we predict the outcome of the process. We do not know whether or when any such approvals or permits can be obtained, or whether or not any third parties will attempt to interfere with our ability to obtain and maintain such permits or approvals. If we are unable to obtain and maintain the necessary approvals and permits, we may not be able to recover our investment in the projects. Failure to obtain and maintain any of these approvals and permits could have a material adverse effect on our business, results of operations, financial condition and prospects.

Our proposed pipelines, including their FERC gas tariffs, will be subject to FERC regulation.

Our FERC tariffs contain pro forma transportation agreements, which must be filed and approved by the FERC. Before we enter into a transportation agreement with a shipper that contains a term that materially deviates from our tariff, we must seek FERC approval. The FERC may approve the material deviation in the transportation agreement; however, in that case, the materially deviating terms must be made available to our other similarly-situated customers. If we fail to seek FERC approval of a transportation agreement that materially deviates from our tariff, or if FERC audits our contracts and finds deviations that appear to be unduly discriminatory, the 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, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation.

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

Any reduction in the capacity of, or the allocations to, interconnecting, third-party pipelines could cause a reduction of volumes transported in our 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 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 our pipelines on land owned by third parties for a period of time. If we were to lose these rights or be required to relocate our pipelines, our business could be materially adversely affected.

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

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

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

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

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. Customers with whom we enter into TUAs for our LNG receiving terminals may 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

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Marketing, which does not have any arrangements for any supplies of LNG or any unconditional commitments from customers for the purchase of natural gas. The loss of any customers, a decline in their creditworthiness, the failure of Cheniere Marketing to obtain LNG or customers for regasified LNG, or a substantial reduction in customers 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 a limited operating history upon which to 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 or cleared on NYMEX and over-the-counter options and swaps with other natural gas merchants and financial institutions. Hedging arrangements would expose us to risk of financial loss in some circumstances, including when:

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

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

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

We have limited the amount of capital available to our LNG and natural gas marketing business to $40 million, plus overhead expenses and storage charges. The business currently has no access to third-party sources of financing. Other investment-grade marketing companies may have greater financial, technical and marketing resources and access to LNG supply than we do. Our LNG and natural gas marketing business is in its early stages of development and may not generate sufficient revenues and cash flows to cover the significant fixed costs of the business. The lack of capital and credit available to our LNG and natural gas marketing business, along with a lack of cash flows, may inhibit our ability to develop and grow the business.

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 with them, our results of operations may be adversely affected.

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

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

- The inability to import LNG into the United States could materially adversely affect our customers and our business plans and results of operations if we have to replace TUAs that terminate or expire;
- Failure of sufficient LNG liquefaction capacity to be constructed worldwide could adversely affect the performance by our customers of their obligations under the TUAs and could reduce our operating revenue and cause us operating losses;
- A shortage of LNG tankers worldwide could adversely affect our and our potential customers ability to import LNG into North America, which could inhibit our growth and cause us operating losses;
- Failure of imported LNG to become a competitive source of energy in North America could adversely affect our ability to enter into TUAs with customers and our ability to import LNG into North America, which could inhibit our growth and cause us operating losses;
- Decreases in the price of natural gas could lead to reduced development of LNG projects worldwide, which could adversely affect our ability to enter into TUAs and natural gas sale contracts with customers, which could inhibit our growth and cause us operating losses; and
- Cyclical changes in the demand for LNG regasification capacity could adversely affect our ability to enter into TUAs and natural gas sale contracts with customers, which could inhibit our growth and cause us operating losses.

Risks Relating to Our Oil and Gas Exploration and Development Business

We may not be successful in our oil and gas exploration and development activities, which may cause this business to become unprofitable.

Our oil and gas exploration and development activities may not be successful if we are not able to find or produce enough oil and gas to generate any profits. Our activities may be curtailed if we are not able to acquire the 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. Shortages of drilling rigs, equipment or supplies could delay or restrict our exploration and development operations. In addition, 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. Any of these factors could have a material adverse effect on the revenues, results of operations and cash flows of our oil and gas exploration and development business.

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 2006 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, including the following:

- historical production from the area compared with production from other producing areas;
- the effects of regulation by governmental agencies;

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- 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, which may be based on 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.

Risks Relating to Our Business in General

We are currently a 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.

We had net losses of $29.5 and $145.9 million for the years ended December 31, 2005 and 2006, respectively. We expect to continue to incur operating losses and experience negative operating cash flow through 2008 and to incur significant capital expenditures through completion of development of the Sabine Pass LNG receiving terminal. Any delays beyond the expected development periods for the Sabine Pass LNG receiving terminal would prolong, and could increase the level of, our operating losses and negative operating cash flows.

Neither we nor Cheniere has ever managed the construction, operation or maintenance of an LNG 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. 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.

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

We 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 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 often 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 maintain and intend to maintain insurance against some, but not all, of these risks and losses. We may not be able to maintain desired or required insurance in the future at rates that we consider reasonable. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our business, results of operations, financial condition and prospects.

Existing and future governmental regulation could result in increased compliance costs or additional operating costs and restrictions.

Our business is and will be subject to extensive federal, state and local laws and regulations that regulate the discharge of natural gas, hazardous substances, materials and other compounds into the environment or otherwise relate to the protection of the environment. Many of these laws and regulations, such as the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Oil Pollution Act and the Clean Water Act, and analogous state laws and regulations, restrict or prohibit the types, quantities and concentration of substances that can be released into the environment in connection with the construction and operation of our LNG receiving terminals and pipelines. Releases in violations of these regulations can lead to substantial liabilities for non-compliance or for pollution or releases of hazardous substances, materials or compounds or otherwise 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 substantial civil and criminal fines and penalties.

Existing environmental laws and regulations may be revised or reinterpreted or new laws and regulations may be adopted or become applicable to us. For example, the adoption of frequently proposed legislation implementing a carbon tax on energy sources that emit carbon dioxide into the atmosphere may have a material adverse effect on the ability of our customers: (i) to import LNG, if imposed on them as importers of potential emission sources, or (ii) to sell regasified LNG, if imposed on them or their customers as natural gas suppliers or consumers. In addition, as we consume retainage gas at the LNG receiving terminals, this carbon tax may also be imposed on us directly. Other future legislation and regulations, such as those relating to the transportation and

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security of LNG imported to our LNG receiving terminal through navigable waterways, could cause additional expenditures, restrictions and delays in our business and to the planned construction of our LNG receiving terminals, the extent of which cannot be predicted and which may require us to limit substantially, delay or cease operations in some circumstances. Revised, reinterpreted or additional laws and regulations that result in increased compliance costs or additional operating costs and restrictions could have a material adverse effect on our business, results of operations, financial condition and prospects.

Hurricanes or other disasters could result in a delay in the completion of our LNG receiving terminals and pipelines, higher construction costs and the deferral of the dates on which our TUA counterparties are obligated to begin making payments to us.

In August and September of 2005, Hurricanes Katrina and Rita and related storm activity, including windstorms, storm surges, floods and tornadoes, caused extensive and catastrophic damage to coastal and inland areas located in the Gulf Coast region of the U.S. (parts of Texas, Louisiana, Mississippi and Alabama) and certain other parts of the southeastern U.S. Construction at the Sabine Pass LNG receiving terminal site was temporarily suspended in connection with Hurricane Katrina, as a precautionary measure. Approximately three weeks after the occurrence of Hurricane Katrina, the terminal site was again secured and evacuated in anticipation of Hurricane Rita, the eye of which made landfall to the east of the site. As a result of these 2005 storms and related matters, the Sabine Pass LNG receiving terminal experienced construction delays and increased costs.

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

Terrorist attacks or military campaigns may adversely impact our business.

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

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 arrangements relating to compensation and benefits with certain of our executive officers, we do not have any employment contracts or other agreements with key personnel binding them to provide services for any particular term. The loss of the services of any of these individuals could seriously harm us. In addition, our future success will depend in part on our ability to attract and retain additional qualified personnel.

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

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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.

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, 2006, 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 to commence 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, Cheniere 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. We have not received any communication from the SEC with regard to this matter since September 2005.

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 2005 and 2006.

	High	Low
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
Three Months Ended		
March 31, 2006	$ 41.32	$ 37.71
June 30, 2006	43.93	33.27
September 30, 2006	37.90	28.74
December 31, 2006	31.70	24.85

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 20, 2007, we had 56.0 million shares of common stock outstanding held by approximately 10,900 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.

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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)				
	2006	2005 (4)	2004 (4)	2003 (4)	2002 (4)
		(as adjusted)	(as adjusted)	(as adjusted)	(as adjusted)
Revenues	$ 2,371	$ 3,005	$ 1,998	$ 658	$ 239
LNG terminal development expenses	12,099	22,020	17,166	6,705	1,557
Exploration expense	3,138	2,839	2,662	1,604	3,336
Depreciation, depletion and amortization	3,131	1,325	507	308	400
General and administrative expenses	58,012	29,145	12,476	2,542	1,918
Loss from operations	(75,874)	(52,561)	(30,930)	(10,501)	(7,062)
Equity in net loss of affiliate (1)					(2,185)
Gain on sale of investment in unconsolidated affiliate (1)		20,206			
Equity in net loss of limited partnership		(1,031)	(1,346)	(4,471)	
Gain on sale of LNG assets				4,760	
Reimbursement from limited partnership investment			2,500		
Loss on early extinguishment of debt (2)	(43,159)				(100)
Derivative gain (loss) (2)	(20,070)	837			
Interest expense	(53,968)	(17,373)	(4)	(88)	(20)
Interest income	49,087	17,520	501	3	8
Minority interest		97	2,862	3,015	
Net loss	(145,853)	(29,538)	(24,876)	(6,440)	(7,163)
Net loss per share (basic and diluted) (3)	$ (2.68)	$ (0.56)	$ (0.64)	$ (0.22)	$ (0.27)
Weighted average shares outstanding (basic and diluted) (3)	54,423	53,097	38,895	29,543	26,595

	December 31,				
	2006	2005 (4)	2004 (4)	2003 (4)	2002 (4)
		(as adjusted)	(as adjusted)	(as adjusted)	(as adjusted)
Cash and cash equivalents	$ 462,963	$ 692,592	$ 308,443	$ 1,258	$ 590
Restricted cash and cash equivalents	355,831	161,561			
Working capital	767,038	810,141	305,752	155	(1,413)
Non-current restricted cash and cash equivalents	892,718	16,500			
Property, plant and equipment, net	748,818	280,106	2,643	2,095	2,433
Debt issuances costs, net	41,545	43,008	1,302		
Goodwill	76,844	76,844			
Total assets	2,604,488	1,290,147	315,330	6,662	4,282
Long-term debt	2,357,000	917,500			
Deferred revenue	41,000	41,000	23,000	1,000	
Total liabilities	2,461,241	1,021,606	28,966	5,452	3,262
Total stockholders equity	143,247	268,541	286,364	1,210	1,020

(1) Effective January 1, 2003, we began accounting for this investment in Gryphon using the cost method of accounting. The amount listed for 2002 represents 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.

(2) Amounts in 2006 primarily relate to losses on the termination of the Sabine Pass Credit Facility and the Term Loan in November 2006. See Note 14 of our Notes to Consolidated Financial Statements.

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

(4) Amounts reported for the years ended December 31, 2005, 2004, 2003 and 2002 have been adjusted to reflect the change in our method of accounting for investments in oil and gas properties from the full cost method to the successful efforts method.

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

General

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 developing a business to market LNG and natural gas. To a limited extent, we are also engaged in oil and natural gas exploration and development activities in the Gulf of Mexico. We operate four business activities: LNG receiving terminal, natural gas pipeline, LNG and natural gas marketing, and oil and gas exploration and development.

LNG Receiving Terminal Business

We have focused our development efforts on three 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. Although we currently own 100% interests in each of the three LNG receiving terminals, we anticipate that our interest in the Sabine Pass LNG receiving terminal will decrease to approximately 92% upon completion of Cheniere Energy Partners, L.P. s proposed initial public offering. In addition, we own a 30% interest in a fourth project, Freeport LNG, located on Quintana Island near Freeport, Texas. Our three LNG receiving terminals have an aggregate designed regasification capacity of approximately 10 Bcf/d, subject to expansion. We have entered into long-term TUAs with Total, Chevron and Cheniere Marketing for an aggregate of 5.0 Bcf/d of the available regasification capacity.

Construction of the Sabine Pass LNG receiving terminal commenced in March 2005, and we anticipate commencing operations during the second quarter of 2008. We will contemplate making a final investment decision to complete construction of the Corpus Christi and commence construction of the Creole Trail LNG receiving terminals upon, among other things, achieving acceptable commercial arrangements.

Natural Gas Pipeline 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. We anticipate commencing construction of the Sabine Pass Pipeline in the second quarter of 2007 with construction completed and the pipeline available for commercial operations in the fourth quarter of 2007. We anticipate commencing construction of Phase 1 of the Creole Trail Pipeline (consisting of 78 miles of natural gas pipeline) in the second quarter of 2007 and that Phase 1 operations will commence in the second quarter of 2008. Construction contracts for the Corpus Christi Pipeline have not been negotiated.

LNG and Natural Gas Marketing Business

Our LNG and natural gas marketing business is in its early stages of development. We intend to purchase LNG from foreign suppliers, arrange the transportation of LNG to our network of LNG receiving terminals, utilize Cheniere Marketing s revaporization capacity at our LNG receiving 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. Alternatively, we may purchase LNG from foreign suppliers and sell the LNG to foreign purchasers if more favorable economic conditions exist in those markets. To develop our capability to resell revaporized natural gas in the future, we are engaging in domestic natural gas purchase and sale, transportation and storage transactions, including financial derivative 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. We have historically focused on

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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.

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.

We have obtained financing and approval of our board of directors to construct Phase 1 and Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal and the Sabine Pass Pipeline, at an estimated cost of $1.4 billion to $1.5 billion and $100 million, respectively. In addition, we have obtained financing and board approval to procure all of the pipe needed for both Phase 1 and Phase 2 of the Creole Trail Pipeline (at a cost of approximately $150 million), as well as $50 million for Creole Trail Pipeline construction costs. We will need to obtain additional financing and board of directors approval in order to construct our remaining proposed projects, including the remainder of the Creole Trail Pipeline, the Creole Trail LNG receiving terminal, the Corpus Christi LNG receiving terminal and the Corpus Christi Pipeline. We anticipate that a portion of the net proceeds we receive from the proposed initial public offering by Cheniere Energy Partners, L.P. will be available for use, together with other funds, to finance projects so approved.

As of December 31, 2006, we had working capital of $767.0 million, of which $355.8 million was restricted cash. We believe that we have adequate financial resources available to us to implement the currently approved projects described above. We must augment our existing sources of cash with significant additional funds in order to carry out our long-term business plan for the remaining proposed projects pending approval as described in the preceding paragraph.

Our LNG-related business activities are not expected to begin to operate and generate significant cash flows before 2008. We currently expect that our capital requirements will be financed in part through cash on hand, issuances of project-level debt, equity or a combination of the two and in part with net proceeds of debt or equity securities issued by Cheniere or its subsidiaries.

Customer TUAs

Each of the customers at the Sabine Pass LNG receiving terminal must make payments under its TUA on a take-or-pay basis, which means that the customer will be obligated to pay the full contracted amount of monthly fees whether or not it uses any of its reserved capacity. Provided the Sabine Pass LNG receiving terminal has achieved commercial operation at 2.0 Bcf/d, which we expect will occur during the second quarter of 2008, these take-or-pay TUA payments will be made as follows from third-party customers:

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

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

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

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In addition, Cheniere Marketing has reserved approximately 2.0 Bcf/d of regasification capacity, is entitled to use any capacity not utilized by Total and Chevron and has agreed to make monthly payments to Sabine Pass LNG aggregating approximately $250 million per year for at least 19 years commencing January 1, 2009, plus payments of $5 million per month during an initial commercial operations ramp-up period in 2008. Cheniere has guaranteed Cheniere Marketing s obligations under its TUA.

Our LNG Receiving Terminals

Sabine Pass LNG

We estimate that the aggregate total cost to complete construction of Phase 1 and Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal will be approximately $1.4 billion to $1.5 billion, before financing costs. Our cost estimates are subject to change due to such items as cost overruns, change orders, increased component and material costs, escalation of labor costs and increased spending to maintain our construction schedule. We have obtained all of the financing required to construct the Sabine Pass LNG receiving terminal, and we believe that we have adequate financial resources to complete Phase 1 and Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal and to meet our anticipated operating, maintenance and debt service requirements through the first half of 2009. We will fund the remaining construction period capital resource requirements from $887 million that was placed in a construction account in connection with the issuance of senior secured notes by Sabine Pass LNG in November 2006.

Phase 1 EPC Agreement

In December 2004, Sabine Pass LNG entered into a lump-sum turnkey EPC agreement with Bechtel for Phase 1 of the Sabine Pass LNG receiving terminal. Except for certain third-party work specified in the EPC agreement, the work to be performed by Bechtel includes all of the work required to achieve substantial completion and final completion of Phase 1 of the Sabine Pass LNG receiving terminal in accordance with the requirements of the EPC agreement. Pursuant to the EPC agreement, Sabine Pass LNG agreed to pay Bechtel a contract price of $646.9 million plus certain reimbursable costs for the work performed under the EPC agreement. This contract price is subject to adjustment for certain costs of materials, contingencies, change orders and other items. As of February 14, 2007, change orders for $121.3 million were approved, primarily for design changes, increases in costs of materials, insurance costs and costs related to the 2005 hurricanes, increasing the total contract price to $768.2 million. As of December 31, 2006, we had paid $564.2 of Phase 1 construction costs.

