DYNEGY

2006 ANNUAL REPORT

POWER GENERATION

FINANCIAL HIGHLIGHTS

($ in millions, except per share amounts)	Year Ended December 31, 2006	2005	2004
FINANCIAL DATA			
Operating revenues	**$ 2,017**	$ 2,313	$ 2,451
Power Generation - Midwest operating income	**208**	194	194
Power Generation - Northeast operating income	**55**	29	21
Power Generation - South operating loss	**(55)**	(21)	(52)
Customer Risk Management operating income (loss)	**7**	(647)	(118)
Regulated Energy Delivery operating income	**-**	-	139
Operating income (loss)	**52**	(838)	(100)
Income from discontinued operations, net of tax	**24**	899	165
Net income (loss)	**(333)**	90	(15)
Net income (loss) applicable to common shareholders	**(342)**	68	(37)
Capital expenditures, investments and acquisitions	**163**	315	314
Cash flow provided by (used in) operations	**(194)**	(30)	5
Total long-term debt and obligations	**4,034**	5,606	5,532
COMMON SHARE DATA			
Earnings (loss) per diluted common share	**($0.75)**	$0.18	($0.10)
Annual cash dividend per common share*	**-**	-	-
Market price at year-end	**7.24**	4.84	4.62
Average common shares outstanding (in millions)			
Diluted	**509**	513	504
Basic	**459**	387	378
OPERATING STATISTICS			
Power Generation - Midwest			
Electric power generated (net million megawatt hours)	**22**	22	23
Power Generation - Northeast			
Electric power generated (net million megawatt hours)	**4**	8	6
Power Generation - South			
Electric power generated (net million megawatt hours)	**4**	5	7
Natural Gas Liquids **			
Natural gas liquids produced (thousand barrels per day)	**-**	80	84
Natural gas liquids sold (thousand barrels per day)	**-**	258	283
Fractionation throughput (thousand barrels per day)	**-**	174	203

* Dividend suspended beginning in the third quarter 2002.
** Operating statistics for Natural Gas Liquids for the year ended December 31, 2005 only included statistics through October 31, 2005 due to the sale of the business.

This annual report contains statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward-looking statements." These statements represent our judgment on the future based on various factors and using numerous assumptions, and are subject to known and unknown risks, uncertainties and other factors that could cause our actual results and financial position to differ materially from those contemplated by the statements. You can identify these statements by the fact that they do not relate strictly to historical or current facts, and they include words such as "anticipate," "estimate," "project," "forecast," "plan," "may," "will," "should," "expect" and other words of similar meaning. For information concerning our forward-looking statements and important factors that could cause our actual results to differ materially from those in such statements, see page 22 of the Form 10-K.

Guiding Principles

What we do:

Produce and sell electric energy, capacity and ancillary services in key U.S. markets.

What we value:

- Our colleagues and teamwork.
- Honesty and integrity.
- Clear, candid and open communications.
- Diversity and inclusiveness in culture, experience and ideas.
- Commitment, discipline and focus.
- Individual responsibility and accountability.

How we operate:

- Do the right things with an expectation that the right things will happen.
- Operate safely, efficiently and consistent with our legal, ethical and environmental obligations.
- Trust and respect our fellow employees.
- Engage and develop our employees.
- Do things once and do them right.
- Recognize and reward performance.
- Work cooperatively and collaboratively.

We will be successful when:

- Our investors demonstrate confidence in our business strategy.
- Our employees live these Guiding Principles in their every action.
- Our communities recognize Dynegy as a valued corporate citizen.

To Our Investors:

I would like to begin by thanking you for your continued interest in Dynegy. This is a company committed to clear communications with investors, and, as in past years, I am using this opportunity to discuss events and milestones of the previous year and, going forward, our strategy for creating near-term, medium-term and long-term value for our stockholders.

2006 was a notable year for Dynegy and our investors. We completed our strategic and financial restructuring objectives. We continued to deliver a strong operational performance. And, we announced a significant growth initiative with LS Power. The LS Power combination, which closed on April 2, 2007, increased the scale, scope and diversification of our power generation enterprise to nearly 20,000 megawatts in three strategic regions of the country – the Midwest, the West and the Northeast. This increased scale and scope does not come at the expense of significantly higher corporate overhead or general and administrative costs. In fact, we anticipate modest incremental general and administrative costs of approximately 14 percent for 2007 to support a greater than 70 percent increase in productive assets under management.

Dynegy's new power generation portfolio is also more resilient and diverse, with much stronger free cash flow. Today, LS Power has a 40 percent equity ownership in Dynegy. Our Class B stockholder shares our focus on capitalizing on the dominant trends in our sector today – consolidation and growth in demand for clean, reliable and affordable sources of electricity.

Throughout the year as we worked to define a strategy for sector leadership and growth, we never lost sight of "doing the right things" in terms of our financial and operational performance, our safety and environmental responsibilities and our overarching commitment to delivering value to common stockholders. In each of these areas, we produced strong results that provided the foundation and momentum for future growth.

2006 accomplishments

Financial Performance

In late 2005, we sold our midstream natural gas business to Targa Resources for $2.4 billion. In 2006, we utilized the sales proceeds in an efficient, productive manner to launch and complete a comprehensive liability management plan. This initiative significantly reduced debt and other obligations, simplified our capital structure, eliminated dilutive securities and reduced our interest expense going forward.

Our liability management plan effectively completed our multi-year self-restructuring initiative and furthered our progress in reducing debt, tolling and other obligations from approximately $14 billion in 2002 to approximately $4 billion at the beginning of 2007.

During 2006, we also maintained our commitment to cost control by meeting our general and administrative cost goal of $140 million, excluding legal and settlement charges.

And finally, we prepared ourselves for the future by monetizing non-core assets, including West Coast Power and the Rockingham facility. We sold our 50 percent stake in West Coast Power and received in exchange the remaining 50 percent ownership stake in the Rocky Road power plant, a 351-megawatt natural gas-fired peaking facility near Chicago, and net cash proceeds of approximately $160 million. The addition of the Rocky Road interest strengthened our presence in the Midwest. The Rockingham facility was sold for approximately $195 million. In 2007, following the combination with LS Power, we are continuing to pursue selected non-core asset sales, with our current focus being on divesting of a few facilities located outside of our three core operating regions.

I would also like to mention that we terminated the Sterlington toll contract for $370 million, which resulted in the elimination of nearly $750 million in potential payment obligations. This effectively represented Dynegy's exit from power tolling activities associated with our former marketing and trading era.

Operational Performance

During 2006, Dynegy maintained its commitment to safe, reliable and cost-efficient operations. Despite less robust market conditions marked by lower prices and a 16 percent year-over-year reduction in net volumes, we delivered a strong operational performance that can be attributed to the successful execution of our near-term commercial sales strategy, through which we realized higher prices than average market prices for the year.

We also strive to be the reliable generator of electricity in our regions. The key measurement of in-market availability for our major facilities in our core business regions of the Midwest and Northeast was 87.7 percent and 87.4 percent, respectively, during 2006. This compares favorably to some of the best-run power fleets in the nation, and can be credited to an experienced operations team and a robust preventative and predictive maintenance program focused on ensuring that our facilities are ready to run when our markets and customers require the energy they produce.

Another indication of the strength of our operational platform relates to our strong safety performance. 2006 was our second-best year in terms of safe operations, with nine of 18 plants having no recordable accidents. For example, a nine-week outage at our Baldwin plant, the company's largest power generation facility, involved some 260,000 man-hours of work with no recordable incidents for either the company or our contractor. This is strong evidence of the safety culture at Dynegy and our focus on every employee finishing the workday injury and illness free.

Finally, operations have successfully transitioned to an organizational structure focused on and fully capable of running an expanded power generation portfolio. Led by Steve Furbacher, our President and Chief Operating Officer, we recently announced a leadership organization that sharpens our focus on commercial and operational opportunities. Our commercial and operations teams also benefit from our ongoing investment in improved reporting tools and business processes that focus on simplicity and cost-effectiveness. These tools and processes enable our commercial and operational platforms to support more megawatts of generation without a commensurate increase in costs.

Environmental Responsibility

Dynegy's commitment to environmentally responsible operations starts at the individual facility level and extends to fleet-wide efforts that help us achieve a balance between protecting the environment and supplying clean, reliable and affordable electricity to our markets and regions. During 2006, Dynegy announced an agreement with the Illinois Environmental Protection Agency that is expected to enhance the standing of the company's Midwest fleet as the cleanest group of coal-fired power generation assets in Illinois and among the lowest emission coal fleets in the United States. This agreement builds on already strong emissions reductions. Compared to 1999 levels, our Midwest coal-burning plants have reduced emissions of sulfur dioxide and nitrogen oxides by approximately 90 percent, while increasing electricity production by approximately 20 percent. In addition, recycling and energy efficiency projects have reduced carbon dioxide emissions, while tree-planting initiatives funded by the company have worked to offset carbon dioxide in the atmosphere.

We recognize that the environmental landscape is dynamic in nature, with numerous state and federal proposals aimed at further reductions in power plant emissions. Our focus is on maintaining our strong track record of environmental compliance and working with our customers and communities within the regulatory framework to develop new solutions that will contribute to our long-term ability to produce clean, reliable and affordable electricity from our power generation fleet.

Delivering Value to Investors

Finally, all of our 2006 efforts contributed to strong returns for common stockholders. Dynegy was a top performer in the S&P 500 with a 50 percent increase in our stock price during 2006. We believe our continued listings in both the S&P 500 and the Fortune 500 are testaments to our turnaround. The equity markets have validated that we are solidly on the right track.

In previous years, our focus was on the restoration of value for our senior notes. Today, they are generally trading at or above par. In 2006, we focused on improving our common stockholder returns. As our results demonstrate, our shift to restoring value for common stockholders has already met significant success. We believe our strong operational and growth platforms, coupled with our focus on minimizing costs, will continue to produce strong returns for our common stockholders.

Our Leadership

In wrapping up the discussion of our 2006 accomplishments, I want to give credit to a special group of company stakeholders, our employees. Our results and current momentum would not be possible without the "people assets" that provide guidance and direction, day-to-day leadership and sound operational performance and results. Our company's more than 1,300 employees actively reflect our Guiding Principles. Near the top of the list are the words, "Do the right things with an expectation that the right things will happen." This is how we run our operations and, importantly, how we treat the communities and the natural environment in which we operate.

Our Board of Directors consistently provides leadership, support and guidance for our day-to-day business as well as our future direction, while also adhering to our Guiding Principles and the highest standards of corporate governance. Following the recent completion of the LS Power combination, we welcome the following new members to our Board of Directors: Mike Segal, Chairman and Chief Executive Officer of LS Power Group; Frank Hardenbergh, Vice Chairman of LS Power Group; and James Bartlett, President of LS Power Equity Advisors. Their collective experience represents a valuable new resource for our company.

I would also like to recognize the two Class B Directors who left our Board. I would like to thank Rebecca Roberts and Howard Sheppard, both of whom are affiliated with Chevron Corporation, for their service to Dynegy and wish them the best in their future endeavors. Also, in light of Chevron Corporation no longer being our Class B stockholder, I want to thank David O'Reilly, Peter Robertson, John Watson, John McDonald and the rest of the Chevron team that I have had the pleasure to work with as we restructured and brought Dynegy to where it is today.

Our senior management team has a strong understanding of the company and the industry. In addition to myself and Steve Furbacher, our Executive Management Team includes Holli Nichols, Executive Vice President and Chief Financial Officer; Kevin Blodgett, General Counsel, Executive Vice President-Administration and Secretary; Lynn Lednicky, Executive Vice President, Commercial and Development; and Jason Hochberg, the newest member of our EMT. Jason, who previously served as President of LS Power, is our new Executive Vice President, Strategic Planning and Corporate Business Development. Not only is this one of the best executive teams in the business, with years of experience and industry knowledge – I believe it is the right group of executives to lead our growth.

Our Path Forward

Dynegy's recently completed combination with LS Power represents the transition from our previous era of self-restructuring to a new period of expanded, more diverse operations that provides greater scale and scope in our key markets and stronger positioning for future growth opportunities – in short, from running and restructuring the business to running and growing the business. I would like to discuss the near-term, medium-term and long-term benefits for investors associated with the new company, and then close this year's letter to investors with my thoughts on the next stage of growth for Dynegy.

Near-Term Value

In terms of near-term value, we anticipate strong earnings that are reflected in our current 2007 cash flow and earnings estimates, which include a range of consolidated EBITDA greater than $1 billion. In addition, our business is marked by less volatility on a percentage basis given the more predictable free cash flow from the addition of LS Power's operating assets. Approximately 50 percent of our gross margin was contracted going into 2007 as a result of our participation in the Illinois auction, reliability-must-run contracts, capacity arrangements and other contracts. We will continue to actively manage forward sales commitments in response to market conditions. These strong cash flows provide greater stability of results for our investors.

Medium-Term Value

Over the medium term, we believe our value proposition will be demonstrated through greater fuel, dispatch and geographic diversity in our key regions of the Midwest, the West and the Northeast. In terms of fuel, approximately 21 percent of our fleet is coal-fired, with efficient combined-cycle natural gas generation at approximately 33 percent, peaking gas generation at approximately 40 percent and dual-fuel generation at 6 percent.

Today, we also have significant dispatch diversity, with the notable difference from Dynegy's historic power generation business being an increase in intermediate capabilities given the new company's combined-cycle, natural gas-fired fleet acquired from LS Power.

We believe the next major "event" for the electricity sector is the tightening of generation supply and demand – not on a national basis, but on a regional basis or by NERC region. This has been demonstrated on a short-term basis through weather-driven demand or plant outages, and will be characterized longer-term by the tightening of supply and demand as the U.S. economy continues to strengthen and electricity demand increases.

Power market recovery is expected to place a premium on low-cost generation, including our Illinois coal-fired fleet, and bring expanding spark spreads. We believe this will create more opportunities for combined-cycle facilities and, at some point in the dispatch cycle, more of our peaking units will ramp up in terms of run-times, resulting in increasing upside potential for investors.

Long-Term Value

The new company has a strong vehicle for growth through our participation in a proven development platform that is well-positioned to transition from development options to construction and operational assets. To date, this portfolio includes more than 7,600 megawatts of generation options in various stages of development and approximately 2,500 megawatts of repowering opportunities at existing LS Power sites in strategic load-pocket regions.

Development represents one approach for future growth. The other growth driver will come from our participation in the ongoing consolidation of the electricity sector, which, combined with the expected recovery of power markets, represents the full potential for long-term investor value.

Here, I would like to acknowledge that Dynegy was not the only electricity sector participant to benefit from improving market dynamics in 2006, nor are we the only company to make significant progress in terms of dealing with legacy issues and restoring stockholder value.

I believe the distinguishing factors that set Dynegy apart and establish us as a sector leader with the strong potential for creating investor value include the following attributes:

- An operating portfolio that provides near-term value as a result of stronger free cash flow; medium-term value through the geographic, fuel, dispatch and sales strategy diversity of our power generation platform; and long-term value through the anticipated market recovery and participation in the ongoing consolidation of the electricity sector.
- A flexible development portfolio characterized by more than 10,000 megawatts of repowering and development options – including natural gas, coal and renewables – that provide opportunities for future organic growth or value capture.
- A well-defined and committed environmental spending program that ensures the long-term viability of our power generation fleet, while positioning us "ahead of the curve" compared to our peers. This capital program includes more than $550 million already invested in our conversion to clean-operating Powder River Basin coal, as well as more than $600 million in future spending focused on new emissions controls.

During the past year, we have lived up to our promise of managing the company in a manner marked by integrity. We have developed a straightforward business platform based on "running and growing" a power generation enterprise built on the attributes of safety, reliability, cost-efficiency and environmental responsibility. You have our commitment that this focus will continue in 2007 as we work to develop new opportunities and build new value for our investors.

Bruce A. Williamson
Chairman and Chief Executive Officer
May 21, 2007

Board of Directors

James T. Bartlett, 39
Mr. Bartlett is President of LS Power Equity Advisors. Prior to joining LS Power in 2005, Mr. Bartlett served as a Managing Director in Credit Suisse First Boston's Energy Investment Banking Group where he focused on M&A and financing transactions in the power generation sector. Previously, Mr. Bartlett was an Associate at Kendall Capital Partners and an Analyst at Drexel Burnham Lambert. Mr. Bartlett began his service as a Dynegy director in 2007.

David W. Biegler, 60
Mr. Biegler is the Chairman of Estrella Energy, L.P. He previously served as Chairman of Regency Gas Services, LLC, Vice Chairman, President and Chief Executive Officer of TXU Corp. and Chairman, President and Chief Executive Officer of ENSERCH Corp. Mr. Biegler serves as a Director of Trinity Industries, Inc., Austin Industries and Animal Health International, Inc., as well as Chairman of the American Gas Foundation. He also serves on the boards of numerous charitable organizations including the Children's Medical Center in Dallas, Texas. Mr. Biegler has served as a Dynegy Director since 2003. (2,4)

Thomas D. Clark, Jr., 66
Thomas D. Clark, Jr. is the President of Strategy Associates, a consulting firm specializing in strategy development, strategic planning assistance, corporate governance policy and corporate analysis. He previously served as Dean of the E.J. Ourso College of Business Administration at Louisiana State University, Ourso Distinguished Professor of Business, the Edward G. Schlieder Distinguished Chair of Information Science and Director of the DECIDE Boardroom, an executive decision research and development facility. Mr. Clark also serves as a member of the board of directors of Endeavour International. He has served as a Dynegy Director since 2003. (2,3)

Victor E. Grijalva, 68
Mr. Grijalva is the former Vice Chairman of Schlumberger Limited. Prior to serving in this role, he was Executive Vice President of Schlumberger's Oilfield Services division from 1994 to 1999 and Executive Vice President of the company's Wireline, Testing and Anadrill division from 1992 to 1994. Mr. Grijalva currently serves as a director of Hanover Compressor and Transocean, Inc., and formerly acted as Chairman of the Board for both companies. He has served as a Dynegy Director since 2006. (1,3,4)

Patricia A. Hammick, 60
Ms. Hammick is the former Senior Vice President, Strategy and Communications for Columbia Energy Group. She previously served as an adjunct Professor at George Washington University's Graduate School of Political Management and as Chief Operations Officer of the National Gas Supply Association. Ms. Hammick is a Director of Consol Energy, Inc. A Dynegy Director since 2003, Ms. Hammick was elected Lead Director in 2004.

Frank E. Hardenbergh, 63
Mr. Hardenbergh is Vice Chairman of LS Power Group. Mr. Hardenbergh joined LS Power in 1993. Prior to joining LS Power, Mr. Hardenbergh served as Senior Vice President, General Counsel and member of the Management Committee of the Commercial Union Capital Group. Mr. Hardenbergh was previously Associate General Counsel of the Commercial Union Insurance Companies, the parent company of Commercial Union Capital Group. Prior to joining the Commercial Union Insurance Companies, Mr. Hardenbergh was an Associate with Peabody & Arnold LLP. Mr. Hardenbergh began his service as a Dynegy director in 2007.

George L. Mazanec, 71
Mr. Mazanec is the former Vice Chairman of PanEnergy Corp. He previously served as Advisor to the Chief Operating Officer of Duke Energy Corp. Mr. Mazanec currently serves as a Director of the National Fuel Gas Company, Texas Bank and AEGIS Insurance Services, Inc. In addition, he is a member of the Board of Trustees of DePauw University in Indiana. Mr. Mazanec has served as a Dynegy Director since 2004. (1,2,3)

Robert C. Oelkers, 62
Mr. Oelkers is the former Vice President and Comptroller of Texaco Inc. and President of Texaco International Trader Inc. He has served in leadership roles with several organizations, including the Board of Trustees of Pace University in New York and as a member of the Financial Accounting Standards Board's Advisory Committee. Mr. Oelkers has served as a Dynegy Director since 2002. (1,3,4)

Mike Segal, 56
Mr. Segal is Chairman and Chief Executive Officer of the LS Power Group, a privately held power plant investor, developer and manager. Prior to co-founding LS Power, Mr. Segal served as co-head of Commercial Union Energy Corporation, where he was responsible for managing the Commercial Union Energy Limited Partnership, a partnership focused on investing in power generation projects. Mr. Segal was previously President of The Energy Systems Company, a private developer of cogeneration projects. He held various positions, including General Manager of Power Generation and Systems Planning, with LEMCO Engineers, Inc., an electrical engineering and consulting firm. Prior to LEMCO, Mr. Segal worked for the Department of Energy in the former Soviet Union. Mr. Segal began his service as a Dynegy director in 2007. (4)

William L. Trubeck, 60
Mr. Trubeck is Executive Vice President and Chief Financial Officer of H&R Block, Inc. He previously served as Executive Vice President and Chief Financial Officer of Waste Management, Inc. Prior to these positions, Mr. Trubeck was Senior Vice President and Chief Financial Officer of International Multifoods, Inc., as well as President of its Latin American operations. He serves on the Board of Yellow Roadway Corp. and on the Board of Trustees of Monmouth College in Illinois. Mr. Trubeck has served as a Dynegy Director since 2003. (1,2)

Bruce A. Williamson, 48
Mr. Williamson is Chairman and Chief Executive Officer of Dynegy Inc. Prior to joining Dynegy, he was President and Chief Executive Officer of Duke Energy Global Markets and Duke Energy International. Mr. Williamson was with PanEnergy Corp. in financial and business development leadership roles before its merger with Duke Power. He was also with Shell Oil Company for 14 years in exploration and production and finance roles. Mr. Williamson has served as a Dynegy Director since 2002. He was named Chairman of the Board in 2004.

Dynegy Board Committees
(1) Audit and Compliance Committee
(2) Compensation and Human Resources Committee
(3) Corporate Governance and Nominating Committee
(4) Performance Review Committee

Executive Management Team

Bruce A. Williamson, 48
Chairman and Chief Executive Officer. He is responsible for the development and execution of Dynegy's business strategies with a focus on growth, sector leadership and delivering value to investors. Mr. Williamson joined Dynegy in 2002 as President and CEO. He was named Chairman of the Board in 2004.

Stephen A. Furbacher, 59
President and Chief Operating Officer. He is responsible for all aspects of the operational and commercial activities of Dynegy's power generation business. Mr. Furbacher joined the company in 1996.

J. Kevin Blodgett, 35
General Counsel, Executive Vice President-Administration and Secretary. He is responsible for the company's legal and administrative affairs, including legal services supporting the company's operational, commercial and corporate areas, as well as human resources, information technology, building services, facilities and supply chain management. Mr. Blodgett joined Dynegy in 2000.

Jason A. Hochberg, 35
Executive Vice President, Strategic Planning and Corporate Business Develoment. He is responsible for identifying opportunities and strategies for building value at both the Dynegy corporate level and within the company's power generation business. Mr. Hochberg joined the company in 2007.

Lynn A. Lednicky, 46
Executive Vice President, Commercial and Development. He is responsible for commercializing the company's nearly 20,000-megawatt asset base, while overseeing near-term development projects. Mr. Lednicky joined the company in 1991.

Holli C. Nichols, 36
Executive Vice President and Chief Financial Officer. She is responsible for the company's financial affairs, including finance and accounting, treasury, risk management, internal audit and credit agency relationships, as well as investor and public relations. Ms. Nichols joined Dynegy in 2000.

Corporate Information

Corporate Headquarters

Dynegy Inc.
1000 Louisiana Street
Suite 5800
Houston, Texas 77002
713-507-6400
1-877-Dynegy9 (396-3499)
www.dynegy.com

Stock Exchange and Certification Information

In 2006, Dynegy's Chief Executive Officer provided to the NYSE the annual CEO certification regarding Dynegy's compliance with the NYSE's corporate governance listing standards. In addition, Dynegy's CEO and Chief Financial Officer filed with the U.S. Securities and Exchange Commission all required certifications regarding the quality of Dynegy's public disclosures in its 2006 periodic reports.

Our Class A common stock is listed on the New York Stock Exchange under the symbol "DYN."

Investor Information

Individual stockholders, security analysts, portfolio managers and other institutional investors seeking information about the company should contact Dynegy Investor Relations at 713-507-6466, 1-800-800-8220 or by e-mail at ir@dynegy.com.

Additional copies of this report may be obtained free of charge by contacting Investor Relations or by visiting Dynegy's web site at www.dynegy.com.

This report is presented for the general information of the stockholders and not in connection with the sale, offer to sell or the solicitation of any offer to buy securities, nor is it intended to be a representation by the company of the value of its securities.

Customer Information

Customers seeking information about the company should contact the Dynegy Customer Line at 1-877-4Dynegy (439-6349).

Media Information

Journalists seeking information about the company should contact the Dynegy Media Line at 713-767-5800.

Registrar and Transfer Agent

Mellon Investor Services LLC
480 Washington Boulevard
Jersey City, New Jersey 07310
1-888-921-5563
www.melloninvestor.com

Annual Meeting

The Annual Meeting of Shareholders will be held on July 18, 2007.

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

FORM 10-K

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

For the fiscal year ended December 31, 2006

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

For the transition period from to

Commission file number: 1-15659

DYNEGY INC.
(Exact name of registrant as specified in its charter)

Illinois	**74-2928353**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

1000 Louisiana, Suite 5800
Houston, Texas 77002
(Address of principal executive offices)

(713) 507-6400
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Class A common stock, no par value	New York Stock Exchange

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

Title of each class
None

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

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

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

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

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

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

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

As of June 30, 2006, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $2,187,357,631 based on the closing sale price as reported on the New York Stock Exchange.

Number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: Class A common stock, no par value per share, 401,210,616 shares outstanding as of February 22, 2007; Class B common stock, no par value per share, 96,891,014 shares outstanding as of February 22, 2007.

DOCUMENTS INCORPORATED BY REFERENCE. Part III (Items 10, 11, 12, 13 and 14) incorporates by reference portions of the Notice and Proxy Statement for the registrant's 2007 Annual Meeting of Shareholders, which the registrant intends to file not later than 120 days after December 31, 2006. However, if such Notice and Proxy Statement is not filed within such 120-day period, the Items comprising the Part III information will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period, pursuant to General Instruction G(3).

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DYNEGY INC.
FORM 10-K

TABLE OF CONTENTS

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PART I

DEFINITIONS

As used in this Form 10-K, the abbreviations contained herein have the meanings set forth in the glossary beginning on page F-72. Additionally, the terms "Dynegy", "we", "us" and "our" refer to Dynegy Inc. and its subsidiaries, unless the context clearly indicates otherwise.

Item 1. *Business*

THE COMPANY

Overview

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily on the power generation sector of the energy industry and our primary business is the production and sale of electric energy, capacity and ancillary services from our 11,739 MW fleet (20 plants) of owned or leased power generation facilities.

Dynegy began operations in 1985 and became incorporated in the state of Illinois in 1999 in anticipation of our February 2000 acquisition of Illinova Corporation. Our principal executive office is located at 1000 Louisiana Street, Suite 5800, Houston, Texas 77002, and our telephone number at that office is (713) 507-6400.

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document we file at the SEC's Public Reference Room at 100 F Street N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the SEC's Public Reference Room. Our SEC filings are also available to the public at the SEC's web site at *www.sec.gov*. No information from such web site is incorporated by reference herein. Our SEC filings are also available free of charge on our web site at *www.dynegy.com*, as soon as reasonably practicable after those reports are filed with or furnished to the SEC. The contents of our website are not intended to be, and should not be considered to be, incorporated by reference into this Form 10-K.

On September 14, 2006, we entered into a Plan of Merger, Contribution and Sale Agreement (the "Merger Agreement") with LSP Gen Investors, L.P., LS Power Partners, L.P., LS Power Equity Partners PIE I, L.P., LS Power Associates, L.P., and LS Power Equity Partners, L.P. (collectively, the "LS Entities"), part of the LS Power Group, a privately held power plant investor, developer and manager, to combine a portion of the LS Entities' operating generation portfolio with our generation assets, and for us to acquire a 50 percent ownership interest in a development company that is currently controlled by the LS Entities. The combined company ("New Dynegy") will have nearly 20,000 MW of generating capacity. Upon completion of the Merger Agreement, which is subject to the affirmative vote of holders of at least two-thirds of our Class A common stock and the satisfaction of other conditions, the combined company will own 29 operating power plants in 13 states (excludes the 351 MW Calcasieu generation facility which we have agreed to sell to Entergy Gulf States, Inc. ("Entergy") employing a balanced mix of fuel sources with baseload, intermediate, and peaking dispatch capabilities, greater cash flow-generating opportunity than Dynegy alone, and significant scale and scope in three key geographic regions. The expanded portfolio will also include a controlling interest in the Plum Point facility, a 665 MW coal-fired plant currently under construction in Arkansas. Additionally, the development joint venture (referred to herein as the development company) will provide us with a 50 percent ownership interest in an established growth vehicle. The LS Entities' current development activities include nine projects totaling more than 7,600 MW in various stages of development and approximately 2,300 MW of repowering and/or expansion opportunities.

If the transaction is consummated, the LS Entities will receive 340 million shares of New Dynegy's Class B common stock, $100 million in cash and $275 million aggregate principal amount of notes to be issued by

New Dynegy. New Dynegy will also assume approximately $1.9 billion in net debt (debt less restricted cash and investments) from the LS Entities. Please read Note 3—Business Combinations and Acquisitions—LS Power for further discussion of the terms of the Merger Agreement as well as the proxy statement/prospectus of Dynegy Acquisition, Inc. filed with the SEC on February 13, 2007.

General

Our assets are located in the Midwest, New York, Texas, Nevada and the Southeast. Our diverse power generation facilities generate electricity by burning coal, natural gas or oil. We sell electric energy, capacity and ancillary services by various means: (i) primarily through bilateral negotiated contracts with third parties and into regional central markets and (ii) with lesser volumes through structured wholesale over-the-counter markets and directly to end-use customers.

We are currently evaluating our portfolio in anticipation of consummating the LS Power transaction with the goal of focusing on regions and markets where we will have a significant asset position. This evaluation could result in sales of assets that are not considered strategic fits within our generating fleet. Our current generating facilities are as follows:

Facility	Total Net Generating Capacity (MW)(1)	Primary Fuel Type	Dispatch Type	Location	NERC Region (ISO)
Baldwin	1,800	Coal	Baseload	Baldwin, IL	SERC (MISO)
Havana Units 1-5	228	Oil	Peaking	Havana, IL	SERC (MISO)
Unit 6	441	Coal	Baseload	Havana, IL	SERC (MISO)
Hennepin	293	Coal	Baseload	Hennepin, IL	SERC (MISO)
Oglesby	63	Gas	Peaking	Oglesby, IL	SERC (MISO)
Stallings	89	Gas	Peaking	Stallings, IL	SERC (MISO)
Tilton	188	Gas	Peaking	Tilton, IL	SERC (MISO)
Vermilion Units 1-2	164	Coal/Gas	Baseload	Oakwood, IL	SERC (MISO)
Unit 3	12	Oil	Peaking	Oakwood, IL	SERC (MISO)
Wood River Units 1-3	119	Gas	Peaking	Alton, IL	SERC (MISO)
Units 4-5	446	Coal	Baseload	Alton, IL	SERC (MISO)
Rocky Road	330	Gas	Peaking	East Dundee, IL	RFC (PJM)
Riverside/ Foothills	960	Gas	Peaking	Louisa, KY	RFC (PJM)
Rolling Hills	965	Gas	Peaking	Wilkesville, OH	RFC (PJM)
Renaissance	776	Gas	Peaking	Carson City, MI	RFC (MISO)
Bluegrass (2)	576	Gas	Peaking	Oldham Co., KY	SERC (LG&E)
Total Midwest	*7,450*				
Independence	1,064	Gas	Intermediate	Scriba, NY	NPCC (NYISO)
Roseton (3)	1,185	Gas/Oil	Intermediate	Newburgh, NY	NPCC (NYISO)
Danskammer Units1-2	123	Gas/Oil	Peaking	Newburgh, NY	NPCC (NYISO)
Units 3-4 (3)	370	Coal/Gas/Oil	Baseload	Newburgh, NY	NPCC (NYISO)
Total Northeast	*2,742*				
Calcasieu (4)	351	Gas	Peaking	Sulphur, LA	SERC
Heard County	539	Gas	Peaking	Heard Co., GA	SERC
Black Mountain (5)	43	Gas	Baseload	Las Vegas, NV	WECC
CoGen Lyondell	614	Gas	Baseload	Houston, TX	ERCOT (ISO)
Total South	*1,547*				
Total Fleet Capacity	*11,739*				

(1) Unit capacity values are based on winter capacity.
(2) Effective September 1, 2006, Louisville Gas & Electric, and therefore Bluegrass, left the MISO market and resumed operation as a stand-alone control area.
(3) We lease the Roseton facility and units 3 and 4 of the Danskammer facility pursuant to a leveraged lease arrangement that is further described in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Off-Balance Sheet Arrangements—DNE Leveraged Lease beginning on page 50.
(4) On January 31, 2007, we entered into an agreement to sell our interest in the Calcasieu power generation facility to Entergy. Subject to regulatory approval, the transaction is expected to close in early 2008. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Calcasieu on page F-20 for further discussion.
(5) We own a 50% interest in this facility and the remaining 50% interest is held by Chevron U.S.A., which we refer to as Chevron, our largest shareholder. Total output capacity of this facility is 85 MW.

We also have a CRM business which represents our legacy trading business. After the termination of the Sterlington tolling agreement on March 7, 2006, the CRM business primarily consists of the Kendall tolling agreement (excluding the Sithe toll which is in our GEN-NE segment and is an intercompany agreement), as well as our legacy gas, power and emissions trading positions. On September 14, 2006, we agreed to acquire the Kendall facility either through the planned acquisition of assets from the LS Entities or as a separate transaction. The Kendall tolling arrangement will become an intercompany obligation under our GEN-MW segment upon the closing of the transaction. We report the results of this business as a separate reportable segment.

Business "Drivers" in the Power Generation Industry

Profitability of our business is largely a function of the difference between market prices for electricity and our cost to produce electricity at our various facilities from which we sell some of our energy under longer-term contracts, either directly to our customers or through the over-the-counter wholesale energy markets. We sell the remaining production into the shorter-term and spot markets (otherwise called day-ahead and real-time markets). We also hedge a portion of the output from our facilities in the financial markets based on our perspective of market fundamentals.

Market Prices for Wholesale Power. Future market prices are driven by expectations of buyers and sellers as to the fundamental supply/demand balance, similar to many other commodity markets. Short-term power market prices are determined largely by the balance of supply and demand in a region and are heavily influenced by weather. Both short-term and long-term prices are also heavily impacted by the price of natural gas, which is also impacted by regional weather effects. At times in certain markets, power prices rise and fall in tandem with natural gas prices. In some markets in which we operate, there is an excess of power generation supply compared to demand. However, due to demand growth out-pacing supply growth, we expect that this excess supply will diminish over time as consumption continues to grow, likely resulting in increased market prices for power.

Summer and winter weather extremes can cause increased electricity consumption, driving up prices in affected regions. Conversely, during spring and fall when weather tends to be milder, market prices are usually less extreme.

In regions with centrally dispatched market structures (such as the Midwest and Northeast regions), all generators receive the same price for energy generated based on the price required to justify production of the last megawatt that is needed to balance supply with demand. For example, a less-efficient (i.e. more expensive) natural gas-fired unit may be needed in some hours to meet demand. If this unit's production is required to meet demand, its higher production costs will set the market clearing price that will be paid to all generators, regardless of the price that any other unit may have offered into the market or its cost of generation. In other regions, prices are determined on a bilateral basis between buyers and sellers.

Production Costs. Another key aspect of profitability is our cost to produce electricity. The main variable component of that cost is fuel. Our coal-fired generation facilities are our lowest cost facilities. Therefore, most of our coal-fired generation facilities run the majority of any given day throughout the year unless a particular unit is unavailable due to either planned or unplanned maintenance activity. In today's environment, our natural gas and oil fueled generation facilities are more expensive to operate than our coal-fired facilities. As a result, these plants only run on those days, or parts of days, when market demand and price are sufficient to economically justify dispatch of these higher cost units.

We also incur operations and maintenance (O&M) costs at our facilities. We categorize these costs as either fixed O&M or variable O&M. Fixed O&M is generally the non-fuel cost to maintain and operate a unit. This includes both major maintenance that must occur every few years to ensure reliability of a unit and routine maintenance, which must be performed more frequently. Variable O&M is the incremental cost that occurs for each dispatch, including fuel needed to start-up a unit and the cost of consumables used during operation.

Emissions Allowances. Operation of our power generation facilities is subject to regulatory limitations on emissions of both sulfur dioxide (SO_2) and nitrogen oxide (NO_X). We are granted emissions credit allowances by regulatory bodies on an annual basis. To the extent that our inventory of emissions allowances, including those that we carry forward from earlier years, are not sufficient to allow us to operate our plants within the emissions guidelines of the various air districts, we will either purchase additional emissions credits from third parties or reduce operation of that unit. Conversely, if we have more emissions credits on hand than are required to operate our facilities, we may opportunistically sell these credits, subject to certain regulatory limitations and restrictions contained in our DMG consent decree, or hold them in inventory until they are needed. Based on current projections, we do not expect a net expenditure from the purchase and sale of emissions allowances in the near term. Please read "Regulatory and Environmental Matters—Environmental, Health and Safety Matters—Multi-Pollutant Air Emission Initiatives" beginning on page 16 for a discussion of regulatory initiatives that will impact emissions over the longer term.

Services Provided. We sell electric energy, capacity and ancillary services from our facilities. Energy is the actual output of electricity that is measured in MWh at the wholesale level and is usually measured in KWh at the retail level. The capacity of a generation facility is its electricity production capability, measured in MW. Each NERC region must have sufficient generating capacity to meet expected consumption of electricity (known as load). Each NERC region calculates a reserve requirement, which is additional necessary capacity that a region must have in order to manage potential unit outages. Electricity consumers will, for reliability or regulatory reasons, contract for capacity from a capacity supplier from one or more of the generating units that the supplier owns. Ancillary services are the products of a generation facility that support the transmission grid operation, allow generation to follow real-time changes in load, and provide emergency reserves for major changes to the balance of generation and load.

We sell these components of electricity to our customers under short-term or long-term contractual agreements or tariffs. Most of the energy and capacity transactions that we enter into are based on industry standard contracts. We also sell into central markets operated by RTOs and ISOs. We enter into negotiated contracts for each product or a combination of products with other customers as well.

Customers. Our customers include RTOs and ISOs, integrated utilities, municipalities, electric cooperatives, transmission and distribution utilities, industrial customers, power marketers, banks, hedge funds, other power generators and commercial end-users. We sell electric energy, capacity and ancillary services to some or all of these customers for various lengths of time. Some of our customers, such as municipalities or integrated utilities, purchase our products in order to serve their retail, commercial and industrial customers. Other customers, such as some power marketers, may buy from us to serve load or may purchase power as a hedge against other power sales that they have made, such that they are effectively a "middle man" between generators and end-users.

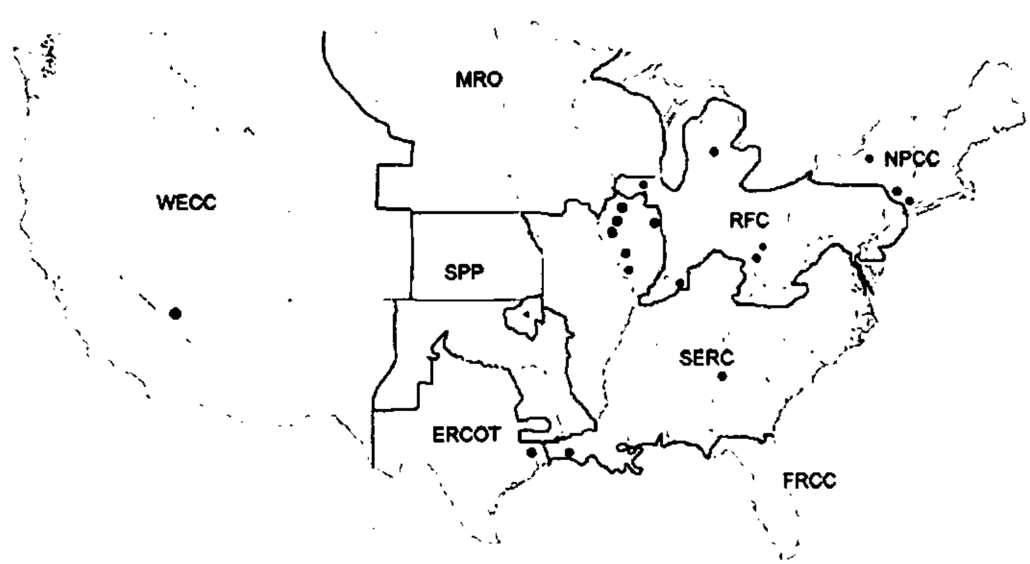
Dispatch Type. Our generation assets include baseload, peaking and intermediate dispatch types. Baseload generation is low-cost and economically attractive to dispatch around the clock throughout the year. A baseload facility is usually expected to run between 80%-90% of the hours in a given year. Intermediate generation is not as efficient and/or economic as baseload generation but is intended to dispatch to serve load during higher load times such as during daylight hours and sometimes on weekends. Peaking generation is the least efficient and highest cost generation and is generally dispatched to serve load during the highest load times such as hot summer and cold winter days. Our intermediate and peaking facilities are fueled by fuel oil or natural gas.

Capital Expenditures. Our capital expenditures are for the continued maintenance of our facilities to ensure their continued reliability and for investment in new equipment for either environmental compliance or increasing profitability. In 2006, we had approximately $148 million in capital expenditures for our entire fleet of generation assets, of which $90 million was for capital maintenance projects, $2 million was for development projects, primarily for the conversion of our Vermilion facility to PRB coal, and $56 million was for other environmental expenditures.

NERC Regions, RTOs and ISOs. In discussing our business, we often refer to NERC regions. The North American Electric Reliability Council (NERC) and its eight regional reliability councils (as of December 31, 2006) were formed to ensure the reliability and security of the electricity system. The regional reliability councils set standards for reliable operation and maintenance of power generation facilities and transmission systems. NERC reports seasonally and annually on generation and transmission status in each region.

Separately, RTOs and ISOs centrally operate markets and transmission across a regional footprint in some of the markets in which we operate. They are responsible for secure dispatch of all generation facilities in that footprint, and are responsible for both maximum utilization and efficiency of the transmission system within what have been determined to be secure levels. RTOs and ISOs administer electricity markets for physical and financial energy markets in the short term, usually day ahead and real-time markets. NERC regions and RTOs/ ISOs often have different geographic footprints and while there may be physical overlap, their respective roles and responsibilities do not.

NERC Regions as of December 31, 2006



Reliability. We seek to operate and maintain our generation fleet efficiently and safely, with an eye toward future maintenance and improvements, resulting in increased reliability. This increased reliability impacts our results to the extent that our generation units are available during times that it is economically sound to run. These efforts are reflected not only in capital improvements, but also in organizational and program changes.

Regulatory & Legislative Considerations

Our business is subject to extensive federal, state and local laws and regulations governing the generation and sale of electricity, the discharge of materials into the environment and otherwise relating to environmental, health and safety. Following is a summary of key regulatory and environmental considerations impacting our power generation operations. Please read "—Regulatory and Environmental Matters" beginning on page 15 for further discussion of the environmental and regulatory restrictions applicable to our business.

Rates. Our wholesale power sales are governed by the FERC. With the exception of CoGen Lyondell and Black Mountain, which are Qualifying Facilities (QFs), all of our facilities currently have the authority to charge market-based rates for wholesale power. Many of our facilities also have cost-based tariffs for providing reactive power support. We are subject to FERC's regulations governing market behavior and prohibiting market manipulation, the violation of which could result in the revocation or suspension of our market-based rate authority as well as refunds, disgorgement of profits and monetary penalties.

Market Structure. Our sales of electricity and related services to particular customers and/or at a particular price are subject to the market structure and related rules in the states or regions where we operate. For instance, in organized markets like Texas, bids and prices are capped, and in the New York market, there is a price mitigation procedure to correct the adverse impact of errors or other activities outside the bounds of market rules and policies. In the state of Illinois, a resource procurement auction was recently conducted, resulting in the award of binding contracts between the utilities and wholesale energy providers such as Dynegy.

SO_2 and NO_X Emissions. The Clean Air Act and comparable state laws and regulations require that specified reductions in SO_2 and NO_X emissions be achieved. More recent regulations, including the Clean Air Interstate Rule (CAIR), require significant emissions reductions over the next several years. We have expended capital and installed emission control equipment at a number of our facilities to meet current requirements and expect to expend significant additional capital in the future to satisfy prospective requirements.

Mercury Emissions. The Clean Air Mercury Rule (CAMR), issued by the EPA in March 2005, requires that specified reductions in mercury emissions be achieved from the air emissions of coal-fired power plants. States are required to adopt the federal CAMR or a state rule meeting its minimum requirements. Both the states of Illinois and New York, where we have significant coal-fired assets, have recently adopted more stringent rules that will require greater reductions in emissions and thus could entail additional capital expenditures, in each case sooner than would CAMR. Our projected capital expenditures through 2013 include controls that we believe will achieve the new mercury emission reduction requirements. Additional capital expenditures may be required at our Wood River facility in 2015 depending on the performance of equipment installed between now and then.

Water Withdrawals. The Clean Water Act and comparable state laws and regulations require that the location, design, construction and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. The cooling water intake structures at four of our coal plants and one of our fuel oil plants in Illinois and New York are subject to this requirement. The scope of the requirement and the compliance methodologies allowed may become more restrictive, resulting in potentially significant increased costs. In addition, the timing for compliance may be adjusted.

Carbon Emissions. Our Northeast assets may become subject to a state-driven greenhouse gas emission reduction program known as the Regional Greenhouse Gas Initiative (RGGI). RGGI is a program under development by nine New England and Mid-Atlantic states to reduce carbon dioxide emissions from power plants. The state of New York has introduced, as a "pre-proposal", a rule which would require affected generators to purchase 100 percent of the carbon credits needed to operate their facilities through an auction process. The final program requirements of RGGI and subsequent impact to our operations are not known at this time. The Northeast states currently intend to finalize carbon dioxide emissions requirements for electric generating facilities during 2007, with implementation to begin in 2009. Additional regulations are under consideration by various policy-making bodies and, if adopted, could impact our operations and require additional capital expenditures. Please read Note 18—Regulatory Issues on page F-53 for further discussion.

SEGMENT DISCUSSION

Our business operations are focused primarily on the wholesale power generation sector of the energy industry. We report the results of our power generation business based on geographical location and how we allocate resources as three separate segments in our consolidated financial statements: (1) the Midwest segment (GEN-MW), (2) the Northeast segment (GEN-NE) and (3) the South segment (GEN-SO). We also separately report the results of our legacy CRM business, excluding the Sithe toll which is an intercompany agreement now and is included in GEN-NE. As described below, our NGL business, which was conducted through DMSLP and its subsidiaries, was sold to Targa Resources, Inc. (Targa) on October 31, 2005. Additionally, as described below, our former REG business, which was conducted through Illinois Power Company and its subsidiaries, was sold to Ameren Corporation on September 30, 2004. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest.

Power Generation—Midwest Segment

Our Midwest fleet comprises 13 facilities located in Illinois (9 facilities), Michigan (1 facility), Ohio (1 facility) and Kentucky (2 facilities), with a total capacity of 7,450 MW. With the exception of our Bluegrass peaking facility in the LG&E control area, our Midwest fleet as of December 31, 2006 operates entirely within either the Midwest ISO (MISO) or the Pennsylvania-New Jersey-Maryland Interconnection (PJM). Key details of the Midwest fleet are as follows:

Facility	Total Net Generating Capacity (MW)(1)	Primary Fuel Type	Dispatch Type	Location	NERC Region (ISO)
Baldwin	1,800	Coal	Baseload	Baldwin, IL	SERC (MISO)
Havana Units 1-5	228	Oil	Peaking	Havana, IL	SERC (MISO)
Unit 6	441	Coal	Baseload	Havana, IL	SERC (MISO)
Hennepin	293	Coal	Baseload	Hennepin, IL	SERC (MISO)
Oglesby	63	Gas	Peaking	Oglesby, IL	SERC (MISO)
Stallings	89	Gas	Peaking	Stallings, IL	SERC (MISO)
Tilton	188	Gas	Peaking	Tilton, IL	SERC (MISO)
Vermilion Units 1-2	164	Coal/Gas	Baseload	Oakwood, IL	SERC (MISO)
Unit 3	12	Oil	Peaking	Oakwood, IL	SERC (MISO)
Wood River Units 1-3	119	Gas	Peaking	Alton, IL	SERC (MISO)
Units 4-5	446	Coal	Baseload	Alton, IL	SERC (MISO)
Rocky Road	330	Gas	Peaking	East Dundee, IL	RFC (PJM)
Riverside/ Foothills	960	Gas	Peaking	Louisa, KY	RFC (PJM)
Rolling Hills	965	Gas	Peaking	Wilkesville, OH	RFC (PJM)
Renaissance	776	Gas	Peaking	Carson City, MI	RFC (MISO)
Bluegrass (2)	576	Gas	Peaking	Oldham Co., KY	SERC (LG&E)
Total Midwest	*7,450*				

(1) Unit capacity values are based on winter capacity.
(2) Effective September 1, 2006, Louisville Gas & Electric, and therefore Bluegrass, left the MISO market and resumed operations as a stand-alone control area.

As of the beginning of 2006, all of our Midwest coal facilities had been converted to the use of PRB coal. PRB coal is a cleaner-burning coal with lower sulfur content, making it more economic to burn while emitting lower amounts of sulfur dioxide. These conversions and upgrades have enhanced reliability of the units, decreased emissions and lowered maintenance costs.

Midwest Fleet-MISO

At December 31, 2006, we owned nine generating facilities with an aggregate net generating capacity of 4,619 MW located within MISO. The MISO market includes all of Wisconsin and Michigan and portions of Ohio, Kentucky, Indiana, Illinois, Nebraska, Kansas, Missouri, Iowa, Minnesota, North Dakota, Montana and Manitoba, Canada.

All of our coal-fired generation in the Midwest is in the MISO market footprint, as is our Renaissance peaking facility. MISO's role is to ensure equal access to the transmission system and to maintain or improve electric system reliability in the Midwest. MISO was founded in 1996, and was specifically configured to comply with FERC's concept of an independent organization that will ensure the smooth regional flow of electricity in a competitive wholesale marketplace. MISO's primary objective is to "direct traffic" on the wholesale bulk electric power lines. In this role, MISO ensures that every electric industry participant has access to the lines and that no entity has the ability to deny access to a competitor. MISO also manages the use of the lines to make sure that they do not become overloaded. MISO operates physical and financial energy markets using a system known as Locational Marginal Pricing (LMP). This system calculates a price for every generator and load point within the MISO area. This system is "price-transparent", allowing generators and load serving entities to see real-time price effects of transmission constraints and impacts of generation and load changes to prices at each point. MISO operates day-ahead and real-time markets into which generators can offer to provide energy. Financial Transmission Rights (FTRs) allow users to manage the cost of transmission congestion (the inability to physically move power from one location to another) and corresponding price differentials across the market area. MISO currently does not have a formal capacity market or ancillary services market. An independent market monitor is responsible for ensuring that MISO markets are operating properly and without manipulation. MISO has proposed an energy-only market design to meet resource adequacy (i.e., causing new generation to be built when needed). Market participants are currently debating this proposal, and the form and timeframe for implementation of a system other than an energy-only market are uncertain.

Contracted Capacity. Through our participation in the recent Illinois resource procurement auction, we entered into energy product supply agreements with subsidiaries of Ameren for the following products:

- Up to 1,200 megawatts in each hour around the clock for the time period of January 1, 2007 through May 31, 2008, at the price of $64.77 per megawatt-hour; and
- Up to 200 megawatts in each hour around the clock for the time period of January 1, 2007 through May 31, 2009, at the price of $64.75 per megawatt-hour.

Under the terms of these agreements, we expect to deliver electricity together with capacity and specified ancillary, transmission and load-following services necessary to serve a portion of Ameren's full-requirements residential and small customer load.

In addition to capacity committed under our contract with Ameren, we expect all of our remaining capacity in the MISO area of the region will be sold under other bilateral capacity contracts in 2007.

Illinois Resource Procurement Auction. In September 2006, the first reverse auction was concluded to procure power with delivery beginning in 2007. The ICC did not investigate the results of the Fixed Price

Auction segment, which covered substantially all of the retail needs for those customers taking fixed-price service from the largest electric utilities in Illinois (Commonwealth Edison Company and the three Ameren Illinois utilities: AmerenIP, AmerenCIPS and AmerenCILCO). Subsequent auctions would likely cover only a portion of the total retail needs of the utilities because of the use of staggered contracts for certain customer classes. The ICC did initiate an investigation into the Hourly Auction segment, and we have intervened in that proceeding.

There will continue to be challenges to the auction process. Numerous parties have appealed various aspects of the ICC Orders approving the auctions to the state intermediate appellate courts. Among others, the Governor and Attorney General (who has been an active party in the regulatory proceedings) have announced their opposition to the auctions and the Attorney General filed with the State Supreme Court for expedited review of the ICC's auction orders and a stay of the auction pending that review, which was denied. The appellate court cases have been consolidated and are in the briefing stage; we anticipate a ruling sometime in 2007, with the possibility of further review by the Illinois Supreme Court. In addition, at least one bill has been introduced in the Illinois General Assembly to extend the rate freeze previously in effect through the end of 2006, which may have an impact on Ameren's ability to meet its contractual obligations under the SFC's. There is also the possibility of additional political, legislative, judicial and/or regulatory actions over the next several months that could alter substantially the rights and obligations under or relating to the SFC's.

Environmental and Regulatory Considerations. In 2005, we settled a lawsuit filed by the U.S. EPA and the DOJ in the U.S. District Court for the Southern District of Illinois that alleged violations of the Clean Air Act and related federal and Illinois regulations concerning certain maintenance, repair and replacement activities at our Baldwin generating station. A consent decree was finalized in July 2005. The consent decree requires us to (i) pay a $9 million civil penalty; (ii) fund several environmental mitigation projects in the additional aggregate amount of $15 million; and (iii) install equipment in emission control projects at our Baldwin, Vermilion and Havana plants that we currently anticipate, based upon ongoing engineering estimates, will cost approximately $675 million through 2012.

Please read "—Regulatory and Environmental Matters" beginning on page 15 for discussion of the environmental and regulatory restrictions applicable to our business.

Midwest Fleet-PJM

At December 31, 2006, we owned interests in three generating facilities, Rocky Road, Rolling Hills, and Riverside/Foothills, with an aggregate net generating capacity of 2,255 MW located within PJM. The majority of power generated by those facilities is sold to wholesale customers in the PJM market.

PJM currently administers markets for wholesale electricity and provides transmission planning for the region, utilizing the LMP system described above. PJM operates day-ahead and real-time markets into which generators can bid to provide electricity and ancillary services. PJM also administers markets for capacity. An independent market monitor continually monitors PJM markets for manipulation or improper behavior by any entity. In addition, FERC recently accepted PJM's proposed changes to its capacity markets (Reliability Pricing Model, or "RPM"), including establishing longer-term markets for capacity to improve market signals for new generation.

We sell substantially all of our capacity each year via the over-the-counter capacity market as well as through capacity auctions held by PJM. The remainder of capacity and energy is sold primarily into wholesale markets.

Power Generation—Northeast Segment

Our Northeast fleet comprises three facilities located in New York. We own the Independence power generating facility, and we operate two generating facilities, Roseton and Danskammer, under long-term lease arrangements. Our Roseton and Danskammer facility sites are adjacent and share common resources such as fuel handling, a docking terminal, personnel and systems. The combined generating capacity of our Northeast fleet is 2,742 MW.

Facility (1)	Total Net Generating Capacity (MW)(2)	Primary Fuel Type	Dispatch Type	Location	NERC Region (ISO)
Independence	1,064	Gas	Intermediate	Scriba, NY	NPCC (NYISO)
Roseton (3)	1,185	Gas/Oil	Intermediate	Newburgh, NY	NPCC (NYISO)
Danskammer Units1-2	123	Gas/Oil	Peaking	Newburgh, NY	NPCC (NYISO)
Units 3-4 (3)	370	Coal/Gas/Oil	Baseload	Newburgh, NY	NPCC (NYISO)
Total Northeast	2,742				

(1) Does not include the hydroelectric generation facilities acquired as part of our Sithe Energies acquisition. For further information, please see Note 10—Unconsolidated Investments—Variable Interest Entities beginning on page F-34.

(2) Unit capacity values are based on winter capacity.

(3) We lease the Roseton facility and units 3 and 4 of the Danskammer facility pursuant to a leveraged lease arrangement that is further described in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Off-Balance Sheet Arrangements—DNE Leveraged Lease beginning on page 50.

Northeast Fleet-NYISO. All of our Northeast facilities are located in the New York Independent System Operator (NYISO) area. NYISO administers the state-wide transmission system and spot markets for electricity, calculates electricity prices, and dispatches generation using an LMP model. NYISO also administers markets for capacity and certain ancillary services. An independent market monitor continually monitors NYISO markets for manipulation or improper behavior by an entity. In 2003, NYISO implemented a "Demand Curve" mechanism for calculating pricing for installed capacity for three locational zones: New York City, Long Island, and the rest of the state of New York. Our facilities operate outside of New York City and Long Island. Capacity pricing is calculated as a function of NYISO's annual target reserve margin (18% for 2006-2007), the estimated cost of "new entrant" generation, estimated peak demand, and the actual amount of capacity bid into the market. The Demand Curve mechanism provides for incrementally higher capacity pricing at lower reserve margins, such that "new entrant" economics become attractive as the reserve margin approaches target levels. The intention of the Demand Curve mechanism is to ensure that existing generation has enough revenue to maintain operations when capacity revenues are coupled with energy and ancillary service revenues. Additionally, the Demand Curve mechanism is intended to attract new investment in generation in the locations in which it is needed most.

Due to transmission constraints, prices vary across the state and are generally higher in the Eastern part of New York, where our Roseton and Danskammer facilities are located, and in New York City. (Our Independence facility is located in the Northwest part of the state.) Current reserve margins of 24% are somewhat above the NYISO's target reserve margin of 18%. We believe that reserve margins are likely to return to target levels by 2009 to 2011.

Contracted Capacity. Approximately 70% of the Independence facility's capacity is obligated under a capacity sales agreement, which runs through 2014. Revenue from this capacity obligation is largely fixed with a variable discount that varies each month based on the price of power at Pleasant Valley LMP. Additionally, we supply steam from our Independence facility to a third party at a fixed yearly rate and supply up to 44 MW of fixed price energy to that third party under that agreement. For the uncommitted portion of our Northeast fleet, due to the standard capacity market operated by NYISO and liquid over-the-counter market for NYISO capacity products, we are able to sell substantially all of our capacity into the market each month. This provides for a steady stream of capacity revenues at market prices from our facilities both in the short-term and for the foreseeable future.

Environmental and Regulatory Considerations. Please read "—Regulatory and Environmental Matters" beginning on page 15 for discussion of the environmental and regulatory restrictions applicable to our business.

Power Generation—South Segment

Our South fleet comprises two natural gas-fired peaking facilities and two natural gas-fired cogeneration facilities totaling 1,547 MW of electric generating capacity. Key details of the South fleet are as follows:

Facility	Total Net Generating Capacity (MW)(1)	Primary Fuel Type	Dispatch Type	Location	NERC Region (ISO)
Calcasieu (2)	351	Gas	Peaking	Sulphur, LA	SERC
Heard County	539	Gas	Peaking	Heard Co., GA	SERC
Black Mountain (3)	43	Gas	Baseload	Las Vegas, NV	WECC
CoGen Lyondell	614	Gas	Baseload	Houston, TX	ERCOT (ISO)
Total South	*1,547*				

(1) Unit capacity values are based on winter capacity.
(2) On January 31, 2007, we entered into an agreement to sell our interest in the Calcasieu power generation facility to Entergy. Subject to regulatory approval, the transaction is expected to close in early 2008. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Calcasieu on page F-20 for further discussion.
(3) We own a 50% interest in this facility and the remaining 50% interest is held by Chevron. Total generating capacity of this facility is 85 MW.

South Fleet-SERC

Our Calcasieu and Heard County facilities are located in SERC. SERC territory includes all or portions of the states of Illinois, Missouri, Kentucky, Arkansas, Tennessee, West Virginia, Virginia, North Carolina, South Carolina, Louisiana, Mississippi, Alabama and Georgia.

Our South Fleet SERC assets are located within control areas of vertically integrated utilities and municipalities. All power sales and purchases are consummated between individual parties and are physically delivered either within or across control areas of the transmission owners. The present market framework in SERC is not a centralized market, and it is not expected that this region will transition to centralized competitive markets for energy and capacity in the foreseeable future.

The SERC region currently has surplus generation capacity, resulting from past competition among merchant plant developers, significantly exceeding SERC's estimated target reserve margin of approximately 15% to 17%. The overcapacity is concentrated in the Entergy and Southern sub-regions of SERC (where the Calcasieu and Heard County facilities are located). This overcapacity has historically depressed energy and capacity values in this region; this influence may continue until demand growth absorbs excess supply.

On January 31, 2007, we entered into an agreement to sell our interest in the Calcasieu power generation facility to Entergy. Subject to regulatory approval, the transaction is expected to close in early 2008. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Calcasieu on page F-20 for further discussion.

Contracted Capacity. Given the Southeast's regulated market structure, these two plants principally sell capacity to the local regulated utilities and energy and ancillary services through bilateral transactions with the utilities and wholesale buyers.

South Fleet-ERCOT

Our CoGen Lyondell facility is located in ERCOT, which comprises a majority of the state of Texas.

This market is administered by ERCOT ISO, which oversees competitive wholesale and retail markets. ERCOT's operations are overseen by the PUCT. ERCOT operates as the single control area within its region and operates energy markets for market participants. Price mitigation measures in ERCOT include a $1,000 per MWh offer cap. ERCOT is considering wholesale market design changes including LMP (similar to markets in MISO, NYISO and PJM) in response to a PUCT rule. Implementation details and timing of these market changes have not yet been finalized, but are expected in approximately 2009.

The ERCOT region currently has surplus generation capacity indicated by a NERC estimated 2006 reserve margin of 14%, exceeding ERCOT's target minimum reserve margin of 12.5%. This overcapacity has historically depressed energy and capacity values in this region. However, previously released reports from ERCOT indicate that reserve margins may fall below the 12.5% level by 2010 to 2013 due to announced generating retirements and mothballed units.

Contracted Capacity. Since its inception, the CoGen Lyondell facility has sold steam and 70 MW of capacity and energy to its site host, Lyondell Chemical Company, under long-term contracts which expired in December 2006. The steam and energy sales contracts were amended and extended beginning January 1, 2007. We sell up to 80 MW of capacity and energy and 1.5 million pounds per hour of steam for a base contract term from January 2007 through December 2021 and subsequent automatic rollover terms of two years each thereafter through as long as December 2046.

The balance of Cogen Lyondell's capacity and energy (approximately 534 MW) are sold through bilateral transactions or through the ERCOT daily market.

Environmental and Regulatory Considerations. During 2006, the Cogen Lyondell facility installed NO_x emissions reduction controls, at a cost of approximately $15 million, to satisfy Houston-area ozone rules. When the project is completed in 2007, at a total cost of approximately $23 million including interest on construction, the facility is expected to be in environmental compliance for the foreseeable future.

Please read "—Regulatory and Environmental Matters" beginning on page 15 for further discussion of the environmental and regulatory restrictions applicable to our business.

South Fleet Equity Investments

Black Mountain. Our Black Mountain plant is a PURPA QF located near Las Vegas, Nevada, in the WECC. Capacity and energy from this facility are sold to Nevada Power Company under a long-term PURPA QF contract.

Customer Risk Management

After the termination of the Sterlington tolling agreement on March 7, 2006, the CRM business primarily consists of a remaining power tolling arrangement relating to the Kendall facility, as well as our legacy physical natural gas supply contracts, natural gas transportation contracts and natural gas, power and emissions trading positions. A tolling arrangement is a contract whereby a generation owner sells rights to dispatch the unit at a defined heat rate and for terms and conditions provided for in the agreement while the owner continues to operate the facility. The buyer under a tolling arrangement generally provides fuel in accordance with dispatch instructions for the unit.

We mitigated the effect of the Kendall tolling arrangement through November 2008 by entering into a "back-to-back" power purchase agreement with a subsidiary of Constellation Energy Commodities Group, Inc. ("Constellation"), under which we receive payments which offset our obligations to the owner of the facility. Pursuant to this arrangement, we are obligated to make aggregate payments of approximately $416 million to the owner of the facility in exchange for access to power generated by the facility, resulting in a total obligation of $335 million, net of $81 million to be received from Constellation over the next 23 months. On September 14, 2006, we agreed to acquire the Kendall facility either through the planned acquisition of assets from the LS Entities or as a separate transaction. The Kendall tolling arrangement will become an intercompany obligation under our GEN-MW segment upon the closing of the transaction. As a result, the impact of the toll in the consolidated financial statements would be eliminated in consolidated results.

Legacy Marketing and Trading. Regarding our legacy natural gas, power and emission businesses, we have substantially reduced the size of our mark-to-market portfolio since October 2002, when we initiated our efforts to exit the CRM business.

Natural Gas—We have exited a significant portion of our physical and financial natural gas marketing and trading business and expect to have substantially exited this business by the end of 2007, with the exception of a minimal number of physical natural gas transactions that expire between 2010 and 2017. Many of our remaining transactions relate to the sale of natural gas to power plants, municipalities, and other industrial users in various regions across the U.S. along with financial contracts that hedge the price exposure inherent in those contracts. These remaining transactions still require cash payments to purchase natural gas for our customers; however, those cash requirements are partially offset by the proceeds received from financial contracts hedging the supply. We will continue our efforts to exit the remaining transactions as allowed by market liquidity, credit requirements, and market opportunities.

Power—We have substantially exited our remaining CRM power business, exclusive of the remaining power tolling arrangement in the segment with the exception of a minimum number of positions that will remain until 2010. These transactions primarily relate to past trading activity that was conducted in prior years for periods that have yet to mature. These transactions are accounted for on a mark-to-market basis and will continue to result in volatility in our statement of operations as prices change during the year. We will continue our efforts to exit the remaining transactions as allowed by market liquidity, credit requirements, and market opportunities.

