DYNEGY HOLDINGS INC
Form 10-K
February 25, 2010

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

FORM 10-K

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

For the fiscal year ended December 31, 2009

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

For the transition period from ________ to ________

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

Entity	Commission File Number	State of Incorporation	I.R.S. Employer Identification No.
Dynegy Inc.	001-33443	Delaware	20-5653152
Dynegy Holdings Inc.	000-29311	Delaware	94-3248415

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

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

Securities registered pursuant to Section12(b) of the Act:

Title of each class	Name of each exchange on which registered
Dynegy's Class A common stock, $0.01 par value	New York Stock Exchange

Securities registered pursuant to Section12(g) of the Act:

None
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Dynegy Inc.	Yes x No ¨
Dynegy Holdings Inc.	Yes ¨ No x

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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.

Dynegy Inc.	Yes ¨ No x
Dynegy Holdings Inc	Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Dynegy Inc.	Yes x No ¨
Dynegy Holdings Inc	Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Dynegy Inc.	Yes ¨ No ¨
Dynegy Holdings Inc	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.

Dynegy Inc.	x
Dynegy Holdings Inc.	x

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

	Large accelerated filer	Accelerated filer	Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company
Dynegy Inc.	x	¨	¨	¨
Dynegy Holdings Inc.	¨	¨	x	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Dynegy Inc.	Yes ¨ No x
Dynegy Holdings Inc.	Yes ¨ No x

As of June 30, 2009, the aggregate market value of the Dynegy Inc. common stock held by non-affiliates of the registrant was $1,144,695,131 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: For Dynegy Inc., Class A common stock, $0.01 par value per share, 601,240,118 shares outstanding as of February 19, 2010; Class B common stock, $0.01 par value, zero shares outstanding as of February 19, 2010. All of Dynegy Holdings Inc.'s outstanding common stock is owned indirectly by Dynegy Inc.

This combined Form 10-K is separately filed by Dynegy Inc. and Dynegy Holdings Inc. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to a registrant other than itself.

DOCUMENTS INCORPORATED BY REFERENCE-Dynegy Inc. Part III (Items 10, 11, 12, 13 and 14) incorporates by reference portions of the Notice and Proxy Statement for the registrant's 2010 Annual Meeting of Stockholders, which the registrant intends to file not later than 120 days after December 31, 2009.

REDUCED DISCLOSURE FORMAT-Dynegy Holdings Inc. Dynegy Holdings Inc. meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and therefore is filing this Form 10-K with the reduced disclosure format.

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DYNEGY INC. and DYNEGY HOLDINGS INC.

FORM 10-K

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EXPLANATORY NOTE

This report includes the combined filing of Dynegy Inc. (“Dynegy”) and Dynegy Holdings Inc. (“DHI”). DHI is the principal subsidiary of Dynegy, providing approximately 100 percent of Dynegy’s total consolidated revenue for the year ended December 31, 2009 and constituting approximately 100 percent of Dynegy’s total consolidated asset base as of December 31, 2009.

Unless the context indicates otherwise, throughout this report, the terms “the Company”, “we”, “us”, “our” and “ours” are used refer to both Dynegy and DHI and their direct and indirect subsidiaries. Discussions or areas of this report that apply only to Dynegy or DHI are clearly noted in such discussions or areas.

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PART I

DEFINITIONS

As used in this Form 10-K, the abbreviations listed below have the following meanings:

ANPR	Advanced Notice of Proposed Rulemaking
APB	Accounting Principles Board
APIC	Additional Paid-in-Capital
ARB	Accounting Research Bulletin
ARO	Asset retirement obligation
BACT	Best Available Control Technology (air)
BART	Best Available Retrofit Technology
BTA	Best technology available (water intake)
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	The California Independent System Operator
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CAVR	The Clean Air Visibility Rule
CCB	Coal combustion byproducts
CERCLA	The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CO2	Carbon dioxide
CO2e	The climate change potential of other GHGs relative to the global warming potential of CO2
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CRM	Our former customer risk management business segment
CWA	Clean Water Act
CUSA	Chevron U.S.A. Inc.
DHI	Dynegy Holdings Inc., Dynegy's primary financing subsidiary
DMSLP	Dynegy Midstream Services L.P.
DMT	Dynegy Marketing and Trade
DNE	Dynegy Northeast Generation
EAB	The Environmental Appeals Board of the U.S. Environmental Protection Agency
EBITDA	Earnings before interest, taxes, depreciation and amortization
EITF	Emerging Issues Task Force
EPA	United States Environmental Protection Agency
ERISA	The Employee Retirement Income Security Act of 1974, as amended
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIP	Federal Implementation Plan
FSP	FASB Staff Position
FTC	U.S. Federal Trade Commission
FTR	Financial Transmission Rights
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-WE	Our power generation business—West segment
GHG	Greenhouse gas
HAPs	Hazardous air pollutants, as defined by the Clean Air Act
ICAP	Installed capacity

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ICC	Illinois Commerce Commission
IMA	In-Market Availability
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	Independent System Operator—New England
LMP	Locational Marginal Pricing
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LTIP	Long-Term Incentive Plan
MACT	Maximum Available Control Technology
MISO	Midwest Independent Transmission System Operator
MGGA	Midwest Greenhouse Gas Accord
MGGRP	Midwestern Greenhouse Reduction Program
MMBtu	Millions of British thermal units
MRTU	Market Redesign and Technology Upgrade
MW	Megawatts
MWh	Megawatt hour
NERC	North American Electric Reliability Council
NGL	Our natural gas liquids business segment
NOL	Net operating loss
NOx	Nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NYISO	New York Independent System Operator
NYDEC	New York Department of Environmental Conservation
OCI	Other Comprehensive Income
OTC	Over-the-counter
PCAOB	Public Company Accounting Oversight Board (United States)
PJM	PJM Interconnection, LLC
PPA	Power purchase agreement
PPEA	Plum Point Energy Associates
PRB	Powder River Basin coal
PSD	Prevention of Significant Deterioration
PURPA	The Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility
RCRA	The Resource Conservation and Recovery Act of 1976, as amended
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SCEA	Sandy Creek Energy Associates, LP
SCH	Sandy Creek Holdings, LLC
SEC	U.S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO2	Sulfur dioxide
SPDES	State Pollutant Discharge Elimination System
VaR	Value at Risk
VIE	Variable Interest Entity
VLGC	Very large gas carrier

WAPA	Western Area Power Administration
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council

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Item 1. Business

THE COMPANY

We are holding companies and conduct substantially all of our business operations through our subsidiaries. Our primary business is the production and sale of electric energy, capacity and ancillary services from our fleet of eighteen operating power plants in six states totaling approximately 12,300 MW of generating capacity.

Dynegy began operations in 1985. DHI is a wholly owned subsidiary of Dynegy. Dynegy became incorporated in the State of Delaware in 2007. 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 (for Dynegy) 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.

We sell electric energy, capacity and ancillary services on a wholesale basis from our power generation facilities. Energy is the actual output of electricity and is measured in MWh. The capacity of a power generation facility is its electricity production capability, measured in MW. Wholesale electricity customers will, for reliability reasons and to meet regulatory requirements, contract for rights to capacity from generating units. Ancillary services are the products of a power generation facility that support the transmission grid operation, follow real-time changes in load and provide emergency reserves for major changes to the balance of generation and load. We sell these products individually or in combination to our customers under short-, medium- and long-term contractual agreements or tariffs.

Our customers include RTOs and ISOs, integrated utilities, municipalities, electric cooperatives, transmission and distribution utilities, industrial customers, power marketers, financial participants such as banks and hedge funds, other power generators and commercial end-users. All of our products are sold on a wholesale basis for various lengths of time from hourly to multi-year transactions. Some of our customers, such as municipalities or integrated utilities, purchase our products for resale in order to serve their retail, commercial and industrial customers. Other customers, such as some power marketers, may buy from us to serve their own wholesale or retail customers or as a hedge against power sales they have made.

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Our Power Generation Portfolio

Our current operating generating facilities are as follows:

Facility	Total Net Generating Capacity (MW)(1)	Primary Fuel Type	Dispatch Type	Location	Region
Baldwin	1,800	Coal	Baseload	Baldwin, IL	MISO
Kendall	1,200	Gas	Intermediate	Minooka, IL	PJM
Ontelaunee	580	Gas	Intermediate	Ontelaunee Township, PA	PJM
Havana Units 1-5	228	Oil	Peaking	Havana, IL	MISO
Unit 6	441	Coal	Baseload	Havana, IL	MISO
Hennepin	293	Coal	Baseload	Hennepin, IL	MISO
Oglesby	63	Gas	Peaking	Oglesby, IL	MISO
Stallings	89	Gas	Peaking	Stallings, IL	MISO
Vermilion Units 1-2	164	Coal/Gas	Baseload	Oakwood, IL	MISO
Unit 3	12	Oil	Peaking	Oakwood, IL	MISO
Wood River (2)	446	Coal	Baseload	Alton, IL	MISO
Total Midwest	5,316				
Moss Landing Units 1-2	1,020	Gas	Intermediate	Monterey County, CA	CAISO
Units 6-7	1,509	Gas	Peaking	Monterey County, CA	CAISO
Morro Bay (3)	650	Gas	Peaking	Morro Bay, CA	CAISO
South Bay (4)	309	Gas	Peaking	Chula Vista, CA	CAISO
Oakland	165	Oil	Peaking	Oakland, CA	CAISO
Black Mountain (5)	43	Gas	Baseload	Las Vegas, NV	WECC
Total West	3,696				
Independence	1,064	Gas	Intermediate	Scriba, NY	NYISO
Roseton (6)	1,185	Gas/Oil	Peaking	Newburgh, NY	NYISO
Casco Bay	540	Gas	Intermediate	Veazie, ME	ISO-NE
Danskammer Units1-2	123	Gas/Oil	Peaking	Newburgh, NY	NYISO
Units 3-4 (6)	370	Coal/Gas	Baseload	Newburgh, NY	NYISO
Total Northeast	3,282				
Total Fleet Capacity	12,294				

(1) Unit capabilities are based on winter capacity.

(2) Represents Units 4 and 5 generating capacity. Units 1-3, with a combined net generating capacity of 119 MW, are currently in lay-up status and out of operation

(3) Represents Units 3 and 4 generating capacity. Units 1 and 2, with a combined net generating capacity of 352 MW, are currently in lay-up status and out of operation.

(4) Represents Units 1 and 2 and the combustion turbine generating capacity. Units 3 and 4, with a combined net generating capacity of 395 MW, were permanently retired on December 31, 2009.

(5) We own a 50 percent interest in this facility. Total output capacity of this facility is 85 MW.

(6) 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—Disclosure of Contractual Obligations and Contingent Financial Commitments—Off-Balance Sheet Arrangements—DNE Leveraged Lease.

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Our Strategy

Our business strategy seeks to create stockholder value through:

- a diverse portfolio of power generation assets;
- a diverse commercial strategy that includes buying and selling electric energy, capacity and ancillary services either short-, medium- or long-term and sales and purchases of emissions credits, fuel supplies and transportation services. In addition, our short- and medium-term strategy attempts to capture the extrinsic value inherent in our portfolio. We seek to strike a balance between contracting for short- and medium-term stability of earnings and cash flows while maintaining unhedged volumes to capitalize on expected increases in commodity prices in the longer term;
- safe, low cost plant operations, with a focus on having our plants available and “in the market” when it is economical to do so; and
- a simple, flexible capital structure to support our business and commercial operations and to position us to pursue industry consolidation opportunities.

Maintain a Diverse Portfolio to Capitalize on Market Opportunities and Mitigate Risk. We operate a portfolio of generation assets that is diversified in terms of dispatch profile, fuel type and geography. Baseload generation is generally low-cost and economically attractive to dispatch around the clock throughout the year. A baseload facility is usually expected to run in excess of 70 percent of the hours in a given year. Intermediate generation may not be as efficient and/or economical as baseload generation, but is typically intended to be dispatched 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.

Power prices have significantly declined since the summer of 2008. This decline reflects a similar decline in natural gas prices and the impact of general economic conditions, including a recessionary environment that has negatively impacted the demand for electricity. Despite these effects, we continue to believe that, over the longer term, power demand and power pricing should increase. As a result, we believe our substantial coal-fired, baseload fleet should benefit from the impact of higher power prices in the Midwest and Northeast, allowing us to capture higher margins over time. We anticipate that our combined cycle units also should benefit from increased run-times as heat rates expand, with improved margins and cash flows as demand increases in our key markets.

In addition, we believe that our portfolio of assets helps to mitigate certain risks inherent in our business. For example, weather patterns, regulatory regimes and commodity prices often differ by region and state. By maintaining geographic diversity, we lessen the impact of an individual risk in any one region and are better positioned to improve the level and consistency of our earnings and cash flows.

Employ a Flexible Commercial Strategy to Maintain Long-Term Market Upside Potential While Protecting Against Downside Risks. We expect to see tightening reserve margins through time in the regions in which our assets are located. As these reserve margins tighten, we expect to see our generating assets increase in value through improved cash flows and earnings as capacity utilization and power prices improve. Given current market pricing and conditions, we see limited long-term attractive commercial arrangements.

We plan to continue to volumetrically hedge the expected output from our facilities over a rolling 1-3 year time frame with the goal of achieving an efficient balance of risk and reward. Keeping the portfolio completely open and selling in the day-ahead market, for instance, would force us to take weather and general economic-related risks, as well as price risk of correlated commodities. These risks can cause significant swings in financial performance in any one year and are not consistent with our efforts to improve predictability of short- and medium-term earnings and cash flows.

Our commercial strategy seeks to balance the goal of protecting cash flow in the short- and medium-term with maintaining the ability to capture value longer term as markets tighten. In order to maximize the value of our assets, we seek to capture intrinsic and extrinsic value. Opportunities to capture extrinsic value - that is, value beyond that ascribed to our generating capacity based solely on a current price strip - arise from time to time in the form of price volatility, differences in counterparties' views of forward prices and other activities. In order to execute our strategy, we utilize a wide range of products and contracts such as power purchase agreements, fuel supply contracts, capacity auctions, bilateral capacity contracts, power and natural gas swap agreements, power, heat rate and natural gas options and other financial instruments.

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We also seek to balance predictability of earnings and cash flow with achieving the highest level of earnings and cash flow. Short-term market volatility can negatively impact our profitability; we will seek to reduce those negative impacts through the disciplined use of short- and medium-term forward economic hedging instruments. Through the use of forward economic hedging instruments, including various products and contracts such as options and swaps, we seek to capture the extrinsic value inherent in our portfolio. Due to a number of variables – including changes in correlations between gas and power, time decay, changes in commodity prices, volatility and liquidity – we intend to actively and continuously balance our asset and hedge portfolios.

We expect to engage in less economic hedging activity beyond a three-year time frame in order to realize the anticipated benefit of improved market prices over time as the supply and demand balance tightens.

We set specific limits for “gross margin at risk” for our assets and economic hedges. These limits require power hedging above minimum levels, while requiring that corresponding fuel supplies are appropriately hedged as we progress through time. We also specifically attempt to manage basis risk to hubs that are not the natural sales hub for a facility and maintain focus on optimizing the commercial factors that we can control and mitigating commodity risk where appropriate and possible.

Operate Our Assets Safely and Cost-Efficiently to Maximize Revenue Opportunities and Operating Margins. We have a history of strong plant operations and are committed to operating our facilities in a safe, reliable, low-cost and environmentally compliant manner. By maintaining and operating our assets in an effort to ensure plant availability, high dispatch and capacity factors and an increased focus on operating and capital costs, we believe we are positioned to capture opportunities in the marketplace effectively and to maximize our operating margins.

Our power generation facilities are managed to require a relatively predictable level of maintenance capital expenditures without compromising operational integrity. Our capital expenditures are applied to the maintenance of our facilities to ensure their continued reliability and to investment in new equipment for either environmental compliance or increasing profitability. We seek to operate and maintain our generation fleet efficiently and safely, with an eye toward increased reliability and environmental stewardship. This increased reliability impacts our results to the extent that our generation units are available during times that it is economically sound to run. For units that are subject to contracts for capacity, our ability to secure availability payments from customers is dependent on plant availability.

Maintain a Simple, Flexible Capital Structure that is Integrated with our Operating Strategy. We believe that the power industry is a commodity cyclical business with significant commodity price volatility and considerable capital investment requirements. Thus, maximizing economic returns in this market environment requires a capital structure that can withstand fuel and power price volatility as well as a commercial strategy that seeks to capture the value associated with both medium- and long-term price trends. We seek to maintain a capital structure, including debt amounts and maturities, debt covenants and overall liquidity, that is suitable for our commercial strategy and the commodity cyclical market in which we operate.

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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 our resources, as three separate segments in our consolidated financial statements: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. The results of our legacy operations, including CRM, are included in Other. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest. Please read Note 24—Segment Information for further information regarding the financial results of our business segments.