Phase 2 Stage 1 Construction Agreements

In July 2006, Sabine Pass LNG entered into three construction agreements to facilitate construction of the Phase 2 Stage 1 expansion, as follows:

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

EPC Tank Contract. Sabine Pass LNG entered into an EPC LNG tank contract with Zachry Construction Corporation, or Zachry, and Diamond LNG LLC, or Diamond, under which Zachry and Diamond will furnish all plant, labor, materials, tools, supplies, equipment, transportation, supervision, technical, professional and other services, and perform all operations necessary and required to satisfactorily engineer, procure materials for and construct the two Phase 2 Stage 1 LNG storage

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tanks. In addition, Sabine Pass LNG has the option (to be elected on or before March 31, 2007) for Zachry and Diamond to engineer, procure and construct a sixth LNG storage tank, with the cost and completion date to be agreed upon if the option is exercised. We do not expect to exercise this option. The tank contract provides that Zachry and Diamond will receive a lump-sum, total fixed price payment for the two Phase 2 Stage 1 tanks of approximately $140.9 million, which is subject to adjustment based on fluctuations in the cost of labor and certain materials, including the steel used in the Phase 2 Stage 1 tanks, and change orders.

EPC LNG Unit Rate Soil Contract. Sabine Pass LNG entered into an EPC LNG unit rate soil contract with Remedial Construction Services, L.P., or Recon. Under the soil contract, Recon is required to furnish all plant, labor, materials, tools, supplies, equipment, transportation, supervision, technical, professional and other services, and perform all operations necessary and required to satisfactorily conduct soil remediation and improvement on the Phase 2 site, unless otherwise set forth in the soil contract. Upon issuing a final notice to proceed in August 2006, Sabine Pass LNG paid Recon an initial payment of approximately $2.9 million. The soil contract price is based on unit rates. Payments under the soil contract will be made based on quantities of work performed at unit rates.

As of December 31, 2006, we had paid $44.0 million of Phase 2 Stage 1 construction costs.

Corpus Christi LNG

We currently estimate that the cost of constructing the Corpus Christi LNG receiving terminal will be approximately $650 million to $750 million, before financing costs. This estimate is based in part on our negotiations with a major international EPC contractor and is subject to change. The Corpus Christi LNG receiving terminal project costs are expected to be funded through project financing, 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. We will contemplate making a final investment decision to complete construction of the Corpus Christi LNG receiving terminal upon, among other things, achieving acceptable commercial arrangements.

In order to accelerate the timing of its development of the Corpus Christ LNG receiving terminal, Corpus Christi LNG elected in April 2006 to commence preliminary site work and entered into an engineering, procurement and construction services agreement for preliminary work with La Quinta LNG Partners, L.P., or La Quinta. La Quinta is a limited partnership whose general partners are Zachry and AMEC E&C Services, Inc. Under the terms of the agreement, La Quinta has provided Corpus Christi LNG with certain preliminary design, engineering, construction and site preparation work on a reimbursable basis in connection with the Corpus Christi LNG receiving terminal. Such preliminary site work commenced during the second quarter of 2006 and has been completed. We anticipate that payments to be made by Corpus Christi LNG to La Quinta for work performed under the agreement will not exceed $35 million. We have funded the amounts payable under the La Quinta EPC agreement from existing cash balances.

Creole Trail LNG

We currently estimate that the cost of constructing the Creole Trail LNG receiving terminal will be approximately $850 million to $950 million, before financing costs. Our cost estimate is preliminary and subject to change. We currently expect to fund the Creole Trail LNG receiving terminal project costs through project financing, 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 with capital contributions by the limited partners. We did not receive any capital calls, and made no capital contributions, in 2006. In view of the closing of a $383 million private placement of notes in December 2005 by Freeport LNG, we do not anticipate any capital calls 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 our equity or debt securities.

Our Proposed Pipelines

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

Sabine Pass Pipeline

We estimate 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 and right-of-ways, to be approximately $100 million, before financing costs. This cost estimate is subject to change due to such items as cost overruns, change orders, delays in construction, increased component and material costs and escalation of labor costs. We have sufficient funds to construct the Sabine Pass Pipeline.

In February 2006, Cheniere Sabine Pass Pipeline, L.P. entered into an EPC pipeline contract with Willbros Engineers, Inc., or Willbros. Under the EPC pipeline contract, Willbros will provide Sabine Pass Pipeline, L.P. with services for the management, engineering, material procurement, construction and construction management of the Sabine Pass Pipeline. Sabine Pass Pipeline, L.P. entered into the EPC pipeline contract sufficiently in advance of commencement of physical construction of the pipeline in order to perform detailed engineering and procure materials. This EPC pipeline contract, among other things, provides for a guaranteed maximum price of approximately $67.7 million, subject to adjustment under certain circumstances, as provided in the contract.

Creole Trail Pipeline

We estimate the total cost to construct Phase 1 and Phase 2 of the Creole Trail Pipeline to be approximately $400 million to $450 million and $200 million to $250 million, respectively, before financing costs. Our cost estimates are subject to change due to such items as cost overruns, change orders, delays in construction, increased component and material costs and escalation of labor costs.

Cheniere Creole Trail Pipeline, L.P., or CCTP, has entered into the following purchase orders with two suppliers for the procurement of all of the pipe required to construct both Phase 1 and Phase 2 of the Creole Trail Pipeline:

In August 2006, CCTP entered into a purchase order with CPW America Co. for the purchase of approximately 60 miles of pipe at an aggregate cost of approximately $63.8 million, which is payable in increments beginning with a payment of $6.4 million made in August 2006. Subsequent payment increments are tied to coil production milestones with additional remaining payments due on a per lot basis related to pipe production shipping and delivery milestones. The purchase order provides that all pipe is to be manufactured between January 1, 2007 and the end of the first week of March 2007, with all pipe delivered prior to April 15, 2007 for use in Phase 1 of the Creole Trail Pipeline. CCTP has the

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right to terminate the purchase order for its convenience, subject to making specified cancellation payments that begin at 3% and increase to 100% of the value of the lots produced depending on the achievement of specified production measures.

In August 2006, CCTP also entered into a purchase order with ILVA S.p.A., or ILVA, for the purchase of approximately 180 miles of pipe. In January 2007, CCTP entered into an amendment to the purchase order with ILVA to terminate for convenience approximately 116 miles of the pipe, which reduced the cost of this purchase order to approximately $67.4 million. Under the amended purchaser order, approximately 7 miles of pipe will be produced and delivered in 2007 for use in Phase 1 of the Creole Trail Pipeline, and an additional approximately 58 miles of pipe will not begin production prior to December 1, 2007 for delivery in 2008 for use in Phase 2 of the Creole Trail Pipeline.

In addition to the above, CCTP also entered into a purchase order in April 2006 with ILVA for the purchase of approximately 15 miles of pipe at an aggregate cost of approximately $16 million for use in Phase 1 of the Creole Trail Pipeline. Progress payments will be due on a periodic basis after specified production measures have been achieved. CCTP has the right to terminate the purchase order for its convenience, subject to making specified cancellation payments that begin at $0.5 million and increase, depending on the achievement of specified production measures, to 100% of the value after pipe forming but prior to shipment.

In January 2007, CCTP entered into two construction agreements in connection with the construction of Phase 1 of the Creole Trail Pipeline, as follows:

CCTP entered into a construction agreement with Sunland Construction, Inc., or Sunland, pursuant to which Sunland will perform all construction work for approximately 23 miles of Phase 1 of the Creole Trail Pipeline. The contract price is currently estimated to be approximately $70.1 million. Cheniere is required to provide credit support of up to $12 million for CCTP s obligations under the agreement in the form of a guaranty, letter of credit or escrowed funds. Sunland may not commence work until CCTP issues a notice to proceed. If CCTP issues the notice to proceed after April 16, 2007, then Sunland is entitled to an increase in the estimated contract price equal to 1% of the estimated contract price per month for each full month of delay.

CCTP entered into a construction agreement with Sheehan Pipe Line Construction Company, or Sheehan, pursuant to which Sheehan will perform all construction work for approximately 36 miles of Phase 1 of the Creole Trail Pipeline. The contract price is currently estimated to be approximately $65.6 million.

Corpus Christi Pipeline

Construction contracts for the Corpus Christi Pipeline 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. We have committed $40 million initially to our marketing and trading activities, in addition to overhead costs and storage charges. We expected that our committed amount will increase as our LNG and natural gas marketing business develops.

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

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Debt Agreements

Sabine Pass LNG Senior Secured Notes

In November 2006, Sabine Pass LNG consummated a private offering of an aggregate principal amount of $2,032 million senior secured notes, or the Sabine Pass LNG notes, consisting of $550 million of 7 $^{1}/4$% Senior Secured Notes due 2013, or the 2013 notes, and $1,482 million of 7 $^{1}/2$% Senior Secured Notes due 2016, or the 2016 notes. The Sabine Pass LNG notes were offered to qualified institutional buyers pursuant to Rule 144A under the Securities Act and in offshore transactions to non-United States persons in reliance on Regulation S under the Securities Act. At closing, net proceeds of approximately $2 billion from the offering were used as follows: approximately $380 million to repay borrowings under, and replace, the $1.5 billion amended Sabine Pass credit facility described below; approximately $380 million was distributed to our wholly-owned subsidiary, Cheniere LNG Holdings, LLC, for repayment of the term loan described below; approximately $335 million was used to fund a reserve account for scheduled interest payments on the Sabine Pass LNG notes through May 2009; and approximately $18 million was used to terminate swap agreements entered into in connection with the amended Sabine Pass credit facility and the term loan and for other expenses. The remaining approximately $887 million of net proceeds from the offering will be used to fund the remaining costs to complete Phase 1 and Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal.

Interest on the Sabine Pass LNG notes is payable semi-annually in arrears on May 30 and November 30 of each year, beginning May 30, 2007. The Sabine Pass LNG notes are secured on a first-priority basis by a security interest in all of its equity interests and substantially all of its operating assets. The indenture governing the Sabine Pass LNG notes contains covenants that limit the ability of Sabine Pass LNG to, among other things: make certain investments or pay dividends or distributions on its equity interests or subordinated indebtedness or purchase or redeem or retire equity interests; incur additional indebtedness or issue preferred stock; incur liens; restrict dividends or other payments by restricted subsidiaries; consolidate, merge or sell or lease all or substantially all of its assets; enter into transactions with affiliates; and enter into sale and leaseback transactions.

Sabine Pass LNG may redeem some or all of the Sabine Pass LNG notes at a redemption price equal to 100% of the principal amount plus a make-whole premium, plus accrued and unpaid interest and additional interest, if any, to the redemption date. Until November 30, 2009, Sabine Pass LNG may redeem up to 35% of the aggregate principal amount of the 2013 notes and up to 35% of the aggregate principal amount of the 2016 notes with the net cash proceeds of one or more equity offerings by Sabine Pass LNG with the proceeds that Sabine Pass LNG retains or that are contributed to Sabine Pass LNG, as applicable, at par plus a premium equal to the coupon, plus accrued and unpaid interest and additional interest, if any, as long as at least 65% of the aggregate principal amount of the 2013 notes and 2016 notes, respectively, remains outstanding immediately after such optional redemption and such optional redemption occurs within 90 days of the date of the closing of such equity offering.

Under the indenture governing the Sabine Pass LNG notes, except for permitted tax distributions, Sabine Pass LNG may not make distributions until certain conditions are satisfied. The indenture requires that Sabine Pass LNG apply its net operating cash flow (i) first, to fund with monthly deposits its next semiannual payment of approximately $75.5 million of interest on the Sabine Pass LNG notes, and (ii) second, to fund a one-time, permanent debt service reserve fund equal to one semiannual interest payment of approximately $75.5 million on the Sabine Pass LNG notes. Distributions will be permitted only after Phase 1 target completion, as defined in the indenture governing the Sabine Pass LNG notes, or such earlier date as project revenues are received, upon satisfaction of the foregoing funding requirements, after satisfying a fixed charge coverage ratio test of 2:1 and after satisfying other conditions specified in the indenture.

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

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Securities Act. The notes bear interest at a rate of 2.25% per year. The notes are convertible at any time into our common stock under certain circumstances at an initial conversion rate of 28.2326 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 was 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, 2006, no holders had elected to convert their notes.

Cheniere Holdings Term Loan

In August 2005, Cheniere LNG Holdings, LLC, or Cheniere LNG Holdings, an indirect wholly-owned subsidiary of Cheniere, entered into a $600 million term loan, or Term Loan, with Credit Suisse. The Term Loan had an interest rate of LIBOR plus a 2.75% margin and matured 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 resulted in an annual fixed interest rate of 7.25% (including the 2.75% margin) for the first five years. We repaid the Term Loan and terminated the related swap agreements in November 2006 with net proceeds received from the issuance of the Sabine Pass LNG notes.

Amended Sabine Pass Credit Facility

In February 2005, Sabine Pass LNG entered into an $822 million credit agreement with HSBC Bank, USA and Société Générale and a syndicate of financial institutions, and related interest rate swap agreements with HSBC Bank, USA and Société Générale. This original credit facility was subsequently amended and restated in July 2006. The amended credit facility increased the amount of loans available to Sabine Pass LNG from $822 million under the original credit facility to $1.5 billion to finance Phase 1 and Phase 2 Stage 1 expansion construction of the Sabine Pass LNG receiving terminal. In connection with the closing of the credit facility and subsequent amendment, we entered into interest rate swap agreements with HSBC Bank, USA and Société Générale. In connection with the issuance of the Sabine Pass LNG notes in November 2006, the amended credit facility and related interest rate swaps were paid in full and terminated.

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Historical Cash Flows

The following table summarizes the changes in our cash and cash equivalents for the years ended 2006, 2005 and 2004. Additional discussion of the key elements contributing to the changes between periods follows the table (in thousands).

	Years Ended December 31,		
	2006	2005	2004
Cash provided by (used in):			
Operating activities	$ (80,426)	$ (18,956)	$ (1,451)
Investing activities	(1,539,928)	(405,587)	1,975
Financing activities	1,390,725	808,692	306,661
Net increase (decrease) in cash and cash equivalents	$ (229,629)	$ 384,149	$ 307,185
Cash and cash equivalents at end of year	$ 462,963	$ 692,592	$ 308,443

Operating Activities Net cash used in operations increased to $80.4 million in 2006 compared to $19.0 million in 2005 and $1.5 million in 2004. Net cash used in operations in 2006 was primarily related to the continued development of our LNG receiving terminals and related activities, including increased support costs. In addition, we incurred prepayment penalties and a cash derivative loss related to the termination of our interest rate swaps upon the early termination of the Sabine Pass credit facility and the Term Loan. Net cash used in operating activities for 2005 and 2004 also included costs resulting from the continued development of our LNG receiving terminals and related activities, including increased support costs; however, such costs were partially offset by advance LNG terminal capacity reservation fees of $18.0 million and $22.0 million in 2005 and 2004, respectively.

Investing Activities Net cash used in investing activities was $1.5 billion during 2006 compared to $405.6 million in 2005, and net cash provided by investing activities was $2.0 million in 2004. During 2006, we funded $1.2 billion primarily related to restricted cash balances as required by the Sabine Pass LNG notes. In 2006, we also recorded $440.4 million to construction-in-progress related to our LNG receiving terminal and natural gas pipeline activities. During 2005, we recorded $229.7 million to construction-in-progress related to Phase 1 of the Sabine Pass LNG receiving terminal, and we funded $177.4 million related to restricted cash balances as required by the Term Loan and the Sabine Pass credit facility. Our cash used in investing activities in 2005 was partially offset by $20.2 million in proceeds received from the sale of our interest in Gryphon Exploration Company. Net cash provided by investing activities in 2004 were primarily from the sale of certain of our oil and gas properties, partially offset by the purchase of oil and gas properties and other fixed assets.

Financing Activities Net cash provided by financing activities was $1.4 billion during 2006 compared to $808.7 million in 2005 and $306.7 million in 2004. During 2006, we received $2.0 billion in proceeds from the issuance of the Sabine Pass LNG notes and $383.4 million in borrowings under the amended Sabine Pass credit facility. These proceeds were partially offset by the repayments of our amended Sabine Pass credit facility and Term Loan in the amounts of $383.4 million and $598.5 million, respectively, and by $43.9 million in debt issuance costs related to the amended Sabine Pass credit facility and the Sabine Pass LNG notes. During 2005, we received proceeds from the Term Loan and the issuance of our Convertible Senior Unsecured Notes in the amounts of $600.0 million and $249.3 million (net of $75.7 million for the issuer call spread), respectively. 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, net cash provided by financing activities of $306.7 million was primarily the result of the sale of our common stock, raising $305.9 million (net of $15.1 million of offering costs).

Due to the factors described above, our cash and cash equivalents decreased to $463.0 million as of December 31, 2006 compared to $692.6 million at December 31, 2005. Our working capital also decreased to $767.0 million as of December 31, 2006 compared to $810.1 million at December 31, 2005.

Issuances of Common Stock

During 2006, 2005 and 2004, we raised $2.0 million, $3.0 million and $305.9 million, respectively, net of offering costs, from the exercise of stock options, the exchange or exercise of warrants, a public equity offering of common stock and the sale of Cheniere common stock to accredited investors pursuant to Regulation D.

During 2006, we issued a total of 710,685 shares of our common stock. A total of 309,734 shares of our common stock were issued pursuant to the exercise of stock options, resulting in net cash proceeds of $2.0 million. In addition, 76,534 shares were issued in satisfaction of cashless exercises of options to purchase 97,801 shares of common stock. A total of 78,671 shares were issued in 2006 to executive officers in the form of non-vested restricted stock awards related to our performance in 2005, and we issued 241,240 shares of non-vested restricted stock to new employees. We paid federal payroll withholding taxes of $1.0 million in exchange for 25,733 shares of our common stock, which related to common stock previously awarded to officers that vested during 2006. These shares were initially recorded as treasury shares, at cost, but were subsequently retired. In December 2006, 30,239 shares were issued to outside directors in the form of non-vested (restricted) stock awards related to their services provided in 2006.