Emissions—We have a forward obligation to deliver SO_2 emissions allowances through 2008. Our financial statements reflect the gain or loss on this obligation resulting from the price fluctuation in SO_2 emissions allowances. This obligation will be satisfied by our current inventory of physical SO_2 emissions allowances, and such inventory is valued at the lower of cost or market, in accordance with GAAP. Upon settlement of the forward obligation, we will recognize a gain to the extent that the delivery price is higher than the book value of our inventory. Upon delivery of the emissions allowances, we expect a positive cash flow as the third party makes payment for the emissions allowances. The inventory of emissions allowances that we use to fulfill this forward obligation is separate from the inventory and needs of our power generation business.

Other

Corporate

Other also includes corporate governance roles and functions, which are managed on a consolidated basis, and specialized support functions such as finance, accounting, risk control, tax, legal, human resources, administration and information technology. Corporate general and administrative expenses, income taxes and interest expenses, except for interest on borrowings incurred by our operating segments, are also included, as are corporate-related other income and expense items. Results for our discontinued global communications business are also included in this segment in periods where appropriate.

Natural Gas Liquids

Our natural gas liquids segment consisted of our midstream asset operations, located principally in Texas, Louisiana and New Mexico, and our North American natural gas liquids marketing business, all of which we sold in October 2005. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Discontinued Operations–Natural Gas Liquids beginning on page F-23 for further discussion.

Regulated Energy Delivery

Our regulated energy delivery segment consisted of our former Illinois Power Company subsidiary, which we sold in September 2004. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Sale of Illinois Power beginning on page F-21 for further discussion.

REGULATORY AND ENVIRONMENTAL MATTERS

Our business is subject to extensive federal, state and local laws and regulations governing the generation and sale of electricity.

Federal. Our ability to charge market-based rates for electricity, as opposed to cost-based rates, is governed by the FERC. We have been granted market-based rate authority for wholesale power sales from our exempt wholesale generator facilities, which include all of our facilities except CoGen Lyondell and Black Mountain. These two facilities are Qualifying Facilities, which have various exemptions from federal regulation and sell electricity directly to purchasers under power purchase agreements. Our market-based rate authority is predicated on FERC not finding the existence of market power for our facilities with market-based rates, and our next triennial market power review is currently scheduled for filing with the FERC in mid-2008. The FERC has adopted market behavior rules and regulations designed to prohibit energy market manipulation. A violation of these regulations could result in the revocation or suspension of our market-based rate authority, as well as refunds, disgorgement of profits and potential monetary penalties. Please read Note 18—Regulatory Issues beginning on page F-53 for further discussion.

State. Our business also is subject to regulation in the states where we operate. Proposed reforms to these regulations are pending in several states, including Illinois and New York. Please read "—Segment Discussion" beginning on page 7 for further discussion of these state regulations by segment.

Environmental, Health and Safety Matters

Our business is subject to extensive federal, state and local laws and regulations governing discharge of materials into the environment or otherwise relating to environmental, health and safety protection for our employees and communities. We are committed to operating within these regulations and to conducting our business in a safe and environmentally responsible manner. The regulatory landscape is subject to change and has become more stringent over time. Failure to acquire or maintain permits or to otherwise comply with applicable rules and regulations may result in fines and penalties. Additionally, the process for acquiring or maintaining permits or otherwise complying with applicable rules and regulations may require unprofitable or unfavorable operating conditions or significant capital and operating expenditures.

Our aggregate expenditures (both capital and operating) for compliance with laws and regulations related to the protection of the environment associated with our power generation fleet were approximately $60 million in 2006, compared to approximately $56 million in 2005 and approximately $25 million in 2004. The 2006 expenditures include approximately $21 million for consent decree projects and $8 million associated with the conversion of our Vermilion and Havana facilities to PRB coal, compared to $27 million in 2005 for the PRB coal conversion projects. We estimate that total environmental expenditures (both capital and operating) in 2007 will be approximately $110 million, including approximately $90 million for consent decree projects and approximately $15 million for O&M. These 2007 expenditures do not include approximately $10 million for several environmental mitigation projects that are also part of the DMG consent decree or amounts assumed as a result of the proposed Merger Agreement with the LS Entities. In 2007, the projected costs are associated primarily with enhanced air pollution controls and handling of combustion byproducts. Changes in environmental regulations or outcomes of litigation, the ongoing appeal of the New York State Pollution Discharge Elimination System (SPDES) Permit issued to Danskammer in June 2006 and the SPDES Permit renewal proceeding involving Roseton, could result in additional requirements that would necessitate increased future spending and potentially adverse operating conditions.

Ongoing and Future Environmental Initiatives. Current and proposed legislation and rulemaking contain requirements for further environmental control that we expect may result in substantial capital investments and operational costs. Sources of these ongoing and potential future requirements include:

- Legislative and regulatory proposals to adopt stringent controls on SO_2, NO_X and mercury emissions from coal-fired power plants;
- Clean Air Act requirements relating to air emissions, construction and operating permits and compliance certifications;
- Clean Water Act requirements to reduce impacts of water intake structures on aquatic species at certain of our power plants;
- Possible future requirements to reduce carbon dioxide emissions to address concerns about global warming; and
- The State of New York's consideration of a New Source Review rule that is more restrictive than the Federal New Source Review program, as it relates to routine maintenance, repair and replacement activities.

Following is a description of reasonably anticipated environmental initiatives for which we could incur significant expenditures, depending on the outcome.

Multi-Pollutant Air Emission Initiatives. In recent years, various federal and state legislative and regulatory multi-pollutant initiatives have been introduced. In early 2005, the EPA finalized several rules that would collectively require reductions of approximately 70% each in emissions of SO_2, NO_X and mercury from coal-fired electric generating units by 2015 (2018 for mercury).

The Clean Air Interstate Rule (CAIR) is intended to reduce SO_2 and NO_X emissions across the eastern United States (29 states and the District of Columbia) and address fine particulate matter and ground-level ozone National Ambient Air Quality Standards. The rule includes both seasonal and annual NO_X control programs as well as an annual SO_2 control program. A majority of our generating facilities will be subject to these programs. The compliance deadline for Phase I for the NO_X control program is in 2009; the SO_2 control program becomes effective in 2010. The final compliance phase begins in 2015. In April 2006, the U.S. EPA Administrator published a final rule that includes a federal implementation plan (FIP) to reduce transport of fine particulate matter and ozone. States may choose to develop their own NO_X requirements, within their respective state implementation plans, at least as stringent as the FIP, else the EPA will apply the FIP requirements to these states. Participation by states in the CAIR regional trading program is not mandatory.

The CAIR rule establishes a cap-and-trade program projected to reduce NO_X and SO_2 emissions by 61 percent and 73 percent, respectively, by 2018 and requires states to achieve the required reductions by adopting CAIR or state rules. The Illinois EPA has proposed a rule to implement the CAIR requirements that would require greater reductions in NO_X emissions from electric generators by setting aside 30 percent of the available NO_X emission allowances for energy efficiency and conservation projects, making the allowances unavailable to generators.

The U.S. EPA issued the Clean Air Mercury Rule (CAMR) for control of mercury emissions in March 2005 and, in December 2006, promulgated a backstop plan to ensure that power plants affected by the CAMR reduce their mercury emissions on schedule. CAMR establishes a cap-and-trade program that would reduce emissions of mercury from coal-fired power plants and, according to the EPA, the rule will reduce utility emissions of mercury from 48 tons per year to 15 tons per year by 2018, a reduction of nearly 70 percent from 1999 emission levels. The federal rule requires states to promulgate rules at least as stringent as CAMR. In December 2006 the Illinois Pollution Control Board approved a state rule that would require greater mercury emissions reductions and in a shorter time period than CAMR. The Illinois Rule will require additional capital and O&M expenditures at each of our Illinois coal-fired plants beginning in 2007. The state of New York has also approved a mercury rule that is more stringent than CAMR, and will likely require additional capital and operating costs.

We initially opposed the Illinois mercury rule because the schedule for implementation was considered impractical. In settling our opposition to the rule, we agreed to join with the Illinois Environmental Protection Agency in advancing a revised regulatory proposal that would significantly reduce mercury emissions but allow sufficient time to meet the emission limitation while making further reductions in emissions of sulfur dioxide, nitrogen oxides and particulate matter from the company's generation facilities. The rule approved by the Illinois Pollution Control Board in December 2006 included the revised proposal covering multiple pollutants, including mercury, NO_X and SO_2.

The Clean Air Visibility Rule (CAVR) addresses the requirement for states to analyze and include "Best Available Retrofit Technology" (BART) requirements for individual facilities in their state implementation plans to address regional haze, which rules are due by the end of 2008 with compliance expected five years later. The requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain regulated pollutants in specific industrial categories, including utility boilers. The record for the final rule contains an analysis that demonstrates that for electric generating units subject to CAIR, CAIR will generally result in more visibility improvements than BART would provide. Therefore, it may prove sufficient for states that adopt CAIR to substitute its requirements for BART controls otherwise required by SIPs under CAVR. In preparing their SIPs, states are required to do so in tandem with the recommendation of their state environmental Regional Planning Organizations, which may be more stringent than CAIR.

The Clean Air Act. The Clean Air Act and comparable state laws and regulations relating to air emissions impose responsibilities on owners and operators of sources of air emissions, including requirements to obtain construction and operating permits as well as compliance certifications and reporting obligations. The Clean Air Act requires that fossil-fueled plants have sufficient SO_2 and, in some regions NO_X emission allowances, as well as meet certain pollutant emission standards. Our electric generation facilities, some of which have changed their operations to accommodate new control equipment or changes in fuel mix, are presently in compliance with these requirements. In order to ensure continued compliance with the Clean Air Act and related rules and regulations, including ozone-related requirements, we have plans to install emission reduction technology and expect to incur a total capital expenditure of up to $7 million in 2007 pursuant to such plans.

Water Issues. Our water withdrawals and wastewater discharges are permitted under the Clean Water Act and analogous state laws. Section 316(b) of the Clean Water Act and comparable state water laws and regulations, require that the location, design, construction and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impact. The cooling water intake structures at four of our coal and one of our fuel oil-fired facilities in Illinois and New York are subject to this requirement.

The U.S. EPA issued rules in July 2004 establishing national standards aimed at protecting aquatic life at power generating facilities with existing cooling water intake structures. The rule requires a Comprehensive Demonstration Study (CDS) for each affected facility to provide information needed to determine necessary facility-specific modifications and cost estimates for implementation. The required studies are either underway or complete at all of the affected facilities, and the rule requires that final compliance plans be in place by January 2008. Once compliance measures are determined and approved by regulators, a facility may have several years to implement the measures. Due to the wide range of measures potentially applicable to a given facility, and since the final selection of compliance measures will be at least partially dependent upon the CDS information, we are not able to estimate our total fleet cost for complying with the rule at this time.

On January 25, 2007, the United States Court of Appeals for the Second Circuit remanded to the EPA a substantive portion of these rules, including EPA's determination of BTA for existing water intake structures. The Court's remand of the rule to EPA has created uncertainty concerning the performance standard and the schedule for implementing the requirement. Further appellate review of the rule may be pursued or EPA may revise the rule in accordance with the Court's opinion. The scope of requirements and the compliance methodologies allowed may become more restrictive, resulting in potentially significantly increased costs. In addition, the timing for compliance may be adjusted.

As with air quality, the requirements applicable to water quality are expected to increase in the future. A number of efforts are under way within the EPA to evaluate water quality criteria for parameters associated with the by-products of fossil fuel combustion. These parameters include arsenic, mercury and selenium. Significant changes in these criteria could impact discharge limits and could require our facilities to install additional water treatment equipment.

We are currently involved in an administrative proceeding in New York relating to the permit governing the cooling water intake structure at our Roseton facility. If the proceeding is resolved unfavorably to us, we could be required to expend material capital or to reduce plant operations. We have recently successfully completed similar administrative proceedings concerning our Danskammer facility resulting in a new permit Challenges to the new Danskammer permit by environmental groups that participated in the proceeding could result in material capital expenditures or reduced plant operations. For further discussion of these matters, please see Note 17—Commitments and Contingencies—Danskammer State Pollutant Discharge Elimination System Permit beginning on page F-48 and Note 17—Commitments and Contingencies—Roseton State Pollutant Discharge Elimination System Permit beginning on page F-49, respectively.

Global Climate Change. The international treaty relating to global warming (commonly known as the Kyoto Protocol) would have required reductions in emissions of greenhouse gases, primarily carbon dioxide and methane, by industry, including power generating facilities, if ratified by the United States. As an alternative to Kyoto, which became effective (without ratification by the United States) in February 2005, current U.S. policy regarding greenhouse gases favors voluntary reductions, increased operating efficiency, and continued research and technology development. Although several bills have been introduced in Congress that would compel reductions in carbon dioxide emissions, there are presently no federal mandatory greenhouse gas reduction requirements. The likelihood of any federal mandatory carbon dioxide emissions reduction program being adopted in the near future, and the specific requirements of any such program, is uncertain. However, a number of states where we operate power generation facilities in the Northeast and Midwest have proposed or are in the process of developing regulatory programs to manage greenhouse gas emissions. Please read "Multi-Pollutant Air Emission Initiatives" above for further discussion.

Any adoption by the federal or state governments of programs mandating a substantial reduction in greenhouse gas emissions could have far-reaching and significant impacts on the energy industry. Although we cannot predict the potential impact of such laws or regulations on our future financial condition, results of operations or cash flows, we will continue to monitor and participate in greenhouse gas policy developments in the regions in which we operate and will continue to assess and respond to the potential impact on our business operations.

Regional Greenhouse Gas Initiative. RGGI is a program under development by nine New England and Mid-Atlantic states to reduce carbon dioxide emissions from power plants through a cap and trade program. The state of New York has introduced, as a "pre-proposal", a rule that would require any fossil fuel fired electric generator larger than 25 MW to hold CO_2 emission allowances in the amount of its annual CO_2 emissions. The state would auction CO_2 emission allowances annually. The CO_2 emission allowances available for purchase by generators would be capped at approximately 64 million tons of CO_2 emissions. Affected generators would be required to purchase 100 percent of the carbon credits needed to operate their facilities through the auction process. The final program requirements of RGGI and subsequent impact to our operations are not known at this time, but the Northeast states currently intend to finalize carbon dioxide emissions requirements for electric generating facilities within the next few months.

Remedial Laws. We are also subject to environmental requirements relating to handling and disposal of toxic and hazardous materials, including provisions of CERCLA and RCRA and similar state laws. CERCLA imposes strict liability on persons that contributed to release of a "hazardous substance" into the environment. These persons include the current or previous owner and operator of a facility and companies that disposed, or arranged for disposal, of hazardous substances found at a contaminated facility. CERCLA also authorizes the

EPA and, in some cases, private parties to take actions in response to threats to public health or the environment and to seek recovery for costs of cleaning up hazardous substances that have been released and for damages to natural resources from responsible parties. Further, it is not uncommon for neighboring landowners and other affected parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. CERCLA or RCRA could impose remedial obligations at a variety of our facilities.

Additionally, the EPA may develop new regulations that impose additional requirements on facilities that store or dispose of non-hazardous fossil fuel combustion materials, including coal ash. If so, we and other similarly situated power generators may be required to change current waste management practices and incur additional capital expenditures to comply with these regulations.

As a result of their age, a number of our facilities contain quantities of asbestos-containing materials, lead-based paint, and/or other regulated materials. Existing state and federal rules require the proper management and disposal of these materials. We have developed a management plan that includes proper maintenance of existing non-friable asbestos installations and removal and abatement of asbestos-containing materials where necessary because of maintenance, repairs, replacement or damage to the asbestos itself.

Health and Safety Rules. Our operations are subject to requirements of the Occupational Safety and Health Administration (OSHA) and other comparable federal, state and provincial statutes. We have processes in place to identify and evaluate risk in order to ensure that non-compliances are detected and corrected in a timely manner. We believe we currently comply and expect to continue to comply in all material respects with applicable rules and regulations.

COMPETITION

Demand for power may be met by generation capacity based on several competing technologies, such as natural gas-fired, coal-fired or nuclear generation, as well as power generating facilities fueled by alternative energy sources, including hydro power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. Our power generation businesses in the Midwest, Northeast, and South compete with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities and other energy service companies. We believe that our ability to compete effectively in these businesses will be driven in large part by our ability to achieve and maintain a low cost of production, primarily by managing fuel costs, and to provide reliable service to our customers. We believe our primary competitors consist of at least 15 companies in the power generation business.

OPERATIONAL RISKS AND INSURANCE

We are subject to all risks inherent in the power generation business. These risks include, but are not limited to, equipment breakdowns or malfunctions, explosions, fires, terrorist attacks, product spillage, weather including hurricanes and tornados, nature including earthquakes and inadequate maintenance of rights-of-way, which could result in damage to or destruction of operating assets and other property, or could result in personal injury, loss of life or pollution of the environment, as well as curtailment or suspension of operations at the affected facility. We maintain general public liability, property/boiler and machinery, and business interruption insurance in amounts that we consider to be appropriate for such risks. Such insurance is subject to deductibles and caps that we consider reasonable and not excessive given the current insurance market environment. The costs associated with these insurance coverages have been volatile during recent periods, and may continue to be so in the future. The occurrence of a significant event not fully insured or indemnified against by a third party, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. While we currently maintain levels and types of insurance that we believe to be prudent under current insurance industry market conditions, our potential inability to secure these levels and types of insurance in the future could negatively impact our business operations and financial stability, particularly if an uninsured loss were to occur. No assurance can be given that we will be able to maintain these levels of insurance in the future at rates we consider commercially reasonable.

We also face market, price, credit and other risks relative to our business. Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk beginning on page 81 for further discussion of these risks.

In addition to these operational risks, we also face the risk of damage to our reputation and financial loss as a result of inadequate or failed internal processes and systems. A systems failure or failure to enter a transaction properly into our records and systems may result in an inability to settle a transaction in a timely manner or cause a contract breach. Our inability to implement the policies and procedures that we have developed to minimize these risks could increase our potential exposure to damage to our reputation and to financial loss. Please read Item 9A. Controls and Procedures beginning on page 84 for further discussion of our internal control systems.

SIGNIFICANT CUSTOMERS

For the year ended December 31, 2006, approximately 23%, 19% and 18% of our consolidated revenues were derived from transactions with AmerenIP, MISO and NYISO, respectively. For the year ended December 31, 2005, approximately 26% and 20% of our consolidated revenues were derived from transactions with NYISO and AmerenIP, respectively. For the year ended December 31, 2004, approximately 13% of our consolidated revenues were derived from transactions with NYISO. No other customer accounted for more than 10% of our consolidated revenues during 2006, 2005 or 2004.

EMPLOYEES

At December 31, 2006, we had approximately 348 employees at our administrative offices and approximately 991 employees at our operating facilities. Approximately 640 employees at Dynegy-operated facilities are subject to collective bargaining agreements with various unions that expire in June 2007 (Midwest) and in February 2008 (Northeast). We believe relations with our employees are satisfactory.

Item 1A. ***Risk Factors***

Forward-Looking Statements

This Form 10-K includes statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward-looking statements". All statements included or incorporated by reference in this annual report, other than statements of historical fact, that address activities, events or developments that we or our management expect, believe or anticipate will or may occur in the future are forward-looking statements. These statements represent our reasonable judgment on the future based on various factors and using numerous assumptions and are subject to known and unknown risks, uncertainties and other factors that could cause our actual results and financial position to differ materially from those contemplated by the statements. You can identify these statements by the fact that they do not relate strictly to historical or current facts. They use words such as "anticipate," "estimate", "project", "forecast", "plan," "may", "will", "should", "expect" and other words of similar meaning. In particular, these include, but are not limited to, statements relating to the following:

- expectations and beliefs related to the combination with the LS Entities, including satisfying closing conditions and obtaining shareholder approval;
- anticipated benefits and expected synergies resulting from the combination with the LS Entities and beliefs associated with the integration of operations of both companies;
- projected operating or financial results, including anticipated cash flows from operations, revenues and profitability;
- expectations regarding capital expenditures, interest expense and other payments;
- beliefs and assumptions about economic conditions and the demand and prices for electricity;
- beliefs about commodity pricing and generation volumes;
- our focus on safety and our ability to efficiently operate our assets so as to maximize our revenue generating opportunities;
- strategies to capture opportunities presented by rising commodity prices and strategies to manage our exposure to energy price volatility;
- plans to achieve fuel-related, general and administrative, and other targeted cost savings;
- beliefs and assumptions relating to liquidity, including the ability to satisfy or refinance debt maturities and other obligations before or as they come due;
- strategies to address our substantial leverage, to access the capital markets, or to obtain additional financing on more favorable financing terms;
- measures to compete effectively with industry participants;
- beliefs and assumptions about market competition, fuel supply, power demand, generation capacity and regional recovery of the wholesale power generation market;
- sufficiency of coal and fuel oil inventories and transportation, including strategies to deploy coal supplies;
- beliefs about the outcome of legal, regulatory, administrative and environmental matters;
- expectations regarding environmental matters, including costs of compliance and availability and adequacy of emission credits;
- expectations and estimates regarding the DMG consent decree and the associated costs;
- positioning our power generation business for future growth and pursuing and executing acquisition, disposition or combination opportunities; and
- measures to complete the exit from the customer risk management business and the costs associated with this exit.

Any or all of our forward-looking statements may turn out to be wrong. They can be affected by inaccurate assumptions or by known or unknown risks, uncertainties and other factors, many of which are beyond our control, including those set forth below.

Factors That May Affect Future Results

Risks Related to Our Business

The Merger Agreement with the LS Entities and related transactions, regardless of whether they are ultimately consummated, have presented and will continue to present us with certain risks and uncertainties, and have imposed and will continue to impose on us and our business and operations certain restrictions and significant financial and other costs. In addition, if the Merger Agreement and related transactions are ultimately consummated, the expected benefits of the Merger Agreement and related transactions may not be realized in a timely or efficient manner or at all, and the LS Entities, by virtue of their stock ownership of New Dynegy, will have significant influence over New Dynegy's business and operations and may have interests that differ from, and conflict with, the interests of our other shareholders.

The consummation of the Merger Agreement with the LS Entities and related transactions is subject to the approval of our shareholders. We cannot assure you that we will receive the approval of our shareholders in a timely manner or at all and, as a result, we cannot assure you that the Merger Agreement and related transactions will be consummated in a timely manner or at all. Moreover, a substantial delay in obtaining the approval of our shareholders could have a material adverse effect on our and/or New Dynegy's business, financial condition and results of operations and may cause us and/or the LS Entities to abandon the Merger Agreement and related transactions. In addition, the Merger Agreement restricts us, without the LS Entities' consent, from taking certain specified actions until the Merger Agreement is consummated or terminated. These restrictions may prevent us from pursuing otherwise attractive business opportunities and effecting other beneficial transactions and changes to our business and operations prior to the consummation or termination of the Merger Agreement.

We entered into the Merger Agreement with the LS Entities with the expectation that the combination of our business and operations with the business and operations of the power generation entities to be contributed by the LS Entities pursuant to the Merger Agreement would result in various benefits, including, among other things, certain synergies, cost savings and operating efficiencies. We cannot assure you that such benefits will be realized in a timely manner, in full or at all.

In addition, we have incurred and expect to continue to incur significant costs in connection with consummating the Merger Agreement and related transactions. We also expect to incur, upon the consummation of the Merger Agreement and related transactions, costs in connection with integrating our operations and procedures with the operations and procedures of the power generation entities to be contributed by the LS Entities. Moreover, we cannot assure you that the anticipated synergies, cost savings and operating efficiencies related to the integration of our business with that of the power generation entities to be contributed by the LS Entities will offset these costs over time, in a timely manner, in full or at all.

If the Merger Agreement and related transactions are consummated, we will face significant challenges in integrating our operations and procedures with the operations and procedures of the power generation entities to be contributed by the LS Entities. As a result, we cannot assure you that the integration will be completed in a timely or efficient manner. In addition, such integration efforts could also divert our management's focus and resources from our and, subsequent to the consummation of the Merger Agreement, New Dynegy's day-to-day business and operations. Such diversion of our management's focus and resources could have a material and adverse effect on our and, subsequent to the consummation of the Merger Agreement, New Dynegy's business, financial condition and results of operations.

Furthermore, subsequent to the consummation of the Merger Agreement and related transactions, the LS Entities will own approximately 40% of the voting power of New Dynegy and will have the right to nominate up to three members of the 11-member board of directors of New Dynegy. By virtue of such stock ownership and board representation, the LS Entities will have the power to influence New Dynegy's affairs as well as the outcome of matters submitted to a vote of New Dynegy's stockholders. Moreover, the LS Entities may have interests that differ from, and conflict with, those of our other shareholders, who will be holders of New Dynegy's common stock upon the consummation of the Merger Agreement and related transactions.

Our growth strategy may include acquisitions or combinations that could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to realize anticipated benefits of those transactions.

Our growth strategy may include acquiring or combining with other businesses, such as the power generation facility acquisitions we propose to make pursuant to the Merger Agreement. We may not be able to identify suitable acquisition or combination opportunities or finance and complete any particular acquisition or combination successfully. Furthermore, acquisitions and combinations involve a number of risks and challenges, including:

- diversion of management's attention;
- the need to integrate acquired or combined operations;
- potential loss of key employees;
- difficulty in evaluating the power assets, operating costs, infrastructure requirements, environmental and other liabilities, and other factors beyond our control;
- potential lack of operating experience in new geographic/power markets;
- an increase in our expenses and working capital requirements; and
- the possibility that we may be required to issue a substantial amount of additional equity securities or incur additional debt to finance any such transactions.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows or realize synergies or other anticipated benefits from a strategic transaction. Furthermore, the market for transactions is highly competitive, which may adversely affect our ability to find transactions that fit our strategic objectives. In pursuing our strategy, consistent with industry practice, we routinely engage in discussions with industry participants regarding potential transactions, large and small. We intend to continue to engage in strategic discussions and we will need to respond to potential opportunities quickly and decisively. As a result, strategic transactions may occur at anytime and may be significant in size relative to our assets and operations.

Because many of our power generation facilities operate mostly without term power sales agreements and because wholesale power prices are subject to significant volatility, our revenues and profitability are subject to significant fluctuations.

Most of our facilities operate as "merchant" facilities without term power sales agreements. Without term power sales agreements, we cannot be sure that we will be able to sell any or all of the electric energy, capacity or ancillary services from our facilities at commercially attractive rates or that our facilities will be able to operate profitably. This could lead to decreased financial results as well as future impairments of our property, plant and equipment or to the retirement of certain of our facilities resulting in economic losses and liabilities.

Because we largely sell electric energy, capacity and ancillary services into the wholesale energy spot market or into other power markets on a term basis, we are not guaranteed any rate of return on our capital investments. Rather, our financial condition, results of operations and cash flows are likely to depend, in large part, upon prevailing market prices for power and the fuel to generate such power. Wholesale power markets are subject to significant price fluctuations over relatively short periods of time and can be unpredictable.

Given the volatility of power commodity prices, to the extent we do not secure term power sales agreements for the output of our power generation facilities, our revenues and profitability will be subject to increased volatility, and our financial condition, results of operations and cash flows could be materially adversely affected.

Our hedging activities will not fully protect us from exposure to commodity price risks, and we are vulnerable to decreases in power prices and increases in the price of natural gas, coal and oil. To the extent we do engage in hedging activities, our models representing the market may be inaccurate.

Since a substantial portion of our production capacity may not be hedged and is thus subject to commodity price risks, we have the potential to receive higher or lower prices for capacity, energy and ancillary services resulting in volatile revenue and cash flow. To the extent that our generated power is not subject to a power purchase agreement or similar arrangement, we generally will pursue sales of such generated power based on current market prices. Where forward sales are not executed, we will be impacted by changes in commodity prices, and, in an environment where fuel costs increase and power prices decrease, our financial condition, results of operations and cash flows may be materially adversely affected. In those instances where we do execute forward sales or related financial transactions, our internal models may not accurately represent the markets in which we participate, potentially causing us to make less favorable decisions.

Unauthorized hedging and related activities by our employees could result in significant losses.

We intend to continue our commercial strategy, which emphasizes forward power sales opportunities to capture attractive market prices in the near-term. We have adopted various internal policies and procedures designed to monitor hedging activities and positions. These policies and procedures are designed, in part, to prevent unauthorized purchases or sales of products by our employees. We cannot assure, however, that these steps will detect and prevent all violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. A significant policy violation that is not detected could result in a substantial financial loss for us.

We are exposed to the risk of fuel and fuel transportation cost increases and interruptions in fuel supplies because some of our facilities do not have long-term coal, natural gas or liquid fuel supply agreements.

Many of our power generation facilities, specifically those that are natural gas-fired, purchase their fuel requirements under short-term contracts or on the spot market. As a result, we face the risks of supply interruptions and fuel price volatility, as fuel deliveries may not exactly match that required for energy sales, due in part to our need to pre-purchase fuel inventories for reliability and dispatch requirements.

Moreover, operation of many of our coal-fired generation facilities is highly dependent on our ability to procure coal. Although we have long-term contracts in place for our coal and coal transportation needs, power generators in the Midwest and the Northeast have experienced significant pressures on available coal supplies that are either transportation or supply related. If we are unable to procure fuel for physical delivery at prices we consider favorable, our financial condition, results of operations and cash flows could be materially adversely affected.

Availability and cost of emission credits could materially impact our costs of operations.

We are required to maintain, either by allocation or purchase, sufficient emission credits to support our operations in the ordinary course of operating our power generation facilities. These credits are used to meet our obligations imposed by various applicable environmental laws. If our operational needs require more than our allocated allowances of emission credits, we may be forced to purchase such credits on the open market, which could be costly. If we are unable to maintain sufficient emission credits to match our operational needs, we may have to curtail our operations so as not to exceed our available emission credits, or install costly new emissions controls. As we use the emissions credits that we have purchased on the open market, costs associated with such purchases will be recognized as operating expense. If such credits are available for purchase, but only at significantly higher prices, the purchase of such credits could materially increase our costs of operations in the affected markets.

Competition in wholesale power markets, together with an oversupply of power generation capacity in certain regional markets, may have a material adverse effect on our financial condition, results of operations and cash flows.

We have numerous competitors and additional competitors may enter the industry. Our power generation business competes with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities and other energy service companies in the sale of energy, as well as in the procurement of fuel, transmission and transportation services. Moreover, aggregate demand for power may be met by generation capacity based on several competing technologies, as well as power generating facilities fueled by alternative or renewable energy sources, including hydroelectric power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. Regulatory initiatives designed to enhance renewable generation could increase competition from these types of facilities. In addition, a buildup of new electric generation facilities in recent years has resulted in an abundance of power generation capacity in certain regional markets we serve.

We also compete against other energy merchants on the basis of our relative operating skills, financial position and access to credit sources. Energy customers, wholesale energy suppliers and transporters often seek financial guarantees, credit support such as letters of credit, and other assurances that their energy contracts will be satisfied. Companies with which we compete may have greater resources in these areas. In addition, many of our current facilities are relatively old. Newer plants owned by competitors will often be more efficient than some of our plants, which may put some of our plants at a competitive disadvantage. Over time, some of our plants may become obsolete in their markets, or be unable to compete, because of the construction of new, more efficient plants.

Other factors may contribute to increased competition in wholesale power markets. New forms of capital and competitors have entered the industry in the last several years, including financial investors who perceive that asset values are at levels below their true replacement value. As a result, a number of generation facilities in the United States are now in the hands of lenders and investment companies. Furthermore, mergers and asset reallocations in the industry could create powerful new competitors. Under any scenario, we anticipate that we will face competition from numerous companies in the industry, some of which have superior capital structures.

Moreover, many companies in the regulated utility industry, with which the wholesale power industry is closely linked, are also restructuring or reviewing their strategies. Several of those companies have discontinued or are discontinuing their unregulated activities and seeking to divest their unregulated subsidiaries. Some of those companies have had, or are attempting to have, their regulated subsidiaries acquire assets out of their or other companies' unregulated subsidiaries. This may lead to increased competition between the regulated utilities and the unregulated power producers within certain markets. The future of the wholesale power generation industry is unpredictable, but may include restructuring and consolidation within the industry, the sale, bankruptcy or liquidation of certain competitors, the re-regulation of certain markets or a long-term reduction in new investment into the industry. To the extent that competition increases, our financial condition, results of operations and cash flows may be materially adversely affected.

The regional concentration of our business in the Midwest may increase the effects of adverse trends in that market.

A substantial portion of our business is located in the Midwest region of the United States. Changes in economic conditions in this market, including changing demographics, or oversupply of or reduced demand for power, could have a material adverse effect on our financial condition, results of operations and cash flows. A substantial portion of our net income is derived from our Baldwin facility. Any disruption of production at that facility could have a material adverse effect on our financial condition, results of operations and cash flows.

Under the terms of the power purchase agreement with AmerenIP, which expired at the end of 2006, our Midwest coal plants were partially contracted to AmerenIP at a fixed price per megawatt hour. For the year ended December 31, 2006, approximately 23% of our consolidated revenues were derived from transactions with AmerenIP. Currently, our results in the Midwest are exposed to volatility in market prices which could cause us to realize losses in a weak power price environment.

We depend on transmission facilities operated by RTOs and ISOs, which could result in an inability to sell and deliver power to the market that may, in turn, adversely affect the profitability of our generation facilities.

Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") have emerged in most of the markets in which we operate and compete. The RTOs and ISOs provide transmission services, administer transparent and competitive power markets and maintain system reliability. Many of these RTOs and ISOs operate real-time and day-ahead markets in which we sell energy. We may be affected by changes in market rules, tariffs, market structures, administrative fee allocations and market bidding rules in these RTOs and ISOs. The ISOs or RTOs that oversee most of the wholesale power markets impose, and in the future may continue to impose, price limitations, offer caps and other mechanisms to guard against the potential exercise of market power in these markets. These types of price limitations and other regulatory mechanisms may adversely affect the profitability of our generation facilities that sell energy and capacity into the wholesale power markets.

We do not own, control or set the rates for the transmission facilities we use to deliver energy, capacity and ancillary services to our customers. In addition, transmission capacity may not be available to us, the total costs of transmission may exceed our projections or cause us to forego transactions, and changes in the transmission grid could reduce our revenues.

We do not own or control the transmission facilities required to sell the wholesale power from our generation facilities. If the transmission service from these facilities is unavailable or disrupted, or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be materially adversely affected. Furthermore, the rates for transmission capacity from these facilities are set by others and the market and thus are subject to changes, some of which could be significant. Moreover, changes in the transmission infrastructure within or connecting individual markets could reduce prices in those markets by increasing the amount of generating capacity competing to serve the same markets. As a result, our business financial condition, cash flows and results of operations may be materially adversely affected.

An event of loss and certain other events relating to our Dynegy Northeast Generation facilities could trigger a substantial obligation that would be difficult for us to satisfy.

We acquired the DNE power generating facilities in January 2001 for $950 million. In May 2001, we entered into an asset-backed sale-leaseback transaction relating to these facilities to provide us with long-term acquisition financing. In this transaction, we sold four of the six generating units comprising these facilities for approximately $920 million to Danskammer OL LLC and Roseton OL LLC, and we concurrently agreed to lease them back from these entities. We have no option to purchase the leased facilities at Roseton or Danskammer at the end of their lease terms, which end in 2035 and 2031, respectively. If one or more of the leases were to be terminated prior to the end of its term because of an event of loss, because it becomes illegal for us to comply with the lease, or because a change in law makes the facility economically or technologically obsolete, we would be required to make a termination payment in an amount sufficient to redeem the pass-through trust certificates related to the unit or facility for which the lease is terminated. As of December 31, 2006, the termination payment would be approximately $1 billion for all of our DNE facilities. It could be difficult for us to raise sufficient funds to make this termination payment if a termination of this type were to occur with respect to the DNE facilities, resulting in a material adverse effect on our financial conditions, results of operations, liquidity or cash flows.

Our business is subject to complex government regulation. Changes in these regulations or in their implementation may affect costs of operating our facilities or our ability to operate our facilities or increase competition, any of which may negatively impact our results of operations.

We are subject to extensive federal, state and local laws and regulations governing the generation and sale of energy commodities, as well as discharge of materials into the environment and otherwise relating to the environment and public health and safety in each of the jurisdictions in which we will have operations. Compliance with these laws and regulations requires expenses (including legal representation) and monitoring, capital and operating expenditures, including those related to pollution control equipment, emission credits, remediation obligations and permitting at various operating facilities. Furthermore, these regulations are subject to change at any time, and we cannot predict what changes may occur in the future or how such changes might affect any facet of our business.

The costs and burdens associated with complying with the increased number of regulations may have a material adverse effect on us, if we fail to comply with the laws and regulations governing our business or if we fail to maintain or obtain advantageous regulatory authorizations and exemptions. Moreover, increased competition resulting from potential legislative changes, regulatory changes or other factors may create greater risks to the stability of our power generation earnings and cash flows generally. We could suffer erosion in market position, revenues and profits as competitors gain access to the service territories of our power generation subsidiaries.

Our costs for compliance with existing environmental laws are significant, and costs for compliance with new environmental laws could adversely affect our financial condition, results of operations and cash flows.

Our business is subject to extensive and frequently changing environmental regulation by federal, state and local authorities. Such environmental regulation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances into the environment. Existing environmental laws and regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us or our facilities, litigation or regulatory or enforcement proceedings could be commenced and future changes in environmental laws and regulations could occur, including potential regulatory and enforcement developments related to air emissions. Proposals currently under consideration could, if and when adopted or enacted, require us to make substantial capital and operating expenditures. If any of these events occur, our business, operations and financial condition could be materially adversely affected.

Moreover, many environmental laws require approvals or permits from governmental authorities for the operation of a power generation facility, before construction or modification of a project may commence or before wastes or other materials may be discharged into the environment. The process for obtaining necessary permits can be lengthy and complex and can sometimes result in the establishment of permit conditions that make the project or activity for which the permit was sought unprofitable or otherwise unattractive. Even where permits are not required, compliance with environmental laws and regulations can require significant capital and operating expenditures. We are required to comply with numerous environmental laws and regulations, and to obtain numerous governmental permits when we construct, modify and operate our facilities. In addition, certain of our facilities are also required to comply with the terms of consent decrees or other governmental orders.

With the continuing trend toward stricter standards, greater regulation and more extensive permitting requirements, our capital and operating environmental expenditures are likely to be substantial and may increase in the future. We may not be able to obtain or maintain all required environmental regulatory permits or other approvals that we need to operate our business. If there is a delay in obtaining any required environmental regulatory approvals or permits, or if we fail to obtain or comply with any required approval or permit, the operation of our facilities may be interrupted or become subject to additional costs and, as a result, our business, financial condition, results of operations and cash flows could be materially adversely affected.

Different regional power markets in which we compete or may compete in the future have changing transmission regulatory structures, which could materially adversely affect our performance in these regions.

Our financial condition, results of operations and cash flows are likely to be affected by differences in market and transmission regulatory structures in various regional power markets. Problems or delays that may arise in the formation and operation of new or maturing RTOs and similar market structures, or changes in geographic scope, rules or market operations of existing RTOs, may affect our ability to sell, the prices we receive for, or the cost to transmit power produced by our generating facilities. Rules governing the various regional power markets may also change from time to time, which could affect our costs or revenues. We are unable to assess fully the impact that these uncertainties may have on our business, as it remains unclear which companies will be participating in the various regional power markets, or how RTOs will develop or what regions they will cover.

Our financial condition, results of operations and cash flows could be adversely impacted by strikes or work stoppages by our unionized employees.

A majority of the employees at our facilities are subject to collective bargaining agreements with various unions that expire in 2007 and 2008. If union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strife or disruption, we could experience reduced power generation or outages if replacement labor is not procured. The ability to procure such replacement labor is uncertain. Strikes, work stoppages or an inability to negotiate future collective bargaining agreements on favorable terms could have a material adverse effect on our financial condition, results of operations and cash flows.

In the past, we have reported material weaknesses in our internal control over financial reporting and may identify material weaknesses in the future that could adversely affect investor confidence and impair the value of our common stock.

In connection with our management's assessments of the effectiveness of our internal control over financial reporting as of December 31, 2004 and 2005 and September 30, 2006, our management concluded that, as of such dates, we did not maintain effective internal control over our financial reporting due to a material weakness in our processes, procedures and controls related to the preparation, analysis and recording of the income tax provision. These control deficiencies have resulted in the restatement of our 2005, 2004 and 2003 annual consolidated financial statements. In addition, our management concluded that, as of September 30, 2006, we did not maintain effective internal control over our financial reporting due to a material weakness in our processes, procedures and controls related to the calculation and analysis of our risk management asset and liability balances. This material weakness resulted in an adjustment to our condensed consolidated financial statements as of and for the three months ended March 31, 2006 prior to being reported in our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006. As further described in Item 9A "Controls and Procedures," we remediated both material weaknesses during 2006 and determined that our internal control over financial reporting was effective as of December 31, 2006. However, despite the remedial measures that we implemented and our continuing efforts to improve our internal control over our financial reporting, we may not be able to implement and maintain effective internal control over our financial reporting in the future. Moreover, we have experienced from time to time deficiencies in our internal control over our financial reporting that have not risen to the level of a material weakness. Although we have been able to remediate these deficiencies in the past, we cannot assure you that a material weakness will not exist in the future, as additional deficiencies in our internal control over our financial reporting may be discovered which may rise to the level of a material weakness.

Any failure to remedy additional deficiencies in our internal control over our financial reporting that may be discovered in the future or to implement new or improved controls, or difficulties encountered in the implementation of such controls, could cause us to fail to meet our reporting obligations or result in material misstatements in our financial statements. Any such failure could, in turn, affect the future ability of our management to certify that our internal control over our financial reporting is effective and, moreover, affect the results of our independent registered public accounting firm's attestation report regarding our management's assessment. Inferior internal control over our financial reporting could also subject us to the scrutiny of the SEC, the New York Stock Exchange (on which our Class A common stock is listed and traded) and other regulatory bodies and could cause investors to lose confidence in our reported financial information, which could have an adverse effect on the trading price of our common stock.

The ultimate outcome of unresolved legal proceedings and investigations relating to our past activities cannot be predicted. Any adverse determination could have a material adverse effect on our financial condition, results of operations and cash flows.

We are, or have in recent years been, a party to various material litigation matters and regulatory matters arising out of our business operations. These matters include, among other things, certain actions and investigations by the FERC and related regulatory bodies, litigation with respect to alleged actions in the western power and natural gas markets, purported class action suits with respect to alleged violations of the Employment Retirement Income Security Act of 1974 and various other matters. The ultimate outcome of pending matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome in each case reasonably be estimated.

Risks Related to Investing in Our Common Stock

If we issue a material amount of our common stock in the future or certain of our stockholders sell a material amount of our common stock, our ability to use our federal net operating losses to offset our future taxable income may be limited under Section 382 of the Internal Revenue Code.

Our ability to utilize previously incurred federal net operating losses (NOLs) to offset future taxable income would be limited if we were to undergo an "ownership change" within the meaning of Section 382 of the Internal Revenue Code (the "Code"). In general, an "ownership change" occurs whenever the percentage of the stock of a corporation owned by "5-percent shareholders" (within the meaning of Section 382 of the Code) increases by more than 50 percentage points over the lowest percentage of the stock of such corporation owned by such "5-percent shareholders" at anytime over the preceding three years. Under certain circumstances, sales or dispositions of our common stock by Chevron, or other stockholders could trigger an "ownership change", and we will have limited control over the timing of any such sales or dispositions of our common stock. Any such future ownership change could result in limitations, pursuant to Section 382 of the Code, on our utilization of federal NOLs to offset our future taxable income.

More specifically, depending on prevailing interest rates and our market value at the time of such future ownership change, an ownership change under Section 382 of the Code would establish an annual limitation which might prevent full utilization of the deferred tax assets attributable to our previously incurred federal NOLs against the total future taxable income of a given year. The proposed Merger Agreement with the LS Entities will increase the likelihood that previously incurred federal NOLs will become subject to the limitations set forth in Section 382 of the Code. If such an ownership change were to occur, our and, subsequent to the consummation of the Merger Agreement and related transactions (if consummated), New Dynegy's ability to raise additional equity capital may be limited.

The magnitude of such limitations and their effect on us and, subsequent to the consummation of the Merger Agreement with the LS Entities and related transactions (if consummated), their effect on New Dynegy, is difficult to assess and depends in part on our or New Dynegy's (as the case may be) value at the time of any such ownership change and prevailing interest rates. For accounting purposes, at December 31, 2006, our net operating loss deferred tax asset attributable to our previously incurred federal NOLs was valued at approximately $332 million.

The payment of dividends on our common stock is restricted and, moreover, subject to the discretion of our Board of Directors.

The financing agreements under which certain of our subsidiaries are borrowers and we are guarantors contain certain restrictions on the payment of dividends on our Class A common stock. Moreover, even if permitted under our financing agreements, dividend payments on our Class A common stock will be at the discretion of our Board of Directors. We have not paid a dividend on any class of our common stock since 2002.

We have significant debt that could negatively impact our business, and our credit ratings are less than investment grade.

We are highly leveraged, and have pledged substantially all of our assets to secure our debt. We have total debt of $3.3 billion at December 31, 2006. Our significant level of debt could:

- make it difficult to satisfy our financial obligations, including debt service requirements;
- limit our ability to obtain additional financing to operate our business;
- limit our financial flexibility in planning for and reacting to business and industry changes;
- impact the evaluation of our creditworthiness by counterparties to commercial agreements and affect the level of collateral we are required to post under such agreements;
- place us at a competitive disadvantage compared to less leveraged companies;
- increase our vulnerability to general adverse economic and industry conditions, including changes in interest rates and volatility in commodity prices; and
- require us to dedicate a substantial portion of our cash flows to payments on our debt, thereby reducing the availability of our cash flow for other purposes including our operations, capital expenditures and future business opportunities.

We may incur additional indebtedness as part of completing the Merger Agreement and related transactions in the future. If new debt is added to our current debt levels, the related risks that we face could increase significantly.

Our access to the capital markets may be limited.

We are a highly leveraged company with near-term capital needs; we may also require additional capital from time to time beyond the near-term. Unlike those companies in the power generation industry that are "investment grade" and for which the capital markets are typically open, our access to the capital markets may be limited. Moreover, the timing of any capital-raising transaction may be impacted by unforeseen events, such as strategic growth opportunities, legal judgments or regulatory requirements, which could require us to pursue additional capital in the near-term. Our ability to obtain capital and the costs of such capital are dependent on numerous factors, including:

- general economic and capital market conditions;
- covenants in our existing debt and credit agreements;
- credit availability from banks and other financial institutions;
- investor confidence in us and the regional wholesale power markets;
- our financial performance and the financial performance of our subsidiaries;
- our levels of indebtedness;
- our requirements for posting collateral under various commercial agreements;

- our maintenance of acceptable credit ratings;
- our cash flow;
- provisions of tax and securities laws that may impact raising capital; and
- our long-term business prospects.

We may not be successful in obtaining additional capital for these or other reasons. An inability to access capital may limit our ability to pursue development projects, plant improvements or acquisitions that we may rely on for future growth and to comply with regulatory requirements and, as a result, may have a material adverse effect on our financial condition, results of operations and cash flows, and on our ability to execute our business strategy.

The interests of Chevron may conflict with your interests.

At December 31, 2006, Chevron owned approximately 19.4% of the voting power of Dynegy (assuming conversion of all of the Class B common stock beneficially owned by Chevron). By virtue of such stock ownership, Chevron has the power to influence our affairs and the outcome of matters required to be submitted to stockholders for approval.

Item 1B. ***Unresolved Staff Comments***

Not applicable.

Item 2. ***Properties***

We have included descriptions of the location and general character of our principal physical operating properties by segment in "Item 1. Business" beginning on page 1. Those descriptions are incorporated herein by this reference. Substantially all of our assets, including the power generation facilities we own, are pledged as collateral to secure the repayment of, and our other obligations under, the Fourth Amended and Restated Credit Facility (first lien) and the 8.375% Senior Unsecured Notes due 2016 issued by DHI (second lien). Please read Note 12—Debt beginning on page F-36 for further discussion.

Our principal executive office located in Houston, Texas is held under a lease that expires in December 2017 as a result of an extension signed in 2006. We also lease additional offices or warehouses in the states of California, Colorado, Illinois, Indiana, New York and Texas.

Item 3. ***Legal Proceedings***

For a description of our material legal proceedings, please read Note 17—Commitments and Contingencies beginning on page F-47, which is incorporated herein by reference.

Item 4. ***Submission of Matters to a Vote of Security Holders***

No matter was submitted to a vote of our security holders during the fourth quarter 2006.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Our Class A common stock, no par value per share, is listed and traded on the New York Stock Exchange under the ticker symbol "DYN". The number of stockholders of record of our Class A common stock as of February 22, 2007, based upon records of registered holders maintained by our transfer agent, was 19,389.

Our Class B common stock, no par value per share, is neither listed nor traded on any exchange. All of the shares of Class B common stock are owned by Chevron.

The following table sets forth the high and low closing sales prices for the Class A common stock for each full quarterly period during the fiscal years ended December 31, 2006 and 2005 and during the elapsed portion of our first fiscal quarter of 2007 prior to the filing of this Form 10-K, as reported on the New York Stock Exchange Composite Tape.

Summary of Dynegy's Common Stock Price

	High	Low
2007:		
First Quarter (through February 22, 2007)	$8.08	$6.52
2006:		
Fourth Quarter	$7.24	$5.36
Third Quarter	6.34	5.09
Second Quarter	5.47	4.68
First Quarter	5.72	4.72
2005:		
Fourth Quarter	$5.07	$4.15
Third Quarter	5.63	4.35
Second Quarter	5.10	3.23
First Quarter	4.75	3.62

During the fiscal years ended December 31, 2006 and 2005, our Board of Directors did not elect to pay a common stock dividend. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Dividends on Common Stock" on page 52 for further discussion of our dividend policy and the impact of dividend restrictions contained in our financing agreements. Any decision to pay a dividend will be at the discretion of the Board of Directors, and subject to the terms of our then-outstanding indebtedness, but we do not expect to pay a common stock dividend in the foreseeable future. We have not paid a dividend on any class of our common stock since 2002. Please read Note 19—Capital Stock—Common Stock beginning on page F-55 for further discussion.

Shareholder Agreement

A shareholder agreement that we entered into with Chevron in 2003, as amended on May 26, 2006, grants Chevron preemptive rights to acquire shares of our common stock in proportion to its then-existing interest in our equity value whenever we issue any equity securities, including securities issued pursuant to employee benefit plans. Chevron agreed to waive its preemptive rights with respect to the equity securities we issued in connection with the Series B Exchange and our August 2003 refinancing and up to $250 million in equity securities we may issue in one or more future underwritten offerings.

In addition, Chevron and its affiliates may acquire up to 40% of the total combined voting power of our outstanding voting securities without restriction in the shareholder agreement. Shares of Class B common stock issued to Chevron upon the mandatory conversion of Chevron's Class C convertible preferred stock are not counted when calculating this 40% threshold. We have agreed not to take any action that would cause Chevron's ownership to exceed this 40% threshold.

If Chevron or its affiliates wish to acquire more than 40% of the total combined voting power of our outstanding voting securities, the shareholder agreement requires Chevron to make an offer to acquire all of our outstanding voting securities for cash or freely tradable securities listed on a national securities exchange. Any offer by Chevron or its affiliates for all of our outstanding voting securities would be subject to the auction procedures outlined in the agreement.

Chevron's ownership of our Class B common stock entitles it to designate up to three members of our Board of Directors. The shareholder agreement prohibits Chevron from selling or transferring shares of Class B common stock except in the following transactions:

- a widely-dispersed public offering;
- an unsolicited sale to a third party, provided that we or our designee are given the opportunity to purchase the shares proposed to be sold; or
- a solicited sale to an acceptable third party, provided that if we advise Chevron that the sale to a third party is not acceptable, we must purchase all of the offered shares for cash at a purchase price equal to 105% of the third party offer.

Upon the sale or transfer to any person other than an affiliate of Chevron, the shares of Class B common stock automatically convert into shares of Class A common stock.

The shareholder agreement further provides that we may require Chevron and its affiliates to sell all of the shares of Class B common stock under specified circumstances. These rights are triggered if Chevron or its Board designees block—which they are entitled to do under our Bylaws—any of the following transactions two times in any 24-month period or three times over any period of time:

- the issuance of new shares of stock where the aggregate consideration to be received exceeds the greater of $1 billion or one-quarter of our total market capitalization;
- any merger, consolidation, joint venture, liquidation, dissolution, bankruptcy, acquisition of stock or assets, or issuance of common or preferred stock, any of which would result in payment or receipt of consideration having a fair market value exceeding the greater of $1 billion or one-quarter of our total market capitalization; or
- any other material transaction or series of related transactions which would result in the payment or receipt of consideration having a fair market value exceeding the greater of $1 billion or one-quarter of our total market capitalization.

However, upon occurrence of one of these triggering events and in lieu of selling Class B common stock, Chevron may elect to retain the shares of Class B common stock but forfeit its right and the right of its Board designees to block the subject transaction. A block consists of a vote against a proposed transaction by either (a) all of Chevron's representatives on our Board of Directors present at the meeting where the vote is taken (if the transaction would otherwise be approved by our Board of Directors) or (b) any of the Class B common stock held by Chevron and its affiliates if the transaction otherwise would be approved by at least two-thirds of all other shares entitled to vote on the transaction, excluding shares held by our management, directors or subsidiaries.

The shareholder agreement also prohibits us from taking the following actions:

- issuing any shares of Class B common stock to any person other than Chevron and its affiliates;
- adopting a shareholder rights plan, "poison pill" or similar device that prevents Chevron from exercising its rights to acquire shares of common stock or from disposing of its shares when required by us; and

- acquiring, owning or operating a nuclear power facility, other than being a passive investor in a publicly-traded company that owns a nuclear facility.

Generally, the provisions of the shareholder agreement terminate on the date Chevron and its affiliates cease to own shares representing at least 15% of our outstanding voting power. At such time, all of the shares of Class B common stock held by Chevron would convert to shares of Class A common stock.

Chevron has agreed to vote its shares of Class B common stock in favor of the Merger Agreement and the merger with the LS Entities. As a result of the transaction, all of Chevron's Class B common stock will be converted into shares of Class A common stock of New Dynegy.

Registration Rights Agreement

We have entered into a registration rights agreement with Chevron that grants Chevron certain registration rights with respect to its shares of our Class B common stock in the event the proposed Merger Agreement with the LS Entities is not consummated. Under the agreement, we would be required to prepare and file with the SEC, and use our best efforts to cause to be declared effective, a shelf registration statement covering the resale of the shares of Class B common stock held by Chevron. If the Merger Agreement is not consummated, Chevron could also require us to effect up to two underwritten offerings during the period ending on December 31, 2007, and up to two additional underwritten offerings per calendar year thereafter. New Dynegy has also entered into a registration rights agreement with Chevron, under which New Dynegy will have similar obligations with respect to the resale of the shares of Class A common stock of New Dynegy which Chevron will own if the proposed Merger Agreement with the LS Entities is consummated.

Shareholder Return Performance Presentation

The performance graph shown on the following page was prepared by Research Data Group, Inc., using data from the Research Data Group's database. As required by applicable rules of the SEC, the graph was prepared based upon the following assumptions:

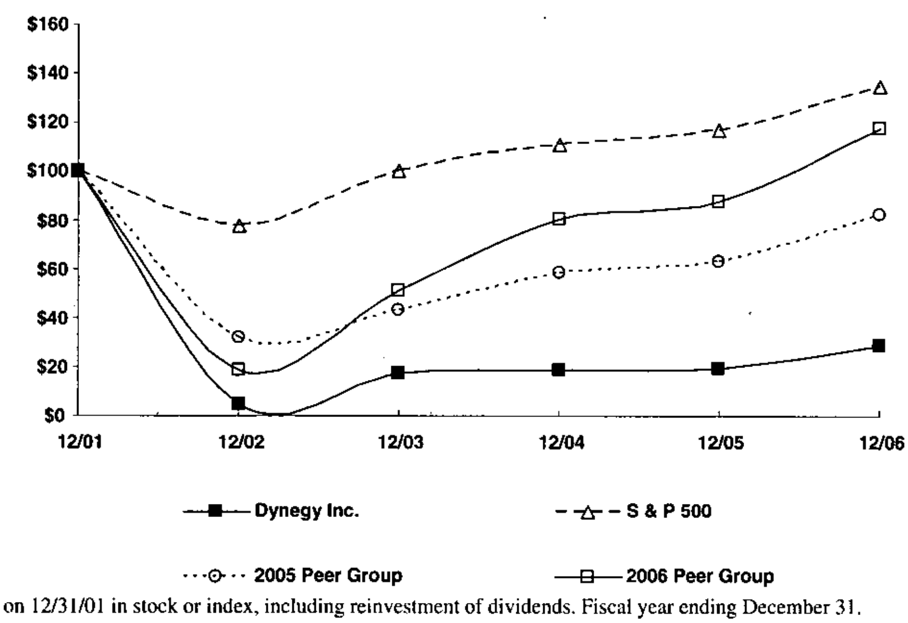
1. $100 was invested in Dynegy Class A common stock, the S&P 500, the 2006 Peer Group (as defined below) and the 2005 Peer Group (as defined below) on December 31, 2001.
2. The returns of each component company in the 2006 Peer Group and the 2005 Peer Group are weighed based on the market capitalization of such company at the beginning of the measurement period.
3. Dividends are reinvested on the ex-dividend dates.

Our peer group for the fiscal year ended December 31, 2006, which we refer to as the "2006 Peer Group," is comprised of AES Corporation; Mirant Corporation; NRG Energy, Inc.; and Reliant Energy, Inc. Our peer group for the fiscal year ended December 31, 2005, which we refer to as the "2005 Peer Group," is comprised of AES Corporation; Calpine Corporation; Duke Energy Corporation; El Paso Corporation; NRG Energy, Inc.; and Reliant Energy, Inc.

For our 2006 Peer Group, we eliminated Calpine Corporation, Duke Energy Corporation and El Paso Corporation. We effected this change in an attempt to better reflect our current industry peers based on the comparability of each company's size, asset profile and business focus and strategy. While our 2006 business operations were focused primarily on power generation, our 2005 Peer Group included companies that competed with us in more than one line of business, namely power generation and/or natural gas liquids.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Dynegy Inc., The S & P 500 Index,
The 2005 Peer Group And The 2006 Peer Group



* $100 invested on 12/31/01 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

	12/01	12/02	12/03	12/04	12/05	12/06
Dynegy Inc.	100.00	4.68	16.98	18.33	19.20	28.72
S & P 500	100.00	77.90	100.24	111.15	116.61	135.03
2005 Peer Group	100.00	32.12	43.43	58.75	63.39	82.48
2006 Peer Group	100.00	18.79	50.86	80.21	87.54	117.72

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

The above stock price performance comparison and related discussion is not to be deemed incorporated by reference by any general statement incorporating by reference this Form 10-K into any filing under the Securities Act of 1933 or under the Securities Exchange Act of 1934, or otherwise, except to the extent that we specifically incorporate this stock price performance comparison and related discussion by reference, and is not otherwise deemed "filed" under the Acts.

Item 6. ***Selected Financial Data***

The selected financial information presented below was derived from, and is qualified by reference to, our Consolidated Financial Statements, including the notes thereto, contained elsewhere herein. The selected financial information should be read in conjunction with the Consolidated Financial Statements and related notes and Management's Discussion and Analysis of Financial Condition and Results of Operations.

Dynegy's Selected Financial Data

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(in millions, except per share data)				
Statement of Operations Data (1):					
Revenues	$ 2,017	$2,313	$2,451	$2,599	$ 2,109
Depreciation and amortization expense	(230)	(220)	(235)	(373)	(378)
Goodwill impairment	—	—	—	(311)	(814)
Impairment and other charges	(155)	(46)	(78)	(225)	(176)
General and administrative expenses	(196)	(468)	(330)	(315)	(297)
Operating income (loss)	52	(838)	(100)	(769)	(1,146)
Interest expense and debt conversion expense	(631)	(389)	(453)	(503)	(241)
Income tax benefit	168	395	172	296	337
Net loss from continuing operations	(358)	(804)	(180)	(813)	(1,217)
Income (loss) from discontinued operations (3)	24	899	165	81	(1,136)
Cumulative effect of change in accounting principles	1	(5)	—	40	(234)
Net income (loss)	$ (333)	$ 90	$ (15)	$ (692)	$(2,587)
Net income (loss) applicable to common stockholders (4)	(342)	68	(37)	321	(2,917)
Basic earnings (loss) per share from continuing operations	$ (0.80)	$(2.13)	$(0.53)	$ 0.53	$ (4.23)
Basic net income (loss) per share	(0.75)	0.18	(0.10)	0.86	(7.97)
Diluted earnings (loss) per share from continuing operations	$ (0.80)	$(2.13)	$(0.53)	$ 0.50	$ (4.23)
Diluted net income (loss) per share	(0.75)	0.18	(0.10)	0.78	(7.97)
Shares outstanding for basic EPS calculation	459	387	378	374	366
Shares outstanding for diluted EPS calculation	509	513	504	423	370
Cash dividends per common share	$ —	$ —	$ —	$ —	$ 0.15
Cash Flow Data:					
Net cash provided by (used in) operating activities	$ (194)	$ (30)	$ 5	$ 876	$ (25)
Net cash provided by (used in) investing activities	358	1,824	262	(266)	677
Net cash used in financing activities	(1,342)	(873)	(115)	(900)	(44)
Cash dividends or distributions to partners, net	(17)	(22)	(22)	—	(55)
Capital expenditures, acquisitions and investments	(163)	(315)	(314)	(338)	(981)

	December 31,				
	2006	2005	2004	2003	2002
			(in millions)		
Balance Sheet Data (2):					
Current assets	$2,082	$ 3,706	$2,728	$ 3,074	$ 7,574
Current liabilities	1,259	2,116	1,802	2,450	6,748
Property and equipment, net	4,951	5,323	6,130	8,178	8,458
Total assets	7,630	10,126	9,843	12,801	20,020
Long-term debt (excluding current portion)	3,190	4,228	4,332	5,893	5,454
Notes payable and current portion of long-term debt	68	71	34	331	861
Serial preferred securities of a subsidiary	—	—	—	11	11
Subordinated debentures	—	—	—	—	200
Series B Preferred Stock (5)	—	—	—	—	1,212
Series C convertible preferred stock	—	400	400	400	—
Minority interest	—	—	106	121	146
Capital leases not already included in long-term debt	6	—	—	—	15
Total equity	2,267	2,140	1,956	1,975	2,256

(1) The Sithe Energies (February 1, 2005) and Northern Natural (February 1, 2002) acquisitions were accounted for in accordance with the purchase method of accounting and the results of operations attributable to the acquired businesses are included in our financial statements and operating statistics beginning on the acquisitions' effective date for accounting purposes.

(2) The Sithe Energies and Northern Natural acquisitions were each accounted for under the purchase method of accounting. Accordingly, the purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values as of the effective dates of each transaction. See note (1) above for respective effective dates.

(3) Discontinued operations include the results of operations from the following businesses:
- Northern Natural (sold third quarter 2002);
- U.K. Storage—Hornsea facility (sold fourth quarter 2002) and Rough facility (sold fourth quarter 2002);
- DGC (portions sold in fourth quarter 2002 and first and second quarters 2003);
- Global Liquids (sold fourth quarter 2002);
- U.K. CRM (substantially liquidated in first quarter 2003); and
- DMSLP (sold fourth quarter 2005).

(4) In August 2003, we consummated a restructuring of our Series B Preferred Stock in which we recognized an approximate $1 billion gain on the restructuring.

(5) The 2002 amount equals $1.5 billion in proceeds related to outstanding Series B Preferred Stock less a $660 million implied dividend recognized in connection with a beneficial conversion option plus $372 million in accretion of the implied dividend through December 31, 2002.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

The following discussion should be read together with the audited consolidated financial statements and the notes thereto included in this report.

OVERVIEW

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily on the power generation sector of the energy industry. We report the results of our power generation business as three separate segments in our consolidated financial statements: (1) the Midwest segment (GEN-MW); (2) the Northeast segment (GEN-NE); and (3) the South segment (GEN-SO). We also separately report the results of our CRM business, which primarily consists of the Kendall power tolling arrangement (excluding the Sithe toll which is now in our GEN-NE segment and is an intercompany agreement) as well as our legacy natural gas, power and emission trading positions. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest. As described below, our NGL business, which was conducted through DMSLP and its subsidiaries, was sold to Targa on October 31, 2005. Additionally, as described below, our former REG business, which was conducted through Illinois Power and its subsidiaries, was sold to Ameren Corporation on September 30, 2004.

The following is a brief discussion of each of our power generation segments, including a list of key factors that have affected, and are expected to continue to affect, their respective earnings and cash flows. We also present a brief discussion of our CRM business, our corporate-level expenses and our discontinued businesses. This "Overview" section concludes with a discussion of our 2006 company highlights, our key objectives and our ongoing strategic outlook. Please note that this "Overview" section is merely a summary and should be read together with the remainder of this Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, as well as our audited consolidated financial statements, including the notes thereto, and the other information included in this report.

Business Discussion

Power Generation Business

We generate earnings and cash flows in the three segments within our power generation business through sales of electric energy, capacity and ancillary services. Primary factors affecting our earnings and cash flows in the power generation business are the prices for power, natural gas and coal, which in turn are largely driven by supply and demand. As further discussed below, demand for power can vary regionally due to weather and general economic conditions, among other things. Power supplies similarly vary by region and are impacted significantly by available generating capacity, transmission capacity and federal and state regulation. We are also impacted by the relationship between prices for power and natural gas and prices for power and fuel oil, commonly referred to as the "spark spread", which impacts the margin we earn on the electricity we generate. We believe that our significant coal-fired generating facilities partially mitigate our sensitivity to changes in the spark spread, in that our delivered cost of coal, particularly in the Midwest region, is relatively stable and positions us for potential increases in earnings and cash flows in an environment where both power and natural gas prices increase.

Other factors that have affected, and are expected to continue to impact, earnings and cash flows for this business include:

- our ability to control capital expenditures, which primarily are limited to maintenance, safety, environmental and reliability projects, and to control other costs through disciplined management;

- our ability to optimize our assets by maintaining a high in-market availability, reliable run-time and safe, efficient operations;
- the cost of compliance with existing and future environmental requirements that are likely to be more stringent and more comprehensive; and
- the evaluation of our generation portfolio for rationalization of non-strategic assets.

Please read Item 1A. Risk Factors beginning on page 22 for additional factors that could affect our future operating results, financial condition and cash flows.

In addition to these overarching factors, other factors have influenced, and are expected to continue to influence, earnings and cash flows for our three reportable segments within the power generation business.

