DYNEGY INC /IL/
Form 10-K
March 14, 2005
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2004

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

For the transition period from to

Commission file number: 1-15659

DYNEGY INC.

(Exact name of registrant as specified in its charter)

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

1000 Louisiana, Suite 5800

Houston, Texas 77002

(Address of principal executive offices)

(Zip Code)

(713) 507-6400

(Registrant s telephone number, including area code)

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

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

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

Title of each class	Name of each exchange on which registered
None	

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. x

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes x No ¨

The aggregate market value of the voting and non-voting equity held by non-affiliates of the registrant as of June 30, 2004, computed by reference to the closing sale price of the registrant s common stock on the New York Stock Exchange on such date, was $1,191,578,385, using the definition of beneficial ownership contained in Rule 13d-3 under the Securities Exchange Act of 1934 and excluding shares held by directors and executive officers.

Number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date: Class A common stock, no par value per share, 283,759,437 shares outstanding as of March 4, 2005; Class B common stock, no par value per share, 96,891,014 shares outstanding as of March 4, 2005.

DOCUMENTS INCORPORATED BY REFERENCE. Part III (Items 10, 11, 12, 13 and 14) incorporates by reference portions of the Notice and Proxy Statement for the registrant s 2005 Annual Meeting of Shareholders, which will be filed not later than 120 days after December 31, 2004.

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DYNEGY INC. FORM 10-K

INTRODUCTORY NOTE

This Form 10-K reflects the effect of the following items on our historical consolidated financial statements and related information, as reported in Amendment No. 2 to our Annual Report of Form 10-K for the year ended December 31, 2003, which was filed on January 18, 2005:

An increase of $16 million to the after-tax asset impairment charge of $120 million originally recorded in the fourth quarter 2003, associated with the sale of Illinois Power and

A $45 million increase to our deferred tax liability at December 31, 2003, as well as increases to income tax expense in periods prior to 2004, related to errors in our previously completed tax basis balance sheet review.

Although neither of these items were considered material to the periods to which they related, these items, in aggregate, are material to our 2004 results. We are required to restate prior periods in accordance with APB 20, Accounting Changes. The items are discussed in more detail in the Explanatory Note to the accompanying consolidated financial statements beginning on page F-10. The following Items of our Form 10-K for the year ended December 31, 2003, as amended by Amendment No. 2, are affected by these items:

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

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

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

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PART I

DEFINITIONS

As used in this Form 10-K, the abbreviations contained herein have the meanings set forth in the glossary beginning on page F-86. Additionally, the terms Dynegy, we, us and our refer to Dynegy Inc. and its subsidiaries, unless the context clearly indicates otherwise.

Item 1. *Business*

THE COMPANY

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily in two areas of the energy industry: power generation and natural gas liquids.

During 2004, we made substantial progress toward the completion of our efforts to restructure our company to align more closely our asset base with our business strategy. Our significant accomplishments during this period include the sale of Illinois Power to Ameren for $2.3 billion, which reduced debt and preferred stock obligations by $1.8 billion, the replacement of our $1.1 billion credit facility with a new $1.3 billion credit facility, the restructuring of our Independence and Kendall tolling arrangements, the termination of four long-term natural gas transportation agreements, sales of non-core GEN and NGL assets generating approximately $260 million in proceeds and the pre-payment of the ABG Gas Supply financing and the ChevronTexaco junior notes.

We also continued our exit from the customer risk management business. Collateral to support our CRM business declined 22% from $121 million at the end of 2003 to $94 million at the end of 2004, primarily due to termination of the ABG Gas Supply contract. Our remaining customer risk management business, which primarily consists of our three remaining power tolling arrangements (including the Gregory toll, which expires in July 2005, but excluding the Independence toll, which is now part of our GEN segment) as well as our gas transportation agreements and legacy power and gas trading positions, will continue to impact negatively our cash flows and operating results until the associated obligations have been terminated, restructured or satisfied.

With only a few significant legacy matters remaining to be addressed, more of our company s resources are available to continue our efforts to operate our energy businesses safely, reliably and efficiently, to manage the costs across our organization and to deliver value to our investors. We are also continuing to focus on identifying and evaluating strategic growth opportunities, particularly organic or bolt-on projects, such as the conversion of our Havana power generating facility to lower-cost and lower-emission PRB coal, to improve the operational performance and efficiency of certain assets, enabling us to realize costs savings and to capture even more of the benefit of increases in commodity prices.

Such opportunities may also include merger and acquisition activities, which we discuss and evaluate as part of our ongoing business strategy. For example, in January 2005 we completed the purchase from Exelon Corporation of all of the outstanding capital stock of ExRes SHC, Inc., the parent company of Sithe Energies, Inc., which we refer to as Sithe Energies, and Sithe/Independence Power Partners, L.P., which we refer to as Independence. The financial terms of the acquisition included our payment of $135 million, subject to certain specified purchase price adjustments, and our consolidation of $919 million in face value project debt. Through this acquisition, we acquired the 1,021 MW combined-cycle Independence power generation facility located near Scriba, NY, four natural gas-fired merchant facilities in New York and four hydroelectric generation facilities in Pennsylvania. Independence holds power tolling, financial swap and other contracts with other of our subsidiaries. As a result of the acquisition, these contracts have become intercompany agreements and their financial statement impact will be substantially eliminated. This transaction both furthered our restructuring goal of addressing our outstanding power tolling arrangements, as well as enabled us to expand our generation capacity in a market where we have an existing presence.