During 2005, we issued a total of 3,602,549 shares of our common stock. In February 2005, we acquired the 33.3% minority interest in Corpus Christi LNG through the acquisition of BPU LNG, Inc. in exchange for 2.0 million restricted shares of our common stock valued at $77.0 million plus direct transaction costs. A total of 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 also issued 15,000 shares of non-vested restricted stock to employees. 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 17,942,208 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 restricted 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 restricted stock awards related to our performance in 2004, recording $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. During 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.

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Contractual Obligations

We are committed to making cash payments in the future on certain of our contracts. Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2006 (in thousands).

	Payments Due for Years Ending December 31,				
	Total	**2007**	**2008-2009**	**2010-2011**	**Thereafter**
Long-term debt					
Convertible senior unsecured notes (1)	$ 325,000	$	$	$	$ 325,000
Senior notes (1)	2,032,000				2,032,000
Operating lease obligations					
LNG site rental (2)	132,104	1,507	3,012	3,002	124,583
Tug boat (2)	123,304	1,554	12,330	12,330	97,090
Office buildings and facilities (2)(4)	24,166	1,574	4,879	4,793	12,920
Construction and purchase obligations (3)(5)	902,706	596,286	306,420		
Other obligations (6)	30,736	1,706	5,205	5,825	18,000
Total	$ 3,570,016	$ 602,627	$ 331,846	$ 25,950	$ 2,609,593

(1) A discussion of these obligations can be found at Note 14 of our Notes to Consolidated Financial Statements.
(2) A discussion of these obligations can be found at Note 4 of our Notes to Consolidated Financial Statements.
(3) A discussion of these obligations can be found at Note 22 of our Notes to Consolidated Financial Statements.
(4) Minimum lease payments have not been reduced by a minimum sublease rental of $4.2 million due in the future under noncancelable subleases.
(5) Represents construction contracts and obligations to purchase long-lead equipment and materials for our LNG receiving terminals and natural gas pipelines.
(6) Includes obligations for a natural gas storage contract, telecommunication services and software licensing. See Note 22 of our Notes to Consolidated Financial Statements.

In addition, in the ordinary course of business, we maintain letters of credit and have certain cash and cash equivalents restricted in support of certain performance obligations of our subsidiaries. Restricted cash and cash equivalents and outstanding letters of credit totaled approximately $1.2 billion at December 31, 2006. For more information, see Note 3 Restricted Cash and Cash Equivalents of our Notes to Consolidated Financial Statements.

LNG Receiving Terminal Construction Contracts

As more fully described in Note 22 of our Notes to Consolidated Financial statements, we have entered into construction contracts with various third parties to construct Phase 1 and Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal. We estimate that the cost to construct Phase 1 and Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal will be approximately $1.4 billion to $1.5 billion, before financing costs.

Natural Gas Pipeline Construction Contracts

As more fully described in Note 22 of our Notes to Consolidated Financial Statements, we have entered into construction contracts and purchase orders with various third parties to construct and purchase pipe for our Sabine Pass Pipeline and Creole Trail Pipeline.

Off-Balance Sheet Arrangements

As of December 31, 2006, 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.

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Inflation

During 2004, 2005 and 2006, 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 Sabine Pass LNG receiving terminal and labor costs in connection with the collateral effects of the 2005 hurricanes.

Results of Operations Comparison of the Fiscal Years Ended December 31, 2006 and 2005

	Year Ended December 31, 2006					
	LNG Receiving Terminal	Natural Gas Pipeline	LNG & Natural Gas Marketing	Oil & Gas Exploration & Development	Corporate & Other	Consolidated
Revenue	$	$	$ 61	$ 2,310	$	$ 2,371
Operating costs and expenses						
LNG receiving terminal and pipeline development expenses	21,684	(8,268)			(1,317)	12,099
Exploration costs				3,138		3,138
Oil and gas production costs				237		237
Impairment of fixed assets					1,628	1,628
Depreciation, depletion and amortization	137		107	227	2,660	3,131
General and administrative expenses	6,571	13	6,869	1,895	42,664	58,012
Total operating costs and expenses	28,392	(8,255)	6,976	5,497	45,635	78,245
Income (loss) from operations	(28,392)	8,255	(6,915)	(3,187)	(45,635)	(75,874)
Loss on early extinguishment of debt	(43,159)					(43,159)
Derivative loss	(20,070)					(20,070)
Interest expense	(35,990)	(256)			(17,722)	(53,968)
Interest income	15,871		208		33,008	49,087
Other income			1	175		176
Income (loss) before income taxes	(111,740)	7,999	(6,706)	(3,012)	(30,349)	(143,808)
Income tax provision					(2,045)	(2,045)
Net income (loss)	$ (111,740)	$ 7,999	$ (6,706)	$ (3,012)	$ (32,394)	$ (145,853)

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	Year Ended December 31, 2005 (as adjusted)					
	LNG Receiving Terminal	Natural Gas Pipeline	LNG & Natural Gas Marketing	Oil & Gas Exploration & Development	Corporate & Other	Consolidated
Revenue	$	$	$	$ 3,005	$	$ 3,005
Operating costs and expenses						
LNG receiving terminal and pipeline development expenses	14,118	7,598			304	22,020
Exploration costs				2,839		2,839
Oil and gas production costs				237		237
Depreciation, depletion and amortization	55			58	1,212	1,325
General and administrative expenses	7,288	3		424	21,430	29,145
Total operating costs and expenses	21,461	7,601		3,558	22,946	55,566
Loss from operations	(21,461)	(7,601)		(553)	(22,946)	(52,561)
Gain on sale of investment in unconsolidated affiliate				20,206		20,206
Equity in net loss of limited partnership	(1,031)					(1,031)
Derivative gain	837					837
Interest expense	(9,424)				(7,949)	(17,373)
Interest income	2,645				14,875	17,520
Other income				722		722
Income (loss) before income taxes and minority interest	(28,434)	(7,601)		20,375	(16,020)	(31,680)
Income tax benefit					2,045	2,045
Minority interest	97					97
Net income (loss)	$ (28,337)	$ (7,601)	$	$ 20,375	$ (13,975)	$ (29,538)

Consolidated

Our consolidated financial results for the year ended December 31, 2006 reflect a net loss of $145.9 million, or $2.68 per share (basic and diluted), compared to a net loss of $29.5 million, or $0.56 per share (basic and diluted), in 2005.

The major factors contributing to our net loss of $145.9 million in 2006 were charges for general and administrative (G&A) expenses of $58.0 million, a loss on early extinguishment of debt of $43.2 million, a derivative loss of $20.1 million primarily related to the termination of our interest rate swaps associated with the early termination of debt, interest expense of $54.0 million and LNG receiving terminal and pipeline development expenses of $12.1 million, partially offset by interest income of $49.1 million. Absent the loss of ($63.2 million) from the early extinguishment of debt and related derivative loss, we would have reported a net loss of $82.7 million, or $1.52 per share (basic and diluted), for 2006. The major factors contributing to our $29.5 million net loss in 2005 were LNG receiving terminal and pipeline development expenses of

$22.0 million and G&A 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 $49.7 million, or $0.94 per share (basic and diluted), for 2005.

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As of January 1, 2006, we adopted SFAS No. 123R, *Share-Based Payment*, which requires that all share-based payments to employees be recognized in the financial statements based on their fair value at the date of grant. As a result, we recorded $17.3 million of non-cash compensation expense related to stock options in 2006.

LNG Receiving Terminal Segment

Financial results for our LNG receiving terminal segment for the year ended December 31, 2006 reflect a net loss of $111.7 million, compared to a net loss of $28.4 million for 2005.

LNG receiving terminal development expenses were 54% higher in 2006 ($21.7 million) than in 2005 ($14.1 million). Our development expenses included professional costs associated with front-end engineering and design work, obtaining orders from the FERC authorizing construction of our facilities and other required permitting for our planned LNG receiving terminals. In addition, development expenses included other costs related to employees directly involved in our development activities and land site rentals.

A significant portion of the development expenses related to our LNG receiving terminals included the expenses of our employees directly involved in LNG development activities. For 2006, employee-related costs (net of capitalization) increased to $10.5 million (including an increase of $3.8 million for non-cash compensation primarily resulting from stock option expense) from $6.4 million in 2005. The increase in employee-related costs was due to an increase in the average number of employees engaged in LNG terminal receiving development activities from 25 in 2005 to 62 in 2006, offset by an increase in the amount of employee-related costs capitalized as a result of employee s time being directly related to construction activities at our Sabine Pass and Corpus Christi LNG receiving terminal sites. In addition, land site rental charges of $1.5 million were charged to development expense in 2006 in accordance with FASB Staff Position (FSP) FAS 13-1, *Accounting for Rental Costs Incurred During a Construction Period,* which became effective January 1, 2006. These costs were capitalized in 2005.

G&A expenses were 10% lower in 2006 ($6.6 million) than in 2005 ($7.3 million). Our G&A expenses primarily related to a management fee (net of capitalization) as prescribed by contractual management services agreements between Sabine Pass LNG and two other wholly-owned subsidiaries, evaluation of software required for Sabine Pass LNG receiving terminal operations, and Hurricane Rita relief efforts. The $0.7 million decrease in 2006 compared to 2005 was primarily due to decreased software evaluation.

In connection with the issuance of the Sabine Pass LNG notes in November 2006, we terminated the amended Sabine Pass credit facility and Term Loan. As a result, we recorded a $43.2 million loss on the early extinguishment of debt related to the expensing of debt issuance costs and a $20.1 million derivative loss primarily as a result of terminating related interest rate swaps. In 2005, we recorded a $0.8 million derivative gain related to the ineffective portion of our interest rate swaps associated with the Sabine Pass credit facility entered into in February 2005.

Interest expense increased 283% in 2006 ($36.0 million, net of capitalized interest) from 2005 ($9.4 million, net of capitalized interest). The significant increase was due to the longer period of time for borrowings under the Term Loan to be outstanding in 2006 compared to 2005, and the closing of the $2.0 billion Sabine Pass LNG notes offering in November 2006. Borrowings under the amended Sabine Pass credit facility in 2006 had no impact on interest expense as all related interest was capitalized.

Interest income increased 512% in 2006 ($15.9 million) compared to 2005 ($2.6 million). The increase in interest income was due to an increase in average invested cash balances in 2006 over 2005.

In 2005, we recorded a $1.0 million loss related to our equity share of the loss of Freeport LNG. We did not record any loss associated with this investment in 2006 as our investment basis was zero, and we have no current intention or obligation to fund any of Freeport LNG s losses.

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Natural Gas Pipeline Segment

Financial results for our natural gas pipeline segment for the year ended December 31, 2006 reflect net income of $8.0 million, compared to a net loss of $7.6 million in 2005.

Natural gas pipeline development expenses decreased $15.9 million in 2006 to a negative expense of $8.3 million compared to an expense of $7.6 million in 2005. Historically, our natural gas pipeline development expenses primarily included professional fees associated with front-end engineering and design work, obtaining orders from the FERC authorizing construction of our pipelines and other required permitting for our planned natural gas pipelines. During the second quarter of 2006, however, we recognized regulatory assets, as prescribed by SFAS No. 71 (see Note 3 Property, Plant and Equipment of our Notes to Consolidated Financial Statements), that had previously been expensed as pipeline development expenses.

LNG and Natural Gas Marketing Segment

Financial results for our LNG and natural gas marketing segment for the year ended December 31, 2006 reflect a net loss of $6.7 million, compared to zero in 2005. In 2005, minor personnel expenses related to marketing activities were included in Corporate and Other. G&A expenses incurred in 2006 were primarily related to employee costs, software evaluation costs and legal and consulting fees.

Oil and Gas Exploration and Development Segment

Financial results for our oil and gas exploration and development segment for the year ended December 31, 2006 reflect a net loss of $3.0 million, compared to net income of $20.4 million for 2005. The decrease in net income was primarily attributable to the $20.2 million gain on the sale of our investment in Gryphon in 2005. G&A expenses increased in 2006 compared to 2005 as a result of non-cash share-based compensation primarily from stock option expenses.

Corporate and Other

Financial results for corporate and other activities for the year ended December 31, 2006 reflect a net loss of $32.4 million, compared to a net loss of $14.0 million for 2005.

G&A expenses increased $21.3 million, or 100%, to $42.7 million in 2006 compared to $21.4 million in 2005. The increase in G&A expenses primarily resulted from the expansion of our business (including increases in our corporate staff from an average of 47 employees in 2005 to an average of 95 employees in 2006). Included in G&A expenses is an increase in non-cash compensation of $11.1 million primarily resulting from stock option expense. Corporate employee-related costs for 2006 and 2005 included non-cash compensation of $27.0 million and $12.6 million, respectively.

Interest expense increased 124% in 2006 ($17.7 million) compared to 2005 ($7.9 million). The increase was due to the longer period of time for borrowings under our Convertible Senior Unsecured Notes and our Term Loan to be outstanding in 2006 compared to 2005.

Interest income increased 121% in 2006 ($33.0 million) compared to 2005 ($14.9 million). The increase in interest income was due to an increase in average invested cash balances in 2006 over 2005.

An income tax provision of $2.0 million was recognized in 2006 relating to the portion of the change in our tax asset valuation account that was allocable to the deferred income tax on the decrease in accumulated other comprehensive income (OCI) primarily related to interest rate derivative instruments in accordance with SFAS No. 109, *Accounting for Income Taxes*, and EITF *Abstract*, Topic D-32. A $2.0 million tax benefit was recorded in 2005 relating to the portion of the change in our tax asset valuation account that was allocable to the deferred income tax on the increase in accumulated OCI related to interest rate derivative instruments.

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

	Year Ended December 31, 2005 (as adjusted)					
	LNG Receiving Terminal	Natural Gas Pipeline	LNG & Natural Gas Marketing	Oil & Gas Exploration & Development	Corporate & Other	Consolidated
Revenue	$	$	$	$ 3,005	$	$ 3,005
Operating costs and expenses						
LNG receiving terminal and pipeline development expenses	14,118	7,598			304	22,020
Exploration costs				2,839		2,839
Oil and gas production costs				237		237
Depreciation, depletion and amortization	55			58	1,212	1,325
General and administrative expenses	7,288	3		424	21,430	29,145
Total operating costs and expenses	21,461	7,601		3,558	22,946	55,566
Loss from operations	(21,461)	(7,601)		(553)	(22,946)	(52,561)
Gain on sale of investment in unconsolidated affiliate				20,206		20,206
Equity in net loss of limited partnership	(1,031)					(1,031)
Derivative gain	837					837
Interest expense	(9,424)				(7,949)	(17,373)
Interest income	2,645				14,875	17,520
Other income				722		722
Income (loss) before income taxes and minority interest	(28,434)	(7,601)		20,375	(16,020)	(31,680)
Income tax benefit					2,045	2,045
Minority interest	97					97
Net income (loss)	$ (28,337)	$ (7,601)	$	$ 20,375	$ (13,975)	$ (29,538)

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	Year Ended December 31, 2004 (as adjusted)					
	LNG Receiving Terminal	Natural Gas Pipeline	LNG & Natural Gas Marketing	Oil & Gas Exploration & Development	Corporate & Other	Consolidated
Revenue	$	$	$	$ 1,998	$	$ 1,998
Operating costs and expenses						
LNG receiving terminal and pipeline development expenses	15,310	1,847			9	17,166
Exploration costs				2,662		2,662
Oil and gas production costs				117		117
Depreciation, depletion and amortization	77			52	378	507
General and administrative expenses				794	11,682	12,476
Total operating costs and expenses	15,387	1,847		3,625	12,069	32,928
Loss from operations	(15,387)	(1,847)		(1,627)	(12,069)	(30,930)
Reimbursement from limited partner	2,500					2,500
Equity in net loss of limited partnership	(1,346)					(1,346)
Interest expense					(4)	(4)
Interest income	28				473	501
Other income				1,541		1,541
Net loss before minority interest	(14,205)	(1,847)		(86)	(11,600)	(27,738)
Minority interest	2,862					2,862
Net income (loss)	$ (11,343)	$ (1,847)	$	$ (86)	$ (11,600)	$ (24,876)

Consolidated

Our consolidated financial results for the year ended December 31, 2005 reflect a net loss of $29.5 million, or $0.56 per share (basic and diluted), compared to a net loss of $24.9 million, or $0.64 per share (basic and diluted), in 2004.

The major factors contributing to our net loss of $29.5 million in 2005 were LNG receiving terminal and pipeline 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 $49.7 million, or $0.94 per share (basic and diluted), for 2005. The major factors contributing to our $24.9 million net loss in 2004 were LNG receiving terminal and pipeline development expenses of $17.2 million and G&A 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 Segment

Financial results for our LNG receiving terminal segment for the year ended December 31, 2005 reflect a net loss of $28.3 million, compared to a net loss of $11.3 million for 2004.

LNG receiving terminal development expenses were 8% lower in 2005 ($14.1 million) than in 2004 ($15.3 million). Our development expenses primarily included professional fees associated with front-end engineering and design work, obtaining orders from the FERC authorizing construction of our facilities and other required permitting for our planned LNG receiving terminals and other initiatives that complement the development of our LNG receiving terminal business. Expenses of our LNG employees involved in development activities have also been included. Beginning in the first quarter of 2005, costs related to the construction of Phase 1 of the Sabine Pass LNG receiving terminal were capitalized.

LNG receiving terminal development expenses were mainly attributable to our Creole Trail and Corpus Christi LNG receiving terminal projects and Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal. 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.

In 2004, we recorded $5.8 million in 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 development expenses of $6.4 million related to Phase 1 of the Sabine Pass LNG receiving terminal and $375,000 related to the Creole Trail LNG receiving terminal, in 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 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).