NERC Regions, RTOs and ISOs. In discussing our business, we often refer to NERC regions. The NERC and its eight regional reliability councils (as of December 31, 2009) 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. For example, each NERC region establishes a minimum operating reserve requirement to ensure there is sufficient generating capacity to meet expected demand within its region. Each NERC region reports seasonally and annually on the status of generation and transmission in each region.

Separately, RTOs and ISOs administer the transmission infrastructure and markets across a regional footprint in most of the markets in which we operate. They are responsible for dispatching all generation facilities in their respective footprints and are responsible for both maximum utilization and reliable and efficient operation of the transmission system. RTOs and ISOs administer energy and ancillary service markets in the short-term, usually day ahead and real-time markets. Several RTOs and ISOs also ensure long-term planning reserves through monthly, semi-annual, annual and multi-year capacity markets. The RTOs and ISOs that oversee most of the wholesale power markets currently impose, and will likely continue to impose, both bid and price limits. They may also enforce caps and other mechanisms to guard against the exercise of market dominance in these markets. NERC regions and RTOs/ISOs often have different geographic footprints, and while there may be geographic overlap between NERC regions and RTOs/ISOs, their respective roles and responsibilities do not generally overlap.

In RTO and ISO regions with centrally dispatched market structures, all generators selling into the centralized market receive the same price for energy sold based on the bid price associated with the production of the last MWh that is needed to balance supply with demand within a designated zone or at a given location (different zones or locations within the same RTO/ISO may produce different prices respective to other zones within the same RTO/ISO due to losses and congestion). For example, a less-efficient and/or less economical natural gas-fired unit may be needed in some hours to meet demand. If this unit's production is required to meet demand on the margin, its bid price will set the market clearing price that will be paid for all dispatched generation (although the price paid at other zones or locations may vary because of congestion and losses), regardless of the price that any other unit may have offered into the market. In RTO and ISO regions with centrally dispatched market structures and location-based marginal pricing clearing structures (e.g. PJM, NYISO, and ISO-NE), generators will receive the location-based marginal price for their output. The location-based marginal price, absent congestion, would be the marginal price of the most expensive unit needed to meet demand. In regions that are outside the footprint of RTOs/ISOs, prices are determined on a bilateral basis between buyers and sellers.

Market-Based Rates. Our ability to charge market-based rates for wholesale sales of electricity, as opposed to cost-based rates, is governed by FERC. We have been granted market-based rate authority for wholesale power sales from our EWG facilities, as well as wholesale power sales by our power marketing entities, Dynegy Power Marketing Inc. and Dynegy Marketing and Trade LLC. The Dynegy EWG facilities include all of our facilities except our investments in Nevada Cogeneration Associates #2 ("Black Mountain"), Allegheny Hydro No. 8 Ltd. and Allegheny Hydro No. 9, Ltd. These facilities are known as QFs, and have various exemptions from federal regulation and sell electricity directly to purchasers under negotiated and previously approved power purchase agreements.

Our market-based rate authority is predicated on a finding by FERC that our entities with market-based rates do not have market power, and a market power analysis is generally conducted once every three years for each region on a rolling basis (known as the triennial market power review). The triennial market power review for our MISO facilities was filed with the FERC in June 2009. The triennial market power review for our GEN-NE and PJM facilities was filed at FERC in August 2008. FERC issued an order accepting this filing in December 2008. The triennial market power reviews for our GEN-WE facilities will be filed pursuant to a FERC established schedule.

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Power Generation—Midwest Segment

GEN-MW is comprised of eight facilities in Illinois and one in Pennsylvania with a total generating capacity of 5,316 MW. As of December 31, 2009, GEN-MW operated entirely within either the MISO or the PJM.

RTO/ISO Discussion

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. As of December 31, 2009, we owned seven power generating facilities that sell into the MISO market and are located in Illinois, with an aggregate net generating capacity of 3,536 MW within MISO.

The MISO market is designed to ensure that every electric industry participant has access to the grid and that no entity has the ability to deny access to a competitor. MISO also manages the use of transmission lines to make sure that they do not become overloaded. MISO operates physical and financial energy markets using a system known as LMP, which calculates a price for every generator and load point within MISO. 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. MISO does not administer a centralized capacity market.

FTRs allow users to manage the cost of transmission congestion (as measured by LMP differentials, between source and sink points on the transmission grid) and corresponding price differentials across the market area. MISO implemented the Ancillary Services Market (Regulation and Operating Reserves) on January 6, 2009 and implemented an enforceable Planning Reserve Margin for each planning year effective June 1, 2009. A feature of the Ancillary Services Market is the addition of scarcity pricing that, during supply shortages, can raise the combined price of energy and ancillary services significantly higher than the previous cap of $1,000/MWh. An independent market monitor is responsible for ensuring that MISO markets are operating competitively and without exercise of market power.

PJM. The PJM market includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. As of December 31, 2009, we owned two generating facilities that sell into the PJM market and are located in Illinois and Pennsylvania with an aggregate net generating capacity of 1,780 MW.

PJM 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 any exercise of market power or improper behavior by any entity. PJM implemented a forward capacity auction, the RPM, which established long-term markets for capacity in 2007. In addition to entering into bilateral capacity transactions, we have participated in RPM base residual auctions through PJM's planning year 2012-2013, which ends May 31, 2013, as well as ongoing incremental auctions to balance positions and offer residual capacity that may become available.

PJM, like MISO, dispatches power plants to meet system energy and reliability needs, and settles physical power deliveries at LMPs. This value is determined by an ISO-administered auction process, which evaluates and selects the least costly supplier offers or bids to create reliable and least-cost dispatch. The ISO-sponsored LMP energy markets consist of two separate and characteristically distinct settlement time frames. The first is a security-constrained, financially firm, day-ahead unit commitment market. The second is a security-constrained, financially settled, real-time dispatch and balancing market. Prices paid in these LMP energy markets, however, are affected by, among other things, (i) market mitigation measures, which can result in lower prices associated with certain generating units that are mitigated because they are deemed to have the potential to exercise locational market power, and (ii) existing $1,000/MWh energy market price caps that are in place.

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Contracted Capacity and Energy

MISO. Power prices in MISO are a significant driver of our overall financial performance due to the fact that a significant portion of our total power generating capacity is located in MISO and is attributable to coal-fired baseload units. We commercialize these assets through a combination of bilateral physical and financial power, fuel and capacity contracts.

PJM. Our generation assets in PJM are natural gas-fired combined cycle intermediate dispatch facilities. We commercialize these assets through a combination of bilateral power, fuel and capacity contracts. We commercialize our capacity through either the RPM auction or on a bilateral basis. Additionally, as of December 31, 2009, approximately 280 MW of capacity at our Kendall facility was contracted under a tolling agreement through 2017. In January 2010, we executed an agreement to terminate the tolling arrangement.

Regulatory Considerations

In July 2007, legislative leaders in the State of Illinois announced a comprehensive transitional rate relief package that significantly altered the power procurement process and provided rate relief for electric consumers. The rate relief program provided approximately $1 billion to help provide assistance to utility customers in Illinois and fund the power procurement agency. As part of this rate relief package, we made payments totaling $25 million over a 29-month period with the final payment made in 2009.

MISO. Actual reserve margins are substantially above MISO's current required reserve margin of 15.4 percent and are increasing year over year, largely due to increased wind generation capacity and decreased demand. The reserve margin based on available capacity was 43.8 percent during the 2009 summer season as compared to 32 percent during the 2008 summer season.

PJM. Actual reserve margins are somewhat above PJM's current required installed reserve margin of 15 percent and are decreasing year over year. The reserve margin based on deliverable capacity was 19.67 percent for Planning Year 2009/10 as compared to 21.03 percent for Planning Year 2008/09. PJM's required installed reserve margin is increasing year over year, and will increase to 15.5 percent for Planning Year 2010/11.

Construction Project

Plum Point. We own an approximate 37 percent interest in PPEA Holding Company LLC ("PPEA Holding"), which, through its wholly owned subsidiary, PPEA, owns an approximate 57 percent undivided interest in the Plum Point Energy Station (the "Plum Point Project"), a 665 MW coal-fired power generation facility under construction in Mississippi County, Arkansas. The Plum Point Project is currently expected to commence commercial operations in August 2010. All of PPEA's 378 MW have been contracted for an initial 30-year period. The PPAs provide for a pass-through of commodity, fuel, transportation and emissions expenses. We consider our interest in PPEA Holding a non-core asset and intend to pursue alternatives regarding our remaining ownership interest.

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Power Generation—West Segment

GEN-WE is comprised of four natural gas-fired power generation facilities located in California (3) and Nevada (1) and one fuel oil-fired power generation facility located in California, totaling 3,696 MW of electric generating capacity.

RTO/ISO Discussion

CAISO. CAISO covers approximately 90 percent of the State of California. At December 31, 2009, we owned four generating facilities in California within CAISO. The South Bay and Oakland facilities are designated as RMR units by the CAISO.

Contracted Capacity and Energy

CAISO. In CAISO, where our assets include intermediate dispatch and peaking facilities, we seek to mitigate spark spread variability through RMR, tolling arrangements and physical and financial bilateral power and fuel contracts. All of the capacity of our Moss Landing Units 6 and 7 and Morro Bay facility are contracted under tolling arrangements through 2013. Our Oakland and South Bay facilities operate under RMR contracts.

Regulatory Considerations

CAISO. CAISO launched its new market design, MRTU, in April 2009. MRTU provides more effective and transparent congestion management and a day-ahead market that co-optimizes energy and reserve procurement.

On the state level, there are numerous other ongoing market initiatives that impact wholesale generation, principally the development of resource adequacy rules and capacity markets.

The CPUC requires a Resources Adequacy margin of 15 to 17 percent. The actual reserve margin generally moves within, or close to, this range but seasonal and regional fluctuations exist.

Equity Investment

Black Mountain. We have a 50 percent indirect ownership interest in the Black Mountain facility, which 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 that runs to 2023.

Power Generation—Northeast Segment

GEN-NE is comprised of four facilities located in New York (3) and Maine (1), with a total capacity of 3,282 MW. We own and operate the Independence, Casco Bay and Danskammer Units 1 and 2 power generating facilities, and we operate the Roseton and Danskammer Units 3 and 4 facilities 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.

RTO/ISO Discussion

The market in which GEN-NE resides is characterized by two interconnected and actively traded competitive markets: the NYISO (an ISO) and the ISO-NE (an RTO). In the GEN-NE markets, load-serving entities generally lack their own generation capacity, with much of the generation base aging and the current ownership of the generation spread among several unaffiliated operators. Thus, commodity prices are more volatile on an as-delivered basis than in other regions due to the distance and occasional physical constraints that impact the delivery of fuel into the region.

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Although both RTOs/ISOs and their respective energy markets are functionally, administratively and operationally independent, they follow, to a certain extent, similar market designs. Both the NYISO and the ISO-NE dispatch power plants to meet system energy and reliability needs and settle physical power deliveries at LMPs as discussed above. The energy markets in both the NYISO and ISO-NE also have defined, but different, mitigation protocols for bidding.

In addition to energy delivery, the NYISO and ISO-NE administer markets for installed capacity, ancillary services and FTRs.

NYISO. The NYISO market includes virtually the entire state of New York. At December 31, 2009, we operated three facilities within NYISO with an aggregate net generating capacity of 2,742 MW.

Capacity pricing is calculated as a function of NYISO's annual required reserve margin, the estimated net cost of "new entrant" generation, estimated peak demand and the actual amount of capacity bid into the market at or below the demand curve. 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 required minimum levels. The intent of the demand curve mechanism is to ensure that existing generation has enough revenue to recover their investment 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 general sector in which it is needed most when that new capacity is needed. To calculate the price and quantity of installed capacity, three ICAP demand curves are utilized: one for Long Island, one for New York City and one for Statewide (commonly referred to as Rest of State). Our facilities operate in the Rest of State market.

Due to transmission constraints, energy prices vary across New York and are generally higher in the Southeastern part of New York, where our Roseton and Danskammer facilities are located, and in New York City and Long Island. Our Independence facility is located in the Northwest part of the state.

ISO-NE. The ISO-NE market includes the six New England states of Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island and Maine. As of December 31, 2009, we owned and operated one power generating facility (Casco Bay) within the ISO-NE, with an aggregate net generating capacity of 540 MW. ISO-NE is in the process of implementing a FCM as described in more detail below.

Contracted Capacity and Energy

NYISO. We commercialize these assets through a combination of bilateral physical and financial power, fuel and capacity contracts.

At our Independence facility, 740 MW of capacity is contracted under a capacity sales agreement that runs through 2014. Revenue from this capacity obligation is largely fixed with a variable discount that varies each month based on the LMP at Pleasant Valley. Additionally, we supply steam and up to 44 MW of electric energy from our Independence facility to a third party at a fixed price.

For the uncommitted portion of our NYISO 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 remaining capacity into the market. This provides relatively stable capacity revenues at market prices from our facilities in the short-term and is expected to for the foreseeable future.

ISO-NE. Three forward capacity auctions have been held to date with capacity clearing prices ranging from $4.50 kW/month for the 2010/2011 market period to $2.95 kW/month for the 2012/2013 market period. These capacity clearing prices represent the floor price and the actual rate paid to market participants that were affected by pro-rationing due to oversupply conditions. The delivery of capacity under the forward capacity market will be fully effective on June 1, 2010.

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Regulatory Considerations

NYISO. The actual amount of installed capacity is somewhat above NYISO's current required margin of 16.5 percent. FERC recently accepted a proposed increase in the required reserve margin to 18 percent in the New York Control Area, which is effective for the period of May 2010 through April 2011. This increase will require load-serving entities to procure more capacity relative to the load forecast; however, due to lower demand related to, among other things, weakness in the overall economy, the increase will likely result in little or no change in the capacity market.

ISO-NE. The ISO-NE is in the process of restructuring its capacity market and will be transitioning from a fixed payment structure to a forward capacity structure where capacity prices are determined through auctions. The delivery of capacity under the forward capacity market will be fully effective June 1, 2010. Discussions to address improvements with the forward capacity market design are currently underway by the ISO and its stakeholders.

The actual amount of installed capacity is significantly above the ISO-NE's current installed Capacity Requirement of 9.9%. ISO-NE, similar to other periods, has proposed an installed Capacity Requirement of 9.7% for the period of June 2010 through May 2011, which was accepted by FERC in February 2009. Generator additions, combined with increased demand response participation in the capacity market and weakness in the overall economy, will exert downward pressure on the capacity market.

Other

Corporate governance roles and functions, which are managed on a consolidated basis, and specialized support functions such as finance, accounting, commercial, risk control, tax, legal, regulatory, human resources, administration and information technology, are included in Other in our segment reporting. Corporate general and administrative expenses, income taxes and interest expenses are also included, as are corporate-related other income and expense items. Results for our legacy CRM operations, which primarily consist of a minimal number of power and natural gas trading positions, are also included in Other.

ENVIRONMENTAL MATTERS

Our business is subject to extensive federal, state and local laws and regulations governing discharge of materials into the environment. We are committed to operating within these regulations and to conducting our business in an environmentally responsible manner. The environmental, legal and regulatory landscape is subject to change and has become more stringent over time. The process for acquiring or maintaining permits or otherwise complying with applicable rules and regulations may create unprofitable or unfavorable operating conditions or require significant capital and operating expenditures. Any failure to acquire or maintain permits or to otherwise comply with applicable rules and regulations may result in fines and penalties or negatively impact our ability to advance projects in a timely manner, if at all. Further, changed interpretations of existing regulations may subject historical maintenance, repair and replacement activities at our facilities to claims of noncompliance.

Our aggregate expenditures (both capital and operating) for compliance with laws and regulations related to the protection of the environment were approximately $320 million in 2009 compared to approximately $245 million in 2008 and approximately $108 million in 2007. The 2009 expenditures include approximately $260 million for projects related to our Midwest Consent Decree (which is discussed below) compared to $215 million for Midwest Consent Decree projects in 2008. We estimate that total environmental expenditures in 2010 will be approximately $235 million, including approximately $200 million in capital expenditures and approximately $35 million in operating expenditures. Changes in environmental regulations or outcomes of litigation and administrative proceedings could result in additional requirements that would necessitate increased future spending and could create adverse operating conditions. Please read Note 21—Commitments and Contingencies for further discussion of this matter.

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Climate Change

For the last several years, there has been a robust public debate about climate change and the potential for regulations requiring lower emissions of GHG, primarily CO2 and methane. We believe that the focus of any federal program attempting to address climate change should include three critical, interrelated elements: (i) the environment, (ii) the economy and (iii) energy security.