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

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document we file at the SEC s Public Reference Room at 450 Fifth Street, N.W., 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 website, 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.

SEGMENT DISCUSSION

Our current business operations are focused primarily in two areas of the energy industry: power generation and natural gas liquids. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. As described below, our former regulated energy delivery business, which was conducted through Illinois Power and its subsidiaries, was sold to Ameren Corporation on September 30, 2004. We also separately report the results of our customer risk management business, which primarily consists of our three remaining power tolling arrangements (including the Gregory toll, which expires in July 2005, but excluding the Independence toll, which is part of our GEN segment for 2005) as well as our gas transportation contracts and legacy gas and power trading positions. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and infrastructure depreciation and amortization, but because of their nature, these items are not reported as a separate segment.

Power Generation

General. Our power generation segment is engaged in the production and sale of electric power from our owned and leased facilities. We sell power and related products and services, including capacity, into real-time and day-ahead markets, as well as on a forward basis. We seek to optimize our power generating assets and to mitigate our exposure to commodity prices through financial instruments and other transactions, including hedges related to our generation capacity and power purchases related to our supply obligations. Additionally, to mitigate risk related to fuel requirements at our generation facilities, we are also party to long-term coal purchase and transportation agreements and to short-term natural gas and fuel oil agreements.

We sell our power products and services under short- and long-term agreements. Short-term sales usually occur through industry standard contracts. Conversely, long-term sales usually occur under negotiated arrangements. Long-term contractual arrangements that we may enter into include:

- Sales of capacity purchased by customers to meet regulatory reserve requirements. Under these types of contracts, the purchasers may also acquire the option to purchase energy at an index or other pre-arranged price.

Tolling agreements under which we receive fixed payments in return for the customer s ability to purchase fuel for one of our facilities and take title to the power generated. Some contracts may also include provisions for reimbursement of variable operating and maintenance costs.

Ancillary services agreements under which we sell load regulation, scheduling services, reserves and voltage support to purchasers for fixed prices.

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Our customers include independent system operators (ISOs), municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities, industrial customers, power marketers, other power generators and commercial end-users.

Additionally, markets exist for the purchase and sale of emission credits. From time to time, we either purchase emission credits from third parties in quantities sufficient to operate our plants within the emission guidelines of the various air districts or pay mitigation fees to the applicable air district as required. We may also sell emission credits that we do not need to utilize with respect to emissions from our generating facilities. Please read Regulation Power Generation Regulation beginning on page 21 and Environmental and Other Matters beginning on page 24 for further discussion of the environmental and regulatory restrictions applicable to our business.

U.S. Generation Facilities. We own or lease electric power generation facilities with an aggregate net generating capacity of 11,699 MWs located in six regions of the United States. The following table describes our current generation facilities by name, region, location, net capacity, fuel and dispatch type.

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REGIONAL SUMMARY OF OUR U.S. GENERATION FACILITIES[1]

(as of December 31, 2004)

Region/Facility	Location	Total Net Generating Capacity (MWs)	Primary Fuel Type	Dispatch Type
Midwest-MAIN				
Baldwin	Baldwin, IL	1,768	Coal	Baseload
Havana:				
Havana Units 1-5	Havana, IL	238	Oil	Peaking
Havana Unit 6	Havana, IL	445	Coal	Baseload
Hennepin	Hennepin, IL	290	Coal	Baseload
Oglesby	Oglesby, IL	54	Gas	Peaking
Stallings	Stallings, IL	82	Gas	Peaking
Tilton	Tilton, IL	176	Gas	Peaking
Vermilion	Oakwood, IL	191	Coal/Gas/Oil	Baseload/ Peaking
Wood River:				
Wood River Units 1-3	Alton, IL	130	Gas	Peaking
Wood River Units 4-5	Alton, IL	452	Coal	Baseload
Rocky Road (2)	East Dundee, IL	165	Gas	Peaking
Total Midwest-MAIN		3,991		
Midwest-ECAR				
Riverside (6)	Louisa, KY	495	Gas	Peaking
Rolling Hills	Wilkesville, OH	825	Gas	Peaking
Foothills	Louisa, KY	330	Gas	Peaking
Renaissance	Carson City, MI	660	Gas	Peaking
Bluegrass	Oldham Co., KY	495	Gas	Peaking
Total Midwest-ECAR		2,805		
Northeast-NPCC				
Roseton (3)	Newburgh, NY	1,210	Gas/Oil	Intermediate
Danskammer:				
Danskammer Units 1 2	Newburgh, NY	128	Gas/Oil	Peaking
Danskammer Units 3-4 (3)	Newburgh, NY	370	Coal/Gas/Oil	Baseload
Total Northeast-NPCC		1,708		
Southeast-SERC				
Calcasieu	Sulphur, LA	320	Gas	Peaking
Heard County	Heard Co., GA	495	Gas	Peaking
Rockingham	Rockingham, NC	825	Gas/Oil	Peaking
Total Southeast-SERC		1,640		
West-WECC				
Cabrillo I Encina (4)	Carlsbad, CA	480	Gas	Intermediate