Power Generation—Midwest Segment. Our assets in the Midwest include a coal-fired fleet and a natural gas-fired fleet. Although the primary factor affecting earnings and cash flows in GEN-MW, especially for the coal-fired fleet, is the market price of power, the following specific factors also affect or could affect the performance of this reportable segment:

- Our ability to maintain sufficient coal inventories, which is dependant upon the continued performance of the railroads for deliveries of coal in a consistent and timely manner, impacts our ability to serve the critical winter and summer on-peak loads;
- Any pursuit of the state of Illinois of legislation for a limitation of CO_2 emissions that is more stringent than federal guidelines could impose additional costs on our facilities;
- Political, legislative, judicial and/or regulatory actions over the next several months that could alter the Illinois auction results substantially;
- A significant amount of cash will be utilized for capital expenditures required to comply with the Midwest consent decree for the next few years; and
- Earnings and cash flows are primarily weather driven for our natural gas-fired fleet. A warm summer or cold winter increases demand for electricity, which in turn can increase run time of our peaking units and the demand for capacity and energy from these units.

Power Generation—Northeast Segment. Our assets in the Northeast include natural gas, fuel oil and coal-fired facilities. The following specific factors also impact or could impact the performance of this reportable segment:

- Our ability to maintain sufficient coal and fuel oil inventories, including the continued deliveries of coal in a consistent and timely manner, impacts our ability to serve the critical winter and summer on-peak load;
- State-driven programs aimed at capping mercury and carbon dioxide emissions that are more stringent than federal guidelines could impose additional costs on our facilities; and
- The outcome of administrative proceedings and litigation specific to water intake issues could materially impact operating costs at two of our New York facilities.

Power Generation—South Segment. Assets in our South segment are all natural gas-fired facilities. Our ERCOT facility is a baseload facility, and our other wholly-owned assets in the segment are peaking units. The following specific factors also impact or could impact the performance of this reportable segment:

- For the peaking units, earnings and cash flows are primarily weather driven. A warm summer or cold winter increases the demand for electricity, which in turn can increase the run time of our peaking plants;
- Our ability to enter into capacity agreements for our peaking units could impact future results;

- Wholesale market design changes in ERCOT could impact our ability to sell the remainder of the energy and ancillary products of the CoGen Lyondell facility into the bilateral ERCOT markets or the daily ERCOT market, and
- Our agreement dated January 31, 2007, to sell our interest in the Calcasieu power generation facility to Entergy. Subject to regulatory approval the transaction is expected to close in early 2008.

Customer Risk Management

Our CRM segment is comprised largely of the Kendall power tolling arrangement (excluding the Sithe toll which is now in our GEN-NE segment and is an intercompany agreement). We have agreed to acquire the Kendall facility from the LS Entities, and upon the closing of that acquisition the Kendall tolling arrangement will become an intercompany obligation under our GEN-MW segment. As a result, the accounting impact of the toll would be eliminated in our consolidated results. In addition, our CRM segment includes remaining natural gas, power and emission trading positions. We are actively pursuing opportunities to terminate, assign or renegotiate the terms of our remaining obligations under these agreements when circumstances are economically advantageous to us.

Regarding our legacy natural gas, power and emission trading positions, we have substantially reduced the size of our mark-to-market portfolio since October 2002, when we initiated our efforts to exit the CRM business. Our remaining natural gas transactions still require us to purchase natural gas for our customers; however, those cash requirements are partially offset by the proceeds received from financial contracts hedging a significant portion of the supply. Therefore, the profit and loss impacts of price movements are mitigated by these offsetting financial positions. All that remains of our power trading business, exclusive of our power tolling arrangement, is a minimal number of positions that will remain until 2010. Finally, we have a forward obligation to deliver SO_2 emissions allowances through 2008. Our financial statements reflect the gain or loss on this obligation resulting from the price fluctuation in SO_2 emissions allowances. This obligation will be satisfied by our current inventory of physical SO_2 emissions allowances, and such inventory is valued at the lower of cost or market, in accordance with GAAP. Upon settlement of the forward obligation, we will recognize a gain to the extent that the delivery price is higher than the book value of our inventory. Upon delivery of the emissions allowances, we expect a positive cash flow as the third party makes payment for the emissions allowances. The inventory of emissions allowances that we use to fulfill our forward obligation is separate from the inventory and needs of our power generation business.

Other

Other and Eliminations also includes corporate-level expenses such as general and administrative and interest. Significant items impacting future earnings and cash flows include:

- interest expense, which reflects debt with a weighted-average rate of approximately 8%, and will continue to reflect our non-investment grade credit ratings;
- general and administrative costs (G&A), with respect to which we have implemented a number of initiatives that have yielded savings, and which will be impacted by, among other things, (i) any future corporate-level litigation reserves or settlements; (ii) potential funding requirements under our pension plans; and (iii) increased G&A associated with additional resources required for the management and administration of assets acquired through the planned merger with the LS Entities; and
- income taxes, which will be impacted by our ability to realize our significant deferred tax assets, including loss carryforwards.

Discontinued Businesses

Natural Gas Liquids. Our natural gas liquids business, which we sold to Targa in October 2005, was comprised of our natural gas gathering and processing assets and integrated downstream assets used to fractionate, store, terminal, transport, distribute and market natural gas liquids. NGL's results are reflected in Discontinued Operations in our consolidated statements of operations.

Regulated Energy Delivery. Our regulated energy delivery business was comprised of our Illinois Power subsidiary prior to its sale to Ameren in September 2004. REG's results are reflected in Continuing operations in our consolidated statements of operations due to our significant continuing involvement with Ameren through power sales agreements.

Important Events

Pending LS Power Combination. On September 14, 2006, we entered into the Merger Agreement with the LS Entities, part of the LS Power Group, a privately held power plant investor, developer and manager, to combine a portion of the LS Entities' operating generation portfolio with our generation assets, and for us to acquire a 50 percent ownership interest in a development company that is currently controlled by the LS Entities. The combined company ("New Dynegy") will have nearly 20,000 MW of generating capacity. Upon completion of the Merger Agreement, which is subject to the affirmative vote of the holders of at least two-thirds of our Class A common stock and the satisfaction of other conditions, the combined company will own 29 operating power plants in 13 states (excludes the 351 MW Calcasieu generating facility, which we have agreed to sell to Entergy) employing a balanced mix of fuel sources with baseload, intermediate, and peaking dispatch capabilities, enhanced cash flow-generating opportunities, and significant scale and scope in three key geographic regions. The expanded portfolio will also include a controlling interest in the Plum Point facility, a 665 MW coal-fired plant currently under construction in Arkansas. Additionally, the development joint venture (referred to herein as the development company) will provide us with a 50 percent ownership interest in an established growth vehicle. The LS Entities' current development activities include nine projects totaling more than 7,600 MW in various stages of development and approximately 2,300 MW of repowering and/or expansion opportunities.

Under the terms of the Merger Agreement, at closing the LS Entities will receive 340 million shares of New Dynegy's Class B common stock, $100 million in cash and $275 million aggregate principal amount of notes to be issued by New Dynegy. New Dynegy will also assume approximately $1.9 billion in net debt (debt less restricted cash and investments) from the LS Entities. Please read Note 3—Business Combinations and Acquisitions—LS Power on page F-17 for further discussion of the terms of the Merger Agreement as well as the proxy statement/prospectus of Dynegy Acquisition, Inc. filed with the SEC on February 13, 2007.

Illinois Resource Procurement Auction. As a result of the Illinois resource procurement auction, in September 2006, DPM entered into two SFCs with subsidiaries of Ameren Corporation (the "Ameren Illinois Utilities") to provide the Ameren Illinois Utilities with capacity, energy and related services.

Both of the SFCs are for services required by the Ameren Illinois Utilities to serve their residential and commercial electric customers starting January 1, 2007. The products to be provided by DPM under both SFCs include electric energy and certain ancillary and other services necessary to serve a full-requirements load. The first SFC extends through May 31, 2008 and is for 24 tranches of up to 50 MW per tranche. This amount translates to approximately 22.43% of the total Ameren Illinois Utilities' relevant customers' load during each hour of the contract period. The pricing for the first SFC is $64.77 per MW. The second SFC extends through May 31, 2009 and is for four tranches of up to 50 MW per tranche. This amount translates to approximately 3.74% of the total Ameren Illinois Utilities' relevant customers' load during each hour of the contract period. The pricing for the second SFC is $64.75 per MW. There is a possibility of political, legislative, judicial and/or regulatory actions over the next several months that could substantially affect the ability of the Ameren Illinois Utilities to honor their contractual commitments under the SFCs. We cannot predict the outcome of the ongoing actions, but an adverse result could negatively impact our financial position, results of operations and cash flows.

Liability Management. We initiated several transactions to reduce debt and other obligations as well as enhance our capital structure during 2006 and accomplished the following:

- March 2006—we entered into a third amended and restated credit agreement.
- April 2006—we completed a tender offer and consent solicitation in which we purchased $151 million of our $225 million outstanding Second Priority Senior Secured Floating Rate Notes due 2008 (the "2008 Notes"), substantially all of our $625 million 9.875% Second Priority Senior Secured Notes due 2010 and all $900 million of our 10.125% Second Priority Senior Secured Notes due 2013.
- April 2006—we issued $750 million aggregate principal amount of our 8.375% Senior Unsecured Notes due 2016 in a private offering.
- April 2006—we entered into a fourth amended and restated credit agreement.
- May 2006—we completed an offer to convert all $225 million of our outstanding 4.75% Convertible Subordinated Debentures due 2023 into shares of our Class A common stock and cash.
- May 2006—we completed a public offering of 40.25 million shares of our Class A common stock, including 5.25 million shares purchased pursuant to an underwriters' over-allotment option, for proceeds of $23 million.
- May 2006—we redeemed from Chevron all 8 million shares of our outstanding Series C convertible preferred stock for a cash purchase price of $400 million.
- May 2006—we entered into a $150 million Term Loan structured as a new tranche under the Fourth Amended and Restated Credit Facility.
- July 2006—we redeemed all $74 million of our remaining 2008 Notes.
- July 2006—we issued $297 million additional principal amount of our 8.375% Senior Unsecured Notes due 2016 in exchange for all $419 million of outstanding Independence subordinated debt.
- November 2006—we repaid the $150 million Term Loan with proceeds from the sale of the Rockingham facility.

Please read Note 12—Debt beginning on page F-36 for further discussion.

Other. In addition to these events, we also accomplished the following:

- March 2006—we completed the termination of the Sterlington long-term wholesale power-tolling contract with Ouachita Power LLC with a cash payment of approximately $370 million.
- March 2006—we completed our acquisition of NRG's 50% ownership interest in the entity that owns the Rocky Road power plant, a 330-megawatt natural gas-fired peaking facility near Chicago (of which Dynegy already owned 50%). In addition, we completed the sale to NRG of our 50% ownership interest in a joint venture between us and NRG that has ownership in power plants in southern California. As a result of these two transactions, we received net cash proceeds of approximately $165 million from NRG.
- November 2006—we completed the sale of our Rockingham peaking facility to Duke Power for $194 million.

Key Objectives

First and foremost, we are focused on closing the Merger Agreement and related transactions with the LS Entities and integrating the two portfolios. If the transaction is consummated, we intend to use the combined company's power generation facility base and development portfolio as a platform for future growth and to take advantage of market opportunities, including commodity price volatility and expected regional market recoveries, to enhance our financial performance. We believe the combined company will be positioned to participate in further industry consolidation opportunities and to capitalize on expected regional power market recoveries designed to improve the predictability and quality of our cash flows.

Our commercial objectives are focused on three elements:

- Employing a business model and capital structure appropriate for a commodity cyclical business;
- Maintaining a diverse portfolio of assets consisting of both low-cost plants and those that can provide reliability and other services to the markets both during peak-demand periods and as overall regional electric demand increases over time; and
- Ensuring that all of our power generation facilities are ready to produce electricity when market demand and, therefore, market price, is highest.

More specifically, our business strategy includes the following:

Employ a Commodity Cyclical Business Model. We intend to optimize our assets by selling electricity and capacity into the spot and term markets when pricing is most attractive. This objective is best achieved through a diverse portfolio of assets commercialized through a combination of spot market sales and term contracts. While we do not have a prescribed allocation of volumes between spot and term market sales, we generally intend to rely on our low-cost coal facilities and term contractual sales arrangements to provide a base level of cash flow, while preserving financial exposure to market prices. We believe this strategy will allow us to benefit from both short-term and long-term market price increases. Consequently, our financial results will be sensitive to, and generally correlated with, commodity prices (especially natural gas prices, regional power prices and the "spread" between them).

We intend to maintain certain longer-term sales arrangements while retaining an ability to participate in near-term markets through both physical transactions and financial hedges, thereby creating a more stable portfolio that, while dependent on cyclical commodity markets, is also positioned to capture higher energy margins and improved capacity pricing.

Establish an Appropriate Capital Structure. We believe that the power industry is a commodity cyclical business with significant commodity price volatility and a considerable capital investment requirement. Thus, maximizing economic returns in this market environment requires a capital structure that can withstand power price volatility as well as a commercial strategy that captures the value associated with both short-term and long-term price trends. We intend to maintain a capital structure that is suitable for our commercial strategy and the commodity cyclical market in which we operate. Maintaining appropriate debt levels, maturities, and overall liquidity are key elements of this capital structure.

Consistent with these objectives, we are exploring a number of options to ensure an appropriate capital structure. Considerations include modifying the existing DHI bank debt arrangements, including increasing DHI's revolving credit facility, and increasing the capacity of existing letter of credit facilities to support future liquidity and collateral needs. As a result of our review and discussions with potential lenders, we may elect to pursue alternative capital structures, including holding our Sithe and LS entity assets under DHI, to be implemented in connection with the Merger Agreement with the LS Entities.

Such alternative capital structures, if they are implemented, could affect our earnings and cash flows in 2007 and beyond.

Focus on Operational Excellence. We focus on improving our historically strong operating track record to achieve increased plant availability, higher dispatch and capacity factors, and improved cost controls. By managing fuel costs, minimizing plant outages and reducing corporate overhead, we aim to improve our ability to effectively capture revenue opportunities in the market place. Moreover, we commit to operating our facilities in a safe, reliable and environmentally compliant manner.

Tightly Manage Costs and Expenditures. We manage costs and capital expenditures effectively. Likewise, our power generation facilities are managed to require a relatively predictable level of maintenance capital expenditures without compromising operational integrity. We believe these ongoing efforts should allow us to maintain focus on being a reliable, low-cost producer of power.

Position for Regional Market Recovery. We operate a balanced portfolio of generation assets that is diversified in terms of geography, fuel type and dispatch profile. As a result, we believe our substantial coal-fired, baseload fleet should continue to benefit from the impact of higher natural gas prices on power prices in the Midwest and Northeast, allowing it to capture greater margins. It is anticipated that, following the consummation of the Merger Agreement with the LS Entities, the combined cycle units should provide meaningful cash flows and should benefit from improved margins as demand increases in the Western and Northeast markets.

Please read Item 1A. Risk Factors beginning on page 22 for additional factors that could impact our future operating results, financial condition and cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, collateral requirements, fixed capacity payments and contractual obligations, capital expenditures and working capital needs. Examples of working capital needs include prepayments or cash collateral associated with purchases of commodities, particularly natural gas, coal and fuel oil, facility maintenance costs and other costs such as payroll. Our liquidity and capital resources are primarily derived from cash flows from operations, cash on hand, borrowings under our financing agreements, proceeds from asset sales and proceeds from capital market transactions.

Debt Obligations

During 2006, we continued our efforts to enhance our capital structure flexibility, reduce our outstanding debt and extend our maturity profile. Repayments of long-term debt totaled $1,930 million for the year ended December 31, 2006 and consisted of the following payments:

- $900 million in aggregate principal amount on our 10.125% Second Priority Senior Secured Notes due 2013;
- $614 million in aggregate principal amount on our 9.875% Second Priority Senior Secured Notes due 2010;
- $225 million in aggregate principal amount on our 2008 Notes;
- $150 million in aggregate principal amount on our Term Loan due 2012;
- $23 million in aggregate principal amount on our 7.45% Senior Notes due 2006; and
- $18 million in aggregate principal amount on our 8.50% secured bonds due 2007.

In addition to the above repayments, we redeemed all of the outstanding shares of our Series C Preferred for $400 million and we completed an offer to convert all $225 million of our outstanding 4.75% Convertible Subordinated Debentures due 2023 into shares of our Class A common stock and cash. Further, we issued $297 million principal amount of additional 8.375% Senior Unsecured Notes due 2016 in exchange for all $419 million of outstanding Independence subordinated debt.

These repayments were partially offset by $1,071 million of proceeds from the following sources, net of approximately $29 million of debt issuance costs:

- $750 million aggregate principal amount from a private offering of our 8.375% Senior Unsecured Notes due 2016;
- $200 million letter of credit facility due 2012; and
- $150 million term loan due 2012.

Following these transactions, our debt maturity profile as of December 31, 2006 includes $68 million in 2007, $44 million in 2008, $57 million in 2009, $73 million in 2010, $561 million in 2011 and approximately $2,455 million thereafter. Maturities for 2007 represent principal payments on the Independence Senior Notes and our 7.45% DHI Senior Notes included in Notes payable and current portion of long-term debt on our consolidated balance sheets. Scheduled maturities of debt expected to be acquired in the Merger Agreement with the LS Entities are: $14 million in 2007, $14 million in 2008, $164 million in 2009, $16 million in 2010, $18 million in 2011 and approximately $2,077 million thereafter. Please read Note 3—Business Combinations and Acquisitions—LS Power beginning on page F-17 for further discussion.

Summarized Debt and Other Obligations. The following table depicts our consolidated third party debt obligations, including the principal-like maturities associated with the DNE leveraged lease, and the extent to which they are secured as of December 31, 2006 and 2005:

	December 31, 2006	December 31, 2005
	(in millions)	
First Secured Obligations		
Dynegy Holdings Inc.	$ 200	$ —
Sithe Energies (1)	448	885
Total First Secured Obligations	648	885
Second Secured Obligations	11	1,750
Unsecured Obligations	3,375	2,571
Subtotal	4,034	5,206
Preferred Obligations	—	400
Total Obligations	$4,034	$5,606
Less: DNE Lease Financing (2)	(801)	(785)
Less: Preferred Obligations	—	(400)
Other (3)	25	(122)
Total Notes Payable and Long-term Debt (4)	$3,258	$4,299

(1) Please read Note 3—Business Combinations and Acquisitions—Sithe Energies beginning on page F-18 for further discussion.

(2) Represents present value of future lease payments discounted at 10%.

(3) Consists of net premiums on debt of $25 million and net discounts on debt of $122 million at December 31, 2006 and 2005, respectively.

(4) Does not include letters of credit.

Collateral Postings

We continue to use a significant portion of our capital resources, in the form of cash and letters of credit, to satisfy counterparty collateral demands. These counterparty collateral demands reflect our non-investment grade credit ratings and counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. We manage the level of our collateral postings by line of business, rather than by reportable segment. This is primarily because collateral postings are generally determined on a counterparty basis, and our counterparties conduct business across reportable segments. The following table summarizes our consolidated collateral postings to third parties by line of business at February 22, 2007, December 31, 2006 and December 31, 2005:

	February 22, 2007	December 31, 2006	December 31, 2005
		(in millions)	
By Business:			
Generation business	$178	$134	$280
Customer risk management business	50	54	91
Other	7	7	10
Total	$235	$195	$381
By Type:			
Cash (1)	$ 40	$ 38	$122
Letters of credit	195	157	259
Total	$235	$195	$381

(1) Cash collateral consists of either cash deposits to cover physical deliveries or liabilities on mark-to-market positions or prepayments for commodities or services that are in advance of normal payment terms.

The increase in collateral postings from December 31, 2006 to February 22, 2007 is primarily due to increased fuel purchases and collateral postings just ahead of monthly commodity settlements.

The decrease in collateral postings from December 31, 2005 to December 31, 2006 is primarily due to a return of collateral postings of approximately $146 million in our generation business and $37 million in our customer risk management business. This decrease is primarily a result of decreases in commodity prices since the end of 2005 as well as the expiration of certain hedging positions. In addition, the $44 million of collateral posted on behalf of West Coast Power was returned as a result of the sale of our 50% interest in West Coast Power to NRG, completed on March 31, 2006.

Going forward, we expect counterparties' collateral demands to continue to reflect changes in commodity prices, including seasonal changes in weather-related demand, as well as their views of our creditworthiness. In addition, the contemplated merger with the LS Entities and the effect of the Illinois resource procurement auction will have a significant impact on our exposure to collateral demands. We believe that we have sufficient capital resources to satisfy counterparties' collateral demands, including those for which no collateral is currently posted, for the foreseeable future. Over the longer term, we expect to achieve incremental collateral reductions associated with the completion of our exit from the customer risk management business.

Disclosure of Contractual Obligations and Contingent Financial Commitments

We incur contractual obligations and financial commitments in the normal course of our operations and financing activities. Contractual obligations include future cash payments required under existing contracts, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related operating activities. Financial commitments represent contingent obligations, such as financial guarantees, that become payable only if specified events occur. Details on these obligations are set forth below.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2006. Cash obligations reflected are not discounted and do not include accretion or dividends.

	Payments Due by Period						
	Total	2007	2008	2009	2010	2011	Thereafter
Long-term debt (including current portion)	$3,258	$ 68	$ 44	$ 57	$ 73	$561	$2,455
Interest payments on debt	2,019	283	260	253	248	205	770
Operating leases	1,476	139	164	164	117	133	759
Capital leases	16	2	2	2	2	2	6
Capacity payments	688	77	76	77	78	80	300
Conditional purchase obligations	114	12	11	11	12	13	55
Pension funding obligations	63	25	29	9	—	—	—
Other obligations	28	5	5	5	5	—	8
Total contractual obligations	$7,662	$611	$591	$578	$535	$994	$4,353

The table above does not include amounts of long-term debt or other contractual obligations that are expected to be assumed as a result of the proposed Merger Agreement with the LS Entities. Please read Note 3—Business Combinations and Acquisitions—LS Power beginning on page F-17 for further discussion.

Long-Term Debt (Including Current Portion). Total amounts of Long-term debt (including current portion) are included in the December 31, 2006 consolidated balance sheet. For additional explanation, please read Note 12—Debt beginning on page F-36.

Operating Leases. Operating leases includes the minimum lease payment obligations associated with our DNE leveraged lease. For additional information, please read "—Liquidity and Capital Resources—Off-Balance Sheet Arrangements—DNE Leveraged Lease" beginning on page 50. Amounts also include minimum lease payment obligations associated with office and office equipment leases.

In addition, we are party to two charter party agreements relating to VLGCs previously utilized in our global liquids business. The aggregate minimum base commitments of the charter party agreements are approximately $14 million each year for the years 2007 through 2009, and approximately $51 million through lease expiration. The charter party rates payable under the two charter party agreements vary in accordance with market-based rates for similar shipping services. The $14 million and $51 million amounts set forth above are based on the minimum obligations set forth in the two charter party agreements. The primary terms of the charter party agreements expire August 2013 and August 2014, respectively. On January 1, 2003, in connection with the sale of our global liquids business, we sub-chartered both VLGCs to a wholly-owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter agreements. We continue to rely on the sub-charters with a subsidiary of Transammonia to satisfy the obligations of our two charter party agreements. To date, the subsidiary of Transammonia has complied with the terms of the sub-charter agreements.

Capital Leases. In January 2006, we entered into an obligation under a capital lease related to a coal loading facility which will be used in the transportation of coal to our Vermilion generating facility. Pursuant to our agreement with the lessor, we are obligated for minimum payments in the aggregate amount of $16 million over the remaining term of the lease.

Capacity Payments. Capacity payments include future payments aggregating $416 million under the Kendall power tolling arrangement, as further described in Item 1. Business—Segment Discussion—Customer Risk Management beginning on page 12.

In November 2004, we entered into a "back-to-back" power purchase agreement under which a subsidiary of Constellation receives our rights to capacity and energy under the Kendall power tolling arrangement for a four-year term expiring in November 2008. Although we are still obligated under the Kendall toll, as of December 31, 2006, we will receive approximately $81 million in aggregate cash payments from Constellation to offset our fixed payment obligations under the Kendall toll through November 2008, which payment obligations are reflected in the table above. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Kendall on page F-23 for further discussion.

In addition, capacity payments include fixed obligations associated with transmission, transportation and storage arrangements totaling approximately $272 million.

Conditional Purchase Obligations. Amounts relate to our co-sourcing agreement with Accenture LLP for employee and infrastructure outsourcing. In early 2006, we amended the agreement to reduce our annual rate and to extend the term through 2016. We are obligated for minimum payments of approximately $114 million over the term of the agreement. This amended agreement may be cancelled at any time upon the payment of a termination fee not to exceed $1.7 million. This termination fee is in addition to amounts due for services provided through the termination date.

Pension Funding Obligations. Amounts include estimated defined benefit pension funding obligations for 2007 ($25 million), 2008 ($29 million) and 2009 ($9 million). Although we expect to continue to incur funding obligations subsequent to 2009, such amounts have not been included in this table because our estimates are imprecise.

Other Obligations. Other obligations include amounts related to a long-term coal agreement to assist in the delivery of coal to our Danskammer plant in Newburgh, New York. The agreement extends until 2010, and the minimum aggregate payments through expiration total approximately $10 million as of December 31, 2006. In addition, included in other obligations are payments associated with a capacity contract between Independence and Con Edison. The aggregate payments through the 2014 expiration are approximately $18 million as of December 31, 2006. Please read Note 3—Business Combinations and Acquisitions—Sithe Energies beginning on page F-18 for more information on this agreement.

Contingent Financial Obligations

The following table provides a summary of our contingent financial obligations as of December 31, 2006 on an undiscounted basis. These obligations represent contingent obligations that may require a payment of cash upon the occurrence of specified events.

	Expiration by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
			(in millions)		
Letters of Credit (1)	$157	$121	$ 36	$—	$—
Surety Bonds (2)(3)	21	21	—	—	—
Guarantees (4)	4	—	4	—	—
Kendall guarantee (4)	200	200	—	—	—
Total Financial Commitments	$382	$342	$ 40	$—	$—

(1) Amounts include outstanding letters of credit.

(2) Surety bonds are generally on a rolling 12-month basis. The $21 million of surety bonds were supported by collateral.

(3) As part of the power purchase agreement with Constellation, under which Constellation effectively receives our rights to purchase approximately 570 MW of capacity and energy arising from our tolling contract with

Kendall, we have guaranteed Constellation the receipt of $3.5 million in reactive power revenues over the four-year period of the power purchase agreement which ends November 2008. Our receipt of these reactive power revenues to offset this obligation is predicated on, among other things, filing a reactive power tariff with the FERC.

(4) On September 14, 2006, certain of the LS Entities and Kendall Power LLC ("Kendall Power"), a newly formed wholly-owned subsidiary of Dynegy, entered into a Limited Liability Company Membership Interests and Stock Purchase Agreement (the "Kendall Agreement") pursuant to which Kendall Power agreed to acquire all of the outstanding interests in LSP Kendall Holdings, LLC for $200 million in cash, as adjusted for certain changes in working capital. The closing of the Kendall Agreement will occur only if the closing of the Merger Agreement does not occur. We have agreed to guarantee certain of Kendall Power's obligations under the Kendall Agreement. Please read Note 17—Commitments and Contingencies—Guarantees and Indemnifications—Kendall Guarantee on page F-51 for further discussion.

The table above does not include contingent financial obligations that are expected to be assumed as a result of the proposed Merger Agreement with the LS Entities.

Off-Balance Sheet Arrangements

DNE Leveraged Lease. In May 2001, we entered into an asset-backed sale-leaseback transaction to provide us with long-term financing for our acquisition of certain power generating facilities. In this transaction, which was structured as a sale-leaseback to minimize our operating cost of the facilities on an after-tax basis and to transfer ownership to the purchaser, we sold for approximately $920 million four of the six generating units comprising the facilities to Danskammer OL LLC and Roseton OL LLC, each of which was newly formed by an unrelated third party investor, and we concurrently agreed to lease them back from these entities, which we refer to as the owner lessors. The owner lessors used $138 million in equity funding from the unrelated third party investor to fund a portion of the purchase of the respective facilities. The remaining $800 million of the purchase price and the related transaction expenses was derived from proceeds obtained in a private offering of pass-through trust certificates issued by two of our subsidiaries, Dynegy Danskammer, L.L.C. and Dynegy Roseton, L.L.C., which serve as lessees of the applicable facilities. The pass-through trust certificate structure was employed, as it has been in similar financings historically executed in the airline and energy industries, to optimize the cost of financing the assets and to facilitate a capital markets offering of sufficient size to enable the purchase of the lessor notes from the owner lessors. The pass-through trust certificates were sold to qualified institutional buyers in a private offering and the proceeds were used to purchase debt instruments, referred to as lessor notes, from the owner lessors. The lease payments on the facilities support the principal and interest payments on the pass-through trust certificates, which are ultimately secured by a mortgage on the underlying facilities.

As of December 31, 2006, future lease payments are $108 million for 2007, $144 million for 2008, $141 million for 2009, $95 million for 2010, $112 million for 2011 and $179 million for 2012, with $533 million in the aggregate due from 2013 through lease expiration. The Roseton lease expires on February 8, 2035 and the Danskammer lease expires on May 8, 2031. We have no option to purchase the leased facilities at the end of their respective lease terms. DHI has guaranteed the lessees' payment and performance obligations under their respective leases on a senior unsecured basis. At December 31, 2006, the present value (discounted at 10%) of future lease payments was $801 million.

The following table sets forth our lease expenses and lease payments relating to these facilities for the periods presented.

	2006	2005	2004
		(in millions)	
Lease Expense	$50	$50	$50
Lease Payments (Cash Flows)	$60	$60	$60

If one or more of the leases were to be terminated because of an event of loss, because it had become illegal for the applicable lessee to comply with the lease or because a change in law had made the facility economically or technologically obsolete, DHI would be required to make a termination payment in an amount sufficient to redeem the pass-through trust certificates related to the unit or facility for which the lease was terminated at par plus accrued and unpaid interest. As of December 31, 2006, the termination payment at par would be approximately $1 billion for all of the DNE facilities, which exceeds the $920 million we received on the sale of the facilities. If a termination of this type were to occur with respect to all of the DNE facilities, it would be difficult for DHI to raise sufficient funds to make this termination payment. Alternatively, if one or more of the leases were to be terminated because we determine, for reasons other than as a result of a change in law, that it has become economically or technologically obsolete or that it is no longer useful to our business, DHI must redeem the related pass-through trust certificates at par plus a make-whole premium in an amount equal to the discounted present value of the principal and interest payments still owing on the certificates being redeemed less the unpaid principal amount of such certificates at the time of redemption. For this purpose, the discounted present value would be calculated using a discount rate equal to the yield-to-maturity on the most comparable U.S. Treasury security plus 50 basis points.

For further discussion of the accounting and required disclosure surrounding the subsidiaries that issued the pass-through certificates and purchased the notes from the owner lessors, please read Note 10—Unconsolidated Investments—Variable Interest Entities beginning on page F-34.

Capital Expenditures

We continue to tightly manage our operating costs and capital expenditures. We had approximately $155 million in capital expenditures during 2006. Our 2006 capital spending by reportable segment was as follows (in millions):

GEN-MW	$101
GEN-NE	22
GEN-SO	24
Other	8
Total	$155

Capital spending in our GEN-MW segment primarily consisted of maintenance capital projects, as well as approximately $2 million spent on development capital. Development capital spending primarily related to the conversion of our Vermilion facility to PRB coal. Capital spending in our GEN-NE and GEN-SO segments primarily consisted of maintenance and environmental projects.

We expect capital expenditures for 2007 to approximate $415 million, including the capital expenditures that may be associated with the LS Entities. This primarily includes maintenance capital projects, environmental projects and limited development projects. The capital budget is subject to revision as opportunities arise or circumstances change.

Our capital expenditures in 2007 and beyond will continue to be limited by negative covenants contained in our debt instruments. These covenants place specific dollar limitations on our ability to incur capital expenditures. Please read Note 12—Debt beginning on page F-36 for further discussion of these limitations. Our long term capital expenditures in the GEN-MW segment will also be significantly impacted by the DMG consent decree which obligates us to, among other things, install additional emission controls at our Baldwin and Havana plants which, based on ongoing engineering estimates, is expected to cost approximately $675 million from 2007 through 2012.

Financing Trigger Events

Our debt instruments and other financial obligations include provisions which, if not met, could require early payment, additional collateral support or similar actions. These trigger events include leverage ratios and other financial covenants, insolvency events, defaults on scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. We do not have any trigger events tied to specified credit ratings or stock price in our debt instruments and are not party to any contracts that require us to issue equity based on credit ratings or other trigger events.

Commitments and Contingencies

Please read Note 17—Commitments and Contingencies beginning on page F-47, which is incorporated herein by reference, for a discussion of our commitments and contingencies.

Dividends on Common Stock

Dividend payments on our common stock are at the discretion of our Board of Directors. We have not paid a dividend on our common stock since 2002, and we did not declare or pay a dividend on our common stock for the year ended December 31, 2006 and do not foresee a declaration of dividends in the near term due to the dividend restrictions contained in our financing agreements.

Internal Liquidity Sources

Our primary internal liquidity sources are cash flows from operations and cash on hand.

Current Liquidity. The following table summarizes our consolidated revolver capacity and liquidity position at February 22, 2007, December 31, 2006 and December 31, 2005:

	February 22, 2007	December 31, 2006	December 31, 2005
		(in millions)	
Total revolver capacity	$ 470	$ 470	$ —
Total additional letter of credit capacity	194	194	325(1)
Outstanding letters of credit under credit facility	(195)	(157)	(259)
Unused credit facility capacity	469	507	66
Cash	372(2)	371(2)	1,549(2)(3)
Total available liquidity	$ 841	$ 878	$1,615

(1) On April 19, 2006, we entered into a fourth amended and restated credit agreement which consists of (i) a $470 million revolving credit component and (ii) a $200 million letter of credit component. Please read Note 12—Debt—Fourth Amended and Restated Credit Facility beginning on page F-36 for further discussion of our amended credit facility. Our credit facility capacity is limited by, and will increase or decrease with changes in cash collateral on deposit.

(2) The February 22, 2007, December 31, 2006 and December 31, 2005 amounts include approximately $41 million, $46 million, and $21 million, respectively, of cash that remains in the Europe and $18 million, $10 million and $19 million, respectively, of cash that remains in the Canada.

(3) The December 31, 2005 amount includes approximately $13 million of cash held by our NGL business. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Discontinued Operations—Natural Gas Liquids beginning on page F-23.

Cash Flows from Operations. We had operating cash outflows of $194 million for the year ended December 31, 2006. This consisted of $698 million in operating cash flows from our power generation business, reflecting positive earnings for the period and increases in working capital due to returns of cash collateral postings. These cash flows were offset by $892 million of cash outflows relating to our customer risk management business and corporate-level expenses. Please read "—Results of Operations—Operating Income" and "—Cash Flow Disclosures" for further discussion of factors impacting our operating cash flows for the periods presented.

Our future operating cash flows will vary based on a number of factors, many of which are beyond our control, including the price of natural gas and its correlation to power prices, the cost of coal and fuel oil and the value of ancillary services. Additionally, the availability of our plants during peak demand periods will be required to allow us to capture attractive market prices when available. Over the longer term, our operating cash flows also will be impacted by, among other things, our ability to tightly manage our operating costs, including maintenance costs. Our ability to achieve targeted cost savings in the face of industry-wide increases in labor and benefits costs, together with changes in commodity prices, will impact our future operating cash flows. Please read "—Results of Operations—2007 Outlook" beginning on page 68 for further discussion.

Cash on Hand. At February 22, 2007 and December 31, 2006, we had cash on hand of $372 million and $371 million, respectively, as compared to $1,549 million at the end of 2005. This decrease in cash on hand at February 22, 2007 and December 31, 2006 as compared to the end of 2005 is primarily attributable to cash used for debt repayments, litigation settlements and capital expenditures.

Revolver Capacity. On April 19, 2006, we entered into the Fourth Amended and Restated Credit Facility, replacing the former Third Amended and Restated Credit Facility with a $470 million revolving credit facility, thereby providing the return to DHI of $335 million plus accrued interest in cash collateral securing the former Third Amended and Restated Credit Facility. As of February 22, 2007, $195 million in letters of credit are outstanding but undrawn, and we have no revolving loan amounts drawn under the Fourth Amended and Restated Credit Facility. Please read Note 12—Debt—Fourth Amended and Restated Credit Facility beginning on page F-36 for further discussion of our amended credit facility.

External Liquidity Sources

Our primary external liquidity sources are proceeds from asset sales and other types of capital-raising transactions, including public or private equity issuances.

Asset Sale Proceeds. In March 2006, we completed our ownership exchange transactions with NRG which comprised our acquisition of NRG's 50% ownership interest in the entity that owns the Rocky Road power plant (of which we already owned 50%), and the sale to NRG of our 50% ownership interest in the West Coast Power plant, a joint venture between us and NRG, which has ownership in power plants in southern California. As a result of the two transactions, we received cash proceeds of approximately $165 million, net of cash acquired, from NRG. Please read Note 3—Business Combinations and Acquisitions—Rocky Road on page F-18 for further discussion. Also, please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—West Coast Power on page F-21 for further discussion.

In November 2006, we completed our sale to Duke Energy Carolinas, LLC (a subsidiary of Duke Energy) ("Duke Power") of our Rockingham facility, a peaking facility in North Carolina, which is included in our GEN-SO reportable segment, for $194 million in cash. A portion of the proceeds from the sale were used to repay our borrowings under the $150 million Term Loan, with the remaining proceeds used as an additional source of liquidity. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Rockingham on page F-20 for further discussion. Please read Note 12—Debt—Fourth Amended and Restated Credit Facility on page F-36 for further discussion of the Term Loan.

On January 31, 2007, we entered into an agreement to sell our interest in the Calcasieu power generation facility to Entergy for approximately $57 million, subject to regulatory approval. The transaction is expected to close in early 2008. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Calcasieu on page F-20 for further discussion.

We are continuing to evaluate our generation fleet based primarily on geographic location, fuel supply, market structure and market recovery expectations. This evaluation will consider the combined portfolio of Dynegy and the LS Entities in anticipation of the pending transaction. Consistent with industry practice, we periodically consider divestitures of non-core generation assets where the balance of the factors described above suggests that such assets' earnings potential is limited or that the value that can be captured through a divestiture outweighs the benefits of continuing to own and operate such assets. In conducting our current portfolio review, we are considering, among other things, divesting certain assets that (i) are primarily peaking in nature and generally operate in locations where market recovery is projected to occur much further in the future than in other regions in which we will have a significant asset position, or (ii) could present value propositions through potential dispositions not likely to be achieved through continued ownership and operation by us. As a result of this review, we are considering selling our 614 MW Cogen Lyondell generation facility, our 576 MW Bluegrass generation facility and our 539 MW Heard County generation facility. Moreover, dispositions of one or more other generation facilities could occur in 2007 or beyond. Were any such sale or disposition to be consummated, the disposition could result in accounting charges related to the affected asset(s), and our earnings and cash flows could be affected in 2007 and beyond.

Capital-Raising Transactions. As part of our ongoing efforts to maintain a capital structure that is closely aligned with the cash-generating potential of our asset-based business, which is subject to cyclical changes in commodity prices, we will continuously explore additional sources of external liquidity both in the near- and long-term. The timing of any transaction may be impacted by events, such as strategic growth opportunities, legal judgments or regulatory requirements, which could require us to pursue additional capital in the near-term. In particular, in connection with the pending transaction with the LS Entities, we will be evaluating various opportunities to provide additional liquidity and streamline the combined company's capital structure.

These transactions may include capital markets transactions. The receptiveness of the capital markets to a public offering cannot be assured and may be negatively impacted by, among other things, our non-investment grade credit ratings, significant debt maturities, long-term business prospects and other factors beyond our control. Any issuance of equity likely would have other effects as well, including shareholder dilution. Further, our ability to issue debt securities is limited by our financing agreements, including our Fourth Amended and Restated Credit Facility. Please read Note 12—Debt—Fourth Amended and Restated Credit Facility beginning on page F-36 for further discussion.

RESULTS OF OPERATIONS

Overview and Discussion of Comparability of Results. In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for 2006, 2005 and 2004. At the end of this section, we have included our business outlook for each segment.

We report the results of our power generation business as three separate segments in our consolidated financial statements: (1) the Midwest segment (GEN-MW); (2) the Northeast segment (GEN-NE); and (3) the South segment (GEN-SO). We also separately report the results of our CRM business, which primarily consists of the Kendall tolling agreement, the remaining power tolling arrangement (excluding the Sithe toll which is now in our GEN-NE segment and is an intercompany agreement), as well as legacy natural gas, power and emissions trading positions. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest. Beginning January 1, 2006, all direct general and administrative expenses are included in Other and Eliminations unless they are specifically identified with the respective segment. This change in allocation methodology is a result of our efforts to better align our corporate cost structure with a single line of business.

As described below, substantially all of our NGL business, which was conducted through DMSLP and its subsidiaries and comprised our NGL reportable segment, was sold to Targa on October 31, 2005. Additionally, as described below, our former REG business, which was conducted through Illinois Power and its subsidiaries and comprised our REG reportable segment, was sold to Ameren Corporation on September 30, 2004.

Summary Financial Information. The following tables provide summary financial data regarding our consolidated and segmented results of operations for 2006, 2005 and 2004, respectively.

Year Ended December 31, 2006

	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$208	$ 55	$(55)	$ 7	$(163)	$ 52
Losses from unconsolidated investments	—	—	(1)	—	—	(1)
Other items, net	2	9	1	4	38	54
Interest expense and debt conversion costs						(631)
Loss from continuing operations before taxes						(526)
Income tax benefit						168
Loss from continuing operations						(358)
Income from discontinued operations, net of taxes						24
Cumulative effect of change in accounting principle, net of taxes						1
Net loss						$(333)

Year Ended December 31, 2005

	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$194	$ 29	$(21)	$(647)	$(393)	$ (838)
Earnings (losses) from unconsolidated investments	7	—	(5)	—	—	2
Other items, net	2	5	(1)	—	20	26
Interest expense						(389)
Loss from continuing operations before taxes						(1,199)
Income tax benefit						395
Loss from continuing operations						(804)
Income from discontinued operations, net of taxes						899
Cumulative effect of change in accounting principle, net of taxes						(5)
Net income						$ 90

Year Ended December 31, 2004

	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$194	$ 21	$(52)	$(118)	$(145)	$(100)
Earnings from unconsolidated investments	80	—	112	—	—	192
Other items, net	—	—	1	(3)	11	9
Interest expense						(453)
Loss from continuing operations before taxes						(352)
Income tax benefit						172
Loss from continuing operations						(180)
Income from discontinued operations, net of taxes						165
Net loss						$ (15)

The following table provides summary segmented operating statistics for 2006, 2005 and 2004, respectively:

	Year Ended December 31,		
	2006	2005	2004
GEN-MW			
Million Megawatt Hours Generated—Gross and Net	21.5	21.9	22.6
Average Actual On-Peak Market Power Prices ($/MWh) (1):			
Cinergy (Cin Hub)	$ 52	$ 64	$ 43
Commonwealth Edison (NI Hub)	$ 52	$ 62	$ 42
GEN-NE			
Million Megawatt Hours Generated—Gross and Net	4.4	8.3	6.0
Average Actual On-Peak Market Power Prices ($/MWh) (1):			
New York—Zone G	$ 76	$ 92	$ 62
New York—Zone A	$ 59	$ 76	$ 53
GEN-SO			
Million Megawatt Hours Generated—Gross	4.6	7.3	8.5
Million Megawatt Hours Generated—Net	3.9	5.3	6.7
Average Actual On-Peak Market Power Prices ($/MWh) (1):			
Southern	$ 55	$ 71	$ 49
ERCOT	$ 63	$ 80	$ 51
SP-15	$ 62	$ 73	$ 55
Average natural gas price—Henry Hub ($/MMBtu) (2)	$6.74	$8.80	$5.85

(1) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices realized by the company.

(2) Reflects the average of daily quoted prices for the periods presented and does not necessarily reflect prices realized by the company.

The following tables summarize significant items on a pre-tax basis, with the exception of the tax items, affecting net income (loss) for the periods presented.

	Year Ended December 31, 2006					
	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Eliminations	Total
	(in millions)					
Debt conversion costs	$ —	$—	$—	$—	$(249)	$(249)
Asset impairments	(110)	—	(45)	—	—	(155)
Legal and settlement charges	—	—	—	(53)	—	(53)
Sithe Subordinated Debt exchange charge	—	(36)	—	—	—	(36)
Acceleration of financing costs	—	—	—	—	(36)	(36)
Taxes	—	—	—	—	(29)	(29)
Discontinued operations	—	—	—	23	7	30
Total	$(110)	$ (36)	$ (45)	$ (30)	$(307)	$(528)

	Year Ended December 31, 2005					
	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Eliminations	Total
	(in millions)					
Discontinued operations (1)	$—	$—	$—	$ 6	$1,250	$1,256
Sterlington toll settlement	—	—	—	(364)	—	(364)
Legal and settlement charges	—	—	—	(38)	(249)	(287)
Independence toll settlement charge	—	—	—	(169)	—	(169)
Asset impairment	(29)	—	—	—	—	(29)
Impairment of generation investments	—	—	(27)	—	—	(27)
Restructuring costs	—	—	—	—	(11)	(11)
Taxes	—	—	—	—	89	89
Total	$(29)	$—	$(27)	$(565)	$1,079	$ 458

(1) Discontinued operations for NGL includes gain on sale of DMSLP of $1,087 million.

	Year Ended December 31, 2004					
	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Elimination	Total
	(in millions)					
Discontinued operations (1)	$—	$—	$—	$ 19	$257	$276
Kendall toll restructuring	—	—	—	(115)	—	(115)
Legal and settlement charges	(9)	—	2	(13)	(93)	(113)
Impairment of West Coast Power	—	—	(85)	—	—	(85)
Loss on sale of Illinois Power	—	—	—	—	(58)	(58)
Impairment of Illinois Power	—	—	—	—	(54)	(54)
Acceleration of financing costs	—	—	—	—	(14)	(14)
Gas transportation contracts	—	—	—	88	—	88
Gain on sale of Joppa	75	—	—	—	—	75
Taxes	—	—	—	—	24	24
Gain on sale of Oyster Creek	—	—	15	—	—	15
Total	$ 66	$—	$(68)	$ (21)	$ 62	$ 39

(1) Discontinued operations for NGL includes pre-tax gains on sales of Indian Basin, Hackberry LNG and Sherman totaling $36 million, $17 million and $16 million, respectively.

Year Ended 2006 Compared to Year Ended 2005

Operating Income (Loss)

Operating income was $52 million for the year ended December 31, 2006, compared to an operating loss of $838 million for the year ended December 31, 2005.

Power Generation—Midwest Segment. Operating income for GEN-MW was $208 million for the year ended December 31, 2006, compared to $194 million for the year ended December 31, 2005. GEN-MW results for 2006 include a $110 million pre-tax impairment associated with our Bluegrass facility. GEN-MW results for 2005 include a $29 million pre-tax charge associated with the impairment of a natural gas turbine which was sold in 2006. GEN-MW results for the year ended December 31, 2005 also included general and administrative expenses of $33 million. Beginning in 2006, general and administrative expenses are reported in Other and Eliminations. Please read "Results of Operations—Year Ended 2006 Compared to Year Ended 2005—Operating Income (Loss)—Other" for a consolidated discussion of general and administrative expenses.

Results from our coal-fired generating units increased from $415 million for the year ended December 31, 2005 to $466 million for 2006. Average actual on-peak prices in the CinHub/Cinergy pricing region decreased from $64 per MWh in the year ended December 31, 2005 to $52 per MWh for the year ended December 31, 2006. Generated volumes decreased from 21.9 million MWh in the year ended December 31, 2005 to 21.5 million MWh in the same period in 2006. Despite the decrease in market prices and the decrease in output, the increase in results was primarily driven by higher realized power prices. We realized higher power prices in the first quarter 2006 as we settled forward power sales. Additionally, results from our coal-fired generating units were negatively impacted by the AmerenIP contract during the second and third quarters of 2005, preventing us from recognizing the full benefit of market prices during the 2005 period. During certain peak periods in 2005, Ameren took higher volumes than we expected, resulting in a need to purchase power at market prices in order to satisfy our obligations for forward sales previously made to other third-parties. We did not experience a similar situation under the AmerenIP contract in 2006. This was offset by mark-to-market income of approximately $14 million for the year ended December 31, 2006, compared with mark-to-market income of $23 million for the year ended December 31, 2005. These transactions are primarily related to options and other financial transactions that economically hedged our generation assets but were not designated as cash flow hedges. The higher realized prices were also partially offset by higher operating costs due to the timing of scheduled maintenance.

Results for our natural gas-fired peaking facilities in GEN-MW improved by $13 million, increasing from $7 million for 2005 to $20 million for the same period in 2006. This improvement was the result of our acquisition of the remaining ownership interest in the Rocky Road facility and the related increase in capacity fees. This increase was partially offset by lower pricing and volumes. Additionally, our 2005 results included a $5 million charge associated with the write-down of spare parts inventory.

Depreciation expense increased from $157 million in 2005 to $168 million in 2006 as a result of our acquisition of the remaining ownership interest in the Rocky Road facility and capital projects placed into service in 2006. The capital projects were primarily related to the conversion of the Havana facility to burn PRB coal. Please read Note 5—Restructuring and Impairment Charges—Asset Impairments for further discussion. Our 2005 results also included a $7 million charge associated with the write-off of an environmental project.

Power Generation—Northeast Segment. Operating income for GEN-NE was $55 million for the year ended December 31, 2006, compared to $29 million for the year ended December 31, 2005. GEN-NE results for the year ended December 31, 2005 included general and administrative expenses of $22 million. Beginning in 2006, general and administrative expenses are reported in Other and Eliminations. Please read "Results of Operations—Year Ended 2006 Compared to Year Ended 2005—Operating Income (Loss)—Other" for a consolidated discussion of general and administrative expenses.

Results for our Roseton and Danskammer facilities decreased from $53 million in 2005 to $33 million in 2006 primarily as a result of lower prices and volumes. Average on-peak prices for Zone G, the market served by these two facilities, decreased from $92 per MWh in 2005 to $76 per MWh in 2006. Generated volumes decreased from 6.0 million MWh in 2005 compared to 2.7 million MWh in 2006. Compressed spark spreads for part of the year resulted in lower production of our Roseton facility, where volumes fell by 2.9 million MWH from 2005 to 2006. Additionally, the year ended December 31, 2006 included a fuel oil inventory write-down of approximately $6 million.

Independence contributed results of $46 million for the year ended December 31, 2006, compared with $18 million for the period from February through December 2005. Average on-peak prices for Zone A decreased from $76 per MWh in 2005 to $59 per MWh in 2006. Generated volumes decreased from 2.3 million MWh in 2005 to 1.7 million MWh in 2006. Although market prices and generated volumes from our Independence facility decreased year over year, we received a benefit from the realization of higher power prices in the first half of 2006, as we settled forward power sales. Results for 2006 also reflect the benefit of increased capacity payments in the merchant market.

Depreciation expense for GEN-NE increased from $21 million in 2005 to $24 million in 2006, as the result of acquiring the Independence facility in February 2005 as well as the result of capital projects placed into service in 2006.

Power Generation—South Segment. Operating loss for GEN-SO was $55 million for the year ended December 31, 2006, compared to an operating loss of $21 million for the year ended December 31, 2005. GEN-SO results for 2006 include a $9 million impairment of our Rockingham facility as a result of the sale of the facility. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Rockingham for further discussion. Additionally, we recorded a $36 million impairment associated with the Calcasieu natural gas-fired peaking facility. Please read Note 5—Restructuring and Impairment Charges—Asset Impairments on page F-24 for further discussion. GEN-SO results for the year ended December 31, 2005 also included general and administrative expenses of $11 million. Beginning in 2006, general and administrative expenses are reported in Other and Eliminations. Please read "Results of Operations—Year Ended 2006 Compared to Year Ended 2005—Operating Income (Loss)—Other" for a consolidated discussion of general and administrative expenses.

Results from our ERCOT facility decreased by $8 million from $6 million in 2005 to a loss of $2 million in 2006, primarily driven by decreases in ancillary services revenue caused by a depressed ancillary services market in the ERCOT region during 2006. Also included in the 2006 results are $1 million of mark-to-market losses compared to zero in 2005.

Results from our other South assets increased from $4 million in 2005 to $13 million in 2006, primarily as a result of increased volumes and pricing for our peaking facilities.

Depreciation expense was $21 million in 2006 compared to $23 million in 2005.

Customer Risk Management. Operating income was $7 million for 2006, compared to an operating loss of $647 million for 2005. CRM's 2006 results reflect charges of approximately $53 million in legal reserves resulting from additional activities during the period that negatively affected management's assessment of probable and estimable losses associated with the applicable proceedings and settlements. These charges were partially offset by mark-to-market income on our legacy coal, natural gas, emissions, and power positions. CRM's 2005 results were impacted by the following items:

- $364 million charge associated with the agreement to terminate our Sterlington tolling arrangement.
- $169 million charge associated with the Sithe Energies acquisition. Prior to the acquisition, Independence held a power tolling contract and a natural gas supply agreement with our CRM segment. Upon completion of the purchase, these contracts became intercompany agreements under our GEN-NE segment, and were effectively eliminated on a consolidated basis, resulting in the $169 million charge upon completion of the acquisition.
- $74 million net losses related to our legacy power positions, primarily fixed payments on our remaining power tolling arrangements in excess of realized margins on power generated and sold.
- $38 million charge related to increased legal reserves. The increased legal reserves resulted from additional activities during the year that affected management's assessment of the probable and estimable loss associated with the applicable proceedings.
- $26 million net mark-to-market losses from our legacy natural gas and emissions positions.

These losses were partly offset by a $21 million gain related to the termination of a contract to sell emissions allowances.

Other. Other operating loss was $163 million for 2006, compared to $393 million for 2005. Results include approximately $143 million of general and administrative expenses, including costs related to our business segments, which prior to 2006 were included in the individual segments. Results for 2005 included general and administrative expenses of $364 million.

Consolidated general and administrative expenses decreased from $468 million for 2005 to $196 million for 2006. General and administrative expenses for 2005 included a $236 million charge associated with settlement of our shareholder class action litigation and other legal settlement charges totaling $51 million, while 2006 included $53 million in additional legal reserves. Additionally, compensation and benefits costs and professional and legal fees were lower in 2006 compared to 2005.

Earnings from Unconsolidated Investments

The $1 million loss reported from unconsolidated investments for 2006 was primarily related to the GEN-SO investment in Black Mountain. During 2006, we recorded equity earnings of $8 million related to our investment in Black Mountain offset by a $9 million impairment charge. This charge is the result of a decline in value of the investment related to the high cost of fuel in relation to a third party power purchase agreement through 2023 for 100% of the output of the facility. This agreement provides that Black Mountain (Nevada Cogeneration) will receive payments that decrease over time. The $2 million earnings reported for 2005 included $7 million earnings from the GEN-MW investment in Rocky Road, largely offset by results from GEN-SO investments in both Black Mountain and West Coast Power.

Other Items, Net

Other items, net totaled $54 million of income for 2006, compared to $26 million of income for 2005. The increase was primarily associated with higher interest income in 2006 resulting from higher cash balances and higher interest rates.

Interest Expense

Interest expense and debt conversion costs totaled $631 million for 2006, compared to $389 million for 2005. The increase was primarily due to debt conversion and acceleration of financing costs, as well as a $36 million charge associated with the Sithe Subordinated Debt exchange. These charges were partially offset by reductions due to lower principal amounts outstanding as a result of our liability management program. Please read Note 12—Debt for further discussion

Income Tax Benefit

Our income tax benefit from continuing operations was $168 million in 2006, compared to an income tax benefit from continuing operations of $395 million in 2005. The 2006 effective tax rate was 32%, compared to 33% in 2005. The 2006 tax benefit included a $29 million expense related to various adjustments anticipated as a result of the Canadian authorities' audit of prior year income tax returns. The 2005 tax benefit included an $18 million expense and a $13 million expense related to an increase in the valuation allowance associated with capital losses and foreign NOLs, respectively. Excluding these items from the 2006 and 2005 calculations would result in effective tax rates of 37% and 36% in 2006 and 2005, respectively. In general, differences between these adjusted effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax basis differences.

Please read Note 14—Income Taxes beginning on page F-42 for further discussion of our income taxes.

Discontinued Operations

Income From Discontinued Operations Before Taxes. Discontinued operations include DMSLP in our former NGL segment, our U.K. CRM business, our former DGC segment and our U.K. natural gas storage assets from our CRM segment. The following summarizes the activity included in income from discontinued operations:

Year Ended December 31, 2006

	U.K. CRM	DGC	NGL	Total
		(in millions)		
Operating income included in income from discontinued operations	$18	$—	$ 6	$24
Other items, net included in income from discontinued operations	5	1	—	6
Income from discontinued operations before taxes				30
Income tax expense				(6)
Income from discontinued operations				$24

Year Ended December 31, 2005

	U.K. CRM	NGL	Total
		(in millions)	
Operating income included in income from discontinued operations	$—	$1,320	$1,320
Earnings from unconsolidated investments included in income from discontinued operations	—	5	5
Other items, net included in income from discontinued operations	6	(22)	(16)
Interest expense included in income from discontinued operations			(53)
Income from discontinued operations before taxes			1,256
Income tax expense			(357)
Income from discontinued operations			$ 899

As further discussed in Note 4—Dispositions, Contract Terminations and Discontinued Operations—Discontinued Operations—Natural Gas Liquids beginning on page F-23, on October 31, 2005, we completed the sale of DMSLP. As a result of the sale, and as required SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144), we have reclassified the operations related to DMSLP, which comprised of the remaining operations of our NGL segment, from continuing operations to discontinued operations.

In 2006, pre-tax income from discontinued operations of $30 million ($24 million after-tax) included $6 million in pre-tax income attributable to NGL and a pre-tax gain of $21 million associated with a receivable previously reserved in our U.K. CRM business. In 2005, pre-tax income from discontinued operations of $1,256 million ($899 million after-tax) included $1,250 million in pre-tax income attributable to NGL. Included in NGL's 2005 pre-tax income is a pre-tax gain on the sale of DMSLP of $1,087 million and income attributable to ten months of operations.

In accordance with EITF Issue 87-24, "Allocation of Interest to Discontinued Operations" (EITF Issue 87-24), we have allocated interest expense to discontinued operations associated with debt instruments that were required to be paid upon the sale of DMSLP. Interest expense included in income from discontinued operations, which includes interest incurred on our former term loan and our former Generation facility debt, totaled zero and $53 million during 2006 and 2005, respectively.

Income Tax (Expense) Benefit From Discontinued Operations. We recorded an income tax expense from discontinued operations of $6 million in 2006, compared to an income tax expense from discontinued operations of $357 million in 2005. The income tax expense in 2005 includes a $112 million benefit associated with reducing a valuation allowance related to our capital loss carryforward, which primarily relates to our third quarter 2002 sale of Northern Natural Gas. We reduced the valuation allowance as a result of capital gains expected to be recognized from our sale of DMSLP. For further information regarding the sale, please see Note 4—Dispositions, Contract Terminations and Discontinued Operations—Discontinued Operations—Natural Gas Liquids. The effective rates for 2006 and 2005, adjusting for the reduction of the valuation allowance in 2005, are 28% and 38%, respectively.

Cumulative Effect of Change in Accounting Principles

On January 1, 2006, we adopted SFAS No. 123(R), "Share-Based Payment" (SFAS No. 123(R)). In connection with its adoption, we realized a cumulative effect loss of approximately $1 million, net of tax expense of zero. For further information, please see Note 2—Summary of Significant Accounting Policies—Accounting Principles Adopted—SFAS No. 123(R) on page F-16.

On December 31, 2005, we adopted FIN No. 47. In connection with its adoption, we realized a cumulative effect loss of approximately $5 million ($7 million pre-tax). For further information, please see Note 2—Summary of Significant Accounting Policies—Asset Retirement Obligations beginning on page F-11.

Year Ended 2005 Compared to Year Ended 2004

Operating Loss

Operating loss was $838 million for the year ended December 31, 2005, compared to $100 million for the year ended December 31, 2004.

Power Generation—Midwest Segment. Operating income for GEN-MW was $194 million for the years ended December 31, 2005 and 2004.

Results from our coal-fired generating units increased from $392 million for the year ended December 31, 2004 to $415 million for 2005. Average on-peak prices in the NI Hub/Com Ed pricing region increased from $42 per MWh in 2004 to $62 per MWh for 2005. Additionally, volumes were up 3%, from 20.7 million MWh for 2004 to 21.3 million MWh. Despite the increases in volumes and price, results from our coal-fired generating units were negatively impacted by the AmerenIP contract, preventing us from recognizing the full benefit of the increase in market prices. Volumes sold pursuant to this contract with AmerenIP increased 25% in 2005 compared to 2004, resulting in a reduced supply of power available for sale at prevailing market prices in 2005. During certain peak periods, Ameren took higher volumes than we expected, resulting in a need to purchase power at market prices in order to satisfy our obligations. Volumes, excluding those sold under the AmerenIP contract, decreased by 1.7 million MWh from 2004 to 2005. Additionally, GEN-MW's results for 2005 include $23 million of net mark-to-market income. As a result of increased power prices and overall power price volatility, we recognized $9 million of mark-to-market gains during 2005 associated with options sold during the period, and $8 million of mark-to-market gains associated with other financial transactions. Additionally, as of December 31, 2005, we recorded $5 million of income related to FTRs that were not designated as cash flow hedges. For the year ended December 31, 2004, our results included $16 million of mark-to-market losses, primarily related to options and other transactions that economically hedged our generation assets, and were not accounted for as cash flow hedges.

Results for our natural gas-fired peaking facilities in GEN-MW improved by $11 million, from a loss of $4 million for 2004 to earnings of $7 million for 2005. This improvement was a result of favorable power pricing, caused primarily by warm weather and generally higher fuel prices. These factors made it economical to produce substantially more power than our natural gas-fired facilities produced in 2004. However, our 2005 results also include a charge of $5 million related to the write-down of spare parts inventory.

General and administrative expense for GEN-MW decreased from $38 million in 2004 to $33 million in 2005 largely due to expenses associated with the DMG consent decree in 2004. Depreciation expense increased slightly, from $156 million in 2004 to $157 million in 2005. Improved 2005 results at both our coal and natural gas-fired facilities were offset by a $29 million charge associated with the impairment of a natural gas turbine, which was sold in 2006, as well as a $7 million charge associated with the write-off of an environmental project.

Power Generation—Northeast Segment. Operating income for GEN-NE was $29 million for the year ended December 31, 2005, compared to $21 million for the year ended December 31, 2004.

Results from our Roseton, Danskammer and Independence facilities were $71 million for 2005, compared with $44 million in 2004. Beginning in February 2005, GEN-NE's results include earnings from the Independence facility. See Note 3—Business Combinations and Acquisitions—Sithe Energies beginning on page F-18 for further discussion of the acquisition of Independence. The addition of Independence and increased power prices were the primary driver of earnings in 2005. Average on-peak market prices increased from $62 per MWh in 2004 to $92 per MWh in 2005. Compressed spark spreads for part of the year resulted in lower production at our Roseton facility, where volumes fell by 0.5 million MWh from 2004 to 2005. However, during the times Roseton was running, spark spreads were higher than the previous year. Generated volumes at our Danskammer facility rose by 0.4 million MWh from 2004 to 2005. The benefit of increased spark spreads was partly offset by operating expense, which increased from $120 million in 2004 to $139 million in 2005, primarily as a result of the timing of maintenance projects, as well as an increase in labor costs. GEN-NE's results included $12 million of mark-to-market losses and $17 million of mark-to-market gains in 2005 and 2004 respectively, related to financial transactions not designated as cash flow hedges.

General and administrative expense in GEN-NE increased from $13 million in 2004 to $22 million in 2005, primarily as a result of the addition of our Independence facility. Depreciation expense for GEN-NE increased from $10 million to $21 million, also as the result of the addition of the Independence facility.

Power Generation—South Segment. Operating loss for GEN-SO was $21 million for the year ended December 31, 2005, compared to a loss of $52 million for the year ended December 31, 2004.

Results from our ERCOT facility improved by $18 million, from a loss of $12 million for 2004 to income of $6 million for 2005. Power prices in the ERCOT region increased by 57% from 2004 to 2005; and we were also able to provide additional ancillary services to the market. Results from our peaker assets in the Southeast increased, from a loss of $5 million in 2004 to earnings of $4 million in 2005, as a result of improved spark spreads in the region.

Included in the 2004 results discussed above are $8 million of mark-to-market losses, $3 million of which relates to hedge ineffectiveness in the ERCOT region, and $5 million of which relates to financial transactions not designated as cash flow hedges.

General and administrative expense was $11 million in both 2004 and 2005. Depreciation expense decreased slightly, from $25 million in 2004 to $23 million for 2005.

Customer Risk Management. Operating loss for the CRM segment was $647 million for 2005. Results for 2005 were impacted by the following items:

- $364 million charge associated with the agreement to terminate our Sterlington tolling arrangement.
- $169 million charge associated with the Sithe Energies acquisition. Prior to the acquisition, Independence held a power tolling contract and a natural gas supply agreement with our CRM segment. Upon completion of the purchase, these contracts became intercompany agreements under our GEN-NE

segment, and were effectively eliminated on a consolidated basis, resulting in the $169 million charge upon completion of the acquisition.

- $74 million net losses related to our legacy power positions, primarily fixed payments on our remaining power tolling arrangements in excess of realized margins on power generated and sold.
- $26 million net mark-to-market loss from our legacy natural gas and emissions positions.
- $38 million charge related to increased legal reserves. The increased legal reserves resulted from additional activities during the year that affected management's assessment of the probable and estimable loss associated with the applicable proceedings.

These losses were partly offset by a $21 million gain related to the termination of a contract to sell emissions allowances.

Results for 2004 were impacted by the following items:

- $88 million gain associated with the exit of four natural gas transportation agreements in support of our third party marketing business; offset by
- $115 million charge associated with our entry into a "back-to-back" power purchase agreement with a subsidiary of Constellation in November 2004 to mitigate the effect of the Kendall tolling arrangement through November 2008.

CRM's results for 2004 also reflect the impact of fixed payments on our remaining power tolling arrangements in excess of realized margins on power generated and sold and include $10 million in gains associated with the mark-to-market value of certain legacy natural gas contracts which had previously been accounted for on an accrual basis.