We cannot confidently predict the final outcome of the current debate on climate change nor can we predict with confidence the ultimate requirements of proposed or anticipated federal and state legislation and regulations intended to address climate change. These activities, and the highly politicized nature of climate change, suggest a trend toward increased regulation of CO2 that could result in a material adverse effect on our financial condition, results of operations and cash flows. Existing and anticipated federal and state regulations intended to address climate change may significantly increase the cost of providing electric power, resulting in far-reaching and significant impacts on us and others in the power generation industry over time. It is possible that federal and state actions intended to address climate change could result in costs assigned to GHG emissions that we would not be able to fully recover through market pricing or otherwise. If capital and/or operating costs related to compliance with regulations intended to address climate change become great enough to render the operations of certain plants uneconomical, we could, at our option and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate such plants and forego such capital and/or operating costs.

Power generating facilities are a major source of GHG emissions – in 2009, our facilities in GEN-MW, GEN-WE and GEN-NE emitted approximately 22.1 million, 3.7 million and 5.8 million tons of CO2, respectively. The amounts of CO2 emitted from our facilities during any time period will depend upon their dispatch rates during the period.

Though we consider our largest risk related to climate change to be legislative and regulatory changes intended to slow or prevent it, we are subject to physical risks inherent in industrial operations including severe weather events such as hurricanes and tornadoes. To the extent that changes in climate effect changes in weather patterns (such as more severe weather events) or changes in sea level where we have generating facilities, we could be adversely affected. To the extent that climate change results in changes in sea level, we would expect such effects to be gradual and amenable to structural mitigation during the useful life of the facilities. However, if this is not the case it is possible that we would be impacted in an adverse way, potentially materially so. We could experience both risks and opportunities as a result of related physical impacts. For example, more extreme weather patterns – namely, a warmer summer or a cooler winter – could increase demand for our products. However, we also could experience more difficult operating conditions in that type of environment. We maintain various types of insurance in amounts we consider appropriate for risks associated with weather events.

Federal Legislation Regarding Greenhouse Gases. Several bills have been introduced in Congress since 2003 that if passed would compel reductions in CO2 emissions from power plants, but only recently has a proposed bill received majority support in the U.S. House of Representatives or U.S. Senate. In June 2009, the House of Representatives passed the American Clean Energy and Security Act of 2009 (“H.R. 2454”). Title III of H.R. 2454 would add a new Title VII to the CAA creating a Global Warming Pollution Reduction Program. H.R. 2454 would also create a national cap-and-trade program aimed at reducing CO2 emissions to three percent below 2005 levels by 2012, 17 percent below 2005 levels by 2020, 42 percent below 2005 levels by 2030 and 83 percent below 2005 levels by 2050.

Several bills have been introduced in the Senate; one bill similar to H.R. 2454, S. 1733, has been passed by the Senate Environment and Public Works Committee.

Federal Regulation of Greenhouse Gases. Recent court decisions and interpretations of the CAA by the EPA have added complexity to the national debate over the appropriate regulatory mechanisms for controlling and reducing CO2 emissions. In April 2007, the U.S. Supreme Court issued its decision in Massachusetts v. EPA, a case involving the regulation of GHG emissions from new motor vehicles. The Court ruled that GHGs meet the definition of a pollutant under the CAA and that regulation of GHG emissions is authorized by the CAA. The Court ruled that the EPA had a duty to determine whether or not GHG emissions from motor vehicles might reasonably be anticipated to endanger public health or welfare within the meaning of the CAA. In July 2008, the EPA issued an ANPR on Regulating Greenhouse Gas Emissions Under the Clean Air Act. The ANPR sought comment on a wide range of issues related to regulation of GHG under the present CAA. The then Administrator of the EPA expressed his opinion in the ANPR that the CAA was “ill-suited for the task of regulating” GHG.

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With the change in administration following the 2008 Presidential election, many policies and interpretations of environmental laws and regulations by the former administration are being reevaluated. In response to the ruling in Massachusetts v. EPA, the new Administrator of the EPA issued a proposed finding in April 2009 that GHG emissions from motor vehicles cause or contribute to air pollution that endangers the public health and welfare. After a comment period, the new Administrator of the EPA issued a final endangerment finding under Section 202(a) of the CAA in December 2009. The decision found that six GHGs in the atmosphere may reasonably be anticipated to endanger public health and welfare. Subsequently, petitions for administrative reconsideration of EPA's endangerment finding were filed, and sixteen petitions for review of the final EPA action have been filed in the U.S. Court of Appeals for the District of Columbia by organizations representing industry, an organization representing nine members of Congress, and by the states of Alabama, Texas and Virginia.

In anticipation of its final endangerment finding, the EPA issued several proposed rules concerning GHGs in September 2009:

- The EPA and the U.S. Department of Transportation proposed a joint rule that would regulate GHG emissions from passenger cars and light trucks under Section 202(a) of the CAA. While this proposed rule will not directly affect us, if it becomes final it may render GHGs, including CO2, "subject to regulation" under the CAA, potentially triggering the requirements of the PSD program including the requirement to implement BACT for control of CO2 for new and modified stationary sources such as power plants.

- The EPA released its final rule requiring mandatory reporting of GHG emissions from all sectors of the economy. This rule requires that certain sources, including our power generating facilities, monitor and report GHG emissions. The rule went into effect in January 2010 and requires that reports of GHG emissions be filed annually thereafter. We have implemented new processes and procedures to report these emissions as required and intend to comply with this rule.

- The EPA proposed to "phase in" new GHG emissions applicability thresholds for its PSD permit program and for the operating permit program under Title V of the CAA. The proposed rule would establish a temporary GHG applicability threshold for these programs at 25,000 tons per year of CO2e for new sources, and a temporary GHG significance level under the PSD Permit Program between 10,000 and 25,000 tons per year CO2e for modifications to major sources. Public debate is ongoing as to the EPA's legal authority to adopt this rule, making legal challenges to the rule likely. We cannot predict with confidence the outcome of this rulemaking process or a specific impact on our generating portfolio.

State Regulation of Greenhouse Gases. Many states where we operate generation facilities have, are considering, or are in some stage of implementing, regulatory programs intended to reduce emissions of GHGs from stationary sources as a means of addressing climate change. Beginning in 2009, our generating facilities in New York and Maine were required to purchase CO2 allowances, from the states where they operate, in sufficient quantities to cover CO2 emissions. Please see "Northeast" below for further information. Beginning in 2012, our generating facilities in California are also expected to be required to purchase CO2 allowances in sufficient quantities to cover CO2 emissions. Please see "West" below for further information.

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Midwest. Our assets in Illinois may become subject to a regional GHG cap and trade program being developed under the MGGA. The MGGA is an agreement among six states and the Province of Manitoba to create the MGGRP to establish GHG reduction targets and timeframes consistent with member states' targets and to develop a market-based and multi-sector cap and trade mechanism to achieve the GHG reduction targets. Illinois has set a goal of reducing GHG emissions to 1990 levels by the year 2020, and to 60 percent below 1990 levels by 2050.

The MGGRP is, however, still in an early stage of development and specific targets for GHG emission reductions and regulations to achieve such targets have not yet been agreed to by the members.

West. We currently expect that our assets in California will be subject to the California Global Warming Solutions Act ("AB 32"), which became effective in January 2007. AB 32 requires the CARB to develop a GHG emission control program that will reduce emissions of GHG in the state to their 1990 levels by 2020. Final regulations necessary to meet the 2020 GHG emissions cap are required by January 2011, and a fully effective regulatory program must be in place by January 2012. The CARB released preliminary draft regulations to meet the AB 32 mandate through a cap and trade program in November 2009. Initially, the program is expected to apply to large stationary sources including power generation facilities. GHG emission allowances are expected to be sold at auctions beginning in the fall of 2011. The details of the auction and other compliance rules will be outlined in draft rules expected to be released in Spring 2010.

The State of California is a party to a regional GHG cap and trade program being developed under the WCI to reduce GHG emissions in the participating states. The WCI is a collaborative effort among seven states and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. California's implementation of AB 32 is expected to constitute the state's contribution to the WCI and to form the model for other participating jurisdictions.

Northeast. On January 1, 2009, our assets in New York and Maine became subject to a state-driven GHG emission control program known as RGGI. RGGI was developed and implemented by ten New England and Mid-Atlantic states to reduce CO2 emissions from power plants. The participating RGGI states implemented rules regulating GHG emissions using a cap-and-trade program to reduce CO2 emissions by at least 10 percent of 2009 emission levels by the year 2018. Compliance with the allowance requirement under the RGGI cap-and-trade program can be achieved by reducing emissions, purchasing or trading allowances, or securing offset allowances from an approved offset project. While allowances are sold by year, actual compliance is measured across a three year control period. The first control period is for the 2009-2011 timeframe.

In December 2009, RGGI held its sixth auction, in which approximately 28 million allowances for allocation year 2009, and 1.5 million allowances for allocation year 2012, were sold at clearing prices of $2.05 and $1.86 per allowance, respectively. We have participated in each of the quarterly RGGI auctions (or in secondary markets, as appropriate) to secure some allowances for our affected assets. We expect that the increased operating costs resulting from purchase of CO2 allowances will be at least partially reflected in market prices. The RGGI states plan to continue to conduct quarterly auctions in 2010 and 2011.

Our generating facilities in New York and Maine emitted approximately 5.8 million tons of CO2 during 2009, this includes our Bridgeport facility which was sold in the LS Power Transactions. Based on the average clearing price of $2.91 for 2009 allowances sold in all auctions held to date, we estimate our cost of allowances required to operate these facilities during 2009 would be approximately $16.9 million. The RGGI compliance period is three years, so the actual cost of allowances required for our 2009 operations may vary from this estimate as a result of purchases and/or sales of allowances between now and 2012, which may result in a lower or higher average allowance cost.

Climate Change Litigation. There is a risk of litigation from those seeking injunctive relief from or to impose liability on sources of GHG emissions, including power generators, for claims of adverse effects due to climate change. Recent court decisions disagree on whether the claims are subject to resolution by the courts and whether the plaintiffs have standing to sue.

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In September 2009, the U.S. Court of Appeals for the 2nd Circuit held that the U.S. District Court is an appropriate forum for resolving claims by eight states and New York City against six electric power generators related to climate change. Similarly, in October 2009, the U.S. Court of Appeals for the 5th Circuit held that claims related to climate change by property owners along the Mississippi Gulf Coast against energy companies could be resolved by the courts. However, in September 2009, the U.S. District Court for the Northern District of California dismissed claims related to climate change by an Alaskan community against 24 companies in the energy industry, including us, in Native Village of Kivalina and City of Kivalina v. ExxonMobil Corporation, et al. Please read Note 21—Commitments and Contingencies for further discussion of this case.

The conflict in recent court decisions illustrates the unsettled law related to claims based on the effects of climate change. Nevertheless, the decisions affirming the jurisdiction of the courts and the standing of the plaintiffs to bring these claims could result in an increase in similar lawsuits and associated expenditures by companies like ours.

Carbon Initiatives. We participate in several programs that partially offset or mitigate our GHG emissions. In the lower Mississippi River Valley, we have partnered with the U.S. Fish & Wildlife Service to restore more than 45,000 acres of hardwood forests by planting more than 2 million bottomland hardwood seedlings. In California, we are evaluating the use of bio-fuels as a means of reducing reliance on traditional fuels. In Illinois, we are funding prairie, bottomland hardwood and savannah restoration projects in partnership with the Illinois Conservation Foundation. We also have programs to reuse CCB produced at our coal-fired generation units through agreements with cement manufacturers that incorporate the material into cement products, helping to reduce CO2 emissions from the cement manufacturing process.

Our Moss Landing facility in California is involved in a pilot project with Calera Corporation that treats flue gas emissions from the facility in a process that produces materials similar to Portland cement and aggregate. The Calera carbonate mineralization process binds CO2 with minerals in brines or seawater in a manner that has the potential to permanently sequester the CO2 in the solid materials it produces. If this process can be developed on a commercial scale, it would provide a means of capturing CO2 and creating beneficial, marketable products for the building materials industry.

Through membership in organizations such as the Electric Power Research Institute, we participate in research aimed at reducing or mitigating emissions of GHG from electric power generation.

Other Environmental Matters

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 percent each in emissions of SO2 and NOx by 2015 and mercury by 2018 from coal-fired power generation units.

CAIR, which is intended to reduce SO2 and NOx emissions from power generation sources across the eastern United States (29 states and the District of Columbia) and to address fine particulate matter and ground-level ozone National Ambient Air Quality Standards, was issued as a final rule in April 2006. CAIR was challenged and the U.S. Court of Appeals for the District of Columbia has remanded the rule to the EPA to correct several aspects of the rule determined by the Court to be unacceptable. The rule remains effective until the EPA completes its rulemaking to replace CAIR. Our facilities in Illinois and New York are subject to state SO2 and NOx limitations more stringent than those imposed by the currently effective CAIR. The EPA is expected to propose a new CAIR rule in the spring of 2010 and it is possible that this new rule will require greater emissions reductions, and therefore increased environmental expenditures, from power generating facilities like ours.

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CAVR requires states to analyze and include BART requirements for individual facilities in their SIPs to address regional haze. 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 State of New York has initiated rulemaking to establish BART limits that may result in more stringent emission control requirements, and significant expenditures for environmental control equipment, for our Danskammer facility.

In March 2005, the EPA issued the CAMR for control of mercury emissions from coal-fired power plants and established a cap and trade program requiring states to promulgate rules at least as stringent as CAMR. In December 2006, the Illinois Pollution Control Board approved a state rule for the control of mercury emissions from coal-fired power plants that required 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 will likely require us to incur additional capital and operating costs. In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CAMR; however, the Illinois and New York mercury regulations remain in effect. In December 2009, the EPA issued information requests under Section 114 of the CAA to many coal and oil fired steam electric generating companies, including certain of our operating companies. These requests require stack tests to develop information on emissions of mercury and other HAPs and will be used by the EPA to develop emission standards for HAPs under Section 112 of the CAA.

The Clean Air Act

The CAA 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 CAA requires that fossil-fueled plants have sufficient emission allowances to cover actual SO2 emissions and in some regions NOX emissions, and that they meet certain pollutant emission standards as well. Our 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 CAA and related rules and regulations, including ozone-related requirements, we have plans to install emission reduction technology. When our plans are complete, our four coal-fired units at our Baldwin and Havana facilities will have dry flue gas desulphurization systems for the control of SO2 emissions, and electrostatic precipitators and baghouses for the control of particulate emissions. Selective catalytic reduction technology for the control of NOX emissions has been installed and operated on three of these units for several years; GEN-MW's remaining units use low-NOX burners and overfire air to lower NOX emissions. Our coal-fired units at our Vermillion and Hennepin facilities have electrostatic precipitators and baghouses for the control of particulate matter. We anticipate that we will have activated carbon injection technology for the control of mercury emissions installed and operating on 95 percent of GEN-MW's coal-fired capacity by mid-2010 and the final unit by 2013.

Midwest Consent Decree. In 2005, we settled a lawsuit filed by the EPA and the U.S. Department of Justice that alleged violations of the CAA and related federal and Illinois regulations concerning certain maintenance, repair and replacement activities at our Baldwin generating facility. A consent decree was finalized in July 2005 that would prohibit operation of certain of our power generating facilities after certain dates unless specified emission control equipment is installed (the "Midwest Consent Decree"). We have achieved all emission reductions to date under the Midwest Consent Decree and are in the process of installing additional emission control equipment to meet future Midwest Consent Decree emission limits. We anticipate our costs associated with the Midwest Consent Decree projects, which we expect to incur through 2013, will be approximately $960 million, which includes approximately $545 million spent to date. This estimate required a number of assumptions about uncertainties that are beyond our control, including an assumption that labor and material costs will increase at four percent per year over the remaining project term. The following are the future estimated capital expenditures required to comply with the Midwest Consent Decree:

2010	2011	2012	2013
	(in millions)		
$ 185	$ 140	$ 75	$ 15

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If the costs of these capital expenditures become great enough to render operation of the affected facility or facilities uneconomical, we could at our option, cease to operate the facility or facilities and forego these expenditures without any further obligations under the Midwest Consent Decree.

Information Request under Section 114 of the Clean Air Act. In March 2009, we received an information request from the EPA regarding maintenance, repair and replacement projects undertaken between January 2000 and the present at the Danskammer facility. We submitted responses to the information request in April and July 2009 and are continuing to cooperate with the EPA to provide additional information as requested. The information request is related to a nationwide enforcement initiative by the EPA targeting electric utilities. The EPA's inquiry may lead to claims of CAA violations that could result in an enforcement action, the scope of which cannot be predicted with confidence at this time, but which could have a material adverse effect on our financial condition, results and cash flows.