G&A expenses were $7.3 million in 2005 compared to zero in 2004. Our 2005 G&A expenses primarily related to a management fee (net of capitalization) as prescribed by contractual management services agreements between Sabine Pass LNG and two other wholly-owned subsidiaries, evaluation of software required for Sabine Pass LNG receiving terminal operations, and Hurricane Rita relief efforts.

In 2005, our 30% equity share of the net loss of Freeport LNG resulted in a reported net loss of $1.0 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 of our Notes to Consolidated Financial Statements).

In January 2004, we received the final $2.5 million payment from Freeport LNG pursuant to the terms of an 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.

The increase in interest expense (net of capitalization) of $9.4 million in 2005 compared to zero in 2004 resulted from borrowing under the Term Loan during the third quarter of 2005.

Interest income increased to $2.6 million in 2005 from $28,000 in 2004 due to an increase in average invested cash balances in 2005 over 2004.

Natural Gas Pipeline Segment

Financial results for our natural gas pipeline segment for the year ended December 31, 2005 reflect a net loss of $7.6 million, compared to a net loss of $1.8 million in 2004.

In 2005, we incurred $7.6 million in LNG pipeline development expenses primarily related to our Sabine Pass and Creole Trail pipeline projects.

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Oil and Gas Exploration and Development Segment

Financial results for our oil and gas exploration and development segment for the year ended December 31, 2005 reflect a net income of $20.4 million, compared to a net loss of $86,000 for 2004. The increase in net income was primarily attributable to the $20.2 million gain on the sale of our investment in Gryphon in 2005.

Corporate and Other

Financial results for corporate and other activities for the year ended December 31, 2005 reflect a net loss of $14.0 million, compared to a net loss of $11.6 million for 2004.

G&A expenses increased $9.7 million, or 83%, to $21.4 million in 2005 compared to $11.7 million in 2004. The increase in G&A expenses primarily resulted from the expansion of our business (including increases in our 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 amortization of deferred compensation associated with non-vested stock awards.

Interest expense increased to $7.9 million in 2005 from $4,000 in 2004. This increase was attributable to the issuance of our Convertible Senior Unsecured Notes and our Term Loan during the third quarter of 2005.

Interest income increased to $14.9 million in 2005 from $0.5 million 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 in the third quarter of 2005.

An income tax benefit of $2.0 million was recognized in 2005 relating to the portion of the change in our tax asset valuation account that was allocable to the deferred income tax on the increase in accumulated OCI related to interest rate derivative instruments in accordance with SFAS No. 109, *Accounting for Income Taxes*, and EITF *Abstract*, Topic D-32.

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.

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

Effective January 1, 2006, we converted from the full cost method to the successful efforts method of accounting for our investments in oil and gas properties. While our primary focus is the development of our LNG-related businesses, we have continued to be involved, to a limited extent, in oil and gas exploration and development activities in the U.S. Gulf of Mexico. We believe that, in light of our current level of exploration and development activities, the successful efforts method of accounting provides a better matching of expenses to the period in which oil and gas production is realized. As a result, we believe that the change in accounting method at this time is appropriate. The change in accounting method constitutes a Change in Accounting Principle, requiring that all prior period financial statements be adjusted to reflect the results and balances that would have been reported had we been following the successful efforts method of accounting from our inception.

The cumulative effect of the change in accounting method as of December 31, 2005 and 2004 was to reduce the balance of our net investment in oil and gas properties and retained earnings at those dates by $18.0 million and $18.2 million, respectively. The change in accounting method resulted in a decrease in the net loss of $0.3 million and an increase in the net loss of $0.3 million for the years ended December 31, 2005 and 2004, respectively, and had no impact on earnings per share (basic and diluted) for these respective periods (see Note 16 Adjustment to Financial Statements Successful Efforts of our Notes to Consolidated Financial Statements). The change in method of accounting had no impact on cash or working capital.

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 have been 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.

Successful Efforts Method of Accounting

We have elected to follow the successful efforts method of accounting for our oil and gas properties. Under this method, production costs, geological and geophysical costs (including the cost of seismic data), delay rentals, costs of unsuccessful exploratory wells, and internal costs directly related to our exploration and development activities are charged to expense as incurred. The costs of property acquisitions, successful exploratory wells, development costs, and support equipment and facilities are initially capitalized when incurred. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we review proved oil and gas properties and other long-lived assets for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amount of the properties is written down to their estimated fair value. The factors used to determine fair value include, but are not limited to, estimates of proved

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reserves, future commodity prices, timing of future production, future capital expenditures and a risk-adjusted discount rate. Individually significant unproved properties are also periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Depreciation, depletion and amortization of proved oil and gas properties is determined on a field-by-field basis using the unit-of-production method over the life of the remaining proved reserves.

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.

Regulated Natural Gas Pipelines

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

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

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principles based on on-going changes in the regulatory and economic environment. Items that may influence our assessment are:

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

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

Cash Flow Hedges

As defined in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, cash flow hedge transactions hedge the exposure to variability in expected future cash flows (i.e., in our case, the variability of floating interest rate exposure). In the case of cash flow hedges, the hedged item (the underlying risk) is generally unrecognized (i.e., not recorded on the balance sheet prior to settlement), and any changes in the fair value, therefore, will not be recorded within earnings. Conceptually, if a cash flow hedge is effective, this means that a variable, such as a movement in interest rates, has been effectively fixed so that any fluctuations will have no net result on either cash flows or earnings. Therefore, if the changes in fair value of the hedged item are not recorded in earnings, then the changes in fair value of the hedging instrument (the derivative) must also be excluded from the income statement or else a one-sided net impact on earnings will be reported, despite the fact that the establishment of the effective hedge results in no net economic impact. To prevent such a scenario from occurring, SFAS No. 133 requires that the fair value of a derivative instrument designated as a cash flow hedge be recorded as an asset or liability on the balance sheet, but with the offset reported as part of other comprehensive income, to the extent that the hedge is effective. We assess both at the inception of each hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. On an on-going basis, we monitor the actual dollar offset of the hedges market values compared to hypothetical cash flow hedges. The cash flow hedge contracts are generally deemed to be highly effective if the R-squared is greater than 80 percent and the dollar offset correlation is within 80 percent to 125 percent. Any ineffective portion of the cash flow hedges 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 of our Notes to Consolidated Financial Statements.

Share-Based Compensation Expense

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123R using the modified prospective transition method, and therefore have not restated the results of prior periods. Under this

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

Determining the appropriate fair value model and calculating the fair value of share-based payment awards require the input of highly subjective assumptions, including the expected life of the share-based payment awards and stock price volatility. We believe that implied volatility, calculated based on traded options of our common stock, combined with historical volatility is an appropriate indicator of expected volatility and future stock price trends. Therefore, expected volatility for the year ended December 31, 2006 was based on a combination of implied and historical volatilities. The assumptions used in calculating the fair value of share-based payment awards represent our best estimates, but these estimates involve inherent uncertainties and the application of management judgment. As a result, if factors change and we use different assumptions, our stock-based compensation expense could be materially different in the future. In addition, we are required to estimate the expected forfeiture rate and only recognize expense for those shares expected to vest. If our actual forfeiture rate is materially different from our estimate, the stock-based compensation expense could be significantly different from what we have recorded in the current period. See Note 16 Share-Based Compensation of our Notes to Consolidated Financial Statements for a further discussion on share-based compensation.

New Accounting Pronouncements

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

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

In July 2006, the FASB issued FASB Interpretation, or FIN, No. 48, *Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109*. FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes*. It prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This new standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN No. 48 are to be applied to all tax positions upon initial adoption

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of this standard. Only tax positions that meet the more likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption of FIN No. 48. The cumulative effect of applying the provisions of FIN No. 48 should be reported as an adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year. The provisions of FIN No. 48 are effective for fiscal years beginning after December 15, 2006. Earlier application is permitted as long as the enterprise has not yet issued financial statements, including interim financial statements, in the period of adoption. We believe that the adoption of FIN No. 48 will not have a material impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS No. 157 clarifies the principle that fair value should be based on the assumptions that market participants would use when pricing an asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, with early adoption permitted. We believe that the adoption of SFAS No. 157 will not have a material impact on our financial position, results of operations or cash flows.

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

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

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

Commodity Prices

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.

Cash Investments

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

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

INDEX TO FINANCIAL STATEMENTS

CHENIERE ENERGY, INC. AND SUBSIDIARIES

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

Management s Report on Internal Control Over Financial Reporting

As management, we are responsible for establishing and maintaining adequate internal control over financial reporting for Cheniere Energy, Inc. and its subsidiaries, 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, 2006, 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, 2006, has been audited by UHY 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

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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, 2006 and 2005, and the related consolidated statements of operations, stockholders equity and cash flows for each of the three years in the period ended December 31, 2006. 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 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, 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, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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, 2006, 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 February 27, 2007 expressed an unqualified opinion on management s assessment of, and the effective operation of, internal control over financial reporting.

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

/s/ UHY LLP
UHY LLP

Houston, Texas

February 27, 2007

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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, 2006, 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, 2006, 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, 2006, 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, 2006 and 2005, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2006, and our report dated February

27, 2007 expressed an unqualified opinion on those consolidated financial statements.

/s/ UHY LLP

UHY LLP

Houston, Texas

February 27, 2007

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

(in thousands, except share data)

	December 31,	
	2006	**2005**
		(As Adjusted)
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 462,963	$ 692,592
Restricted cash and cash equivalents	355,831	161,561
Advances to EPC contractor		8,087
Interest receivable	6,642	1,173
Accounts receivable	1,299	1,739
Derivative assets		5,468
Prepaid expenses	2,242	843
Total current assets	828,977	871,463
NON-CURRENT RESTRICTED CASH AND CASH EQUIVALENTS	892,718	16,500
PROPERTY, PLANT AND EQUIPMENT, NET	748,818	280,106
DEBT ISSUANCE COSTS, NET	41,545	43,008
GOODWILL	76,844	76,844
LONG-TERM DERIVATIVE ASSETS		1,837
INTANGIBLE LNG ASSETS	4,331	93
ADVANCES UNDER LONG-TERM CONTRACTS	7,101	
OTHER	4,154	296
Total assets	$ 2,604,488	$ 1,290,147
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 3,659	$ 778
Accrued liabilities	58,280	54,544
Current portion of long-term debt		6,000
Total current liabilities	61,939	61,322
LONG-TERM DEBT	2,357,000	917,500
DEFERRED REVENUE	41,000	41,000
LONG-TERM DERIVATIVE LIABILITIES		1,682
OTHER NON-CURRENT LIABILITIES	1,302	102
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY		
Preferred stock, $.0001 par value, 5,000,000 shares authorized, none issued		

Common stock, $.003 par value		
Authorized: 120,000,000 shares at December 31, 2006 and 2005, respectively		
Issued and outstanding: 55,212,771 and 54,521,131 shares at December 31, 2006 and 2005, respectively	166	164
Additional paid-in-capital	390,256	375,551
Deferred compensation		(9,684)
Accumulated deficit	(247,141)	(101,288)
Accumulated other comprehensive (loss) income	(34)	3,798
Total stockholders equity	143,247	268,541
Total liabilities and stockholders equity	$ 2,604,488	$ 1,290,147

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

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS

(in thousands, except per share data)

	Year Ended December 31,		
	2006	**2005**	**2004**
		(As Adjusted)	**(As Adjusted)**
Revenues			
Oil and gas sales	$ 2,310	$ 3,005	$ 1,998
Marketing revenue	61		
Total revenues	2,371	3,005	1,998
Operating costs and expenses			
LNG receiving terminal and pipeline development expenses	12,099	22,020	17,166
Exploration costs	3,138	2,839	2,662
Oil and gas production costs	237	237	117
Depreciation, depletion and amortization	3,131	1,325	507
Impairment of fixed assets	1,628		
General and administrative expenses	58,012	29,145	12,476
Total operating costs and expenses	78,245	55,566	32,928
Loss from operations	(75,874)	(52,561)	(30,930)
Gain on sale of investment in unconsolidated affiliate		20,206	
Equity in net loss of limited partnership		(1,031)	(1,346)
Reimbursement from limited partnership investment			2,500
Loss on early extinguishment of debt	(43,159)		
Derivative gain (loss)	(20,070)	837	
Interest expense	(53,968)	(17,373)	(4)
Interest income	49,087	17,520	501
Other income	176	722	1,541
Loss before income taxes and minority interest	(143,808)	(31,680)	(27,738)
Income tax (provision) benefit	(2,045)	2,045	
Loss before minority interest	(145,853)	(29,635)	(27,738)
Minority interest		97	2,862
Net loss	$ (145,853)	$ (29,538)	$ (24,876)
Net loss per common share basic and diluted	$ (2.68)	$ (0.56)	$ (0.64)
Weighted average number of common shares outstanding basic and diluted	54,423	53,097	38,895

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

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY

(in thousands)

	Common Stock		Treasury Stock					Accumulated Other	
	Shares	Amount	Shares	Amount	Additional Paid-In Capital	Deferred Compen-sation	Accumulated Deficit	Comprehensive Income (loss)	Total Stockholders Equity
Balance December 31, 2003 (as adjusted)	32,976	$ 99		$	$ 47,985	$	$ (46,874)	$	$ 1,210
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							(24,876)		(24,876)
Balance December 31, 2004 (as adjusted)	50,919	153			364,504	(6,543)	(71,750)		286,364
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							(29,538)		(29,538)
Balance December 31, 2005 (as adjusted)	54,521	164			375,551	(9,684)	(101,288)	3,798	268,541
Issuances of stock	386	1			1,995				1,996
Issuances of restricted stock	350	1			(1)				
Forfeitures of restricted stock	(18)		18						
Reversal of deferred compensation					(9,684)	9,684			
Stock-based compensation expense					23,371				23,371
Treasury stock acquired	(26)		26	976	(976)				
Treasury stock retired			(44)	(976)					(976)
Comprehensive loss:									
Interest rate swaps								(3,798)	(3,798)
Foreign currency translation								(34)	(34)
Net loss							(145,853)		(145,853)

Balance December 31, 2006	55,213	$	166		$		$	390,256	$		$	(247,141)	$	(34)	$	143,247

The accompanying notes are an integral part of these financial statements

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2006	2005	2004
		(As Adjusted)	(As Adjusted)
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (145,853)	$ (29,538)	$ (24,876)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	3,131	1,325	507
Impairment of unproved properties	416	601	335
Dry hole expense	1,673	809	
Non-cash compensation	21,768	3,583	3,618
Gain on sale of investment in unconsolidated affiliate		(20,206)	
Deferred tax provision (benefit)	2,045	(2,045)	
Equity in net loss of limited partnership		1,031	1,346
Loss on early extinguishment of debt	37,136		
Minority interest		(97)	(2,862)
Other	5,755	986	(2,518)
Changes in operating assets and liabilities			
Accounts receivable affiliate			1,000
Other accounts receivable	(5,842)	(320)	(890)
Prepaid expenses	(1,522)	(280)	(257)
Deferred revenue		18,000	22,000
Regulatory asset	(12,343)		
Accounts payable and accrued liabilities	13,210	7,195	1,146
NET CASH USED IN OPERATING ACTIVITIES	(80,426)	(18,956)	(1,451)
CASH FLOWS FROM INVESTING ACTIVITIES:			
LNG terminal and pipeline construction-in-progress	(440,367)	(229,705)	
Investment in restricted cash and cash equivalents	(1,070,713)	(177,385)	
Advance to EPC contractor, net of transfers to construction-in-progress		(8,087)	
Purchases of fixed assets	(10,527)	(5,811)	(915)
Investment in limited partnership		(2,102)	(275)
Oil and gas property additions	(4,135)	(3,299)	(1,235)
Proceeds from sale of investment in unconsolidated affiliate		20,206	
Advances under long-term contracts	(7,101)		
Sale of interest in oil and gas prospects	448	1,235	2,381
Other	(7,533)	(639)	2,019
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	(1,539,928)	(405,587)	1,975
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuances of Senior Notes	2,032,000		
Issuance of convertible senior unsecured notes		325,000	

Proceeds from Term Loan		600,000	
Repayment of Term Loan	(598,500)	(1,500)	
Borrowings under Sabine Pass Credit Facility	383,400		
Repayment of Sabine Pass Credit Facility	(383,400)		
Purchase of issuer call spread		(75,703)	
Debt issuance costs	(43,796)	(42,124)	(1,302)
Sale of common stock	1,953	2,972	320,933
Offering costs		(27)	(15,050)
Other	(932)	74	2,080
NET CASH PROVIDED BY FINANCING ACTIVITIES	1,390,725	808,692	306,661
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(229,629)	384,149	307,185
CASH AND CASH EQUIVALENTS BEGINNING OF YEAR	692,592	308,443	1,258
CASH AND CASH EQUIVALENTS END OF YEAR	$ 462,963	$ 692,592	$ 308,443

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

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 developing a business to market LNG and natural gas primarily through our wholly-owned subsidiary, Cheniere Marketing, Inc. (Cheniere Marketing). To a limited extent, we are also engaged 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 2006 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

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

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

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Regulated Operations

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

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

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

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

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

Effective January 1, 2006, we converted from the full cost method to the successful efforts method of accounting for our investments in oil and gas properties. While our primary focus is the development of our LNG-related businesses, we have continued to be involved, to a limited extent, in oil and gas exploration and development activities in the U.S. Gulf of Mexico. We believe that, in light of our current level of exploration and development activities, the successful efforts method of accounting provides a better matching of expenses to the period in which oil and gas production is realized. As a result, we believe that the change in accounting method was appropriate. The change in accounting method constituted a Change in Accounting Principle, requiring that all prior period financial statements be adjusted to reflect the results and balances that would have been reported had we been following the successful efforts method of accounting from our inception. The cumulative effect of the change in accounting method as of December 31, 2005 and 2004 was to reduce the balance of our net investment in oil and gas properties and retained earnings at those dates by $18.0 million and $18.2 million, respectively. The change in accounting method resulted in a decrease in the net loss of $0.3 million for the year ended December 31, 2005 and an increase in net loss by $0.3 million for the year ended December 31, 2004. There was no material impact on earnings per share (basic and diluted) for these respective

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

periods (see Note 16 Adjustment to Financial Statements Successful Efforts of our Notes to Consolidated Financial Statements). The change in method of accounting had no impact on cash or working capital.