Other. During 2004, results included operating income of $139 million related to our former REG business. This includes a $58 million charge related to the sale of Illinois Power and a $54 million charge for the impairment of assets.

Finally, results for 2005 include a $236 million charge associated with the settlement of our shareholder class action litigation and other legal settlement charges totaling $13 million. Results for 2005 also include an $11 million charge associated with our December 2005 restructuring. Results for 2004 include approximately $92 million of expenses related to legal and settlement charges. The legal charges resulted from additional activities during the period that affected management's assessment of the probable and estimable loss associated with the applicable proceedings. In addition, 2005 results benefited from lower compensation, insurance and external consultant costs compared to the same period in 2004.

Earnings from Unconsolidated Investments

Total earnings from unconsolidated investments were $2 million for the year ended December 31, 2005, compared to $192 million for the year ended December 31, 2004.

Power Generation—Midwest Segment. Earnings from unconsolidated investments for GEN-MW were $7 million for the year ended December 31, 2005, compared to $80 million for the year ended December 31, 2004. Both periods included $7 million of earnings related to our Rocky Road investment, which we then owned jointly with NRG Energy. 2004 earnings also included a gain of $75 million related to our sale of our 20% interest in the Joppa power generation facility. Additionally, 2004 earnings included an $8 million impairment related to the sale of our 50% interest in the Michigan Power generating facility, which, when netted against our earnings from the investment for 2004, resulted in a $2 million net loss.

Power Generation—South Segment. Losses from unconsolidated investments for GEN-SO were $5 million for 2005, compared with earnings of $112 million for 2004.

For 2005, our 50% interest in our investment in Black Mountain (Nevada Cogeneration) reported earnings of $5 million; however, these earnings were more than offset by a $13 million impairment charge. This charge is the result of a decline in value of the investment related to the high cost of fuel in relation to a third party power purchase agreement through 2023 for 100% of the output of the facility. This agreement provides that Black Mountain (Nevada Cogeneration) will receive payments that decrease over time. Additionally, in 2005 we recorded a $10 million impairment charge related to our investment in West Coast Power, related to the sale of our 50% interest in the investment to our partner, NRG. This charge almost completely offset the $11 million of 2005 earnings from the investment. Finally, 2005 earnings include $6 million of earnings from our investment in a generating facility located in Panama, which were largely offset by a $4 million impairment charge associated with the sale of our 50% interest in this facility.

Our West Coast Power investment was the primary driver of equity earnings in this segment during 2004. Total earnings from the investment of $165 million in 2004 were partially offset by an impairment charge of $85 million triggered by the expiration of West Coast Power's CDWR contract, resulting in net earnings of $80 million. Earnings for 2004 also include a gain of $15 million on the sale of our 50% interest in the Oyster Creek facility in Texas. In addition to the gain on sale, we reported $5 million of earnings from the Oyster Creek investment. In September 2004, we sold our 50% interest in the Hartwell facility, resulting in a gain of approximately $2 million. Our 2004 earnings from Hartwell, including this gain, were $4 million. Our 2004 earnings also included approximately $2 million from Commonwealth, which we sold in the fourth quarter 2004. Finally, our 2004 earnings included $5 million from our investment in Black Mountain (Nevada Cogeneration).

Other Items, Net

Other items, net totaled $26 million of income in 2005, compared to $9 million in 2004. The increase is primarily associated with higher interest income in 2005 due to higher cash balances and higher interest rates.

Interest Expense

Interest expense totaled $389 million in 2005, compared to $453 million in 2004. The decrease is primarily attributable to lower average principal balances in 2005, resulting from the sale of Illinois Power in September 2004, partially offset by the acquisition of Sithe in early 2005, increases in LIBOR and decreased amortization of debt issuance costs in 2005.

Income Tax Benefit

We reported an income tax benefit from continuing operations of $395 million in 2005, compared to an income tax benefit from continuing operations of $172 million in 2004. The 2005 effective tax rate was 33%, compared to 49% in 2004. The 2005 tax benefit includes an $18 million expense and $13 million expense related to an increase in the valuation allowance associated with capital losses and foreign NOLs, respectively. The 2004 tax benefit includes a $27 million benefit related to a reduction in a deferred tax capital losses valuation allowance associated with anticipated gains on asset sales and a $9 million benefit primarily related to IRS, state and foreign audits and settlements and other items. Excluding these items from the 2005 and 2004 calculations would result in effective tax rates of 36% in 2005 and 39% in 2004. In general, differences between these adjusted effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax basis differences.

Please read Note 14—Income Taxes beginning on page F-42 for further discussion of our income taxes.

Discontinued Operations

Income From Discontinued Operations Before Taxes. Discontinued operations include our global liquids business and DMSLP in our former NGL segment, our U.K. CRM business and U.K. natural gas storage assets in

CRM segment and our communications business in Other and Eliminations. The following summarizes the activity included in income from discontinued operations:

Year Ended December 31, 2005

	U.K. CRM	NGL	Total
	(in millions)		
Operating income included in income from discontinued operations	$—	$1,320	$1,320
Earnings from unconsolidated investments included in income from discontinued operations	—	5	5
Other items, net included in income from discontinued operations	6	(22)	(16)
Interest expense included in income from discontinued operations			(53)
Income from discontinued operations before taxes			1,256
Income tax expense			(357)
Income from discontinued operations			$ 899

Year Ended December 31, 2004

	U.K. CRM	DGC	NGL	Total
	(in millions)			
Operating income included in income from discontinued operations	$ 1	$—	$293	$ 294
Earnings from unconsolidated investments included in income from discontinued operations	—	—	10	10
Other items, net included in income from discontinued operations	18	3	(22)	(1)
Interest expense included in income from discontinued operations				(27)
Income from discontinued operations before taxes				276
Income tax expense				(111)
Income from discontinued operations				$ 165

As further discussed in Note 4—Dispositions, Contract Terminations and Discontinued Operations—Discontinued Operations—Natural Gas Liquids beginning on page F-23, on October 31, 2005, we completed the sale of DMSLP. As a result of the sale, and as required by SFAS No. 144, we have reclassified the operations related to DMSLP, which comprised of the remaining operations of our NGL segment, from continuing operations to discontinued operations.

In 2005, pre-tax income from discontinued operations of $1,256 million ($899 million after-tax) included $1,250 million in pre-tax income attributable to NGL. In 2004, pre-tax income from discontinued operations of $276 million ($165 million after-tax) included $254 million in pre-tax income attributable to NGL. Included in NGL's 2005 pre-tax income was a pre-tax gain on the sale of DMSLP of $1,087 million and income attributable to ten months of operations. NGL's pre-tax income in 2004 included income attributable to twelve months of operations, as well as pre-tax gains of $17 million, $16 million and $36 million, respectively, from our Hackberry LNG, Sherman processing plant and Indian Basin sales, offset by an impairment of $5 million for our Puckett natural gas treating plant and gathering system due to rapidly depleting reserves associated with that facility.

In accordance with EITF Issue 87-24, we have allocated interest expense to discontinued operations associated with debt instruments that were required to be paid upon the sale of DMSLP. Interest expense included in income from discontinued operations, which includes interest incurred on our term loan scheduled to mature in 2010 and our Generation facility debt scheduled to mature in 2007, totaled $53 million and $27 million for 2005 and 2004, respectively.

Income Tax Expense From Discontinued Operations. We recorded an income tax expense from discontinued operations of $357 million in 2005, compared to an income tax expense from discontinued operations of $111 million in 2004. These amounts reflect effective rates of 28% and 40%, respectively. The income tax expense in 2005 includes a $121 million benefit associated with reducing a valuation allowance related to our capital loss carryforward, which primarily relates to our third quarter 2002 sale of NNG. We reduced the valuation allowance as a result of capital gains recognized from our sale of DMSLP. For further information regarding the sale, please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Discontinued Operations—Natural Gas Liquids beginning on page F-23. The income tax expense in 2004 includes $20 million in tax expenses related to the conclusion of prior year tax audits. Excluding these items, the 2005 and 2004 effective tax rates would be 38% and 33%, respectively. In general, differences between these effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax differences.

Cumulative Effect of Change in Accounting Principle

On December 31, 2005, we adopted FIN No. 47. In connection with its adoption, we realized a cumulative effect loss of approximately $5 million ($7 million pre-tax). For further information, please see Note 2—Summary of Significant Accounting Policies—Asset Retirement Obligations beginning on page F-11.

2007 Outlook

Our current portfolio consists primarily of baseload coal assets in GEN-MW and GEN-NE and natural gas-fired peaking assets throughout GEN-MW and GEN-SO. In addition to the volumes committed under the contracts resulting from the Illinois resource procurement auction and power and steam delivery commitments from our Independence and ERCOT facilities, the output from our facilities is available for other forward sales opportunities to capture attractive market prices. To the extent that we choose not to enter into forward sales, the gross margin from our assets is a function of price movements in the coal, natural gas, fuel oil and power commodity markets. The only intermediate (combined cycle) assets in our current portfolio are the Independence and ERCOT natural gas-fired facilities.

In September 2006, we and the LS Entities announced an agreement to, among other things, combine a portion of the LS Entities' operating generation portfolio with our current operating assets into a diversified operating portfolio. The combination, which requires receipt of the required vote of our shareholders and the satisfaction of other conditions, will yield a more robust and diverse portfolio than either entity possesses currently. The LS Entities' portfolio consists primarily of natural gas-fired intermediate (combined cycle) assets with a significant portion of the output committed under multi-year power purchase agreements or hedged through financial agreements. The LS Entities' portfolio includes significant generating capacity located in the Western Electricity Coordinating Council NERC region, a region that is expected to continue to experience demand growth but in which we currently own no significant generating assets. The combination will result in a more balanced portfolio geographically and in terms of fuel type and dispatch characteristics.

The following summarizes our outlook for our current power generation business and our customer risk management business.

Power Generation Business. Generally, we expect that future financial results will continue to reflect sensitivity to fuel and emissions commodity prices, market structure and prices for electric energy, ancillary services and capacity, transportation and transmission logistics, weather conditions and in-market asset availability (IMA). Our commercial team actively manages commodity price risk associated with our unsold power production by entering into forward sales in the prompt one to three months. Decisions regarding longer term forward sales opportunities to capture attractive market prices are made by the executive management team. To the extent we do not choose to forward sell energy from our generation fleet, changes in commodity prices will affect our earnings based on the direction and significance of the commodity price movement.

GEN- MW. We expect our results to continue to be impacted by power prices, fuel prices, fuel availability and unit availability.

In 2007, GEN-MW results will be affected by the delivery obligations resulting from our participation in the Illinois resource procurement auction. We participated in the Illinois resource procurement auction in September 2006 and were awarded contracts for delivery of up to 1,200 MW into the Ameren portion of the auction for the time period from January 1, 2007 through May 31, 2008 and up to an additional 200 MW for the time period from January 1, 2007 through May 31, 2009. The volumes we expect to deliver under the resulting agreements are significantly less than the maximum volumes AmerenIP was allowed to take under the AmerenIP contract that expired at the end to 2006 (1,400 MW max compared to 2,800 MW max). Under the auction contracts, the Ameren Illinois Utilities will continue to have similar volumetric options as AmerenIP had under the contract which expired at the end of 2006. The power commodity price under the auction-related agreements is higher than existed under our previous contract (approximately \$65/MWh under the auction contract compared to \$30/MWh under the previous contract) as are Dynegy's costs to manage deliveries. All other volumes which we produce are available to be sold in the term or spot markets at prevailing market pricing. We anticipate that the revenues generated by our Midwest facilities will improve significantly beginning in 2007 with the implementation of contracts resulting from the auction and the sale of additional volumes into the MISO wholesale markets at prevailing market prices.

Another factor impacting our results in the Midwest in 2007 will be the regulatory environment in Illinois. Within the Illinois political arena, there continues to be challenges to the auction process. There is a possibility of political, legislative, judicial and/or regulatory actions over the next several months that could alter the auction results substantially. Please read Note 18—Regulatory Issues—Illinois Resource Procurement Auction on page F-53 for further details.

Our IMA will also impact GEN-MW's results. We use IMA to monitor fleet performance over time. This measure quantifies the percentage of generation for each unit that was available when market prices were favorable for participation. IMA is calculated on a unit specific basis as a ratio of dispatchable capacity actually available during periods when each unit is scheduled to be available and the megawatt hours resulting from the capacity of each facility multiplied by the hours when the market pricing for electricity and fuel and the variable costs to operate indicate each unit can be profitably dispatched. Through our focus on safe and efficient operations, we seek to maximize our IMA and, as a result, our revenue generating opportunities. The IMA for our coal-fired fleet through December 31, 2006 was approximately 88%, compared to 90.4% for the comparable period of 2005. We attempt to schedule maintenance and repair work to minimize downtime during peak demand periods, but only to the extent doing so does not compromise a safe working environment for our employees and contractors.

In 2005, DMG entered into a comprehensive, Midwest system-wide settlement with the EPA and other parties, resolving the environmental litigation related to our Baldwin Energy Complex in Illinois. The settlement involves substantial emission reductions from our Illinois coal-fired power plants and the completion of several supplemental environmental projects in the Midwest. Through December 31, 2006, DMG had achieved all of the emission reductions scheduled to date and was developing plans to install additional emission control equipment to meet future, more stringent emission limits. DMG recently received a construction permit for a mercury control project at the Vermilion Power Station that is scheduled for operation by June 30, 2007. Our estimated costs associated with the consent decree projects, which we expect to incur through 2012, are approximately \$675 million.

We have diligently worked with our rail service provider to decrease our risk of coal delivery-related disruptions, including the periodic re-deployment of existing rail assets and coal supplies in an opportunistic fashion to provide coal deliveries to our highest margin plants and allow full economic dispatch during peak demand. At this time, we believe that the core issues which created previous delivery uncertainty are resolved and our ability to maintain or build coal inventory at each of our coal-fired facilities continues to be sufficient to meet forecast requirements.

Through 2010, 97% of our Midwest coal requirements are contracted. Additionally, 98% of our coal requirements for 2007 and 2008 are contracted at a fixed price. Our longer term results are sensitive to changes in coal prices to the extent that our current fixed price arrangements expire or are adjusted through contract re-openers or related provisions.

In 2007, we are considering selling our 576 MW Bluegrass generation facility. Please read "Asset Sale Proceeds" beginning on page 53 for further discussion.

GEN-NE. We expect our results to continue to be impacted by power prices, fuel prices, fuel availability and unit availability. Spreads between power and fuel costs are expected to remain volatile as fuel prices change based on demand and weather. This volatility has significant impact on the run-time for the Roseton unit. All of our coal supply requirements for 2007 are contracted at a fixed price. We continue to maintain sufficient coal and oil inventories and contractual commitments to provide us with a stable fuel supply.

Additionally, our results could be affected by potential changes in New York state environmental regulations, as well as our ability to obtain permits necessary for the operation of our facilities. For further discussion of these matters, please see Note 17—Commitments and Contingencies—Danskammer State Pollutant Discharge Elimination System Permit beginning on page F-48 and Note 17—Commitments and Contingencies—Roseton State Pollutant Discharge Elimination System Permit beginning on page F-49, respectively.

GEN-SO. Our results at the CoGen Lyondell facility will be affected by our contract with Lyondell Chemical Company ("Lyondell") which became effective on January 1, 2007. Under this contract, we sell up to approximately 80 MW of energy and 1.5 million pounds per hour of steam from our CoGen Lyondell cogeneration facility to Lyondell for an initial term from January 2007 through December 2021 and subsequent automatic rollover terms of two years each thereafter through December 2046. Incremental annual operating income associated with this contract is expected to range between $40 million to $55 million. The primary drivers of this improvement are the adjustment to the price of steam supplied to Lyondell and our ability to optimize power and steam generation for the combined Lyondell and CoGen Lyondell facility to capture maximum market potential from the CoGen Lyondell cogeneration facility.

Our peaking facilities in the South continue to contribute revenue from sales of capacity mainly to local load-serving entities or wholesale buyers. We currently have the majority of the portfolio capacity committed in the near-term, and a portion of our portfolio capacity committed on an annual basis through 2015. We continue to pursue opportunities to sell additional capacity from these facilities as well as our Lyondell cogeneration facility. We expect opportunities for capacity sales will develop at times during the year. However, due to the regulated, non-liquid market in the southeast region, our results will continue to be impacted by our ability to complete additional sales to a limited pool of buyers for these products and as a result, we anticipate capacity pricing in the South region will lag the remainder of the country.

In 2007, we are considering selling our 614 MW CoGen Lyondell and our 539 MW Heard County generation facility. Please read "Asset Sale Proceeds" beginning on page 53 for further discussion.

CRM. Our CRM business' future results of operations will be impacted by our ability to complete our exit from this business. Our CRM business remains a party to certain legacy natural gas, power and emission transactions, most of which have been hedged. Although we continue to work diligently to minimize the financial impact of the CRM segment, we expect to continue to incur cash outflows associated with these legacy transactions. We are proactively working with our customers to exit the remainder of our obligations on economically favorable terms.

CASH FLOW DISCLOSURES

The following table includes data from the operating section of the consolidated statements of cash flows and includes cash flows from our discontinued operations, which are disclosed on a net basis in income from discontinued operations, net of tax expense, in the consolidated statements of operations:

	Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Operating cash flows from our generation businesses	$ 698	$ 472	$ 421
Operating cash flows from our customer risk management business	(461)	(21)	(371)
Operating cash flows from our natural gas liquids business	—	288	278
Operating cash flows from Illinois Power	—	—	213
Other operating cash flows	(431)	(769)	(536)
Net cash provided by (used in) operating activities	$(194)	$ (30)	$ 5

Operating Cash Flow. Our cash flow used in operations totaled $194 million for the twelve months ended December 31, 2006. During the period, our power generation business provided positive cash flow from operations of $698 million primarily due to positive earnings for the period, increases in working capital due to returns of cash collateral postings and decreased accounts receivable balances. Our CRM business used approximately $461 million in cash primarily due to (i) a $370 million termination payment on our Sterlington tolling contract, (ii) a $44 million settlement payment to resolve claims relating to a former Master Netting Setoff Security Agreement with Enron, and (iii) a $37 million settlement of class action claims by California parties alleging price manipulation and false reporting of natural gas trades by our former gas trading business. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Sterlington Contract Termination on page F-21 for further information. Other and Eliminations includes a use of approximately $431 million in cash primarily due to interest payments to service debt and general and administrative expenses, partially offset by interest income on cash balances and the receipt of approximately $20 million associated with the resolution of a legal dispute.

Our cash flow used in operations totaled $30 million for the twelve months ended December 31, 2005. During the period, our power generation business provided positive cash flow from operations of $472 million, due primarily to positive earnings for the period as well as the return of cash collateral of approximately $66 million during 2005. This was offset by increased accounts receivable balances due to higher prices at December 31, 2005 as compared to December 31, 2004. Our customer risk management business had cash outflows of approximately $21 million, due primarily to fixed payments associated with the former Sterlington and Gregory power tolling arrangement and our final payment of $26 million related to our exit from four long-term natural gas transportation contracts. This was offset partially by the return of approximately $43 million of cash collateral during 2005. Our discontinued natural gas liquids business provided cash flow from operations of $288 million due primarily to positive earnings for the period as well as the return of cash collateral. Other and Eliminations included a use of approximately $769 million in cash due primarily to our payments of $255 million in connection with the settlement of the shareholder class action litigation, interest payments to service debt, pension plan contributions of approximately $31 million, state tax payments and general and administrative expenses.

Our cash flow provided by operations totaled $5 million for the twelve months ended December 31, 2004. During the period, our power generation business provided positive cash flow from operations of $421 million due primarily to positive earnings for the period and increased business activity, partially offset by increased cash collateral posted in lieu of letters of credit. Our customer risk management business used approximately $371 million in cash due primarily to fixed payments associated with the aforementioned power tolling arrangements and related natural gas transportation agreements, a $117.5 million payment related to the restructuring of the

Kendall toll, increased cash collateral posted in lieu of letters of credit and our exit from four long-term natural gas transportation contracts. Our discontinued natural gas liquids business provided cash flow from operations of $278 million due primarily to positive earnings, partially offset by increased prepayments due to higher sales. Illinois Power provided cash flow from operations of $213 million due primarily to positive earnings for the period. Other and Eliminations includes a use of approximately $536 million in cash due primarily to interest payments to service debt, settlement payments and general and administrative expenses.

Capital Expenditures and Investing Activities. Cash provided by investing activities during the twelve months ended December 31, 2006 totaled $358 million. Capital spending of $155 million was primarily comprised of $101 million, $22 million, and $24 million in the GEN-MW, GEN-NE, and GEN-SO segments, respectively. The capital spending for each segment primarily related to maintenance and environmental capital projects. In addition, there was approximately $8 million of capital expenditures in the Other segment.

Proceeds from the sale and acquisition of unconsolidated investments, net of cash acquired, totaled $165 million in 2006. This included net cash proceeds of $205 million from the sale of our 50% ownership interest in West Coast Power to NRG. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—West Coast Power for further information. This was partially offset by a payment of $45 million for our acquisition of NRG's 50% ownership interest in Rocky Road, which included $5 million of cash on hand. Please read Note 3—Business Combinations and Acquisitions—Rocky Road for more information.

Proceeds from assets sales, net totaled $227 million in 2006 and primarily consisted of proceeds from the sale of our Rockingham facility for $194 million. Please read Note 4— Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Rockingham for more information. In addition, we received proceeds of $15 million associated with the sale of our natural gas liquids business in 2005. Please read Note 4— Dispositions, Contract Terminations and Discontinued Operations—Discontinued Operations—Natural Gas Liquids for more information. We also received proceeds of $14 million associated with the sale of a natural gas turbine that was not in use.

The decrease in restricted cash of $121 million related primarily to the return of our $335 million deposit associated with our former cash collateralized facility, offset by a $200 million deposit associated with our new cash collateralized facility and a $14 million increase in the Independence restricted cash balance.

Cash provided by investing activities during the twelve months ended December 31, 2005 totaled $1,824 million. Capital spending of $195 million was primarily comprised of $113 million, $21 million, $9 million and $45 million in the GEN-MW, GEN-NE, GEN-SO and NGL segments, respectively. The capital spending for our GEN-MW segment primarily related to capital maintenance projects, as well as $17 million and $10 million in development capital associated with the completion of the Vermilion and Havana PRB conversions, respectively. Capital spending for our GEN-NE and GEN-SO segments primarily related to maintenance and environmental projects. Capital spending in our NGL segment primarily related to capital maintenance projects and wellconnects.

The cost to acquire Sithe Energies, net of cash proceeds, totaled $120 million. The increase in restricted cash of $353 million related primarily to a $335 million deposit associated with our cash collateralized facility, as well as an $18 million increase in the Independence restricted cash balance.

Net cash proceeds from asset sales of $2,488 million consisted of the following items:

- $2,382 million, net of transaction costs, from the sale of DMSLP;
- a $100 million return of funds held in escrow, offset by a $5 million payment to Ameren associated with a working capital adjustment, both of which related to the sale of Illinois Power; and
- $10 million from the sale of land at our Port Everglades facility.

Net cash provided by investing activities during 2004 totaled $262 million. Capital spending of $311 million was comprised primarily of $113 million, $17 million, $15 million, $61 million and $92 million in the GEN-MW, GEN-NE, GEN-SO, NGL and REG segments, respectively. The capital spending for our GEN-MW segment primarily related to capital maintenance projects, as well as approximately $41 million related to developmental projects. Capital spending for our GEN-NE and GEN-SO primarily related to maintenance and environmental projects. Capital spending in our NGL segment related primarily to maintenance capital projects and wellconnects, as well as approximately $21 million on developmental projects. Capital spending in our REG segment related primarily to projects intended to maintain system reliability and new business services.

Net cash proceeds from asset sales of $576 million consisted of the following items:

- $217 million from the sale of Illinois Power, net of cash retained by Illinois Power of $52 million;
- $152 million from the sale of our equity investments in the Oyster Creek, Hartwell, Michigan Power, Jamaica and Commonwealth generating facilities;
- $99 million from the sale of Joppa;
- $48 million from the sale of Indian Basin;
- $34 million from the sale of Sherman;
- $17 million from the sale of our remaining financial interest in the Hackberry LNG project; and
- $9 million from the sale of PESA.

The cash proceeds were partially offset by $3 million of capitalized business acquisition costs incurred in connection with the Sithe Energies acquisition.

Financing Activities. Cash used in financing activities during the twelve months ended December 31, 2006 totaled $1,342 million. Repayments of long-term debt totaled $1,930 million for the twelve months ended December 31, 2006 and consisted of the following payments:

- $900 million in aggregate principal amount on our 10.125% Second Priority Senior Secured Notes due 2013;
- $614 million in aggregate principal amount on our 9.875% Second Priority Senior Secured Notes due 2010;
- $225 million in aggregate principal amount on our Second Priority Senior Secured Floating Rate Notes due 2008;
- $150 million in aggregate principal amount on our Term Loan;
- $23 million in aggregate principal amount on our 7.45% Senior Notes due 2006; and
- $18 million in aggregate principal amount on our 8.50% secured bonds due 2007.

Debt conversion costs of $249 million consisted of the following payments:

- $204 million to redeem the Second Priority Senior Secured Notes mentioned above, including approximately $3 million of transaction costs;
- $44 million aggregate premium to induce conversion of our $225 million 4.75% Convertible Subordinated Debentures due 2023; and
- $1 million in transaction costs associated with the redemption of our Series C Preferred.

The repayments were partially offset by $1,071 million of proceeds from the following sources, net of approximately $29 million of debt issuance costs:

- $750 million aggregate principal amount from a private offering of our 8.375% Senior Unsecured Notes due 2016;

- $200 million, letter of credit facility due 2012; and
- $150 million, term loan due 2012.

Proceeds from the issuance of common stock consisted primarily of approximately $178 million in proceeds from a public offering of 40.25 million shares of our Class A common stock at $4.60 per share, net of underwriting fees. Dividend payments totaling $17 million were also made on our Series C Preferred prior to its redemption.

Cash used in financing activities during the twelve months ended December 31, 2005 totaled $873 million. Repayments of long-term debt totaled $1,432 million for the twelve months ended December 31, 2005 and consisted of the following payments:

- $600 million aggregate principal amount outstanding under a revolver due May 2007;
- $597 million on the term loan;
- $183 million on the Riverside facility debt;
- $34 million on the Independence Senior Notes due 2007; and
- $18 million on a maturing series of DHI senior notes.

The repayments were partially offset by proceeds from the October 2005 draw-down on the $600 million aggregate principal outstanding revolver due May 2007. Cash used in financing activities also includes semi-annual dividend payments totaling $22 million on our Series C Preferred and distributions of $25 million to minority interest owners.

Net cash used in financing activities during 2004 totaled $115 million. Our financing cash outflows were primarily related to repayments of long-term debt totaling $650 million and consisted primarily of the following payments:

- $223 million to redeem the outstanding Chevron junior notes;
- $185 million under our ABG Gas Supply financing;
- $95 million for a maturing series of Illinova senior notes;
- $78 million on the Tilton capital lease; and
- $65 million on Illinois Power's transitional funding trust notes.

These repayments of long-term debt were offset by proceeds from our $600 million aggregate principal outstanding secured term loan, net of issuance costs of $19 million. We made semi-annual dividend payments totaling $22 million on our Series C Preferred and made distributions to minority interest owners totaling $32 million.

SEASONALITY

Our revenues and operating income are subject to fluctuations during the year; primarily due to the impact seasonal factors have on sales volumes and the prices of power and natural gas. Power marketing operations and generating facilities have higher volatility and demand, respectively, in the summer cooling months. This trend may change over time as demand for natural gas increases in the summer months as a result of increased natural gas-fired electricity generation.

CRITICAL ACCOUNTING POLICIES

Our Accounting Department is responsible for the development and application of accounting policy and control procedures. This department conducts these activities independent of any active management of our risk exposures, is independent of our business segments and reports to the Chief Financial Officer.

The process of preparing financial statements in accordance with GAAP requires our management to make estimates and judgments. It is possible that materially different amounts could be recorded if these estimates and judgments change or if actual results differ from these estimates and judgments. We have identified the following six critical accounting policies that require a significant amount of estimation and judgment and are considered to be important to the portrayal of our financial position and results of operations:

- Revenue Recognition and Valuation of Risk Management Assets and Liabilities;
- Valuation of Tangible and Intangible Assets;
- Estimated Useful Lives;
- Accounting for Contingencies, Guarantees and Indemnifications;
- Accounting for Income Taxes; and
- Valuation of Pension and Other Post-Retirement Plans Assets and Liabilities.

Revenue Recognition and Valuation of Risk Management Assets and Liabilities

We utilize two comprehensive accounting models in reporting our consolidated financial position and results of operations as required by GAAP—an accrual model and a fair value model. We determine the appropriate model for our operations based on guidance provided in applicable accounting standards and positions adopted by the FASB or the SEC.

The accrual model is used to account for substantially all of the operations conducted in our GEN-MW, GEN-NE and GEN-SO segments. These segments consist largely of the ownership and operation of physical assets that we use in various generation operations. We earn revenue from our facilities in three primary ways: (1) sale of energy generated by our facilities; (2) sale of ancillary services, which are the products of a generation facility that support the transmission grid operation, allow generation to follow real-time changes in load, and provide emergency reserves for major changes to the balance of generation and load; and (3) sale of capacity. We recognize revenue from these transactions and transactions from our legacy businesses when the product or service is delivered to a customer.

The fair value model is used to account for forward physical and financial transactions, which meet the definition of a derivative contract as defined by SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended, (SFAS No. 133). The criteria are complex, but generally require these contracts to relate to future periods, to contain fixed price and volume components and to have terms that require or permit net settlement of the contract in cash or the equivalent. SFAS No. 133 concluded that these contracts should be accounted for at fair value. In part, this conclusion is based on the cash settlement provisions in these agreements, as well as the volatility in commodity prices, interest rates and, if applicable, foreign exchange rates, which impact the valuation of these contracts. Since these transactions may be settled in cash or the equivalent, the value of the assets and liabilities associated with these transactions is reported at estimated settlement value based on current forward prices and rates as of each balance sheet date.

Typically, derivative contracts can be accounted for in three different ways: (1) as an accrual contract, if the criteria for the "normal purchase normal sale" exception are met and documented; (2) as a cash flow or fair value hedge, if the criteria are met and documented; or (3) as a mark-to-market contract with changes in fair value recognized in current period earnings. Generally, we only mark-to-market through earnings our derivative contracts if they do not qualify for the "normal purchase normal sale" exception or as a cash flow hedge. Because derivative contracts can be accounted for in three different ways, and as the "normal purchase normal sale" exception and cash flow and fair value hedge accounting are elective, the accounting treatment used by another party for a similar transaction could be different from the accounting treatment we use.

In order to estimate the fair value of our portfolio of transactions, which meet the definition of a derivative and do not qualify for the "normal purchase normal sale" exception, we use a liquidation value approach assuming that the ability to transact business in the market remains at historical levels. The estimated fair value of the portfolio is computed by multiplying all existing positions in the portfolio by estimated prices, reduced by a time value of money adjustment and reserves for credit and price. The estimated prices in this valuation are based either on (1) prices obtained from market quotes, when there are an adequate number of quotes to consider the period liquid, or, if market quotes are unavailable or the market is not considered liquid, (2) prices from a proprietary model which incorporates forward energy prices derived from market quotes and values from previously executed transactions. The amounts recorded as revenue change as these estimates are revised to reflect actual results and changes in market conditions or other factors, many of which are beyond our control. In addition, due to assumptions inherent to the modeling process, the fair value determined by another party could differ significantly from the amounts included in our financial statements.

Please read Note 6—Risk Management Activities and Financial Instruments beginning on page F-26 for further discussion of our accounting for risk management instruments.

Valuation of Tangible and Intangible Assets

We evaluate long-lived assets, such as property, plant and equipment and investments, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Factors we consider important, which could trigger an impairment analysis, include, among others:

- significant underperformance relative to historical or projected future operating results;
- significant changes in the manner of our use of the assets or the strategy for our overall business;
- significant negative industry or economic trends; and
- significant declines in stock value for a sustained period.

We assess the carrying value of our property, plant and equipment in accordance with SFAS No. 144. If an impairment is indicated, the amount of the impairment loss recognized would be determined by the amount the book value exceeds the estimated fair value of the assets. The estimated fair value may include estimates based upon discounted cash-flow projections, recent comparable market transactions or quoted prices to determine if an impairment loss is required. For assets identified as held for sale, the book value is compared to the estimated sales price less costs to sell. There is a significant amount of judgment involved in cash-flow estimates, including assumptions regarding market convergence, discount rates and capacity. The assumptions used by another party could differ significantly from our assumptions. Please read Note 5—Restructuring and Impairment Charges beginning on page F-24 for discussion of impairment charges we recognized in 2006, 2005 and 2004.

We follow the guidance of APB 18, "The Equity Method of Accounting for Investments in Common Stock", SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities", (SFAS No. 115), and EITF Issue 02-14, "Whether an Investor Should Apply the Equity Method of Accounting to Investments Other Than Common Stock", (EITF 02-14), when reviewing our investments. The book value of the investment is compared to the estimated fair value, based either on discounted cash flow projections or quoted market prices, if available, to determine if an impairment is required. We record a loss when the decline in value is considered other than temporary.

Our assessments regarding valuation of tangible and intangible assets are subject to estimates and judgment of management. Market conditions, energy prices, estimated useful lives of the assets, discount rate assumptions and legal factors impacting our business may have a significant effect on the estimates and judgment of management. If different judgments were applied, estimates could differ significantly. Actual results could vary materially from these estimates.

Please read Note 11—Intangible Assets beginning on page F-35 for further discussion of our accounting for intangible assets.

Estimated Useful Lives

The estimated useful lives of our long-lived assets are used to compute depreciation expense, future AROs and are used in impairment testing. Estimated useful lives are based, among other things, on the assumption that we provide an appropriate level of capital expenditures while the assets are still in operation. Without these continued capital expenditures, the useful lives of these assets could decrease significantly. Estimated lives could be impacted by such factors as future energy prices, environmental regulations, various legal factors and competition. If the useful lives of these assets were found to be shorter than originally estimated, depreciation expense may increase, liabilities for future AROs may be insufficient and impairments in carrying values of tangible and intangible assets may result.

Please read Note 9—Property, Plant and Equipment beginning on page F-31 for further discussion of our estimated useful lives.

Accounting for Contingencies, Guarantees and Indemnifications

We are involved in numerous lawsuits, claims, proceedings, and tax-related audits in the normal course of our operations. In accordance with SFAS No. 5, "Accounting for Contingencies" (SFAS No. 5), we record a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. We review our loss contingencies on an ongoing basis to ensure that we have appropriate reserves recorded on our consolidated balance sheets as required by SFAS No. 5. These reserves are based on estimates and judgments made by management with respect to the likely outcome of these matters, including any applicable insurance coverage for litigation matters, and are adjusted as circumstances warrant. Our estimates and judgment could change based on new information, changes in laws or regulations, changes in management's plans or intentions, the outcome of legal proceedings, settlements or other factors. If different estimates and judgments were applied with respect to these matters, it is likely that reserves would be recorded for different amounts. Actual results could vary materially from these reserves.

Liabilities are recorded when an environmental assessment indicates that remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based, in part, on relevant past experience, currently enacted laws and regulations, existing technology, site-specific costs and cost-sharing arrangements. Recognition of any joint and several liability is based upon our best estimate of our final pro-rata share of such liability. These assumptions involve the judgments and estimates of management and any changes in assumptions could lead to increases or decreases in our ultimate liability, with any such changes recognized immediately in earnings.

We follow the guidance of FIN No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN No. 45), for disclosure and accounting of various guarantees and indemnifications entered into during the course of business. When a guarantee or indemnification subject to FIN No. 45 is entered into, an estimated fair value of the underlying guarantee or indemnification is recorded. Some guarantees and indemnifications could have significant financial impact under certain circumstances, however management also considers the probability of such circumstances occurring when estimating the fair value. Actual results may materially differ from the estimated fair value of such guarantees and indemnifications.

Under the provisions of SFAS No. 143, "Asset Retirement Obligations" (SFAS No. 143), and FIN No. 47 "Accounting for Conditional Asset Retirements" (FIN No. 47), we are required to record the present value of the future obligations to retire tangible, long-lived assets on our consolidated balance sheets as liabilities when the liability is incurred. Significant judgment is involved in estimating our future cash flows associated with such obligations, as well as the ultimate timing of the cash flows. If our estimates for the amount or timing of the cash flows change, the change may have a material impact on our results of operations.

Please read Note 2—Summary of Significant Accounting Policies—Asset Retirement Obligations beginning on page F-11 for further discussion of our accounting for AROs.

Accounting for Income Taxes

We follow the guidance in SFAS No. 109, "Accounting for Income Taxes" (SFAS No. 109), which requires that we use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences.

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes in each of the jurisdictions in which we operate. This process involves estimating our actual current tax payable and related tax expense together with assessing temporary differences resulting from differing tax and accounting treatment of certain items, such as depreciation, for tax and accounting purposes. These differences can result in deferred tax assets and liabilities, which are included within our consolidated balance sheets.

We must then assess the likelihood that our deferred tax assets will be recovered from future taxable income and, to the extent we believe that it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized, we must establish a valuation allowance. We consider all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed. Evidence used includes information about our current financial position and our results of operations for the current and preceding years, as well as all currently available information about future years, anticipated future performance, the reversal of deferred tax liabilities and tax planning strategies.

Management believes future sources of taxable income, reversing temporary differences and other tax planning strategies will be sufficient to realize deferred tax assets for which no reserve has been established. While we have considered these factors in assessing the need for a valuation allowance, there is no assurance that a valuation allowance would not need to be established in the future if information about future years changes. Any change in the valuation allowance would impact our income tax benefit (expense) and net income (loss) in the period in which such a determination is made.

Please read Note 14—Income Taxes beginning on page F-42 for further discussion of our accounting for income taxes and any change in our valuation allowance.

Valuation of Pension and Other Post-Retirement Plans Assets and Liabilities

Our pension and other post-retirement benefit costs are developed from actuarial valuations. Inherent in these valuations are key assumptions including the discount rate and expected long-term rate of return on plan assets. Material changes in our pension and other post-retirement benefit costs may occur in the future due to changes in these assumptions, changes in the number of plan participants and changes in the level of benefits provided.

The discount rate is subject to change each year, consistent with changes in applicable high-quality, long-term corporate bond indices. Long-term interest rates increased during 2006. Accordingly, at December 31, 2006, we used a discount rate of 5.87% for pension plans and 5.90% for other retirement plans, an increase of 35 and 37 basis points, respectively, from the 5.52% for pension plans rate and 5.53% for other retirement plans rate used as of December 31, 2005. This increase in the discount rate decreased the underfunded status of the plans by $13 million.

Effective December 31, 2005, we changed to a yield curve approach for determining the discount rate. Projected benefit payments were matched against the discount rates in the Citigroup Pension Discount Curve to produce a weighted-average equivalent discount rate of 5.52% for the pension plans and 5.53% for the other post-retirement plans. In prior years, the discount rate we used was based on Moody's Aa Corporate Bond Rate. We changed our methodology because we believe the yield curve approach is a more accurate estimate of plan liabilities particularly due to the significant change in the composition of the participants in our pension and other retirement plans as a result of the sales of DMSLP and Illinois Power.

The expected long-term rate of return on pension plan assets is selected by taking into account the asset mix of the plans and the expected returns for each asset category. Based on these factors, our expected long-term rate of return as of January 1, 2007 and 2006 was 8.25%.

We adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106 and 132 (R)" (SFAS No. 158), on December 31, 2006. On December 31, 2006, our annual measurement date, the accumulated benefit obligation related to our pension plans exceeded the fair value of the pension plan assets (such excess is referred to as an unfunded accumulated benefit obligation). Under the provisions of SFAS No. 158, we recorded an adjustment to accumulated other comprehensive income of approximately $56 million upon adoption.

A relatively small difference between actual results and assumptions used by management may have a material effect on our financial statements. Assumptions used by another party could be different than our assumptions. The following table summarizes the sensitivity of pension expense and our projected benefit obligation, or PBO, to changes in the discount rate and the expected long-term rate of return on pension assets:

	Impact on PBO, December 31, 2006	Impact on 2007 Expense
	(in millions)	
Increase in Discount Rate—50 basis points	$(16)	$(2)
Decrease in Discount Rate—50 basis points	18	2
Increase in Expected Long-term Rate of Return—50 basis points	—	(1)
Decrease in Expected Long-term Rate of Return—50 basis points	—	1

We expect to make $25 million in cash contributions related to our pension plans during 2007. In addition, it is likely that we will be required to continue to make contributions to the pension plans beyond 2007. Although it is difficult to estimate these potential future cash requirements due to uncertain market conditions, we currently expect that the cash requirements would be approximately $29 million in 2008 and $10 million in 2009.

Please read Note 20—Employee Compensation, Savings and Pension Plans beginning on page F-61 for further discussion of our pension-related assets and liabilities.

RECENT ACCOUNTING PRONOUNCEMENTS

See Note 2—Summary of Significant Accounting Policies—Accounting Principles Adopted beginning on page F-16 for a discussion of recently issued accounting pronouncements affecting us. Specifically, we adopted SFAS No. 123(R), and SFAS No. 154, "Accounting Changes and Error Corrections—A Replacement of APB Opinion No. 20 and SFAS No. 3", on January 1, 2006 and SFAS No. 158 on December 31, 2006. We adopted EITF Issue 05-6, "Determining the Amortization Period for Leasehold Improvements", and FSP FIN No. 45-3, "Application of FASB Interpretation No. 45 to Minimum Revenue Guarantees Granted to a Business or Its Owners", on January 1, 2006. We adopted FIN No. 47 on December 31, 2005. We adopted EITF Issue 04-8, EITF Issue 02-14 and certain provisions of FIN No. 46R on January 1, 2004.

RISK-MANAGEMENT DISCLOSURES

The following table provides a reconciliation of the risk-management data on the consolidated balance sheets:

	As of and for the Year Ended December 31, 2006 (in millions)
Balance Sheet Risk-Management Accounts	
Fair value of portfolio at January 1, 2006	$(112)
Risk-management losses recognized through the income statement in the period, net	39
Cash paid related to risk-management contracts settled in the period, net	(22)
Changes in fair value as a result of a change in valuation technique (1)	—
Non-cash adjustments and other (2)	148
Fair value of portfolio at December 31, 2006	$ 53

(1) Our modeling methodology has been consistently applied.
(2) This amount consists of changes in value associated with cash flow hedges on forward power sales and fair value hedges on debt.

The net risk-management asset of $53 million is the aggregate of the following line items on the consolidated balance sheets: Current Assets—Assets from risk-management activities, Other Assets—Assets from risk-management activities, Current Liabilities—Liabilities from risk-management activities and Other Liabilities—Liabilities from risk-management activities.

Risk-Management Asset and Liability Disclosures

The following table depicts the mark-to-market value and cash flow components, based on contract terms, of our net risk-management assets and liabilities at December 31, 2006. As opportunities arise to monetize positions that we believe will result in an economic benefit to us, we may receive or pay cash in periods other than those depicted below.

Net Risk-Management Asset and Liability Disclosures

	Total	2007	2008	2009	2010	2011	Thereafter
				(in millions)			
Mark-to-Market (1)(3)	$(44)	$(45)	$(3)	$—	$—	$1	$3
Cash Flow (2)	(43)	(45)	(4)	—	—	1	5

(1) Mark-to-market reflects the fair value of our risk-management asset position, which considers time value, credit, price and other reserves necessary to determine fair value. These amounts exclude the fair value associated with certain derivative instruments designated as hedges. The net risk-management asset at December 31, 2006 of $53 million on the consolidated balance sheets includes the $44 million liability herein offset by hedging instruments. Cash flows have been segregated between periods based on the delivery date required in the individual contracts.
(2) Cash flow reflects undiscounted cash inflows and outflows by contract based on the tenor of individual contract position for the remaining periods. These anticipated undiscounted cash flows have not been adjusted for counterparty credit or other reserves. These amounts exclude the cash flows associated with certain derivative instruments designated as hedges.
(3) Our mark-to-market values at December 31, 2006 were derived solely from market quotations instead of the combination of long-term valuation models and market quotations used in prior years.

Derivative Contracts

The absolute notional contract amounts associated with our commodity risk-management, interest rate and foreign currency exchange contracts are discussed in Item 7A. Quantitative and Qualitative Disclosures About Market Risk below.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

We are exposed to commodity price variability related to our power generation business and legacy trading portfolio. In addition, fuel requirements at our power generation facilities represent additional commodity price risks to us. In order to manage these commodity price risks, we routinely utilize various fixed-price forward purchase and sales contracts, futures and option contracts traded on the New York Mercantile Exchange and swaps and options traded in the over-the-counter financial markets to:

- manage and hedge our fixed-price purchase and sales commitments;
- reduce our exposure to the volatility of cash market prices; and
- hedge our fuel requirements for our generating facilities.

The potential for changes in the market value of our commodity, interest rate and currency portfolios is referred to as "market risk". A description of each market risk category is set forth below:

- commodity price risks result from exposures to changes in spot prices, forward prices and volatilities in commodities, such as electricity, natural gas, coal, fuel oil, emissions and other similar products;
- interest rate risks primarily result from exposures to changes in the level, slope and curvature of the yield curve and the volatility of interest rates; and
- currency rate risks result from exposures to changes in spot prices, forward prices and volatilities in currency rates.

In the past, we have attempted to manage these market risks through diversification, controlling position sizes and executing hedging strategies. The ability to manage an exposure may, however, be limited by adverse changes in market liquidity, our credit capacity or other factors.

VaR. In addition to applying business judgment, we use a number of quantitative tools to monitor our exposure to market risk. These tools include stress and scenario analyses performed periodically that measure the potential effects of various market events.

The modeling of the risk characteristics of our mark-to-market portfolio involves a number of assumptions and approximations. We estimate VaR using a JP Morgan RiskMetrics™ approach assuming a one-day holding period. Inputs for the VaR calculation are prices, positions, instrument valuations and the variance-covariance matrix. VaR does not account for liquidity risk or the potential that adverse market conditions may prevent liquidation of existing market positions in a timely fashion. While management believes that these assumptions and approximations are reasonable, there is no uniform industry methodology for estimating VaR, and different assumptions and/or approximations could produce materially different VaR estimates.

We use historical data to estimate our VaR and, to better reflect current asset and liability volatilities, this historical data is weighted to give greater importance to more recent observations. Given our reliance on historical data, VaR is effective in estimating risk exposures in markets in which there are not sudden fundamental changes or shifts in market conditions. An inherent limitation of VaR is that past changes in market risk factors, even when weighted toward more recent observations, may not produce accurate predictions of future market risk. VaR should be evaluated in light of this and the methodology's other limitations.

VaR represents the potential loss in value of our mark-to-market portfolio due to adverse market movements over a defined time horizon within a specified confidence level. For the VaR numbers reported below, a one-day time horizon and a 95% confidence level were used. This means that there is a one in 20 statistical chance that the daily portfolio value will fall below the expected maximum potential reduction in portfolio value at least as large as the reported VaR. Thus, a change in portfolio value greater than the expected change in portfolio value on a single trading day would be anticipated to occur, on average, about once a month. Gains or losses on a single day can exceed reported VaR by significant amounts. Gains or losses can also accumulate over a longer time horizon such as a number of consecutive trading days.

In addition, we have provided our VaR using a one-day time horizon and a 99% confidence level. The purpose of this disclosure is to provide an indication of earnings volatility using a higher confidence level. Under this presentation, there is a one in 100 statistical chance that the daily portfolio value will fall below the expected maximum potential reduction in portfolio value at least as large as the reported VaR. We have also disclosed a two-year comparison of daily VaR in order to provide context for the one-day amounts.

The following table sets forth the aggregate daily VaR and average VaR of the mark-to-market portion of our generation business and legacy trading portfolios.

Daily and Average VaR for Mark-to-Market Portfolios

	December 31, 2006	December 31, 2005
	(in millions)	
One Day VaR—95% Confidence Level	$1	$5
One Day VaR—99% Confidence Level	$1	$6
Average VaR for the Year-to-Date Period—95% Confidence Level	$3	$7

Credit Risk. Credit risk represents the loss that we would incur if a counterparty fails to perform pursuant to the terms of its contractual obligations. To reduce our credit exposure, we execute agreements that permit us to offset receivables, payables and mark-to-market exposure. We attempt to further reduce credit risk with certain counterparties by obtaining third party guarantees or collateral as well as the right of termination in the event of default.

Our Credit Department, based on guidelines approved by the Board of Directors, establishes our counterparty credit limits. Our industry typically operates under negotiated credit lines for physical delivery and financial contracts. Our credit risk system provides current credit exposure to counterparties on a daily basis.

The following table represents our credit exposure at December 31, 2006 associated with the mark-to-market portion of our risk-management portfolio, on a net basis.

Credit Exposure Summary

	Investment Grade Quality	Non-Investment Grade Quality	Total
		(in millions)	
Type of Business:			
Financial Institutions	$ 71	$—	$ 71
Utility and Power Generators	33	1	34
Total	$104	$ 1	$105

Of the $1 million in credit exposure to non-investment grade counterparties, 97% is collateralized or subject to other credit exposure protection.

Interest Rate Risk. Interest rate risk primarily results from variable rate debt obligations. Although changing interest rates impact the discounted value of future cash flows, and therefore the value of our risk management portfolios, the relative near-term nature and size of our risk management portfolios minimizes the impact. Management continues to monitor our exposure to fluctuations in interest rates and may execute swaps or other financial instruments to change our risk profile for this exposure.

We are exposed to fluctuating interest rates related to variable rate financial obligations. As of December 31, 2006, our fixed rate debt instruments as a percentage of total debt instruments was 82%. Based on sensitivity analysis of the variable rate financial obligations in our debt portfolio as of December 31, 2006, it is estimated that a one percentage point interest rate movement in the average market interest rates (either higher or lower) over the 12 months ended December 31, 2007 would either decrease or increase income before taxes by approximately $7 million. Hedging instruments that impact such interest rate exposure are included in the sensitivity analysis. Over time, we may seek to reduce the percentage of fixed rate financial obligations in our debt portfolio through the use of swaps or other financial instruments.

Foreign Currency Exchange Rate Risk. Foreign currency risk arises from our investments in affiliates and subsidiaries owned and operated in foreign countries. Such risk is also a result of risk management transactions with customers in countries outside the United States. Management monitors our exposure to fluctuations in foreign currency exchange rates. When possible, contracts are denominated in or indexed to the U.S. dollar.

At December 31, 2006, our primary foreign currency exchange rate exposures were the Canadian Dollar and European Euro. Additionally, as further discussed in "Liquidity and Capital Resources—Internal Liquidity Sources—Current Liquidity" beginning on page 52, at December 31, 2006, approximately $56 million cash denominated in the U.K. Pound, the Euro and the Canadian Dollar remains in the U.K. and Canada.

Derivative Contracts. The absolute notional financial contract amounts associated with our commodity risk-management and interest rate contracts accounted for on a mark-to-market basis were as follows at December 31, 2006 and 2005, respectively:

Absolute Notional Contract Amounts

	December 31, 2006	December 31, 2005
Natural Gas (Trillion Cubic Feet)	0.309	0.374
Electricity (Million Megawatt Hours) (1)	138.705	30.479
Emission Credits (Million Tons) (2)	0.0155	0.043
Fuel Oil (Million Barrels)	1.620	0.725
Fair Value Hedge Interest Rate Swaps (In Millions of U.S. Dollars)	$ 525	$ 525
Fixed Interest Rate Received on Swaps (%)	4.331	4.331
Interest Rate Risk-Management Contract (In Millions of U.S. Dollars)	$ 231	$ 306
Fixed Interest Rate Paid (%)	5.35	5.29
Interest Rate Risk-Management Contract (In Millions of U.S. Dollars)	$ 206	$ 281
Fixed Interest Rate Received (%)	5.28	5.23

(1) This amount includes notional volumes related to FTRs.

(2) These amounts represent emission credit contracts that we are required to account for as derivatives under SFAS No. 133. These amounts do not include the emission credits that we have recorded in our inventory related to allowances that we utilize in running our power generation fleet.

Item 8. ***Financial Statements and Supplementary Data***

Our financial statements and financial statement schedules are set forth at pages F-1 through F-102 inclusive, found at the end of this annual report, and are incorporated herein by reference.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

Not applicable.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). This evaluation included consideration of the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time period specified by the SEC. This evaluation also considered the work completed relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002, which is further described below. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2006 to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). Our 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 (GAAP). Our internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of our company are being made only in accordance with authorizations of our management and directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our 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. Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2006. In making this assessment, we used the criteria set forth in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on the results of this assessment and on those criteria, we concluded that our internal control over financial reporting was effective as of December 31, 2006.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

Remediation of Prior Material Weaknesses

Material Weakness Related to Income Taxes. As previously reported, as of December 31, 2005 and September 30, 2006, we did not maintain effective controls over the completeness and accuracy of the tax provision and deferred income tax balances in accordance with GAAP. Specifically, our processes, procedures and controls related to the preparation, analysis and recording of the income tax provision were not effective to ensure that the tax provision and deferred tax balances were recorded in accordance with GAAP. As of December 31, 2006, we have fully remediated this material weakness in internal control over financial reporting.

Specifically, during 2005 and 2006, numerous steps were taken to improve our internal controls around our tax accounting and tax reconciliation processes, procedures and controls:. These steps included (i) increased levels of review in the preparation of the quarterly and annual tax provisions; (ii) implemented new processes and procedures around the identification, analysis and recording the tax effects of significant transactions; (iii) implemented and formalized processes, procedures and documentation standards relating to preparation and analysis of the income tax provision; (iv) restructured our Tax Department to ensure appropriate segregation of duties regarding preparation and review of the quarterly and annual tax provision; (v) enhanced the competencies of our Tax Department personnel through the addition of experienced tax professionals; and (vi) formalized communication channels between the Tax and Accounting Departments.

During the fourth quarter 2006, we completed implementing the following steps: (i) further formalized and documented the procedures around the preparation and review of the tax provision; (ii) enhanced processes related to tax accounts in the general ledger and improved documentational support for computations; and (iii) enhanced the competencies and capabilities of our Tax Department personnel through ongoing formal training initiatives in key tax-related areas.

Material Weakness Related to Risk Management Assets and Liabilities. As previously reported, as of September 30, 2006, we did not maintain effective controls over the accuracy of our risk management asset and liability balances. Our processes, procedures and controls related to the calculation and analysis of applicable pricing data were not effective to ensure that the risk management asset and liability balances were accurately reflected in the financial statements. As of December 31, 2006, we have fully remediated this material weakness in internal control over financial reporting.

Specifically, during 2006, we implemented the following steps around our risk management asset and liability valuation process: (i) automated a process step that was previously performed manually; (ii) further formalized and documented the procedures around the end-of-day valuation process; (iii) expanded the review and validation process with respect to pricing data; (iv) performed a review of all pricing data to eliminate redundant or unnecessary data; (v) implemented a new monthly process to identify pricing data related to active positions; and (vi) further restricted access to and assigned accountability for process documentation.

Changes in Internal Control over Financial Reporting

The changes described in "Remediation of Prior Material Weaknesses" above were changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information***

Not applicable.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

Executive Officers

Set forth below are the names and positions of our executive officers as of February 27, 2007, together with their ages and years of service with us.

Name	Age	Position(s)	Served With the Company Since
Bruce A. Williamson	47	Chief Executive Officer and Chairman of the Board	2002
Stephen A. Furbacher	59	President and Chief Operating Officer	1996
Holli C. Nichols	36	Executive Vice President and Chief Financial Officer	2000
J. Kevin Blodgett	35	General Counsel, Executive Vice President—Administration and Secretary	2000
Lynn A. Lednicky	46	Executive Vice President—Commercial and Development	1991

The executive officers named above will serve in such capacities until the next annual meeting of our Board of Directors, or until their respective successors have been duly elected and have been qualified, or until their earlier death, resignation, disqualification or removal from office.

Bruce A. Williamson has served as Chief Executive Officer and as a director of Dynegy since October 2002 and as Chairman of the Board of Dynegy since May 2004. Prior to joining Dynegy, Mr. Williamson served in various capacities with Duke Energy and its affiliates. From August 2001 to October 2002, he served as President and Chief Executive Officer of Duke Energy Global Markets. In this capacity, he was responsible for all Duke Energy business units with global commodities and international business positions. From 1997 to August 2001, he served as Senior Vice President of Business Development and Risk Management and President and Chief Executive Officer at Duke Energy International. Mr. Williamson joined PanEnergy Corporation in June 1995, which then merged with Duke Power in June 1997. Prior to the Duke-PanEnergy merger, he served as PanEnergy's Vice President of Finance. Before joining PanEnergy, he held positions of increasing responsibility at Shell Oil Company, advancing over a 14-year period to Assistant Treasurer. He currently serves as a Director of Questar Corporation.

Stephen A. Furbacher has served as President and Chief Operating Officer since August 2005 and as Executive Vice President of Dynegy's previously owned natural gas liquids business segment from September 1996 to August 2005. Mr. Furbacher is responsible for overseeing our power generation operations and, until October 31, 2005, the Midstream operations. He joined Dynegy in May 1996, just prior to our acquisition of Chevron's midstream business. Before joining Dynegy, he served as President of Warren Petroleum Company, the natural gas liquids division of Chevron U.S.A. He began his career with Chevron in August 1973 and served in positions of increasing responsibility before being named President of Warren Petroleum Company in July 1994.

Holli C. Nichols has served as Executive Vice President and Chief Financial Officer since November 2005. Ms. Nichols is responsible for financial affairs, including finance and accounting, treasury, risk management, internal audit and investor and credit agency relationships. Ms. Nichols previously served as Senior Vice President and Treasurer from May 2004 to November 2005 and served as our Senior Vice President and Controller from June 2003 to May 2004 and as Vice President, Assistant Corporate Controller and Senior Consultant from May 2000 to June 2003. Ms. Nichols joined Dynegy from PricewaterhouseCoopers LLP in May 2000.

J. Kevin Blodgett has served as General Counsel and Executive Vice President—Administration of Dynegy since November 2005 and as Secretary since March 2006. Mr. Blodgett is responsible for our legal and administrative affairs, including legal services supporting Dynegy's operational, commercial and corporate areas, as well as ethics and compliance, human resources, information technology, building services, real estate and procurement management. Mr. Blodgett previously served as Senior Vice President, Human Resources from August 2004 to November 2005, as Group General Counsel—Corporate Finance & Securities and Corporate Secretary from May 2003 to August 2004 and as Assistant General Counsel, Senior Corporate Counsel and Corporate Counsel from October 2000 to May 2003. Mr. Blodgett joined Dynegy from Baker Botts LLP in October 2000.

Lynn A. Lednicky has served as Executive Vice President—Commercial and Development Group since January 2007. Mr. Lednicky is responsible for commercializing Dynegy's asset base and overseeing Dynegy's development projects within the power generation business. Mr. Lednicky has previously served as Executive Vice President of Strategic Planning and Corporate Business Development of Dynegy from November 2005 to January 2007, Senior Vice President of Strategic Planning and Corporate Business Development from July 2003 to November 2005, and Senior Vice President of Power Origination from December 2000 to July 2003. Mr. Lednicky joined Dynegy's predecessor Destec Energy, Inc. in July 1991.

Code of Ethics. We have adopted a Code of Ethics within the meaning of Item 406(b) of Regulation S-K. This Code of Ethics applies to our Chief Executive Officer, Chief Financial Officer, Controller and other persons performing similar functions designated by the Chief Financial Officer, and is incorporated as an exhibit to this Form 10-K.

Other Information. We intend to include the other information required by this Item 10 in our definitive proxy statement for our 2007 annual meeting of shareholders under the headings "Proposal 1—Election of Directors" and "Executive Compensation—Section 16(a) Beneficial Ownership Reporting Compliance," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2006. However, if such proxy statement is not filed within such 120-day period, the other information required by this Item 10 will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 11. *Executive Compensation*

We intend to include information with respect to executive compensation in our upcoming proxy statement under the heading "Executive Compensation", which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2006. However, if such proxy statement is not filed within such 120-day period, information with respect to executive compensation will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2006 as it relates to our equity compensation plans for our Class A common stock, the only class with respect to which we offer equity compensation.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	4,916,736	$13.34	13,595,621
Equity compensation plans not approved by security holders (1)	2,444,206	$11.23	5,115,888
Total	7,360,942	$12.63	18,711,509

(1) The plans that were not approved by our security holders are as follows: Extant Plan, Dynegy 2001 Non-Executive Stock Incentive Plan and Dynegy UK Plan. Please read Note 19—Capital Stock—Stock Options beginning on page F-55 for a brief description of our equity compensation plans, including these plans.

Consummation of the Merger Agreement with the LS Entities will result in a change in control as defined in our severance pay plans, as well as the various grant agreements. Please read Note 3—Business Combinations and Acquisitions—LS Power beginning on page F-17 for further discussion of the transaction. As a result, all outstanding long-term incentive awards previously granted to employees will fully vest and restrictions on shares of restricted stock previously awarded to employees will lapse immediately upon the closing of the transaction. The Merger Agreement provides that all such long-term incentive awards and shares of restricted stock will be covered by identical equity compensation plans provided by New Dynegy. The accelerated vesting and lapse of restrictions will not have a material effect on New Dynegy's financial condition, results of operations or cash flows.

We intend to include information regarding ownership of our outstanding securities in our upcoming proxy statement under the heading "Principal Shareholders", which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2006. However, if such proxy statement is not filed within such 120-day period, information regarding ownership of our outstanding securities will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 13. *Certain Relationships and Related Transactions and Director Independence*

We intend to include the information regarding related party transactions in our definitive proxy statement for our 2007 annual meeting of shareholders under the headings "Corporate Governance", "Principal Stockholders", "Proposal 1—Election of Directors" and "Executive Compensation—Employment Agreements and Change-in-Control Agreements" and "—Certain Relationships and Related Transactions," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2006. However, if such proxy statement is not filed within such 120-day period, the information regarding related party transactions will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 14. *Principal Accountant Fees and Services*

We intend to include information regarding principal accountant fees and services in our upcoming proxy statement under the heading "Independent Auditors", which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2006. However, if such proxy statement is not filed within such 120-day period, information regarding principal accountant fees and services will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

PART IV

Item 15. *Exhibits, Financial Statement Schedules*

(a) The following documents, which we have filed with the SEC pursuant to the Securities Exchange Act of 1934, as amended, are by this reference incorporated in and made a part of this report:

1. Financial Statements—Our consolidated financial statements are incorporated under Item 8. of this report.

2. Financial Statement Schedules—Financial Statement Schedules are incorporated under Item 8. of this report.

3. Exhibits—The following instruments and documents are included as exhibits to this report. All management contracts or compensation plans or arrangements set forth in such list are marked with a ††.

Exhibit Number	Description
2.1	—Purchase Agreement, dated February 2, 2004, among Dynegy Inc., Illinova Corporation, Illinova Generating Company and Ameren Corporation (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on February 4, 2004, File No. 1-15659).
2.2	—Plan of Merger, Contribution and Sale Agreement, dated September 14, 2006 by and among Dynegy Inc., LSP Gen Investors, LP, LS Power Partners, LP, LS Power Equity Partners PIE I, L.P., LS Power Equity Partners, L.P., LS Power Associates, L.P., Falcon Merger Sub Co. and Dynegy Acquisition, Inc. (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
2.3	—Limited Liability Company Membership Interests and Stock Purchase Agreement, dated as of September 14, 2006, among LS Power Associates, L.P., LS Power Equity Partners, L.P., LS Power Equity Partners PIE I, L.P., LS Power Partners, L.P. and Kendall Power LLC (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
3.1	—Amended and Restated Articles of Incorporation of Dynegy Inc. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2006 of Dynegy Inc., File No. 1-15659).
3.2	— Statement of Resolution Establishing Series of Series C Convertible Preferred Stock of Dynegy Inc. (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
3.3	—Amended and Restated Bylaws of Dynegy Inc. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. filed on November 21, 2005, File No. 1-15659).
3.4	—Amendment No. 1, effective as of May 19, 2006, to the Amended and Restated Bylaws of Dynegy Inc., dated as of November 16, 2005 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 22, 2006, File No. 1-15659).
4.1	—Indenture, dated as of December 11, 1995, by and among NGC Corporation, the Subsidiary Guarantors named therein and the First National Bank of Chicago, as Trustee (incorporated by reference to exhibits to the Registration Statement on Form S-3 of NGC Corporation, Registration No. 33-97368).

Exhibit Number	Description
4.2	—First Supplemental Indenture, dated as of August 31, 1996, by and among NGC Corporation, the Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1996 of NGC Corporation, File No. 1-11156).
4.3	—Second Supplemental Indenture, dated as of October 11, 1996, by and among NGC Corporation, the Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1996 of NGC Corporation, File No. 1-11156).
4.4	—Fourth Supplemental Indenture among NGC Corporation, Destec Energy, Inc. and The First National Bank of Chicago, as Trustee, dated as of June 30, 1997, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.12 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1997 of NGC Corporation, File No. 1-11156).
4.5	—Fifth Supplemental Indenture among NGC Corporation, the Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, dated as of September 30, 1997, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.18 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1997 of NGC Corporation, File No. 1-11156).
4.6	—Sixth Supplemental Indenture among NGC Corporation, the Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, dated as of January 5, 1998, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.19 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1997 of NGC Corporation, File No. 1-11156).
4.7	—Seventh Supplemental Indenture among NGC Corporation, the Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, dated as of February 20, 1998, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.20 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1997 of NGC Corporation, File No. 1-11156).
4.8	—Eighth Supplemental Indenture, dated July 25, 2003, that certain Indenture, dated as of December 11, 1995, between Dynegy Holdings Inc. and Wilmington Trust Company, as trustee (incorporated by reference to Exhibit 99.3 to the Current Report on Form 8-K of Dynegy Inc. filed on July 28, 2003, File No. 1-15659).
4.9	—Subordinated Debenture Indenture between NGC Corporation and The First National Bank of Chicago, as Debenture Trustee, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.10	—Amended and Restated Declaration of Trust among NGC Corporation, Wilmington Trust Company, as Property Trustee and Delaware Trustee, and the Administrative Trustees named therein, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.6 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).