The Clean Water Act

Our water withdrawals and wastewater discharges are permitted under the CWA and analogous state laws. The cooling water intake structures at several of our facilities are regulated under section 316(b) of the CWA. This provision generally directs that standards set for facilities require that the location, design, construction and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impact. These standards are developed and implemented for power generating facilities through NPDES permits or SPDES permits. Historically, standards for minimizing adverse environmental impacts of cooling water intakes have been made by permitting agencies on a case-by-case basis considering the best professional judgment of the permitting agency.

In 2004, the EPA issued the Cooling Water Intake Structures Phase II Rules (the "Phase II Rules"), which set forth standards to implement the BTA requirements for cooling water intakes at existing facilities. The rules were challenged by several environmental groups and in 2007 were struck down by the U.S. Court of Appeals for the 2nd Circuit in Riverkeeper, Inc. v. EPA. The Court's decision remanded several provisions of the rules to the EPA for further rulemaking. Several parties sought review of the decision before the U.S. Supreme Court. In April 2009, the U.S. Supreme Court ruled that the EPA permissibly relied on cost-benefit analysis in setting the national BTA performance standard and in providing for cost-benefit variances from those standards as part of the Phase II Rules.

In July 2007, following remand of the rules by the U.S. Court of Appeals, the EPA suspended its Phase II Rules and advised that permit requirements for cooling water intake structures at existing facilities should once more be established on a case-by-case best professional judgment basis until replacement rules are issued. The scope of requirements, timing for compliance and the compliance methodologies that will ultimately be allowed by future rulemaking may become more restrictive, resulting in potentially significantly increased costs.

The environmental groups that participate in our NPDES and SPDES permit proceedings generally argue that only closed cycle cooling meets the BTA requirement. The issuance and renewal of NPDES and or SPDES permits for four of our facilities have been challenged on this basis.

- Danskammer SPDES Permit – In January 2005, the NYSDEC issued a draft SPDES permit renewal for the Danskammer power generation facility. Three environmental groups sought to impose a permit requirement that the Danskammer facility install a closed cycle cooling system. Following a formal evidentiary hearing, the revised Danskammer SPDES permit was issued in June 2006 without requiring installation of a closed cycle cooling system. The permit was upheld on appeal by the Appellate Division and petitions for leave to appeal to the New York Court of Appeals were denied.

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Roseton SPDES Permit – In April 2005, the NYSDEC issued a draft SPDES permit renewal for the Roseton power generation facility. The draft Roseton SPDES permit would require 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 Roseton 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 facility install a closed cycle cooling system. In September 2006, the administrative law judge issued a ruling admitting the petitioners to 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 the petitioners, NYSDEC staff and us. The adjudicatory hearing on the draft Roseton SPDES permit will be scheduled after the Commissioner rules on the appeal. We believe that the petitioners' claims lack merit and we plan to continue to oppose those claims vigorously.

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- Moss Landing NPDES Permit – The California Regional Water Quality Control Board ("California Water Board") issued an NPDES permit for the Moss Landing power generation facility in 2000 in connection with modernization of the facility. A local environmental group sought review of the permit contending that the once through seawater-cooling system at the Moss Landing power generation facility should be replaced with a closed-cycle cooling system to meet the BTA requirements. Following an initial remand from the courts, the California Water Board affirmed its BTA finding. The California Water Board's decision was affirmed by the Superior Court in 2004 and by the Court of Appeals in 2007. The petitioners filed a petition for review by the California Supreme Court, which was granted in March 2008. The California Supreme Court deferred further action pending final disposition of the U.S. Supreme Court challenge regarding the Phase II Rules. The California Supreme Court has since directed the parties to brief all issues raised by the pleadings. The petitioner's brief was filed in December 2009 and our response is due in March 2010. We believe that petitioner's claims lack merit and we plan to continue opposing those claims vigorously.

Due to 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.

- South Bay NPDES Permit – The California Regional Water Quality Control Board for the San Diego Region (the "San Diego Regional Water Board") recently granted an administrative extension of the South Bay facility's NPDES permit until December 31, 2010. Under the terms of the extension, operation of Units 3 and 4 was authorized through December 31, 2009. These units have ceased operation. The administrative extension authorized operation of Units 1 and 2 only through December 31, 2010, absent further action by the San Diego Regional Water Board. The San Diego Regional Water Board has scheduled a public hearing for March 2010 to receive evidence on the impacts of the South Bay intake and discharge.

In June 2009, the California Water Board issued its draft Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (the "Policy"). If the Policy becomes final in its present form, it will require that existing power plants either: (i) reduce their water intake flow rate to a level commensurate with that which can be achieved by a closed cycle wet cooling system; or (ii) reduce impingement mortality and entrainment to a level comparable to that achieved by such a reduced water intake flow rate using operational or structural controls, or both. The Policy may allow less stringent requirements under limited circumstances for very efficient generating units, such as Moss Landing's Units 1 and 2. Compliance with the Policy would be required at our South Bay power generation facility by December 2012, at our Morro Bay power generation facility by December 2015 and at our Moss Landing power generation facility by December 2017. A public hearing was held on the policy in September 2009 and public comments were taken through the end of September 2009. We filed substantial comments on the draft policy.

Given the numerous variables and factors involved in calculating the potential costs associated with closed cycle cooling, any decision to install such a system at any of our facilities, should they be required, would be made on a case-by-case basis considering all relevant factors at such time. If capital expenditures related to cooling water systems become great enough to render the operation of the plant uneconomical, we could, at our option, and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate such facility and forego these capital expenditures.

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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 relate primarily to arsenic, mercury and selenium. Significant changes in these criteria could impact discharge limits and could require us to spend significant environmental capital to install additional water treatment equipment at our facilities.

Coal Combustion Byproducts

The combustion of coal to generate electric power creates large quantities of ash that are managed at power generation facilities in dry form in landfills and in liquid or slurry form in surface impoundments. Each of our coal-fired plants has at least one CCB management unit. At present, CCB management is regulated by the states as solid waste. The EPA has considered whether CCB should be regulated as a hazardous waste on two separate occasions, including most recently in 2000, and both times has declined to do so. The December 2008 failure of a CCB surface impoundment dike at the Tennessee Valley Authority’s Kingston Plant in Tennessee accompanied by a very large release of ash slurry has resulted in renewed scrutiny of CCB management.

In response to the Kingston ash slurry release, the EPA initiated an investigation of the structural integrity of certain CCB surface impoundment dams including those at our GEN-MW facilities. Our surface impoundment dams were found to be in satisfactory condition, the highest rating. Additionally, the EPA announced plans to develop regulations regarding the handling and disposal of CCB by the end of 2009 to address the management of CCB; while no proposed rule has been released to date, a proposed rule is expected to be released in the first quarter 2010.

Certain environmental organizations have advocated designation of CCB as a hazardous waste; however, many state environmental agencies have expressed strong opposition to such designation. The regulations being developed by the EPA could lead to new requirements related to CCB management units. The nature and scope of these requirements cannot be predicted with confidence at this time, but could have a material adverse effect on our financial condition, results of operations and cash flows. Further, public perception or new regulations regarding the reuse of coal ash may limit or eliminate the market that currently exists for coal ash reuse, which could have material adverse affects on our financial condition, results of operations and cash flows.

Remedial Laws

We are 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 for contributions to contaminated sites resulting from the release of “hazardous substances” into the environment. Those with potential liabilities 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 with respect to a variety of our facilities and operations.

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.

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COMPETITION

Demand for power may be met by generation capacity based on several competing generation 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, West and Northeast compete with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities, other energy service companies and financial institutions. 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. Our ability to compete effectively will also be impacted by various governmental and regulatory activities designed to reduce GHG emissions and to support the construction and operation of renewable-fueled power generation facilities. For example, regulatory requirements for load-serving entities to acquire a percentage of their energy from renewable-fueled facilities will potentially reduce the demand for energy from coal-fired facilities such as those we own and operate. We believe our primary competitors consist of at least 20 companies in the power generation business.

SIGNIFICANT CUSTOMERS

For the year ended December 31, 2009, approximately 19 percent, 12 percent and 11 percent of our consolidated revenues were derived from transactions with MISO, NYISO and PJM, respectively. For the year ended December 31, 2008, approximately 25 percent and 11 percent of our consolidated revenues were derived from transactions with MISO and NYISO, respectively. For the year ended December 31, 2007, approximately 23 percent, 17 percent and 11 percent of our consolidated revenues were derived from transactions with MISO, NYISO and Ameren, respectively. No other customer accounted for more than 10 percent of our consolidated revenues during 2009, 2008 or 2007.

EMPLOYEES

At December 31, 2009, we had approximately 472 employees at our corporate headquarters and approximately 1,263 employees at our facilities, including field-based administrative employees. Approximately 763 employees at Dynegy-operated facilities are subject to collective bargaining agreements with various unions that expire in August 2010, June 2011 and January 2013. 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 includ are not limited to, statements relating to the following:

- the timing and anticipated benefits to be achieved through our 2010-2013 company-wide cost savings program;

- beliefs and assumptions relating to liquidity, available borrowing capacity and capital resources generally;

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- expectations regarding environmental matters, including costs of compliance, availability and adequacy of emission credits, and the impact of ongoing proceedings and potential regulations or changes to current regulations, including those relating to climate change, air emissions, cooling water intake structures, coal combustion byproducts, and other laws and regulations to which we are, or could become, subject;
- beliefs about commodity pricing and generation volumes;
- anticipated liquidity in the regional power and fuel markets in which we transact, including the extent to which such liquidity could be affected by poor economic and financial market conditions or new regulations and any resulting impacts on financial institutions and other current and potential counterparties;
- sufficiency of, access to and costs associated with coal, fuel oil and natural gas inventories and transportation thereof;
- beliefs and assumptions about market competition, generation capacity and regional supply and demand characteristics of the wholesale power generation market, including the anticipation of a market recovery over the longer term;
- the effectiveness of our strategies to capture opportunities presented by changes in commodity prices and to manage our exposure to energy price volatility;
- beliefs and assumptions about weather and general economic conditions;
- beliefs regarding the current economic downturn, its trajectory and its impacts;
- projected operating or financial results, including anticipated cash flows from operations, revenues and profitability;
- beliefs and expectations regarding financing and associated credit ratings, development and timing and disposition of the Plum Point Project;
- expectations regarding our revolver capacity, credit facility compliance, collateral demands, capital expenditures, interest expense and other payments;
- our focus on safety and our ability to efficiently operate our assets so as to maximize our revenue generating opportunities and operating margins;
- beliefs about the outcome of legal, regulatory, administrative and legislative matters; and
- expectations and estimates regarding capital and maintenance expenditures, including the Midwest Consent Decree and its associated costs.

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 the Operation of Our Business

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

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 will 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. Such factors that may materially impact the power markets and our financial results include:

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- the continuing economic downturn, the existence and effectiveness of demand-side management and conservation efforts and the extent to which they impact electricity demand;

- regulatory constraints on pricing (current or future) or the functioning of the energy trading markets and energy trading generally;

- fuel price volatility; and

- increased competition or price pressure driven by generation from renewable sources.

Many of our facilities operate as "merchant" facilities without long-term power sales agreements. Consequently, we cannot be sure that we will be able to sell any or all of the electric energy, capacity or ancillary services from those 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.

Given the volatility of power commodity prices, to the extent we do not secure long-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 commercial strategy may result in lost opportunities and, in any case, may not be executed as planned.

We seek to commercialize our assets through sales arrangements of various tenors. In doing so, we attempt to balance a desire for greater predictability of earnings and cash flows in the short- and medium-term with a belief that commodity prices will rise over the longer term, creating upside opportunities for those with unhedged generation volumes. Our ability to successfully execute this strategy is dependent on a number of factors, many of which are outside our control, including market liquidity, the availability of counterparties willing to transact at prices we believe are commercially acceptable and the reliability of the people and systems comprising our commercial operations function. The availability of market liquidity and willing counterparties could be negatively impacted by continued poor economic and financial market conditions, including impacts on financial institutions and other current and potential counterparties. If we are unable to transact in the short- and medium-term, our financial condition, results of operations and cash flows will be subject to significant uncertainty and volatility. Alternatively, significant contract execution for this period may precede a run-up in commodity prices, resulting in lost upside opportunities and mark-to-market accounting losses causing significant variability in net income and other GAAP reported measures.

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 fuel oil supply agreements.

We purchase the fuel requirements for many of our power generation facilities, primarily those that are natural gas-fired, 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 those required for energy sales, due in part to our need to pre-purchase fuel inventories for reliability and dispatch requirements.

Moreover, profitable operation of many of our coal-fired generation facilities is highly dependent on our ability to procure coal at prices we consider reasonable. Power generators in the Midwest and the Northeast have experienced significant pressures on available coal supplies that are either transportation or supply related. In the Midwest, a majority of our coal supply is not contracted beyond 2010. Additionally, our Midwest coal transportation agreement expires in 2013, and we expect any revision or extension to result in higher coal transportation costs. We have entered into term contracts for South American coal, which we use for our GEN-NE coal facility, and for PRB, which we use for our GEN-MW coal facilities. We cannot assure you that we will be able to renew our coal procurement and transportation contracts when they terminate on terms that are favorable to us or at all. Further, our and our suppliers' ability to procure South American coal is subject to local political and other factors that could have a negative impact on our coal deliveries regardless of our contract situation. Permit limitations that restrict the sulfur content of coal used at our coal facilities limit our options for coal fuel supply, creating risk for us in terms of our ability to procure coal for periods and at prices we believe are firm and favorable.

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Further, any changes in the costs of coal, fuel oil, natural gas or transportation rates and changes in the relationship between such costs and the market prices of power will affect our financial results. 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.

Our costs of compliance with existing environmental requirements are significant, and costs of compliance with new environmental requirements or factors could materially 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, transportation, treatment, storage and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances (including GHG) into the environment, and in connection with environmental impacts associated with cooling water intake structures. Existing environmental laws and regulations may be revised or reinterpreted, new laws and regulations may be adopted or may become applicable to us or our facilities, and litigation or enforcement proceedings could be commenced against us. Proposals being considered by federal and state authorities (including proposals regarding regulation of GHGs) could, if and when adopted or enacted, require us to make substantial capital and operating expenditures or consider retiring certain of our facilities. If any of these events occur, our financial condition, results of operations and cash flows could be materially adversely affected.

Many environmental laws require approvals or permits from governmental authorities before construction, modification or operation of a power generation facility may commence. Certain environmental permits must be renewed periodically in order for us to continue operating our facilities. The process of obtaining and renewing 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. If there is a delay in obtaining any required environmental regulatory approvals or permits, if we fail to obtain any required approval or permit, or if we are unable to comply with the terms of such approvals or permits, the operation of our facilities may be interrupted or become subject to additional costs. Further, changed interpretations of existing regulations may subject historical maintenance, repair and replacement activities at our facilities to claims of noncompliance. As a result, our financial condition, results of operations and cash flows could be materially adversely affected. 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 environmental standards and more extensive regulatory and permitting requirements, our capital and operating environmental expenditures are likely to be substantial and may increase in the future.

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 would 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 in each of the jurisdictions in which we have operations. Compliance with these ever-changing laws and regulations requires expenses (including legal representation) and monitoring, capital and operating expenditures. Potential changes in laws and regulations that could have a material impact on our business include: re-regulation of the power industry in markets in which we conduct business; the introduction, or reintroduction, of rate caps or pricing constraints; increased credit standards, collateral costs or margin requirements, as well as reduced market liquidity, as a result of potential OTC market regulation; or a variation of these. Furthermore, these and other market-based rules and 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.

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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 within the sector 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.

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

We are required to maintain, either through allocation or purchase, sufficient emission allowances to support our operations in the ordinary course of operating our power generation facilities. These allowances are used to meet our obligations imposed by various applicable environmental laws and the trend toward more stringent regulations (including regulations regarding GHG emissions) will likely require us to obtain new or additional emission allowances. If our operational needs require more than our allocated quantity of emission allowances, we may be forced to purchase such allowances on the open market, which could be costly. If we are unable to maintain sufficient emission allowances to match our operational needs, we may have to curtail our operations so as not to exceed our available emission allowances, or install costly new emissions controls. As we use the emissions allowances that we have purchased on the open market, costs associated with such purchases will be recognized as operating expense. If such allowances are available for purchase, but only at significantly higher prices, their purchase could materially increase our costs of operations in the affected markets and materially adversely affect our financial condition, results of operations and cash flows.

Competition in wholesale power markets, together with the age of certain of our generation facilities and 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, other energy service companies and financial institutions in the sale of electric energy, capacity and ancillary services, 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 oversupply 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. Electric 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, certain 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 these plants at a competitive disadvantage. Over time, some of our plants may become unable to compete, because of the construction of new plants which could have a number of advantages including; more efficient equipment, newer technology that could result in fewer emissions, or more advantageous locations on the electric transmission system. Additionally, these competitors may be able to respond more quickly to new laws and regulations because of the newer technology utilized in their facilities or the additional resources derived from owning more efficient facilities. Taken as a whole, the potential disadvantages of our aging fleet could result in lower run-times or even early asset retirement.