Black Mountain (5)	Las Vegas, NV	43	Gas	Baseload
El Segundo (4)	El Segundo, CA	335	Gas	Intermediate
Cabrillo II (4)	San Diego, CA	87	Gas	Peaking
Total West-WECC		945		
Texas-ERCOT				
CoGen Lyondell	Houston, TX	610	Gas	Baseload
TOTAL		11,699		

(1) We own 100% of each unit listed except as otherwise indicated. For each unit in which we own less than a 100% interest, the Total Net Generating Capacity set forth in this table includes only our proportionate share of such unit s gross generating capacity.

(2) We own a 50% interest in this facility and the remaining 50% interest is held by NRG Energy, Inc.

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(3) We lease the Roseton facility and units 3 and 4 of the Danskammer facility pursuant to a leveraged lease arrangement that is further described in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Off-Balance Sheet Arrangements DNE Leveraged Lease beginning on page 45.
(4) We own a 50% interest in each of these facilities through West Coast Power, L.L.C., a joint venture with NRG Energy. Our 50% interest in West Coast Power s Long Beach generation facility has not been included because this asset was retired effective January 1, 2005 as discussed further below.
(5) We own a 50% interest in this facility and the remaining 50% interest is held by ChevronTexaco.
(6) We lease this facility.

Midwest region Mid-America Interconnected Network (MAIN). At December 31, 2004, we owned nine generating facilities with an aggregate net generating capacity of 3,991 MWs located within MAIN. The generating capacity of our MAIN facilities represents approximately 6% of the generating capacity within the MAIN region. The MAIN market includes all of Illinois and portions of Missouri, Wisconsin, Iowa, Minnesota and Michigan.

Approximately 50% of the power generated by our MAIN facilities was sold pursuant to a former power purchase agreement between DMG and Illinois Power which expired at the end of 2004. This agreement, which was served through Illinois Power s former generation facilities now owned by DMG, provided Illinois Power with approximately 70% of its capacity requirements through December 2004. The contract provided for fixed capacity payments based on the capacity reserved, as well as variable energy payments for each MWh of energy delivered under the contract based on DMG s cost of generation. Under the former agreement, DMG served as the provider of last resort to Illinois Power, providing the resources through which Illinois Power fulfilled its load obligations; it also supplied all ancillary services required by Illinois Power. This power purchase agreement provided a substantial portion of the operating income from our power generation business in 2004.

In connection with our sale of Illinois Power to Ameren in the third quarter 2004, we entered into a new contract to sell to Illinois Power 2,800 MWs of capacity at $48 per KW-yr and up to 11.5 million MWh of energy at a fixed price of $30 per MWh to Illinois Power for two years beginning in January 2005. We also agreed to sell 300 MWs of capacity in 2005 and 150 MWs of capacity in 2006 to Illinois Power at a fixed price of $16 per KW-yr with an option to purchase energy at market-based prices. Under this arrangement, we no longer are the provider of last resort to Illinois Power. Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations 2005 Outlook GEN Outlook beginning on page 67 for further discussion.

Approximately 9% of our total capacity in this region which is not committed under the Illinois Power power purchase agreement will be sold under capacity contracts in 2005, including 165 MWs related to our interest in Rocky Road through 2009. The remainder of the capacity and energy is sold primarily into wholesale markets in MAIN, the neighboring East Central Reliability, or ECAR, and the Pennsylvania-New Jersey-Maryland market, or PJM.

All of our MAIN facilities (except Rocky Road, which is located in PJM) are located in a market to be administered by the Midwest ISO Regional Transmission Organization, or MISO. Formation of MISO was approved by the FERC in 2001, and MISO currently administers transmission operations. MISO has received FERC approval to begin operating energy markets on April 1, 2005. MISO has indicated that it plans to use locational-pricing for energy, as well as financial transmission rights to allow market participants to manage transmission risks. MISO has proposed implementation of a capacity market by June 1, 2006, but has not yet committed to a specific market design. The impact on our results of operations, financial condition and cash flows of MISO capacity market structures, should they be implemented, cannot currently be estimated.

The MAIN region currently has excess generation capacity as a result of recent development projects. This overcapacity is evidenced by the NERC s estimated 2004 reserve margin of 30%. MISO proposals to implement

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reserve requirements and capacity markets are currently under development, but we expect reserve margin targets will generally be consistent with the 15% target reserve margin of Pennsylvania-New Jersey-Maryland Interconnection, LLC, or PJM. Overcapacity in the MAIN region has depressed energy and capacity prices and likely will continue to do so absent peak demand growth and/or plant retirements. Based on current expectations of future demand growth and retirements, we believe that reserve margins are likely to return to target levels within the next 3-5 years.