Exhibit Number	Description
4.11	—Series A Capital Securities Guarantee Agreement executed by NGC Corporation and The First National Bank of Chicago, as Guarantee Trustee, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.12	—Common Securities Guarantee Agreement of NGC Corporation, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.13	—Registration Rights Agreement, dated as of May 28, 1997, among NGC Corporation, NGC Corporation Capital Trust I, Lehman Brothers, Salomon Brothers Inc. and Smith Barney Inc. (incorporated by reference to Exhibit 4.11 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.14	—Indenture, dated as of September 26, 1996, restated as of March 23, 1998, and amended and restated as of March 14, 2001, between Dynegy Holdings Inc. and Bank One Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2000 of Dynegy Holdings Inc., File No. 0-29311).
4.15	—First Supplemental Indenture, dated July 25, 2003 to that certain Indenture, dated as of September 26, 1996, between Dynegy Holdings Inc. and Wilmington Trust Company, as trustee (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on July 28, 2003, File No. 1-15659).
4.16	—Second Supplemental Indenture, dated as of April 12, 2006, to that certain Indenture, originally dated as of September 26, 1996, as amended and restated as of March 23, 1998 and again as of March 14, 2001, by and between Dynegy Holdings Inc. and Wilmington Trust Company (as successor to JPMorgan Chase Bank, N.A.), as trustee, as supplemented by that certain First Supplemental Indenture, dated as of July 25, 2003 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 12, 2006, File No. 1-15659).
4.17	—Registration Rights Agreement, dated as of April 12, 2006, by and among Dynegy Holdings Inc. and the several initial purchasers party thereto (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Inc. filed on April 12, 2006, File No. 1-15659).
4.18	—Exchange and Registration Rights Agreement (Preferred Stock), dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.19	—Amended and Restated Registration Rights Agreement (Common Stock), dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.20	—Amended and Restated Shareholder Agreement, dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.21	—Second Amended and Restated Shareholder Agreement, dated as of May 26, 2006, by and between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 1, 2006, File No. 1-15659).

Exhibit Number	Description
4.22	—Indenture, dated as of August 11, 2003, among Dynegy Holdings Inc., the guarantors named therein, Wilmington Trust Company, as trustee, and Wells Fargo Bank Minnesota, N.A., as collateral trustee, including the form of promissory note for each series of notes issuable pursuant to the Indenture (incorporated by reference to Exhibit 4.8 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.23	—Supplemental Indenture, dated August 24, 2005, between Dynegy Midstream Holdings, Inc., Dynegy Storage Technology and Services, Inc., Dynegy Gas Transportation, Inc., Dynegy Holdings Inc., the guarantors named therein, and Wilmington Trust Company, as trustee and Wells Fargo Bank, N.A., as collateral trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K of Dynegy Holdings Inc. filed on March 29, 2006, File No. 000-29311).
4.24	—Second Supplemental Indenture, dated as of March 28, 2006, by and among Dynegy Holdings Inc., the guarantors party thereto, Wilmington Trust Company, as trustee, and Wells Fargo Bank, N.A., as collateral trustee, supplementing the Indenture, dated as of August 11, 2003 (as supplemented by the Supplemental Indenture, dated as of August 24, 2005), pursuant to which the Second Priority Senior Secured Floating Rate Notes due 2008, 9.875% Second Priority Senior Secured Notes due 2010 and 10.125% Second Priority Senior Secured Notes due 2013 of Dynegy Holdings Inc. were issued (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on March 29, 2006, File No. 1-15659).
4.25	—Indenture, dated August 11, 2003, between Dynegy Inc., Dynegy Holdings Inc. and Wilmington Trust Company, as trustee, including the form of debenture issuable pursuant to the Indenture (incorporated by reference to Exhibit 4.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.26	—Supplemental Indenture, dated as of May 16, 2006, by and among Dynegy Inc., Dynegy Holdings Inc., and Wilmington Trust Company, as trustee, supplementing the Indenture, dated as of August 11, 2003, pursuant to which the 4.75% Convertible Subordinated Debentures due 2023 of Dynegy Inc. were issued (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 16, 2006, File No. 1-15659).
4.27	—Registration Rights Agreement, dated August 11, 2003, among Dynegy Inc., Dynegy Holdings Inc. and the initial purchasers named therein (incorporated by reference to Exhibit 4.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.28	—Registration Rights Agreement, dated as of March 29, 2006, by and among Dynegy Holdings Inc. and the several initial purchasers party thereto (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Inc. filed on April 12, 2006, File No. 1-15659).
4.29	—Registration Rights Agreement, effective as of July 21, 2006, by and among Dynegy Holdings Inc. RCP Debt, LLC and RCMF Debt, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on July 24, 2006, File No. 1-15659).
4.30	—Trust Indenture, dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and IBJ Schroder Bank & Trust Company, as Trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).

Exhibit Number	Description
4.31	—First Supplemental Indenture, dated as of January 1, 1993, to the Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and IBJ Schroder Bank & Trust Company, as Trustee (incorporated by reference to Exhibit 4.23 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).
4.32	—Second Supplemental Indenture, dated as of October 23, 2001, to the Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and The Bank of New York, as Trustee (incorporated by reference to Exhibit 4.24 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).
4.33	—Global Note representing the 8.50% Secured Bonds due 2007 of Sithe/Independence Power Partners, L.P. (incorporated by reference to Exhibit 4.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2005 of Dynegy Inc., File No. 1-15659).
4.34	—Global Note representing the 9.00% Secured Bonds due 2013 of Sithe/Independence Power Partners, L.P. (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2005 of Dynegy Inc., File No. 1-15659).
4.35	—Registration Rights Agreement, effective as of July 21, 2006, by and among Dynegy Holdings Inc., RCP Debt, LLC and RCMF Debt, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on July 24, 2006, File No. 1-15659).
4.36	—Shareholder Agreement, dated as of September 14, 2006, among Dynegy Acquisition, Inc. and LS Power Partners, L.P., LS Power Associates, L.P., LS Power Equity Partners, L.P., LS Power Equity Partners PIE I, L.P. and LSP Gen Investors, L.P. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
4.37	—Registration Rights Agreement, dated as of September 14, 2006, among Dynegy Acquisition, Inc., LS Power Partners, L.P., LS Power Associates, L.P., LS Power Equity Partners, L.P., LS Power Equity Partners PIE I, L.P. and LSP Gen Investors, L.P. (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
4.38	—Registration Rights Agreement, dated as of September 14, 2006, among Dynegy Acquisition, Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
4.39	—Registration Rights Agreement, dated as of September 14, 2006, among Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.4 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
4.40	—Lock-Up Agreement, dated as of September 14, 2006, by and among LSP Gen Investors, LP, LS Power Partners, LP, LS Power Associates, L.P., LS Power Equity Partners PIE I, LP, LS Power Equity Partners, L.P. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.5 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).

There have not been filed or incorporated as exhibits to this annual report, other debt instruments defining the rights of holders of our long-term debt, none of which relates to authorized indebtedness that exceeds 10% of our consolidated assets. We hereby agree to furnish a copy of any such instrument not previously filed to the SEC upon request.

Exhibit Number	Description
10.1	—Dynegy Inc. 1998 U.K. Stock Option Plan (incorporated by reference to Exhibit 10.4 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156). ††
10.2	—Dynegy Inc. Amended and Restated Employee Equity Option Plan (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156). ††
10.3	—Dynegy Inc. 1999 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156). ††
10.4	—Dynegy Inc. 2000 Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156). ††
10.5	—Amendment to the Dynegy Inc. 2000 Long Term Incentive Plan effective January 1, 2006 (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).††
10.6	—Dynegy Inc. 2001 Non-Executive Stock Incentive Plan (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080). ††
10.7	—Dynegy Inc. 2002 Long Term Incentive Plan (incorporated by reference to Appendix A to the Definitive Proxy Statement on Schedule 14A of Dynegy Inc., File No. 1-15659, filed with the SEC on April 9, 2002).,††
10.8	—Amendment to the Dynegy Inc. 2002 Long Term Incentive Plan, effective January 1, 2006 (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).††
10.9	—Extant, Inc. Equity Compensation Plan (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-47422). ††
10.10	—Employment Agreement, dated October 18, 2002, between Bruce A. Williamson and Dynegy Inc. (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2002 of Dynegy Inc., File No. 1-15659). ††
10.11	—First Amendment to October 18, 2002 Employment Agreement, dated August 17, 2005, between Bruce A. Williamson and Dynegy Inc. (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2005 of Dynegy Inc., File No. 1-15659). ††
10.12	—Second Amendment to October 18, 2002 Employment Agreement, dated September 15, 2005, between Bruce A. Williamson and Dynegy Inc. (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2005, File No. 1-15659). ††
10.13	—Third Amendment to October 18, 2002 Employment Agreement, dated as of March 16, 2006, between Dynegy Inc. and Bruce A. Williamson (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659). ††
10.14	—Agreement Concerning Employment Agreement and Stock Options, dated as of March 16, 2006, between Dynegy Inc. and Bruce A. Williamson (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659). ††

Exhibit Number	Description
10.15	—Non-Qualified Stock Option Award Agreement, dated as of March 16, 2006, between Dynegy Inc., all of its subsidiaries and Bruce A. Williamson (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659). ††
10.16	—Form of Performance Award Agreement (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659). ††
10.17	—Form of Non-Qualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.7 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).††
10.18	—Form of Restricted Stock Award Agreement (Managing Directors and Above) (incorporated by reference to Exhibit 10.8 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).††
10.19	—Form of Restricted Stock Award Agreement (Directors and Below) (incorporated by reference to Exhibit 10.9 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659). ††
10.20	—Severance Agreement and Release, dated December 31, 2005, between Dynegy Inc. and Carol F. Graebner (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on January 6, 2006, File No. 1-15659). ††
10.21	—Severance Agreement and Release, dated December 31, 2005, between Dynegy Inc. and R. Blake Young (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on January 6, 2006, File No. 1-15659).††
10.22	—Dynegy Inc. 401(k) Savings Plan, as amended and restated effective January 1, 2002 (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 383-76570). ††
10.23	—First Amendment to the Dynegy Inc. 401(k) Savings Plan, effective February 11, 2002 (incorporated by reference to Exhibit 10.19 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). ††
10.24	—Second Amendment to the Dynegy Inc. 401(k) Savings Plan, effective January 1, 2002 (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). ††
10.25	—Third Amendment to the Dynegy Inc. 401(k) Savings Plan, effective October 1, 2003 (incorporated by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). ††
10.26	—Amendment to the Dynegy Inc. 401(k) Savings Plan, effective January 1, 2004 (incorporated by reference to Exhibit 10.18 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). ††
10.27	—Dynegy Inc. 401(k) Savings Plan Trust Agreement (incorporated by reference to Exhibit 10.2 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76570). ††
10.28	—Dynegy Inc. Deferred Compensation Plan (incorporated by reference to Exhibit 4.6 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080). ††
10.29	—Dynegy Inc. Deferred Compensation Plan Trust Agreement (incorporated by reference to Exhibit 4.7 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080). ††

Exhibit Number	Description
10.30	—Dynegy Inc. Short-Term Executive Stock Purchase Loan Program (incorporated by reference to Exhibit 10.19 to the Annual Report on Form 10-K for the Year Ended December 31, 2001 of Dynegy Inc., File No. 1-15659). ††
10.31	—Dynegy Inc. Deferred Compensation Plan for Certain Directors (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). ††
10.32	—First Amendment to the Dynegy Inc. Deferred Compensation Plan for Certain Directors, dated September 15, 2005 (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2005, File No. 1-15659). ††
10.33	—Second Amendment to the Dynegy Inc. Deferred Compensation Plan for Certain Directors, dated December 16, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on December 22, 2005, File No. 1-15659). ††
10.34	—Dynegy Inc. Executive Severance Pay Plan, as amended and restated effective as of February 1, 2005 (incorporated by reference to Exhibit 99.3 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2005, File No. 1-15659). ††
10.35	—First Amendment to the Dynegy Inc. Executive Severance Pay Plan, dated September 15, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2005, File No. 1-15659). ††
10.36	—Second Amendment to the Dynegy Inc. Executive Severance Pay Plan, dated October 31, 2005 (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on November 4, 2005, File No. 1-15659). ††
10.37	—Second Supplement to the Dynegy Inc. Executive Severance Pay Plan, dated November 20, 2003 (incorporated by reference to Exhibit 99.4 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2005, File No. 1-15659). ††
10.38	—First Amendment to the Second Supplement to the Dynegy Inc. Executive Severance Pay Plan, dated June 22, 2005 (incorporated by reference to Exhibit 99.5 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2005, File No. 1-15659). ††
10.39	—Second Amendment to the Second Supplement to the Dynegy Inc. Executive Severance Pay Plan, dated September 15, 2005 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2005, File No. 1-15659). ††
10.40	—Third Amendment to the Second Supplement to the Dynegy Inc. Executive Severance Pay Plan, dated October 31, 2005 (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Dynegy Inc. filed on November 4, 2005, File No. 1-15659). ††
10.41	—Dynegy Inc. Mid-Term Incentive Performance Award Program (incorporated by reference to Exhibit 10.29 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). ††
10.42	—Termination of the Dynegy Inc. Mid-Term Incentive Performance Award Program, effective January 1, 2006 (incorporated by reference to Exhibit 10.35 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2005 of Dynegy Inc., File No. 1-15659). ††
10.43	—Dynegy Inc. Incentive Compensation Plan, as amended and restated effective January 1, 2006 (incorporated by reference to Exhibit 10.36 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2005 of Dynegy Inc. File No. 1-15659).††

Exhibit Number	Description
10.44	—Dynegy Northeast Generation, Inc. Savings Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-111985). ††
10.45	—Amendment to the Dynegy Northeast Generation, Inc. Savings Incentive Plan, effective January 1, 2004 (incorporated by reference to Exhibit 10.31 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659): ††
10.46	—Dynegy Inc. Severance Pay Plan, as amended and restated effective February 1, 2005 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2005, File No. 1-15659). ††
10.47	—First Amendment to the Dynegy Inc. Severance Pay Plan, dated October 31, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on November 4, 2005, File No. 1-15659). ††
10.48	—Second Amendment to the Dynegy Inc. Severance Pay Plan, dated December 14, 2005 (incorporated by reference to Exhibit 10.41 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2005 of Dynegy Inc. File No. 1-15659).††
10.49	—First Supplemental Plan to the Dynegy Inc. Severance Pay Plan, dated June 22, 2005 (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2005, File No. 1-15659). ††
10.50	— First Amendment to the First Supplemental Plan to the Dynegy Inc. Severance Pay Plan, dated October 31, 2005 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on November 4, 2005, File No. 1-15659). ††
10.51	— Fourth Amended and Restated Credit Agreement, dated as of April 19, 2006, among Dynegy Holdings Inc., as borrower, Dynegy Inc., as parent guarantor, the other guarantors party thereto, the lenders party thereto and various other parties thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 20, 2006, File No. 1-15659).
10.52	—Amendment No. 1, dated as of May 26, 2006, to the Fourth Amended and Restated Credit Agreement, dated as of April 19, 2006, among Dynegy Holdings Inc., as borrower, Dynegy Inc., as parent guarantor, the other guarantors party thereto, the lenders party thereto and the various other parties thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 1, 2006, File No. 1-15659).
10.53	—Amendment No. 2, dated as of July 11, 2006, to the Fourth Amended and Restated Credit Agreement, dated as of April 19, 2006, among Dynegy Holdings Inc., as borrower, Dynegy Inc., as parent guarantor, the other guarantors party thereto, the lenders party thereto and the various other parties thereto (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2006 of Dynegy Inc., File No. 1-15659).
10.54	—Shared Security Agreement, dated April 1, 2003, among Dynegy Holdings, Inc., various grantors named therein, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.32 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659).
10.55	—Non-Shared Security Agreement, dated April 1, 2003, among Dynegy Inc., various grantors named therein and Bank One, N.A. as collateral agent (incorporated by reference to Exhibit 10.33 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659):

Exhibit Number	Description
10.56	—Collateral Trust and Intercreditor Agreement, dated as of April 1, 2003, among Dynegy Holdings Inc., various grantors named therein, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.34 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659).
10.57	—Amendment No. 1 to Collateral Trust and Intercreditor Agreement, dated as of May 28, 2004, among Dynegy Holdings Inc., various grantors named therein, JPMorgan Chase Bank, as collateral agent, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2004 of Dynegy Inc., File No. 1-15659).
10.58	—Intercreditor Agreement, dated August 11, 2003, among Dynegy Holdings Inc., various grantors named therein, Wilmington Trust Company, as corporate trustee, John M. Beeson, Jr., as individual trustee, Bank One, NA, as collateral agent, and Wells Fargo Bank Minnesota, N.A., as collateral trustee (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.59	—Second Lien Shared Security Agreement, dated August 11, 2003, among Dynegy Holdings Inc., various grantors named therein and Wells Fargo Bank Minnesota, N.A., as collateral trustee (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.60	—Second Lien Shared Security Agreement Supplement, dated as of August 24, 2005, by Dynegy Midstream Holdings, Inc., Dynegy Storage Technology and Services, Inc. and Dynegy Gas Transportation, Inc. in favor of Wells Fargo Bank, N.A., as collateral trustee (supplementing the Second Lien Shared Security Agreement dated August 11, 2003 among Dynegy Holdings Inc., Dynegy Inc., as a grantor, the other grantors named therein and Wells Fargo Bank Minnesota, N.A., as collateral trustee) (incorporated by reference to Exhibit 10.12 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2006 of Dynegy Inc., File No. 1-15659).
10.61	—Second Lien Non-Shared Security Agreement, dated August 11, 2003, among Dynegy Inc., various grantors named therein and Wells Fargo Bank Minnesota, N.A., as collateral trustee (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.62	—Purchase Agreement, dated August 1, 2003, among Dynegy Inc., Dynegy Holdings Inc. and the initial purchasers named therein (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.63	—Purchase Agreement, dated August 1, 2003, among Dynegy Holdings Inc., the guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.64	—Purchase Agreement, dated September 30, 2003, among Dynegy Holdings Inc., the guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 15, 2003, File No. 1-15659).
10.65	—Purchase Agreement, dated as of March 29, 2006, for the sale of $750,000,000 aggregate principal amount of the 8.375% Senior Unsecured Notes due 2016 of Dynegy Holdings Inc. among Dynegy Holdings Inc. and the several initial purchasers named therein (incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2006 of Dynegy Inc., File No. 1-15659).

Exhibit Number	Description
10.66	—Escrow Agreement, dated as of September 30, 2004, among Illinova Corporation, Ameren Corporation and JPMorgan Chase Bank, as escrow agent (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2004 of Dynegy Inc., File No. 1-15659).
10.67	—Stock Purchase Agreement, dated as of November 1, 2004, among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. (incorporated by reference to Exhibit 10.48 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc. File No. 1-15659)
10.68	—Amendment to Stock Purchase Agreement (Special Payroll Payment), dated as of January 28, 2005, among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc. File No. 1-15659)
10.69	—Amendment to Stock Purchase Agreement, dated as of January 31, 2005, among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).
10.70	—Amendment to Stock Purchase Agreement (Luz Sale), dated as of January 31, 2005, among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).
10.71	—Tenth Amendment to Amended and Restated Base Gas Sales Agreement, dated as of June 29, 2001, by and between Enron North America Corp. and Sithe/Independence Power Partners, L.P. (incorporated by reference to Exhibit 10.52 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc. File No. 1-15659).
10.72	—Assignment and Assumption Agreement, dated as of November 17, 2004, between Dynegy Power Marketing, Inc. and Constellation Energy Commodities Group, Inc. (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc., File No. 1-15659).
10.73	—Partnership Interest Purchase Agreement, dated as of August 2, 2005, among Dynegy Inc. Dynegy Holdings Inc., Dynegy Midstream Holdings, Inc., and Dynegy Midstream G.P., Inc. as Sellers and Targa Resources, Inc., Targa Resources Partners OLP LP, and Targa Midstream GP, LLC as Buyers (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2005 of Dynegy Inc., File No. 1-15659).
10.74	—Steam and Electric Power Sales Agreement, dated as of September 6, 2005, between Cogen Lyondell, Inc. and Lyondell Chemical Company (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2005 of Dynegy Inc., File No. 1-15659).
10.75	—Services Agreement for CLI Facility, dated as of September 6, 2005, between Cogen Lyondell, Inc. and Lyondell Chemical Company (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2005 of Dynegy Inc., File No. 1-15659).
10.76	—Amended and Restated Lease and Easement Agreement, dated as of September 6, 2005, between Cogen Lyondell, Inc. and Lyondell Chemical Company (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2005 of Dynegy Inc., File No. 1-15659).

Exhibit Number	Description
10.77	—Guaranty Agreement, dated as of September 6, 2005, by Dynegy Holdings Inc. on behalf of Cogen Lyondell, Inc. in favor of Lyondell Chemical Company (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2005 of Dynegy Inc., File No. 1-15659).
10.78	—Termination Agreement and Release, dated as of December 23, 2005, between Quachita Power, LLC and Dynegy Power Marketing, Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on December 28, 2005, File No. 1-15659).
10.79	—Purchase Agreement (Rocky Road Power), dated December 27, 2005, between NRG Rocky Road LLC, NRG Energy, Inc., Termo Santander Holding, L.L.C. and Dynegy Inc. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on December 28, 2005, File No. 1-15659).
10.80	—Purchase Agreement (West Coast Power), dated December 27, 2005, between NRG West Coast LLC, NRG Energy, Inc., DPC II Inc. and Dynegy Inc. (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on December 28, 2005, File No. 1-15659).
10.81	—Stipulation of Settlement, dated May 2, 2005, (Shareholder Class Action Litigation) (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2005 of Dynegy Inc., File No. 1-15659).
10.82	—Stipulation of Settlement, dated April 29, 2005, (Shareholder Derivative Litigation) (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2005 of Dynegy Inc., File No. 1-15659).
10.83	—Baldwin Consent Decree, approved May 27, 2005 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 31, 2005, File No. 1-15659).
10.84	—Director Compensation Summary (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 24, 2005, File No. 1-15659). ††
10.85	—Purchase Agreement, dated as of May 21, 2006, by and between Dynegy Inc. and Rockingham Power, L.L.C., as sellers, and Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC, as purchaser (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 25, 2006, File No. 1-15659).
10.86	—Preferred Stock Redemption Agreement, dated as of May 22, 2006, by and between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on May 25, 2006, File No. 1-15659).
10.87	—Exchange Agreement, dated as of July 21, 2006, by and among Dynegy Holdings Inc., RCP Debt, LLC and RCMF Debt, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on July 24, 2006, File No. 1-15659).
10.88	—Voting Agreement, dated as of September 14, 2006, by and among LSP Gen Investors, LP, LS Power Partners LP, LS Power Associates, L.P., LS Power Equity Partners PIE I, LP, LS Power Equity Partners, L.P. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
10.89	—Voting Agreement, dated as of September 14, 2006, by and among LS Power Associates, L.P., LSP Gen Investors, LP, LS Power Equity Partners PIE I, LP, LS Power Equity Partners, L.P., LS Power Partners, LP and Bruce A. Williamson, Stephen A. Furbacher, Holli C. Nichols, Lynn A. Lednicky and J. Kevin Blodgett (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).

Exhibit Number	Description
10.90	—Corporate Opportunity Agreement, dated as of September 14, 2006, between Dynegy Acquisition, Inc. and LS Power Development, LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
10.91	—BGS-FP Supplier Forward Contract dated September 20, 2006 (Term through May 31, 2008) by and between Dynegy Power Marketing, Inc., Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS and Illinois Power Company d/b/a AmerenIP (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on September 25, 2006, File No. 1-15659).
10.92	—BGS-FP Supplier Forward Contract dated September 20, 2006 (Term through May 31, 2009) by and between Dynegy Power Marketing, Inc., Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS and Illinois Power Company d/b/a AmerenIP (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on September 25, 2006, File No. 1-15659).
10.93	—Asset Purchase Agreement, dated January 31, 2007, by and between Dynegy Holdings Inc., Calcasieu Power, LLC and Entergy Gulf States, Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on February 2, 2007, File No. 1-15659).
14.1	—Dynegy Inc. Code of Ethics for Senior Financial Professionals (incorporated by reference to Exhibit 14.1 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1- 15659).
**21.1	—Subsidiaries of the Registrant.
**23.1	—Consent of PricewaterhouseCoopers LLP.
**23.2	—Consent of PricewaterhouseCoopers LLP (West Coast Power LLC).
**24.1	—Powers of Attorney of Directors and Officers of the registrant (included on the Form 10-K Signature Page).
**31.1	—Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.2	—Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
†32.1	—Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
†32.2	—Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

** Filed herewith

† Pursuant to Securities and Exchange Commission Release No. 33-8238, this certification will be treated as "accompanying" this report and not "filed" as part of such report for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or the Exchange Act, or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, the thereunto duly authorized.

DYNEGY INC.

Date: February 27, 2007

By: /s/ BRUCE A. WILLIAMSON

Bruce A. Williamson
Chief Executive Officer and
Chairman of the Board

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints J. Kevin Blodgett, Kent R. Stephenson and Heidi D. Lewis, each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign, execute and file this report under the Securities Exchange Act of 1934 and any and all amendments to this report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or theirs or his or her substitutes, may do or cause to be done by virtue hereof.

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

/s/ BRUCE A. WILLIAMSON **Bruce A. Williamson**	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 27, 2007
/s/ HOLLI C. NICHOLS **Holli C. Nichols**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2007
/s/ CAROLYN J. STONE **Carolyn J. Stone**	Senior Vice President and Controller (Principal Accounting Officer)	February 27, 2007
/s/ DAVID W. BIEGLER **David W. Biegler**	Director	February 27, 2007
/s/ THOMAS D. CLARK, JR. **Thomas D. Clark, Jr.**	Director	February 27, 2007
/s/ VICTOR E. GRIJALVA **Victor E. Grijalva**	Director	February 27, 2007
/s/ PATRICIA A. HAMMICK **Patricia A. Hammick**	Director	February 27, 2007
/s/ GEORGE L. MAZANEC **George L. Mazanec**	Director	February 27, 2007

/s/ Robert C. Oelkers Robert C. Oelkers	Director	February 27, 2007
/s/ Rebecca B. Roberts Rebecca B. Roberts	Director	February 27, 2007
/s/ Howard B. Sheppard Howard B. Sheppard	Director	February 27, 2007
/s/ William L. Trubeck William L. Trubeck	Director	February 27, 2007

DYNEGY INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Dynegy Inc:

We have completed integrated audits of Dynegy Inc.'s consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedules

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Dynegy Inc. and its subsidiaries at December 31, 2006 and 2005, and the 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. In addition, in our opinion, the financial statement schedules listed in the accompanying index present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 17, the Company is the subject of substantial litigation. The Company's ongoing liquidity, financial position and operating results may be adversely impacted by the nature, timing and amount of the resolution of such litigation. The consolidated financial statements do not include any adjustments, beyond existing accruals applicable under Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies," that might result from the ultimate resolution of such matters.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A, that 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), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company 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 the 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 opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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. An audit of internal control over financial reporting includes 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 consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

PricewaterhouseCoopers LLP
Houston, Texas
February 27, 2007

DYNEGY INC.

CONSOLIDATED BALANCE SHEETS
(in millions, except share data)

	December 31, 2006	December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 371	$ 1,549
Restricted cash	280	397
Accounts receivable, net of allowance for doubtful accounts of $48 and $103, respectively	257	611
Accounts receivable, affiliates	1	29
Inventory	194	214
Assets from risk-management activities	794	665
Deferred income taxes	93	14
Prepayments and other current assets	92	227
Total Current Assets	2,082	3,706
Property, Plant and Equipment	6,473	6,515
Accumulated depreciation	(1,522)	(1,192)
Property, Plant and Equipment, Net	4,951	5,323
Other Assets		
Unconsolidated investments	—	270
Restricted investments	83	85
Assets from risk-management activities	16	165
Intangible assets	347	392
Deferred income taxes	12	3
Other long-term assets	139	182
Total Assets	$ 7,630	$10,126
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 172	$ 504
Accounts payable, affiliates	—	46
Accrued interest	66	159
Accrued liabilities and other current liabilities	231	649
Liabilities from risk-management activities	722	687
Notes payable and current portion of long-term debt	68	71
Total Current Liabilities	1,259	2,116
Long-term debt	2,990	4,028
Long-term debt to affiliates	200	200
Long-Term Debt	3,190	4,228
Other Liabilities		
Liabilities from risk-management activities	35	255
Deferred income taxes	469	558
Other long-term liabilities	410	429
Total Liabilities	5,363	7,586
Commitments and Contingencies (Note 17)		
Redeemable Preferred Securities, redemption value of zero at December 31, 2006 and $400 at December 31, 2005 (Note 15)	—	400
Stockholders' Equity		
Class A Common Stock, no par value, 900,000,000 shares authorized at December 31, 2006 and December 31, 2005; 403,137,339 and 305,129,052 shares issued and outstanding at December 31, 2006 and December 31, 2005, respectively	3,367	2,949
Class B Common Stock, no par value, 360,000,000 shares authorized at December 31, 2006 and December 31, 2005; 96,891,014 shares issued and outstanding at December 31, 2006 and December 31, 2005	1,006	1,006
Additional paid-in capital	39	51
Subscriptions receivable	(8)	(8)
Accumulated other comprehensive income, net of tax	67	4
Accumulated deficit	(2,135)	(1,793)
Treasury stock, at cost, 1,787,004 and 1,714,026 shares at December 31, 2006 and December 31, 2005, respectively	(69)	(69)
Total Stockholders' Equity	2,267	2,140
Total Liabilities and Stockholders' Equity	$ 7,630	$10,126

See the notes to the consolidated financial statements

DYNEGY INC.

CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per share data)

	Year Ended December 31,		
	2006	2005	2004
Revenues	$ 2,017	$ 2,313	$ 2,451
Cost of sales, exclusive of depreciation shown separately below	(1,387)	(2,416)	(1,850)
Depreciation and amortization expense	(230)	(220)	(235)
Impairment and other charges	(155)	(46)	(78)
Gain (loss) on sale of assets, net	3	(1)	(58)
General and administrative expenses	(196)	(468)	(330)
Operating income (loss)	52	(838)	(100)
Earnings (losses) from unconsolidated investments	(1)	2	192
Interest expense	(382)	(389)	(453)
Debt conversion costs	(249)	—	—
Other income and expense, net	54	26	12
Minority interest expense	—	—	(3)
Loss from continuing operations before income taxes	(526)	(1,199)	(352)
Income tax benefit	168	395	172
Loss from continuing operations	(358)	(804)	(180)
Income from discontinued operations, net of tax expense of $6, $357 and $111, respectively (Note 4)	24	899	165
Income (loss) before cumulative effect of change in accounting principles	(334)	95	(15)
Cumulative effect of change in accounting principles, net of tax benefit of zero, $2 and zero, respectively (Note 2)	1	(5)	—
Net income (loss)	(333)	90	(15)
Less: preferred stock dividends	9	22	22
Net income (loss) applicable to common stockholders	$ (342)	$ 68	$ (37)
Earnings (Loss) Per Share (Note 16):			
Basic earnings (loss) per share:			
Loss from continuing operations	$ (0.80)	$ (2.13)	$ (0.53)
Income from discontinued operations	0.05	2.32	0.43
Cumulative effect of change in accounting principles	—	(0.01)	—
Basic earnings (loss) per share	$ (0.75)	$ 0.18	$ (0.10)
Diluted earnings (loss) per share:			
Loss from continuing operations	$ (0.80)	$ (2.13)	$ (0.53)
Income from discontinued operations	0.05	2.32	0.43
Cumulative effect of change in accounting principles	—	(0.01)	—
Diluted earnings (loss) per share	$ (0.75)	$ 0.18	$ (0.10)
Basic shares outstanding	459	387	378
Diluted shares outstanding	509	513	504

See the notes to the consolidated financial statements

DYNEGY INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (333)	$ 90	$ (15)
Adjustments to reconcile income (loss) to net cash flows from operating activities:			
Depreciation and amortization	265	278	356
Impairment and other charges	155	46	83
(Earnings) losses from unconsolidated investments, net of cash distributions	1	73	(66)
Risk-management activities	(87)	46	(50)
Gain on sale of assets, net	(5)	(1,096)	(11)
Deferred taxes	(162)	(73)	(74)
Cumulative effect of change in accounting principles (Note 2)	(1)	5	—
Reserve for doubtful accounts	(35)	1	—
Liability associated with natural gas transportation contracts (Note 4)	—	—	(148)
Independence toll settlement charge (Note 3)	—	169	—
Legal and settlement charges	(2)	119	104
Sterlington toll settlement charge (Note 4)	—	364	—
Sithe Subordinated Debt exchange charge (Note 12)	36	—	—
Debt conversion costs	249	—	—
Other	71	18	(49)
Changes in working capital:			
Accounts receivable	391	(134)	4
Inventory	8	(91)	(36)
Prepayments and other assets	126	148	(107)
Accounts payable and accrued liabilities	(885)	(2)	(13)
Changes in non-current assets	11	(15)	(22)
Changes in non-current liabilities	3	24	49
Net cash provided by (used in) operating activities	(194)	(30)	5
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(155)	(195)	(311)
Proceeds from asset sales, net	227	2,488	576
Business acquisitions, net of cash acquired	(8)	(120)	(3)
Proceeds from exchange of unconsolidated investments, net of cash acquired (Note 3 and Note 4)	165	—	—
(Increase) decrease in restricted cash	121	(353)	—
Other investing, net	8	4	—
Net cash provided by investing activities	358	1,824	262
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from long-term borrowings	1,071	600	581
Repayments of borrowings	(1,930)	(1,432)	(650)
Debt conversion costs	(249)	—	—
Redemption of Series C Preferred (Note 13)	(400)	—	—
Net proceeds from issuance of capital stock	183	2	5
Dividends and other distributions, net	(17)	(22)	(22)
Other financing, net	—	(21)	(29)
Net cash used in financing activities	(1,342)	(873)	(115)
Effect of exchange rate changes on cash	—	—	(1)
Net increase (decrease) in cash and cash equivalents	(1,178)	921	151
Cash and cash equivalents, beginning of period	1,549	628	477
Cash and cash equivalents, end of period	$ 371	$ 1,549	$ 628

See the notes to the consolidated financial statements

DYNEGY INC.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(in millions)

	Common Stock	Additional Paid-In Capital	Subscriptions Receivable	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Treasury Stock	Total
December 31, 2003	$3,854	$ 41	$ (8)	$(20)	$(1,824)	$(68)	$1,975
Net loss	—	—	—	—	(15)	—	(15)
Other comprehensive income, net of tax	—	—	—	7	—	—	7
Options exercised	5	(6)	—	—	—	—	(1)
Dividends and other distributions	—	—	—	—	(22)	—	(22)
401(k) plan and profit sharing stock	6	—	—	—	—	—	6
Options and restricted stock granted	—	6	—	—	—	—	6
December 31, 2004	$3,865	$ 41	$ (8)	$(13)	$(1,861)	$(68)	$1,956
Net income	—	—	—	—	90	—	90
Other comprehensive income, net of tax	—	—	—	17	—	—	17
Options exercised	4	1	—	—	—	(1)	4
Dividends and other distributions	—	—	—	—	(22)	—	(22)
401(k) plan and profit sharing stock	5	—	—	—	—	—	5
Options and restricted stock granted	—	9	—	—	—	—	9
Shareholder litigation settlement	81	—	—	—	—	—	81
December 31, 2005	$3,955	$ 51	$ (8)	$ 4	$(1,793)	$(69)	$2,140
Net loss	—	—	—	—	(333)	—	(333)
Other comprehensive income, net of tax	—	—	—	98	—	—	98
Adjustment to initially apply SFAS No. 158, net of tax benefit of $21	—	—	—	(35)	—	—	(35)
Options exercised	5	(5)	—	—	—	—	—
Dividends and other distributions	—	—	—	—	(9)	—	(9)
401(k) plan and profit sharing stock	3	—	—	—	—	—	3
Options and restricted stock granted	—	8	—	—	—	—	8
Equity issuance (Note 12)	185	(7)	—	—	—	—	178
Equity conversion (Note 12)	225	(8)	—	—	—	—	217
December 31, 2006	$4,373	$ 39	$ (8)	$ 67	$(2,135)	$(69)	$2,267

See the notes to the consolidated financial statements

DYNEGY INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in millions)

	Year Ended December 31,		
	2006	2005	2004
Net income (loss)	$(333)	$ 90	$ (15)
Cash flow hedging activities, net:			
Unrealized mark-to-market gains (losses) arising during period, net	95	(70)	(62)
Reclassification of mark-to-market (gains) losses to earnings, net	(17)	84	36
Changes in cash flow hedging activities, net (net of tax benefit (expense) of $(46), $(8) and $16, respectively)	78	14	(26)
Foreign currency translation adjustments	(1)	8	(11)
Minimum pension liability (net of tax benefit (expense) of ($5), $3 and $(26), respectively)	10	(5)	44
Unrealized gains on securities, net of tax expense of $(7)	11	—	—
Other comprehensive income, net of tax	98	17	7
Comprehensive income (loss)	$(235)	$107	$ (8)

See the notes to the consolidated financial statements

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Operations of the Company

Dynegy Inc. (together with our subsidiaries, "we", "us" or "our") is a holding company and conducts substantially all of its business through its subsidiaries. Our current business operations are focused primarily on the power generation sector of the energy industry. We report the results of our power generation business as three separate segments in our consolidated financial statements: (1) the Midwest segment (GEN-MW); (2) the Northeast segment (GEN-NE); and (3) the South segment (GEN-SO). We also separately report the results of our CRM business, which primarily consists of our Kendall power tolling arrangement (and does not include the Sithe toll which is in GEN-NE and is an intercompany agreement) as well as legacy natural gas, power and emissions trading positions. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest. As described below, our natural gas liquids business, which was conducted through DMSLP and its subsidiaries, was sold to Targa Resources, Inc. (Targa) on October 31, 2005. Additionally, as described below, our former regulated energy delivery business, which was conducted through Illinois Power and its subsidiaries, was sold to Ameren Corporation on September 30, 2004.

Note 2—Summary of Significant Accounting Policies

The preparation of consolidated financial statements in conformity with GAAP requires management to make informed estimates and judgments that affect our reported financial position and results of operations based on currently available information. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (i) developing fair value assumptions, including estimates of future cash flows and discount rates, (ii) analyzing tangible and intangible assets for possible impairment, (iii) estimating the useful lives of our assets, (iv) assessing future tax exposure and the realization of deferred tax assets, (v) determining amounts to accrue for contingencies, guarantees and indemnifications and (vi) estimating various factors used to value our pension assets and liabilities. Actual results could differ materially from our estimates.

Principles of Consolidation. The accompanying consolidated financial statements include our accounts and the accounts of our majority-owned or controlled subsidiaries and VIEs for which we are the primary beneficiary. Intercompany accounts and transactions have been eliminated. Certain reclassifications have been made to prior-period amounts to conform with current-period presentation.

Cash and Cash Equivalents. Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid short-term investments with original maturities of three months or less.

Restricted Cash. Restricted cash represents cash that is not readily available for general purpose cash needs. Restricted cash at December 31, 2006 includes cash posted to support the letter of credit component of our Fourth Amended and Restated Credit Facility. We are required to post cash collateral in an amount equal to 103% of outstanding letters of credit.

Restricted cash at December 31, 2006 also includes amounts related to the terms of the indenture governing the Independence senior debt, which among other things, prohibit cash distributions by Independence to its affiliates, including us, unless certain project reserve accounts are funded to specified levels and the required debt service coverage ratio is met. Independence also has restricted investment balances which are included in prepayments and other current assets and restricted investments on our consolidated balance sheets. We include all changes in restricted cash, including those associated with the Independence senior debt, in investing cash flows on the consolidated statements of cash flows.

Allowance for Doubtful Accounts. We establish provisions for losses on accounts receivable if it becomes probable we will not collect all or part of outstanding balances. We review collectibility and establish or adjust our allowance as necessary. We primarily use a percent of balance methodology and methodologies involving historical levels of write-offs. The specific identification method is also used in certain circumstances.

Unconsolidated Investments. We use the equity method of accounting for investments in affiliates over which we exercise significant influence, generally occurring in ownership interests of 20% to 50%, and also occurring in lesser ownership percentages due to voting rights or other factors. Our share of net income (loss) from these affiliates is reflected in the consolidated statements of operations as earnings (losses) from unconsolidated investments. Any excess of our investment in affiliates, as compared to our share of the underlying equity that is not recognized as goodwill, is amortized over the estimated economic service lives of the underlying assets. All investments in unconsolidated affiliates are periodically assessed for other-than-temporary declines in value, with write-downs recognized in earnings from unconsolidated investments in the consolidated statements of operations.

Please read Note 5—Restructuring and Impairment Charges beginning on page F-24 for a discussion of impairment charges we recognized in 2006, 2005, and 2004.

Available-for-Sale Securities. For securities classified as available-for-sale that have readily determinable fair values, the change in the unrealized gain or loss, net of deferred income tax, is recorded as a separate component of accumulated other comprehensive income (loss) in the consolidated statements of comprehensive income (loss). Realized gains and losses on investment transactions are determined using the specific identification method.

Inventory. Our natural gas, coal, emissions allowances and fuel oil inventories are carried at the lower of weighted average cost or at market. Our materials and supplies inventory is carried at the lower of cost or market using the specific identification method.

We adopted EITF Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty", in the fourth quarter 2005. Accordingly, we account for exchanges of inventory with the same counterparty as one transaction at fair value.

We may opportunistically sell emissions allowances, subject to certain regulatory limitations and restrictions contained in our DMG consent decree, or hold them in inventory until they are needed. In the past, we have sold emission allowances that relate to future periods. To the extent the proceeds received from the sale of such allowances exceed our cost, we defer the associated gain until the period to which the allowance relates, as we may be required to purchase emissions allowances in future periods. As of December 31, 2006, we had aggregate deferred gains of $20 million, consisting of $11 million included in Other accrued liabilities and $9 million included in Other long-term liabilities, respectively, on our consolidated balance sheets. As of December 31, 2005, we had aggregate deferred gains of $22 million, consisting of $11 million included in Other accrued liabilities and $11 million included in Other long-term liabilities, respectively, on our consolidated balance sheets.

Property, Plant and Equipment. Property, plant and equipment, which consists principally of power generating facilities, is recorded at historical cost. Expenditures for major replacements, renewals and major maintenance are capitalized and depreciated over the expected maintenance cycle. We consider major maintenance to be expenditures incurred on a cyclical basis to maintain and prolong the efficient operation of our assets. Expenditures for repairs and minor renewals to maintain assets in operating condition are expensed. Depreciation is provided using the straight-line method over the estimated economic service lives of the assets, ranging from 3 to 40 years. Composite depreciation rates (which we refer to as composite rates) are applied to functional groups of assets having similar economic characteristics. The estimated economic service lives of our functional asset groups are as follows:

Asset Group	Range of Years
Power Generation Facilities	20 to 40
Transportation Equipment	5 to 10
Buildings and Improvements	10 to 39
Office and Miscellaneous Equipment	3 to 20

Gains and losses on sales of individual assets or asset groups are reflected in gain (loss) on sale of assets, net, in the consolidated statements of operations. We assess the carrying value of our property, plant and equipment in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). If an impairment is indicated, the amount of the impairment loss recognized would be determined by the amount the book value exceeds the estimated fair value of the assets. The estimated fair value may include estimates based upon discounted cash-flow projections, recent comparable market transactions or quoted prices to determine if an impairment loss is required. For assets identified as held for sale, the book value is compared to the estimated sales price less costs to sell.

Please read Note 5—Restructuring and Impairment Charges beginning on page F-24 for a discussion of impairment charges we recognized in 2006, 2005 and 2004.

Asset Retirement Obligations. We record the present value of our legal obligations to retire tangible, long-lived assets on our balance sheets as liabilities when the liability is incurred. Significant judgement is involved in estimating future cash flows associated with such obligations, as well as the ultimate timing of the cash flows. Effective December 31, 2005, we adopted the provisions of FIN No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN No. 47) which is an interpretation of SFAS No. 143, "Asset Retirement Obligations", (SFAS No. 143). Under the provisions of FIN No. 47, we recorded additional AROs to recognize the costs of the future removal of asbestos containing materials from certain of our power generation facilities. As a result, we recorded an after-tax charge of $5 million, which is included in the consolidated statements of operations as a cumulative effect of change in accounting principles. FIN No. 47, if it had been adopted as of January 1, 2004, would have had no material effect on our results of operations or earnings per share, and would have resulted in an additional $14 million of AROs included in our long-term liabilities at December 31, 2004.

In addition to the AROs discussed above, our AROs relate to activities such as ash pond and landfill capping, dismantlement of power generation facilities, closure and post-closure costs, environmental testing, remediation, monitoring and land and equipment lease obligations. Annual amortization of the assets associated with the AROs was $2 million each in 2006, 2005 and 2004. A summary of changes in our AROs is as follows:

	Year Ended December 31,		
	2006	2005	2004
		(in millions)	
Beginning of year	$ 56	$ 46	$ 41
New ARO (1)	6	1	—
Accretion expense	6	4	5
Sale of DMSLP	—	(11)	—
Implementation of FIN No. 47	—	16	—
Revision of previous estimate (2)	(12)	—	—
End of year	$ 56	$ 56	$ 46

(1) During 2006, we recorded additional AROs in the amount of $6 million related to our obligation to remediate a landfill located at our Danskammer generating facility. During 2005, we determined we would be obligated to dismantle our Danskammer generating facility upon its retirement. Therefore, we recorded an ARO in the amount of $1 million. There were no additional AROs, other than those recorded under the provisions of FIN No. 47, recorded or settled during 2006, 2005 or 2004.

(2) During 2006, we revised our ARO obligation downward by $12 million based on revised estimates of the costs to remediate ash ponds at certain of our coal fired generating facilities.

We have additional potential retirement obligations for dismantlement of power generation facilities. Our current intent is to maintain these facilities in a manner such that they will be operated indefinitely. As such, we cannot estimate any potential retirement obligations associated with these assets. Liabilities will be recorded in accordance with SFAS No. 143 at the time we are able to estimate these AROs.

Contingencies, Commitments, Guarantees and Indemnifications. We are involved in numerous lawsuits, claims, proceedings and tax-related audits in the normal course of our operations. In accordance with SFAS No. 5, "Accounting for Contingencies" (SFAS No. 5), we record a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. We review our loss contingencies on an ongoing basis to ensure that we have appropriate reserves recorded on our consolidated balance sheets as required by SFAS No. 5. These reserves are based on estimates and judgments made by management with respect to the likely outcome of these matters, including any applicable insurance coverage for litigation matters, and are adjusted as circumstances warrant. Our estimates and judgment could change based on new information, changes in laws or regulations, changes in management's plans or intentions, the outcome of legal proceedings, settlements or other factors. If different estimates and judgments were applied with respect to these matters, it is likely that reserves would be recorded for different amounts. Actual results could vary materially from these estimates and judgments.

Liabilities for environmental contingencies are recorded when an environmental assessment indicates that remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based, in part, on relevant past experience, currently enacted laws and regulations, existing technology, site-specific costs and cost-sharing arrangements. Recognition of any joint and several liability is based upon our best estimate of our final pro-rata share of such liability. These assumptions involve the judgments and estimates of management, and any changes in assumptions could lead to increases or decreases in our ultimate liability, with any such changes recognized immediately in earnings.

We follow the guidance of FIN No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN No. 45) for disclosures and accounting of various guarantees and indemnifications entered into during the course of business. When a guarantee or indemnification subject to FIN No. 45 is entered into, an estimated fair value of the underlying guarantee or indemnification is recorded. Some guarantees and indemnifications could have significant financial impact under certain circumstances, however management also considers the probability of such circumstances occurring when estimating the fair value. Actual results may materially differ from the estimated fair value of such guarantees and indemnifications.

Intangible Assets. Intangible assets represent the fair value of assets, apart from goodwill, that arise from contractual rights or other legal rights. In accordance with SFAS No. 141, "Business Combinations" (SFAS No. 141), we record only those intangible assets that are distinctly separable from goodwill and can be sold, transferred, licensed, rented, or otherwise exchanged in the open market. Additionally, we recognize intangible assets for those assets that can be exchanged in combination with other rights, contracts, assets or liabilities.

In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), we initially record and measure intangible assets based on the fair value of those rights transferred in the transaction in which the asset was acquired. Those measurements are based on quoted market prices for the asset, if available, or measurement techniques based on the best information available such as a present value of future cash flows measurement. Present value measurement techniques involve judgments and estimates made by management about prices, cash flows, discount factors and other variables, and the actual value realized from those assets could vary materially from these judgments and estimates. We amortize our definite-lived intangible assets based on the useful life of the respective asset as measured by the life of the contract. If the intangible asset does not have a finite life based on the contractual or legal right, an estimate is made of the useful life based on the pattern in which the economic benefits of the asset are expected to be consumed. Intangible assets are also subjected to impairment testing when a triggering event occurs, and an impairment loss is recognized if the carrying amount of an intangible exceeds its fair value.

Revenue Recognition and Valuation of Risk Management Assets and Liabilities. We utilize two comprehensive accounting models in reporting our consolidated financial position and results of operations as required by GAAP—an accrual model and a fair value model. We determine the appropriate model for our operations based on guidance provided in applicable accounting standards and positions adopted by the FASB or the SEC. We have applied these accounting policies on a consistent basis during the three years in the period ended December 31, 2006.

The accrual model is used to account for substantially all of the operations conducted in our GEN-MW, GEN-NE and GEN-SO segments. These segments consist largely of the ownership and operation of physical assets that we use in various generation operations. We earn revenue from our facilities in three primary ways: (1) sale of energy generated by our facilities; (2) sale of ancillary services, which are the products of a generation facility that support the transmission grid operation, allow generation to follow real-time changes in load, and provide emergency reserves for major changes to the balance of generation and load; and (3) sale of capacity. We recognize revenue from these transactions when the product or service is delivered to a customer.

The fair value model is used to account for forward physical and financial transactions which meet the definition of a derivative contract as defined by SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended, (SFAS No. 133). The criteria are complex, but generally require these contracts to relate to future periods, to contain fixed price and volume components and to have terms that require or permit net settlement of the contract in cash or the equivalent. SFAS No. 133 concluded that these contracts should be accounted for at fair value. In part, this conclusion is based on the cash settlement provisions in these agreements, as well as the volatility in commodity prices, interest rates and, if applicable, foreign exchange rates, which impact the valuation of these contracts. Since these transactions may be settled in cash or the equivalent, the value of the assets and liabilities associated with these transactions is reported at estimated settlement value based on current forward prices and rates as of each balance sheet date.

Typically, derivative contracts can be accounted for in three different ways: (1) as an accrual contract, if the criteria for the "normal purchase normal sale" exception are met and documented; (2) as a cash flow or fair value hedge, if the criteria are met and documented; or (3) as a mark-to-market contract with changes in fair value recognized in current period earnings. Generally, we only mark-to-market through earnings our derivative contracts if they do not qualify for the "normal purchase normal sale" exception or as a cash flow hedge. Because derivative contracts can be accounted for in three different ways, and as the "normal purchase normal sale" exception and cash flow and fair value hedge accounting are elective, the accounting treatment used by another party for a similar transaction could be different than the accounting treatment we use.

In order to estimate the fair value of our portfolio of transactions which meet the definition of a derivative and do not qualify for the "normal purchase normal sale" exception, we use a liquidation value approach assuming that the ability to transact business in the market remains at historical levels. The estimated fair value of the portfolio is computed by multiplying all existing positions in the portfolio by estimated prices, reduced by a time value of money adjustment and reserves for credit and price. The estimated prices in this valuation are based either on (1) prices obtained from market quotes, when there are an adequate number of quotes to consider the period liquid, or, (2) if market quotes are unavailable or the market is not considered liquid, prices from a proprietary model which incorporates forward energy prices derived from market quotes and values from previously executed transactions. The amounts recorded as revenue change as these estimates are revised to reflect actual results and changes in market conditions or other factors, many of which are beyond our control.

Cash inflows and cash outflows associated with the settlement of risk management activities are recognized in net cash provided by (used in) operating activities on the consolidated statements of cash flows.

Income Taxes. We follow the guidance in SFAS No. 109, "Accounting for Income Taxes" (SFAS No. 109), which requires that we use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences.

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes in each of the jurisdictions in which we operate. This process involves estimating our actual current tax payable and related tax expense together with assessing temporary differences resulting from differing tax and accounting treatment of certain items, such as depreciation, for tax and accounting purposes. These differences can result in deferred tax assets and liabilities, which are included within our consolidated balance sheets.

We must then assess the likelihood that our deferred tax assets will be recovered from future taxable income and, to the extent we believe that it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized, we must establish a valuation allowance. We consider all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed. Evidence used includes information about our current financial position and our results of operations for the current and preceding years, as well as all currently available information about future years, anticipated future performance, the reversal of deferred tax liabilities and tax planning strategies.

Management believes future sources of taxable income, reversing temporary differences and other tax planning strategies will be sufficient to realize deferred tax assets for which no reserve has been established. While we have considered these factors in assessing the need for a valuation allowance, there is no assurance that a valuation allowance would not need to be established in the future if information about future years changes. Any change in the valuation allowance would impact our income tax benefit (expense) and net income (loss) in the period in which such a determination is made.

Please read Note 14—Income Taxes beginning on page F-42 for further discussion of our accounting for income taxes and any change in our valuation allowance.

Earnings Per Share. Basic earnings per share represents the amount of earnings for the period available to each share of common stock outstanding during the period. Diluted earnings per share amounts include the effect of issuing shares of common stock for outstanding stock options and performance based stock awards under the treasury stock method if including such potential common shares is dilutive.

Foreign Currency. For subsidiaries whose functional currency is not the U.S. Dollar, assets and liabilities are translated at year-end rates of exchange, and revenues and expenses are translated at monthly average exchange rates. Translation adjustments for the asset and liability accounts are included as a separate component of accumulated other comprehensive income in stockholders' equity. Currency transaction gains and losses are recorded in other income and expense, net; on the consolidated statements of operations and totaled gains (losses) of approximately $1 million, ($4) million and $1 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Employee Stock Options. On January 1, 2003, we adopted the fair-value based method of accounting for stock-based employee compensation under SFAS No. 123, "Accounting for Stock-Based Compensation", (SFAS No. 123) and used the prospective method of transition as described under SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure" (SFAS No. 148). Under the prospective method of transition, all stock options granted after January 1, 2003 were accounted for on a fair value basis. Options granted prior to January 1, 2003 continued to be accounted for using the intrinsic value method. Accordingly, for options granted prior to January 1, 2003, compensation expense was not reflected for employee stock options unless they were granted at an exercise price lower than market value on the grant date. We granted in-the-money options in the past and recognized compensation expense over the applicable vesting periods. No in-the-money stock options have been granted since 1999.

In December 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment" (SFAS No. 123(R)) which revises SFAS No. 123. SFAS No. 123(R) requires all companies to expense the fair value of employee stock options and other forms of stock-based compensation. We adopted SFAS No. 123(R) effective January 1, 2006, using the modified prospective transition method permitted under this pronouncement. Our cumulative effect of implementing this standard, which consists entirely of a forfeiture adjustment, was less than $1 million after tax.

In November 2005, the FASB issued FSP No. 123(R)-3, "Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards". We have adopted the short-cut method to calculate the beginning balance of the APIC pool of the excess tax benefit, and to determine the subsequent impact on the APIC pool and unaudited condensed consolidated statements of cash flows of the tax effects of employee stock-based compensation awards that were outstanding upon our adoption of FAS 123(R). Utilizing the short-cut method, we have determined that we have a "Pool of Windfall" tax benefits that can be utilized to offset future shortfalls that may be incurred.

The adoption of SFAS No. 123(R) had no material impact on our consolidated statements of operations, our consolidated statements of cash flows and basic and diluted loss per share for the year ended December 31, 2006, compared to amounts that would have been reported pursuant to our previous accounting. Had compensation cost for all stock options granted prior to 2003 been determined on a fair value basis consistent with SFAS No. 123, our net income (loss) and basic and diluted earnings (loss) per share amounts would have approximated the following pro forma amounts for the years ended December 31, 2005 and 2004, respectively.

	Years Ended December 31,	
	2005	2004
	(in millions, except per share data)	
Net income (loss) as reported	$ 90	$ (15)
Add: Stock-based employee compensation expense included in reported net loss, net of related tax effects	6	4
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(8)	(27)
Pro forma net income (loss)	$ 88	$ (38)
Earnings (loss) per share:		
Basic—as reported	$0.18	$(0.10)
Basic—pro forma	$0.17	$(0.16)
Diluted—as reported	$0.18	$(0.10)
Diluted—pro forma	$0.17	$(0.16)

Please read Note 19—Capital Stock beginning on page F-55 for further discussion of our share-based compensation and expense recognized for 2006, 2005 and 2004.

Accounting Principles Adopted

SFAS No. 123(R). Please see Employee Stock Options beginning on page F-15 for information regarding our adoption of SFAS 123(R).

SFAS No. 153. In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets—An Amendment of APB Opinion No. 29" (SFAS No. 153). The guidance in APB Opinion No. 29, "Accounting for Nonmonetary Transactions" (Opinion No. 29), is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in that Opinion, however, included certain exceptions to that principle. SFAS No. 153 amends Opinion No. 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. We adopted SFAS No. 153 on January 1, 2006. The adoption of this standard did not have a material effect on our results of operations, financial position or cash flows.

SFAS No. 154. In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections—A Replacement of APB Opinion No. 20 and SFAS No. 3" (SFAS No. 154). SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle and applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. SFAS No. 154 requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. The provisions of SFAS No. 154 are effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. Adoption of this standard did not have a material effect on our results of operations, financial position or cash flows.

SFAS No. 158. On September 29, 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106 and 132 (R)" (SFAS No. 158). SFAS No. 158 requires employers to recognize the overfunded or underfunded status of a defined benefit or other postretirement plan (other than a multi-employer plan) as an asset or liability in its statement of financial position, and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. In addition, SFAS No. 158 requires employers to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. We adopted SFAS No. 158 on December 31, 2006 and recorded a pre-tax adjustment to accumulated other comprehensive income of approximately $56 million upon adoption. Please read Note 20—Employee Compensation, Savings and Pension Plans on page F-61 for further information.

SAB 108. On September 13, 2006, the SEC released SAB No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB No. 108). SAB No. 108 states that a registrant's materiality evaluation of an identified unadjusted error should quantify the effects of the identified unadjusted error on each financial statement and related financial statement disclosure. SAB No. 108 also states that registrants electing not to restate prior periods should reflect the effects of initially applying SAB No. 108 in their annual financial statements covering the first fiscal year ending after November 15, 2006. SAB No. 108 did not have a material effect on our results of operations, financial position or cash flows.

FSP FIN No. 45-3. In November 2005, the FASB issued FASB Staff Position No. 45-3, "Application of FASB Interpretation No. 45 to Minimum Revenue Guarantees Granted to a Business or Its Owners" (FSP FIN No. 45-3). It served as an amendment to FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others", by adding minimum revenue guarantees to the list of examples of contracts to which FIN No. 45 applies. Under FSP FIN No. 45-3, a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. FSP FIN No. 45-3 is effective for new minimum revenue guarantees issued or modified on or after January 1, 2006 and did not have a material effect on our results of operations, financial position or cash flows.

EITF Issue 05-6. In June 2005, the EITF reached consensus on Issue No. 05-6, "Determining the Amortization Period for Leasehold Improvements" (EITF Issue 05-6). EITF Issue 05-6 provides guidance on determining the amortization period for leasehold improvements acquired in a business combination or acquired subsequent to lease inception. The adoption of this standard on January 1, 2006 did not have a material effect on our results of operations, financial position or cash flows.

Accounting Principles Not Yet Adopted

FIN No. 48. On July 12, 2006, the FASB issued FIN No. 48, "Accounting for Uncertainty in Income Taxes" (FIN No. 48). FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS No. 109. FIN No. 48 prescribes a recognition threshold and measurement attributes for the financial statement recognition and measurement of an income tax position taken or expected to be taken in an income tax return. FIN No. 48 is effective for fiscal years beginning after December 15, 2006, and the cumulative effect of adopting FIN No. 48 will be recorded as an adjustment to retained earnings as of January 1, 2007. Additional guidance from the FASB on FIN No. 48 is pending. We are currently evaluating the impact of adopting FIN No. 48, but do not expect the adoption to have a material impact on our consolidated financial statements. However, the adoption will result in a decrease to our NOL carryforwards offset by equal changes to deferred tax liabilities or other deferred tax assets.

SFAS No. 157. On September 15, 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements. Accordingly, SFAS No. 157 does not require any new fair value measurements; however for some entities the application of SFAS No. 157 will change current practice. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact of this statement on our financial statements.

Note 3—Business Combinations and Acquisitions

LS Power. On September 14, 2006, we entered into a Plan of Merger, Contribution and Sale Agreement (the "Merger Agreement") by and among Dynegy Inc., Dynegy Acquisition, Inc., a Delaware corporation ("New Dynegy"), Falcon Merger Sub Co., an Illinois corporation and a wholly owned subsidiary of New Dynegy ("Merger Sub"), LSP Gen Investors, L.P., LS Power Partners, L.P., LS Power Equity Partners PIE I, L.P., LS Power Associates, L.P., and LS Power Equity Partners, L.P. (collectively, the "LS Entities"), pursuant to which Merger Sub will be merged with and into us, as a result of which we will become a wholly-owned subsidiary of New Dynegy.

A portion of the LS Entities' operating generation portfolio will be combined with our generating assets and operations, and New Dynegy will acquire a 50 percent ownership interest in a development company that is currently controlled by the LS Entities. Upon completion of the Merger Agreement, each share of our Class A Common Stock and our Class B Common Stock will be converted into the right to receive one share of New Dynegy Class A Common Stock, par value $0.01 per share ("New Dynegy Class A Common Stock").

If the transaction is consummated, the LS Entities will contribute certain interests in power generation assets to New Dynegy in exchange for (i) 340 million shares of New Dynegy Class B Common Stock, par value $0.01 per share ("New Dynegy Class B Common Stock" and, together with New Dynegy Class A Common Stock, the "New Dynegy Common Stock"), (ii) $100 million in cash, and (iii) $275 million in aggregate principal amount of notes payable to be issued by New Dynegy.

Under the terms of the Merger Agreement, we and the LS Entities agreed not to (i) solicit proposals relating to alternative business combination transactions or (ii) subject to certain exceptions, enter into discussions or an agreement concerning or provide confidential information in connection with any proposals for alternative business combination transactions. The Merger Agreement provides certain termination rights to both us and the LS Entities, and further provides that, upon termination of the Merger Agreement under certain circumstances, (i) we may be required to pay the LS Entities or (ii) the LS Entities may be required to pay us, an aggregate termination fee of $100 million, as described in the Merger Agreement. The affirmative vote of two-thirds of the (i) issued and outstanding shares of our Class A Common Stock voting as a class, (ii) issued and outstanding shares of our Class B Common Stock voting as a class and (iii) issued and outstanding shares of our Common Stock voting together as a class is required to approve the merger. Assuming all necessary conditions are satisfied, which cannot be guaranteed, the transaction is expected to close at the end of the first quarter 2007.

Kendall Power. On September 14, 2006, the LS Entities and Kendall Power LLC ("Kendall Power"), a newly formed wholly owned subsidiary of Dynegy, entered into a Limited Liability Company Membership Interests and Stock Purchase Agreement (the "Kendall Agreement") pursuant to which Kendall Power agreed to acquire all of the outstanding interests in LSP Kendall Holdings, LLC for $200 million in cash, as adjusted for certain changes in working capital. The closing of the Kendall Agreement will occur only if closing does not occur with respect to the transactions contemplated by the Merger Agreement. We have agreed to guarantee certain of Kendall Power's obligations under the Kendall Agreement. Please read Note 17—Commitments and Contingencies—Guarantees and Indemnifications—Kendall Guarantee beginning on page F-51 for further discussion.

Rocky Road. On March 31, 2006, contemporaneous with our sale of our interest in WCP (Generation) Holdings LLC ("West Coast Power") (please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—West Coast Power), we completed our acquisition of NRG's 50% ownership interest in Rocky Road Power, LLC ("Rocky Road"), the entity that owns the Rocky Road power plant, a 330-megawatt natural gas-fired peaking facility near Chicago (of which we already owned 50%), for proceeds of $165 million, net of cash acquired. As a result of the transaction, we became the primary beneficiary of the entity as provided under the guidance in FIN No. 46(R), "Consolidation of Variable Interest Entities an interpretation of ARB No. 51", and thus consolidated the assets and liabilities of the entity at March 31, 2006. Please read Note 10—Unconsolidated Investments—Variable Interest Entities for further discussion.

Sithe Energies. On January 31, 2005, we acquired 100% of the outstanding common shares of ExRes SHC, Inc. ("ExRes"), the parent company of Sithe Energies, Inc. ("Sithe Energies") and Sithe/Independence Power Partners, L.P. ("Independence"). The results of the operations of ExRes have been included in our consolidated financial statements since that date. Through this acquisition, we acquired the 1,064 MW Independence power generation facility located near Scriba, New York, as well as natural gas-fired merchant facilities in New York and hydroelectric generation facilities in Pennsylvania. We have not consolidated the entities that own these four natural gas-fired facilities and four hydroelectric generation facilities, in accordance with the provisions of FIN No. 46R. See Note 10—Unconsolidated Investments—Variable Interest Entities beginning on page F-34 for additional discussion of these facilities. In addition to these power plants, we acquired the 740 MW firm capacity sales agreement between Independence and Con Edison, a subsidiary of Consolidated Edison, Inc. This agreement, which runs through 2014, will provide us with annual cash receipts of approximately $100 million, subject to the restrictions on distribution under Independence's indebtedness. Revenue from this capacity obligation is largely fixed with a variable discount that varies each month based on the price of power at Pleasant Valley LMP. Independence holds power tolling, financial swap and other contracts with other Dynegy subsidiaries. Because of the acquisition, these contracts have become intercompany agreements, and their financial statement impact has been substantially eliminated. This transaction enabled us to address one of our outstanding power tolling arrangements and to expand our generation capacity in a market where we have an existing presence.

The aggregate purchase price was comprised of (i) $135 million cash, which was reduced by a purchase price adjustment of approximately $2 million; (ii) transaction costs of approximately $16 million, approximately $3 million of which were paid in 2004; and (iii) the assumption of $919 million of face value project debt, which was recorded at its fair value of $797 million as of January 31, 2005. Please read Note 12—Debt—Sithe Energies Debt beginning on page F-39 for additional information regarding the debt assumed.