Successful Efforts Method of Accounting

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

Capitalized Exploratory Well Costs

In April 2005, the FASB issued FSP No. FAS 19-1, *Accounting for Suspended Well Costs*, which amends SFAS No. 19*, Financial Accounting and Reporting by Oil and Gas Producing Companies*. Under the provisions of FSP No. FAS 19-1, exploratory well costs continue to be capitalized after the completion of drilling when (i) the well has found a sufficient quantity of reserves to justify completion as a producing well and (ii) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, or if an enterprise obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. FSP No. FAS 19-1 provides several indicators that can assist an entity in demonstrating that sufficient progress is being made when assessing the reserves and economic viability of the project.

At December 31, 2006, our suspended well costs for wells on which drilling was completed more than one year ago were $0.2 million relating to a single well. There were no suspended well costs charged to expense for the year ended December 31, 2006.

Asset Retirement Obligations

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Revenue Recognition

LNG regasification capacity fees are recognized as revenue over the term of the respective terminal use agreement (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 underproduced or overproduced imbalance occurs. To the extent an overproduced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability. At December 31, 2006 and 2005, we had no gas imbalances.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Expenditures for construction activities, major renewals and betterments are capitalized, while expenditures for maintenance and repairs and general and administrative activities are charged to expense as incurred. Interest costs incurred on debt obtained for the construction of property, plant and equipment are capitalized as construction-in-progress over the construction period or related debt term, whichever is shorter. Once placed into service, the LNG receiving terminal construction costs will be depreciated using the straight-line depreciation method. We are in the process of determining the most appropriate approach in grouping identifiable components with similar estimated useful lives. Estimated useful lives for components, once construction is completed, are currently estimated to range between 10 and 50 years. Depreciation of computer and office equipment, computer software, leasehold improvements and vehicles is computed using the straight-line method over the estimated useful lives of the assets, which range from two to ten years. Upon retirement or other disposition of property, plant and equipment, the cost and related accumulated depreciation are removed from the account, and the resulting gains or losses are recorded in operations.

In accordance with SFAS No. 144, management reviews property, plant and equipment for impairment periodically and whenever events or changes in circumstances have indicated that the carrying amount of property, plant and equipment might not be recoverable. No such impairment was recorded for the years ended December 31, 2006 or 2005.

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

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

value, therefore, will not be recorded within earnings. Conceptually, if a cash flow hedge is effective, this means that a variable, such as a movement in interest rates, has been effectively fixed so that any fluctuations will have no net result on either cash flows or earnings. Therefore, if the changes in fair value of the hedged item are not recorded in earnings, then the changes in fair value of the hedging instrument (the derivative) must also be excluded from the income statement or else a one-sided net impact on earnings will be reported, despite the fact that the establishment of the effective hedge results in no net economic impact. To prevent such a scenario from occurring, SFAS No. 133 requires that the fair value of a derivative instrument designated as a cash flow hedge be recorded as an asset or liability on the balance sheet, but with the offset reported as part of other comprehensive income, to the extent that the hedge is effective. We assess both at the inception of each hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. On an on-going basis we monitor the actual dollar offset of the hedges market values as compared to hypothetical cash flow hedges. Any ineffective portion of the cash flow hedges will be reflected in earnings. Ineffectiveness is the amount of gains or losses from derivative instruments which are not offset by corresponding and opposite gains or losses on the expected future transaction.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires 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 items subject to estimates and assumptions include, but are not limited to, the carrying amount of property, plant and equipment, and goodwill; valuation allowances for income tax assets; and the fair value of share-based payments. Actual results could differ significantly from those estimates.

Cash Equivalents

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

Fair Value of Financial Instruments

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

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, 2006.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 (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.

Share-Based Compensation Expense

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

Determining the appropriate fair value model and calculating the fair value of share-based payment awards requires the use of highly subjective assumptions, including the expected life of the share-based payment awards and stock price volatility. We believe that implied volatility, calculated based on traded options of our common stock, combined with historical volatility is an appropriate indicator of expected volatility and future stock price

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

trends. Therefore, the expected volatility for the year ended December 31, 2006 used in our fair value model was based on a combination of implied and historical volatilities. The assumptions used in calculating the fair value of share-based payment awards represent our best estimates, but these estimates involve inherent uncertainties and the application of management judgment. As a result, if factors change and we use different assumptions, our stock-based compensation expense could be materially different in the future. In addition, we are required to estimate the expected forfeiture rate and only recognize expense for those shares expected to vest. If our actual forfeiture rate is materially different from our estimate, future stock-based compensation expense could be significantly different from what we have recorded in the current period (see Note 19 Share-Based Compensation for further discussion on share-based compensation).

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, warrants and unvested stock is anti-dilutive to our net loss per share under SFAS No. 128. Stock options, warrants and unvested stock representing securities that could potentially dilute basic EPS in the future that were not included in the diluted computation because they would have been anti-dilutive for the years 2006, 2005 and 2004 were 5.7 million, 5.7 million and 3.1 million, respectively. In addition, common shares of 9.2 million and 4.0 million 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 2006 and 2005, respectively, 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 2006 and 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 9.2 million.

New Accounting Pronouncements

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

In March 2006, the FASB issued SFAS No. 156, *Accounting for Servicing of Financial Assets An Amendment to FASB Statement No. 140*. SFAS No. 156 requires entities to recognize a servicing asset or liability

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS No. 157 clarifies the principle that fair value should be based on the assumptions that market participants would use when pricing an asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, with early adoption permitted. We believe that the adoption of SFAS No. 157 will not have a material impact on our financial position, results of operations or cash flows.

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

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

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 3 RESTRICTED CASH AND CASH EQUIVALENTS

In August 2006, Cheniere Creole Trail Pipeline, L.P., our wholly-owned subsidiary (CCTP), entered into a purchase order with ILVA S.p.A (ILVA) for the purchase of pipe at an aggregate cost of approximately $175.7 million (see Note 22 Commitments and Contingencies). Associated with this purchase order, CCTP delivered a standby letter of credit to ILVA in the amount of $87.9 million to secure CCTP s obligations under the purchase order. This letter of credit required a deposit of $87.9 million with the issuer of the letter of credit and has been recorded as non-current restricted cash and cash equivalents on our Consolidated Balance Sheet at December 31, 2006. Once the value of the goods and services paid by CCTP exceeds the value of the letter of credit, ILVA will submit a notice of reduction to the issuing bank to reduce the amount of the letter of credit by 100% of any subsequent payments by CCTP. The non-current restricted cash and cash equivalents cash collateral account on deposit with the issuing bank will be reduced by such amount.

In November 2006, Sabine Pass LNG, L.P. our wholly-owned subsidiary (Sabine Pass LNG), consummated a private offering of an aggregate principle amount of $2 billion of Senior Secured Notes consisting of $550 million of 7 $^{1}/4$% Senior Secured Notes due 2013 (the 2013 Notes) and $1.5 billion of 7 $^{1}/2$% Senior Secured Notes due 2016 (the 2016 Notes and collectively with the 2013 Notes, the Senior Notes) (See Note 14 Long-Term Debt). Under the terms and conditions of the Senior Notes, we were required to fund cash reserve accounts for $335.0 million related to future interest payments through May 2009 and approximately $887 million to pay the remaining costs to complete Phase 1 and Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal. These cash accounts are controlled by a collateral trustee, and therefore, are shown as restricted cash and cash equivalents on our Consolidated Balance Sheet. As of December 31, 2006, $355.3 million related to future interest payments and accrued construction costs have been classified as a current asset, and $803.6 million related to remaining construction costs have been classified as a non-current asset on our Consolidated Balance Sheet.

At December 31, 2005, Sabine Pass LNG had a restricted cash and cash equivalents balance of $8.9 million, classified as a current asset, under the terms of an $822 million credit facility (Sabine Pass Credit Facility), which was subsequently terminated using a portion of the proceeds from the issuance of the Senior Notes in November 2006 (see Note 14 Long-Term Debt).

In August 2005, Cheniere LNG Holdings, LLC, our wholly-owned subsidiary (Cheniere LNG Holdings), entered into a $600 million Senior Secured Term Loan (Term Loan), with Credit Suisse, Cayman Islands Branch (Credit Suisse), who also served 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 $216.2 million into two collateral accounts: $181.0 million into a debt service reserve collateral account and $35.2 million into a capital contribution reserve collateral account. These funds were 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 had been funded to Sabine Pass LNG. Because the accounts were controlled by the collateral agent, our cash and cash equivalent balance of $168.5 million held in these accounts as of December 31, 2005 were classified as restricted on our Consolidated Balance Sheet. Of this amount, $16.5 million was classified as non-current due to the timing of certain required debt amortization payments. In November 2006, the Term Loan was terminated using a portion of the proceeds from the issuance of the Senior Notes.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 4 LEASES

Future Annual Minimum Lease Payments

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

Year Ending December 31,	Operating Leases (2)
2007	$ 3,161
2008	4,267
2009	4,258
2010	4,216
2011	4,214
Thereafter (1)	142,501
Total	$ 162,617

(1) Thereafter includes the remaining initial term and extensions of the Sabine Pass LNG site and tug boat leases, as these lease option renewals were reasonably assured, as defined in SFAS No. 13, *Accounting for Leases.*

(2) Future annual minimum lease payments do not include $4.2 million expected to be recovered through sublease agreements for our Texas Avenue Office Lease.

Pennzoil Office Lease

In 2006, we entered into a lease agreement, as amended, for new office space with Sunbelt Management Company, to lease five floors (approximately 102,206 square feet) in the North Tower of Houston Pennzoil Place. The initial term runs from April 2007 through October 2017 with an option to cancel by payment of a fee after year six, and a renewal option to extend for three successive five-year terms. Under the lease, monthly payments commence on the seventh month after the start of the lease at a monthly rental rate of $68,000 that escalates to $119,000 if we elect to extend the lease term. In addition, we will pay additional rental in the form of operating expenses plus a 3% management fee.

Texas Avenue Office Lease

In October 2003, we entered into a lease agreement with Hines Interests, L.P. for office space with a term that runs from December 2003 through April 2014 at an initial monthly rental rate of $21,000 that escalates to $24,000 beginning in February 2009 through the remaining term of the lease. In May 2004, we amended our office lease agreement to increase our rentable square footage, which runs from September 2004 through August 2009 at a rate of $14,000 per month beginning in June 2005. In March 2005, we amended our office lease to increase our rentable square footage to include an additional floor on the premises, which runs from May 2005 through January 2014. Under the amended lease, there are no monthly lease payments for the additional floor from May 2005 through April 2007, after which time the beginning monthly rental rate of $30,000 that escalates to $39,000 per month through January 2014. We are also responsible for our proportionate share of the building operating expenses.

In September 2006, we entered into a sublease agreement with Kayne Anderson Capital Advisors, LP (Kayne) for Kayne to lease approximately one-half of a floor under the Texas Avenue Office Lease. The term runs from May 2007 through January 2014. Kayne will pay a monthly base rental rate of $20,000 per month commencing on the fourth month after the start of the lease, and will be responsible for operating expenses plus a 3% management fee.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In October 2006, we entered into a sublease with Crimson Exploration, Inc. (Crimson) for Crimson to rent one floor under the Texas Avenue Office Lease. The term runs from April 2007 through January 2014. Crimson will pay a monthly base rental of $35,000 per month commencing on the seventh month after the start of the lease, and will be responsible for operating expenses plus a 3% management fee.

Tug Boat Lease

Sabine Pass TUG Services, LLC, our wholly owned subsidiary (Sabine TUG Services), entered into a Marine Services Agreement (the Tug Agreement) with Alpha Marine Services, LLC (Alpha) for the use of four tug boats and marine services for the Sabine Pass LNG receiving terminal. The term of the Tug Agreement commences no earlier than October 2007 and no later than February 2008 for a period of 10 years, with an option to renew two additional, consecutive terms of five years each. The day rate for three tugs is $13,984/day, which is comprised of a service component of $11,375/day and an equipment component of $2,609/day. The fourth tug has the same equipment component of $870/day, but has a different service component depending on usage. Sabine TUG Services does have the option to purchase the tug boats if Alpha is found to be in default, as defined in the Tug Agreement. We determined, at the inception of the lease, that the option to purchase the tug boats in the Tug Agreement was remote, as we did not believe that Alpha would be in default during the term of the Tug Agreement. In accordance with EITF 01-08, *Determining Whether an Arrangement Contains a Lease*, we have determined that the Tug Agreement contains a lease for the four tugs specified in the Tug Agreement. In addition, we have concluded that the tug boat lease contained in the Tug Agreement is an operating leases as defined in SFAS No. 13, and as such, the equipment component of the Tug Agreement will be charged to expense over the term of the Tug Agreement as it becomes payable.

LNG Site Leases

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

In January 2005, we exercised our options and entered into three land leases for the site of the Sabine Pass LNG receiving terminal. The leases have an initial term of 30 years, with options to renew for six 10-year extensions with similar terms as the initial term. In February 2005, two of the three leases were amended, thereby increasing the total acreage under lease to 853 acres and increasing the annual lease payments to $1.5 million. The annual lease payments will be adjusted for inflation based on a consumer price index, as defined in the lease agreements, every five years. For 2005, these payments were capitalized ($1.5 million) as part of the construction cost of the Sabine Pass LNG receiving terminal; however, beginning January 2006, these lease payments have been expensed as required by FSP 13-1 and resulted in $1.5 million being included as LNG receiving terminal development expense on the Consolidated Statement of Operation for 2006.

NOTE 5 ADVANCES TO EPC CONTRACTOR

In December 2004, Sabine Pass LNG entered into an engineering, procurement and construction (EPC) contract with Bechtel Corporation (Bechtel) to construct 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 (NTP) related to the construction of Phase 1. A payment of $32.3 million was made to Bechtel in March 2005 when the NTP was issued and that amount was classified as a current asset on the Consolidated Balance Sheet. In accordance with the payment schedule included in the EPC contract, $2.7 million per month was being reclassified to construction-in-progress over a twelve-month period. As of December 31, 2006 and 2005, the remaining balance of the advance was zero and $8.1 million, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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,	
	2006	2005
		(As Adjusted)
LNG TERMINAL COSTS		
LNG terminal construction-in-progress	$ 684,008	$ 271,142
LNG site and related costs, net	1,467	1,249
Total LNG terminal costs	685,475	272,391
NATURAL GAS PIPELINE COSTS		
Natural gas pipeline construction-in-progress	45,615	
Pipeline right-of-ways	2,134	
Total natural gas pipeline costs	47,749	
OIL AND GAS PROPERTIES, successful efforts method		
Proved	2,343	97
Unproved	779	1,600
Accumulated depreciation, depletion and amortization	(263)	(57)
Total oil and gas properties, net	2,859	1,640
FIXED ASSETS		
Computers and office equipment	5,352	3,611
Furniture and fixtures	1,310	1,145
Computer software	8,043	1,640
Leasehold improvements	2,206	1,757
IT projects-in-progress	1,724	
Other	123	26
Accumulated depreciation	(6,023)	(2,104)
Total fixed assets, net	12,735	6,075
PROPERTY, PLANT AND EQUIPMENT, net	$ 748,818	$ 280,106

LNG Terminal Costs

Once placed into service, LNG terminal construction-in-progress costs will be depreciated using the straight-line depreciation method. We are in the process of determining the most appropriate approach for grouping identifiable components with similar estimated useful lives. Estimated useful lives for components, once construction is completed, are currently estimated to range between 10 and 50 years.

In February 2005 and July 2006, Phase 1 and Phase 2 Stage l, respectively, of the Sabine Pass LNG receiving terminal project satisfied our criteria for capitalization. Accordingly, costs associated with the construction of Phase 1 and Phase 2-Stage 1 of the Sabine Pass LNG receiving terminal have been capitalized as construction-in-progress since those dates. During the years ended December 31, 2006 and 2005, we had capitalized $24.9 million and $6.1 million, respectively, of interest expense related to these construction projects. In March 2006, our Corpus Christi LNG receiving terminal satisfied the criteria for capitalization. Accordingly, costs associated with the initial site work for the Corpus Christi LNG receiving terminal have been capitalized as construction-in progress since that time. During the year ended December 31, 2006, we capitalized $0.5 million of interest expense related to this construction project.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Natural Gas Pipeline Costs

Our developing natural gas pipeline business is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, and we have determined that our pipelines to be constructed have met the criteria found in SFAS No. 71. Accordingly, we began applying the provisions of SFAS No. 71 to the affected pipeline subsidiaries in the second quarter of 2006. Natural gas pipeline costs also include amounts capitalized as AFUDC. The rates used in the calculation of AFUDC are determined in accordance with guidelines established by the FERC. AFUDC represents the cost of debt and equity funds used to finance our natural gas pipeline additions during construction. AFUDC is capitalized as a part of the cost of our natural gas pipelines. Under regulatory rate practices, we generally are permitted to recover AFUDC, and a fair return thereon, through our rate base after our natural gas pipelines are placed in service. During the year ended December 31, 2006, we capitalized $1.1 million of AFUDC to our natural gas pipeline projects.

Oil and Gas Properties

In the first quarter of 2006, we converted from the full cost method to the successful efforts method of accounting for our investments in oil and gas properties; therefore our oil and gas property balance presented above has been adjusted to reflect this change (see Note 16 Adjustment to Financial Statements Successful Efforts).