Midwest region East Central Area Reliability Council (ECAR). We own or lease interests in five generating facilities with an aggregate net generating capacity of 2,805 MWs located within ECAR. The majority of the power generated by our ECAR facilities is sold to wholesale customers in the ECAR market, which includes all or portions of the states of Indiana, Ohio, Michigan, Virginia, West Virginia, Tennessee, Kentucky, Maryland and Pennsylvania.

At the end of 2003, we entered into a contract for 495 MWs of our Renaissance facility s generating capacity, which expired in September 2004. In July 2004, we entered into an agreement with a term from June 2005 through May 2006 to sell 500 MWs of capacity from our peaking facilities in the ECAR region. In August 2004, we entered into an additional agreement with a term from May 2005 through September 2005 to sell 330 MWs of our Renaissance facility s net generating capacity. The generating capacity of our ECAR facilities represents approximately 2% of the generating capacity within the region.

Our Renaissance and Bluegrass facilities are located in the MISO. Our Riverside, Rolling Hills, and Foothills facilities are located within PJM. PJM s geographic area has significantly expanded in the past two years, including the addition of the AEP service area in which the Riverside, Rolling Hills, and Foothills facilities are located. The boards of PJM and MISO have committed to establish a joint and common market across their respective regions; however, there can be no assurance that efforts to integrate the two market structures will be successful.

PJM currently administers markets for wholesale electricity and provides transmission planning for the region. PJM operates day-ahead and real time markets into which generators can bid to provide electricity and ancillary services. To account for transmission congestion and losses, PJM calculates prices using a locational-based pricing model that is also used to determine generation unit dispatch. Wholesale electricity prices in PJM are currently capped at $1,000 per MWh. PJM also administers markets for installed capacity, which are an important potential revenue source for peaking facilities. PJM has proposed changes to its capacity markets, including establishing longer-term markets for capacity to improve market signals for new generation, although there are no assurances that such proposals will be implemented. The future economic impact, if any, of PJM and MISO policies and proposals on our ECAR facilities cannot currently be estimated.

The ECAR region currently has excess generation capacity as a result of recent development projects. This overcapacity is evidenced by the NERC s estimated 2004 reserve margin of 27%. MISO has indicated that it will enforce the current reserve requirement in each Reliability Region (i.e., MAIN, ECAR and MAPP) until such time that a capacity market is implemented. The reserve requirement to apply during the period following establishment of such capacity market has not been determined. This overcapacity has depressed energy and capacity values in this region and likely will continue to do so absent peak demand growth and/or plant retirements. Based on current expectations of future demand growth and retirements, we believe that reserve margins are likely to return to target levels within the next 3-5 years.

Northeast region Northeast Power Coordinating Council (NPCC). We lease two generating facilities in New York, which we refer to as the DNE facilities, with an aggregate net generating capacity of 1,708 MWs. Our DNE facilities sites are adjacent and share common resources such as fuel handling, a docking terminal, personnel and systems. The generating capacity of these facilities represents approximately 5% of the generating capacity in the state of New York.

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On January 31, 2005, we acquired from Exelon Corporation the 1,021 MW Independence power generating facility in New York. Prior to this acquisition, we were entitled to 955 MW of the power generated by this facility under the Independence tolling arrangement. The toll remained in effect and was transformed into an intercompany obligation under our GEN segment. Additionally, we acquired four natural gas-fired merchant facilities in New York and four hydroelectric generation facilities in Pennsylvania. Approximately 72% of the Independence facility s capacity is obligated under a capacity sales agreement, which runs through 2014. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion of this acquisition.

The New York Independent System Operator, or NYISO, administers the statewide transmission system and spot markets for electricity and, like PJM, calculates electricity prices and dispatches generation using a locational-based pricing model. NYISO also administers markets for installed capacity, operating reserves and regulation service. NYISO employs an AMP in its day-ahead electricity market that caps energy bids when certain bid screen criteria are exceeded. In 2003, NYISO implemented a Demand Curve mechanism for calculating pricing for installed capacity for three locational zones: New York City, Long Island, and the rest of the State of New York. Our facilities operate outside of New York City and Long Island. Capacity pricing is calculated as a function of NYISO s 18% target reserve margin, estimated cost of new entrant generation, estimated peak demand, and the actual amount of capacity bid into the market. The demand curve mechanism provides for incrementally higher capacity pricing at lower reserve margins, such that new entrant economics become attractive as the reserve margin approaches target levels.

Due to transmission constraints, prices vary across the state and are generally higher in the Eastern part of New York, where our Roseton and Danskammer facilities are located, and in New York City. Our Independence facility is located in the Northwest part of the state. Current reserve margins of 21% are somewhat above the NYISO s target reserve margin of 18%. We believe that reserve margins are likely to return to target levels within the next 3-5 years.

Southeast region Southeastern Electric Reliability Council (SERC). We own interests in three generating facilities with an aggregate net generating capacity of 1,640 MWs located within SERC. SERC includes all or portions of the states of Missouri, Kentucky, Arkansas, Tennessee, West Virginia, Virginia, North Carolina, South Carolina, Louisiana, Mississippi, Alabama and Georgia. The generating capacity of these facilities represents approximately 1% of the generating capacity in SERC. Of our 1,640 MWs of net generating capacity in SERC, 665 MWs, or 40%, is sold under contract. A contract for our Calcasieu facility s 320 MWs of capacity expired in December 2004. In January and February 2004, we signed two agreements to sell an aggregate 215 MWs of our Rockingham facility s net generation capacity, with terms beginning in 2006 and expiring in 2010. We also signed an agreement in January 2004 covering an additional 165 MWs of our Rockingham facility s net generating capacity, which expired in September 2004.