The allocation of purchase price to specific assets and liabilities is based, in part, upon outside appraisals using customary valuation procedures and techniques. That allocation changed during the fourth quarter 2005 after we received information related to investment valuations and tax basis balances. The acquisition resulted in an excess of the fair value of assets acquired over cost of the acquisition. This excess was then allocated to property, plant and equipment and intangible assets acquired, including intangible assets arising from contracts with us, on a pro-rata basis. The following table summarizes the fair values of the assets and liabilities acquired at the date of acquisition, January 31, 2005 (in millions):

Other current assets	$ 88
Restricted cash and investments	132
Property, plant and equipment	353
Assets from risk-management activities	62
Intangible assets	657
Other assets	4
Total assets acquired	$ 1,296
Current liabilities	$ (98)
Deferred income taxes	(193)
Other long-term liabilities	(59)
Long-term debt	(797)
Total liabilities assumed	$(1,147)
Net assets acquired	$ 149

Included in the assets acquired are restricted cash and investments of approximately $132 million. The restricted investments include Federal Home Loan Bank Bonds, U.S. Treasury Bonds, and high-grade short-term commercial paper. The restricted cash and investments are related to a sinking fund required by Independence's debt instruments, including a major overhaul reserve, a debt service reserve, a principal payment reserve, an interest reserve and a project restoration reserve. Restrictions on the cash and investments are scheduled to be lifted at the end of the project financing term in 2014. For further discussion, please read Note 12—Debt—Sithe Energies Debt beginning on page F-45.

Of the $657 million of acquired intangible assets, $488 million was allocated to the firm capacity sales agreement with Con Edison. This asset will be amortized on a straight-line basis over the remaining life of the contract as a reduction to revenue in our consolidated statements of operations, through October 2014. In addition, Independence holds a power tolling contract and a natural gas supply agreement with another of our subsidiaries, which were valued at $153 million and $16 million, respectively, as of January 31, 2005. Upon completion of our purchase of Independence, the power tolling agreement and the natural gas supply agreement were effectively settled, which resulted in a 2005 charge equal to their fair values, in accordance with EITF Issue 04-01, "Accounting for Pre-existing Contractual Relationships Between the Parties to a Purchase Business Combination". As a result, we recorded a 2005 pre-tax charge of $169 million, which is included in cost of sales on our consolidated statements of operations. Upon settlement of the power tolling and natural gas supply agreements, the firm capacity sales agreement with Con Edison is the only remaining intangible asset associated with the acquisition of ExRes, which is included in intangibles and prepaids and other current assets on our consolidated balance sheets.

We exercised our right to require Exelon to decommission, sell, or otherwise dispose of all four natural gas-fired merchant facilities owned by ExRes. Under the terms of the purchase agreement, Exelon was to direct the disposition of these facilities and indemnify us with respect to all past and present operations. On June 1 and August 4, 2005 we entered into agreements, as directed by Exelon, to sell the ownership and operating interests in the facilities. The transactions, which were approved by the FERC and the New York Public Service Commission, closed on October 31, 2005 and had no impact on our consolidated financial statements as Exelon received the proceeds from the sale. Further, Exelon is entitled to cause us to decommission, sell, or bankrupt any or all of the four hydroelectric facilities owned by ExRes, for which we have been indemnified for any losses.

Note 4—Dispositions, Contract Terminations and Discontinued Operations

Dispositions and Contract Terminations

Calcasieu. On January 31, 2007, we entered into an agreement to sell our interest in the Calcasieu power generation facility to Entergy Gulf States, Inc. ("Entergy") for approximately $57 million, subject to regulatory approval. The transaction is expected to close in early 2008. We recorded a pre-tax impairment of approximately $36 million in the year ended December 31, 2006, which was included in Impairment and other charges on our consolidated statements of operations. Please read Note 5—Restructuring and Impairment Charges—Asset Impairments on page F-24 for further discussion.

Rockingham. On November 9, 2006, we completed the sale to Duke Energy Carolinas, LLC (a subsidiary of Duke Energy) ("Duke Power") of our Rockingham facility, a peaking facility in North Carolina, which is included in our GEN-SO reportable segment, for $194 million in cash. A portion of the proceeds from the sale were used to repay our borrowings under the $150 million Term Loan, with the remaining proceeds used as an additional source of liquidity. Please read Note 12—Debt—Fourth Amended and Restated Credit Facility beginning on page F-36 for further discussion of the Term Loan.

Beginning in the second quarter 2006, Rockingham met the held for sale classification requirements of SFAS No. 144, and continued to meet the requirements through the closing of the sale on November 9, 2006. SFAS No. 144 requires that long-lived assets not be depreciated or amortized while they are classified as held for sale. As a result, we discontinued depreciation and amortization of Rockingham's property, plant and equipment during the second quarter 2006. Depreciation and amortization expense related to Rockingham totaled $2 million, $6 million and $6 million in the years ended December 31, 2006, 2005 and 2004, respectively. In addition, SFAS No. 144 requires a loss to be recognized if assets held for sale less liabilities held for sale are in excess of fair value less costs to sell. Accordingly, we recorded a pre-tax impairment of $9 million in the year ended December 31, 2006 which is included in Impairment and other charges on our consolidated statements of operations.

West Coast Power. On March 31, 2006, contemporaneous with our purchase of Rocky Road (please read Note 3—Business Combinations and Acquisitions—Rocky Road on page F-18), we completed the sale to NRG of our 50% ownership interest in West Coast Power, a joint venture between us and NRG which has ownership interests in the West Coast Power power plants in southern California totaling approximately 1,800 megawatts, for proceeds of approximately $165 million, net of cash acquired. We did not recognize a material gain or loss on the sale. Pursuant to our divestiture of West Coast Power, we no longer maintain a significant variable interest in the entity as provided by the guidance in FIN No. 46(R). Please read Note 10—Unconsolidated Investments—Variable Interest Entities on page F-34 for further discussion.

Sterlington Contract Termination. In December 2005, we entered into an agreement to terminate the Sterlington long-term wholesale power tolling contract with Ouachita Power LLC ("Ouachita"), a joint venture of GE Energy Financial Services and Cogentrix Energy, Inc. Under the terms of the agreement, we paid Ouachita approximately $370 million in March 2006 to eliminate approximately $449 million in capacity payment obligations through 2012 and avoid approximately $295 million in additional capacity payment obligations that would arise if Ouachita exercised its option to extend the contract through 2017. We recognized a pre-tax charge of approximately $364 million ($229 million after-tax) in 2005 related to this transaction.

Sale of Illinois Power. On September 30, 2004, we sold all of our outstanding common and preferred shares of Illinois Power Company, which formerly comprised our REG segment, as well as our 20% interest in the Joppa power generation facility, to Ameren Corporation for $2.3 billion.

During 2005, we paid approximately $5 million to Ameren for a final working capital purchase price adjustment. As a result of an adjustment to the contingent liabilities identified as part of the Illinois Power sale, we recorded a $12 million charge in 2005 and we paid $8 million in partial satisfaction of such contingent liabilities. For further discussion, please read Note 17—Commitments and Contingencies—Guarantees and Indemnifications—Illinois Power Indemnities beginning on page F-52. The adjustment to the contingent liabilities resulted in an increase to our capital loss carryforward, and a corresponding increase to the deferred tax valuation allowance of $4 million.

During 2004, Illinois Power met the held for sale classification requirements of SFAS No. 144, and continued to meet the requirements through the closing of the sale on September 30, 2004. We discontinued depreciation and amortization of Illinois Power's property, plant and equipment and regulatory assets, effective February 1, 2004. Depreciation and amortization expense related to Illinois Power totaled $10 million the year ended December 31, 2004. In addition, SFAS No. 144 requires a loss to be recognized by the amount Assets held for sale less Liabilities held for sale are in excess of fair value less costs to sell. Accordingly, we recorded a pre-tax loss on the sale of $112 million in the year ended December 31, 2004. Of the charge, $58 million is reflected in gain (loss) on sale of assets, net and $54 million of the charge is reflected in impairment and other charges on our consolidated statements of operations.

Further, pursuant to SFAS No. 144, we are not reporting the results of Illinois Power's operations as a discontinued operation. If we were to account for Illinois Power as a discontinued operation, its results of operations would be condensed into income from discontinued operations, net of taxes, on our consolidated statements of operations, and prior periods would be required to be restated to conform to this presentation. To qualify for discontinued operations classification, SFAS No. 144 and subsequent interpretations, specifically EITF Issue 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations", require that the seller have no significant continuing involvement with the business being sold. However, we sold capacity and energy to Illinois Power under a two-year power purchase agreement which began in January 2005. Consequently, because we still had significant continuing involvement with Illinois Power, we continued to include the historical results of Illinois Power's operations as part of our continuing operations. Additionally, power sales to Illinois Power occurring subsequent to the disposition are reported in our consolidated statements of operations as third party sales. Approximately $466 million, $459 million and $109 million of revenues, derived from power sales to Illinois Power occurring subsequent to the disposition, are reflected in our continuing operations for the periods ending December 31, 2006, 2005 and 2004, respectively.

Had the results of Illinois Power been excluded from our comparative results as though the sale had occurred at the beginning of 2004, our revenues; loss before cumulative effect of changes in accounting principles, net of tax; net income (loss) applicable to common stockholders; and associated basic and diluted earnings (loss) per share would have approximated the following pro forma amounts for the year ended December 31, 2004 (in millions, except per share data):

Revenues:	
As reported	$2,451
Pro forma	1,658
Loss before cumulative effect of change in accounting principles, net of tax:	
As reported	$ (15)
Pro forma	(32)
Net loss applicable to common stockholders:	
As reported	$ (37)
Pro forma	(54)
Loss per share—Loss before cumulative effect of change in accounting principles, net of tax:	
Basic—as reported	$ (0.10)
Basic—pro forma	$ (0.14)
Diluted—as reported	$ (0.10)
Diluted—pro forma	$ (0.14)
Loss per share—Net loss applicable to common stockholders:	
Basic—as reported	$ (0.10)
Basic—pro forma	$ (0.14)
Diluted—as reported	$ (0.10)
Diluted—pro forma	$ (0.14)

Joppa. In September 2004, we recorded a pre-tax gain of $75 million upon closing of the sale of our 20% interest in the Joppa power generating facility. This gain is included in earnings (losses) from unconsolidated investments on our consolidated statements of operations.

Sherman. In November 2004, we sold our Sherman natural gas processing facility located in Sherman, Texas. This sale resulted in a pre-tax gain of approximately $16 million. This gain is included in income from discontinued operations on our consolidated statements of operations.

Indian Basin. In April 2004, we sold our 16% interest in the Indian Basin Gas Processing Plant for approximately $48 million, and we recognized a pre-tax gain on the sale of approximately $36 million. This gain is included in income from discontinued operations on our consolidated statements of operations.

PESA. In April 2004, we sold our interest in the Plantas Eolicas, S.A. de R.L. 20 MW wind-powered electric generation facility located in Costa Rica for approximately $11 million. We recognized a pre-tax loss of approximately $1 million on the sale. This loss is included in gain (loss) on sale of assets, net on our consolidated statements of operations.

Kendall. In November 2004, DPM entered into a "back to back" power purchase agreement with Constellation Energy Commodities Group, Inc. ("Constellation") under which Constellation will effectively receive DPM's rights to purchase approximately 570 MW of capacity and energy arising under DPM's tolling contract with LSP-Kendall Energy, LLC for a four-year term from December 2004 through November 2008. DPM will remain the primary obligor under the Kendall tolling contract, but will receive offsetting payments from Constellation during the four-year term.

In connection with this transaction, DPM paid Constellation $117.5 million in cash and effectively eliminated approximately $161 million of our future fixed payment obligations under the Kendall tolling contract through November 2008. We recognized a pre-tax charge of approximately $115 million ($72 million after-tax) related to this transaction. The charge is included in cost of sales on the consolidated statements of operations.

Gas Transportation Contracts. In June 2004, we agreed to exit four long-term natural gas transportation contracts whose purpose was to secure firm pipeline capacity through 2014 in support of our former third party marketing and trading business. In exchange for exiting these obligations, we paid $20 million in June 2004, $16 million in December 2004 and $26 million in March 2005. This payment obligation was recorded at its fair value of $40 million and was accreted to $42 million over the period July 1, 2004 through March 31, 2005. Additionally, we reversed an aggregate liability of $148 million associated with the transportation contracts that was originally established in 2001 and recognized a pre-tax gain of $88 million related to these transactions. This gain is included in revenues on our consolidated statements of operations and is included in the results of our CRM segment. This agreement eliminated our obligation to make approximately $295 million in aggregate fixed capacity payments from April 2005 through 2014.

Discontinued Operations

Natural Gas Liquids. On October 31, 2005, we completed the sale of DMSLP, which comprised substantially all remaining operations of our NGL business, to Targa and two of its subsidiaries for $2.44 billion in cash.

In 2006, we received $15 million from Targa which represents the final portion of the sales price owed to us.

Pursuant to SFAS No. 144, we are reporting the results of NGL's operations as a discontinued operation. Accordingly, the results of operations of our NGL business have been included in discontinued operations for all periods presented. EITF Issue 87-24, "Allocation of Interest to Discontinued Operations" (EITF Issue 87-24) requires that interest expense on debt that was required to be repaid upon the sale of DMSLP should be reclassified to discontinued operations. Therefore, interest expense on our former term loan and our former generation facility debt was allocated to discontinued operations, as the respective debt instruments were paid upon the sale of DMSLP. Such interest expense, inclusive of amortization of debt issuance costs, totaled $53 million and $27 million for the years ended December 31, 2005 and 2004, respectively.

Additionally, results from NGL's operations include revenues and cost of sales arising from intersegment transactions, which ceased after the sale of DMSLP. NGL processed natural gas and sold this natural gas to CRM for resale to third parties. NGL also purchased natural gas from CRM and electricity from GEN. As the intersegment revenues and cost of sales included in NGL's results were reclassified to discontinued operations, the effects of these intersegment transactions eliminated in consolidation, including the ultimate third-party settlement, previously recorded in other segments, were also reclassified to discontinued operations.

Other. We sold or liquidated some of our operations during 2003, including DGC (our communications business) and our U.K. CRM business, which have been accounted for as discontinued operations under SFAS No. 144.

The following table summarizes information related to our discontinued operations, including the NGL business operations discussed above:

	U.K. CRM	DGC	NGL	Total
	(in millions)			
2006				
Income from operations before taxes	$ 23	$ 1	$ 6	$ 30
Income from operations after taxes	19	1	4	24
2005				
Revenue	$—	$—	$4,125	$4,125
Income from operations before taxes	6	—	163	169
Income (loss) from operations after taxes	(1)	2	223	224
Gain on sale before taxes	—	—	1,087	1,087
Gain on sale after taxes	—	—	675	675
2004				
Revenue	$—	$—	$3,753	$3,753
Income from operations before taxes	19	3	254	276
Income (loss) from operations after taxes	(7)	2	170	165

In 2006, we recognized approximately $21 million of pre-tax income associated with a U.K. CRM receivable previously reserved that is now expected to be collected.

In 2005, we recognized $3 million of pre-tax income primarily associated with U.K. CRM's receipt of a third party bankruptcy settlement, offset by foreign currency exchange losses.

In 2004, we recognized $17 million of pre-tax income related to translation gains on foreign currency in the U.K. Please read Note 6—Risk Management Activities and Financial Instruments—Accounting for Derivative Instruments and Hedging Activities—Net Investment Hedges In Foreign Operations beginning on page F-27 for further discussion. Also in 2004, we recognized $3 million of pre-tax income associated with DGC's receipt of $3 million from a third party in settlement of a prior contractual claim and a tax expense of $20 million related to charges resulting from the conclusion of prior year tax audits.

Note 5—Restructuring and Impairment Charges

Asset Impairments. At September 30, 2006, we tested the Bluegrass generation facility for impairment based on the FERC's recent approval and Louisville Gas and Electric's ("LG&E") completion of various compliance steps to allow it to withdraw from participation in the MISO market as of September 1, 2006. The

Bluegrass facility has historically sold power into the MISO market through transmission provided by LG&E. This change will limit our ability or increase the cost to deliver power to the MISO market. After testing, we recorded a pre-tax impairment charge of $96 million ($61 million after-tax) in the GEN-MW segment. This charge is included in Impairment and other charges in our consolidated statements of operations. We determined the fair value of the facility using the expected present value technique.

At December 31, 2006, we determined that it was more likely than not that certain assets would be sold prior to the end of their previously estimated useful lives. Therefore, impairment analyses were performed and we recorded a total pre-tax impairment charge of $50 million ($32 million after tax). Of this charge, $36 million relates to the Calcasieu facility and is recorded in the GEN-SO segment. The remaining $14 million relates to the Bluegrass facility and is recorded in the GEN-MW segment. This charge is included in Impairment and other charges in our consolidated statements of operations. We determined the fair value of the Bluegrass facility using the expected present value technique. We determined the fair value of the Calcasieu facility based on the purchase price in the sales agreement.

In 2006, we recorded a $9 million pre-tax impairment of our investment in Black Mountain. Please read Note 10—Unconsolidated Investments—Power Generation—South Investments beginning on page F-32 for further discussion.

In 2005, we recorded $13 million, $10 million and $4 million in pre-tax impairments of our investments in Black Mountain, West Coast Power and Panama, respectively. Please read Note 10—Unconsolidated Investments—Power Generation—South Investments beginning on page F-32 for further discussion. Also in 2005, we recorded in GEN-MW an impairment of an unused turbine totaling $29 million. We determined the fair value of the turbine based on market prices of similar assets available for sale. Also in 2005, we recorded severance and restructuring charges totaling $11 million. For further information, please read "2005 Restructuring" below. Finally, in connection with our sale of DMSLP, included in discontinued operations, were charges of $3 million and $2 million for cancellation fees and operating leases, respectively.

In 2004, we recorded a $112 million pre-tax impairment of our interest in Illinois Power. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Sale of Illinois Power beginning on page F-21 for further discussion. In addition, during 2004, we recorded a $5 million pre-tax charge related to the impairment of one of our NGL assets. Also during 2004, we recorded $85 million in pre-tax impairments of our investment in West Coast Power. Please read Note 10—Unconsolidated Investments—Power Generation—South Investments beginning on page F-32 for further discussion.

2005 Restructuring. In December 2005, in order to better align our corporate cost structure with a single line of business and as part of a comprehensive effort to reduce on-going operating expenses, we implemented a restructuring plan (the "2005 Restructuring Plan"). The 2005 Restructuring Plan resulted in a reduction of approximately 40 positions and was complete by June 30, 2006. We recognized a pre-tax charge of $11 million in the fourth quarter 2005. We recognized approximately $2 million of charges in the year ended December 31, 2006, when transitional services were completed by certain affected employees. These charges related entirely to severance costs.

The following is a schedule of 2006 activity for the severance liabilities recorded in connection with this restructuring (in millions):

Balance at December 31, 2005	$ 9
2006 adjustments to liability	2
Cash payments	(11)
Balance at December 31, 2006	$—

2002 Restructuring. In October 2002, we announced a restructuring plan (the "2002 Restructuring Plan") designed to improve operational efficiencies and performance across our lines of business. The following is a schedule of 2006, 2005 and 2004 activity for the 2002 Restructuring Plan liabilities recorded associated with the severance, cancellation fees and operating leases:

	Severance	Cancellation Fees and Operating Leases	Total
		(in millions)	
Balance at December 31, 2003	$ 23	$ 30	$ 53
2004 adjustments to liability	18	7	25
2004 cash payments	(38)	(12)	(50)
Balance at December 31, 2004	3	25	$ 28
2005 cash payments	—	(9)	(9)
Balance at December 31, 2005	3	16	19
2006 adjustments to liability	—	(1)	(1)
2006 cash payments	—	(8)	(8)
Balance at December 31, 2006	$ 3	$ 7	$ 10

During 2004, the adjustment to the accrued liability primarily reflects increases in the severance accrual due to changes in our estimate of the probable loss associated with the severance claims of our former chief executive officer and our former president. Cash payments during 2004 reflect payments made to our former chief executive officer and our former president.

In addition to the $7 million accrual above, we have a $1 million accrual for operating leases made in connection with the sale of DMSLP. We expect these amounts to be paid by the end of 2007 when the leases expire. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Discontinued Operations—Natural Gas Liquids beginning on page F-23 for further information.

Note 6—Risk Management Activities and Financial Instruments

Our operations are impacted by several factors, some of which may not be mitigated by risk management methods. These risks include, but are not limited to, commodity price, interest rate and foreign exchange rate fluctuations, weather patterns, counterparty credit risks, changes in competition, operational risks, environmental risks and changes in regulations.

We define market risk as changes to our earnings and cash flow resulting from changes in market conditions, including changes in commodity prices, interest rates and currency rates as well as the impact of volatility and market liquidity on such prices. We seek to manage market risk through diversification, controlling position sizes and executing hedging strategies.

Accounting for Derivative Instruments and Hedging Activities

We follow the accounting and disclosure requirements of SFAS No. 133, as amended. Under SFAS No. 133, all derivative instruments are recognized in the balance sheet at their fair values and changes in fair value are recognized immediately in earnings, unless such instruments qualify, and are designated, as hedges of future cash flows, fair values or net investments in foreign operations or qualify, and are designated, as normal purchases and sales.

Cash Flow Hedges. We enter into financial derivative instruments that qualify as cash flow hedges. The maximum length of time for which we have hedged our exposure for cash flow hedges is through 2008. Instruments related to our generation business are entered into for purposes of hedging future fuel requirements and forecasted sales transactions. Interest rate swaps were previously used to convert the floating interest-rate component of some obligations to fixed rates.

Any ineffective portion of a cash flow hedge is reported immediately as a component of income in the consolidated statements of operations. Ineffectiveness associated with cash flow hedges of commodity transactions and interest rate swaps is included in revenues and other income and expense, net, respectively. During the years ended December 31, 2006, 2005 and 2004, we recorded $7 million, $3 million and $(3) million of income (expense), respectively, related to ineffectiveness from changes in fair value of hedge positions. No amounts were excluded from the assessment of hedge effectiveness related to the hedge of future cash flows in any of the periods.

During the years ended December 31, 2006, 2005 and 2004 no amounts were reclassified to earnings in connection with forecasted transactions that were no longer considered probable of occurring.

The balance in cash flow hedging activities, net at December 31, 2006 is expected to be reclassified to future earnings, contemporaneously with the related purchases of fuel or sales of electricity, as applicable to each type of hedge. Of this amount, after-tax gains of approximately $72 million are currently estimated to be reclassified into earnings in 2007. The actual amounts that will be reclassified to earnings over this period and beyond could vary materially from this estimated amount as a result of changes in market prices, hedging strategies, the probability of forecasted transactions occurring and other factors.

Fair Value Hedges. We also enter into derivative instruments that qualify as fair value hedges. We use interest rate swaps to convert a portion of our non-prepayable fixed-rate debt into variable-rate debt. The maximum length of time for which we have hedged our exposure for fair value hedges is through 2012. During the years ended December 31, 2006, 2005 and 2004, there was no ineffectiveness from changes in the fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness. During each of the years ended December 31, 2006, 2005 and 2004, there were no gains or losses related to the recognition of firm commitments that no longer qualified as fair value hedges.

Net Investment Hedges In Foreign Operations. Although we have exited a substantial amount of our foreign operations, we have remaining investments in foreign subsidiaries, the net assets of which are exposed to currency exchange-rate volatility. As of December 31, 2006, 2005 and 2004 we had no net investment hedges in place to hedge that exposure.

During 2003, our efforts to exit the U.K. CRM business and the European communications business were substantially completed. As required by SFAS No. 52, "Foreign Currency Translation," a significant portion of unrealized gains and losses resulting from translation and financial instruments utilized to hedge currency exposures previously recorded in stockholders' equity were recognized in income, resulting in an after-tax loss of approximately $16 million. During 2004, we repatriated a majority of our cash from the U.K. by repayment of intercompany loans, resulting in the substantial liquidation of our investment in the U.K. As a result, we recognized approximately $17 million of pre-tax translation gains in income that arose since April 1, 2003 and had accumulated in stockholders' equity.

Accumulated Other Comprehensive Income. Accumulated other comprehensive income, net of tax, is included in stockholders' equity on the consolidated balance sheets as follows:

	December 31, 2006	December 31, 2005
	(in millions)	
Cash flow hedging activities, net	$ 76	$ (2)
Foreign currency translation adjustment	23	24
Minimum pension liability	—	(18)
Unrecognized prior service cost and actuarial loss	(43)	—
Available for sale securities	11	—
Accumulated other comprehensive income, net of tax	$ 67	$ 4

Notional Contract Amounts. The absolute notional contract amounts associated with the derivative instruments designated as hedges were as follows:

	December 31, 2006	December 31, 2005
Fair Value Hedge Interest Rate Swaps (in Millions of U.S. Dollars)	$ 525	$ 525
Fixed Interest Rate Received on Swaps (Percent)	4.331	4.331
Natural Gas Cash Flow Hedges (Trillion Cubic Feet)	0.010	0.012
Electricity Cash Flow Hedges (Million Megawatt Hours)	51.664	14.460
Fuel Oil Cash Flow Hedges (Million Barrels)	1.620	0.725

Fair Value of Financial Instruments. The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS No. 107, "Disclosures About Fair Value of Financial Instruments". We have determined the estimated fair-value amounts using available market information and selected valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies could have a material effect on the estimated fair-value amounts.

The carrying values of current financial assets and liabilities approximate fair values due to the short-term maturities of these instruments. The carrying amounts and fair values of debt are included in Note 12—Debt beginning on page F-36. The carrying amounts and fair values of our other financial instruments were:

	December 31,			
	2006		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Dynegy Inc.				
Series C Convertible Preferred Stock	$—	$—	$400	$414
Dynegy Holdings Inc.				
Fair Value Hedge Interest Rate Swap	(19)	(19)	(13)	(13)
Interest Rate Risk-Management Contracts	(1)	(1)	(2)	(2)
Commodity Cash Flow Hedge Contracts	114	114	(1)	(1)
Commodity Risk-Management Contracts	14	14	88	88

The fair value of the Series C convertible preferred stock at December 31, 2005 is based on an estimate that reflects debt and equity market information for comparable securities and also incorporates the original lock-up period of the security, which expired in the first quarter 2005. The fair value stated above is the mid-point of the valuation range of $411 million to $417 million at December 31, 2005. The fair value of interest rate and commodity risk-management contracts were based upon the estimated consideration that would be received to terminate those contracts in a gain position and the estimated cost that would be incurred to terminate those contracts in a loss position.

Concentration of Credit Risk. We sell our energy products and services to customers in the electric and natural gas distribution industries and to entities engaged in industrial and petrochemical businesses. These industry concentrations have the potential to impact our overall exposure to credit risk, either positively or negatively, because the customer base may be similarly affected by changes in economic, industry, weather or other conditions.

At December 31, 2006, our credit exposure as it relates to the mark-to-market portion of our risk management portfolio totaled $105 million. To reduce our credit exposure, we execute agreements that permit us to offset receivables, payables and mark-to-market exposure. We attempt to further reduce credit risk with certain counterparties by obtaining third party guarantees or collateral as well as the right of termination in the event of default.

Our Credit Department establishes our counterparty credit limits. Our industry typically operates under negotiated credit lines for physical delivery and financial contracts. Our credit risk system provides current credit exposure to counterparties on a daily basis.

We enter into master netting agreements both to mitigate credit exposure and to reduce collateral requirements. In general, the agreements include our risk management subsidiaries and allow the aggregation of credit exposure, margin and set-off. As a result, we decrease a potential credit loss arising from a counterparty default.

We include cash collateral deposited with counterparties in Prepayments and other current assets and Other long-term assets on our consolidated balance sheets. We include cash collateral due to counterparties in Accrued liabilities and other current liabilities on our consolidated balance sheets.

Note 7—Cash Flow Information

Following are supplemental disclosures of cash flow and non-cash investing and financing information:

	Year Ended December 31,		
	2006	2005	2004
		(in millions)	
Interest paid (net of amount capitalized)	$405	$ 408	$429
Taxes paid (refunds), net	$ 9	$ 45	$ 4
Detail of businesses acquired:			
Current assets and other	$ 14	$ 217	$—
Fair value of non-current assets	13	1,076	—
Liabilities assumed, including deferred taxes	18	(1,147)	—
Cash balance acquired	(5)	(26)	—
Cash paid, net of cash acquired	$ 40	$ 120	$—
Other non-cash investing and financing activity:			
Conversion of Convertible Subordinated Debentures due 2023 (Note 12) (1)	$225	$ —	$—
Sithe Subordinated Debt exchange, net (Note 12) (2)	122	—	—
Addition of a capital lease (3)	6	—	—
Marketable securities (4)	18	—	—

(1) On May 15, 2006, we converted all $225 million of our outstanding 4.75% Convertible Subordinated Debentures due 2023 into shares of our Class A common stock (the "Convertible Debenture Exchange"). In this transaction, we issued an aggregate of 54,598,369 shares of our Class A common stock and paid the debenture holders an aggregate of approximately $47 million in premiums and accrued and unpaid interest using cash on hand. Please read Note 12—Debt—Convertible Subordinated Debentures due 2023 on page F-40 for further information.

(2) On July 21, 2006, DHI executed an exchange agreement of approximately $419 million principal amount of the subordinated debt of Independence, together with all claims for accrued and unpaid interest thereon, for approximately $297 million principal amount of DHI's 8.375% Senior Unsecured Notes due 2016. Please read Note 12—Debt—Sithe Energies Debt beginning on page F-39 for further information.

(3) In January 2006, we entered into an obligation under a capital lease related to a coal loading facility which will be used in the transportation of coal to our Vermilion generating facility. Pursuant to our agreement with the lessor, we are obligated for minimum payments in the aggregate amount of $17 million over the ten-year term of the lease.

(4) In November 2006, the New York Mercantile Exchange completed its initial public offering. As a result, we received ninety thousand shares due to our two membership seats. These shares were valued at approximately $18 million at December 31, 2006.

Note 8—Inventory

A summary of our inventories is as follows:

	December 31, 2006	December 31, 2005
	(in millions)	
Materials and supplies	$ 90	$ 90
Coal	56	44
Fuel oil	32	41
Emissions allowances	15	36
Natural gas storage	1	3
	$194	$214

In addition, we had zero and $13 million of emissions allowances at December 31, 2006 and 2005, respectively, related to future periods included in Other long-term assets on our consolidated balance sheets.

Note 9—Property, Plant and Equipment

A summary of our property, plant and equipment is as follows:

	December 31, 2006	December 31, 2005
	(in millions)	
Generation assets:		
GEN—MW	$ 5,070	$ 4,928
GEN—NE	625	593
GEN—South	569	789
IT systems and other	209	205
	6,473	6,515
Accumulated depreciation	(1,522)	(1,192)
	$ 4,951	$ 5,323

Interest capitalized related to costs of projects in process of development totaled $3 million, $3 million and $4 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Note 10—Unconsolidated Investments

Our unconsolidated investments consist primarily of investments in affiliates that we do not control, but where we have significant influence over operations. Our principal equity method investments consist of entities that operate generation assets. We entered into these ventures principally to share risk and leverage existing commercial relationships. These ventures maintain independent capital structures and have financed their operations either on a non-recourse basis to us or through their ongoing commercial activities. As of December 31, 2006, we hold an investment in a joint venture in which Chevron or its affiliates are investors. For additional information about this investment, please read Note 13—Related Party Transactions beginning on page F-40.

A summary of our unconsolidated investments is as follows:

	December 31,	
	2006	2005
	(in millions)	
Equity affiliates:		
GEN—MW	$—	$ 60
GEN—SO	—	210
Total unconsolidated investments	$—	$ 270

Cash distributions received from our equity investments during 2006, 2005 and 2004 were zero, $80 million and $136 million, respectively. Undistributed earnings from our equity investments included in accumulated deficit at December 31, 2006 and 2005 totaled zero and $154 million, respectively.

Power Generation—Midwest Investments. GEN—MW equity investments at December 31, 2005 included a 50% ownership interest in Rocky Road Power, L.L.C., a 330 MW power generation facility in East Dundee, Illinois.

On March 31, 2006, we completed the sale to NRG of our 50% ownership interest in our unconsolidated investment in West Coast Power as well as our acquisition of NRG's ownership interest in Rocky Road. As a result of the transactions, we received cash proceeds of approximately $165 million, net of cash acquired, from NRG. Under the terms of this agreement, we did not recognize a material gain or loss on the sale of West Coast Power. For further discussion, please read Note 3—Business Combinations and Acquisitions—Rocky Road on page F-18 and Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—West Coast Power on page F-21.

In 2004, we sold our 20% interest in the Joppa power generating facility as further discussed in Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Sale of Illinois Power beginning on page F-21.

Power Generation—South Investments. GEN—SO equity investments at December 31, 2006 include a 50% ownership interest in Black Mountain (Nevada Cogeneration Associates #2), an 85 MW power generation facility in Las Vegas, Nevada that owns fossil fuel electric generation facilities.

In 2006 and 2005, we recorded impairment charges of $9 million and $13 million, respectively, related to our 50% interest in Black Mountain. These charges are the result of declines in value of the investment caused by an increase in the cost of fuel in relation to a third party power purchase agreement through 2023 for 100% of the output of the facility. This agreement provides that Black Mountain (Nevada Cogeneration) will receive payments that decrease over time.

Additionally, in December 2005, we entered into an agreement to sell our 50% interest in PanAm Generating Ltd. As a result of this agreement, we recorded a $4 million impairment charge to reduce the book value of our investment to the agreed-upon sales price. In May 2006, we sold our interest in this facility. Net proceeds associated with the sale were approximately $3 million, and we did not recognize a gain or loss on the sale.

Our most significant investment in generating capacity was our interest in West Coast Power. In March 2006, we sold our unconsolidated investment in West Coast Power to NRG. For further discussion, please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—West Coast Power.

Our net investment in West Coast Power totaled approximately $205 million at December 31, 2005. West Coast Power provided equity earnings of approximately zero, $11 million and $153 million in the years ended December 31, 2006, 2005 and 2004, respectively. Our West Coast Power related earnings for 2005 were offset by an impairment charge of approximately $10 million, primarily to write down our investment balance to the agreed-upon sales price. Our West Coast Power related earnings for 2004 include a $12 million charge representing our share of an asset impairment. Additionally, our West Coast Power related earnings were partially offset by an impairment of $73 million, primarily due to the expiration of the CDWR contract in December 2004.

In 2004, we sold our unconsolidated investment in the Commonwealth generating facility. We did not recognize a material gain or loss on this sale.

In 2004, we sold our unconsolidated investments in the Oyster Creek, Michigan Power and Hartwell generating facilities for aggregate net cash proceeds of approximately $132 million. We recognized gains of $15 million and $2 million related to our sales of Oyster Creek and Hartwell, but did not recognize a material gain or loss on the sale of Michigan Power. However, during the year ended December 31, 2004, we recorded an impairment on our investment in Michigan Power totaling $8 million, to adjust our book value to the sale price.

During 2004, we sold our interest in our power generating facility located in Jamaica. Net proceeds associated with the sale were approximately $5.5 million, and we did not recognize a material gain or loss on the sale.

Summarized Information. Summarized aggregate financial information for unconsolidated equity investments and our equity share thereof was:

	December 31,					
	2006		2005		2004	
	Total	Equity Share	Total	Equity Share	Total	Equity Share
			(in millions)			
Current assets	$ 92	$46	$ 411	$205	$ 595	$276
Non-current assets	167	84	1,299	650	1,626	754
Current liabilities	21	10	80	40	177	71
Non-current liabilities	52	26	87	44	101	49
Revenues	89	44	633	272	1,430	611
Operating income	19	10	75	34	441	206
Net income	16	8	75	34	413	193

Losses from unconsolidated investments of $1 million for the year ended December 31, 2006 include the $8 million above offset by the $9 million impairment of our investment in Black Mountain.

Earnings from unconsolidated investments of $2 million for the year ended December 31, 2005, include $11 million from West Coast Power and $23 million from our other unconsolidated investments, offset by $10 million, $13 million and $4 million impairments of our investment in West Coast Power, Black Mountain and Panama, respectively, and $5 million of earnings from NGL investments which are included in income from discontinued operations.

Earnings from unconsolidated investments of $192 million for the year ended December 31, 2004 include $153 million from West Coast Power, $40 million from our other unconsolidated investments, and gains on the sales of our 20% interest in the Joppa facility, our equity investment in Oyster Creek and our equity investment in Hartwell of $75 million, $15 million and $2 million, respectively. These gains were partially offset by a $73 million impairment of our investment in West Coast Power and an $8 million impairment of our Michigan Power equity investment, $10 million of earnings from NGL investments, which are included in income (loss) from discontinued operations, as well as $2 million primarily due to amortization of the difference between the cost of our unconsolidated investments and our underlying equity in their net assets.

Variable Interest Entities. On January 31, 2005, we completed the acquisition of ExRes SHC, Inc., the parent company of Sithe Energies, Inc., which we refer to as "Sithe Energies", and Sithe/Independence Power Partners, L.P., which we refer to as "Independence". ExRes SHC, Inc., which we refer to as "ExRes", owns through its subsidiaries four natural gas-fired merchant facilities in New York and four hydroelectric generation facilities in Pennsylvania. The entities owning these facilities meet the definition of VIEs. In accordance with the purchase agreement, Exelon Corporation, which we refer to as "Exelon", has the sole and exclusive right to direct our efforts to decommission, sell, bankrupt, or otherwise dispose of the hydroelectric facilities owned through the VIE entities. Exelon is obligated to reimburse ExRes for all costs, liabilities, and obligations of the entities owning these hydroelectric generation facilities, and to indemnify ExRes with respect to the past and present assets and operations of the entities. As a result, we are not the primary beneficiary of the entities and have not consolidated them in accordance with the provisions of FIN No. 46R.

With regard to the four natural gas-fired merchant facilities located in New York, we had the option to elect to decommission any or all of these facilities within a 180-day period after the January 31, 2005 closing date. Prior to expiration of the option period, which ended on July 30, 2005, we elected to decommission all four of the natural gas-fired merchant facilities owned by ExRes. Under the terms of the purchase agreement, Exelon was permitted to direct the decommissioning, sale or other disposal of the facilities. Further, Exelon is obligated to indemnify us with respect to all operations prior to February 1, 2005 and subsequent to our election to decommission or sell the facilities. They also must provide written consent for any payments or actions outside the ordinary course of operations. On June 1 and August 4, 2005, we entered into agreements, as directed by Exelon, to sell our ownership and operating interests in the four natural gas-fired power generation peaking facilities to Alliance Energy Group LLC. The transactions, which were approved by the FERC and the New York Public Service Commission, closed on October 31, 2005 and had no impact on our consolidated financial statements, as Exelon received the proceeds from the sale. As a result of the rights retained by Exelon with respect to these facilities, we are not the primary beneficiary of these VIEs, and have not consolidated them in accordance with the provisions of FIN No. 46(R). Please read Note 3—Business Combinations and Acquisitions—Sithe Energies beginning on page F-18 for further discussion regarding this acquisition.

The hydroelectric generation facilities have commitments and obligations that are off-balance sheet with respect to Dynegy arising under operating leases for equipment and long-term power purchase agreements with local utilities. At December 31, 2006, the equipment leases have remaining terms from two to fifteen years and involve future lease payments of $114 million over the terms of the leases. Additionally, each of these facilities is party to a long-term power purchase agreement with a local utility. Under the terms of each of these agreements, a project tracking account, which we refer to as the "Tracking Account", was established to quantify the difference between (i) the facility's fixed price revenues under the power purchase agreement and (ii) the respective utility's Public Utility Commission approved avoided costs associated with those power purchases plus accumulated interest on the balance. Each power purchase agreement calls for the hydroelectric facility to return to the utility the balance in the Tracking Account before the end of the facility's life through decreased pricing under the respective power purchase agreement. Two of the four hydroelectric facilities are currently in the Tracking Account repayment period of the contract, whereby balances are repaid through decreased pricing. This pricing cannot be decreased below a level sufficient to allow the facilities to recover their operating costs, exclusive of lease or interest costs. The remaining two facilities are anticipated to begin reducing the Tracking Accounts in 2006. The aggregate balance of the Tracking Accounts as December 31, 2006 was approximately $316 million, and the obligations with respect to each Tracking Account are secured by the assets of the respective facility. The decreased pricing necessary to reduce the Tracking Accounts may cause the facilities to operate at a net cash deficit. As discussed above, the obligations of the four hydroelectric facilities are non-recourse to us. Under the terms of the stock purchase agreement with Exelon, we are indemnified for any net cash outflow arising from ownership of these facilities.

Note 11—Intangible Assets

Pursuant to our acquisition of Sithe Energies in February 2005, we recorded a significant intangible asset related to a capacity agreement between Sithe Independence Power Partners and Con Edison, a large utility in the state of New York and a subsidiary of Consolidated Edison, Inc. That contract provides Independence the right to sell 740 MW of capacity until 2014 at fixed prices that are currently above the prevailing market price of capacity for the New York Rest of State market. Since the asset arises from a contractual relationship that provides the obligation to sell capacity and the right to collect capacity payments, it was recorded as an identifiable intangible asset as defined in SFAS No. 141. The fair value recorded related to this intangible asset was $488 million. That amount is currently being amortized into earnings based on a straight-line amortization over the remaining contractual term of the agreement. That amortization expense is being recognized in the revenue line of our consolidated statements of operations where we record the revenues received from the contract. The annual amortization of the intangible asset is expected to approximate $50 million. The balance, net of accumulated amortization, totaled $383 million and $442 million at December 31, 2006 and 2005, respectively. Amortization expense was approximately $59 million and $46 million for the years ended December 31, 2006 and 2005, respectively. We have not recorded any impairment related to this intangible asset.

Pursuant to our acquisition of NRG's 50% ownership interest in the Rocky Road power plant, we recorded an intangible asset in the amount of $29 million. That amount is currently being amortized into earnings based on a straight-line amortization over the remaining contractual term of the agreement. That amortization expense is being recognized in the revenue line of our consolidated statements of operations where we record the revenues received from the contract. The annual amortization of the intangible asset is expected to be approximately $10 million. The balance, net of accumulated amortization, totaled $22 million at December 31, 2006. Amortization expense was approximately $7 million for the year ended December 31, 2006. Please read Note 3—Business Combinations and Acquisitions—Rocky Road on page F-18 for further discussion.

Note 12—Debt

A summary of our long-term debt is as follows:

	December 31, 2006		December 31, 2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Dynegy Holdings Inc.				
Term facility, floating rate due through 2012	$ 200	$ 200	$ —	$ —
Senior Notes, 7.45% due 2006	—	—	22	23
Senior Notes, 6.875% due 2011	493	499	499	492
Senior Notes, 8.75% due 2012	488	529	491	538
Senior Unsecured Notes, 8.375% due 2016	1,047	1,102	—	—
Senior Debentures, 7.125% due 2018	173	169	175	158
Senior Debentures, 7.625% due 2026	173	168	174	158
Second Priority Senior Secured Notes, floating rate due 2008	—	—	225	238
Second Priority Senior Secured Notes, 9.875% due 2010	11	12	625	685
Second Priority Senior Secured Notes, 10.125% due 2013	—	—	900	1,015
Subordinated Debentures payable to affiliates, 8.316%, due 2027	200	191	200	176
Sithe Energies				
Subordinated Debt, 7.0% due 2034	—	—	419	253
Senior Notes, 8.5% due 2007	39	39	57	57
Senior Notes, 9.0% due 2013	409	446	409	441
Dynegy Inc.				
Convertible Subordinated Debentures, 4.75% due 2023	—	—	225	294
	3,233		4,421	
Unamortized premium (discount) on debt, net (1)	25		(122)	
	3,258		4,299	
Less: Amounts due within one year, including non-cash amortization of basis adjustments	68		71	
Total Long-Term Debt	$3,190		$4,228	

(1) Change from December 31, 2005 to December 31, 2006 is primarily due to the Sithe debt exchange.

Aggregate maturities of the principal amounts of all long-term indebtedness as of December 31, 2006 are as follows:

	Total	2008	2009	2010	2011	Thereafter
	(in millions)					
Dynegy Holdings Inc.	$2,776	$—	$—	$11	$492	$2,273
Sithe Energies (1)	414	44	57	62	69	182
Total	$3,190	$ 44	$ 57	$73	$561	$2,455

Fourth Amended and Restated Credit Facility. On April 19, 2006, we entered into a fourth amended and restated credit agreement (the "Fourth Amended and Restated Credit Facility") with Citicorp USA, Inc. and JPMorgan Chase Bank, N.A., as co-administrative agents, JPMorgan Chase Bank, N.A., as collateral agent, Citicorp USA, Inc., as payment agent, Citigroup Global Markets Inc. and JPMorgan Securities Inc., as joint lead arrangers, and the other financial institutions parties thereto as lenders. The Fourth Amended and Restated Credit

Facility amends our former credit facility (last amended on March 6, 2006) by increasing the amount of the existing $400 million revolving credit facility to $470 million and adding a $200 million term letter of credit facility. The revolving facility, which is currently undrawn, is available for general corporate purposes and for letters of credit. The term facility has been fully drawn and the proceeds placed in a collateral account to support the issuance of letters of credit. Letters of credit issued under the former credit facility were continued under the Fourth Amended and Restated Credit Facility.

The Fourth Amended and Restated Credit Facility is secured by substantially all of the assets of DHI, as borrower, and certain of its subsidiaries, as subsidiary guarantors, and certain of our assets, as parent guarantor. The revolving credit facility portion of the Fourth Amended and Restated Credit Facility matures April 19, 2009 and the term letter of credit portion matures on January 31, 2012. Borrowings for both the revolving and term portions under the Fourth Amended and Restated Credit Facility bear interest at the relevant Eurodollar rate plus a ratings-based margin of 150 basis points or the relevant base rate plus a ratings-based margin of 50 basis points. Letters of credit can be issued under the revolving portion of the facility at a ratings-based rate of 150 basis points. An unused commitment fee of 37.5 basis points is payable on the unused portion of the revolving credit facility. The margin payable for borrowing, the rate payable for letters of credit and the unused commitment fee will decrease upon meeting specified improvements in Standard and Poor's and Moody's credit ratings for the facility.

The Fourth Amended and Restated Credit Facility contains mandatory prepayment provisions associated with specified asset sales and dispositions (including as a result of casualty or condemnation) and the receipt of proceeds by DHI and certain of its subsidiaries of any permitted additional non-recourse indebtedness. Commencing in 2008 with respect to the fiscal year ending December 31, 2007, each year DHI will be required to apply toward the prepayment of the loans and the permanent reduction of the commitments under the revolving credit facility (or post cash collateral in lieu thereof) a portion of its excess cash flow as calculated under the Fourth Amended and Restated Credit Facility for the prior fiscal year. This portion will be 50% initially and will fall to 25% when and if DHI's leverage ratio is less than or equal to 3.50:1.00.

The Fourth Amended and Restated Credit Facility contains customary affirmative covenants and negative covenants and events of default. Subject to certain exceptions, DHI and its subsidiaries are subject to restrictions on incurring additional indebtedness, limitations on capital expenditures and limitations on dividends and other payments with respect to capital stock. The Fourth Amended and Restated Credit Facility also contains certain financial covenants, including (1) a covenant (measured at the last day of the fiscal quarter as specified below) that requires DHI and certain of its subsidiaries to maintain a ratio of secured debt to adjusted EBITDA no greater than 3.0:1 (December 31, 2006); 2.75:1 (March 31, 2007); 2.5:1 (June 30, 2007); 2.25:1 (September 30, 2007) and 2.0:1 (December 31, 2007 and thereafter) and (2) a covenant that requires DHI and certain of its subsidiaries to maintain an interest coverage ratio as of the last day of the measurement periods ending December 31, 2006 of no less than 1.50:1; ending March 31, June 30, September 30 and December 31, 2007 and March 31, 2008 of no less than 1.625:1, and ending June 30, 2008 and thereafter of no less than 1.75:1. We are in compliance with these covenants as of December 31, 2006.

On May 26, 2006, we closed a $150 million term loan (the "Term Loan"), of which $50 million was used to make a one-time cash dividend from DHI to Dynegy (the "DHI Dividend") and the remainder used for working capital and general corporate purposes. Please read Note 13—Related Party Transactions—Series C Convertible Preferred Stock beginning on page F-40 for further discussion. The Term Loan was structured as a new tranche under the Fourth Amended and Restated Credit Facility and was repaid with proceeds from the sale of Rockingham on November 14, 2006. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Rockingham on page F-20 for further discussion of the sale.

Senior Notes. The notes are unsecured and not subject to a sinking fund. On April 12, 2006, DHI issued $750 million aggregate principal amount of our 8.375% Senior Unsecured Notes due 2016 (the "New Senior

Notes") in a private offering (the "Senior Notes Offering"). The New Senior Notes are not redeemable at our option prior to maturity. The New Senior Notes are our senior unsecured obligations and rank equal in right of payment to all of our existing and future senior unsecured indebtedness, and are senior to all of our existing and any of our future subordinated indebtedness. We have not guaranteed the New Senior Notes, and the assets and operations that we own through subsidiaries other than DHI (principally our Independence plant) do not support the New Senior Notes. The proceeds from the Senior Notes Offering, together with cash on hand, were used to fund the SPN Tender Offer discussed above. On September 14, 2006, DHI exchanged the New Senior Notes for a new issue of substantially identical notes registered under the Securities Act of 1933. Please read "Senior Unsecured Notes" below for further information.

Senior Unsecured Notes. On September 14, 2006, pursuant to the registration rights agreements pertaining to the New Senior Notes and the Additional Notes, we completed an exchange offer of $1,047 million aggregate principal amount of DHI's 8.375% Senior Unsecured Notes due 2016 registered under the Securities Act of 1933 for all $1,047 million aggregate principal amount of DHI's outstanding 8.375% Senior Unsecured Notes due 2016.

Second Priority Senior Secured Notes. On April 12, 2006, we completed a cash tender offer and consent solicitation (the "SPN Tender Offer"), in which we purchased $151 million of our $225 million Second Priority Senior Secured Floating Rate Notes due 2008 (the "2008 Notes"), $614 million of our $625 million 9.875% Second Priority Senior Secured Notes due 2010 (the "2010 Notes") and all $900 million of our 10.125% Second Priority Senior Secured Notes due 2013 (the "2013 Notes" and collectively with the "2008 Notes" and the "2010 Notes," the "Second Priority Notes"). In connection with the SPN Tender Offer, we amended the indenture under which the Second Priority Notes were issued to eliminate or modify substantially all of the restrictive covenants, certain events of default and related provisions and release certain liens securing the obligations of DHI and the guarantors of the Second Priority Notes.

Total cash paid to repurchase the $1,664 million of Second Priority Notes, including consent fees and accrued interest, was $1,904 million. We recorded a charge of approximately $228 million in 2006 associated with this transaction, of which $202 million is included in debt conversion costs, and $26 million of acceleration of amortization of financing costs and write-offs of discounts and premiums is included in interest expense on our consolidated statements of operations.

On July 15, 2006, we redeemed the remaining $74 million of our 2008 Notes, at a redemption price of 103% of the principal amount, plus accrued and unpaid interest to the redemption date. The interest rate on the 2008 Notes was based on three-month LIBOR plus 650 basis points. We recorded a charge of approximately $2 million in 2006 associated with this transaction, which is included in debt conversion costs on our consolidated statements of operations. The remaining outstanding 2010 Notes are redeemable at our option on or after July 15, 2007 in accordance with the terms of the indenture governing the Second Priority Notes.

Each of DHI's existing and future wholly owned domestic subsidiaries that guarantee DHI's obligations under its amended and restated credit facility also guarantee the obligations under the remaining outstanding notes on a senior secured basis. In addition, Dynegy and its other subsidiaries that guarantee DHI's amended and restated credit facility also guarantee the obligations under the remaining outstanding notes on a senior secured basis. The remaining outstanding notes and guarantees are senior obligations secured by a second-priority lien on, subject to certain exceptions and permitted liens, all of DHI's and its guarantors' existing and future property and assets that secure DHI's obligations under its amended and restated credit facility.

The SPN Indenture governing the remaining outstanding notes contains restrictive covenants that limit the ability of DHI and its subsidiaries that guarantee the notes to, among other things: (1) redeem, repurchase or pay dividends or distributions on capital stock; (2) make investments or restricted payments; (3) incur or guarantee additional indebtedness; (4) create certain liens; (5) engage in sale and leaseback transactions; (6) consolidate, merge or transfer all or substantially all of its assets; or (7) engage in certain transactions with affiliates. The terms of our former credit facility and the SPN Indenture governed the use of proceeds from our October 31, 2005 sale of DMSLP.

Subordinated Debentures. In May 1997, NGC Corporation Capital Trust I ("Trust") issued, in a private transaction, $200 million aggregate liquidation amount of 8.316% Subordinated Capital Income Securities ("Trust Securities") representing preferred undivided beneficial interests in the assets of the Trust. The Trust invested the proceeds from the issuance of the Trust Securities in an equivalent amount of DHI's 8.316% Subordinated Debentures ("Subordinated Debentures"). The sole assets of the Trust are the Subordinated Debentures. The Trust Securities are subject to mandatory redemption in whole, but not in part, on June 1, 2027, upon payment of the Subordinated Debentures at maturity, or in whole, but not in part, at any time, contemporaneously with the optional prepayment of the Subordinated Debentures, as allowed by the associated indenture. The Subordinated Debentures are redeemable, at DHI's option, at specified redemption prices. The Subordinated Debentures represent DHI's unsecured obligations and rank subordinate and junior in right of payment to all of DHI's senior indebtedness to the extent and in the manner set forth in the associated indenture. We have irrevocably and unconditionally guaranteed, on a subordinated basis, payment for the benefit of the holders of the Trust Securities the obligations of the Trust to the extent the Trust has funds legally available for distribution to the holders of the Trust Securities. Since the Trust is considered a SPE, and the holders of the Trust Securities absorb a majority of the Trust's expected losses, DHI's obligation is represented by the Subordinated Debentures payable to the deconsolidated Trust.

We may defer payment of interest on the Subordinated Debentures as described in the indenture, although we have not yet done so and have continued to pay interest as and when due.

Sithe Energies Debt. On January 31, 2005, we completed the acquisition of ExRes, the parent company of Sithe Energies and Independence. Upon the closing, we consolidated $919 million in face value project debt, which was recorded at its fair value of $797 million as of January 31, 2005, for which certain of the entities acquired are obligated. Please read Note 3—Business Combinations and Acquisitions—Sithe Energies beginning on page F-18 for further discussion of this transaction.

Long-term debt consolidated upon completion of the Sithe Energies acquisition consisted of the following as of January 31, 2005:

	Face Value	Premium (Discount)	Fair Value
		(in millions)	
Subordinated Debt, 7.0% due 2034	$419	$(167)	$252
Senior Notes, 8.5% due 2007	91	3	94
Senior Notes, 9.0% due 2013	409	42	451
Total Independence Debt	$919	$(122)	$797

The senior debt and subordinated debt are secured by substantially all of the assets of Independence, but are not guaranteed by us or DHI. The difference of $122 million between the face value and the fair value of the Independence Debt that was recognized upon the acquisition of ExRes will be accreted into interest expense over the life of the debt.

The terms of the indenture governing the senior debt, among other things, prohibit cash distributions by Independence to its affiliates, including Dynegy, unless certain project reserve accounts are funded to specified levels and the required debt service coverage ratio is met. The indenture also includes other covenants and restrictions, relating to, among other things, prohibitions on asset dispositions and fundamental changes, reporting requirements and maintenance of insurance. As of December 31, 2006 and 2005, Independence had restricted cash of $80 and $62 million, respectively, as reflected on our consolidated balance sheets. As of December 31, 2006, Independence had short term and long term restricted investment balances of zero and $83 million, respectively. As of December 31, 2005, Independence had short-term and long-term restricted investment balances of $2 million and $85 million, respectively. The restricted investment balances are included in prepayments and other current assets and restricted investments, respectively, on our consolidated balance sheets.

On July 21, 2006, DHI executed and consummated an exchange agreement (the "Exchange Agreement"), by and among DHI and RCP Debt, LLC and RCMF Debt, LLC (together, the "Reservoir Entities"). Pursuant to the Exchange Agreement, the Reservoir Entities exchanged approximately $419 million principal amount of the subordinated debt of Independence, together with all claims for accrued and unpaid interest thereon and all other rights and all obligations of the Reservoir Entities under the agreement pursuant to which the subordinated debt was issued (together, the "Sithe Debt"), for approximately $297 million principal amount of DHI's 8.375% Senior Unsecured Notes due 2016 (the "Additional Notes"). The Additional Notes have terms and conditions identical to, and are fungible for trading and other purposes with, the $750 million aggregate principal amount of the New Senior Notes issued on April 12, 2006. On September 14, 2006, DHI exchanged the Additional Notes for a new issue of substantially identical notes registered under the Securities Act of 1933. We recorded a charge of approximately $36 million in 2006 associated with this transaction, which is included in interest expense on our consolidated statements of operations. Please read "Senior Unsecured Notes Exchange Offer" below for further information.

Convertible Subordinated Debentures due 2023. On May 15, 2006, we converted all $225 million of our outstanding 4.75% Convertible Subordinated Debentures due 2023 into shares of our Class A common stock (the "Convertible Debenture Exchange"). In this transaction, we issued an aggregate of 54,598,369 shares of our Class A common stock and paid the debenture holders an aggregate of approximately $47 million in premiums and accrued and unpaid interest using cash on hand. We recorded a charge of approximately $44 million in 2006 associated with this transaction, which is included in debt conversion costs on our consolidated statements of operations.

Note 13—Related Party Transactions

Transactions with Chevron. Transactions with Chevron resulted from purchases and sales of natural gas and natural gas liquids between our affiliates and Chevron. We believe that these transactions were executed on terms that were fair and reasonable. During the years ended December 31, 2006, 2005 and 2004, our marketing business recognized net purchases from Chevron of $52 million, $45 million and $23 million, respectively. In accordance with the net presentation provisions of EITF Issue 02-03 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF Issue 02-03), all of these transactions, whether physically or financially settled, have been presented net on the consolidated statements of operations. In addition, during the years ended December 31, 2006, 2005 and 2004, our other businesses recognized aggregate sales to Chevron of zero, $1.2 billion and $1.1 billion, respectively, and aggregate purchases of approximately zero, $1 billion and $1.1 billion, respectively, which are reflected gross on the consolidated statements of operations.

Series C Convertible Preferred Stock. In August 2003, we issued to Chevron 8 million shares of our Series C Convertible Preferred Stock due 2033, which we refer to as our "Series C Preferred". We accrued dividends on our Series C Preferred at a rate of 5.5% of the liquidation value per annum. In May 2006, we redeemed all of the outstanding shares of our Series C Preferred, which were held by Chevron. In order to redeem the Series C Preferred, we paid Chevron $400 million in cash, plus accrued and unpaid dividends totaling approximately $6.3 million. We used approximately $178 million in net proceeds from an equity offering of 40.25 million shares of our Class A common stock that closed on the same day (includes net proceeds of $23 million from the underwriters' exercise of their option to purchase an additional 5.25 million shares), with the balance funded from cash on hand and the DHI Dividend. The redemption of the Series C Preferred eliminated the associated $22 million annual preferred dividend and reduced the number of diluted shares of our common stock outstanding.

Equity Investments. We hold an investment in a joint venture in which Chevron or its affiliates are also investors. The investment is a 50% ownership interest in Black Mountain (Nevada Cogeneration Associates #2), which holds our Black Mountain power generation facility. Prior to the sale of DMSLP, we previously held a 22.9% ownership interest in VESCO, a venture that operates a natural gas liquids processing, extraction, fractionation and storage facility in the Gulf Coast region, in which Chevron or its affiliates are also investors. During the years ended December 31, 2006, 2005 and 2004, our portion of the net income from joint ventures with Chevron was approximately $8 million, $8 million and $13 million, respectively.

We also purchase and sell, or have purchased or sold, natural gas, natural gas liquids, crude oil, emissions and power and, in some instances, earn management fees from certain entities in which we have equity investments. During the years ended December 31, 2006, 2005 and 2004, we recognized net sales to affiliates related to these transactions of zero, $0.2 billion and $0.3 billion, respectively. In accordance with the net presentation provisions of EITF Issue 02-03, all of these transactions, whether physically or financially settled, have been presented net on the consolidated statements of operations. In addition, during the years ended December 31, 2006, 2005 and 2004, our other businesses recognized aggregate sales to these affiliates of zero million, $4 million and $12 million, respectively, and aggregate purchases of zero, $135 million and $170 million, respectively, which are reflected gross on the consolidated statements of operations. Revenues were related to the supply of fuel for use at generation facilities, primarily West Coast Power, and the supply of natural gas sold by retail affiliates. Expenses primarily represent the purchase of natural gas liquids that were subsequently sold in our marketing operations.

Short-Term Executive Stock Purchase Loan Program. In July 2001, we established the Dynegy Inc. Short-Term Executive Stock Purchase Loan Program pursuant to which eligible employees were loaned funds to acquire Class A common stock through market purchases. We terminated this program as it related to new loans effective June 30, 2002. The notes bear interest at the greater of 5% or the applicable federal rate as of the loan date, are full recourse to the participants and matured on December 19, 2004.

Under this program, at December 31, 2006, approximately $8 million, which included accrued and unpaid interest, was owed to us. We are actively pursuing, through litigation and otherwise, repayment of the past due amounts owed to us under these loans. The loans are accounted for as subscriptions receivable within stockholders' equity on the consolidated balance sheets and at December 31, 2006 and 2005 are fully reserved.

December 2001 Equity Purchases. In December 2001, ten former members of our senior management purchased Class A common stock from us in a private placement pursuant to Section 4(2) of the Securities Act of 1933. These former officers received loans from us totaling approximately $25 million to purchase the common stock at a price of $19.75 per share, the same price as the net proceeds per share received by us from a concurrent public offering. The loans bear interest at 3.25% per annum and are full recourse to the borrowers. Such loans are accounted for as subscriptions receivable within stockholders' equity on the consolidated balance sheets.

At December 31, 2006, one of our former executive officers, who resigned his position following our October 2002 restructuring, had a balance of approximately $511,000 remaining under the December 2001 equity purchase with an extended maturity date of September 30, 2007 for the loan. The extended loan bears interest at the same interest rate as the initial loan. The loan is accounted for as subscriptions receivable within stockholders' equity on the consolidated balance sheets and at December 31, 2006 and 2005 is fully reserved. No other December 2001 equity purchase loans are outstanding as of December 31, 2006.

Note 14—Income Taxes

Income Tax Benefit. We are subject to U.S. federal, foreign and state income taxes on our operations. Components of loss from continuing operations before income taxes were as follows:

	Year Ended December 31,		
	2006	2005	2004
	(in millions)		
Loss from continuing operations before income taxes:			
Domestic	$(531)	$(1,209)	$(328)
Foreign	5	10	(24)
	$(526)	$(1,199)	$(352)

Components of income tax benefit related to loss from continuing operations were as follows:

	Year Ended December 31,		
	2006	2005	2004
	(in millions)		
Current tax benefit (expense):			
Domestic	$ 2	$ 4	$ (8)
Foreign	(2)	—	—
Deferred tax benefit (expense):			
Domestic	159	405	181
Foreign	9	(14)	(1)
Income tax benefit	$168	$395	$172

Income tax benefit related to loss from continuing operations for the years ended December 31, 2006, 2005 and 2004, were equivalent to effective rates of 32%, 33% and 49%, respectively. Differences between taxes computed at the U.S. federal statutory rate and our reported income tax benefit were as follows:

	Year Ended December 31,		
	2006	2005	2004
	(in millions)		
Expected tax benefit at U.S. statutory rate (35%)	$184	$420	$123
State taxes	32	18	10
Foreign taxes	(6)	2	(9)
Valuation allowance	(4)	(33)	27
IRS and state audits and settlements	(38)	(3)	5
Basis differentials and other	—	(9)	16
Income tax benefit	$168	$395	$172

Deferred Tax Liabilities and Assets. Significant components of deferred tax assets and liabilities were as follows:

	December 31, 2006	December 31, 2005
	(in millions)	
Deferred tax assets:		
Current:		
Reserves (legal, environmental and other)	$ 15	$ 25
NOL carryforwards	95	—
Subtotal	110	25
Less: valuation allowance	(7)	—
Total current deferred tax assets	103	25
Non-current:		
NOL carryforwards	317	270
AMT credit carryforwards	251	256
Capital loss carryforward	17	17
Foreign tax credits	23	23
Other	—	28
Reserves (legal, environmental and other)	51	66
Miscellaneous book/tax recognition differences	9	29
Subtotal	668	689
Less: valuation allowance	(62)	(70)
Total non-current deferred tax assets	606	619
Deferred tax liabilities:		
Current:		
Miscellaneous book/tax recognition differences	10	11
Total current deferred tax liabilities	10	11
Non-current:		
Depreciation and other property differences	903	974
Power contract	143	200
Other	17	—
Total non-current deferred tax liabilities	1,063	1,174
Net deferred tax liability	$ 364	$ 541

NOL Carryforwards. At December 31, 2006, we had approximately $948 million of regular federal tax NOL carryforwards after considering the effect of carryback to prior years and $1,730 million of AMT NOL carryforwards. The federal and AMT NOL carryforwards will expire beginning in 2024 through 2026. Certain provisions of the Internal Revenue Code placed an annual limitation on our ability to utilize certain tax carryforwards existing as of the date of a 2005 business acquisition. However, due to the impact of certain 2006 transactions, the limitation is no longer applicable. If certain substantial changes in the Company's ownership should occur, there could be an annual limitation on the amount of the carryforwards which can be utilized. Upon the adoption of FIN No. 48, a significant amount of the NOL carryforwards will be recharacterized as other deferred tax assets or other deferred tax liabilities; however, there will be no impact to our consolidated financial statements. There was no valuation allowance established at December 31, 2006 for our federal NOL carryforwards, as management believes our NOL carryforward is more likely than not to be fully realized in the future based, among other things, on management's estimates of future taxable net income, future reversals of existing taxable temporary differences and tax planning.

At December 31, 2006, state NOL carryforwards were as follows:

	Amount (in millions)	Expiration Dates
States where we file unitary state income tax returns:		
Illinois	$ 291	2015 & 2018
California	39	2023 & 2026
New Mexico	9	2008 & 2011
States where we file separate state income tax returns:		
Louisiana	215	2020 – 2026
New York	687	2021 – 2026
Kentucky	220	2021 – 2026
Texas	268	2007 – 2011
Iowa	48	2022 – 2026
Georgia	51	2022 – 2026
Pennsylvania	53	2022 – 2026
Other	7	2007 – 2026
Total	$1,888	

During 2004, we established a valuation allowance for certain state NOL carryforwards which management believes are not likely to be fully realized in the future based on our ability to generate gains in the respective state. See "Change in Valuation Allowance" below.