Fixed Assets

Our fixed assets are recorded at cost and are depreciated on a straight-line method based on estimated lives of the individual assets or groups of assets. Depreciation expense related to our property, plant and equipment totaled $2.9 million, $1.3 million and $0.4 million for the years ended December 31, 2006, 2005 and 2004, respectively.

In the third quarter of 2006, we impaired certain leasehold improvement costs related to our current office space under the Texas Avenue Office Lease in accordance with FASB Technical Bulletin No. 79-15, *Accounting for Loss on a Sublease Not Involving the Disposal of a Segment*. The impairment was the result of signing our new office lease for space under the Pennzoil Office Lease (see Note 22 Commitments and Contingencies), and the belief that we would not recover or realize a benefit from the leasehold improvement costs in the future. The impact of this impairment in property, plant and equipment was to increase accumulated depreciation by $1.6 million and recognize an impairment of fixed assets by the same amount in our Consolidated Statement of Operations.

NOTE 7 DEBT ISSUANCE COSTS

As of December 31, 2005, we had capitalized $18.5 million (net of accumulated amortization of $1.7 million) and $15.3 million (net of accumulated amortization of $0.8 million), of costs directly associated with the arrangement of the Sabine Pass Credit Facility and the Term Loan, respectively. These debt issuance costs were being amortized over a period of ten years and seven years, respectively, which were the terms of the Sabine Pass Credit Facility and Term Loan. Although there were no borrowings outstanding under the Sabine Pass Credit Facility as of December 31, 2005, the amortization of the debt issuance cost was 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 to the Sabine Pass LNG receiving terminal was $1.7 million.

When we amended and restated the Sabine Pass Credit Facility in July 2006, we incurred and capitalized an additional $9.1 million in debt issuance costs. These costs, along with the debt issuance costs capitalized as part of the original Sabine Pass Credit Facility, were being amortized using straight-line amortization through July 1, 2015.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In November 2006, we repaid and terminated the amended Sabine Pass Credit Facility and the Term Loan using a portion of the proceeds received from the issuance of the Senior Notes. As a result of the early termination of the amended Sabine Pass Credit Facility and Term Loan, we were required to expense the capitalized unamortized debt issuance costs relating to these two debt facilities. For the year ended December 31, 2006, we expensed debt issuance costs of $37.0 million, which are included on the Consolidated Statement of Operations as a portion of the loss on early extinguishment of debt.

As of December 31, 2006, we had capitalized $41.5 million of costs directly associated with the arrangement of debt financing, net of accumulated amortization, as follows (in thousands):

Long-term Debt	Debt Issuance Costs	Amortization Period	Accumulated Amortization	Net Costs
2013 Senior Notes	$ 9,361	7 years	$ (212)	$ 9,149
2016 Senior Notes	25,223	10 years	(402)	24,821
Convertible Notes	9,542	7 years	(1,967)	7,575
	$ 44,126		$ (2,581)	$ 41,545

Scheduled amortization of these debt issuance costs for the next five years is estimated at $5.2 million per year.

NOTE 8 INVESTMENT IN LIMITED PARTNERSHIP

We account for our 30% limited partnership investment in Freeport LNG Development, L.P. (Freeport LNG) using the equity method of accounting. As of December 31, 2006 and 2005, we had unrecorded cumulative suspended losses of $13.0 million and $4.0 million, respectively, related to our investment in Freeport LNG as the basis in this investment had been reduced to zero. As a result, we did not record our share of the losses of the partnership for all of 2006 and a portion of 2005 because we did not guarantee any obligations and were not committed to provide any further financial support since December 2005.

We recorded zero, $1.0 million and $1.3 million for the years ended December 31, 2006, 2005 and 2004, respectively, related to net losses of Freeport LNG.

The financial position of Freeport LNG at December 31, 2006 and 2005 and the results of Freeport LNG s operations for the years ended December 31, 2006, 2005 and 2004 are summarized as follows (in thousands):

	December 31,	
	2006	**2005**
Current assets	$ 294,847	$ 380,615
Construction-in-progress	594,191	246,351
Fixed assets, net, and other assets	9,684	9,309
Total assets	$ 898,722	$ 636,275
Current liabilities	$ 38,621	$ 53,533
Notes payable	903,369	595,766
Deferred revenue and other deferred credits	5,666	5,748
Partners capital	(48,934)	(18,772)
Total liabilities and partners capital	$ 898,722	$ 636,275

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31,		
	2006	2005	2004
Revenue	$	$	$ 10,000
Loss from continuing operations	(16,631)	(16,238)	(3,569)
Net loss	(30,162)	(16,663)	(3,561)
Cheniere s 30% equity in net loss from limited partnership (1)	$ (9,049)	$ (4,999)	$ (1,068)

(1) During 2006 and 2005, we did not record $9.0 million and $4.0 million of the net losses for such periods, respectively, as the basis in this investment had been reduced to zero and because we did not guarantee any obligations and were not committed to provide any further financial support since December 2005.

NOTE 9 GOODWILL

In February 2005, we acquired the minority interest in Corpus Christi LNG, L.P. (Corpus Christi LNG), through the acquisition of BPU LNG, Inc. (BPU), in exchange for 2.0 million restricted shares of our common stock. BPU held as its sole asset the 33.3% limited partner interest in Corpus Christi LNG. As a result of this transaction, we own 100% of the limited partner interests in Corpus Christi LNG. This transaction was accounted for using the purchase method of accounting as prescribed by SFAS No. 141, *Accounting for Business Combinations*, and was valued at $77.2 million, including direct transaction costs. Of this amount, $76.8 million has been recorded as goodwill and will be accounted for in accordance with SFAS No. 142. The goodwill is the difference between the deemed value of the shares conveyed and the historical carrying value of the minority interest under GAAP plus direct transaction costs. For the calculation of federal income taxes, none of this goodwill amount will be deductible.

We performed an annual goodwill impairment review in the fourth quarter of 2006. This impairment review consisted of comparing the carrying value, including goodwill, of the reporting unit under review to the estimated fair value of the reporting unit. Had the carrying value exceeded the estimated fair value of the reporting unit, an impairment of the reporting unit would have been recognized, resulting in an impairment charge to earnings. A reporting unit is defined as a business segment or component of a business segment that has similar economic characteristics. For our impairment 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.

NOTE 10 DERIVATIVE INSTRUMENTS

Interest Rate Derivative Instruments

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

The Sabine Pass Credit Facility was amended and restated in July 2006, increasing the amount available to Sabine Pass LNG from $822 million to $1.5 billion. In connection with the closing of the amended Sabine Pass Credit Facility in July 2006, we entered into additional interest rate swap agreements with HSBC and Société Générale (the Amended Sabine Swaps and collectively with the Sabine Swaps, the Swaps). The Swaps had

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the combined effect of fixing the LIBOR component of the interest rate payable on borrowings up to a maximum of $1.25 billion at a blended rate of 5.26% from July 25, 2006 through July 1, 2015.

In connection with the closing of the Term Loan on August 31, 2005, Cheniere LNG Holdings entered into interest rate swap agreements with Credit Suisse (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 million. The notional amount declined in accordance with anticipated principal payments under the Term Loan. The Term Loan Swaps had the effect of fixing the LIBOR rate component of the interest rate payable under the Term Loan at 3.75% from August 31, 2005 to September 27, 2007, at 3.98% from September 28, 2007 to September 27, 2008, and at 5.98% from September 28, 2008 to September 30, 2010. The final termination date of the Term Loan Swaps was September 30, 2010.

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

Accounting for Hedges

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

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

SFAS No. 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of accumulated other comprehensive income (AOCI) and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. In our case, the impact on earnings was a reduction of interest expense of $7.2

million and $0.4 million for the years ended December 31, 2006 and 2005, respectively. The ineffective portion of the gain or loss on the derivative instruments, if any, must be recognized currently in earnings. For the years ended December 31, 2006 and 2005, we have recognized a net derivative loss of $20.1 million and gain of $0.8 million, respectively. If the forecasted transaction is no longer probable of occurring, the associated gain or loss recorded in AOCI is recognized currently in earnings.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 11 ACCRUED LIABILITIES

Accrued liabilities consist of the following (in thousands):

	December 31,	
	2006	2005
LNG terminal construction costs	$ 16,334	$ 39,728
Accrued interest expense and related fees	24,861	4,937
Pipeline construction costs	7,039	
Debt issuance costs	783	3,083
Payroll	5,512	2,460
LNG terminal development expenses		1,534
Professional and legal services		1,043
IT Projects-in-progress	1,067	
Other accrued liabilities	2,684	1,759
Accrued liabilities	$ 58,280	$ 54,544

NOTE 12 DEFERRED REVENUE

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

In November 2004, we entered into a TUA to provide Chevron USA, Inc. (Chevron) with approximately 700 MMcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal. In December 2005, Chevron exercised its option to increase its reserved capacity by approximately 300 MMcf/d to approximately 1.0 Bcf/d and paid Sabine Pass LNG an additional $3.0 million advance capacity reservation fee. As of December 31, 2006, Chevron USA had made advance capacity reservation fee payments to Sabine Pass LNG totaling $20.0 million, with $12.0 million paid in 2004 and $8.0 million paid in 2005. These capacity reservation fee payments will be amortized over a 10-year period as a reduction of Chevron s regasification capacity fee under its TUA. As a result, we 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.

In December 2003, we entered into an option agreement with J & S Cheniere S.A. (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 $1.0 million 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.

As of both December 31, 2006 and 2005, we had recorded $41.0 million as deferred revenue related to option and advance capacity reservation fee payments.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 13 MINORITY INTEREST IN LIMITED PARTNERSHIP

In May 2003, we formed a limited partnership, 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, because the minority owner was required to fund 100% of the first $4.5 million of partnership expenditures. Because partnership expenditures had reached $4.5 million 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 own 100% of the limited partner interest of Corpus Christi LNG. We also manage the project as the general partner through one of our wholly-owned subsidiaries.

For the years ended December 31, 2006, 2005 and 2004, our Consolidated Statement of Operations includes zero, $97,000 and $2.9 million, respectively, related to the minority interest of Corpus Christi LNG.

NOTE 14 LONG-TERM DEBT

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

	December 31,	
	2006	**2005**
Senior Notes	$ 2,032,000	$
Convertible Senior Unsecured Notes	325,000	325,000
Term Loan		598,500
	2,357,000	923,500
Less: Current Portion Term Loan		(6,000)

Total Long-Term Debt	$ 2,357,000	$ 917,500

Below is a schedule of future principal payments that we are obligated to make on our outstanding long-term debt at December 31, 2006 (in thousands):

	Payments Due for Years Ended December 31,				
	Total	**2007**	**2008 to 2009**	**2010 to 2011**	**Thereafter**
Senior Notes	$ 2,032,000	$	$	$	$ 2,032,000
Convertible Senior Unsecured Notes	325,000				325,000
Total	$ 2,357,000	$	$	$	$ 2,357,000

Senior Notes

In November 2006, we consummated a private offering of Senior Notes. The Senior Notes were offered to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended (the Securities Act), and in offshore transactions to non-United States persons in reliance on Regulation S under the Securities Act. At closing, net proceeds of approximately $2.0 billion, net of commissions, from the offering

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

were used as follows: approximately $380 million to repay borrowings under, and replace, the Sabine Pass Credit Facility; approximately $380 million to repay the Term Loan; $335.0 million to fund a reserve account for scheduled interest payments on the Senior Notes through May 2009; and approximately $18 million to terminate the interest rate swaps and for other expenses. The remaining approximately $887 million of net proceeds from the offering will be used to fund the remaining costs to complete Phase 1 and Phase 2 Stage 1 of the Sabine Pass LNG receiving terminal.

We may redeem some or all of the Senior Notes at a redemption price equal to 100% of the principal amount plus a make-whole premium, plus accrued and unpaid interest and additional interest, if any, to the redemption date. Until November 30, 2009, we may redeem up to 35% of the aggregate principal amount of the 2013 Notes and up to 35% of the aggregate principal amount of the 2016 Notes with the net cash proceeds of one or more equity offerings by us with the proceeds that we retain or that are contributed to us, as applicable, at par plus a premium equal to the coupon, plus accrued and unpaid interest and additional interest, if any, as long as at least 65% of the aggregate principal amount of the 2013 Notes and the 2016 Notes, respectively, remain outstanding immediately after such optional redemption and such optional redemption occurs within 90 days of the date of the closing of such equity offering.

Under the indenture governing the Senior Notes, except for certain permitted tax distributions, we may not make distributions until certain conditions are satisfied. The indenture requires that we apply our net operating cash flow (i) first, to fund with monthly deposits our next semiannual payment of approximately $75.5 million of interest on the Senior Notes, and (ii) second, to fund a one-time, permanent debt service reserve fund equal to one semiannual interest payment of approximately $75.5 million on the Senior Notes. Distributions will be permitted only after Phase 1 Target Completion, as defined in the indenture governing the Senior Notes, or such earlier date as project revenues are received, upon satisfaction of the foregoing funding requirements, after satisfying a fixed charge coverage ratio test of 2:1 and after satisfying other conditions specified in the indenture.

Total interest expense recognized for the year ended December 31, 2006 was $22.4 million before interest capitalization of $7.6 million.

Convertible Senior Unsecured Notes

In July 2005, we consummated a private offering of $325.0 million aggregate principal amount of Convertible Senior Unsecured Notes due August 1, 2012 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 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 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 $239.8 million, after deducting the cost of the hedge transactions, the

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

underwriting discount and related fees. As of December 31, 2006, no holders had elected to convert their notes. Total interest expense recognized for the years ended December 31, 2006 and 2005 was $8.7 million and $3.7 million before interest capitalization of $0.7 million and $0.2 million, respectively.

Sabine Pass Credit Facility

In February 2005, we entered into the $822 million Sabine Pass Credit Facility which was subsequently amended and restated in July 2006. The amended Sabine Pass Credit Facility increased the amount of the loans available to us from $822 million to $1.5 billion to finance the costs of constructing and placing into operations Phase 1 and the Phase 2 Stage 1 expansion of the Sabine Pass LNG receiving terminal. In connection therewith, we entered into the Swaps to hedge the LIBOR interest rate component of the Sabine Pass Credit Facility. The Swaps had the combined effect of fixing the LIBOR component of the interest rate payable on borrowings up to a maximum of $1.25 billion at a blended rate of 5.26% from July 25, 2006 through July 1, 2015 (see Note 10 Derivative Instruments).

Borrowings under the amended Sabine Pass Credit Facility bore interest at a variable rate equal to LIBOR plus the applicable margin. The applicable margin varied from 0.875% to 1.125% during the term of the amended Sabine Pass Credit Facility. Interest was calculated on the unpaid principal amount outstanding and was payable semi-annually in arrears. A commitment fee of 0.50% per annum on the daily, undrawn portion of the lenders commitment was required. Administrative fees were also paid annually to the agent and the collateral agent. During 2006, borrowings under the amended Sabine Pass Credit Facility totaled $383.4 million. Total interest expense recognized for the years ended December 31, 2006 and 2005 was $13.7 million and $5.3 million before capitalization of $13.0 million and $5.3 million, respectively.

In November 2006, as discussed above, borrowings under the amended Sabine Pass Credit Facility were repaid, and the facility was terminated in conjunction with the closing of the Senior Notes.

Term Loan

In August 2005, Cheniere LNG Holdings entered into a $600 million Term Loan with Credit Suisse. The Term Loan interest rate equaled LIBOR plus a 2.75% margin with a termination date of 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 resulted in an annual fixed interest rate of 7.25% (including the 2.75% margin) for the first five years (see Note 10 Derivative Instruments). Quarterly principal payments of $1.5 million were required through June 30, 2012, and a final principal payment of $559.5 million was required on August 30, 2012.

At December 31, 2005, principal repayments on the Term Loan of $6.0 million were due within the next twelve months and were classified on the Consolidated Balance Sheet as a current liability. Total interest expense recognized for the years ended December 31, 2006 and 2005 was $35.7 million and $14.4 million before interest capitalization of $3.5 million and $603,000, respectively.

In November 2006, as discussed above, the amount outstanding under the Term Loan was repaid, and the Term Loan was terminated in conjunction with the closing of the Senior Notes.

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.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-Term Debt (in thousands):

	Year Ended December 31, 2006		Year Ended December 31, 2005	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
2013 Notes (1)	$ 550,000	$ 547,250	$	$
2016 Notes (1)	1,482,000	1,478,295		
2.25% Convertible Senior Unsecured Notes due 2012 (2)	325,000	334,750	325,000	392,031
Term Loan due 2012 (3)			598,500	598,500
	$ 2,357,000	$ 2,360,295	$ 923,500	$ 990,531

(1) The fair value of our Senior Notes was based on quotations obtained from broker-dealers who made markets in these and similar instruments as of December 29, 2006.

(2) The fair value of our Convertible Senior Unsecured Notes is based on a closing trading price on December 29, 2006 and December 30, 2005.

(3) The Term Loan bore interest based on a floating rate; therefore, the estimated fair value was deemed to equal the carrying amount of these notes.