Our SERC assets are located within the control areas of vertically integrated utilities and municipalities. All power sales and purchases are consummated between individual parties and are physically delivered either within or across the control areas of the transmission owners. The present market framework in SERC is not a centralized market, and the timing of any transition to centralized competitive markets for energy and capacity is currently unknown.

The SERC region currently has excess generation capacity as a result of recent development projects. This overcapacity is evidenced by the NERC s estimated 2004 reserve margin of 51%, which significantly exceeds SERC s estimated target reserve margin of approximately 17%. This overcapacity has depressed energy and capacity values in this region and likely will continue to do so absent peak demand growth and/or plant retirements. Overcapacity is concentrated in the Entergy and Southern sub-regions of SERC, and these regions are unlikely to see reserve margins near target levels within the next ten years. Overcapacity is less severe in the VACAR sub-region of SERC, where we believe market conditions may require new capacity additions within the next 4-6 years.

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West region Western Electricity Coordinating Council (WECC). We own interests in four generating facilities with an aggregate net generating capacity of 945 MWs within WECC. The WECC regional market includes all or parts of the states of Arizona, California, Oregon, Nevada, New Mexico, Colorado, Wyoming, Idaho, Montana, Nebraska, Texas, South Dakota, Utah and Washington. Our generating capacity in the WECC represents less than 1% of the overall generating capacity in this region.

Of our 945 MWs of net generating capacity in the WECC, 902 MWs consists of our 50% share of the 1,804 MWs of facilities owned by West Coast Power. All of the West Coast Power facilities are located in southern California, and the generation output of the facilities was substantially covered by a contract, which we refer to as the CDWR contract, between one of our marketing subsidiaries, as agent for the facility owners, and the CDWR. This contract expired in December 2004.

Since the expiration of the CDWR contract, all of our West Coast Power assets have been operating under Reliability Must Run (RMR) Condition II contracts with the Cal ISO, except for the Long Beach facility, which is discussed below. Under the terms of these RMR contracts, Cal ISO reimburses West Coast Power for 100% of approved costs plus a rate of return specified in the contracts. When the facilities are instructed to provide power by the Cal ISO, they are reimbursed for their variable production costs. Under RMR Condition II, the facilities are 100% committed to the Cal ISO and, therefore, do not experience changes in market conditions through bilateral energy or capacity sales to third parties that might otherwise be consummated. The RMR contracts are effective for calendar year 2005. The Cal ISO may renew or terminate the RMR contracts at its sole option on an annual basis as of the first of the following year. In addition West Coast Power, through one of our marketing subsidiaries, as agent for the facility owner, has entered into a power sales agreement with a major California utility for the sale of 100% of the capacity and associated energy from the El Segundo facility from May through December 2005. During the term of this agreement, the purchaser will be entitled to primary energy dispatch rights for the facility s generating capacity. The agreement is subject to the amendment of the El Segundo RMR agreement to switch to RMR Condition I and to otherwise allow the purchaser to exercise its primary dispatch rights under this agreement while preserving Cal ISO s ability to call on the El Segundo facility as a reliability resource under the RMR agreement, if necessary.

In California s current energy market, the West Coast Power generating facilities are significantly less profitable under RMR contracts or as merchant facilities, and we may consider other alternatives if necessary, including shutting down units if we no longer consider them commercially viable. Based on our ongoing evaluation of strategic alternatives for our West Coast Power assets, we determined that it was not economically feasible to continue to operate our Long Beach generation facility beyond the expiration of the CDWR contract. Therefore, we retired the asset as of January 1, 2005.

Our West Coast Power facilities are located in the Cal ISO control area, which includes facilities serving approximately 75% of California s demand. The Cal ISO schedules transmission transactions, arranges for ancillary services, and administers a real time balancing energy market. Day ahead purchases and sales are executed bilaterally and scheduled for physical delivery by the Cal ISO. There is currently no capacity market in the Cal ISO. The Cal ISO is continuing its plan to move toward a market design similar to PJM and NYISO, although the timing and final structure of any such market design cannot currently be predicted.

For a discussion of litigation and other legal proceedings related to energy market restructuring in California, the impact of current regulations on our WECC facilities and related uncertainty associated with the California wholesale market, please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings California Market Litigation beginning on page F-58.

Texas region Electric Reliability Council of Texas (ERCOT). We own a generating facility with a generating capacity of 610 MWs located in ERCOT. This facility represents less than 1% of the generating capacity in the ERCOT region. The ERCOT market is comprised of the majority of the state of Texas.

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Approximately 13% of our capacity in this region, consisting of 80 MWs of capacity at our CoGen Lyondell facility, is sold under a capacity agreement which expires in December 2006.