At December 31, 2006 and 2005, foreign NOL carryforwards totaled $11 million and $13 million, respectively. During 2005, we established a valuation allowance for certain of the foreign NOL carryforwards which management believed were not likely to be fully realized in the future based on our ability to generate gains in the respective jurisdiction. However, because various adjustments are anticipated as a result of the Canadian authorities' audit of prior year income tax returns, management determined in 2006 that it is more likely than not that the NOL carryforwards will be utilized, and the valuation allowance was released. See "Change in Valuation Allowance" below.

AMT Credit Carryforwards. At December 31, 2006, we had approximately $251 million of AMT credit carryforwards. The AMT credit carryforwards do not expire. There was no valuation allowance established at December 31, 2006 for our AMT credit carryforwards, as management believes the AMT credit carryforward is more likely than not to be fully realized in the future based, among other things, on management's estimates of future taxable net income and future reversals of existing taxable temporary differences.

Capital Loss Carryforwards. At December 31, 2006, we had approximately $49 million of capital loss carryforwards. The capital loss carryforwards expire during 2007 and 2008. At December 31, 2006, we had a valuation allowance for a portion of our capital loss carryforwards, which management believes are not likely to be fully realized in the future based on our ability to generate capital gains.

Foreign Tax Credits. At December 31, 2006 and 2005, we had approximately $23 million of foreign tax credits. The foreign tax credits expire in 2010 through 2014. At December 31, 2006, a full valuation allowance for our foreign tax credits was recorded as we have disposed of or discontinued the majority of our foreign operations and management believes the foreign tax credits are not likely to be fully realized in the future based on our ability to generate foreign source income. Unless we generate foreign source income prior to their expiration, which we do not anticipate, we will write-off the $23 million of foreign tax credits and the related $23 million valuation allowance in the year of their expiration.

Residual U.S. Income Tax on Foreign Earnings. We have provided U.S. deferred taxes with respect to one foreign subsidiary that is in the process of liquidating with previously untaxed earnings and profits. Otherwise, we do not have material undistributed non-previously taxed earnings from our foreign operations, and have sufficient intercompany loans from or other tax attributes related to our affiliates which will allow us the ability to repatriate available funds without incurring residual U.S. income tax. Therefore, except as noted, we have not provided any U.S. deferred taxes or foreign withholding taxes on the actual or deemed remittance of any such earnings.

Texas Margin Tax. In May 2006, Texas enacted a new law that substantially changes the state's tax system. The law replaces the taxable-capital and earned-surplus components of its franchise tax with a new franchise tax that is based on modified gross revenue. This new franchise tax is referred to as the "Margin Tax" and will significantly affect the financial reporting of a wide range of enterprises that have operations in Texas. As a result of the new law, which becomes effective January 1, 2007, we established a deferred tax liability of $2 million related to our Texas operations and removed a deferred tax asset of $1 million related to existing Texas net operating losses since we do not forecast a 2006 Texas income tax liability. We also established a deferred tax asset of $5 million and increased the valuation allowance by an equal and offsetting $5 million. The effect of the change in Texas law produced a total expense, which is included in our income tax benefit, of $1 million for the year ended December 31, 2006.

Change in Valuation Allowance. Realization of our deferred tax assets is dependent upon, among other things, our ability to generate taxable income of the appropriate character in the future. At December 31, 2006, valuation allowances related to capital loss carryforwards, foreign tax credit carryforwards and state NOL carryforwards have been established. During 2006, we increased our valuation allowance associated with various state NOL carryforwards and released a valuation allowance on a foreign NOL carryforward. In 2005, as a result of the sale of DMSLP, as further discussed in Note 4—Dispositions, Contract Terminations and Discontinued Operations—Discontinued Operations—Natural Gas Liquids beginning on page F-23, we reduced the valuation allowance related to our capital loss carryforward. This benefit is reflected in income from discontinued operations on our consolidated statements of operations. We also increased our valuation allowance associated with a state NOL carryforward and established a valuation allowance on a foreign NOL carryforward.

The changes in the valuation allowance by attribute for the years ended December 31, 2006, 2005 and 2004 were as follows:

	Capital Loss Carryforwards	Foreign Tax Credits	State NOL Carryforwards	Foreign NOL Carryforwards	Total
			(in millions)		
Balance as of December 31, 2003	$(161)	$ (9)	$—	$—	$(170)
Changes in valuation allowance—continuing operations	40	(14)	(1)	—	25
Changes in valuation allowance—discontinued operations	9	—	—	—	9
Balance as of December 31, 2004	(112)	(23)	(1)	—	(136)
Acquisition of Sithe Energies	(17)	—	(15)	—	(32)
Changes in valuation allowance—continuing operations	(14)	—	(1)	(13)	(28)
Changes in valuation allowance—discontinued operations	126	—	—	—	126
Balance as of December 31, 2005	(17)	(23)	(17)	(13)	(70)
Changes in valuation allowance—Sithe subordinated debt exchange	—	—	5	—	5
Changes in valuation allowance—continuing operations	—	—	(17)	13	(4)
Balance as of December 31, 2006	$ (17)	$(23)	$(29)	$—	$ (69)

IRS, Canada, and Various State Settlements. Our federal income tax returns are routinely audited by the IRS, and provisions are routinely made in the financial statements in anticipation of the results of these audits. The IRS completed its audit of our 2001-2002 tax returns during late 2005 and in January 2006, we received the Revenue Agent's Report for our 2001-2002 tax years. During 2006, we met with the IRS and tentatively settled those tax years. Also, during 2006, the Canadian Revenue Agency commenced an audit of Dynegy's 2003-2004 tax years. As a result of the IRS settlement, the Canadian audit, and various state settlements, we recorded an expense, which is included in our income tax benefit, of $40 million for the year ended December 31, 2006.

Acquisition of Sithe Energies. On January 31, 2005, we acquired 100% of the outstanding common shares of ExRes, the parent company of Sithe Energies and Independence. Please read Note 3—Business Combinations and Acquisitions—Sithe Energies beginning on page F-18 for further discussion. As a part of this transaction, we recorded a net deferred tax liability of $193 million.

Sithe Subordinated Debt Exchange. In July 2006, we acquired approximately $419 million principal amount of the subordinated debt of Sithe Independence, together with all claims for accrued and unpaid interest, in exchange for approximately $297 million principal amount of DHI's 8.375% Senior Unsecured Notes. The acquisition produced a tax gain of approximately $129 million and increased the amount of state net operating loss carryforwards that can be utilized to reduce state tax liability. The increased projected utilization reduced the amount of the state net operating loss valuation allowance by approximately $5 million. The release of the valuation allowance was applied against noncurrent intangible assets on a prospective basis and therefore did not impact current year earnings. Please read Note 12—Debt—Sithe Energies Debt beginning on page F-39 for further discussion.

Note 15—Redeemable Preferred Securities

Redeemable preferred securities at December 31, 2005 consisted of Series C Convertible Preferred stock and totaled $400 million. In May 2006, we redeemed all of the outstanding shares of our Series C Convertible Preferred stock, which were held by Chevron. Please read Note 13—Related Party Transactions—Series C Convertible Preferred Stock on page F-40 for further discussion of the redemption.

Note 16—Earnings (Loss) Per Share

The reconciliation of basic earnings (loss) per share from continuing operations to diluted earnings (loss) per share from continuing operations is shown in the following table:

	Year Ended December 31,		
	2006	2005	2004
	(in millions, except per share amounts)		
Loss from continuing operations	$ (358)	$ (804)	$ (180)
Convertible preferred stock dividends	(9)	(22)	(22)
Loss from continuing operations for basic loss per share	(367)	(826)	(202)
Effect of dilutive securities:			
Interest on convertible subordinated debentures	3	7	7
Dividends on Series C convertible preferred stock	9	22	22
Loss from continuing operations for diluted loss per share	$ (355)	$ (797)	$ (173)
Basic weighted-average shares	459	387	378
Effect of dilutive securities:			
Stock options	2	2	2
Convertible subordinated debentures	20	55	55
Series C convertible preferred stock	28	69	69
Diluted weighted-average shares	509	513	504
Loss per share from continuing operations			
Basic	$(0.80)	$(2.13)	$(0.53)
Diluted (1)	$(0.80)	$(2.13)	$(0.53)

(1) When an entity has a net loss from continuing operations adjusted for preferred dividends, SFAS No. 128, "Earnings per Share", prohibits the inclusion of potential common shares in the computation of diluted per-share amounts. Accordingly, we have utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for the years ended December 31, 2006 and 2005.

Note 17—Commitments and Contingencies

Set forth below is a summary of certain ongoing legal proceedings. In accordance with SFAS No. 5, we record reserves for contingencies when information available indicates that a loss is probable and the amount of the loss is reasonably estimable. In addition, we disclose matters for which management believes a material loss is at least reasonably possible. In all instances, management has assessed the matters below based on current information and made a judgment concerning their potential outcome, giving due consideration to the nature of the claim, the amount and nature of damages sought and the probability of success. Management's judgment may prove materially inaccurate and such judgment is made subject to the known uncertainty of litigation.

In addition to the matters discussed below, we are party to numerous legal proceedings arising in the ordinary course of business or related to discontinued business operations. In management's opinion, the disposition of these matters will not materially adversely affect our financial condition, results of operations or cash flows.

Gas Index Pricing Litigation. We and our former joint venture affiliate West Coast Power are named defendants in numerous lawsuits in state and federal court claiming damages resulting from alleged price manipulation and false reporting of natural gas prices. The cases are pending in California, Nevada and Alabama. In each of these suits, the plaintiffs allege that we and other energy companies engaged in an illegal scheme to inflate natural gas prices by providing false information to natural gas index publications. All of the complaints rely heavily on prior FERC and CFTC investigations into and reports concerning index-reporting manipulation in the energy industry. Except as specifically mentioned below, the cases are actively engaged in discovery.

During the last year, several cases pending in Nevada federal court were dismissed on defendants' motions. Certain plaintiffs have appealed to the Court of Appeals for the Ninth Circuit, which coordinated the cases before the same appellate panel. A decision from the Court of Appeals is expected sometime in 2007. In February 2007, a Tennessee state court case was also dismissed on defendants' motion.

Pursuant to various motions, the cases pending in California state court have been coordinated before a single judge in San Diego ("Coordinated Gas Index Cases"). In August 2006, we entered into an agreement to settle the class action claims in the Coordinated Gas Index Cases for $30 million. The settlement does not include similar claims filed by individual plaintiffs in the Coordinated Gas Index Cases, which we continue to defend vigorously. In December 2006, the court granted final approval of the settlement and dismissed the class action claims. Also in August 2006, we entered into an agreement to settle the class action claims by California natural gas re-sellers and co-generators (to the extent they purchased natural gas to generate electricity for re-sale) pending in Nevada federal court for $2.4 million. A motion to approve this settlement is expected to be filed by plaintiffs in due course. Both settlements are without admission of wrongdoing, and Dynegy and West Coast Power continue to deny class plaintiffs' allegations.

We are analyzing the remaining natural gas index cases and are vigorously defending against them. We cannot predict with certainty whether we will incur any liability in connection with these lawsuits. However, given the nature of the claims, an adverse result in any of these proceedings could have a material adverse effect on our financial condition, results of operations and cash flows.

California Market Litigation. We and various other power generators and marketers are defendants in numerous lawsuits alleging rate and market manipulation in California's wholesale electricity market during the California energy crisis several years ago. The complaints generally allege unfair, unlawful and deceptive trade practices in violation of the California Unfair Business Practices Act and seek injunctive relief, restitution and unspecified actual and treble damages. A significant majority of these cases were dismissed on grounds of federal preemption. A motion to dismiss one remaining action on similar grounds is pending in federal court. Certain actions, however, in which plaintiffs have not exhausted the appellate process, remain pending in a California appellate court.

We believe that we have meritorious defenses to these claims and are vigorously defending against them. We cannot predict with certainty whether we will incur any liability in connection with these lawsuits. However, given the nature of the claims, an adverse result in any of these proceedings could have a material adverse effect on our financial condition, results of operations and cash flows.

Danskammer State Pollutant Discharge Elimination System Permit. In January 2005, the NYSDEC issued a Draft SPDES Permit renewal for the Danskammer plant, and an adjudicatory hearing was scheduled for the fall of 2005. Three environmental groups sought to impose a permit requirement that the Danskammer plant install a closed cycle cooling system in order to reduce the volume of water withdrawn from the Hudson River, thus reducing aquatic organism mortality. The petitioners claim that only a closed cycle cooling system meets the Clean Water Act's requirement that the cooling water intake structures reflect best technology available (BTA) for minimizing adverse environmental impacts.

A formal evidentiary hearing was held in November and December 2005. The Deputy Commissioner's decision directing that the NYSDEC staff issue the revised Draft SPDES Permit was issued in May 2006. In June 2006, the NYSDEC issued the revised SPDES Permit with conditions generally favorable to us. While the revised SPDES Permit does not require installation of a closed cycle cooling system, it does require aquatic organism mortality reductions resulting from NYSDEC's determination of BTA requirements under its regulations. In July 2006, two of the petitioners filed suit in the Supreme Court of the State of New York seeking to vacate the Deputy Commissioner's decision and the revised Danskammer SPDES Permit. We believe that the decision of the Deputy Commissioner is well reasoned and will be affirmed. However, in the event the decision is not affirmed and we ultimately are required to install a closed cycle cooling system, this could have a material adverse effect on our financial condition, results of operations and cash flows.

Roseton State Pollutant Discharge Elimination System Permit. In April 2005, the NYSDEC issued to DNE a draft SPDES Permit renewal (the "Draft SPDES Permit") for the Roseton plant. The Draft SPDES Permit requires the facility to actively manage its water intake to substantially reduce mortality of aquatic organisms.

In July 2005, a public hearing was held to receive comments on the Draft SPDES Permit. Three environmental organizations filed petitions for party status in the permit renewal proceeding. The petitioners are seeking to impose a permit requirement that the Roseton plant install a closed cycle cooling system in order to reduce the volume of water withdrawn from the Hudson River, thus reducing aquatic organism mortality. The petitioners claim that only a closed cycle cooling system meets the Clean Water Act's requirement that the cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. In September 2006, the administrative law judge issued a ruling admitting the petitioners to full party status and setting forth the issues to be adjudicated in the permit renewal hearing. Various holdings in the ruling have been appealed to the Commissioner of NYSDEC by DNE, NYSDEC staff, and the petitioners. We expect that the adjudicatory hearing on the Draft SPDES Permit will occur in 2007. We believe that the petitioners' claims are without merit, and we plan to oppose those claims vigorously. Given the high cost of installing a closed cycle cooling system, an adverse result in this proceeding could have a material adverse effect on our financial condition, results of operations and cash flows.

Enron Trade Credit Litigation. On October 5, 2006, we entered into a Settlement Agreement and Mutual General Release (the "Settlement Agreement") with Enron Corp. and certain of its subsidiaries and affiliates (collectively the "Enron Parties"). The Settlement Agreement provides for the settlement of all claims by either Dynegy or the Enron Parties against the others arising from or relating to the Master Netting Setoff and Security Agreement (the "MNSSA") dated November 8, 2001. The MNSSA allowed certain amounts owed from Dynegy to the Enron Parties to be set off against other amounts owed from the Enron Parties to Dynegy as a result of the termination of commercial transactions between the parties.

On October 26, 2006, the settlement received final approval from the Bankruptcy Court. Under the Settlement Agreement, Dynegy and the Enron Parties agreed to the following in exchange for the final resolution and mutual release of all claims asserted by any of the parties in the adversary and arbitration proceedings and an action in Canada relating to an Enron Corp. Canadian subsidiary:

- A settlement payment of $44 million by us, payable on the second business day after final Bankruptcy Court approval.
- We retain the right to pursue claims filed against Enron Capital and Trade Resources Limited ("ECTRL") in ECTRL's administration proceedings in the United Kingdom for amounts owed by ECTRL under or in connection with certain underlying commodities contracts.

In accordance with the payment terms, Dynegy funded the settlement on October 30, 2006. The Settlement Agreement further provides for a mutual release of any other claims that exist or could exist between the Dynegy Parties and the Enron Parties through the date payment is made. Neither the Dynegy Parties nor the Enron Parties admit any liability in connection with the Settlement Agreement. We recorded approximately $20 million and $28 million in pre-tax charges related to the settlement and associated legal expenses in the years ended December 31, 2006 and 2005, respectively. These charges are recorded as general and administrative expenses on our consolidated statements of operations.

Other Commitments and Contingencies

In conducting our operations, we have routinely entered into long-term commodity purchase and sale commitments, as well as agreements that commit future cash flow to the lease or acquisition of assets used in our businesses. These commitments have been typically associated with commodity supply arrangements, capital projects, reservation charges associated with firm transmission, transportation, storage and leases for office space, equipment, plant sites, power generation assets and LPG vessel charters. The following describes the more significant commitments outstanding at December 31, 2006.

Purchase Obligations. We have routinely entered into contracts for the purchase and sale of electricity, some of which contain fixed capacity payments. Such obligations are generally payable on a ratable basis, the terms of which extend through September 2017. In return for such fixed capacity payments, we receive the right to generate electricity, which we then may re-market. These types of arrangements are referred to as tolling arrangements. Fixed payments associated with these arrangements totaled approximately $416 million at December 31, 2006. This amount includes the capacity payments on our remaining tolls.

We have other firm capacity payments related to transportation of natural gas. Such arrangements are routinely used in the physical movement and storage of energy. The total of such obligations was $272 million as of December 31, 2006.

We also have a co-sourcing agreement with Accenture LLP for employee and infrastructure outsourcing through October 2015. We are obligated for minimum payments of approximately $114 million over the term of the agreement. This agreement may be cancelled at any time upon the payment of a termination fee not to exceed $2 million. This termination fee is in addition to amounts due for services provided through the termination date.

Advance Agreement. In 1997, we received cash from a natural gas purchaser as an advance payment under our agreement to make future natural gas deliveries over a ten-year period. As a condition of the agreement, we entered into a natural gas swap with a third party under which we became a fixed-price payer on identical volumes to those to be delivered under the agreement at prices based on current market rates. The cash receipt is included as deferred revenue in other short-term liabilities on the consolidated balance sheets and is ratably reduced as natural gas is delivered to the purchaser under the terms of the agreement. The balance at December 31, 2006 was approximately $13 million. The agreement contains specified non-performance penalties that impact both parties and, as a condition precedent, we purchased a surety bond in support of our obligations under the agreement.

Other Minimum Commitments. In January 2006, we entered into an obligation under a capital lease related to a coal loading facility which will be used in the transportation of coal to our Vermilion power generating facility. The Vermilion facility is included in the GEN-MW segment. Pursuant to our agreement with the lessor, we are obligated for minimum payments in the aggregate amount of $17 million over the ten year term of the lease. Minimum commitments at December 31, 2006 were $2 million for each of the years ending 2007, 2008, 2009, 2010, 2011, and beyond $7 million.

In the first quarter 2001, we acquired the DNE power generation facilities. These facilities consist of a combination of baseload, intermediate and peaking facilities aggregating approximately 1,700 MW. The facilities are approximately 50 miles north of New York City and were acquired for approximately $903 million cash, plus inventory and certain working capital adjustments. In May 2001, two of our subsidiaries completed a sale-leaseback transaction to provide term financing for the DNE facilities. Under the terms of the sale-leaseback transaction, our subsidiaries sold plants and equipment and agreed to lease them back for terms expiring within 34 years, exclusive of renewal options. We have no option to purchase the leased facilities at the end of their respective lease terms. If one or more of the leases were to be terminated because of an event of loss, because it had become illegal for the applicable lessee to comply with the lease or because a change in law had made the facility economically or technologically obsolete, DHI would be required to make a termination payment. As of December 31, 2006, the termination payment would be approximately $1 billion for all of the DNE facilities.

Minimum commitments in connection with office space, equipment, plant sites and other leased assets, including the DNE sale-leaseback transaction discussed above, at December 31, 2006, were as follows: 2007-$139 million; 2008-$164 million; 2009-$164 million; 2010-$117 million; 2011-$133 million and beyond-$759 million.

Rental payments made under the terms of these arrangements totaled $80 million in 2006; $88 million in 2005 and $82 million in 2004.

We are party to two charter party agreements relating to VLGCs previously utilized in our global liquids business. The aggregate minimum base commitments of the charter party agreements are approximately $14 million each year for the years 2007 and 2008, and approximately $51 million through lease expiration. The charter party rates payable under the two charter party agreements float in accordance with market based rates for similar shipping services. The $14 million and $51 million numbers set forth above are based on the minimum obligations set forth in the two charter party agreements. The primary term of one charter is through August 2013 while the primary term of the second charter is through August 2014. On January 1, 2003, in connection with the sale of our global liquids business, we sub-chartered both VLGCs to a wholly owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter agreements. To date, the subsidiary of Transammonia has complied with the terms of the sub-charter agreements.

Guarantees and Indemnifications

In the ordinary course of business, we routinely enter into contractual agreements that contain various representations, warranties, indemnifications and guarantees. Examples of such agreements include, but are not limited to, service agreements, equipment purchase agreements, engineering and technical service agreements, and procurement and construction contracts. Some agreements contain indemnities that cover the other party's negligence or limit the other party's liability with respect to third party claims, in which event we will effectively be indemnifying the other party. Virtually all such agreements contain representations or warranties that are covered by indemnifications against the losses incurred by the other parties in the event such representations and warranties are false. While there is always the possibility of a loss related to such representations, warranties, indemnifications and guarantees in our contractual agreements, and such loss could be significant, in most cases management considers the probability of loss to be remote.

Kendall Guarantee. On September 14, 2006, the LS Entities and Kendall Power entered into the Kendall Agreement pursuant to which Kendall Power agreed to acquire all of the outstanding interests in LSP Kendall Holdings, LLC for $200 million in cash, as adjusted for certain changes in working capital. The closing of the Kendall Agreement will occur only if closing does not occur with respect to the transactions contemplated by the Merger Agreement. We have agreed to guarantee certain of Kendall Power's obligations under the Kendall

Agreement. The consummation of the Kendall Agreement is subject to the termination of the Merger Agreement and satisfaction of certain other conditions. Please read Note 3—Business Combinations and Acquisitions—LS Power on page F-17 for further discussion.

WCP Indemnities. In connection with the sale of our 50% interest in West Coast Power to NRG on March 31, 2006, we, NRG and NRG West Coast Power LLC entered into an agreement to allocate responsibility for managing certain litigation and provide for certain indemnities with respect to such litigation. Subject to conditions and limitations specified in that agreement, the parties agreed that we would manage the Gas Index Pricing Litigation described above for which NRG could suffer a loss subsequent to the closing and that we would indemnify NRG for all costs or losses resulting from such litigation, as well as from other proceedings based on similar acts or omissions which formed the basis of such litigation. Further, the parties agreed that we would manage the California Market Litigation described above for which NRG could suffer a loss subsequent to the closing, and that we and NRG would each be responsible for 50% of any costs or losses resulting from that power litigation, as well as from other proceedings based on similar acts or omissions which formed the basis of such litigation. The agreement also provides that NRG will manage other active litigation and indemnify us for any resulting losses, subject to certain conditions. Please also read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—West Coast Power on page F-21 for further discussion.

Targa Indemnities. During 2005, as part of our sale of DMSLP, we agreed to indemnify Targa against losses it may incur under indemnifications DMSLP provided to purchasers of Hackberry and certain other assets, properties and businesses disposed of by DMSLP prior to our sale of DMSLP. We have incurred no significant expense under these prior indemnities and deem their value to be insignificant. We have recorded an accrual in association with the cleanup of groundwater contamination at the Breckenridge Gas Processing Plant. The indemnification provided by DMSLP to the purchaser of the plant has a limit of $5 million. We have also indemnified Targa for certain tax matters arising from periods prior to our sale of DMSLP. We have recorded a reserve associated with this indemnification.

Illinois Power Indemnities. As a condition of our 2004 sale of Illinois Power and our interest in Joppa, we provided indemnifications to third parties regarding environmental, tax, employee and other representations. These indemnifications are limited to a maximum recourse of $400 million. Additionally, we have indemnified third parties against losses resulting from possible adverse regulatory actions taken by the ICC that could prevent Illinois Power from recovering costs incurred in connection with purchased natural gas and investments in specified items. Although there is no limitation on our liability under this indemnity, our indemnity is limited to 50% of any such losses. On July 27, 2005, we made a payment of $8 million to Ameren in settlement of Ameren's indemnification claims with respect to an ICC Order disallowing items relating to one of Illinois Power's natural gas storage fields resulting in a negative revenue requirement impact to Ameren. In anticipation of similar cases, we recognized a pre-tax charge of $12 million in 2005, which is included in general and administrative expense on our consolidated statements of operations. As anticipated, we paid Ameren for an additional amount disallowed in a similar ICC Order in the third quarter of 2006. We have adjusted the amount reserved for the various ongoing cases in light of these and other developments in the cases. Further disallowances and other events which fall within the scope of the indemnity may still occur; however, we are not required to accrue a liability in connection with these indemnifications, as management cannot reasonably estimate a range of outcomes or at this time considers the probability of an adverse outcome as only reasonably possible. We intend to contest any proposed disallowances.

Northern Natural and Other Indemnities. During 2003, as part of our sale of Northern Natural, the Rough and Hornsea natural gas storage facilities and certain natural gas liquids assets, we provided indemnities to third parties regarding environmental, tax, employee and other representations. Maximum recourse under these indemnities is limited to $209 million, $857 million and $28 million for the Northern Natural, Rough and Hornsea natural gas storage facilities and natural gas liquids assets, respectively. We also entered into similar indemnifications regarding environmental, tax, employee and other representations when completing other asset sales such as, but not limited to, Hackberry LNG Project, SouthStar Energy Services, various Canadian assets, Michigan Power, Oyster Creek, Hartwell, Commonwealth, Sherman, Indian Basin and PESA. We have recorded reserves for existing environmental, tax and employee liabilities and have incurred no other expense relating to these indemnities.

Through one of our subsidiaries, we hold a 50% ownership interest in Black Mountain (Nevada Cogeneration) ("Black Mountain"), in which our partner is a Chevron subsidiary. Black Mountain owns the Black Mountain power generation facility and has a power purchase agreement with a third party that extends through April 2023. In connection with the power purchase agreement, pursuant to which Black Mountain receives payments which decrease in amount over time, we agreed to guarantee 50% of certain payments that may be due to the power purchaser under a mechanism designed to protect it from early termination of the agreement. At December 31, 2006, if an event of default due to early termination had occurred under the terms of the mortgage on the facility entered into in connection with the power purchase agreement, we could have been required to pay the power purchaser approximately $60 million under the guarantee. While there is a question of interpretation regarding the existence of an obligation to make payments calculated under this mechanism upon the scheduled termination of the agreement, management does not expect that any such payments would be required.

Note 18—Regulatory Issues

We are subject to regulation by various federal, state and local agencies, including extensive rules and regulations governing transportation, transmission and sale of energy commodities as well as the discharge of materials into the environment or otherwise relating to environmental protection. Compliance with these regulations requires general and administrative, capital and operating expenditures including those related to monitoring, pollution control equipment, emission fees and permitting at various operating facilities and remediation obligations.

Energy Policy Act of 2005. The EPACT was signed into law on August 8, 2005. Title XII of EPACT (Electricity) created new legislation which deals with various matters impacting the power industry, including reliability of the bulk power system; transmission congestion and transmission structure siting and modernization; the repeal of PUHCA; and prohibition of energy market manipulation, with enhanced FERC authority to prohibit market manipulation, including enhanced penalty authority. The FERC has implemented and is considering a number of related regulations to implement EPACT that may impact, among other things, requirements for reliability, QFs, such as CoGen Lyondell and Black Mountain, transmission information availability, transmission congestion, security constrained dispatch, energy market transparency, energy market manipulation and behavioral rules.

Illinois Resource Procurement Auction. In January 2006, the ICC approved a reverse power procurement auction as the process by which utilities will procure power beginning in 2007. The auction occurred in September 2006, and we subsequently entered into two SFCs with subsidiaries of Ameren Corporation to provide capacity, energy and related services. There continue to be challenges to the auction process. The ICC initiated an investigation into the hourly auction segment, and we have intervened in that proceeding.

Further, there is a possibility of political, legislative, judicial and/or regulatory actions over the next several months that could substantially alter the parties' rights and obligations under or relating to the SFCs. Numerous parties have appealed various aspects of the ICC Orders approving the auctions to the state intermediate appellate courts. The Illinois Attorney General has also filed for direct review by the state Supreme Court and a stay of the

ICC Orders pending that review, which was denied. The appellate court cases have been consolidated and are in the briefing stage; we anticipate a ruling this year, with the possibility of further review by the Illinois Supreme Court. There is also the possibility that the Illinois General Assembly will consider legislation regarding retail rates and the use of an auction by electric utilities for procuring power and energy.

Separately, the ICC has opened a docket to consider changes to the auction and auction process prior to the next auction being held. We have intervened in that docket.

Clean Air Mercury Rule. In March 2005, the Administrator of the EPA signed a final Clean Air Mercury Rule ("CAMR") that will require mercury emission reductions to be achieved from existing coal-fired electric generating units. This rule requires all states to adopt either the EPA rule, or a state rule meeting the minimum requirements as outlined in CAMR.

The Illinois EPA has proposed a state-specific rule (the Illinois Mercury Rule) that would require larger percentage reductions in mercury emissions on a significantly shorter timeframe than the CAMR would require. We, along with most other owners of Illinois coal-fired electric generating units, opposed the Illinois Mercury Rule in proceedings before the Illinois Pollution Control Board ("IPCB"). The first hearing was held in June 2006 and the second hearing began on August 14, 2006. DMG filed a Joint Statement with the Illinois EPA on August 21, 2006 supporting a Multi-Pollutant Alternative to the Illinois Mercury Rule that significantly extends the schedule for compliance with the proposed new mercury standard while adding new requirements for the control of sulfur dioxide and nitrogen oxide emissions. On November 2, 2006, the IPCB adopted the Illinois Mercury Rule including the Multi-Pollutant Alternative and transmitted it to the Joint Committee on Administrative Rules ("JCAR"), which approved the rule along with the Multi-Pollutant Alternative on December 12, 2006.

In May 2006, the Governor of New York announced plans to regulate mercury emissions from coal-fired power plants by reducing emissions by approximately 50% by 2010 and 90% by 2015. NYSDEC issued a proposed rule in July 2006 which was adopted on January 27, 2007. The rule establishes reduced mercury emission limits for the Danskammer generating units beginning in January 2010 and beginning in January 2015, the rule imposes further restrictions in emissions for all affected generating units. The rule will not allow trading of mercury emission allowances.

Various state legislative and regulatory bodies may be considering other legislation or rules that could impact current regulations or impose new regulations applicable to us and our subsidiaries. We cannot predict the outcome of these legislative and other regulatory developments, or the effects that they might have on our business.

Carbon Emissions. The international treaty relating to global warming, commonly known as the Kyoto Protocol, requires member nations to reduce emissions of greenhouse gases, primarily carbon dioxide and methane. The United States has declined to ratify the Kyoto Protocol, and instead favors voluntary greenhouse gas emission reductions, increased efficiency in the production and consumption of energy, and continued research and technology development. Our Northeast assets may be subject to a state-driven greenhouse gas program known as the Regional Greenhouse Gas Initiative (RGGI). RGGI is a program under development by seven New England and Mid-Atlantic states to reduce carbon dioxide emissions from power plants. The State of New York has introduced, as a "pre-proposal", a rule that would require affected generators to purchase 100 percent of the carbon credits needed to operate their facilities through an auction process. The final program requirements of RGGI and subsequent impact to our operations are not known at this time, but the Northeast states currently intend to finalize carbon dioxide emissions requirements for electric generating facilities during 2007.

FERC Market-Based Rate Authority. The FERC's market-based rate authority allows the sale of power at negotiated rates through the bilateral market or within an organized energy market, conditioned on periodic re-review. In April 2004, the FERC issued an order concerning the ability of companies to sell electricity at market-based rates. In this order, the FERC adopted two new tests for assessing generation market power. If an applicant for market-based rate authority is found to possess generation market power under these tests and is unsuccessful in challenging that finding, the applicant may either propose mitigation measures or adopt cost-based rates for sales within the relevant markets. If the FERC finds that the proposed mitigation measures fail to eliminate the ability to exercise market power, the applicant's market-based rate authority will be revoked and the applicant will be subject to cost-based default rates, or other cost-based rates proposed by the applicant and approved by the FERC. Our entities with applications pending since February 2002, as well as the entities we acquired in January 2005 in connection with the Sithe Energies acquisition, timely resubmitted their applications to the FERC. On June 16, 2005, the FERC issued an order accepting the updated market power analyses submitted by Sithe Energies and Dynegy. Our next triennial market power analysis is due June 16, 2008. Accordingly, these entities have continuously had market-based rate authority.

We are also subject to the FERC's market behavior rules, which emerged from its consideration of market manipulation in the Western markets. The rules, which were promulgated in 2003 for the purpose of prohibiting manipulation in the wholesale electricity and natural gas markets subject to the FERC's jurisdiction are incorporated in the tariffs of the various Dynegy entities with market based rates for wholesale power and apply to sales in organized and bilateral markets and spot markets, as well as long-term sales (as well as to the wholesale sale of natural gas under a blanket marketing certificate). The remedies for violating the rules could include disgorgement of unjust profits, refunds or suspension or revocation of the authority to sell at market-based rates and penalties. Pursuant to the EPACT, the FERC recently finalized new regulations prohibiting energy market manipulation, which regulations are patterned after the language of the SEC's Rule 10b-5. Subsequently, the FERC rescinded two of the six market behavior rules (as they are covered in FERC's new regulations prohibiting market manipulation or other FERC standards) and codified the remaining four rules in its regulations. The extent to which these regulations will affect the costs or other aspects of our operations is uncertain. However, we believe that our entities subject to the regulations are currently in compliance.

Note 19—Capital Stock

At December 31, 2006, we had authorized capital stock consisting of 900,000,000 shares of Class A common stock and 360,000,000 shares of Class B common stock.

Preferred Stock. Our preferred stock may be issued from time to time in one or more series, the shares of each series to have such designations and powers, preferences, rights, qualifications, limitations and restrictions thereof as specified by our Board of Directors.

Common Stock. At December 31, 2006, there were 500,028,353 shares of Class A and B common stock issued in the aggregate and 1,787,004 shares were held in treasury. During 2006 and 2005, no quarterly cash dividends were paid.

Pursuant to the terms of the Illinova acquisition, we established two classes of common shares, Class A and Class B. All of our Class B common stock is owned by Chevron. Generally, holders of Class A and Class B common stock are entitled to one vote per share on all matters to be voted upon by the shareholders. Holders of Class A common stock may cumulate votes in connection with the election of directors. The election of directors and all other matters will be by a majority of shares represented and entitled to vote, except as otherwise provided by law. Holders of Class B common stock vote together with holders of Class A common stock as a single class on every matter acted upon by the shareholders except for the following matters:

- the holders of Class B common stock vote as a separate class for the election of up to three of our directors, while the holders of Class A common stock vote as a separate class for the remaining directors;

- any amendment to the special corporate governance rights associated with the Class B common stock must be approved by a majority of the directors elected by holders of Class B common stock and a majority of all of our directors or by 66⅔% of the outstanding shares of Class B common stock voting as a separate class, and the affirmative vote of a majority of the shares of Class A and Class B common stock, voting together as a single class; and
- any amendment to the provision of the Amended and Restated Articles of Incorporation addressing the voting rights of holders of Class A and Class B common stock requires the approval of 66⅔% of the outstanding shares of Class B common stock voting as a separate class, and the affirmative vote of a majority of the shares of Class A and Class B common stock, voting together as a single class.

Subject to the preferences of preferred stock, holders of Class A and Class B common stock have equal and ratable rights to dividends, when and if dividends are declared by the Board of Directors. Holders of Class A and Class B common stock are entitled to share ratably, as a single class, in all of our assets available for distribution to holders of shares of common stock upon the liquidation, dissolution or winding up of our affairs, after payment of our liabilities and any amounts to holders of preferred stock, if any.

A share of Class B common stock automatically converts into a share of Class A common stock if it is transferred to any person other than an affiliate of Chevron. Additionally, each share of Class B common stock automatically converts into a share of Class A common stock if the holders of all Class B common stock cease to own collectively at least 15% of our outstanding common stock. Conversely, any shares of Class A common stock acquired by Chevron or its affiliates will automatically convert into shares of Class B common stock, so long as Chevron and its affiliates continue to own 15% or more of the outstanding voting power of Dynegy.

Holders of Class A and Class B common stock generally are not entitled to preemptive rights, subscription rights, or redemption rights, except that Chevron is entitled to preemptive rights under the amended and restated shareholder agreement. The rights and preferences of holders of Class A common stock are subject to the rights of any series of preferred stock we may issue.

Common stock activity for the three years ended December 31, 2006 was as follows:

	Class A Common Stock		Class B Common Stock	
	Shares	Amount	Shares	Amount
	(in millions)			
December 31, 2003	280	$2,848	97	$1,006
Options exercised	3	5	—	—
401(k) plan and profit sharing	2	6	—	—
December 31, 2004	285	$2,859	97	$1,006
Options exercised	1	4	—	—
401(k) plan and profit sharing	1	5		
Shareholder litigation settlement	18	81	—	—
December 31, 2005	305	$2,949	97	$1,006
Options exercised	3	5	—	—
401(k) plan and profit sharing	1	3	—	—
Equity issuance	40	185	—	—
Equity conversion	54	225	—	—
December 31, 2006	403	$3,367	97	$1,006

Treasury Stock. During 2006 and 2005, Class A common shares purchased into treasury totaled 72,978 and 34,843, respectively. All of the purchases were related to forfeitures of restricted stock. There were no purchases or issuances of treasury stock in 2004.

Stock Options. We have nine stock option plans, all of which provide for the issuance of authorized shares of our Class A common stock. Restricted stock awards and option grants are issued under the plans. See restricted stock discussion on p. F-60. Each option granted is exercisable at a strike price, which ranges from $1.47 per share to $56.98 per share for options currently outstanding. A brief description of each plan is provided below:

- ***NGC Plan.*** Created early in our history and revised prior to our becoming a publicly traded company in 1996, this plan provided for the issuance of 13,651,802 authorized shares, had a 10-year term, and expired in May 2006. All option grants are vested.
- ***Employee Equity Plan.*** This plan expired in May 2002 and is the only plan under which we granted options below the fair market value of Class A common stock on the date of grant. This plan provided for the issuance of 20,358,802 authorized shares, and grants under this plan vest on the fifth anniversary from the date of the grant. All option grants are vested.
- ***Illinova Plan.*** Adopted by Illinova prior to the merger with us, this plan expired upon the merger date in February 2000 and provided for the issuance of 3,000,000 authorized shares. All option grants are vested.
- ***Extant Plan.*** Adopted by Extant prior to its acquisition by us, this plan expired in September 2000 and provided for the issuance of 202,577 authorized shares. Grants from this plan vest at 25% per year. All option grants are vested.
- ***UK Plan.*** This plan provided for the issuance of 276,000 authorized shares and has been terminated. All option grants are vested.
- ***Dynegy 1999 Long-Term Incentive Plan ("LTIP").*** This annual compensation plan provides for the issuance of 6,900,000 authorized shares, has a 10-year term and expires in 2009. All option grants are vested.
- ***Dynegy 2000 LTIP.*** This annual compensation plan, created for all employees upon Illinova's merger with us, provides for the issuance of 10,000,000 authorized shares, has a 10-year term and expires in February 2010. Grants from this plan vest in equal annual installments over a three-year period.
- ***Dynegy 2001 Non-Executive LTIP.*** This plan is a broad-based plan and provides for the issuance of 10,000,000 authorized shares, has a ten-year term and expires in September 2011. Grants from this plan vest in equal annual installments over a three-year period.
- ***Dynegy 2002 LTIP.*** This annual compensation plan provides for the issuance of 10,000,000 authorized shares, has a 10-year term and expires in May 2012. Grants from this plan vest in equal annual installments over a three-year period.

All options granted under our option plans cease vesting for employees who are terminated for cause. For voluntary and involuntary termination, disability, retirement or death, continued vesting and/or an extended period in which to exercise vested options may apply, dependent upon the terms of the grant agreement applying to a specific grant that was awarded. It has been our practice to issue shares of common stock upon exercise of stock options generally from previously unissued shares. Options awarded to our executive officers and others who participate in our Executive Severance Pay Plan vest immediately upon the occurrence of a change in control in accordance with the terms of the Second Supplemental Amendment to the Executive Severance Pay Plan.

The Merger Agreement with LS Power will constitute a change in control as defined in our severance pay plans, as well as the various grant agreements. Please read Note 3—Business Combinations and Acquisitions—

LS Power beginning on page F-17 for further discussion of the transaction. As a result, all options previously granted to employees will fully vest immediately upon the closing of the LS Power transaction and related change in control. This occurrence will result in the accelerated vesting of the unvested tranche of previous option grants issued in 2006 and 2005, which will not have a material effect on our financial condition, results of operations or cash flows.

During 2006, we entered into an exchange transaction with our Chairman and CEO. Under the terms of the transaction, the purpose of which was to address uncertainties created by proposed regulations issued in late 2005 pursuant to Section 409A of the Internal Revenue Code, we cancelled all of the 2,378,605 stock options then held by our Chairman and CEO. As consideration for canceling these stock options, we granted our Chairman and CEO 967,707 stock options at an exercise price of $4.88, which equaled the closing price of our Class A common stock on the date of grant, and agreed to make a cash payment to him of approximately $5.6 million on January 15, 2007 based on the in-the-money value of the vested stock options that were cancelled. This cash payment was made as agreed. The newly-granted stock options have a term of 10 years, vest in three equal annual installments beginning on the first anniversary of the grant date and are subject to earlier vesting upon a constructive termination, a termination without cause or a termination resulting from a change in control. We recorded a liability to reflect the agreed upon cash payment. We were not required to record any incremental compensation expense in connection with the transaction.

Compensation expense related to options granted and restricted stock awarded totaled $8 million, $9 million and $6 million for the years ended December 31, 2006, 2005 and 2004, respectively. We recognize compensation expense ratably over the vesting period of the respective awards. Tax benefits for compensation expense related to options granted and restricted stock awarded totaled $3 million, $3 million and $2 million for the years ended December 31, 2006, 2005, and 2004, respectively. As of December 31, 2006, $7 million of total unrecognized compensation expense related to options granted and restricted stock awarded is expected to be recognized over a weighted-average period of 2.0 years. The total fair value of shares vested was $4 million, $6 million and $1 million for the years ended December 31, 2006, 2005 and 2004, respectively. We did not capitalize or use cash to settle any share-based compensation in the year ended December 31, 2006.

Cash received from option exercises for the year ended December 31, 2006 was $5 million, and the tax benefit realized for the additional tax deduction from share-based payment awards totaled $3 million. The total intrinsic value of options exercised and released for the years ended December 31, 2006, 2005 and 2004 was $5 million, $1 million and $5 million, respectively.

In 2006, we granted stock-based compensation awards that cliff vest after three years based on our cumulative operating cash flows for 2006-2008. Compensation expense recorded in the year ended December 31, 2006 related to these "performance units" was less than $1 million and was accrued in Other long-term liabilities in our consolidated balance sheets. The Merger Agreement with the LS Entities will constitute a change in control as related to these performance units.

Stock option activity for the years ended December 31, 2006, 2005 and 2004 was as follows:

	Year Ended December 31,					
	2006		2005		2004	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(options in thousands)					
Outstanding at beginning of period	9,314	$12.66	10,233	$15.91	16,543	$17.99
Granted	3,268	$ 4.88	2,056	$ 4.30	1,503	$ 4.47
Exercised	(1,560)	$ 3.46	(633)	$ 3.44	(2,129)	$ 2.37
Cancelled, forfeited or expired	(3,661)	$ 9.68	(2,342)	$22.15	(5,684)	$24.54
Outstanding at end of period	7,361	$12.63	9,314	$12.66	10,233	$15.91
Vested and unvested expected to vest at December 31, 2006	6,898	$13.16				
Exercisable at end of period	3,774	$20.07	7,059	$15.94	7,722	$20.73

	Year Ended December 31, 2006	
	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at end of period	6.46	$12.37
Vested and unvested expected to vest	6.28	$11.25
Exercisable at end of period	4.01	$ 3.65

During the three-year period ended December 31, 2006, we did not grant any options at an exercise price less than the market price on the date of grant.

Options outstanding as of December 31, 2006 are summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options Outstanding at December 31, 2006	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number of Options Exercisable at December 31, 2006	Weighted Average Exercise Price
	(options in thousands)				
$1.47-$4.30	1,010	6.6	$ 3.27	656	$ 2.71
$4.31-$4.48	360	6.8	$ 4.48	246	$ 4.48
$4.88-$4.88	3,119	9.2	$ 4.88	—	—
$7.02-$16.62	1,133	2.2	$13.72	1,133	$13.72
$20.94-$23.38	195	3.0	$23.36	195	$23.36
$23.85-$23.85	803	4.6	$23.85	803	$23.85
$28.47-$50.63	717	3.9	$45.02	717	$45.02
$52.52-$52.50	5	3.7	$52.50	5	$52.50
$54.99-$54.99	1	4.3	$54.99	1	$54.99
$56.98-$56.98	18	2.4	$56.98	18	$56.98
	7,361			3,774	

For stock options, we determine the fair value of each stock option at the grant date using a Black-Scholes model, with the following weighted-average assumptions used for grants.

	Twelve Months Ended December 31,		
	2006	2005	2004
Dividends	—	—	—
Expected volatility (historical)	48.8%	84.1%	87.5%
Risk-free interest rate	5.1%	4.2%	4.1%
Expected option life	6 Years	10 Years	10 Years

The expected volatility was calculated based on a ten-year historical volatility of our stock price in 2005 and 2004; beginning in first quarter 2006, we used a three-year historical volatility. The risk-free interest rate was calculated based upon observed interest rates appropriate for the term of our employee stock options. Currently, we calculate the expected option life using the simplified methodology suggested by SAB 107, "Share-Based Payment". For restricted stock awards, we consider the fair value to be the closing price of the stock on the grant date. We recognize the fair value of our share-based payments over the vesting periods of the awards, which is typically a three-year service period.

The weighted average grant-date fair value of options granted during the years ended December 31, 2006, 2005 and 2004 was $2.61, $3.66 and $3.88, respectively.

Restricted Stock. Restricted stock activity for the three years ended December 31, 2006 was as follows:

	Year Ended December 31,			
	2006	2006 Weighted Average Grant Date Fair Value	2005	2004
	(shares in thousands)			
Outstanding at beginning of period	1,239	$4.40	902	32
Granted	1,311 (1)	$4.88	632 (2)	945 (3)
Vested	(251)	$4.40	(130)	—
Cancelled or expired	(185)	$4.75	(165)	(75)
Outstanding at end of period	2,114	$4.67	1,239	902

(1) In March 2006, we awarded 1,311,149 shares of restricted stock. The closing stock price was $4.88 on the date of the award.

(2) In January 2005, we awarded 631,524 shares of restricted stock. The closing stock price was $4.30 on the date of the award.

(3) During the first and second quarters 2004, we awarded an aggregate 945,055 shares of restricted stock. The closing stock price of our Class A common stock was $4.48 and $3.85, respectively, on the dates of awards.

All restricted stock awards to employees vest immediately upon the occurrence of a change in control in accordance with the terms of the applicable Severance Pay Plan. The Merger Agreement with the LS Entities will constitute a change in control as defined in our restricted stock agreements. Please read Note 3—Business Combinations and Acquisitions—LS Power beginning on page F-17 for further discussion.

Note 20—Employee Compensation, Savings and Pension Plans

Short-Term Incentive Plan. We maintain a discretionary incentive compensation plan to provide employees with rewards for the achievement of corporate goals and individual, professional accomplishments. Specific awards are at the discretion of the Compensation and Human Resources Committee of the Board of Directors.

In addition, in 2003, we adopted the Mid-Term Incentive Plan. This special compensation program is limited to select employees who were eligible to receive cash compensation of up to 200% of their annual base salary, payable in two installments over a two-year period, based on the performance of our Class A common stock during the last 30 trading days in 2004 and over the entire year in 2005. The first performance period ended December 31, 2004. The first installment in the aggregate amount of approximately $0.6 million was approved by the Compensation and Human Resources Committee of the Board of Directors and was paid during the first quarter 2005. The second and final installment in the aggregate amount of approximately $0.4 million was approved and paid during the first quarter 2006. We account for this cash plan using variable plan accounting and recognized an aggregate amount of approximately $1 million and zero in compensation expense during 2006 and 2005, respectively, associated with the plan. The plan was terminated in February 2006.

401(k) Savings Plan. During the 12-months ended December 31, 2006, our employees participated in four 401(k) savings plans, all of which meet the requirements of Section 401(k) of the Internal Revenue Code and are defined contribution plans subject to the provisions of ERISA. The following summarizes the plans:

- Dynegy Inc. 401(k) Savings Plan—this plan and the related trust fund are established and maintained for the exclusive benefit of participating employees in the United States. All employees of designated Dynegy subsidiaries are eligible to participate in the plan. Employee pre-tax contributions to the plan are matched 100%, up to a maximum of 5% of base pay, subject to IRS limitations. Vesting in our contributions is based on years of service at 25% per full year of service. We may also make annual discretionary contributions to employee accounts, subject to our performance. Matching and discretionary contributions, if any, are allocated in the form of units in the Dynegy common stock fund. During the years ended December 31, 2006, 2005 and 2004, we issued approximately 0.3 million, 0.9 million and 0.9 million shares, respectively, of our common stock in the form of matching contributions to fund the plan. No discretionary contributions were made for any of the years in the three-year period ended December 31, 2006;

- Dynegy Midwest Generation, Inc. 401(K) Savings Plan (formerly the Illinois Power Company Incentive Savings Plan) and Dynegy Midwest Generation, Inc. 401(K) Savings Plan for Employees Covered Under a Collective Bargaining Agreement (formerly the Illinois Power Company Incentive Savings Plan for Employees Covered Under A Collective Bargaining Agreement)—we match 50% of employee contributions to the plans, up to a maximum of 6% of compensation, subject to IRS limitations. Employees are immediately 100% vested in our contributions. Matching contributions to the plans are allocated in the form of units in the Dynegy common stock fund. During the years ended December 31, 2006, 2005 and 2004, we issued 0.2 million, 0.2 million and 0.6 million shares, respectively, of our common stock in the form of matching contributions to the plans; and

- Dynegy Northeast Generation, Inc. Savings Incentive Plan—under this plan, which is for union and non-union employees, we match 24% of employee contributions up to 6% of base salary for union employees and 50% of employee contributions up to 8% of base salary for non-union employees, in each case subject to IRS limitations. Employees are immediately 100% vested in our contributions. Matching contributions to this plan are made in cash and invested according to the employee investment discretion.

During the years ended December 31, 2006, 2005 and 2004, we recognized aggregate costs related to these employee compensation plans of $3 million, $5 million and $7 million, respectively.

Pension and Other Post-Retirement Benefits

We have various defined benefit pension plans and post-retirement benefit plans. All domestic employees participate in the pension plans, but only some of our domestic employees participate in the other post-retirement medical and life insurance benefit plans. Our pension plans are in the form of a cash balance plan and more traditional career average or final average pays formula plans.

Obligations and Funded Status. The following tables contain information about the obligations and funded status of these plans on a combined basis:

	Pension Benefits		Other Benefits	
	2006	2005	2006	2005
	(in millions)			
Projected benefit obligation, beginning of the year	$181	$153	$ 55	$ 46
Business acquisition	—	3	—	—
Service cost	9	11	3	2
Interest cost	10	9	3	2
Plan amendments	—	4	—	—
Actuarial (gain) loss	(6)	6	1	5
Benefits paid	(12)	(5)	(1)	—
Projected benefit obligation, end of the year	$182	$181	$ 61	$ 55
Fair value of plan assets, beginning of the year	$118	$ 88	$—	$—
Business acquisition	—	2	—	—
Actual return on plan assets	15	2	—	—
Employer contributions	14	31	1	—
Benefits paid	(12)	(5)	(1)	—
Fair value of plan assets, end of the year	$135	$118	$—	$—
Funded status	$ (47)	$ (63)	$ (61)	$ (55)
Unrecognized prior service costs		8		—
Unrecognized actuarial (gain) loss		54		24
Net amount recognized		$ (1)		$ (31)

As a result of the acquisition of Sithe, which closed on January 31, 2005, we acquired a small pension plan with approximately $2.7 million in obligations and $2.4 million in assets. As of February 1, 2005, this pension plan was frozen and the employees in this pension plan began to accrue a benefit in our cash balance pension plan. This resulted in an increase of $0.5 million in 2005 net periodic pension cost. For further information, please read Note 3—Business Combinations and Acquisitions—Sithe Energies beginning on page F-18.

The accumulated benefit obligation for all defined benefit pension plans was $157 million and $153 million at December 31, 2006 and 2005, respectively. On December 31, 2006 and 2005, our annual measurement date, the accumulated benefit obligation related to certain of our pension plans exceeded the fair value of the pension plan assets. The following summarizes information for pension plans with an accumulated benefit obligation in excess of plan assets:

	December 31,	
	2006	2005
	(in millions)	
Projected benefit obligation	$182	$181
Accumulated benefit obligation	157	153
Fair value of plan assets	135	118

Amounts recognized in the consolidated balance sheets as of December 31, 2005 consist of:

	Pension Benefits	Other Benefits
	(in millions)	
Accrued benefit liability	$(36)	$(31)
Intangible asset	8	—
Accumulated other comprehensive income	27	—
Net amount recognized	$ (1)	$(31)

As further discussed in Note 2—Summary of Significant Accounting Policies—Accounting Principles Adopted—SFAS No. 158 beginning on page F-16, on September 29, 2006, the FASB issued SFAS No. 158. SFAS No. 158 requires employers to recognize the overfunded or underfunded status of a defined benefit or other postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position, and to recognize changes in that funded status in the year in which the changes occur through comprehensive income.

Under SFAS No. 158, adjustments to the minimum pension liability were eliminated. In the year of adoption, we were required to adjust the minimum pension liability for a final time in accordance with SFAS No. 87. Our adjustment for the year ended December 31, 2006 was $15 million (pre-tax), with an offset to accumulated other comprehensive income. The following table summarizes the change to accumulated other comprehensive income associated with the minimum pension liability:

	2006	2005	2004
		(in millions)	
Change in minimum liability included in other comprehensive income (net of tax benefit (expense) of $(5) million, $3 million and $(26) million, respectively)	$10	$(5)	$44

Subsequent to the final minimum pension liability adjustment, we were required to recognize as a component of accumulated other comprehensive income the gains or losses and prior service costs that existed at December 31, 2006, but that had not been recognized as components of net period benefit cost pursuant to SFAS No. 87 and SFAS No. 106. As a result, the pre-tax amounts recognized in accumulated other comprehensive income as of December 31, 2006 consist of:

	Pension Benefits	Other Benefits
	(in millions)	
Prior service cost	$ 7	$—
Actuarial loss	37	23
Net amount recognized	$44	$ 23

The following table summarizes the incremental effect of this adjustment on accumulated other comprehensive income, as well as other line items impacted on the balance sheet:

	Before Application of SFAS No. 158	Adjustment	After Application of SFAS No. 158
		(in millions)	
Intangible asset	$ 7	$ (7)	$ —
Accrued benefit liability	(59)	(49)	(108)
Deferred tax asset	4	21	25
Accumulated other comprehensive income, pre-tax	12	56	68
Accumulated other comprehensive income, tax impact	(4)	(21)	(25)

Amounts recognized in the consolidated balance sheets as of December 31, 2006 consist of:

	Pension Benefits	Other Benefits
	(in millions)	
Current liabilities	$—	$ (1)
Noncurrent liabilities	(47)	(60)
Net amount recognized	$ (47)	$(61)

The estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive income into net periodic benefit cost during the year ended December 31, 2007 for the defined benefit pension plans are $2 million and $1 million, respectively. The estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive income into net periodic benefit cost during the year ended December 31, 2007 for other postretirement benefit plans are $1 million and zero, respectively. The amortization of prior service cost is determined using a straight line amortization of the cost over the average remaining service period of employees expected to receive benefits under the Plan.

Medicare Prescription Drug, Improvement and Modernization Act of 2003. On December 8, 2003, President Bush signed into law a bill that expands Medicare, primarily adding a prescription drug benefit for Medicare-eligible retirees starting in 2006. In anticipation of this new benefit, the December 31, 2004 Accumulated Postretirement Benefit Obligation was reduced by approximately $1 million, with the expectation that we would coordinate its benefits with the Medicare prescription drug plan. However, in 2006 and 2005, no provisions were set forth to handle this coordination; as a result, the December 31, 2006 Accumulated Postretirement Benefit Obligation does not reflect significant savings due to the Medicare prescription drug plan.

Note 21—Segment Information

We report the results of our power generation business as three separate geographical segments in our consolidated financial statements: (1) the Midwest segment (GEN-MW); (2) the Northeast segment (GEN-NE); and (3) the South segment (GEN-SO). We also continue to separately report the results of our CRM business because of the diversity among its operations. Results associated with our former REG segment are included in Other and Eliminations as this business no longer qualifies as a reportable segment. Results associated with our former NGL and DGC segments are included in discontinued operations in Other and Eliminations due to the sale of these businesses. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest.

Effective July 1, 2004, our power generation segments began transacting directly with third parties on their own behalf. Therefore, certain generation capacity, forward sales, and related market positions previously sold by our power generation segments to CRM are now sold by our power generation segments directly to third parties. Our power generation segments now record revenues for such third party sales as unaffiliated revenues.

Revenues from third party sales in which a power generation segment entity is the legal party to the third party sales contracts are presented gross in the respective power generation segments' unaffiliated revenues for the years ended December 31, 2006, 2005 and 2004.

During 2006, one customer in our GEN-MW segment and one customer in our GEN-NE segment accounted for approximately 20% and 26% of our consolidated revenues, respectively. In 2003 and 2004, one customer in our GEN-NE segment accounted for approximately 13% of our consolidated revenues.

Pursuant to EITF Issue 02-03, all gains and losses on third party energy trading contracts in the CRM business, whether realized or unrealized, are presented net in the consolidated statements of operations. For the purpose of the segment data presented below, intersegment transactions between CRM and our other segments are presented net in CRM intersegment revenues but are presented gross in the intersegment revenues of our other segments, as the activities of our other segments are not subject to the net presentation requirements contained in EITF Issue 02-03. If transactions between CRM and our other segments result in a net intersegment purchase by CRM, the net intersegment purchases and sales are presented as negative revenues in CRM intersegment revenues. In addition, intersegment hedging activities are presented net pursuant to SFAS No. 133.

Subsequent to the final minimum pension liability adjustment, we were required to recognize as a component of accumulated other comprehensive income the gains or losses and prior service costs that existed at December 31, 2006, but that had not been recognized as components of net period benefit cost pursuant to SFAS No. 87 and SFAS No. 106. As a result, the pre-tax amounts recognized in accumulated other comprehensive income as of December 31, 2006 consist of:

	Pension Benefits	Other Benefits
	(in millions)	
Prior service cost	$ 7	$—
Actuarial loss	37	23
Net amount recognized	$44	$ 23

The following table summarizes the incremental effect of this adjustment on accumulated other comprehensive income, as well as other line items impacted on the balance sheet:

	Before Application of SFAS No. 158	Adjustment	After Application of SFAS No. 158
		(in millions)	
Intangible asset	$ 7	$ (7)	$ —
Accrued benefit liability	(59)	(49)	(108)
Deferred tax asset	4	21	25
Accumulated other comprehensive income, pre-tax	12	56	68
Accumulated other comprehensive income, tax impact	(4)	(21)	(25)

Amounts recognized in the consolidated balance sheets as of December 31, 2006 consist of:

	Pension Benefits	Other Benefits
	(in millions)	
Current liabilities	$—	$ (1)
Noncurrent liabilities	(47)	(60)
Net amount recognized	$(47)	$(61)

The estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive income into net periodic benefit cost during the year ended December 31, 2007 for the defined benefit pension plans are $2 million and $1 million, respectively. The estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive income into net periodic benefit cost during the year ended December 31, 2007 for other postretirement benefit plans are $1 million and zero, respectively. The amortization of prior service cost is determined using a straight line amortization of the cost over the average remaining service period of employees expected to receive benefits under the Plan.

Components of Net Periodic Benefit Cost. The components of net periodic benefit cost were:

	Pension Benefits			Other Benefits		
	2006	2005	2004	2006	2005	2004
			(in millions)			
Service cost benefits earned during period	$ 9	$11	$ 20	$ 3	$ 2	$ 5
Interest cost on projected benefit obligation	10	9	33	3	3	10
Expected return on plan assets	(10)	(8)	(38)	—	—	(5)
Amortization of prior service costs	1	1	1	—	—	—
Recognized net actuarial loss	3	2	12	1	1	4
Net periodic benefit cost (income)	$ 13	$15	$ 28	$ 7	$ 6	$ 14
Additional cost due to curtailment	3	3	146	—	—	(9)
Total net periodic benefit cost	$ 16	$18	$174	$ 7	$ 6	$ 5

Assumptions. The following weighted average assumptions were used to determine benefit obligations:

	Pension Benefits December 31,		Other Benefits December 31,	
	2006	2005	2006	2005
Discount rate (1)	5.87%	5.52%	5.90%	5.53%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%

(1) Dynegy utilized a yield curve approach to determine the discount rate as of December 31, 2006 and 2005. Projected benefit payments for the plans were matched against the discount rates in the yield curve.

The following weighted average assumptions were used to determine net periodic benefit cost:

	Pension Benefits Year Ended December 31,			Other Benefits Year Ended December 31,		
	2006	2005	2004	2006	2005	2004
Discount rate	5.52%	5.75%	5.97%	5.53%	5.75%	5.98%
Expected return on plan assets	8.25%	8.25%	8.75%	N/A	N/A	8.75%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%

Our expected long-term rate of return on plan assets for the year ended December 31, 2007 will be 8.25%. This figure begins with a blend of asset class-level returns developed under a theoretical global capital asset pricing model methodology conducted by an outside consultant. In development of this figure, the historical relationships between equities and fixed income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long-term. Current market factors such as inflation and interest rates are also incorporated in the assumptions. The figure also incorporates an upward adjustment reflecting the plan's use of active management and favorable past experience.

The following summarizes our assumed health care cost trend rates:

	December 31,	
	2006	2005
Health care cost trend rate assumed for next year	9.69%	9.47%
Ultimate trend rate	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2016	2015

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The impact of a one percent increase/decrease in assumed health care cost trend rates is as follows:

	Increase	Decrease
	(in millions)	
Aggregate impact on service cost and interest cost	$ 1	$(1)
Impact on accumulated post-retirement benefit obligation	$12	$(9)

Plan Assets. We employ a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. The intent of this strategy is to minimize plan expenses by outperforming plan liabilities over the long run. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks as well as growth, value, and small and large capitalizations. Other assets such as private equity are actively managed to enhance long-term returns while improving portfolio diversification.

Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives may not be used to leverage the portfolio beyond the market value of the underlying investment. Investment risk is measured and monitored on an ongoing basis through quarterly investments portfolio reviews, periodic asset/liability studies, and annual liability measurements.

Our pension plans weighted-average asset allocations by asset category were as follows:

	December 31,	
	2006	2005
Equity securities	71%	70%
Debt securities	29%	30%
Total	100%	100%

Equity securities did not include any of our common stock at December 31, 2006 or 2005.

Contributions. During the year ended December 31, 2006, we contributed approximately $14 million to our pension plans and less than $1 million to our other post-retirement benefit plans. In 2007, we expect to contribute approximately $25 million to our pension plans and less than $1 million to our other postretirement benefit plans.

Our expected benefit payments for future services for our pension and other postretirement benefits are as follows:

	Pension Benefits	Other Benefits
	(in millions)	
2007	$10	$ 1
2008	9	1
2009	8	1
2010	6	2
2011	8	2
2012 – 2016	59	18

Medicare Prescription Drug, Improvement and Modernization Act of 2003. On December 8, 2003, President Bush signed into law a bill that expands Medicare, primarily adding a prescription drug benefit for Medicare-eligible retirees starting in 2006. In anticipation of this new benefit, the December 31, 2004 Accumulated Postretirement Benefit Obligation was reduced by approximately $1 million, with the expectation that we would coordinate its benefits with the Medicare prescription drug plan. However, in 2006 and 2005, no provisions were set forth to handle this coordination; as a result, the December 31, 2006 Accumulated Postretirement Benefit Obligation does not reflect significant savings due to the Medicare prescription drug plan.

Note 21—Segment Information

We report the results of our power generation business as three separate geographical segments in our consolidated financial statements: (1) the Midwest segment (GEN-MW); (2) the Northeast segment (GEN-NE); and (3) the South segment (GEN-SO). We also continue to separately report the results of our CRM business because of the diversity among its operations. Results associated with our former REG segment are included in Other and Eliminations as this business no longer qualifies as a reportable segment. Results associated with our former NGL and DGC segments are included in discontinued operations in Other and Eliminations due to the sale of these businesses. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest.

Effective July 1, 2004, our power generation segments began transacting directly with third parties on their own behalf. Therefore, certain generation capacity, forward sales, and related market positions previously sold by our power generation segments to CRM are now sold by our power generation segments directly to third parties. Our power generation segments now record revenues for such third party sales as unaffiliated revenues.

Revenues from third party sales in which a power generation segment entity is the legal party to the third party sales contracts are presented gross in the respective power generation segments' unaffiliated revenues for the years ended December 31, 2006, 2005 and 2004.

During 2006, one customer in our GEN-MW segment and one customer in our GEN-NE segment accounted for approximately 20% and 26% of our consolidated revenues, respectively. In 2003 and 2004, one customer in our GEN-NE segment accounted for approximately 13% of our consolidated revenues.

Pursuant to EITF Issue 02-03, all gains and losses on third party energy trading contracts in the CRM business, whether realized or unrealized, are presented net in the consolidated statements of operations. For the purpose of the segment data presented below, intersegment transactions between CRM and our other segments are presented net in CRM intersegment revenues but are presented gross in the intersegment revenues of our other segments, as the activities of our other segments are not subject to the net presentation requirements contained in EITF Issue 02-03. If transactions between CRM and our other segments result in a net intersegment purchase by CRM, the net intersegment purchases and sales are presented as negative revenues in CRM intersegment revenues. In addition, intersegment hedging activities are presented net pursuant to SFAS No. 133.

Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the years ended December 31, 2006, 2005 and 2004 is presented below:

Segment Data for the Year Ended December 31, 2006
(in millions)

	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 969	$ 501	$ 334	$ 66	$ —	$1,870
Other	—	129	—	18	—	147
	969	630	334	84	—	2,017
Intersegment revenues	—	(21)	—	21	—	—
Total revenues	$ 969	$ 609	$ 334	$ 105	$ —	$2,017
Depreciation and amortization	$ (168)	$ (24)	$ (21)	$ —	$ (17)	$ (230)
Impairment and other charges	(110)	—	(45)	—	—	(155)
Operating income (loss)	$ 208	$ 55	$ (55)	$ 7	$(163)	$ 52
Earnings (losses) from unconsolidated investments	—	—	(1)	—	—	(1)
Other items, net	2	9	1	4	38	54
Interest expense and debt conversion costs						(631)
Loss from continuing operations before taxes						(526)
Income tax benefit						168
Loss from continuing operations						(358)
Income from discontinued operations, net of taxes						24
Cumulative effect of change in accounting principle, net of taxes						1
Net loss						$ (333)
Identifiable assets:						
Domestic	$4,970	$1,377	$ 595	$ 287	$ 203	$7,432
Other	—	13	5	180	—	198
Total	$4,970	$1,390	$ 600	$ 467	$ 203	$7,630
Capital expenditures	$ (101)	$ (22)	$ (24)	$ —	$ (8)	$ (155)

Segment Data for the Year Ended December 31, 2005
(in millions)

	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 947	$ 772	$ 440	$ 72	$ —	$ 2,231
Other	—	127	—	(45)	—	82
	947	899	440	27	—	2,313
Intersegment revenues	—	3	(35)	32	—	—
Total revenues	$ 947	$ 902	$ 405	$ 59	$ —	$ 2,313
Depreciation and amortization	$ (157)	$ (21)	$ (23)	$ (1)	$ (18)	$ (220)
Impairment and other charges	(36)	—	—	—	(10)	(46)
Operating income (loss)	$ 194	$ 29	$ (21)	$ (647)	$ (393)	$ (838)
Earnings (losses) from unconsolidated investments	7	—	(5)	—	—	2
Other items, net	2	5	(1)	—	20	26
Interest expense						(389)
Loss from continuing operations before taxes						(1,199)
Income tax benefit						395
Loss from continuing operations						(804)
Income from discontinued operations, net of taxes						899
Cumulative effect of change in accounting principle, net of taxes						(5)
Net income						$ 90
Identifiable assets:						
Domestic	$4,926	$1,520	$ 996	$1,014	$1,524	$ 9,980
Other	—	38	5	103	—	146
Total	$4,926	$1,558	$1,001	$1,117	$1,524	$10,126
Unconsolidated investments	$ 60	$ —	$ 210	$ —	$ —	$ 270
Capital expenditures and investments in unconsolidated affiliates	$ (113)	$ (21)	$ (9)	$ —	$ (52)	$ (195)

Segment Data for the Year Ended December 31, 2004
(in millions)

	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 336	$ 189	$ 179	$ 688	$1,146	$2,538
Other	—	—	—	(87)	—	(87)
	336	189	179	601	1,146	2,451
Intersegment revenues	539	238	88	(423)	(442)	—
Total revenues	$ 875	$ 427	$ 267	$ 178	$ 704	$2,451
Depreciation and amortization	$ (156)	$ (10)	$ (25)	$ (1)	$ (43)	$ (235)
Impairment and other charges	—	—	—	—	(78)	(78)
Operating income (loss)	$ 194	$ 21	$ (52)	$ (118)	$ (145)	$ (100)
Earnings (losses) from unconsolidated investments	80	—	112	—	—	192
Other items, net	—	—	1	(3)	11	9
Interest expense						(453)
Loss from continuing operations before taxes						(352)
Income tax benefit						172
Loss from continuing operations						(180)
Income from discontinued operations, net of taxes						165
Net loss						$ (15)
Identifiable assets:						
Domestic	$5,029	$ 423	$1,045	$1,238	$1,908	$9,643
Other	—	—	5	190	5	200
Total	$5,029	$ 423	$1,050	$1,428	$1,913	$9,843
Unconsolidated investments	$ 62	$ —	$ 281	$ —	$ 78	$ 421
Capital expenditures	$ (113)	$ (17)	$ (15)	$ —	$ (166)	$ (311)

Note 22—Quarterly Financial Information (Unaudited)

The following is a summary of our unaudited quarterly financial information for the years ended December 31, 2006 and 2005:

	Quarter Ended			
	March 2006	June 2006	September 2006	December 2006
	(in millions, except per share data)			
Revenues	$ 600	$ 439	$ 581	$ 397
Operating income (loss)	78	19	(18)	(27)
Net loss before cumulative effect of change in accounting principles	—	(207)	(69)	(58)
Net income (loss)	1	(207)	(69)	(58)
Net loss per share before cumulative effect of change in accounting principles	$(0.01)	$(0.48)	$(0.14)	$(0.12)
Net loss per share	$(0.01)	$(0.48)	$(0.14)	$(0.12)

	Quarter Ended			
	March 2005	June 2005	September 2005	December 2005
	(in millions, except per share data)			
Revenues	$ 462	$ 459	$ 770	$ 622
Operating income (loss)	(385)	(64)	65	(454)
Net income (loss) before cumulative effect of change in accounting principles	(262)	25	29	303
Net income (loss)	(262)	25	29	298
Net income (loss) per share before cumulative effect of change in accounting principles	$(0.70)	$0.05	$0.06	$0.75
Net income (loss) per share	$(0.70)	$0.05	$0.06	$0.74

Note 23—Subsequent Events

On January 31, 2007, we entered into an agreement to sell our interest in the Calcasieu power generation facility to Entergy. Subject to regulatory approval the transaction is expected to close in early 2008. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Calcasieu on page F-20 for further discussion.

On February 13, 2007, our registration statement on Form S-4 related to the proposed Merger Agreement with the LS Entities was declared effective by the SEC. Please read Note 3—Business Combinations and Acquisitions—LS Power beginning on page F-17 for further discussion.

DEFINITIONS

As used in this Form 10-K, the abbreviations listed below have the following meanings:

AMP	Automated mitigation procedure
APB	Accounting Principles Board
APIC	Additional paid-in-capital
ARB	Accounting Research Bulletin
ARO	Asset retirement obligation
Bcf/d	Billion cubic feet per day
CAA	Clean Air Act
Cal ISO	The California Independent System Operator
Cal PX	The California Power Exchange
CDWR	California Department of Water Resources
CERCLA	The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFTC	Commodity Futures Trading Commission
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CRM	Our customer risk management business segment
DGC	Dynegy Global Communications
DGC-Asia	Dynegy Global Communications-Asia, our former Asian communications business
DHI	Dynegy Holdings Inc., our primary financing subsidiary
DMG	Dynegy Midwest Generation
DMSLP	Dynegy Midstream Services L.P.
DMT	Dynegy Marketing and Trade
DNE	Dynegy Northeast Generation
DOJ	Department of Justice
DOT	Department of Transportation
DPM	Dynegy Power Marketing Inc
EIOL	Energy Infrastructure Overseas Limited
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPACT	The Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas, Inc.
ERISA	The Employee Retirement Income Security Act of 1974, as amended
EWG	Exempt Wholesale Generators
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FPA	The Federal Power Act of 1935, as amended
FSP	FASB Staff Position
FTC	U.S. Federal Trade Commission
FUCOs	Foreign Utility Companies
GAAP	Generally Accepted Accounting Principles of the United States of America
GEN	Our power generation business
GEN-MW	Our power generation business—Midwest segment
GEN-NE	Our power generation business—Northeast segment
GEN-SO	Our power generation business—South segment
GCF	Gulf Coast Fractionators
HLPSA	The Hazardous Liquid Pipeline Safety Act of 1979, as amended
HSR	Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended

ICC	Illinois Commerce Commission
ISO	Independent System Operator
KW—yr	Kilowatt year
KWh	Kilowatt hour
LMP	Locational marginal pricing
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MBbls/d	Thousands of barrels per day
Mcf	Thousand cubic feet
MISO	Midwest ISO Regional Transmission Organization
MMBtu	Millions of British thermal units
MMCFD	Million cubic feet per day
MW	Megawatts
MWh	Megawatt hour
NERC	North American Electric Reliability Council
NGA	The Natural Gas Act of 1938, as amended
NGL	Our natural gas liquids business segment
NGPA	The Natural Gas Policy Act of 1978, as amended
NGPSA	The Natural Gas Pipeline Safety Act of 1968, as amended
NOL	Net operating loss
NOV	Notice of Violation issued by the EPA
NO_x	Nitrogen oxide
NYISO	New York Independent System Operator
NYDEC	New York Department of Environmental Conservation
PCAOB	Public Company Accounting Oversight Board (United States)
PJM	Pennsylvania-New Jersey-Maryland Interconnection, LLC
PPA	Power purchase agreement
PRB	Powder River Basin coal
PUCT	Public Utility Commission of Texas
PUHCA	The Public Utility Holding Company Act of 1935, as amended
PURPA	The Public Utility Regulatory Policies Act of 1978
QFs	Qualifying Facilities
RCRA	The Resource Conservation and Recovery Act of 1976, as amended
REG	Our regulated energy delivery business segment
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RTO	Regional Transmission Organization
SAB	SEC Staff Accounting Bulletin
SEC	U.S. Securities and Exchange Commission
SERC	Southeastern Electric Reliability Council
SFAS	Statement of Financial Accounting Standards
SFC	Supplier forward contract
SO_2	Sulfur dioxide
SPE	Special Purpose Entity
SPN	Second Priority Senior Secured Notes
T&D	Our former transmission and distribution energy delivery business segment
VaR	Value at Risk
VIE	Variable Interest Entity
VLGC	Very large gas carrier
WECC	Western Electricity Coordinating Council
WTLPS	West Texas LPG Pipeline Limited Partnership, the owner of West Texas LPG Pipeline

Schedule I

DYNEGY INC.

CONDENSED BALANCE SHEETS OF THE REGISTRANT
(in millions)

	December 31, 2006	December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 121	$ 216
Intercompany accounts receivable	1,431	1,772
Intercompany notes receivable	—	120
Deferred income taxes	93	14
Prepayments and other current assets	—	24
Total Current Assets	1,645	2,146
Other Assets		
Investments in affiliates	3,321	3,434
Deferred income taxes	12	3
Other long-term assets	9	9
Total Assets	$ 4,987	$ 5,592
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 8	$ 7
Accrued liabilities and other current liabilities	—	19
Total Current Liabilities	8	26
Long-Term Debt	—	225
Intercompany long-term debt	2,243	2,243
Deferred income taxes	469	558
Total Liabilities	2,720	3,052
Commitments and Contingencies (Note 3)		
Redeemable Preferred Securities, redemption value of zero at December 31, 2006 and $400 at December 31, 2005	—	400
Stockholders' Equity		
Class A Common Stock, no par value, 900,000,000 shares authorized at December 31, 2006 and December 31, 2005; 403,137,339 and 305,129,052 shares issued and outstanding at December 31, 2006 and December 31, 2005, respectively	3,367	2,949
Class B Common Stock, no par value, 360,000,000 shares authorized at December 31, 2006 and December 31, 2005; 96,891,014 shares issued and outstanding at December 31, 2006 and December 31, 2005	1,006	1,006
Additional paid-in-capital	39	51
Subscriptions receivable	(8)	(8)
Accumulated other comprehensive income, net of tax	67	4
Accumulated deficit	(2,135)	(1,793)
Treasury stock, at cost, 1,787,004 and 1,714,026 shares at December 31, 2006 and December 31, 2005, respectively	(69)	(69)
Total Stockholders' Equity	2,267	2,140
Total Liabilities and Stockholders' Equity	$ 4,987	$ 5,592

See Notes to Registrant's Financial Statements and Dynegy Inc.'s Consolidated Financial Statements

Schedule I

DYNEGY INC.

CONDENSED STATEMENTS OF OPERATIONS OF THE REGISTRANT
(in millions)

	Year Ended December 31,		
	2006	2005	2004
Operating loss	$ —	$ (81)	$ (2)
Earnings (losses) from unconsolidated investments	(452)	137	(52)
Interest expense	(6)	(11)	(22)
Debt conversion cost	(46)	—	—
Other income and expense, net	9	5	—
Income (loss) before income taxes	(495)	50	(76)
Income tax benefit	162	40	61
Net income (loss)	(333)	90	(15)
Less: preferred stock dividends	9	22	22
Net income (loss) applicable to common stockholders	$(342)	$ 68	$ (37)

See Notes to Registrant's Financial Statements and Dynegy Inc.'s Consolidated Financial Statements

DYNEGY INC.

CONDENSED STATEMENTS OF CASH FLOWS OF THE REGISTRANT
(in millions)

	Year Ended December 31,		
	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES:			
Operating cash flow, exclusive of intercompany transactions	$ 14	$ (6)	$ (20)
Intercompany transactions	59	(12)	510
Net cash provided by (used in) operating activities	73	(18)	490
CASH FLOWS FROM INVESTING ACTIVITIES:			
Loan to DHI	120	(120)	—
Business acquisitions, net of cash acquired	(8)	—	—
Net cash provided by (used in) investing activities	112	(120)	—
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net repayments of long-term borrowings	—	—	(223)
Debt conversion cost	(46)	—	—
Redemption of Series C Preferred	(400)	—	—
Proceeds from issuance of capital stock	183	2	5
Dividends and other distributions, net	(17)	(22)	(22)
Net cash used in financing activities	(280)	(20)	(240)
Net increase (decrease) in cash and cash equivalents	(95)	(158)	250
Cash and cash equivalents, beginning of period	216	374	124
Cash and cash equivalents, end of period	$ 121	$ 216	$ 374
SUPPLEMENTAL CASH FLOW INFORMATION			
Interest paid (net of amount capitalized)	5	11	29
Taxes paid (net of refunds)	9	45	4
SUPPLEMENTAL NONCASH FLOW INFORMATION			
Conversion of Convertible Subordinated Debentures due 2023	$ 225	$ —	$ —

See Notes to Registrant's Financial Statements and Dynegy Inc.'s Consolidated Financial Statements

DYNEGY INC.

NOTES TO REGISTRANT'S FINANCIAL STATEMENTS

Note 1—Background and Basis of Presentation

These condensed parent company financial statements have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X, as the restricted net assets of Dynegy Inc.'s subsidiaries exceeds 25% of the consolidated net assets of Dynegy Inc. These statements should be read in conjunction with the Consolidated Statements and notes thereto of Dynegy Inc.

We are a holding company and conduct substantially all of our business operations through our subsidiaries. We began operations in 1985 and became incorporated in the state of Illinois in 1999 in anticipation of our February 2000 merger with Illinova Corporation.

Note 2—Debt

For a discussion of our debt facilities, please read Note 12—Debt beginning on page F-36 of our consolidated financial statements. All of our debt obligations outstanding are due subsequent to 2008.

Note 3—Commitments and Contingencies

For a discussion of our commitments and contingencies, please read Note 17—Commitments and Contingencies beginning on page F-47 of our consolidated financial statements.

For a discussion of our guarantees, please read Note 12—Debt beginning on page F-36 of our consolidated financial statements and Note 17—Commitments and Contingencies—Guarantees and Indemnifications beginning on page F-51 of our consolidated financial statements.

Schedule II

DYNEGY INC.

VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2006, 2005 and 2004

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
2006					
Allowance for doubtful accounts	$103	$(35)	$ 43	$(63)	$ 48
Allowance for risk-management assets (1)	10	—	—	(10)	—
Deferred tax asset valuation allowance	70	17	—	(18)	69
2005					
Allowance for doubtful accounts	$159	$ 1	$—	$(57)	$103
Allowance for risk-management assets (1)	6	—	—	4	10
Deferred tax asset valuation allowance	136	—	(5)	(61)	70
2004					
Allowance for doubtful accounts	$184	$ (7)	$ (5)	$(13)	$159
Allowance for risk-management assets (1)	11	—	—	(5)	6
Deferred tax asset valuation allowance (2)	170	(34)	—	—	136

(1) Changes in price and credit reserves related to risk-management assets are offset in the net mark-to-market income accounts reported in revenues.

(2) Decrease in our deferred tax asset valuation relates to our release of a deferred tax capital gains valuation allowance.

WEST COAST POWER LLC

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

WEST COAST POWER LLC

CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS
(unaudited) (in thousands)

	Three Months Ended March 31, 2006
Revenues	$ 66,728
Operating costs, exclusive of depreciation shown separately below	(64,966)
Depreciation and amortization expense	(5,325)
Gain on sale of assets	308
General and administrative expenses	(762)
Operating loss	(4,017)
Interest income	2,047
Net loss	$ (1,970)

See the notes to the condensed consolidated financial statements.

WEST COAST POWER LLC

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS
(unaudited) (in thousands)

	Three Months Ended March 31, 2006
CASH FLOWS FROM OPERATING ACTIVITIES:	
Net loss	$ (1,970)
Adjustments to reconcile net loss to net cash flows from operating activities:	
Depreciation and amortization	5,325
Gain on sale of assets	(308)
Changes in working capital:	
Accounts receivable, net	20,785
Inventory	272
Prepaid expenses	6,161
Accounts payable	(11,268)
Accrued liabilities and other current liabilities	(5,575)
Other	1,157
Net cash provided by operating activities	14,579
CASH FLOWS FROM INVESTING ACTIVITIES:	
Capital expenditures	(41)
Proceeds from asset sales, net	308
Net cash provided by investing activities	267
Net increase in cash and cash equivalents	14,846
Cash and cash equivalents, beginning of period	165,704
Cash and cash equivalents, end of period	$180,550

See the notes to the condensed consolidated financial statements.

WEST COAST POWER LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)
For the interim period ended March 31, 2006

Note 1—Organization

On March 31, 2006, Dynegy Inc. ("Dynegy") completed the sale of its 50% ownership interest in WCP (Generation) Holdings LLC ("Holdings"), our parent, to NRG Energy, Inc. ("NRG") for approximately $205 million. After the transaction, we became an indirect wholly owned subsidiary of NRG. The financial statements included herein are included to comply with Dynegy's requirement to include separate financial statements of investees in accordance with Rule 3-09 of Regulation S-X, and therefore only include financial statements for the periods under which Dynegy owned Holdings.

Note 2—Accounting Policies

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with the instructions to interim financial reporting as prescribed by the SEC. These interim financial statements should be read together with the consolidated financial statements and notes thereto for the year ended December 31, 2005.

The unaudited condensed consolidated financial statements contained in this report include all material adjustments that, in the opinion of management, are necessary for a fair statement of the results for the interim periods. The results of operations for the interim period presented are not necessarily indicative of the results to be expected for the full year or any other interim period due to seasonal fluctuations in demand for our energy products and services, changes in commodity prices, timing of maintenance and other expenditures and other factors. The preparation of the unaudited condensed consolidated financial statements in conformity with Generally Accepted Accounting Principles ("GAAP") requires management to make estimates and judgments that affect our reported financial position and results of operations. These estimates and judgments also impact the nature and extent of disclosure, if any, of our contingent liabilities. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) developing fair value assumptions, including estimates of future cash flows and discounts rates, (2) analyzing tangible and intangible assets for possible impairment, (3) estimating the useful lives of our assets and (4) determining amounts to accrue for contingencies, guarantees and indemnifications. Our actual results from operations could differ materially from our estimates.

Note 3—Related Parties

We purchase fuel for our plants under full requirement natural gas supply agreements ("GSAs") with Dynegy Marketing and Trade ("DMT"), one of our affiliates. Charges for fuel are based upon similar terms and conditions, primarily index, as could be obtained from unrelated third parties. Fuel purchases from DMT are included in affiliated operating costs in the consolidated statements of operations.

We contracted with DYPM to provide all power scheduling, power marketing and risk management for us under an energy management agreement (the "EMA"). Additionally, we contracted with DMT to provide all scheduling of fuel supply.

We entered into operation and maintenance ("O&M") agreements with NRG Cabrillo Power Operations Inc. and NRG El Segundo Operations Inc., two of our affiliates, for Cabrillo I and Cabrillo II effective May 2001 and for El Segundo Power, LLC ("ESP") and Long Beach Generation LLC ("LBG") effective April 2000. Fees for services under these contracts primarily include recovery of the costs of operating the plant as approved in the annual budget, as well as a base monthly fee. When NRG became operator, we contracted with NRG Development Company, Inc., one of our affiliates, to provide services under the Administrative Management Agreement (the "AMA"). Services provided under the AMA included environmental, engineering, legal and public relations services not covered under the O&M agreements. Fees for such services are subject to executive committee approval if the amounts exceed a certain percentage of the applicable annual approved budget.

We entered into an administrative services management agreement (the "ASMA") with Dynegy Power Management Services, L.P., one of our affiliates, under which Dynegy Power Management Services, L.P. provides administrative services such as business management and accounting. Fees for such services are subject to executive committee approval if the amounts exceed a certain percentage of the applicable annual approved budget.

As described above, our affiliates provide various services for us. Charges for these services are included in our operating and general and administrative expenses in the unaudited condensed consolidated statement of operations and consisted of the following costs for the three months ended March 31, 2006 (in thousands):

Dynegy Related Cost	
Fuel	$47,187
EMA Charges	577
Charges included in operating costs	$47,764
ASMA fees included in general and administrative expenses	$ 277
NRG Related Cost	
O&M charges included in operating costs	$ 8,391
AMA charges included in general and administrative expenses	$ 200

Note 4—Commitments and Contingencies

Set forth below is a summary of certain ongoing legal proceedings pending against West Coast Power LLC and its subsidiaries. The matters discussed herein existed at Closing (which occurred on March 31, 2006, the "Closing") of Dynegy's sale of its interest in Holdings. In accordance with SFAS No. 5, we record reserves for contingencies when information available indicates that a loss is probable and the amount of the loss is reasonable estimate. In addition, we disclose for matters for which management believes a material loss is at least reasonably possible.

In addition to matters discussed below, at Closing, we were party to numerous legal proceedings arising in the ordinary course of business or related to discontinued business operations. In management's opinion, the disposition of these matters will not materially adversely affect our financial condition, results of operations, or cash flows.

In all instances, management has assessed the matters below based on current information and made a judgment concerning their potential outcome, giving due consideration to the nature of the claim, the amount and nature of damages sought and the probability of success. Management's judgment may prove materially inaccurate and such judgment is made subject to the known uncertainty of litigation.

Gas Index Pricing Litigation. We are named defendants in numerous lawsuits ain state and federal court claiming damages resulting from alleged price manipulation and false reporting of natural gas price. In cases are pending in California and Nevada. In each of these suits, the plaintiffs allege that we and other energy companies engaged in an illegal scheme to inflate natural gas prices by providing false information to natural gas index publications. All of the complaints rely heavily on prior FERC and CFTC investigations into and reports concerning index-reporting manipulation in the energy industry. Except as specifically mentioned below, the cases are actively engaged in discovery.

In February 2006, we reached a settlement in *In re Natural Gas Commodity Litigation*, resolving a class action lawsuit by all persons who purchased, sold or settled NYMEX Natural Gas Contracts as an opening or closing transaction or otherwise, between June 1, 1999 and December 31, 2002 inclusive. The underlying action alleged the named defendants (including Dynegy and West Coast Power), unlawfully manipulated and aided and abetted the manipulation of the prices of natural gas futures contracts traded on the NYMEX. Pursuant to the settlement, Dynegy and West Coast Power continue to deny plaintiffs' allegations, and Dynegy agreed to pay $7 million in settlement of any and all claims for damages arising from or relating in any way to trading during the Class Period in NYMEX Natural Gas Contracts. The settlement is subject to a fairness hearing and final Court approval.

We are analyzing all of these claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability or to estimate the damages, if any, that might be incurred in connection with these lawsuits. We do not believe that any liability that we might incur as a result of this litigation would have a material adverse effect on our financial condition, results of operations or cash flows.

U.S. Attorney Investigations. The United States Attorney's office in the Northern District of California issued a Grand Jury subpoena requesting information related to our activities in the California energy markets in November 2002. We have been, and intend to continue, cooperating fully with the U.S. Attorney's office in its investigation of these matters, including production of substantial documents responsive to the subpoena and other requests for information. We cannot predict the ultimate outcome of this investigation.

During the last year, several cases pending in Nevada federal court were dismissed on defendants' motions. Certain plaintiffs have appealed to the Court of Appeals for the Ninth Circuit, which coordinated the cases before the same appellate panel. A decision from the Court of Appeals is expected sometime in 2007. In February 2007, a Tennessee state court case was also dismissed on defendants' motion.

Pursuant to various motions, the cases pending in California state court have been coordinated before a single judge in San Diego ("Coordinated Gas Index Cases"). In August 2006, we and Dynegy entered into an agreement to settle the class action claims in the Coordinated Gas Index Cases for $30 million. The settlement does not include similar claims filed by individual plaintiffs in the Coordinated Gas Index Cases, which we continue to defend vigorously. In December 2006, the court granted final approval of the settlement and dismissed the class action claims. Also in August 2006, Dynegy entered into an agreement to settle the class action claims by California natural gas re-sellers and co-generators (to the extent they purchased natural gas to generate electricity for re-sale) pending in Nevada federal court for $2 million. A motion to approve this settlement is expected to be filed by plaintiffs in due course. Both settlements are without admission of wrongdoing, and we and Dynegy continue to deny class plaintiffs' allegations.

We are analyzing the remaining natural gas index cases and are vigorously defending against them. We cannot predict with certainty whether we will incur any liability in connection with these lawsuits. However, given the nature of the claims, an adverse result in any of these proceedings could have a material adverse effect on our financial condition, results of operations and cash flows.

California Market Litigation. We and various other power generators and marketers are defendants in numerous lawsuits alleging rate and market manipulation in California's wholesale electricity market during the California energy crisis several years ago. The complaints generally allege unfair, unlawful and deceptive trade practices in violation of the California Unfair Business Practices Act and seek injunctive relief, restitution and unspecified actual and treble damages. A significant majority of these cases were dismissed on grounds of federal preemption. A motion to dismiss one remaining action on similar grounds is pending in federal court. Certain actions, however, in which plaintiffs have not exhausted the appellate process, remain pending in a California appellate court.

We believe that we have meritorious defenses to these claims and are vigorously defending against them. We cannot predict with certainty whether we will incur any liability in connection with these lawsuits. However, given the nature of the claims, an adverse result in any of these proceedings could have a material adverse effect on our financial condition, results of operations and cash flows.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING TEAM

To the Members of West Coast Power LLC:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in members' equity and cash flows present fairly, in all material respects, the financial position of West Coast Power LLC (the "Company") at December 31, 2005, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 9, the Company is the subject of substantial litigation. The Company's ongoing liquidity, financial position and operating results may be adversely impacted by the nature, timing and amount of the resolution of such litigation. The consolidated financial statements do not include any adjustments, beyond existing accruals applicable under Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies," that might result from the ultimate resolution of such matters.

As discussed in Note 2, effective January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

PricewaterhouseCoopers LLP
Houston, Texas
March 14, 2006

WEST COAST POWER LLC

CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2005
ASSETS	
Current Assets	
Cash and cash equivalents	$ 165,704
Accounts receivable, net of allowance for doubtful accounts of zero	75,654
Inventory	17,937
Prepaid expenses	52,211
Total Current Assets	311,506
Property, Plant and Equipment	600,712
Accumulated depreciation	(224,446)
Property, Plant and Equipment, Net	376,266
Other Long Term Assets	2,036
Total Assets	$ 689,808
LIABILITIES AND MEMBERS' EQUITY	
Current Liabilities	
Accounts payable	$ 3,906
Accounts payable, affiliates	30,547
Accrued liabilities and other current liabilities	8,470
Total Current Liabilities	42,923
Asset retirement obligation	5,481
Total Liabilities	48,404
Commitments and Contingencies (Note 9)	
Total Members' Equity	641,404
Total Liabilities and Members' Equity	$ 689,808

See the notes to the consolidated financial statements.

WEST COAST POWER LLC

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands)

	Year Ended December 31,	
	2005	2004
Revenues	$ 300,581	$ 725,626
Affiliate operating costs, exclusive of depreciation shown separately below	(218,517)	(314,754)
Non-affiliate operating costs, exclusive of depreciation shown separately below	(39,940)	(42,189)
Depreciation and amortization expense	(22,017)	(39,456)
Impairment charges	—	(24,348)
Gain on sale of assets	1	689
General and administrative expenses	(5,318)	(2,078)
Operating income	14,790	303,490
Interest expense	—	(82)
Interest income	6,572	2,539
Net income	$ 21,362	$ 305,947

See the notes to the consolidated financial statements.

WEST COAST POWER LLC

CONSOLIDATED STATEMENTS OF CHANGES IN MEMBERS' EQUITY
(in thousands)

	Members' Equity	Comprehensive Income
Balance at December 31, 2003	$ 648,085	
Net income	305,947	$305,947
Comprehensive income		$305,947
Contributions	5,000	
Distributions	(217,245)	
Other distributions	(6,245)	
Balance at December 31, 2004	$ 735,542	
Net income	21,362	$ 21,362
Comprehensive income		$ 21,362
Distributions	(115,500)	
Balance at December 31, 2005	$ 641,404	

See the notes to the consolidated financial statements.

WEST COAST POWER LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2005	Year Ended December 31, 2004
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 21,362	$ 305,947
Adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	22,017	39,456
Impairment charges	—	24,348
Risk-management activities	(3,559)	3,559
Gain on sale of assets	(1)	(689)
Other, non-cash and adjustments	151	(1,313)
Changes in working capital:		
Accounts receivable, net	38,140	(55,950)
Inventory	1,345	1,281
Prepaid expenses	(366)	(11,584)
Accounts payable	(770)	14,949
Accrued liabilities and other current liabilities	(1,662)	(18,654)
Other	67	(1,512)
Net cash provided by operating activities	76,724	299,838
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(4,251)	(1,386)
Proceeds from asset sales, net	1	3,278
Net cash provided by (used in) investing activities	(4,250)	1,892
CASH FLOWS FROM FINANCING ACTIVITIES:		
Distributions	(115,500)	(217,245)
Net cash used in financing activities	(115,500)	(217,245)
Net increase (decrease) in cash and cash equivalents	(43,026)	84,485
Cash and cash equivalents, beginning of period	208,730	124,245
Cash and cash equivalents, end of period	$ 165,704	$ 208,730
Supplemental Disclosure of Cash Flow Information:		
Interest paid	—	82
Other non-cash investing and financing activity:		
Contribution of El Segundo Power II LLC by NRG	—	5,000

See the notes to the consolidated financial statements.

WEST COAST POWER LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Operations of the Company

Effective June 30, 1999, Dynegy Power Corp. ("DPC"), an indirect wholly owned subsidiary of Dynegy Holdings Inc. ("Dynegy"), and NRG Energy, Inc. ("NRG"), then a subsidiary of Xcel Energy, Inc (collectively, the "Sponsors") formed WCP (Generation) Holdings LLC ("Holdings") and West Coast Power LLC ("WCP", "we", "us" or "our"), both of which are Delaware limited liability companies. The Sponsors have an equal interest in Holdings and share in profits and losses equally. WCP is wholly owned by Holdings and serves as a holding company for El Segundo Power, LLC ("ESP"), El Segundo Power II LLC ("ESP II"), Long Beach Generation LLC ("LBG"), Cabrillo Power I LLC ("Cabrillo I") and Cabrillo Power II LLC ("Cabrillo II"). NRG became an independent public company upon its emergence from bankruptcy on December 5, 2003 and no longer has any material affiliation or relationship with Xcel Energy.

Upon formation of WCP, the assets and liabilities of ESP, LBG, Cabrillo I and Cabrillo II (collectively, the "LLCs") were contributed to WCP by the Sponsors and were recorded at their historical costs because the transfer represented a reorganization of entities under common control. Operations are governed by the executive committee, which consists of two representatives from each Sponsor.

On December 27, 2005, Dynegy entered into an agreement to sell its 50% ownership interest in Holdings to NRG for approximately $205 million, subject to purchase price adjustments. After the transaction, we will become an indirect wholly owned subsidiary of NRG. Dynegy and NRG expect the sale to close in early 2006.

ESP owns a 670-megawatt ("MW") plant located in El Segundo, California, consisting of two operating steam electric generating units. The facility has operated as a merchant plant, selling energy and ancillary services through the deregulated California wholesale electric market and other western markets. In December 2004, the California Independent System Operator ("Cal ISO"), pursuant to its tariff, designated ESP units 3 and 4 as Reliability Must Run ("RMR") units for the calendar year 2005. On December 21, 2004, ESP filed with the Federal Energy Regulatory Commission ("FERC"), an application for approval of its rates as an RMR designated facility. ESP made the election to collect rates as a "Condition 2" plant, effective January 1, 2005. In the third quarter of 2005, ESP entered into a settlement with various California parties including the Cal ISO, regarding the rate application. In the fourth quarter of 2005, FERC issued an order approving the settlement and accepting the agreed upon rates.

On January 27, 2005, Dynegy Power Marketing Inc, an affiliate of ESP, acting as its fully authorized agent, entered into a power purchase agreement with a major California utility for a term commencing May 1, 2005 and ending December 31, 2005. As part of that agreement, ESP was required to obtain certain consents and waivers from Cal ISO and to file for an application with FERC to change from "Condition 2" to "Condition 1" under the Cal ISO tariff. Such consents and waivers were received from the Cal ISO, an application to FERC was filed and the changes were accepted. As a result of these actions, during the term of this agreement, the utility was entitled to primary energy dispatch right for the facility's generating capacity while preserving Cal ISO's ability to call on the El Segundo facility as a reliability resource under the RMR agreement, if necessary. (See Note 7 – Power Purchase Agreement for a more detailed explanation).

In the fourth quarter 2005, ESP entered into a power sales agreement with a major California utility for the sale of 100% of the capacity and associated energy from the El Segundo facility from May 2006 through April 2008. During the term of this agreement, the utility will be entitled to primary energy dispatch right for the facility's generating capacity.

For the calendar year 2006, ESP was not designated as an RMR resource by the Cal ISO.

In October 2004, the FERC approved WCP's settlement of claims relating to western energy market transactions that occurred from January 2000 through June 2001. (See Note 9—Commitments and Contingencies for further discussion of this settlement). Included in this settlement was a payment of $22,544,942 to various California energy purchasers. In order to provide the funds for this settlement, Dynegy has agreed to forego approximately $17,000,000 of distributions from WCP, and NRG has agreed to forego approximately $5,500,000 of distributions and contribute El Segundo Power II LLC valued at $5,000,000 to WCP. The contribution of these assets is reflected as a contribution in the Consolidated Statements of Changes in Members' Equity. WCP paid $6,244,942 of the settlement on behalf of Dynegy in accordance with the settlement agreement, and is recorded as a reduction of Dynegy's member's equity on the Consolidated Statements of Changes in Members' Equity.

On December 30, 2004, NRG West Coast LLC, a Delaware limited liability company, assigned its right, title, and interest in El Segundo Power II LLC to Holdings, which in turn assigned its interest to WCP, as part of the funding of the settlement agreement with the FERC. On February 3, 2005, the California Energy Commission approved the certificate for the construction and operation of a proposed 630-MW combined-cycle facility by ESP II on the site previously used by ESP units 1 and 2. A Petition For Writ of Mandate was filed in the California Supreme Court against the California Energy Commission seeking to invalidate the certificate awarded to ESP II. The Petition was denied without comment. ESP II became 100% owned by WCP on December 30, 2004. No date has been set to commence construction, although California state law requires that construction commence five years after the issuance of the certificate.

LBG owns a 560-MW plant located in Long Beach, California. On January 1, 2005, after due notice to the Cal ISO, the plant was shut down and the operator began decommissioning, environmental remediation of the plant site, equipment salvage and investment recovery efforts.

Cabrillo I owns a 970-MW plant located in Carlsbad, California, consisting of five steam electric generating units and one combustion turbine. The facility has operated as a merchant plant, selling energy and ancillary services through the deregulated California wholesale electric market and other western markets. Cabrillo I was designated as a RMR unit by the Cal ISO for 2004 and 2005. Pursuant to an uncontested settlement agreement filed in December 2004 with the Cal ISO and various interveners in FERC Docket No. ER04-308, RMR rates for the years 2004 through 2006 were agreed upon between the parties. As a part of that settlement, Cabrillo I chose to collect rates as a Condition 2 plant, effective January 1, 2005 (See Note 7 – Power Purchase Agreement for a more detailed explanation). On February 14, 2005, FERC issued an order accepting these rates. In November 2005, Cabrillo I filed with FERC an application to revise its existing RMR agreement with the Cal ISO for Units 1-3 and 5. In December 2005, FERC accepted those rates effective January 1, 2006. Finally, in late December 2005, Cabrillo I, Unit 4 was selected as a RMR resource for 2006 by the Cal ISO. Cabrillo I filed an application on December 29, 2005 to revise its current RMR agreement to include Unit 4 and to change Units 4 and 5 from Condition 2 to Condition 1. Cabrillo I requested an effective date of January 1, 2006. On February 13, 2006, FERC issued an order accepting the revised rates effective as of January 1, 2006. Subsequent to the FERC order approving the Cabrillo I rates, an application for rehearing challenging that order, was filed by an intervenor. We do not know when FERC will rule on that rehearing application.

Cabrillo II owns 13 combustion turbines with an aggregate capacity of 202-MW located throughout San Diego County, California. The facilities have operated as merchant plants, selling energy and ancillary services through the deregulated California wholesale electric market and other western markets. The Cabrillo II combustion turbines except for Division Street, were designated as RMR units by the Cal ISO for 2004 and 2005. Pursuant to an uncontested settlement agreement filed in December 2004 with the Cal ISO and various interveners in FERC Docket No. ER04-308, RMR rates for the years 2004 through 2006 were agreed upon between the parties. As a part of that settlement, Cabrillo I chose to continue collecting rates as a "Condition 2" plant, effective January 1, 2005 (See Note 7 – Power Purchase Agreement for a more detailed explanation). On February 14, 2005, FERC issued an order accepting these rates. Cabrillo II units were also designated RMR units by the Cal ISO for 2006. In November 2005, Cabrillo II filed an application with FERC for approval of its rates. In December 2005, FERC accepted those rates effective January 1, 2006.

Note 2—Accounting Policies

Our accounting policies conform to Generally Accepted Accounting Principles ("GAAP"). Our most significant accounting policies are described below. The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and judgments that affect our reported financial position and results of operations. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) developing fair value assumptions, including estimates of future cash flows and discounts rates, (2) analyzing tangible and intangible assets for possible impairment, (3) estimating the useful lives of our assets and (4) determining amounts to accrue for contingencies, guarantees and indemnifications. Our actual results from operations could differ materially from our estimates.

Principles of Consolidation. The accompanying consolidated financial statements include our accounts after eliminating intercompany accounts and transactions. Certain reclassifications have been made to prior-period amounts to conform with current-period financial statement classifications.

Cash and Cash Equivalents. Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid short-term investments with original maturities of three months or less.

Accounts Receivable and Allowance for Doubtful Accounts. We establish provisions for losses on accounts receivable if it becomes probable we will not collect all or part of outstanding balances. We review collectibility and establish or adjust our allowance as necessary using the specific identification method. As of December 31, 2005, we have no reserve as an allowance for doubtful accounts relating to receivables owed to us by the California Department of Water Resources ("CDWR").

Concentration of Credit Risk. We sell our electricity production to purchasers of electricity in California, which includes the Cal ISO and Dynegy Power Marketing, Inc. ("DYPM"). These industry and geographical concentrations have the potential to impact our overall exposure to credit risk, either positively or negatively, because the customer base may be similarly affected by changes in economic, industry, weather or other conditions.

Inventory. Inventories are valued at the lower of cost or market using the last-in, first-out ("LIFO") or the average cost methods and are comprised of the following:

	December 31, 2005
	(in thousands)
Emissions credits (average cost)	$ 1,411
Materials and supplies (average cost)	3,254
Fuel oil (LIFO)	13,272
	$17,937

In conjunction with the retirement of LBG at the end of 2004, a lower of cost or market analysis was performed on the facility's materials and supplies balance. The vast majority of the materials and supplies were designed for use specifically at LBG or are otherwise obsolete. As a result, an adjustment of $3,027,613, which is included as a charge in operating costs on the consolidated statement of operations, was made to reduce the inventory to net realizable value as of December 31, 2004.

Emission credits represent costs paid by us to acquire additional NO_x credits. We use these credits to comply with emission caps imposed by various environmental laws under which we must operate. As individual credits are used, costs are recognized as operating expense.

If we have more emission credits on hand than are required to operate our facilities, we may sell these credits. To the extent the proceeds received from the sale of such credits exceed our cost, we defer the associated gain until the period to which the allowance relates. As of December 31, 2005 we had a deferred gain of $22,307 included as accrued liabilities and other current liabilities on our consolidated balance sheets. This amount will be realized in 2006.

In addition, emissions allowances related to periods subsequent to 2006 totaling $2,035,931 at December 31, 2005, and emissions allowances related to periods subsequent to 2005 totaling $2,970,900 at December 31, 2004, are included in other long-term assets on the consolidated balance sheets.

Property, Plant and Equipment. Property, plant and equipment, which consists primarily of power generating facilities, furniture, fixtures and computer equipment, is recorded at historical cost. Expenditures for major replacements, renewals and major maintenance are capitalized. We consider major maintenance to be expenditures incurred on a cyclical basis in order to maintain and prolong the efficient operation of our assets. Expenditures for repairs and minor renewals to maintain assets in operating condition are expensed when incurred. Depreciation is provided using the straight-line method over the estimated economic service lives of the assets, ranging from 3 to 30 years. The estimated economic service lives of our asset groups are as follows:

Asset Group	Range of Years
Power Generation Facilities	3 to 30
Furniture and Fixtures	3 to 5
Other Miscellaneous	4 to 20

Gains and losses on sales of individual assets are reflected in gain on sale of assets in the consolidated statement of operations. We assess the carrying value of our plant and equipment in accordance with Statement of Financial Accounting Standards "SFAS" No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." If an impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the related discounted cash flows of the assets and recording a loss if the resulting estimated fair value is less than the book value. For assets identified as held for sale, the book value is compared to comparable market prices or the estimated fair value if comparable market prices are not readily available to determine if an impairment loss is required. Please read Note 4—Impairment of Long-Lived Assets for a discussion of impairment charges we recognized in 2004.

On September 30, 2004, the WCP executive committee consented to a plan to retire the Long Beach facilities effective January 1, 2005. The revision of the expected useful life of Long Beach was a change in accounting estimate, per the guidance in Accounting Principles Board Opinions "APB" No. 20, "Accounting Changes." This change was accounted for in the current and future periods since the change affects both. The remaining asset value, excluding land, as of September 30, 2004 was $9,918,597. The depreciation was accelerated so that the Long Beach facilities were fully depreciated by December 31, 2004.

Asset Retirement Obligations. We adopted SFAS No. 143, "Asset Retirement Obligations," effective January 1, 2003. Under the provisions of SFAS No. 143, we are required to record liabilities for legal obligations to retire tangible, long-lived assets. Those obligations are recorded at a discount when the liability is incurred. Significant judgment is involved in estimating future cash flows associated with such obligations, as well as the ultimate timing of the cash flows. If our estimates on the amount or timing of the cash flow change, the change may have a material impact on our results of operations.

As part of the transition adjustment in adopting SFAS No. 143, existing environmental liabilities in the amount of $5,200,000 were reversed in the first quarter 2003. The fair value of the remediation costs estimated to be incurred upon retirement of the respective assets is included in the asset retirement obligation ("ARO") and was recorded upon adoption of SFAS No. 143. Since the previously accrued liabilities exceeded the fair value of the future retirement obligations, the impact of adopting SFAS No. 143 was an increase in earnings of $1,029,756 in 2003, which is the cumulative effect of change in accounting principle in the consolidated statement of operations.

At January 1, 2004, our ARO liabilities totaled $7,631,979, which includes monitoring charges related to El Segundo Units 1 and 2, as well as dismantlement and remediation at the Cabrillo II facilities since these assets reside on leased property. Annual accretion of the liability towards the ultimate obligation amount was $628,290 during 2004. During 2004, we settled $2,140,550 relating to our ARO. During 2004, the timing or fair value of the estimated cost to be incurred upon retirement related to the dismantlement and remediation changed for the Cabrillo II facilities. These changes resulted in an $896,809 decrease in our ARO liability. Since the change in the ARO liability associated with one of the facilities exceeded the asset retirement cost net of accumulated depreciation, an increase in earnings of $641,236 was recorded during 2004, which is included in non-affiliate operating costs on the consolidated statements of operations. At December 31, 2004, our ARO liabilities totaled $5,222,910.

Annual accretion of the liability towards the ultimate obligation amount was $490,484 during 2005. During 2005, we settled $423,288 relating to our ARO. During 2005, the estimated cost to be incurred upon retirement changed again for the Cabrillo II facilities. These changes resulted in an $190,796 increase in our ARO liability. This change resulted in a decrease in earnings of $150,832 during 2005, which is included in non-affiliate operating costs on the consolidated statements of operations. At December 31, 2005, our ARO liabilities totaled $5,480,902.

In March 2005, the FASB issued Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations," ("FIN No. 47") which is an interpretation of SFAS No. 143. FIN No. 47 defines a conditional ARO as an ARO for which the timing and/or method of settlement are conditional upon future events that may or may not be within the control of the entity. Uncertainty about the timing and method of settlement for a conditional ARO should be considered in estimating the ARO when sufficient information exists. FIN No. 47 clarifies when sufficient information exists to reasonably estimate the fair value of an ARO. FIN No. 47 was effective for fiscal years ending after December 15, 2005. We adopted FIN No. 47 on December 31, 2005 and the adoption did not have a material impact on our consolidated statement of operations or balance sheet.

Other Contingencies. We are involved in numerous lawsuits, claims, and proceedings in the normal course of our operations. In accordance with SFAS No. 5, "Accounting for Contingencies," we record a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. We review our loss contingencies on an ongoing basis to ensure that we have appropriate reserves recorded on the consolidated balance sheets. These reserves are based on estimates and judgments made by management with respect to the likely outcome of these matters, including any applicable insurance coverage for litigation matters, and are adjusted as circumstances warrant. Our estimates and judgment could change based on new information, changes in laws or regulations, changes in management's plans or intentions, the outcome of legal proceedings, settlements or other factors. If different estimates and judgments were applied with respect to these matters, it is likely that reserves would be recorded for different amounts. Actual results could vary materially from these estimates and judgments.

Liabilities for environmental contingencies are recorded when environmental assessment indicates that remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based, in part, on relevant past experience, currently enacted laws and regulations, existing technology, site-specific costs and cost-sharing arrangements. Recognition of any joint and several liability is based upon our best estimate of our final pro-rata share of such liability. These assumptions involve the judgments and estimates of management and any changes in assumptions could lead to increases or decreases in our ultimate liability, with any such changes recognized immediately in earnings.

Goodwill. Goodwill represents, at the time of an acquisition, the amount of purchase price paid in excess of the fair value of net assets acquired. We follow the guidance set forth in SFAS No. 142, "Goodwill and Other Intangible Assets," when assessing the carrying value of our goodwill. Accordingly, we evaluate our goodwill for impairment on an annual basis or when events warrant an assessment. Our evaluation is based, in part, on our estimate of future cash flows. The estimation of fair value is highly subjective, inherently imprecise and can change materially from period to period based on, among other things, an assessment of market conditions, projected cash flows and discount rate. We currently have no remaining goodwill as a result of this impairment. Were we to have goodwill, we would perform our annual impairment test in December, and we may record further impairment losses in future periods as a result of such test.

Revenue Recognition. Revenues received from the RMR agreement with the Cal ISO and the ESP power sales agreement are primarily derived from capacity (availability) payments and amounts based on reimbursing variable costs. Revenues identified as being subject to future resolution are accounted for as discussed above at "Accounts Receivable and Allowance for Doubtful Accounts."

Federal Income Taxes. We are not a taxable entity for federal income tax purposes. The Partnership's income is included in the income tax returns of the partners. Accordingly, there is no provision for income taxes in the accompanying consolidated financial statements.

Fair Value of Financial Instruments. Our financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable and derivative instruments to hedge commodity price and interest rate risk. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable are representative of their respective fair values due to the short-term maturities of these instruments.

Accounting for Derivative Instruments. We may enter into various derivative instruments to hedge the risks associated with changes in commodity prices and interest rates. We use physical and financial forward contracts to hedge a portion of our exposure to price fluctuations of natural gas and electricity.

Under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" as amended, we recognize all derivative instruments on the balance sheet at their fair values, and changes in fair value are recognized immediately in earnings, unless the derivatives qualify, and are designated, as hedges of future cash flows or fair values, or qualify, and are designated, as normal purchases and sales. For derivatives treated as hedges of future cash flows, we record the effective portion of changes in the fair value of the derivative instrument in other comprehensive income until the related hedged items impact earnings. Any ineffective portion of a cash flow hedge is reported in earnings immediately. For derivatives treated as fair value hedges, we record changes in the fair value of the derivative and changes in the fair value of the hedged risk attributable to the related asset, liability or firm commitment in current period earnings. Derivatives treated as normal purchases or sales are recorded and recognized in income using accrual accounting. As of December 31, 2005, we had no derivative instruments recorded on our balance sheet.

Note 3—Goodwill

As of December 31, 2005, we had no goodwill recorded on our balance sheet.

Note 4—Impairment of Long-Lived Assets

In December 2004, we tested our long-lived assets for impairment in accordance with SFAS No. 144. As a result of the expiration of the CDWR contract (See Note 7—Power Purchase Agreement), our impairment analysis of the Cabrillo II facility indicated future cash flows were insufficient to recover the carrying value of the long-lived assets. As a result, we recorded an impairment of $24,348,534, which is included in impairment charges on the consolidated statements of operations. At December 2005, as a result of the pending sale of Dynegy's 50% ownership interest in WCP to NRG, we tested our assets again. Our analysis indicated no impairment was necessary.

Note 5—Derivatives and Hedging

We previously entered into a series of fixed price electricity purchases to hedge a portion of the fair value of our fixed price CDWR Power Purchase Agreement ("PPA"). During the year ended December 31, 2004, there was no ineffectiveness from changes in fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness. Additionally, no amounts were reclassified to earnings in connection with forecasted transactions that were no longer considered probable. Upon acceptance of RMR Condition 2 on December 31, 2004, we are not exposed to the variability of cash flow from sales of power on a merchant basis. We did not enter into any fair value hedges during the year ended December 31, 2005.

The risk management assets and liabilities as of December 31, 2004 are derivatives, primarily gas and power forward sales contracts and swaps utilized to reduce our exposure to commodity price risk. However, these derivatives are not designated as cash flow hedges as defined in SFAS No. 133. As of December 31, 2005, all of our outstanding derivative positions had matured. Please read Note 7—Power Purchase Agreement for a more detailed explanation of our Power Purchase Agreements.

Note 6—Related Parties

We purchase fuel for our plants under full requirement natural gas supply agreements ("GSAs") with Dynegy Marketing and Trade ("DMT"), one of our affiliates. Charges for fuel are based upon similar terms and conditions, primarily index, as could be obtained from unrelated third parties. Fuel purchases from DMT are included in affiliated operating costs in the consolidated statements of operations.

We contracted with DYPM to provide all power scheduling, power marketing and risk management for us under an energy management agreement (the "EMA"). Additionally, we contracted with DMT to provide all scheduling of fuel supply.

We entered into operation and maintenance ("O&M") agreements with NRG Cabrillo Power Operations Inc. and NRG El Segundo Operations Inc., two of our affiliates, for Cabrillo I and Cabrillo II effective May 2001 and for ESP and LBG effective April 2000. Fees for services under these contracts primarily include recovery of the costs of operating the plant as approved in the annual budget, as well as a base monthly fee. When NRG became operator, we contracted with NRG Development Company, Inc., one of our affiliates, to provide services under the Administrative Management Agreement (the "AMA"). Services provided under the AMA included environmental, engineering, legal and public relations services not covered under the O&M agreements. Fees for such services are subject to executive committee approval if the amounts exceed a certain percentage of the applicable annual approved budget.

We entered into an administrative services management agreement (the "ASMA") with Dynegy Power Management Services, L.P., one of our affiliates, under which Dynegy Power Management Services, L.P. provides administrative services such as business management and accounting. Fees for such services are subject to executive committee approval if the amounts exceed a certain percentage of the applicable annual approved budget.

As described above, our affiliates provide various services for us. Charges for these services are included in our operating and general and administrative expenses in the consolidated statements of operations and consisted of the following costs:

	Years Ended December 31,	
	2005	2004
	(in thousands)	
Dynegy Related Cost		
Fuel	$180,796	$267,844
EMA Charges	4,373	9,216
Charges included in operating costs	$185,169	$277,060
ASMA fees included in general and administrative expenses	$ 1,292	$ 1,264
NRG Related Cost		
O&M charges included in operating costs	$ 33,348	$ 37,694
AMA charges included in general and administrative expenses	$ 1,969	$ 1,823

Note 7—Power Purchase Agreement

We entered into a long-term Power Purchase Agreement with the CDWR in March 2001. From March 2001 through December 31, 2004, the CDWR contracted for fixed-price firm energy and system contingent capacity and energy representing a substantial portion of WCP's capacity. Sales to CDWR constituted approximately 71% and 88% of revenues, net of reserves, in 2004 and 2003 respectively.

The CDWR contract expired on December 31, 2004. For 2005, all of our assets operated under RMR Condition 2 contracts with the Cal ISO, except for the Long Beach facility, which was retired effective January 1, 2005 (See Note 2—Accounting Policies—Property, Plant and Equipment for further detailed discussion of the Long Beach retirement). Under the terms of these RMR contracts, the Cal ISO reimburses WCP for 100% of approved costs plus a rate of return specified in the contracts. When the facilities are instructed to provide power by the Cal ISO, they are reimbursed for their variable production costs. Under RMR Condition 2, the facilities are 100% committed to the Cal ISO and, therefore, do not experience changes in market conditions through bilateral energy or capacity sales to third parties that the Company might otherwise enter into. The RMR contracts are effective for calendar year 2005. For 2006, the Cal ISO has agreed to renew its RMR agreements with Cabrillo I and II. All units will be operating under Condition 2 except for Cabrillo I, Units 4 and 5, which will operate under Condition 1.

In addition, ESP entered into a power sales agreement with a major California utility for 100% of the capacity and associated energy from the El Segundo facility from May 2005 through December 2005. During the term of this agreement, the utility will be entitled to primary energy dispatch right for the facility's generating capacity. The agreement permitted the utility to exercise primary dispatch rights under the agreement while preserving Cal ISO's ability to call on the El Segundo facility as a reliability resource under the RMR agreement. The agreement was accounted for as an operating lease of the facility under the requirements of Emerging Issues Task Force ("EITF") Issue No. 01-8 "Determining Whether an Arrangement Contains a Lease", with revenues being recognized on a straight-line basis over the life of the agreement. Sales under this agreement constituted approximately 13% of revenues in 2005.

In the fourth quarter 2005, ESP entered into a power sales agreement with a major California utility for the sale of 100% of the capacity and associated energy from the El Segundo facility from May 2006 through April 2008. During the term of this agreement, the utility will be entitled to primary energy dispatch right for the facility's generating capacity. The agreement will be accounted for as an operating lease of the facility under the requirements of EITF Issue No. 01-8, with revenues being recognized on a straight-line basis over the life of the agreement.

Note 8—Debt

In June 2003, we replaced our Refinanced Credit Agreement with an 18-month $50,000,000 letter of credit facility. With the replacement of the Refinanced Credit Agreement, we are no longer required to maintain restricted cash funds. This agreement requires us to post equal amounts of cash collateral for all letters of credit issued. This letter of credit facility incurs fees at the rate of 0.50% on any outstanding letters of credit plus a commitment fee at the rate of 0.25% on any unused amount of the commitment.

In November 2004, the letter of credit facility was extended until December 31, 2005 and increased from $50,000,000 to $85,000,000 effective January 1, 2005. We incurred financing costs of $275,000 in connection with the renewal of the agreement. These costs were fully amortized during 2005. At December 31, 2004, our deposit for our letter of credit facility was $35,300,000 and is included in prepaid expenses on our consolidated balance sheets. Of this deposit, $28,450,000 was issued in letters of credit. On December 22, 2005, the letter of credit facility was amended, reducing the available amount to $35,000,000 as of December 31, 2005, and extending the termination date to June 30, 2006. At December 31, 2005, our deposit for our letter of credit facility was zero and no letters of credit under the facility were outstanding.

In addition to our letter of credit facility, we also post cash directly with some of our counterparties. These deposits total $48,129,800 for 2005 and are included as prepaid expenses on our consolidated balance sheets.

Our interest costs on the term loans, working capital loans and interest rate swaps (including swap termination costs and amortization costs, which are included in depreciation and amortization expense on the consolidated statements of operations) totaled approximately $275,000 and $500,000 for 2005 and 2004 respectively.

Note 9—Commitments and Contingencies

Set forth below is a description of our material legal proceedings. In addition to the matters described below, we are party to legal proceedings arising in the ordinary course of business. In management's opinion, the disposition of these matters will not materially adversely affect our financial condition, results of operations, or cash flows.

We record reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss is reasonably estimable under SFAS No. 5, "Accounting for Contingencies". For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated. Please see Note 2—Accounting Policies for further discussion. Environmental reserves do not reflect management's assessment of the insurance coverage that may be applicable to the matters at issue. We cannot guarantee that the amount of any reserves will cover any cash obligations we might incur as a result of litigation or regulatory proceedings, payment of which could be material.

With respect to some of the items listed below, management has determined that a loss is not probable or that any such loss, to the extent probable, is not reasonably estimable. In some cases, management is not able to predict with any degree of certainty the range of possible loss that could be incurred. Notwithstanding these facts, management has assessed these matters based on current information and made a judgment concerning their potential outcome, giving due consideration to the nature of the claim, the amount and nature of damages sought and the probability of success. Management's judgment may, as a result of facts arising prior to resolution of these matters or other factors, prove inaccurate and investors should be aware that such judgment is made subject to the known uncertainty of litigation.

California Market Litigation. WCP or it subsidiaries are or were defendants in lawsuits alleging rate and market manipulation in California's wholesale electricity market during the California energy crisis and seeking unspecified treble damages. The cases are: *People of the State of California ex rel. Bill Lockyer, Attorney General v. Dynegy Inc., et al and Bustamante [I] v. Dynegy Inc., et al.* The *Lockyer* case was dismissed in federal district court in the first quarter of 2003 on the grounds of FERC preemption and the filed rate doctrine. The Ninth Circuit Court of Appeals affirmed the dismissal in June 2004, and a Petition for Writ of Certiorari to the U.S. Supreme Court was denied in April 2005. *Bustamante* (I) was remanded to a California state court, and in May 2005, we filed a motion to dismiss. The court granted our motion in October 2005 on grounds of federal preemption. On December 2, 2005, plaintiffs filed a notice of appeal of the dismissal order.

In addition to the lawsuits discussed above, WCP and/or the LLCs were named as defendants in seven other putative class actions and/or representative actions that were filed in state and federal court on behalf of business and residential electricity consumers against numerous power generators and marketers between April and October 2002. The complaints alleged unfair, unlawful and deceptive practices in violation of the California Unfair Business Practices Act and sought an injunction, restitution and unspecified damages. The court dismissed these actions and plaintiffs appealed. The Ninth Circuit affirmed the denial of remand and dismissal of these lawsuits in February 2005.

In December 2002, two additional actions were filed on behalf of consumers and businesses in Oregon, Washington, Utah, Nevada, Idaho, New Mexico, Arizona and Montana that purchased energy from the California market alleging violations of the Cartwright Act and unfair business practices. These cases were subsequently dismissed and re-filed in California Superior Court as one class action complaint styled *Jerry Egger v. Dynegy Inc., et al.* The cases were removed from state court and consolidated with existing actions pending before the U.S. District Court for the Northern District of California. Plaintiffs challenged the removal and the federal court stayed its ruling pending a decision by the Ninth Circuit on the *Bustamante (I)* case referenced above. Although the Ninth Circuit issued a decision remanding that case, no ruling has been made with respect to *Egger*.

In June 2004, the *City of Tacoma v. American Electric Power Service Corporation, et al.*, was filed in Oregon and Washington federal courts against several energy companies seeking more than $30 million in compensatory damages resulting from alleged manipulation of the California wholesale power markets. In February 2005, the respective federal courts granted our motion to dismiss. Shortly thereafter, the plaintiff filed a notice of appeal to the Ninth Circuit. We filed responsive briefs in November 2005. The case remains pending.

We believe that we have meritorious defenses to these claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability or estimate the range of possible loss, if any, that we might incur in connection with these lawsuits. However, given the nature of the claims, an adverse result in any of these proceedings could have a material adverse effect on our financial condition, results of operations and cash flows.

FERC and Related Regulatory Investigations—Requests for Refunds. In October 2004, the FERC approved in all respects the agreement announced by Dynegy and West Coast Power in April 2004, which provided for the settlement of FERC claims relating to western energy market transactions that occurred from January 2000 through June 2001. Market participants (other than the parties to the settlement) were permitted to opt into this settlement and share in the distribution of the settlement proceeds, and most of these other market participants have done so. The Cal ISO will determine the entitlement to refund and/or the liability of each non-settling market participant. Under the terms of the settlement, we will have no further liability to these non-settling parties. The settlement further provides that we are entitled to pursue claims for reimbursement of fuel costs against various non-settling market participants. We are currently pursuing these claims but are unable to predict the amounts that may be recovered from such parties.

The settlement does not apply to the ongoing civil litigation related to the California energy markets described above in which Dynegy and West Coast Power are defendants. The settlement also does not apply to the pending appeal by the CPUC and the California Electricity Oversight Board of the FERC's prior decision to affirm the validity of the West Coast Power-CDWR contract. We are currently awaiting a ruling on this appeal and cannot predict their outcome.

Gas Index Pricing Litigation. We are defending the following suits claiming damages resulting from the alleged manipulation of gas index publications and prices by WCP and/or the LLCs and numerous other power generators and marketers: *ABAG v. Sempra Energy et al.* (filed in state court in November 2004); *Bustamante v. Williams Energy Services et al.* (class action filed in state court in November 2002); *City and County of San Francisco v. Dynegy Inc. et al.* (filed in state court in July 2004); *County of Alameda v. Sempra Energy* (filed in state court in October 2004); *County of San Diego v. Dynegy Inc., Dynegy Marketing and Trade, West Coast Power, et al.* (filed in state court in July 2004); *County of San Mateo v. Sempra Energy et al.* (filed in state court in December 2004); *County of Santa Clara v. Dynegy Inc., Dynegy Marketing and Trade, West Coast Power, et al.* (filed in state court in July 2004); *Fairhaven Power Company v. Encana Corp. et al.* (class action filed in federal court in September 2004); *Ableman Art Glass v. EnCana Corp., et al.* (filed in federal court in December 2004); *Nurserymen's Exchange v. Sempra Energy et al.* (filed in state court in October 2004); *In re: Natural Gas Commodity Litigation* (filed in federal court in January 2004); *Older v. Dynegy Inc. et al.* (filed in federal court in September 2004); *Sacramento Municipal Utility District (SMUD) v. Reliant Energy Services, et al.* (filed in state court in November 2004); *Texas-Ohio Energy, Inc. v. CenterPoint Energy Inc., et al.* (class action filed in federal court in November 2003); *School Project for Utility Rate Reduction v. Sempra Energy, et al.* (filed in state court in November 2004); *Tamco, et al. v. Dynegy, Inc., et al.* (filed in state court in December 2004); *Ever-Bloom,* *Inc. v. AEP Energy Services, Inc., et al.* (filed in federal court in November 2004) and *Utility Savings & Refund v. Reliant Energy Services, et al.* (class action filed in federal court in November 2004). In each of these suits, the plaintiffs allege that we and other energy companies engaged in an illegal scheme to inflate natural gas prices by providing false information to gas index publications, thereby manipulating the price. All of the complaints rely heavily on the FERC and CFTC investigations into and report concerning index-reporting manipulation in the energy industry. The plaintiffs generally seek unspecified actual and punitive damages relating to costs they claim to have incurred as a result of the alleged conduct.

Pursuant to various motions filed by the parties to the litigation described above, the gas index pricing lawsuits pending in state court have been consolidated before a single judge in state court in San Diego. These cases are now entitled the "Judicial Counsel Coordinated Proceeding (JCCP) 4221, 4224, 4226, and 4228, the Natural Gas Anti-Trust Cases, I, II, III, & IV", which we refer to as the "Coordinated Gas Index Cases." In April 2005, defendants moved to dismiss the Coordinated Gas Index Cases on preemption and filed rate grounds. The Court denied defendants' motion in June 2005 and in October 2005 the defendants filed answers to the plaintiffs' complaints. The parties are presently engaged in discovery.

As to the gas index pricing lawsuits that have been filed in federal court, in *Texas-Ohio*, the defendants filed a motion to dismiss in May 2004, which the court granted in April 2005. The remaining federal court cases have been transferred to the federal judge in Nevada who presided over the *Texas-Ohio* matter. In December 2005, the Nevada federal court dismissed three additional cases (*Ableman Art Glass, Fairhaven Power* and *Utility Savings & Refund*) on similar grounds to *Texas-Ohio*, finding plaintiffs' claims barred by the filed rate doctrine.

In February 2006, we reached a settlement in *In re Natural Gas Commodity Litigation*, resolving a class action lawsuit by all persons who purchased, sold or settled NYMEX Natural Gas Contracts as an opening or closing transaction or otherwise, between June 1, 1999 and December 31, 2002 inclusive. The underlying action alleged the named defendants (including Dynegy and West Coast Power), unlawfully manipulated and aided and abetted the manipulation of the prices of natural gas futures contracts traded on the NYMEX. Pursuant to the settlement, Dynegy and West Coast Power continue to deny plaintiffs' allegations, and Dynegy agreed to pay $7 million in settlement of any and all claims for damages arising from or relating in any way to trading during the Class Period in NYMEX Natural Gas Contracts. The settlement is subject to a fairness hearing and final Court approval.

We are analyzing all of these claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability or to estimate the damages, if any, that might be incurred in connection with these lawsuits. We do not believe that any liability that we might incur as a result of this litigation would have a material adverse effect on our financial condition, results of operations or cash flows.

U.S. Attorney Investigations. The United States Attorney's office in the Northern District of California issued a Grand Jury subpoena requesting information related to our activities in the California energy markets in November 2002. We have been, and intend to continue, cooperating fully with the U.S. Attorney's office in its investigation of these matters, including production of substantial documents responsive to the subpoena and other requests for information. We cannot predict the ultimate outcome of this investigation.

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