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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 owned by 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 or spin-off 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. To the extent that competition increases, our financial condition, results of operations and cash flows may be materially adversely affected.

We do not own or control transmission facilities required to sell the wholesale power from our generation facilities. If the transmission service is inadequate, our ability to sell and deliver wholesale power may be materially adversely affected. Furthermore, these transmission facilities are operated by RTOs and ISOs, which are subject to changes in structure and operation and impose various pricing limitations. These changes and pricing limitations may affect our ability to deliver power to the market that would, in turn, adversely affect the profitability of our generation facilities.

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. RTOs and ISOs provide transmission services, administer transparent and competitive power markets and maintain system reliability. Many of these RTOs and ISOs operate in the real-time and day-ahead markets in which we sell energy. The RTOs and ISOs that oversee most of the wholesale power markets impose, and in the future may continue to impose, offer caps and other mechanisms to guard against the potential exercise of market power in these markets as well as price limitations. 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. 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 also affect our ability to sell, the prices we receive 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. Additionally, 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 thus are subject to changes, some of which could be significant. As a result, our financial condition, results of operations and cash flows may be materially adversely affected.

Our financial condition, results of operations and cash flows would 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 from 2010 through 2013. Additionally, unionization activities, including votes for union certification, could occur at our non-union generating facilities in our fleet. 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 commercially reasonable terms could have a material adverse effect on our financial condition, results of operations and cash flows.

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Costs of compliance with our Midwest Consent Decree may be materially adversely impacted by unforeseen labor, material and equipment costs.

As a result of the Midwest Consent Decree, we are required to not operate certain of our most profitable power generating facilities after specified dates unless certain emission control equipment is installed. We have incurred significant costs in complying with the Midwest Consent Decree and anticipate incurring additional significant costs over the course of the next three years. We are exposed to the risk of substantial price increases in the costs of materials, labor and equipment used in the construction of emission control equipment. We are further exposed to risk in that counterparties to the construction contracts may fail to perform, in which case we would be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and possibly cause delays to the project timelines. If the costs of these capital expenditures become great enough to render the operation of the facility uneconomical, we could, at our option, cease to operate the facility or facilities and forego these capital expenditures without incurring any further obligations under the Midwest Consent Decree.

Risks Related to Our Financial Structure, Level of Indebtedness and Access to Capital Markets

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 respective 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 (such as substantial damage to a facility or a condemnation or similar governmental taking or action), 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 compensate the lessor for termination of the lease, including redeeming the pass-through trust certificates related to the unit or facility for which the lease is terminated. As of December 31, 2009, the termination payment would be approximately $853 million 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 condition, results of operations and cash flows.

We have significant debt that could negatively impact our business.

We have and will continue to have a significant amount of debt outstanding. As of December 31, 2009, we had total consolidated debt of approximately $5.6 billion. 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;

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- 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 principal and interest payments on our debt, thereby reducing the availability of our cash flow for other purposes including our operations, capital expenditures and future business opportunities.

Furthermore, we may incur or assume additional debt in the future. If new debt is added to our current debt levels and those of our subsidiaries, the related risks that we and they face could increase significantly.

Our financing agreements governing our debt obligations require us to meet specific financial tests. Our failure to comply with those financial covenants could have a material adverse impact on our business, financial condition, results of operations or cash flows.

Our financing agreements, including the Fifth Amended and Restated Credit Facility, as amended (the “Credit Facility”), have terms that restrict our ability to take specific actions in planning for and responding to changes in our business without the consent of the lenders, even if such actions may be in our best interest. The agreements governing our debt obligations require us to meet specific financial tests both as a matter of course and as a precondition to the incurrence of additional debt and to the making of restricted payments or asset sales, among other things. Our obligations relating to ongoing financial tests include the maintenance of specified financial ratios regarding Secured Debt to EBITDA and EBITDA to Consolidated Interest Expense (as each such term is defined in the Credit Facility). The financial tests set forth as a precondition to the events described above include the demonstration, on a pro forma basis, of a specified ratio of Total Indebtedness to EBITDA (as each such term is defined in the Credit Facility). Any additional long-term debt that we may enter into in the future may also contain similar restrictions.

Our ability to comply with the financial tests and other covenants in our financing agreements, as they currently exist or as they may be amended, may be affected by many events beyond our control, and our future operating results may not allow us to comply with the covenants or, in the event of a default, to remedy that default. Our failure to comply with those financial covenants or to comply with the other restrictions in our financing agreements could result in reduced borrowing capacity or even a default, causing our debt obligations under such financing agreements (and by reason of cross-default or cross-acceleration provisions, our other indebtedness) to become immediately due and payable, which could have a material adverse impact on our business, financial condition, results of operations or cash flows. If those lenders accelerate the payment of such indebtedness, we cannot assure you that we could pay off or refinance that indebtedness immediately and continue to operate our business. If we are unable to repay those amounts, otherwise cure the default, or obtain replacement financing, the holders of the indebtedness under our secured debt obligations would be entitled to foreclose on, and acquire control of substantially all of our assets, which would have a material adverse impact on our financial condition, results of operations and cash flows.

Our access to the capital markets may be limited.

We may require additional capital from time to time. Because of our non-investment grade credit rating and/or general conditions in the financial and credit markets, 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 legal or regulatory requirements, which could require us to pursue additional capital at an inopportune time. Our ability to obtain capital and the costs of such capital are dependent on numerous factors, including:

- general economic and capital market conditions, including the timing and magnitude of market recovery;

- covenants in our existing debt and credit agreements;
- investor confidence in us and the regional wholesale power markets;

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- our financial performance and the financial performance of our subsidiaries;
- our levels of debt;
- our requirements for posting collateral under various commercial agreements;
- our credit ratings;
- our cash flow; 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 comply with regulatory requirements and, as a result, may have a material adverse effect on our financial condition, results of operations and cash flows.

Our non-investment grade status may adversely impact our operations, increase our liquidity requirements and increase the cost of refinancing opportunities. We may not have adequate liquidity to post required amounts of additional collateral.

Our credit ratings are currently below investment grade. We cannot assure you that our credit ratings will improve, or that they will not decline, in the future. Our credit ratings may affect the evaluation of our creditworthiness by trading counterparties and lenders, which could put us at a disadvantage to competitors with higher or investment grade ratings.

In carrying out our commercial business strategy, our current non-investment grade credit ratings have resulted and will likely continue to result in requirements that we either prepay obligations or post significant amounts of collateral to support our business. Various commodity trading counterparties make collateral demands that reflect our non-investment grade credit ratings, the counterparties' views of our creditworthiness, as well as changes in commodity prices. We use a portion of our capital resources, in the form of cash, lien capacity, and letters of credit, to satisfy these counterparty collateral demands. Our commodity agreements are tied to market pricing and may require us to post additional collateral under certain circumstances. If market conditions change such that counterparties are entitled to additional collateral, our liquidity could be strained and may have a material adverse effect on our financial condition, results of operations and cash flows. Factors that could trigger increased demands for collateral include changes in our credit rating or liquidity and changes in commodity prices for power and fuel, among others.

Additionally, our non-investment grade credit ratings may limit our ability to refinance our debt obligations and to access the capital markets at the lower borrowing costs that would presumably be available to competitors with higher or investment grade ratings. Should our ratings continue at their current levels, or should our ratings be further downgraded, we would expect these negative effects to continue and, in the case of a downgrade, become more pronounced.

We conduct a substantial portion of our operations through our subsidiaries and may be limited in our ability to access funds from these subsidiaries to service our debt.

We conduct a substantial portion of our operations through our subsidiaries and depend to a large degree upon dividends and other intercompany transfers of funds from our subsidiaries to meet our debt service and other obligations. In addition, the ability of our subsidiaries to pay dividends and make other payments to us may be restricted by, among other things, applicable corporate and other laws, potentially adverse tax consequences and agreements of our subsidiaries. If we are unable to access the cash flow of our subsidiaries, we may have difficulty meeting our debt obligations.

Risks Related to Investing

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

We may seek to enter into transactions that may include acquiring or combining with other businesses. 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 our management's attention;
- the ability to obtain required regulatory and other approvals;
- the need to integrate acquired or combined operations with our 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 or with different fuel sources;
- 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 or debt securities or assume additional debt in connection with 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 or increase the price we would be required to pay (which could decrease the benefit of the transaction or hinder our desire or ability to consummate the transaction). 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 will need to respond to potential opportunities quickly and decisively. As a result, strategic transactions may occur at any time and may be significant in size relative to our assets and operations.

If Dynegy issues or acquires a material amount of its common stock in the future or certain of its stockholders sell a material amount of Dynegy's common stock, Dynegy's ability to use its federal net operating losses or alternative minimum tax credits to offset its future taxable income may be limited under Sections 382 and 383 of the Internal Revenue Code.

Dynegy's ability to utilize previously incurred federal NOLs and alternative minimum tax (AMT) credits to offset future taxable income would be limited if it 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 any time over the preceding three years. Under certain circumstances, issuances or acquisitions of our own common stock or sales or dispositions of our common stock by 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 Sections 382 and 383 of the Code, on Dynegy's utilization of federal NOLs and AMT credits 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 and AMT credits against the total future taxable income of a given year. The LS Power Transactions and other recent stockholder activity increase the likelihood that previously incurred federal NOLs and AMT credits will become subject to the limitations set forth in Sections 382 and 383 of the Code. If such an ownership change were to occur, our ability to raise additional equity capital may be limited.

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The magnitude of such limitations and their effect on us are difficult to assess and depend in part on our value at the time of any such ownership change and prevailing interest rates. For accounting purposes, at December 31, 2009, Dynegy's net operating loss deferred tax asset attributable to its previously incurred federal NOLs was approximately $125 million and its AMT credits were approximately $272 million.

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" for further discussion, which is incorporated herein by 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 Credit Facility. Please read Note 17—Debt for further discussion.

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

Item 3. Legal Proceedings

Please read Note 21—Commitments and Contingencies—Legal Proceedings for a description of our material legal proceedings, which is incorporated herein by reference.

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

Dynegy. No matter was submitted to a vote of Dynegy's security holders during the fourth quarter 2009.

DHI. Omitted pursuant to General Instruction (I)(2)(c) of Form 10-K.

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PART II

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

Dynegy

Dynegy's Class A common stock, $0.01 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 its Class A common stock as of February 19, 2010, based upon records of registered holders maintained by its transfer agent, was 18,883.

All of the shares of Class B common stock that were previously owned by the LS Power were cancelled as of November 30, 2009.

The following table sets forth the high and low closing sales prices for Dynegy's Class A common stock for each full quarterly period during the fiscal years ended December 31, 2009 and 2008 and during the elapsed portion of Dynegy's first fiscal quarter of 2010 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
2010:		
First Quarter (through February 19, 2010)	$1.99	$1.57
2009:		
Fourth Quarter	$2.63	$1.81
Third Quarter	2.55	1.78
Second Quarter	2.47	1.45
First Quarter	2.69	1.04
2008:		
Fourth Quarter	$4.06	$1.51
Third Quarter	8.76	3.20
Second Quarter	9.64	8.05
First Quarter	8.26	6.44

During the fiscal years ended December 31, 2009 and 2008, Dynegy's 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 Dynegy Common Stock" for further discussion of its dividend policy and the impact of dividend restrictions contained in its financing agreements. Any decision to pay a dividend will be at the discretion of Dynegy's Board of Directors, and subject to the terms of its then-outstanding indebtedness, but Dynegy does not expect to pay a dividend on its common stock in the foreseeable future. Dynegy has not paid a dividend on any class of its common stock since 2002. Please read Note 22—Capital Stock—Common Stock for further discussion.

Shareholder Agreements. Dynegy entered into a shareholder agreement dated as of September 14, 2006 (the "Old Shareholder Agreement") with LSP Gen Investors, L.P., LS Power Partners, L.P., LS Power Equity Partners PIE I, L.P., LS Power Equity Partners, L.P. and LS Power Associates, L.P. (collectively, "LS Power") that imposed upon LS

Power certain restrictions and limitations but also provided them with special approval rights, board representation and certain other rights.

On November 30, 2009, as part of the LS Transactions, Dynegy and LS Power terminated the Old Shareholder Agreement and entered into a second shareholder agreement (the “New Shareholder Agreement”) which, among other things, generally restricts LS Power from increasing its now-reduced ownership for a specified period up to 30 months. Additionally, it provides that we will not issue Dynegy’s equity securities for our own purposes until the earlier of (i) March 31, 2010 or (ii) the first date following closing of the transaction in which LS Power owns, in aggregate, less than 10 percent of Dynegy’s then outstanding Class A common stock. The New Shareholder Agreement does not, however, include any of the special rights (such as Board rights, special approval rights or preemption rights) previously associated with LS Power’s ownership. However, the LS Registration Rights Agreement as amended remains in effect.

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Amended LS Registration Rights Agreement. In conjunction with the signing of the Old Shareholder Agreement, Dynegy also entered into a Registration Rights Agreement with LS Power on September 14, 2006 (the "Registration Rights Agreement"). This Registration Rights Agreement required Dynegy to prepare and file with the SEC a "shelf" registration statement covering the resale of shares of Class A common stock issuable upon the conversion of shares of Class B common stock owned by LS Power. This "shelf" registration statement was filed with the SEC on April 5, 2007. On August 9, 2009 the Registration Rights Agreement was amended (the "Amended Registration Rights Agreement"). The Amended Registration Rights Agreement provides, in part, that Dynegy will be obligated to undertake up to two underwritten offerings for the benefit of LS Power in each twelve-month period, provided that the aggregate proceeds to be received by LS Power under any such offering must not be less than the lesser of $100 million and the then-current market value of 40 million shares of Dynegy's common stock. Dynegy will be able to defer an underwritten offering by LS Power if Dynegy is conducting or about to conduct an underwritten offering of common stock for its own account with aggregate proceeds in excess of $100 million. However, Dynegy will not be permitted to exercise its right to defer an underwritten offering by LS Power during the period ending on the earlier of (i) March 31, 2010 and (ii) the first date on which LS power owns, in aggregate, less than 10 percent of all of Dynegy's Class A common stock, and thereafter Dynegy's deferral right can only be exercised once per calendar year. The Amended Registration Rights Agreement also provides certain "piggyback" rights for LS Power in connection with future equity offerings Dynegy might conduct, subject to customary underwriter limitations.

Stockholder Return Performance Presentation. The graph below compares the cumulative 5-year total return of holders of Dynegy Inc.'s common stock with the cumulative total returns of the S&P 500 index, the S&P Midcap 400 index, and two customized peer groups of companies. The first peer group ("Peer Group No. 1") includes: Mirant Corp., NRG Energy Inc. and RRI Energy Inc.; and the second group ("Peer Group No. 2") includes: Calpine Corp., Mirant Corp., NRG Energy Inc. and RRI Energy Inc. In 2008, Dynegy was included in the S&P 500 and did not include Calpine Corp. in its peer group because Calpine Corp. was still emerging from bankruptcy. In 2009, Dynegy moved into the S&P Midcap 400 and included Calpine Corp. in its peer group. The graph tracks the performance of a $100 investment in our common stock, in each of the peer groups, and the two indices (with the reinvestment of all dividends) from 12/31/2004 to 12/31/2009.

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	12/04	12/05	12/06	12/07	12/08	12/09
Dynegy Inc.	100.00	104.76	156.71	154.55	43.29	39.18
S&P 500	100.00	104.91	121.48	128.16	80.74	102.11
S&P Midcap 400	100.00	112.55	124.17	134.08	85.50	117.46
Peer Group No.1	100.00	101.46	138.14	205.18	86.58	82.26
Peer Group No.2	100.00	101.46	138.14	205.18	86.58	93.46

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.

Unregistered Sales of Equity Securities and Use of Proceeds. When restricted stock awarded by Dynegy becomes taxable compensation to employees, shares may be withheld to cover the employees' withholding taxes. Information on Dynegy's purchases of equity securities by means of such share withholdings during the quarter follows:

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Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 to October 31, 2009	8,567	$ 2.50	—	N/A
November 1 to November 30, 2009	728	$ 1.93	—	N/A
December 1 to December 31, 2009	1,712	$ 1.88	—	N/A
Total	11,007	$ 2.37	—	N/A

These were the only repurchases of equity securities made by Dynegy during the three months ended December 31, 2009. Dynegy does not have a stock repurchase program.

DHI

All of DHI's outstanding equity securities are held by its parent, Dynegy. There is no established trading market for such securities and they are not traded on any exchange.

Securities Authorized for Issuance Under Equity Compensation Plans

Please read Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters—Dynegy for information regarding securities authorized for issuance under our equity compensation plans.