Our Texas facility participates in a market administered by the ERCOT ISO, which oversees competitive wholesale and retail markets. ERCOT s operations are overseen by the PUCT. ERCOT operates as the single control area within its region, and operates capacity and energy markets for market participants. Price mitigation measures in ERCOT include a $1,000 per MWh offer cap. ERCOT is considering wholesale market design changes including locational-based pricing similar to markets in NYISO and PJM in response to a PUCT rule; however, there can be no assurances that such design changes will be implemented.

By most measures, the ERCOT region currently has excess generation capacity as a result of recent development projects. This overcapacity is evidenced by the NERC s estimated 2004 reserve margin of 26%, which is significantly in excess of the ERCOT s target minimum reserve margin of 12.5%. This overcapacity has depressed energy and capacity values in this region and will likely continue to do so absent peak demand growth and/or plant retirements. However, recently released reports from ERCOT indicate that reserve margins may fall below the 12.5% level within the next 1 2 years due to recently announced generating retirements and mothballed units.

International. In addition to our U.S. generating assets, as of December 31, 2004, we owned a 50% interest in a generating facility located in Panama. Upon expiration of a capacity contract in January 2005, this facility is operating on a merchant basis. We are continuing to pursue opportunities to sell our interest in this facility Panama project, as we do not consider it core to our power generation business. Our 18% interest in a 74 MW generation asset in Jamaica was sold in January 2004 for $5.5 million.

Retail Supply Business. We selectively enter into short- and long-term contracts with individual commercial and industrial customers to serve their load requirements in markets where we have a generation presence and where the regulatory environment supports these efforts. Our current sales and retail operations are directed toward Texas, Illinois and New York. In early 2005, we made the decision to formally exit the Retail Supply Business.

Natural Gas Liquids

General. Our natural gas liquids segment consists of our midstream asset operations, located principally in Texas, Louisiana and New Mexico, and our North American natural gas liquids marketing business. This segment has both upstream and downstream components. The upstream components include natural gas gathering and processing; while the downstream components include fractionating, storing, terminalling, transporting, distributing and marketing natural gas liquids.

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The following graphic depicts the revenue opportunities that exist throughout our upstream and downstream operations.

Upstream Business

Our upstream business includes the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting natural gas liquids and removing impurities. We own interests in 17 gas processing plants, including 11 plants we operate. We also operate over 9,385 miles of natural gas gathering pipeline systems associated with the 11 operated facilities and two stand-alone natural gas gathering pipeline systems where gas is treated and/or processed at third-party plants. Our upstream assets are located in the growing oil and gas exploration and production areas of North Texas and Louisiana, and the mature Permian Basin of West Texas and Southeast New Mexico. During 2004, we processed an average of 1.6 Bcf/d of natural gas and produced an average of 82,120 barrels per day of natural gas liquids, in each case, net to our ownership interests. We are also party to natural gas processing agreements with five third-party plants.

Our upstream business is significantly impacted by the types of contracts under which we process gas. There are four primary types of gas processing contracts where natural gas liquids are extracted: percent of proceeds, percent of liquids, keep-whole and wellhead purchase.

Under percent of proceeds, or POP, contracts, a producer delivers to us a percentage of the natural gas liquids and a percentage of the natural gas as payment for our services and retains the value of the remaining natural gas liquids and natural gas at the processing plant tailgate. The producer retains this value by either taking its share of the natural gas liquids and natural gas in kind or by receiving its share of the proceeds from our sale of their share of the commodities.

Under percent of liquids, or POL, contracts, a producer delivers to us a percentage of the natural gas liquids as payment for our services and retains the value of the remaining natural gas liquids and all of the natural gas at the processing plant tailgate. Similar to POP contracts, the producer will either take their share of the natural gas liquids in kind or take the proceeds from our sale of their share of the natural gas liquids.

Under keep-whole, or KW, contracts, we extract natural gas liquids and return to the producer volumes of merchantable natural gas containing the same Btu content as the unprocessed natural gas that was delivered to us. We retain the natural gas liquids as our payment for processing. We must purchase and return to the producer sufficient volumes of merchantable natural gas to replace the Btus that were removed as natural gas liquids through processing so that the producer is kept whole on a Btu basis. This contract type is fully exposed to the frac spread, which is the relative difference in value between natural gas liquids and natural gas on a Btu basis.

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Under wellhead purchase, or WHP, contracts, we purchase unprocessed natural gas from a producer at the wellhead at a discount to the market value of the gas. This discount, together with any value increase for natural gas liquids extracted from the natural gas, is our margin for gathering and processing.

Factors influencing the contract mix at a particular facility include, among other things, the Btu content of the gas, which determines if natural gas liquids must be extracted from the natural gas to meet natural gas pipeline quality specifications; the investment in extensive gathering systems to bring gas to a particular plant; the term of the gas supply contracts behind a processing plant; and the prevailing competitive factors when contracts are negotiated.

We characterize our natural gas processing plants in two categories field plants and straddle plants. The processing contract mix varies significantly between the two categories.