NOTE 16 ADJUSTMENT TO FINANCIAL STATEMENTS SUCCESSFUL EFFORTS

As a result of our election to change our method of accounting for investments in oil and gas properties as discussed in Note 2 Basis of Presentation , adjustments have been made to the financial statements of prior periods as required by SFAS No. 154, *Accounting Changes and Error Corrections*. The effects of the change as it relates to financial data for the periods presented are displayed below (in thousands, except per share data):

Statement of Operations

	Year Ended December 31, 2006		
	As Computed Under Full Cost	As Reported Under Successful	Effect of

		Efforts	Change
	(Unaudited)		
Revenues	$ 2,371	$ 2,371	$
Operating costs and expenses:			
LNG receiving terminal and pipeline development expenses	12,099	12,099	
Exploration costs		3,138	3,138
Oil and gas production costs	237	237	
Impairment of fixed assets	1,628	1,628	
Depreciation, depletion and amortization	3,847	3,131	(716)
Ceiling test write-down	17,295		(17,295)
General and administrative expenses	58,012	58,012	
Total operating costs and expenses	93,118	78,245	(14,873)
Loss from operations	(90,747)	(75,874)	14,873
Non-operating loss	(68,110)	(67,934)	176
Loss before income taxes	(158,857)	(143,808)	15,049
Income tax provision	(2,045)	(2,045)	
Net loss	$ (160,902)	$ (145,853)	$ 15,049
Net loss per share basic and diluted	$ (2.96)	$ (2.68)	$ 0.28

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Statement of Operations

	Year Ended December 31, 2005		
	As Originally Reported	As Reported Under Successful Efforts	Effect of Change
Revenues	$ 3,005	$ 3,005	$
Operating costs and expenses:			
LNG receiving terminal and pipeline development expenses	22,020	22,020	
Exploration costs		2,839	2,839
Oil and gas production costs	237	237	
Depreciation, depletion and amortization	3,702	1,325	(2,377)
Ceiling test write-down			
General and administrative expenses	29,145	29,145	
Total operating costs and expenses	55,104	55,566	462
Loss from operations	(52,099)	(52,561)	(462)
Non-operating income	20,159	20,881	722
Loss before income taxes and minority interest	(31,940)	(31,680)	260
Minority interest	97	97	
Income tax benefit	2,045	2,045	
Net loss	$ (29,798)	$ (29,538)	$ 260
Net loss per share basic and diluted	$ (0.56)	$ (0.56)	$

	Year Ended December 31, 2004		
	As Originally Reported	As Reported Under Successful Efforts	Effect of Change
Revenues	$ 1,998	$ 1,998	$
Operating costs and expenses:			
LNG receiving terminal and pipeline development expenses	17,166	17,166	
Exploration costs		2,662	2,662
Oil and gas production costs	117	117	
Depreciation, depletion and amortization	1,324	507	(817)

Ceiling test write-down			
General and administrative expenses	12,476	12,476	
Total operating costs and expenses	31,083	32,928	1,845
Loss from operations	(29,085)	(30,930)	(1,845)
Non-operating income	1,655	3,192	1,537
Loss before income taxes and minority interest	(27,430)	(27,738)	(308)
Minority interest	2,862	2,862	
Income tax benefit (provision)			
Net loss	$ (24,568)	$ (24,876)	$ (308)
Net loss per share basic and diluted	$ (0.63)	$ (0.64)	$ (0.01)

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Balance Sheet

	December 31, 2006		
	As Computed Under Full Cost	As Reported Under Successful Efforts	Effect of Change
	(Unaudited)		
Current assets	$ 828,977	$ 828,977	$
Oil and gas properties, net	5,787	2,859	(2,928)
Other property, plant and equipment, net	745,959	745,959	
Total property, plant and equipment, net	751,746	748,818	(2,928)
Other non-current assets	1,026,693	1,026,693	
Total assets	$ 2,607,416	$ 2,604,488	$ (2,928)
Current liabilities	$ 61,939	$ 61,939	$
Non-current liabilities	2,399,302	2,399,302	
Common stock	166	166	
Additional paid-in capital	390,256	390,256	
Accumulated deficit	(244,213)	(247,141)	(2,928)
Accumulated other comprehensive loss	(34)	(34)	
Total stockholders equity	146,175	143,247	(2,928)
Total liabilities and stockholders equity	$ 2,607,416	$ 2,604,488	$ (2,928)

	December 31, 2005		
	As Originally Reported	As Reported Under Successful Efforts	Effect of Change
Current assets	$ 871,463	$ 871,463	$
Oil and gas properties, net	19,617	1,640	(17,977)
Other property, plant and equipment, net	278,466	278,466	
Total property, plant and equipment, net	298,083	280,106	(17,977)

Other non-current assets	138,578	138,578	
Total assets	$ 1,308,124	$ 1,290,147	$ (17,977)
Current liabilities	$ 61,322	$ 61,322	$
Non-current liabilities	960,284	960,284	
Common stock	164	164	
Additional paid-in capital	375,551	375,551	
Deferred compensation	(9,684)	(9,684)	
Accumulated deficit	(83,311)	(101,288)	(17,977)
Accumulated other comprehensive income	3,798	3,798	
Total stockholders equity	286,518	268,541	
Total liabilities and stockholders equity	$ 1,308,124	$ 1,290,147	$ (17,977)

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Statement of Cash Flows

	Year Ended December 31, 2006		
	As Computed Under Full Cost	As Reported Under Successful Efforts	Effect of Change
	(Unaudited)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (160,902)	$ (145,853)	$ 15,049
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	3,847	3,131	(716)
Impairment of fixed assets	1,628	1,628	
Ceiling test write-down	17,295		(17,295)
Dry hole expense		1,673	1,673
Impairment of unproved property		416	416
Other adjustments	65,076	65,076	
Changes in operating assets and liabilities	(6,497)	(6,497)	
NET CASH USED IN OPERATING ACTIVITIES	(79,553)	(80,426)	(873)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas property additions, net of sales	(5,008)	(4,135)	873
Other cash flows from other investing activities	(1,535,793)	(1,535,793)	
NET CASH USED IN INVESTING ACTIVITIES	(1,540,801)	(1,539,928)	873
NET CASH PROVIDED BY FINANCING ACTIVITIES	1,390,725	1,390,725	
NET DECREASE IN CASH AND CASH EQUIVALENTS	(229,629)	(229,629)	
CASH AND CASH EQUIVALENTS BEGINNING OF PERIOD	692,592	692,592	
CASH AND CASH EQUIVALENTS END OF PERIOD	$ 462,963	$ 462,963	$

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2005		
	As Originally Reported	As Reported Under Successful Efforts	Effect of Change
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (29,798)	$ (29,538)	$ 260
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	3,702	1,325	(2,377)
Dry hole expense		809	809
Impairment of unproved properties		601	601
Other adjustments	(16,893)	(16,748)	145
Changes in operating assets and liabilities	24,595	24,595	
NET CASH USED IN OPERATING ACTIVITIES	(18,394)	(18,956)	(562)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas property additions, net of sales	(3,861)	(3,299)	562
Other cash flows from other investing activities	(402,288)	(402,288)	
NET CASH USED IN INVESTING ACTIVITIES	(406,149)	(405,587)	562
NET CASH PROVIDED BY FINANCING ACTIVITIES	808,692	808,692	
NET INCREASE IN CASH AND CASH EQUIVALENTS	384,149	384,149	
CASH AND CASH EQUIVALENTS BEGINNING OF PERIOD	308,443	308,443	
CASH AND CASH EQUIVALENTS END OF PERIOD	$ 692,592	$ 692,592	$

	Year Ended December 31, 2004		
	As Originally Reported	As Reported Under Successful Efforts	Effect of Change
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (24,568)	$ (24,876)	$ (308)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	1,324	507	(817)
Dry hole expense			
Impairment of unproved properties		335	335
Other adjustments	(416)	(416)	
Changes in operating assets and liabilities	22,999	22,999	

NET CASH USED IN OPERATING ACTIVITIES	(661)	(1,451)	(790)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas property additions, net of sales	(2,025)	(1,235)	790
Other cash flows from other investing activities	3,210	3,210	
NET CASH PROVIDED BY INVESTING ACTIVITIES	1,185	1,975	790
NET CASH PROVIDED BY FINANCING ACTIVITIES	306,661	306,661	
NET INCREASE IN CASH AND CASH EQUIVALENTS	307,185	307,185	
CASH AND CASH EQUIVALENTS BEGINNING OF PERIOD	1,258	1,258	
CASH AND CASH EQUIVALENTS END OF PERIOD	$ 308,443	$ 308,443	$

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 17 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, 2006 and 2005 include a deferred income tax provision of $2.0 million and a deferred income tax benefit of $2.0 million, respectively. The deferred income tax provision and benefit recorded for the years ended December 31, 2006 and 2005 were recorded in accordance with the guidance in paragraph 140 of SFAS No. 109 and EITF Abstracts, Topic D-32, which, in certain circumstances, require items reported in AOCI to be considered in the realization of the tax benefit associated with a loss from continuing operations. In our situation, the specific circumstance relates to pre-tax Other Comprehensive Income (OCI) of $5.8 million recorded for the year ended December 31, 2005 related to our interest rate swaps (see Note 10 Derivative Instruments and Note 20 Other Comprehensive Loss for additional discussions). The $2.0 million deferred income 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 OCI in our 2005 Consolidated Statement of Stockholders Equity. For the year ended 2006, however, primarily due to the termination of our interest rate swaps, we recorded a pre-tax OCI loss of $5.8 million, and as a result recorded a deferred income tax provision of $2.0 million. Such deferred income tax provision was limited to the amount of the deferred income tax benefit reported in the prior year.

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

	Year Ended December 31,		
	2006	**2005**	**2004**
Current federal income tax expense	$	$	$
Deferred federal income tax (provision) benefit	(2,045)	2,045	
Total income tax (provision) benefit	$ (2,045)	$ 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, 2006 and 2005 are as follows (in thousands):

	Year Ended December 31,	
	2006	**2005**

Deferred tax assets		
Net operating loss carryforwards	$ 54,381	$ 19,310
Advance payments terminal use agreements	14,000	14,000
Start-up costs and construction-in-progress associated with LNG, pipeline and marketing activities	18,727	11,594
Stock grant compensation expense	5,658	
Oil and gas properties and fixed assets (1)	2,248	
Investment in limited partnership	1,538	1,755
	96,552	46,659

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31,	
	2006	**2005**
Deferred tax liabilities		
Oil and gas properties and fixed assets		4,099
Stock grant compensation expense		270
Unrealized gain on hedging transactions		1,968
		6,337
Net deferred tax assets	96,552	40,322
Less: tax asset valuation allowance	(96,552)	(40,322)
	$	$

(1) As discussed below, includes approximately $6.3 million from the change in accounting method which was charged directly to retained earnings effective January 1, 2006.

In accordance with SFAS No. 109, a valuation allowance equal to our net deferred tax asset balance has been established due to the uncertainty of realizing the tax benefits related to our net operating loss (NOL) carryforwards and other deferred tax assets. The change in the deferred tax asset valuation allowance was $56.2 million and $11.3 million for the years ended December 31, 2006 and 2005, respectively. The $56.2 million change in the deferred tax asset valuation allowance in 2006 includes $6.3 million that relates to the deferred tax asset created as a result of our conversion from the full cost method to the successful efforts method of accounting for our investments in oil and gas properties effective January 1, 2006 (see Note 2 Summary of Significant Accounting Policies).

As discussed in Note 19 Share-based Compensation , we adopted SFAS No. 123R effective January 1, 2006. For companies like Cheniere that have NOL carryforwards, SFAS No. 123R affects the manner in which stock-based compensation tax deductions are treated for financial reporting purposes. We may claim stock-based compensation deductions in our federal corporate income tax returns in an amount equal to the related income that is included in our employees reported federal taxable income subject to any other applicable limitations. Under SFAS No. 123R, tax benefits generated in 2006 and subsequent reporting periods related to the excess of tax deductible stock-based compensation over the amount recognized for financial accounting purposes, may not be recorded to additional paid-in-capital (APIC) for financial reporting purposes until the stock-based compensation deductions actually reduce our cash income tax liability. Any tax benefits attributable to these deductions will not be recorded to APIC for financial reporting purposes until such time as all existing and future NOL carryforwards have been fully utilized. As a result of the provisions of SFAS No. 123R, at December 31, 2006, we have excluded $18.4 million of stock-based compensation deductions from our NOL carryforwards for financial reporting purposes. At December 31, 2006, our NOL carryforwards for financial reporting purposes were $155.4 million compared to NOL carryforwards for federal income tax reporting purposes of $173.7 million.

Our NOL carryforwards expire starting in 2012 extending through 2026. Certain of our NOLs which were previously subject to annual utilization limitations under the Internal Revenue Code (IRC) Section 382 change of ownership regulations are now available for utilization due to annual increases in the allowed NOL utilization amounts provided for in IRC Section 382. The NOL carryforward amounts include approximately $11.7 million as of December 31, 2006 and 2005, of excess tax benefits recognized in 2005 and prior years related to the exercise of non-qualified employee stock options and vested stock awards. The full amount of the related tax benefits are included in our deferred tax asset valuation allowance.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31,		
	2006	**2005**	**2004**
U.S. statutory tax rate	35%	35%	35%
Non-deductible executive stock-based compensation expense (1)	(2)%	0%	0%
Deferred tax asset valuation reserve (2)	(35)%	(24)%	(32)%
State income tax expense (net of federal benefit) (3)	0%	(5)%	2%
All other	0%	0%	(5)%
Effective tax rate as reported	(2)%	6%	0%

(1) As discussed above, effective January 1, 2006, we began accounting for stock-based compensation in accordance with SFAS No. 123R. The amount of stock-based compensation deductions for financial reporting purposes included amounts subject to limitations under IRC Section 162(m) which limits, under certain circumstances, the amount of compensation deductible for subject executive officers. This results in stock-based compensation deductions for financial reporting purposes for which a tax benefit will not be realized.

(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. Prior to January 1, 2006, we elected to account for stock-based compensation in accordance with APB Opinion No. 25. 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 date of vesting for vested stock awards and on the date of exercise for stock options. Because the stock-based compensation expense that was required to be included in our reported annual operating losses was significantly less than the amounts that have been included in our employees taxable incomes, the associated excess tax benefits will be charged to equity upon the reversal of the associated valuation allowances. As discussed above, as of December 31, 2005, approximately $11.7 million of deferred excess tax benefits related to the exercise of non-qualified employee stock options and vested stock awards in 2005 and prior reporting periods are included in our financial and federal income tax NOL carryforward amounts. For the year ended December 31, 2006, there was no change in the $11.7 million of deferred excess tax benefits.

(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 periods prior to 2005, our reported effective tax rate included amounts for certain expected deferred state income tax benefits related to our Texas and Louisiana exploration and development operations. In 2005, we determined that we do not expect 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.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 18 WARRANTS

As of December 31, 2006 and 2005, there were no outstanding warrants for the purchase of our common stock. Warrants we had previously issued did not confer upon the holders thereof any voting or other rights of a stockholder of Cheniere Energy. 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 (in thousands, except per share amounts):

	Year Ended December 31,		
	2006	2005	2004
Outstanding at beginning of period		533	2,599
Warrants issued			
Warrants exercised		(530)	(2,044)
Warrants canceled		(3)	(22)
Outstanding at end of period			533
Weighted average exercise price of warrants outstanding	$	$	$ 1.21
Weighted average remaining contractual life of warrants outstanding		N/A	6.0 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.

NOTE 19 SHARE-BASED COMPENSATION

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

Effective January 1, 2006, we adopted SFAS No. 123R, which revised SFAS No. 123 and superseded APB No. 25. SFAS No. 123R requires that all share-based payments to employees be recognized in the financial

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For the years ended December 31, 2006, 2005 and 2004 the total stock-based compensation expense recognized in our net loss was $21.8 million, $3.6 million and $3.6 million, respectively. The impact of adopting SFAS No. 123R on our results of operations for the year ended December 31, 2006 was an increase in expenses of $17.3 million, with a corresponding increase in our loss from operations, loss before income taxes and minority interest, and net loss resulting from the first-time recognition of compensation expense associated with employee stock options. The impact on our basic and diluted net loss per common share was an increase in per share net loss of $0.32. For the year ended December 31, 2006, the total stock-based compensation cost capitalized as part of the cost of capital assets was $1.6 million.

The total unrecognized compensation cost at December 31, 2006 relating to non-vested share-based compensation arrangements granted under the 1997 Plan and 2003 Plan, before any capitalization, was $67.5 million. That cost is expected to be recognized over six years, with a weighted average period of 1.9 years.

Tax deductions are generally available to us in an amount equal to the stock-based compensation income included in the taxable income of our employees, to the extent our corporate-level tax deductions are not otherwise limited by Section 162(m) of the Internal Revenue Code. As previously discussed in Note 17, SFAS No. 123R specifically provides that tax benefits associated with share-based payments to employees may not be recognized unless or until the corresponding tax deductions have reduced current taxes payable. As a result of our cumulative NOL carryovers and resulting valuation allowance, the tax benefits associated with deductions related to share-based payments to employees will not be recognized for financial reporting purposes until such time as all existing and future NOLs have been utilized.

The adoption of SFAS No. 123R had no effect on our net cash flow. Had we been a taxpayer, we would have recognized cash flow resulting from tax deductions in excess of recognized compensation cost as a financing cash flow. We received total proceeds from the exercise of stock options of $2.0 million, $2.5 million and $2.7 million in the years ended December 31, 2006, 2005 and 2004, respectively.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table illustrates the pro forma net income and earnings per share that would have resulted in the years ended December 31, 2005 and 2004 from recognizing compensation expense associated with accounting for employee stock-based awards under the provisions of SFAS No. 123. The reported and pro forma net income and earnings per share for the year ended December 31, 2006 are provided for comparative purposes only, as stock-based compensation expense is recognized in the financial statements under the provisions of SFAS No. 123R (in thousands, except per share data).

	Years Ended December 31,		
	2006	2005	2004
		(As Adjusted)	(As Adjusted)
Net loss as reported	$ (145,853)	$ (29,538)	$ (24,876)
Add: Stock-based employee compensation included in net loss (1)	21,768	3,583	3,618
Deduct:			
Total stock-based employee compensation expense determined under fair value method for all awards, net of related income tax (1)(2)	(21,768)	(16,567)	(5,824)
Pro forma net loss	$ (145,853)	$ (42,522)	$ (27,082)
Net loss per share			
Basic as reported	$ (2.68)	$ (0.56)	$ (0.64)
Diluted as reported	$ (2.68)	$ (0.56)	$ (0.64)
Basic pro forma	$ (2.68)	$ (1.09)	$ (0.70)
Diluted pro forma	$ (2.68)	$ (1.09)	$ (0.70)

(1) Years ended 2005 and 2004 are conformed to 2006 presentation.
(2) Fair value of stock options computed using Black-Scholes option pricing model and the value of non-vested stock based on intrinsic value in accordance with SFAS No. 123R and SFAS No. 123.