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

Dynegy's Selected Financial Data

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(in millions, except per share data)				
Statement of Operations Data (1):					
Revenues	$2,468	$3,324	$2,918	$1,758	$2,004
Depreciation and amortization expense	(335)	(346)	(306)	(208)	(199)
Goodwill impairment	(433)	—	—	—	—
Impairment and other charges, exclusive of goodwill impairment shown separately above	(538)	—	—	(9)	(46)
General and administrative expenses	(159)	(157)	(203)	(196)	(468)
Operating income (loss)	(834)	744	576	220	(826)
Interest expense and debt extinguishment costs (2)	(461)	(427)	(384)	(631)	(389)
Income tax (expense) benefit	315	(90)	(140)	116	391
Income (loss) from continuing operations	(1,040)	188	105	(242)	(796)
Income (loss) from discontinued operations (3)	(222)	(17)	166	(92)	891
Cumulative effect of change in accounting principles	—	—	—	1	(5)
Net income (loss)	$(1,262)	$171	$271	$(333)	$90
Net income (loss) attributable to Dynegy Inc. common stockholders	(1,247)	174	264	(342)	68
Basic earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders	$(1.25)	$0.23	$0.13	$(0.55)	$(2.11)
Basic net income (loss) per share attributable to Dynegy Inc. common stockholders	(1.52)	0.20	0.35	(0.75)	0.18
Diluted earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders	$(1.25)	$0.23	$0.13	$(0.55)	$(2.11)
Diluted net income (loss) per share attributable to Dynegy Inc. common stockholders	(1.52)	0.20	0.35	(0.75)	0.18
Shares outstanding for basic EPS calculation	822	840	752	459	387
Shares outstanding for diluted EPS calculation	826	842	754	509	513
Cash dividends per common share	$—	$—	$—	$—	$—
Cash Flow Data:					
Net cash provided by (used in) operating activities	$135	$319	$341	$(194)	$(30)
	251	(102)	(817)	358	1,824

Net cash provided by (used in) investing activities					
Net cash provided by (used in) financing activities	(608)	148	433	(1,342)	(873)
Cash dividends or distributions to partners, net	—	—	—	(17)	(22)
Capital expenditures, acquisitions and investments	(594)	(640)	(504)	(163)	(315)

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	2009	2008	December 31, 2007 (in millions)	2006	2005
Balance Sheet Data (4):					
Current assets	$2,038	$2,803	$1,663	$1,989	$3,706
Current liabilities	1,847	1,702	999	1,166	2,116
Property and equipment, net	7,117	8,934	9,017	4,951	5,323
Total assets	10,953	14,213	13,221	7,537	10,126
Long-term debt (excluding current portion)	4,775	6,072	5,939	3,190	4,228
Notes payable and current portion of long-term debt	807	64	51	68	71
Series C convertible preferred stock	—	—	—	—	400
Capital leases not already included in long-term debt	4	4	5	6	—
Total equity	2,979	4,485	4,529	2,267	2,140

(1)The LS Power Merger (April 2, 2007) and the Sithe Energies acquisition (February 1, 2005) were each 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)Includes $249 million of debt conversion costs for the twelve months ended December 31, 2006.

(3)Discontinued operations include the results of operations from the following businesses:

- The Arlington Valley and Griffith power generation facilities (collectively, the Arizona power generation facilities") (sold fourth quarter 2009);
- Bluegrass power generating facility (sold fourth quarter 2009);
- Heard County power generating facility (sold second quarter 2009);
- Calcasieu power generating facility (sold first quarter 2008);
- CoGen Lyondell power generating facility (sold third quarter 2007); and
- DMSLP (sold fourth quarter 2005).

(4)The LS Power Merger (April 2, 2007) and the Sithe Energies acquisition (February 1, 2005) 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. Please read note (1) above for respective effective dates.

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Dynegy Holdings' Selected Financial Data

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(in millions, except per share data)				
Statement of Operations Data (1):					
Revenues	$2,468	$3,324	$2,918	$1,758	$2,004
Depreciation and amortization expense	(335)	(346)	(306)	(208)	(199)
Goodwill impairment	(433)	—	—	—	—
Impairment and other charges, exclusive of goodwill impairment shown separately above	(538)	—	—	(9)	(40)
General and administrative expenses	(159)	(157)	(184)	(193)	(375)
Operating income (loss)	(836)	744	595	223	(727)
Interest expense and debt extinguishment costs (2)	(461)	(427)	(384)	(579)	(383)
Income tax (expense) benefit	313	(138)	(105)	89	372
Income (loss) from continuing operations	(1,046)	222	165	(217)	(723)
Income (loss) from discontinued operations (3)	(222)	(17)	166	(91)	809
Cumulative effect of change in accounting principles	—	—	—	—	(5)
Net income (loss)	$(1,268)	$205	$331	$(308)	$81
Net income (loss) attributable to Dynegy Holdings Inc.	$(1,253)	$208	$324	$(308)	$81
Cash Flow Data:					
Net cash provided by (used in) operating activities	$152	$319	$368	$(205)	$(24)
Net cash provided by (used in) investing activities	790	(87)	(688)	357	1,839
Net cash provided by (used in) financing activities	(1,193)	146	369	(1,235)	(734)
Capital expenditures, acquisitions and investments	(596)	(626)	(350)	(155)	(169)

	December 31,				
	2009	2008	2007	2006	2005
	(in millions)				
Balance Sheet Data (1):					
Current assets	$1,988	$2,780	$1,614	$1,828	$3,457
Current liabilities	1,848	1,681	999	1,165	2,212
Property and equipment, net	7,117	8,934	9,017	4,951	5,323
Total assets	10,903	14,174	13,107	8,136	10,580
Long-term debt (excluding current portion)	4,775	6,072	5,939	3,190	4,003
Notes payable and current portion of long-term debt	807	64	51	68	191
Capital leases not already included in long-term debt	4	4	5	6	—
Total equity	3,003	4,583	4,620	3,036	3,331

(1) The Contributed Entities' (as defined in Note 3) assets were contributed to DHI contemporaneously with the LS Power Merger (April 2, 2007). This contribution was accounted for as a transaction between entities under common control. As such, the assets and liabilities were recorded by DHI at Dynegy's historical cost on Dynegy's date of acquisition. Please read Note 3—Business Combination and Acquisitions—LS Assets Contribution for further discussion. Additionally, the Sithe Energies assets were contributed to DHI on April 2, 2007. This contribution was accounted for as a transaction between entities under common control. As such, the assets and liabilities were recorded by DHI at Dynegy's historical cost on Dynegy's date of acquisition, January 31, 2005. In addition, DHI's historical financial statements have been adjusted in all periods presented to reflect the contribution as though DHI had owned these assets beginning January 31, 2005. Please read Note 3—Business Combination and Acquisitions—LS Assets Contribution for further discussion.

(2) Includes $204 million of debt conversion costs for the twelve months ended December 31, 2006.

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(3)Discontinued operations include the results of operations from the following businesses:

- The Arizona power generation facilities (sold fourth quarter 2009);
- Bluegrass power generating facility (sold fourth quarter 2009);
- Heard County power generating facility (sold second quarter 2009);
- Calcasieu power generating facility (sold first quarter 2008);
- CoGen Lyondell power generating facility (sold third quarter 2007); and
- DMSLP (sold fourth quarter 2005).

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 holding companies 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: (i) GEN-MW; (ii) GEN-WE; and (iii) GEN-NE. Because of the diversity among their respective operations and how we allocate our resources, 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, interest and depreciation and amortization. Our 50 percent investment in SCH, which was sold in the fourth quarter 2009, is included in GEN-WE for reporting purposes. Dynegy's 50 percent investment in DLS Power Development, which was dissolved in the first quarter 2009, is included in Other for segment reporting purposes.

In addition to our operating generation facilities, we own an approximate 37 percent interest in PPEA Holding which is included in GEN-MW. PPEA Holding, through its wholly owned subsidiary, PPEA, owns an approximate 57 percent undivided interest in the Plum Point Project.

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 corporate-level expenses. This "Overview" section concludes with a discussion of our 2009 company highlights. 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 include:

- Prices for power, natural gas, coal and fuel oil, which in turn are largely driven by supply and demand. Demand for power can vary due to weather and general economic conditions, among other things. For example, a warm summer or a cold winter typically increases demand for electricity. Conversely, the recessionary economic environment has negatively impacted demand for electricity. Power supplies similarly vary by region and are impacted significantly by available generating capacity, transmission capacity and federal and state regulation;

- The relationship between prices for power and natural gas and prices for power and coal, commonly referred to as the “spark spread” and “dark spread”, respectively, which impacts the margin we earn on the electricity we generate; and

- Our ability to enter into commercial transactions to mitigate short- and medium- term earnings volatility and our ability to manage our liquidity requirements resulting from potential changes in collateral requirements as prices move.

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

- Transmission constraints, congestion, and other factors that can affect the price differential between the locations where we deliver generated power and the liquid market hub;
- Our ability to control capital expenditures, which primarily include maintenance, safety, environmental and reliability projects, and to control operating expenses through disciplined management;
- Our ability to optimize our assets by maintaining a high in-market availability, reliable run-time and safe, low-cost operations;
- The cost of compliance with existing and future environmental requirements that are likely to be more stringent and more comprehensive. Please see Business—Environmental Matters for further discussion; and
- Market supply conditions resulting from federal and regional renewable power initiatives.

Please read Item 1A. Risk Factors 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 as further described below.

Power Generation—Midwest Segment. Our assets in GEN-MW include coal-fired facilities and natural gas-fired facilities. The following specific factors affect or could affect the performance of this reportable segment:

- Our ability to maintain sufficient coal inventories, which is dependent upon the continued performance of the railroads for deliveries of coal in a consistent and timely manner, and its impact on our ability to serve the critical winter and summer on-peak loads;
- Our requirement to utilize a significant amount of cash for capital expenditures required to comply with the Midwest Consent Decree;
- Regional renewable energy mandates and initiatives that may alter supply conditions within the ISO and our generating units' positions in the aggregate supply stack;
- Changes in the MISO market design or associated rules; and
- Changes in the existing PJM RPM capacity markets or in the bilateral MISO capacity markets and any resulting effect on future capacity revenues.

Power Generation—West Segment. Our assets in GEN-WE are all natural gas-fired power generating facilities with the exception of our fuel oil-fired Oakland facility. The following specific factors impact or could impact the performance of this reportable segment:

- The continued need for reliability must-run services from the Oakland and South Bay facilities;
-

The results of the South Bay facility's RMR rate negotiations, in which we intend to collect additional funds equal to the cost of the plant closure less the demolition and remediation costs collected in prior year's rates;

- Our ability to maintain and operate our plants in a manner that ensures we receive full capacity payments under our various tolling agreements; and

- Our ability to maintain the necessary permits to continue to operate our Moss Landing, Morro Bay and South Bay facilities with once-through, seawater cooling systems.

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

- Our ability to maintain sufficient coal and fuel oil inventories, including continued deliveries of coal in a consistent and timely manner, and maintain access to natural gas, impacts our ability to serve the critical winter and summer on-peak loads;

- State-driven programs aimed at capping mercury and/or reducing emission levels of other constituents such as CO_2, NO_x and SO_2 will impose additional costs on our power generation facilities;

- Changes in NYISO/ISO-NE market rules or state-specific mandates that favor and/or subsidize renewable energy sources and demand response initiatives; and

- Our ability to preserve and/or capture value around planned transmission upgrades designed to improve transfer limits around known constraints.

Other

Other 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 interest rate of approximately seven percent;

- General and administrative costs, which will be impacted by, among other things, (i) staffing levels and associated expenses; (ii) funding requirements under our pension plans; (iii) any future corporate-level litigation reserves or settlements and (iv) our ability to realize the planned cost savings reflected in our 2010-2013 cost savings program; and

- Income taxes, which will be impacted by our ability to realize our net operating losses and alternative minimum tax credits.

Other also includes our legacy CRM operations, which primarily consists of a minimal number of legacy power and natural gas trading positions that will remain until 2010 and 2017, respectively.

2009 Highlights

LS Power Transactions. We consummated our transactions (the “LS Power Transactions”) with LS Power in two parts, with the issuance of notes by DHI on December 1, 2009, and the remainder of the transactions closing on November 30, 2009. At closing, Dynegy received: (i) $936 million in cash, net of closing costs (consisting, in part, of (a) the release of $175 million of restricted cash on our consolidated balance sheets that was used to support our funding commitment to the Sandy Creek Project and (b) $214 million for the notes issued by DHI), and (ii) 245 million shares of Dynegy’s Class B common stock from LS Power. In exchange, Dynegy sold to LS Power five peaking and three combined-cycle generation assets, as well as its remaining interest in the Sandy Creek Project under construction in Texas (the “Sandy Creek Project”), and DHI issued the notes to an affiliate of LS Power.

The remaining 95 million shares of Dynegy’s Class B common stock held by LS Power were converted into the same number of shares of Dynegy’s Class A common stock, representing approximately 15 percent of Dynegy’s Class A common stock outstanding.

In connection with the LS Power Transactions, Dynegy and LS Power entered into the New Shareholder Agreement, which, among other things, generally restricts LS Power from increasing its now-reduced ownership for up to 30 months. Additionally, it provides that we will not issue Dynegy's equity securities for our own purposes until the earlier of (i) March 31, 2010 or (ii) the first date following closing of the transaction in which LS Power owns, in aggregate, less than 10 percent of Dynegy's then outstanding Class A common stock. Dynegy and LS Power have also terminated the Old Shareholder Agreement, which provided LS Power with special approval rights, board representation and certain other rights associated with its former Class B common stock. Please read Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities—Shareholder Agreements for further discussion.

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In connection with our closing of the LS Power Transactions, we recorded pre-tax charges of $312 million in the fourth quarter 2009. These charges include $124 million in Gain (loss) on sale of assets, $104 million in Income (loss) from discontinued operations and $84 million in Losses from unconsolidated investments in our consolidated statements of operations. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further discussion.

We also recorded pre-tax impairment charges of $579 million as a result of the negotiations leading up to and entering into the LS Power Transactions. Please read Note 6—Impairment Charges—2009 Impairment Charges—Assets Included in LS Power Transactions for further discussion.

Credit Facility Amendment. On August 5, 2009, we entered into certain amendments to the Credit Facility. Please read Note 17—Debt—Credit Facility for further discussion.

Multi-Year Cost Savings Initiative. On August 10, 2009, we announced an extensive, multi-year program to eliminate certain costs throughout the company. Cumulative savings, relative to our original plan, are expected to be $400 million to $450 million over a four-year period beginning in 2010. Annual savings are expected to be generated through reduced capital, operational and general and administrative expenditures.

Note Repurchase Agreement. On December 31, 2009, DHI completed a note repurchase with one of its larger fixed-income investors. DHI repurchased approximately $833 million aggregate principal amount of its notes, consisting of approximately $421 million of its 6.875% Senior Unsecured Notes due 2011 and approximately $412 million of its 8.750% Senior Unsecured Notes due 2012. The total consideration to effect the note repurchase, inclusive of consent fees, was $879 million. We recorded a charge of $46 million on the extinguishment of this debt.

LIQUIDITY AND CAPITAL RESOURCES

Overview

In this section, we describe our liquidity and capital requirements including our sources and uses of liquidity and capital resources. 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 (including required environmental expenditures), and working capital needs. Examples of working capital needs include purchases and sales of commodities and associated margin and collateral requirements, facility maintenance costs and other costs such as payroll.

Our primary sources of internal liquidity are cash flows from operations, cash on hand, and available capacity under our Credit Facility, of which the revolver capacity of $1,080 million is scheduled to mature in April 2012 and the term letter of credit capacity of $850 million is scheduled to mature in April 2013. Secondarily, we expect to continue utilizing both lien-secured commodity hedging arrangements, which reduce collateral requirements, and commodity-contingent liquidity facilities, which increase potential liquidity availability. Additionally, DHI may borrow money from time to time from Dynegy. These internal liquidity sources are expected to be sufficient to fund the operation of our business, potential requirements to post additional collateral, as well as our planned capital expenditure program, including expenditures in connection with the Midwest Consent Decree, and debt service requirements over the next twelve months. Please read Note 17—Debt—Credit Facility for a discussion of the financial covenants contained in the Credit Facility, as well as the discussion below regarding our Revolver Capacity.

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Our primary sources of external liquidity are asset sales proceeds and proceeds from capital market transactions to the extent we engage in these transactions.