Field Plants. Field plants connect volumes of unprocessed gas from multiple onshore producing wells. Through extensive gathering systems, these volumes are aggregated into sufficient volumes to be economically processed to extract natural gas liquids and to remove water vapor, solids and other contaminants to provide marketable natural gas, commonly referred to in the industry as residue gas. The following map depicts our field plant assets, including our capacity, 2004 natural gas throughput and natural gas liquids production levels for the assets as of year end 2004. Our field plants are located in the mature and prolific Permian Basin of West Texas and Southeast New Mexico, and in North Texas, where we are ideally situated to benefit from the high volume growth Barnett Shale production development.

In our field plants we process natural gas primarily under POP contracts. In 2004, approximately 99% of the volumes processed were under POP settlement terms and the remainder was processed under KW or WHP contracts. We expect a similar contract mix in 2005. This is particularly important because the natural gas processed by all of these facilities contains natural gas liquids in sufficient quantities to require that the natural gas be processed to extract enough of the natural gas liquids to meet gas pipeline and market quality specifications. Having essentially all POP contracts removes the significant price spread risk associated with KW and WHP contracts and makes the key economic drivers for our field plants natural gas and natural gas liquids volumes and the absolute price of both residue gas and natural gas liquids.

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Our field plants recovered an average of 4.28 gallons of natural gas liquids per Mcf of raw gas processed in 2004. The component split of mixed natural gas liquids produced by our field plants in 2004 was as follows:

We are also impacted by producer drilling activity, which is sensitive to commodity prices. Additionally, safe, low-cost and reliable operation of our facilities, together with highly efficient plant operation, improves our competitiveness in attracting new gas volumes to replace intrinsic declines in natural gas well production at the same or better contractual terms.

Straddle Plants. Straddle plants generally are situated on mainline natural gas pipelines. Our straddle plants are located on pipelines transporting natural gas from the Gulf of Mexico to key Midwest and East Coast natural gas markets. The following map depicts our straddle plant assets as of year end 2004, including our capacity, 2004 natural gas throughput and natural gas liquids production levels.

We process natural gas in our straddle plants under POL and KW contracts as well as hybrid contracts that contain different settlement terms. Under hybrid contracts, the settlement outcome can be either POL, KW or a fee and is usually triggered by market conditions, most often automatically, or, in some cases, by the election of one or both of the parties. When it is economical to extract natural gas liquids, these hybrid contracts typically settle under POL terms.

When it is not profitable to extract natural gas liquids (i.e., when the value of the natural gas liquids is less than the value of natural gas on an equivalent Btu basis), most of the volumes processed under these hybrid

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contracts automatically convert to a fee-based processing arrangement. This fee is generally paid in the form of cash and/or a nominal percentage of the natural gas liquids processed. For some of these volumes, the producer and/or the processor have contract settlement election options. The producer can elect to either process or not process, generally on a POL basis. If the producer elects to not process, we often have the option to process on a KW basis. If we elect to not process, either we can cause the gas to bypass the plant, where such capabilities exist, or the producer pays us a per-unit fee to process the gas.

The charts below show the current and expected contract mix for our straddle plants. On the left, the current mix does not reflect an expected FERC approval of hydrocarbon dew point specifications on natural gas pipelines along the Gulf of Mexico. Assuming FERC approves hydrocarbon dew point specifications, significant production historically processed under KW contracts will be generally settled under fee or hybrid contracts. The chart on the right shows our anticipated contract mix following enforcement of hydrocarbon dew point specifications on pipelines in the Gulf area and reflects our expectation of a significant decline in our frac spread exposure.

The results of our straddle plant operations are heavily dependent on the absolute price of natural gas liquids. This is particularly true when processing economics are favorable, as the hybrid contracts settle under POL terms. When processing economics are less favorable, we do have some KW exposure to the frac spread. Our view is that strong natural gas prices will generally continue to depress the frac spread for the foreseeable future. However, our frac spread exposure is limited because most of the hybrid contracts in this price environment settle on fee terms.

As with our field plants, our straddle plants are impacted by producer drilling activity, which is sensitive to commodity prices, as well as our ability to operate safely, reliably and efficiently.

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The straddle plants recovered an average of 1.13 gallons of natural gas liquids per Mcf of raw gas processed in 2004. The component split of mixed natural gas liquids produced by our straddle plants in 2004 was as follows:

Major customers of our upstream business include ChevronTexaco and many other large and small producers. We have a contractual right to process substantially all of ChevronTexaco s gas in North America. Generally, with respect to gas they produce from all areas other than the Gulf of Mexico, we process the gas at field plants owned by us or by third parties. The ChevronTexaco gas processed in our field plants is processed on a POP basis and is based on ChevronTexaco s commitment of such production for the life of the lease from which the production is obtained.

With respect to the gas produced from the Gulf of Mexico area, ChevronTexaco s gas is processed in both straddle plants in which we own an interest and in plants owned by third parties. We operate five of the plants in which we own an interest. ChevronTexaco gas produced from the Gulf of Mexico area is processed on a POL basis when processing is economical or is processed on a fee basis if natural gas liquids extraction is not profitable. The leases, or portions thereof, committed under this agreement are committed for the life of the leases dedicated to us for processing. Until September 1, 2006, ChevronTexaco has agreed to dedicate to us for processing any gas attributable to new production obtained from oil, gas and/or mineral leases not previously dedicated to us for processing as of March 1, 2002. These dedications made by ChevronTexaco may be limited to certain productive horizons and/or may only be partially committed as to acreage.