Stock Options

During 2006, we issued options to purchase 501,220 shares of our common stock under the 2003 Plan. This included options to purchase 131,220 shares, granted to employees primarily as hiring incentives, having an exercise price equal to the stock price on the date of grant, graded vesting over four years, and a 10-year contractual life; an option to purchase 300,000 shares granted to our Chairman of the Board and Chief Executive Officer having an exercise price of $90.00, graded vesting over three years beginning in March 2010, and a 10-year contractual life; fully vested options to purchase a total of 50,000 shares granted to two of our directors having an exercise price equal to the stock price on the date of grant and a 10-year contractual life; and an option to purchase 20,000 shares having an exercise price equal to the stock price on the date of grant, graded vesting over two years, and a five-year contractual life granted to a consultant in exchange for services. These options are being accounted for in accordance with the guidance in SFAS No. 123R, with the exception of the consultant grant, which is being accounted for in accordance with the relevant accounting guidance for equity instruments granted to a non-employee.

We estimate the fair value of stock options under SFAS No. 123R at the date of grant using a Black-Scholes valuation model, which is consistent with the valuation technique we previously utilized to value options for the footnote disclosures required under SFAS No. 123. The following table provides the weighted average

CHENIERE ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

assumptions used in the option valuation model to value options granted in the years ended December 31, 2006, 2005 and 2004, respectively. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant. The expected term (estimated period of time outstanding) of options granted in 2006 is based on the simplified method of estimating expected term for plain vanilla options allowed by Securities and Exchange Commission (SEC) Staff Accounting Bulletin No. 107 and varies based on the vesting period and contractual term of the option. Prior to 2006, the expected term was based on our historical experience and estimate of future behavior of employees. Expected volatility for options granted in 2006 is based on an equally weighted average of the implied volatility of exchange traded options on our common stock expiring more than one year from the measurement date and historical volatility of our common stock for a period equal to the option's expected life. Prior to 2006, estimated volatility was based solely on the historical volatility of our common stock for a period equal to the option s expected life. We have not declared dividends on our common stock.

	Years Ended December 31,		
	2006	2005	2004
		(As Adjusted)	(As Adjusted)
Risk-free rate	4.3-4.8%	3.6-4.5%	3.0-4.1%
Expected life (in years)	6.6	6.4	5.0
Expected volatility range	52-69%	72-101%	91-98%
Weighted average volatility	64%	96%	96%
Expected dividends	0.0%	0.0%	0.0%

The table below provides a summary of option activity under the combined plans as of December 31, 2006, and changes during 2006:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
	(in thousands)			(in thousands)
Outstanding at January 1, 2006	5,125	$ 28.66		
Granted	501	68.76		
Exercised	(408)	36.13		
Forfeited or Expired	(31)	37.35		
Outstanding at December 31, 2006	5,187	34.25	7.2	$ 27,433
Exercisable at December 31, 2006	1,102	$ 13.67	4.5	$ 18,167

The weighted average grant-date fair value of options granted during the years ended December 31, 2006, 2005 and 2004 was $23.07, $20.16 and $5.81, respectively. The total intrinsic value of options exercised during the years ended December 31, 2006, 2005 and 2004 was $12.0 million, $28.0 million and $22.8 million, respectively.

Stock and Non-Vested Stock

We have granted stock and non-vested stock to employees and outside directors under the 2003 Plan. Prior to January 1, 2006, we accounted for grants of non-vested stock using the intrinsic value method under the recognition and measurement principles of APB No. 25 and recognized the computed value of the non-vested stock in stockholders equity as an increase in additional paid-in-capital and a corresponding reduction in

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

stockholders equity attributable to deferred compensation. The balance in deferred compensation was amortized ratably over the vesting period to non-cash compensation expense (before any capitalization) with a corresponding decrease in the deferred compensation balance.

Under SFAS No. 123R, grants of non-vested stock continue to be accounted for on an intrinsic value basis. No recognition of deferred compensation is made in stockholders equity. Instead, the amortization of the calculated value of non-vested stock grants is accounted for as a charge to non-cash compensation and an increase in additional paid-in-capital over the requisite service period. With the adoption of SFAS No. 123R, we offset the remaining unamortized deferred compensation balance ($9.7 million at December 31, 2005) in stockholders equity against additional paid-in-capital. Amortization of the remaining unamortized balance will continue under SFAS No. 123R as described above.

During 2006, shares having three-year graded vesting of 30,239 and 78,671 were issued to our directors and certain of our executive officers. During the year ended December 31, 2006, a total of 241,240 shares of non-vested stock having four-year graded vesting were primarily issued to new employees.

The table below provides a summary of the status of our non-vested shares under the 2003 Plan as of December 31, 2006, and changes during 2006 (in thousands except for per share information):

	Non-Vested Shares	Weighted Average Grant-Date Fair Value Per Share
Non-vested at January 1, 2006	550	$ 21.06
Granted (1)	375	35.60
Vested	(351)	15.34
Forfeited	(19)	37.03
Non-vested at December 31, 2006	555	$ 33.97

(1) Includes an award of 25,000 non-vested shares granted under the French Addendum to the 2003 Plan, which were not issued and outstanding at December 31, 2006.

The weighted average grant-date fair value of non-vested stock granted during the years ended December 31, 2006, 2005 and 2004 was $35.60, $37.98 and $20.93, respectively. The total grant-date fair value of shares vested during the years ended December 31, 2006, 2005 and 2004 was $5.4 million, $3.4 million and $2.4 million, respectively.

Share-Based Plan Descriptions and Information

Our 1997 Plan provided for the issuance of stock options to purchase up to 5.0 million shares of our common stock, all of which have been granted. Non-qualified stock options were granted to employees, contract service providers and outside directors. Option terms for the remaining unexercised options are five years with vesting that generally occurs on a graded basis over three years.

Awards providing for the issuance of up to an aggregate of 11.0 million shares of our common stock may be made under our 2003 Plan. These awards may be in the form of non-qualified stock options, incentive stock options, purchased stock, restricted (non-vested) stock, bonus (unrestricted) stock, stock appreciation rights, phantom stock and other stock-based performance awards deemed by the Compensation Committee to be consistent with the purposes of the 2003 Plan. To date, the only awards made by the Compensation Committee have been in the form of non-qualified stock options, restricted stock and bonus stock. Beginning in 2005, stock

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options granted to employees as hiring incentives have been granted at the money with 10-year terms and graded vesting over four years. Prior to that time, stock options granted as hiring incentives were granted at the money with five-year terms and graded vesting over three years. Retention grants made to employees provide for exercise prices at or in excess of the stock price on the grant date, 10-year terms and graded vesting over three years, which commences on the fourth anniversary of the grant date. Restricted stock that has been granted as a hiring incentive vests over four years on a graded basis, while restricted stock granted from a bonus pool vests over three years. Shares issued under the 2003 Plan are generally newly issued shares.

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. Effective January 1, 2007, employees are immediately vested in the contributions made by us. Our contributions to the 401(k) Plan were $0.9 million and $0.5 million for the years ended December 31, 2006 and 2005, respectively. No discretionary contributions were made by us to the 401(k) Plan to date.

NOTE 20 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,		
	2006	2005	2004
		(As Adjusted)	(As Adjusted)
Net loss	$ (145,853)	$ (29,538)	$ (24,876)
Other comprehensive (loss) income items:			
Cash flow hedges, net of income tax	(3,798)	3,798	
Foreign currency translation	(34)		
Comprehensive loss	$ (149,685)	$ (25,740)	$ (24,876)

NOTE 21 RELATED PARTY TRANSACTIONS

From time to time, officers and employees may charter aircraft for company business travel. We entered into a letter agreement, or charter letter, with an unrelated third-party entity, Western Airways, Inc. (Western), that 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 (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 years ended December 31, 2006 and 2005, we incurred $0.1 million and $0.8 million 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 $1.0 million.

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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 $1.0 million payment to us from J & S Cheniere for the option to acquire regasification capacity at our Sabine Pass and Corpus Christi LNG receiving terminals.

NOTE 22 COMMITMENTS AND CONTINGENCIES

LNG Terminal Commitments and Contingencies

Obligations under LNG TUAs

Sabine Pass LNG has entered into TUAs with Total and Chevron to provide berthing for LNG tankers and for the unloading, storage and regasification of LNG at the 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 the Sabine Pass and Corpus Christi LNG receiving terminals. Following execution of the option agreement, J & S Cheniere paid $1.0 million 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, entered into an option agreement with BPU to provide 100 MMcf/d of regasification capacity at the 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. In December 2005, Freeport LNG announced that it had closed a $383.0 million private placement of notes, which would be used to fund the remaining portion of the initial phase of the project, a portion of the cost of expanding the LNG receiving terminal and development of underground salt cavern gas storage. 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.

Under a settlement agreement dated as of June 14, 2001, we agreed to pay a royalty, which we refer to as the Crest Royalty, should Freeport not pay. This Crest Royalty is calculated based on the volume of natural gas processed through covered LNG facilities. The Crest Royalty is subject to a maximum of $11.0 million

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

per production year, beginning when natural gas is first commercially processed through a covered LNG facility. Freeport LNG has assumed the obligation to pay the Crest Royalty based on natural gas processed at Freeport LNG s receiving terminal. Freeport LNG has entered into TUAs with ConocoPhillips Company and The Dow Chemical Company, under which capacity payments commence when the Freeport LNG receiving terminal begins commercial operations. The ConocoPhillips TUA is for approximately 1.0 Bcf/d. The Dow TUA is for approximately 0.5 Bcf/d. Freeport LNG has announced that it expects to commence commercial operations in 2008.

EPC Terminal Agreements

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 the Sabine Pass LNG receiving terminal. 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 $646.9 million 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 $12.0 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 sustained sendout at a significant rate for a preagreed period of time (currently provided to be a 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 $6.0 million) for each day that commercial operation is achieved prior to April 1, 2008. As of February 14, 2007, change orders for $121.3 million have been approved, increasing the total contract price of Phase 1 to $768.2 million.

In July 2006, Sabine Pass LNG entered into an engineering, procurement, construction and management (EPCM) Agreement for Phase 2 Stage 1 with Bechtel for engineering, procurement, construction and management of construction services in connection with our 1.4 Bcf/d expansion at the Sabine Pass LNG receiving terminal. Under the terms of the EPCM agreement, Bechtel will be paid on a cost reimbursable basis, plus a fixed fee in the amount of $18.5 million. A discretionary bonus may be paid to Bechtel at Sabine Pass LNG s sole discretion upon completion of Phase 2 Stage 1.

In July 2006, Sabine Pass LNG entered into an EPC LNG Unit Rate Soil Improvement Contract with Remedial Construction Services, L.P. (Remedial) for engineering, procurement, and construction of soil improvement work. Work includes, but is not limited to, design, surveying, estimating, procurement and transportation of materials, equipment, labor, supervision and construction activities necessary to satisfactorily complete work on the Phase 2 Stage 1 site, unless otherwise set forth in the soil contract. Payments anticipated to be made by Sabine Pass LNG to Remedial for work performed under the contract are not expected to exceed $28.5 million. Progress payments will be paid based on quantities of work performed at unit rates, minus 10% retainage that will be paid upon final completion as well as any credits and early payment discounts applicable

In July 2006, Sabine Pass LNG entered into an EPC LNG Tank Contract with Diamond LNG LLC (Diamond) and Zachry Construction Corporation (Zachry and collectively with Diamond, the Tank Contractor) for the construction of two Phase 2 Stage 1 LNG storage tanks. In addition, Sabine Pass LNG has the option for the Tank Contractor to engineer, procure and construct a third tank, with the cost and completion

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date thereof to be agreed upon if such option is elected on or before March 31, 2007. Payments anticipated to be made by Sabine Pass LNG to Diamond and Zachry for work performed under the contract are not expected to exceed $140.9 million per revised payment schedule. Initial payments of $6.4 million were made to Diamond and Zachry in August 2006. Additional milestone payments for work incurred, minus a 5% retainage that will be paid upon final completion, will be based on a lump-sum, fixed price, subject to adjustments based on fluctuations in the cost of labor and change orders.

EPC Pipeline Agreements

In February 2006, Cheniere Sabine Pass Pipeline, L.P., our wholly-owned subsidiary, entered into an EPC pipeline contract with Willbros Engineers, Inc. (Willbros). Under the EPC pipeline contract, Willbros will provide Cheniere Sabine Pass Pipeline, L.P. with services for the management, engineering, material procurement, construction and construction management in connection with the Sabine Pass Pipeline. Payments anticipated to be made by Cheniere Sabine Pass Pipeline, L.P. to Willbros for work performed under the agreement are not expected to exceed $67.7 million subject to additions and deductions by change orders as provided in the contract, excluding certain Louisiana sales and use taxes, which Cheniere Sabine Pass Pipeline, L.P. is obligated to reimburse. Progress payments will be paid based on quantities of work performed, minus 5% retainage on construction work that will be paid upon final completion. Such preliminary site work commenced during the second quarter of 2006. As of December 31, 2006, change orders for $1.9 million had been approved, decreasing the total contract price to $65.8 million. Cheniere Sabine Pass Pipeline, L.P. may, at any time, terminate the agreement at its convenience, subject to payments on work performed prior to termination and reasonable direct close-out costs.

In August 2006, CCTP entered into a purchase order with CPW America Co. for the purchase of pipe at an aggregate cost of $63.8 million, payable in increments beginning with a payment made in the third quarter of 2006. Subsequent payment increments are tied to coil production milestones with additional remaining payments due on a per lot basis related to pipe production shipping and delivery milestones. The purchase order provides that all pipe is to be manufactured between January 1, 2007 and the end of the first week of March 2007, with all pipe delivered prior to April 15, 2007. CCTP may, at any time, terminate the purchase order for its convenience, subject to making specified cancellation payments that begin at 3% and increase to 100% of the value of the lots produced depending on the achievement of specified production measures.

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

Natural Gas Storage

In November 2006, Cheniere Marketing, entered into a natural gas storage agreement (the Gas Storage Agreement) with Washington 10 Storage Corporation (Washington) for interstate natural gas storage service

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and capacity of up to a maximum of 3.0 Bcf. The term runs from April 2008 through March 2018. Cheniere Marketing is responsible for paying a monthly deliverable rate and monthly capacity rate, as well as applicable fees authorized overrun rate, an interruptible rate and a fuel charge. The monthly deliverability rate and monthly capacity rate are used to calculate a monthly demand charge of $240,000 per month during the term of the Gas Storage Agreement. Payments anticipated to be made by Cheniere Marketing to Washington under the Gas Storage Agreement are not expected to exceed $28.8 million.

Other Commitments

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

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

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, 2006, 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 to commence a nonpublic factual investigation of actions and communications by us, our current or former directors, officers and employees and other persons in connection with our agreements and negotiations with Chevron, our 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. We have not received any communication from the SEC with regard to this matter since September 2005.

NOTE 23 GAIN ON SALE OF INVESTMENT IN UNCONSOLIDATED AFFILIATE

In October 2000, Cheniere and Warburg, Pincus Energy Partners, L.P. formed Gryphon Exploration Company (Gryphon) to fund an oil and gas exploration program in the Gulf of Mexico. Effective January 1, 2003, our investment (effective 9.3% ownership) in Gryphon was accounted for under the cost method of accounting, and our investment basis was zero. On August 31, 2005, Gryphon was sold for $283.0 million, plus assumption of $14.0 million of net debt in a merger with Woodside Energy (USA). The transaction generated net cash proceeds of $20.2 million 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.

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NOTE 24 BUSINESS SEGMENT INFORMATION

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

Our LNG receiving terminal segment is in various stages of developing three, 100% owned, LNG receiving terminal projects along the U.S. Gulf Coast at the following locations: Sabine Pass LNG in western Cameron Parish, Louisiana on the Sabine Pass Channel; Corpus Christi LNG near Corpus Christi, Texas; and Creole Trail LNG at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. In addition, we own a 30% limited partner interest in a fourth project, Freeport LNG, located on Quintana Island near Freeport, Texas.

Our natural gas pipeline segment is in various stages of developing three, 100% owned, natural gas pipelines in connection with our three LNG receiving terminals to provide access to North American natural gas markets.

Our LNG and natural gas marketing segment is in its early stages of development. We intend to purchase LNG from foreign suppliers, arrange transportation of LNG to our network of LNG receiving terminals, utilize our revaporization capacity at our LNG receiving 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. To develop our capacity to resell revaporized natural gas in the future, we are engaged in domestic natural gas purchase and sale, transportation and storage transactions, including financial derivative transactions, as part of our marketing activities.

Our oil and gas exploration and development segment explores for oil and natural gas using a large seismic database.

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	Segments					
	LNG Receiving Terminal	Natural Gas Pipeline	LNG & Natural Gas Marketing	Oil & Gas Exploration and Development	Corporate and Other (1)	Total Consolidated
	(in thousands)					
As of or for the Year Ended December 31, 2006						
Revenues	$	$	$ 61	$ 2,310	$	$ 2,371
Depreciation, depletion and amortization	137		107	227	2,660	3,131
Non-cash compensation expense	5,726	603	1,265	1,349	12,825	21,768
Income (loss) from operations (2)	(28,392)	8,255	(6,915)	(3,187)	(45,635)	(75,874)
Loss on early extinguishment of debt (3)	(43,159)					(43,159)
Derivative loss (3)	(20,070)					(20,070)
Interest expense	(35,990)	(256)			(17,722)	(53,968)
Interest income	15,871		208		33,008	49,087
Income tax provision						