Current Liquidity. The following table summarizes our consolidated revolver capacity and liquidity position at February 19, 2010, December 31, 2009 and December 31, 2008:

	February 19, 2010	December 31, 2009	December 31, 2008
		(in millions)	
Revolver capacity (1)	$ 1,080	$ 1,080	$ 1,080
Borrowings against revolver capacity	—	—	—
Term letter of credit capacity, net of required reserves	825	825	825
Plum Point and Sandy Creek letter of credit capacity (2)	102	102	377
Outstanding letters of credit (2)	(500)	(536)	(1,135)
Unused capacity	1,507	1,471	1,147
Cash—DHI	693	419	670
Total available liquidity—DHI	2,200	1,890	1,817
Cash—Dynegy	53	52	23
Total available liquidity—Dynegy	$ 2,253	$ 1,942	$ 1,840

(1) We currently have a syndicate of lenders participating in the revolving portion of our Credit Facility with commitments ranging from $10 million to $165 million.
(2) Reflects reduction of $275 million of capacity as of December 31, 2009 related to our investment in the Sandy Creek Project. At the close of the LS Power Transactions, this capacity was eliminated, and $175 million of the $275 million of restricted cash supporting this letter of credit capacity was released to us. See Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—LS Power Transactions for further discussion.

Cash on Hand. At February 19, 2010 and December 31, 2009, Dynegy had cash on hand of $746 million and $471 million, respectively, as compared to $693 million at the end of 2008. The increase in cash on hand at February 19, 2010 compared with December 31, 2009 is primarily related to return of cash from our broker margin account as a result of commodity price changes. The decrease in cash on hand at December 31, 2009 as compared to the end of 2008 is primarily attributable to cash used for debt repayments and capital expenditures partially offset by proceeds from the LS Power Transactions and the sale of Heard County as well as cash generated from the operating activities of our generation business.

At February 19, 2010 and December 31, 2009, DHI had cash on hand of $693 million and $419 million, respectively, as compared to $670 million at the end of 2008. The increase in cash on hand at February 19, 2010 compared with December 31, 2009 is primarily related to return of cash from our broker margin account as a result of commodity price changes. The decrease in cash on hand at December 31, 2009 as compared to the end of 2008 is primarily attributable to cash used for debt repayments, dividends to affiliates and capital expenditures partially offset by proceeds from the LS Power Transactions and the sale of Heard County as well as cash generated from the operating activities of our generation business.

Revolver Capacity. Based on management's current 2010 forecast, DHI's available liquidity under the Credit Facility will likely be reduced during 2010 as a result of the application of the covenant regarding the ratio of secured debt to adjusted EBITDA (as defined therein). The effect of reduced availability under the Credit Facility would be less available liquidity to DHI. However, even assuming such a reduction, we believe we have sufficient liquidity and capital resources to support our operations for the next twelve months. Please read Note 17—Debt—Credit Facility for further discussion of our Credit Facility.

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Operating Activities

Historical Operating Cash Flows. Dynegy's cash flow provided by operations totaled $135 million for the twelve months ended December 31, 2009. DHI's cash flow provided by operations totaled $152 million for the twelve months ended December 31, 2009. During the period, our power generation business provided positive cash flow from operations of $719 million. Cash provided by the operations of our power generation facilities was partly offset by a $173 million increase in cash collateral postings. Other included a use of cash of approximately $584 million and $567 million by Dynegy and DHI, respectively, primarily due to interest payments to service debt and general and administrative expenses. Dynegy's operating cash flow also reflected the payment of $19 million to LS Power in conjunction with the dissolution of DLS Power Holdings and DLS Power Development.

Dynegy's and DHI's cash flow provided by operations totaled $319 million for the twelve months ended December 31, 2008. During the period, our power generation business provided positive cash flow from the operations of our power generation facilities of $869 million, reflecting positive earnings for the period, partly offset by additional collateral requirements due to an increase in the volume of our hedging positions and increased payments associated with our DNE leveraged lease. Please read 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 for further discussion of the DNE lease payments. Other included a use of approximately $550 million in cash primarily due to interest payments to service debt, general and administrative expenses and a $17 million legal settlement payment previously reserved, partially offset by interest income.

Dynegy's cash flow provided by operations totaled $341 million for the twelve months ended December 31, 2007. DHI's cash flow provided by operations totaled $368 million for the twelve months ended December 31, 2007. During the period, our power generation business provided positive cash flow from operations of $934 million primarily due to positive earnings for the period, partly offset by an increased use of working capital. Other included a use of approximately $593 million in cash by Dynegy and approximately $566 million in cash by DHI relating to corporate-level expenses and our former customer risk management business.

Future Operating Cash Flows. 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, collateral requirements, the value of capacity and ancillary services, the run time of our generating facilities, the effectiveness of our commercial strategy, legal, environmental and regulatory requirements, our ability to execute the cost savings contemplated in the 2010-2013 cost savings program and our ability to capture value associated with commodity price volatility.

Collateral Postings. We 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. The following table summarizes our consolidated collateral postings to third parties by line of business at February 19, 2010, December 31, 2009 and December 31, 2008:

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	February 19, 2010	December 31, 2009 (in millions)	December 31, 2008
By Business:			
Generation business	$ 515	$ 638	$ 1,064
Other	189	189	189
Total	$ 704	$ 827	$ 1,253
By Type:			
Cash (1)	$ 204	$ 291	$ 118
Letters of credit	500	536	1,135
Total	$ 704	$ 827	$ 1,253

(1) Includes Broker margin account on our consolidated balance sheets as well as other collateral postings included in Prepayments and other current assets on our consolidated balance sheets.

The changes in letters of credit postings from December 31, 2008 to December 31, 2009 and to February 19, 2010 are primarily related to a reduction of $275 million of capacity related to our former investment in the Sandy Creek Project and lower commodity prices. The decreases were partially offset by an increase in cash collateral postings largely due to an increased volume of transactions executed through our futures clearing manager.

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. 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.

Investing Activities

Capital Expenditures. We continue to tightly manage our operating costs and capital expenditures. Our capital spending by reportable segment during 2009, 2008 and 2007 was as follows:

	December 31,		
	2009	2008 (in millions)	2007
GEN-MW	$ 533	$ 530	$ 300
GEN-WE	45	29	17
GEN-NE	28	36	47
Other	6	16	15
Total	$ 612	$ 611	$ 379

Capital spending in our GEN-MW segment primarily consisted of environmental and maintenance capital projects, as well as approximately $104 million, $203 million and $161 million spent on development capital related to the Plum Point Project during the years ended December 31, 2009, 2008 and 2007, respectively. Capital spending in our GEN-WE and GEN-NE segments primarily consisted of maintenance projects.

We expect capital expenditures for 2010 to approximate $435 million, which is comprised of $410 million, $5 million, $10 million and $10 million in GEN-MW, GEN-WE, GEN-NE and other, respectively. The $410 million of spending planned for GEN-MW includes approximately $200 million of environmental expenditures, of which approximately $185 million is related to the Midwest Consent Decree, approximately $95 million is related to maintenance on our coal and natural gas facilities, approximately $90 million is related to the Plum Point Project and approximately $25 million is related to capitalized interest. The capital expenditures related to the Plum Point Project will be largely funded by non-recourse project debt. Please read Note 17—Debt—Plum Point (Including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds) for further discussion. Other spending primarily includes maintenance capital projects and environmental projects. The capital budget is subject to revision as opportunities arise or circumstances change.

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The Midwest Consent Decree was finalized in July 2005. It prohibits us from operating certain of our power generating facilities after certain dates unless specified emission control equipment is installed. Our long-term capital expenditures in the GEN-MW segment will be significantly impacted by the Midwest Consent Decree. We anticipate our costs associated with the Midwest Consent Decree projects, which we expect to incur through 2013, to be approximately $960 million, which includes approximately $545 million spent to date. This estimate, which is broken down by year below, includes a number of assumptions about uncertainties that are beyond our control. For instance, we have assumed for purposes of this estimate that labor and material costs will increase at four percent per year over the remaining project term. The following are the estimated remaining capital expenditures required to comply with the Midwest Consent Decree:

2010	2011	2012	2013
(in millions)			
$ 185	$ 140	$ 75	$ 15

If the costs of these capital expenditures become great enough to render the operation of the affected facility or facilities uneconomical, we could, at our option, cease to operate the facility or facilities and forego these capital expenditures without incurring any further obligations under the Midwest Consent Decree. Please read Note 21—Commitments and Contingencies—Other Commitments and Contingencies—Midwest Consent Decree for further discussion.

Finally, the SPDES permits renewal application at our Roseton power generating facility and the NPDES permit at our Moss Landing power generating facility have been challenged by local environmental groups which contend the existing once-through, water cooling systems currently in place should be replaced with closed-cycle cooling systems. A decision to install a closed-cycle cooling system at the Roseton or Moss Landing facilities would be made on a case-by-case basis considering all relevant factors at such time, including any relevant costs or applicable remediation requirements. If mandated installation of closed-cycle cooling systems at either of these facilities would result in a material capital expenditure that renders the operation of a plant uneconomical, we could, at our option, and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate such facility and forego these capital expenditures.

Please read Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Disclosure of Contractual Obligations and Contingent Financial Commitments—Off-Balance Sheet Arrangements—DNE Leveraged Lease for further discussion of early lease termination payments. Please read Note 21—Commitments and Contingencies—Legal Proceedings—Roseton State Pollutant Discharge Elimination System Permit and —Commitments and Contingencies—Legal Proceedings—Moss Landing National Pollutant Discharge Elimination System Permit for further discussion.

Asset Dispositions. Proceeds from asset sales in 2009 totaled $652 million and $1,095 million for Dynegy and DHI, respectively. Of the total $936 million and $1,476 million in cash proceeds received by Dynegy and DHI, respectively, at the closing of the LS Power Transactions, $547 million and $990 million related to the disposition of assets, including our interest in the Sandy Creek Project, for Dynegy and DHI, respectively. We also received $175 million from the release of restricted cash on our consolidated balance sheets that was used to support our funding commitment to the Sandy Creek Project. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further information. The remaining $214 million of cash received upon closing the LS Power Transactions relates to the issuance of $235 million notes payable, and is included in Financing Activities. Please read "—Financing Activities" below and Note 18—Related Party Transactions for further discussion.

Additionally, during 2009, we sold the Heard County power generation facility for approximately $105 million, net of transaction costs. Please read Note 4— Dispositions, Contract Terminations and Discontinued Operations—Discontinued Operations—Heard County for further discussion.

Proceeds from asset sales in 2008 totaled $451 million, net of transaction costs, related to the sales of the Rolling Hills power generating facility, Calcasieu power generating facility, the NYMEX shares and seats, and the beneficial interest in Oyster Creek.

Proceeds from asset sales in 2007 totaled $558 million and primarily consisted of $472 million from the sale of our CoGen Lyondell power generation facility and $82 million received in connection with the sale of a portion of our interest in the Plum Point Project. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations for further discussion.

Consistent with industry practice, we regularly evaluate our generation fleet based primarily on geographic location, fuel supply, market structure and market recovery expectations. We consider divestitures of non-core assets where the balance of the above factors 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. We have previously indicated that we consider our investment in PPEA Holding a non-core asset and intend to pursue alternatives regarding our remaining ownership interest.

Other Investing Activities. Cash inflows related to short-term investments during the year ended December 31, 2009 totaled $17 million and $16 million for Dynegy and DHI, respectively, reflecting a distribution from our short-term investments. Cash outflows related to short-term investments during the year ended December 31, 2008 totaled $27 million and $25 million for Dynegy and DHI, respectively, as a result of a reclassification from cash equivalents to short-term investments.

Dynegy made $16 million and $10 million in contributions to DLS Power Holdings during the years ended December 31, 2008 and 2007, respectively. We received a distribution of approximately $7 million and repayment of approximately $3 million of an affiliate receivable upon the sale of a partial interest in Sandy Creek during the year ended December 31, 2008. We received a distribution of approximately $13 million upon the sale of a partial interest in Sandy Creek during the year ended December 31, 2007. Please read Note 14—Variable Interest Entities—Sandy Creek for further discussion.

We paid $128 million, net of cash acquired, during the year ended December 31, 2007 in connection with the completion of the LS Power Merger. Please read Note 3—Business Combinations and Acquisitions—LS Power Business Combination for more information.

There was a $190 million cash inflow during the year ended December 31, 2009 for both Dynegy and DHI, related to changes in restricted cash balances primarily due to the release of $175 million of restricted cash that was used to support our funding commitment to the Sandy Creek Project. There was an $80 million cash inflow during the year ended December 31, 2008 due to changes in restricted cash balances primarily due to a reduction of our cash collateral as a result of SCEA's sale of an 11 percent undivided interest in the Sandy Creek Project, the release of restricted cash and the use of restricted cash for the ongoing construction of the Plum Point project, partially offset by interest income. The increase in restricted cash and investments of $871 million during the twelve months ended December 31, 2007 related primarily to a $650 million deposit associated with our cash collateralized facility, and $323 million posted in support of our proportionate share of capital commitments in connection with the Sandy Creek Project. These additional postings were partially offset by the release of Independence restricted cash in exchange for the posting of a letter of credit.

DHI's affiliate transactions during the year ended December 31, 2009 included $97 million related to the LS Power Transactions. Dynegy repurchased 245 million of its Class B shares with a fair value of $443 million (based on a share price of $1.81 on November 30, 2009) from LS Power by exchanging assets owned by DHI for the shares. In order to effect this exchange, Dynegy paid $540 million cash to a subsidiary of LS Power in exchange for the shares, immediately following which a separate subsidiary of LS Power paid $540 million of cash to DHI in exchange for the assets. The $97 million represents the difference between the $540 million cash received by DHI and the $443 million fair value of the shares received by Dynegy.

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Other included $3 million of insurance proceeds received during the year ended December 31, 2009. Other included $7 million of insurance proceeds received during the year ended December 31, 2008. Additionally, included in Other for Dynegy for the year ended December 31, 2008 is $4 million of proceeds from the liquidation of an investment.

Financing Activities

Historical Cash Flow from Financing Activities. Dynegy's net cash used in financing activities during the twelve months ended December 31, 2009 totaled $608 million. Repayments of borrowings were $890 million, and consisted of the following:

- $421 million in aggregate principal amount on our 6.875 percent senior unsecured notes due 2011 ("2011 Notes");
- $412 million in aggregate principal amount on our 8.75 percent senior unsecured notes due 2012 ("2012 Notes"); and
- $57 million in aggregate principal amount on our Sithe 9.00 percent secured bonds due 2013.

We also paid debt extinguishment costs of $46 million in connection with the repayment of the 2011 Notes and 2012 Notes.

These payments were partially offset by $328 million of net proceeds from the following borrowings:

- $130 million under the PPEA Credit Agreement Facility; and
- $214 million of cash proceeds from the LS Power Transactions allocated to the issuance of $235 million 7.5 percent senior unsecured notes due 2015.

These borrowings were partly offset by $16 million of financing fees related to the Credit Facility Amendment No. 4.

DHI's net cash used in financing activities during the twelve months ended December 31, 2009 totaled $1,193 million. This included the net $608 million used in repayments and extinguishment costs, net of borrowings, incurred by Dynegy, as set forth above, as well as $585 million in aggregate dividend payments to Dynegy.

Dynegy's net cash provided by financing activities during the twelve months ended December 31, 2008 totaled $148 million and DHI's net cash provided by financing activities during the twelve months ended December 31, 2008 totaled $146 million. The cash provided by financing activities primarily related to $192 million of proceeds from borrowings under the PPEA Credit Agreement Facility, partly offset by a $45 million principal payment on our 9.00 percent Sithe secured bonds due 2013.

Dynegy's net cash provided by financing activities during the twelve months ended December 31, 2007 totaled $433 million, which primarily related to $2,758 million of proceeds from long-term borrowings, net of approximately $35 million of debt issuance costs, partially offset by $2,320 million of payments. DHI's net cash provided by financing activities during the twelve months ended December 31, 2007 of $369 million also includes dividend payments of $342 million to Dynegy.

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Summarized Debt and Other Obligations. The following table depicts our consolidated third party debt obligations, including the present value of the DNE leveraged lease payments discounted at 10 percent, and the extent to which they are secured as of December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008
	(in millions)	
First secured obligations	$ 918	$ 919
Unsecured obligations	3,645	4,245
Lease obligations (1)	626	700
Total corporate obligations	5,189	5,864
PPEA and Sithe secured non-recourse obligations (2)	1,031	959
Total obligations	6,220	6,823
Less: Lease obligations (1)	(626)	(700)
Other (3)	(12)	13
Total notes payable and long-term debt (4)	$ 5,582	$ 6,136

(1) Represents present value of future lease payments associated with the DNE lease financing discounted at 10 percent.
(2) Includes PPEA's non-recourse project financing of $644 million and tax-exempt bonds of $100 million. Although we own a 37 percent interest in PPEA Holding, we consolidate PPEA Holding and the debt of its subsidiary, as we are the primary beneficiary of this VIE. Also includes project financing associated with our Independence facility. Please read Note 14—Variable Interest Entities for further discussion.
(3) Consists of net premiums (discounts) on debt of $(12) million at December 31, 2009 and $13 million at December 31, 2008.
(4) Does not include letters of credit.

Please read Note 17—Debt for further discussion of these items. Our debt maturity profile as of December 31, 2009 includes $63 million in 2010, $150 million in 2011, $164 million in 2012, $1,006 million in 2013, zero in 2014 and approximately $3,455 million thereafter. Maturities for 2010 represent principal payments on the Sithe Senior Notes.

In addition to the $63 million of debt maturities due in 2010, we have classified $744 million of PPEA's non-recourse project financing and tax-exempt bonds as current liabilities, as PPEA does not expect to be in compliance with certain restrictions of the applicable financing agreement within the next twelve months. These liabilities are non-recourse to us, and our obligation to support PPEA is limited to a $15 million letter of credit we have posted in support of our contingent equity contribution. Please read Note 17—Debt—Plum Point (Including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds) for further discussion.

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 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 Dynegy or DHI credit ratings or Dynegy's 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.

On October 16, 2009, Standard & Poor's downgraded PPEA's credit rating. Because of this downgrade, certain interest rate swaps to which PPEA is a party may be terminated by the counterparties if there is also a default by the insurer, Ambac, which provides financial guarantee insurance for the swaps. The termination value of the PPEA interest rate swaps at December 31, 2009 was approximately $80 million. Termination of the interest rate swaps, if not paid by

PPEA, could result in the acceleration of the PPEA debt. Our obligations related to our investment in PPEA, excluding the noncontrolling interest holders' obligation, are limited to a $15 million letter of credit issued under our Credit Facility to support our contingent equity contribution to PPEA. Please read Note 17—Debt—Plum Point (Including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds) for further discussion.

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Financial Covenants. Our Credit Facility contains certain financial covenants, including (i) a covenant (measured as of the last day of the relevant fiscal quarter as specified below) that requires DHI and certain of its subsidiaries to maintain a ratio of secured debt to adjusted EBITDA (each as defined therein) for DHI and its relevant subsidiaries of no greater than a specified amount; and (ii) a covenant that requires DHI and certain of its subsidiaries to maintain a ratio of adjusted EBITDA to consolidated interest expense (each as defined therein) for DHI and its relevant subsidiaries as of the last day of the measurement periods as specified below of no less than a specified amount. The following table summarizes the required ratios:

Period Ended:	(i) Secured Debt : Adjusted EBITDA No greater than:	(ii) Adjusted EBITDA : Interest Expense No less than:
December 31, 2009	3.00 : 1	1.75 : 1
March 31, 2010	3.25 : 1	1.70 : 1
June 30, 2010	3.25 : 1	1.60 : 1
September 30, 2010	3.50 : 1	1.30 : 1
December 31, 2010	3.50 : 1	1.30 : 1
March 31, 2011	3.50 : 1	1.35 : 1
June 30, 2011	3.50 : 1	1.40 : 1
September 30, 2011	3.25 : 1	1.60 : 1
December 31, 2011	3.00 : 1	1.60 : 1
Thereafter	2.50 : 1	1.75 : 1

We are in compliance with these covenants as of December 31, 2009. We may in the future experience a reduction in availability under our Credit Facility as a result of EBITDA levels in future periods and a corresponding borrowing limitation under the secured debt to EBITDA covenant. Despite this potential reduction in our available liquidity, we believe we have sufficient liquidity and capital resources to support our operations for the next twelve months. Please read "Revolver Capacity" above for further discussion.

Subject to certain exceptions, DHI and its relevant subsidiaries are subject to restrictions on asset sales, incurring additional indebtedness, limitations on investments and certain limitations on dividends and other payments in respect of capital stock. Please read Note 17—Debt—Credit Facility for further discussion of our amended credit facility.

Capital-Structuring 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 may explore additional sources of external liquidity, including public or private debt or equity issuances. Matters to be considered will include cash interest expense, covenant flexibility and maturity profile, all to be balanced with maintaining adequate liquidity. The timing of any transaction may be impacted by events, such as strategic growth opportunities, legal judgments or regulatory or environmental requirements as well as any decisions to seek an improved credit profile. The receptiveness of the capital markets to an offering of debt or equity securities 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, including current market conditions. Any issuance of equity by Dynegy likely would have other effects as well, including stockholder dilution, and our ability to issue equity securities is limited by the New Shareholder Agreement. This agreement provides that we will not issue Dynegy's equity securities for our own purposes until the earlier of (i) March 31, 2010 or (ii) the first date following closing of the transaction in which LS Power owns, in aggregate, less than 10 percent of Dynegy's then outstanding Class A common stock. Our ability to issue debt securities is limited by our financing agreements, including our Credit Facility.

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In addition, we continually review and discuss opportunities to participate in what we believe will be continuing consolidation of the power generation industry. No such definitive transaction has been agreed to and none can be guaranteed to occur; however, we have successfully executed on similar opportunities in the past and could do so again in the future. Depending on the terms and structure of any such transaction, we could issue significant debt and/or equity securities for capital-raising purposes. We also could be required to assume substantial debt obligations and the underlying payment obligations.

Dividends on Dynegy Common Stock. Dividend payments on Dynegy's common stock are at the discretion of its Board of Directors. Dynegy did not declare or pay a dividend on its common stock for the year ended December 31, 2009 and it does not expect to pay a dividend on its common stock in the foreseeable future.

Credit Ratings

Our credit rating status is currently "non-investment grade"; our senior unsecured debt is rated "B" by Standard & Poor's, "B3" by Moody's, and "B" by Fitch.

Disclosure of Contractual Obligations and Contingent Financial Commitments

We have incurred various 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 revenue-producing activities. Contingent financial commitments represent obligations that become payable only if specified events occur, such as financial guarantees. Details on these obligations are set forth below.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2009. Cash obligations reflected are not discounted and do not include accretion or dividends.

		Expiration by Period			
	Total	Less than 1 Year	1 – 3 Years	3 - 5 Years	More than 5 Years
			(in millions)		
Long-term debt (including current portion) (1)	$5,582	$807	$314	$1,006	$3,455
Interest payments on debt	2,992	377	744	738	1,133
Operating leases	1,026	120	333	312	261
Capital leases	10	2	4	3	1
Coal commitments (2)	391	253	134	4	—
Capacity payments	180	33	65	64	18
Interconnection obligations	18	1	2	2	13
Construction service agreements	340	26	85	96	133
Pension funding obligations	60	19	41	—	—
Other obligations	22	6	5	4	7
Total contractual obligations	$10,621	$1,644	$1,727	$2,229	$5,021

(1) Includes $644 million of PPEA's Construction Loan and $100 million of PPEA's Tax Exempt Bonds. We have classified this $744 million in current liabilities, as PPEA does not expect to be in compliance with certain restrictions of the applicable financing agreement within the next twelve months. Please read Note 17—Debt—Plum

Point (Including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds) for further discussion.

(2) Included based on nature of purchase obligations under associated contracts.

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Long-Term Debt (Including Current Portion). Total amounts of Long-term debt (including current portion) are included in the December 31, 2009 consolidated balance sheet. Please read Note 17—Debt for further discussion.

Interest Payments on Debt. Interest payments on debt represent periodic interest payment obligations associated with our long-term debt (including current portion). Please read Note 17—Debt for further discussion.

Operating Leases. Operating leases includes the minimum lease payment obligations associated with our DNE leveraged lease. Please read "—Liquidity and Capital Resources—Off-Balance Sheet Arrangements—DNE Leveraged Lease" for further discussion. 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 two VLGCs previously utilized in our former global liquids business. The aggregate minimum base commitments of the charter party agreements are approximately $14 million each year for the years 2010 through 2012, and approximately $17 million in aggregate for the period from 2013 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 $17 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 September 2013 and September 2014, respectively. We have 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. We have an obligation under a capital lease related to a coal loading facility, which is used in the transportation of coal to our Vermilion power generating facility. Pursuant to our agreement with the lessor, we are obligated for minimum payments in the aggregate amount of $10 million over the remaining term of the lease.

Coal Commitments. At December 31, 2009, we had contracts in place to supply coal to various of our generation facilities with minimum commitments of $391 million. Obligations related to the purchase of coal were $372 million through 2012, and obligations related to the transportation were $19 million through 2013.

Capacity Payments. Capacity payments include fixed obligations associated with transmission, transportation and storage arrangements totaling approximately $180 million.

Interconnection Obligations. Interconnection obligations represent an obligation with respect to interconnection services for our Ontelaunee facility. This agreement expires in 2025. Our obligation under this agreement is approximately $1 million per year through the term of the contract.

Construction Service Agreements. Construction service agreements represent obligations with respect to long-term plant maintenance agreements. Our obligation under these agreements is approximately $340 million.

Pension Funding Obligations. Amounts include estimated defined benefit pension funding obligations for 2010—$19 million, 2011—$11 million and 2012—$30 million. These amounts reflect increases over prior amounts resulting from declines in investment performance as a result of the ongoing turmoil in the debt and equity markets. Although we expect to continue to incur funding obligations subsequent to 2012, we cannot confidently estimate the amount of such obligations at this time and, therefore, have not included them in the table above. Please read Note 23—Employee Compensation, Savings and Pension Plans—Pension and Other Post-Retirement Benefits—Obligations and Funded Status for further discussion.

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Other Obligations. Other obligations include the following items:

- Payments associated with a capacity contract between Independence and Con Edison. The aggregate payments through the 2014 expiration are approximately $11 million as of December 31, 2009; and

- Reserves of $5 million recorded in connection with uncertain tax positions. Please read Note 19—Income Taxes—Unrecognized Tax Benefits for further discussion.

Contingent Financial Obligations

The following table provides a summary of our contingent financial obligations as of December 31, 2009 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)	$536	$458	$78	$—	$—
Surety bonds (2)	8	8	—	—	—
Guarantees	1	—	1	—	—
Total financial commitments	$545	$466	$79	$—	$—

(1) Amounts include outstanding letters of credit.

(2) Surety bonds are generally on a rolling 12-month basis. The $8 million of surety bonds are primarily supported by collateral.

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 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, for approximately $920 million 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 were 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 pass-through trust certificates and the lessor notes are held by pass-through trusts for the benefit of the certificate holders. 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, 2009, future lease payments are $95 million for 2010, $112 million for 2011, $179 million for 2012, $142 million for 2013, $143 million for 2014 and $248 million in the aggregate due from 2015 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, 2009, the present value (discounted at 10 percent) of future lease payments was $626 million.

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

	2009	2008	2007
		(in millions)	
Lease Expense	$ 50	$ 50	$ 50
Lease Payments (Cash Flows)	$ 141	$ 144	$ 107

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 compensate the lessor for termination of the lease, including redeeming 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, 2009, the termination payment at par would be approximately $853 million for all of the leased facilities. If a termination of this type were to occur with respect to all of the leased 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.

Commitments and Contingencies

Please read Note 21—Commitments and Contingencies, which is incorporated herein by reference, for further discussion of our material commitments and contingencies.

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 the years ended December 31, 2009, 2008 and 2007. At the end of this section, we have included our business outlook for each segment.

We report results of our power generation business as three separate geographical segments as follows: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. Because of the diversity among their respective operations and how we allocate our resources, we report the results of each business as a separate segment in our consolidated financial statements. The results of our legacy operations, including CRM, are included in Other. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization. Our 50 percent investment in SCH, which was sold in the fourth quarter 2009, is included in GEN-WE for reporting purposes. Dynegy’s 50 percent investment in DLS Power Development, which was terminated effective January 1, 2009, is included in Other for segment reporting.

Summary Financial Information. The following tables provide summary financial data regarding Dynegy’s consolidated and segmented results of operations for 2009, 2008 and 2007, respectively.

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Dynegy's Results of Operations for the Year Ended December 31, 2009

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$1,257	$380	$834	$(3)	$2,468
Cost of sales	(505)	(156)	(534)	1	(1,194)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(222)	(120)	(181)	4	(519)
Depreciation and amortization expense	(215)	(62)	(47)	(11)	(335)
Goodwill impairments	(76)	(260)	(97)	—	(433)
Impairment and other charges, exclusive of goodwill impairments shown separately above	(147)	—	(391)	—	(538)
Loss on sale of assets	(96)	—	(28)	—	(124)
General and administrative expense	—	—	—	(159)	(159)
Operating loss	$(4)	$(218)	$(444)	$(168)	$(834)
Earnings (losses) from unconsolidated investments	—	(72)	—	1	(71)
Other items, net	2	3	1	5	11
Interest expense and debt extinguishment costs					(461)
Loss from continuing operations before income taxes					(1,355)
Income tax benefit					315
Loss from continuing operations					(1,040)
Loss from discontinued operations, net of taxes					(222)
Net loss					(1,262)
Less: Net loss attributable to the noncontrolling interests					(15)
Net loss attributable to Dynegy Inc.					$(1,247)

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Dynegy's Results of Operations for the Year Ended December 31, 2008

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$1,621	$702	$1,006	$(5)	$3,324
Cost of sales	(583)	(415)	(705)	10	(1,693)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(203)	(98)	(180)	15	(466)
Depreciation and amortization expense	(205)	(77)	(54)	(10)	(346)
Gain on sale of assets	56	11	—	15	82
General and administrative expense	—	—	—	(157)	(157)
Operating income (loss)	$686	$123	$67	$(132)	$744
Losses from unconsolidated investments	—	(40)	—	(83)	(123)
Other items, net	—	5	6	73	84
Interest expense					(427)
Income from continuing operations before income taxes					278
Income tax expense					(90)
Income from continuing operations					188
Loss from discontinued operations, net of taxes					(17)
Net income					171
Less: Net loss attributable to the noncontrolling interests					(3)
Net income attributable to Dynegy Inc.					$174

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Dynegy's Results of Operations for the Year Ended December 31, 2007

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$1,323	$506	$1,076	$13	$2,918
Cost of sales	(481)	(286)	(688)	19	(1,436)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(190)	(67)	(179)	(4)	(440)
Depreciation and amortization expense	(193)	(55)	(45)	(13)	(306)
Gain on sale of assets	39	—	—	4	43
General and administrative expense	—	—	—	(203)	(203)
Operating income (loss)	$498	$98	$164	$(184)	$576
Earnings (losses) from unconsolidated investments	—	6	—	(9)	(3)
Other items, net	—	—	—	56	56
Interest expense					(384)
Income from continuing operations before income taxes					245
Income tax expense					(140)
Income from continuing operations					105
Income from discontinued operations, net of taxes					166
Net income					271
Less: Net income attributable to the noncontrolling interests					7
Net income attributable to Dynegy Inc.					$264

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The following tables provide summary financial data regarding DHI's consolidated and segmented results of operations for 2009, 2008 and 2007, respectively.

DHI's Results of Operations for the Year Ended December 31, 2009

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE (in millions)	Other	Total
Revenues	$ 1,257	$ 380	$ 834	$ (3)	$ 2,468
Cost of sales	(505)	(156)	(534)	1	(1,194)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(222)	(120)	(181)	2	(521)
Depreciation and amortization expense	(215)	(62)	(47)	(11)	(335)
Goodwill impairments	(76)	(260)	(97)	—	(433)
Impairment and other charges, exclusive of goodwill impairments shown separately above	(147)	—	(391)	—	(538)
Loss on sale of assets	(96)	—	(28)	—	(124)
General and administrative expense	—	—	—	(159)	(159)
Operating loss	$ (4)	$ (218)	$ (444)	$ (170)	$ (836)
Losses from unconsolidated investments	—	(72)	—	—	(72)
Other items, net	2	3	1	4	10
Interest expense and debt extinguishment costs					(461)
Loss from continuing operations before income taxes					(1,359)
Income tax benefit					313
Loss from continuing operations					(1,046)
Loss from discontinued operations, net of taxes					(222)
Net loss					(1,268)
Less: Net loss attributable to the noncontrolling interests					(15)
Net loss attributable to Dynegy Holdings Inc.					$ (1,253)

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DHI's Results of Operations for the Year Ended December 31, 2008

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$1,621	$702	$1,006	$(5)	$3,324
Cost of sales	(583)	(415)	(705)	10	(1,693)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(203)	(98)	(180)	15	(466)
Depreciation and amortization expense	(205)	(77)	(54)	(10)	(346)
Gain on sale of assets	56	11	—	15	82
General and administrative expense	—	—	—	(157)	(157)
Operating income (loss)	$686	$123	$67	$(132)	$744
Losses from unconsolidated investments	—	(40)	—	—	(40)
Other items, net	—	5	6	72	83
Interest expense					(427)
Income from continuing operations before income taxes					360
Income tax expense					(138)
Income from continuing operations					222
Loss from discontinued operations, net of taxes					(17)
Net income					205
Less: Net loss attributable to the noncontrolling interests					(3)
Net income attributable to Dynegy Holdings Inc.					$208

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DHI's Results of Operations for the Year Ended December 31, 2007

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$1,323	$506	$1,076	$13	$2,918
Cost of sales	(481)	(286)	(688)		