Both types of processing agreements with ChevronTexaco allow either party to initiate renegotiation of the commercial terms for processing previously dedicated natural gas production effective in September 2006 and on each successive 10-year anniversary thereafter for ChevronTexaco gas processed in field plants; and, five years thereafter, for gas produced from the Gulf of Mexico and processed in Louisiana straddle plants. During 2004 and 2003, respectively, ChevronTexaco gas accounted for 32% and 46% of the total volume of gas we processed.

Hedging Strategy. As a result of our POP and POL contracts, we take ownership of natural gas and natural gas liquids as payment for our services. We have a comprehensive hedging strategy and related control procedures to manage price risk on these equity volumes. We limit volume considered for hedging and forward selling to Dynegy-owned volumes received at our field processing facilities that must operate for gas to meet natural gas pipeline quality specifications. The portion of equity natural gas and natural gas liquids that we hedge is monitored closely against our field processing plant operations to ensure we hedge no more than the volume we own. We seek to mitigate correlation risk by hedging each natural gas liquid product against our physical production of that product. Realized loss on hedged volumes was $10 million below the average realized price for unhedged volumes for 2004 as compared to $7 million below the average realized price for unhedged volumes for 2003.

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Downstream Business

In our downstream business, we use our integrated assets to fractionate, store, terminal, transport, distribute and market natural gas liquids. Our downstream assets are generally connected to and supplied, in part, by our upstream assets and are located in Mont Belvieu, Texas, the hub of the U.S. natural gas liquids business, and West Louisiana. The following map depicts our downstream assets, including our capacity and throughput capabilities.

Fractionation. When pipeline-quality natural gas is separated from natural gas liquids at processing plants, the natural gas liquids are generally in the form of a commingled stream of light liquid hydrocarbons, which is referred to as mixed or raw natural gas liquids. The mixed natural gas liquids are separated at fractionation facilities through a distillation process into the following component products:

- Ethane, or a mixture of ethane and propane known as EP mix;
- Propane;
- Normal butane;
- Isobutane; and
- Natural gasoline.

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The percentages of these products produced at our fractionators in 2004 were as follows:

We fractionate volumes for customers, from both our own upstream operations and third parties, under contracts that typically include a base fee per gallon plus other fee components that are subject to adjustment for variable costs such as energy consumed in fractionation. We have ownership interests in three stand-alone fractionation facilities that are strategically located on the Texas and Louisiana Gulf Coast. We operate two of the facilities, one at Mont Belvieu, Texas and the other at Lake Charles, Louisiana. During 2004, these facilities fractionated an aggregate average of 183,000 gross barrels per day (net to Dynegy s ownership interests). We also have an equity investment in a third fractionator located in Mont Belvieu, which is subject to a 1996 consent decree with the FTC that prevents us from participating in commercial decisions regarding rates paid by third parties for fractionation services.

The results of our fractionation operations are significantly impacted by the following factors: our ability to attract term volumes of raw natural gas liquids at profitable margins; the impact of frac spreads on the supply of natural gas liquids available for fractionation; the composition of the liquids received; energy costs; and operational efficiencies.

Storage & Terminalling. Our natural gas liquids storage facilities have extensive pipeline connections to third-party pipelines, third-party facilities and to our own fractionation and terminalling facilities. In addition, some of these storage facilities are connected to marine, rail and truck loading and unloading facilities that provide service and products to our customers. We provide long- and short-term storage services and throughput capability to affiliates and third-party domestic customers for a fee.

We own and/or operate a total of 41 storage wells with an aggregate capacity of 108 MMBbls, the usage of which may be limited by brine handling capacity. Brine is utilized to displace natural gas liquids from storage. When large volumes of natural gas liquids are stored, we store the displaced brine in our brine storage ponds adjacent to our storage facilities and, depending on the volume, may inject excess brine in our brine disposal wells. When reduced volumes of natural gas liquids are stored, we utilize the brine from our brine storage ponds to displace the volumes of natural gas liquids removed and, if necessary, can produce additional brine from wells dedicated for that purpose through a process known as brine leaching.

The results of our storage operations are significantly impacted by the following factors: the petrochemical industry s level of capacity utilization and their specific feedstock requirements; our ability to utilize our integrated asset base flexibly to meet changing customer and market demands; and safe, low-cost, efficient operations.

Transportation and Logistics. Our natural gas liquids transportation and logistics infrastructure comprises a wide range of transportation and distribution assets supporting both third-party customers and the delivery requirements of our distribution and marketing business. We provide a fee-based transportation service to refineries and petrochemical companies throughout the Gulf Coast area. These assets are also deployed to serve our wholesale distribution terminals, fractionation facilities, underground storage facilities, pipeline injection terminals and many of the nation s crude oil refineries and petrochemical facilities. Our marine terminals are

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located in Texas, Florida, Louisiana and Mississippi. We also have wholesale propane terminals located in Tennessee, Texas, Mississippi, Kentucky and Florida, and lease capacity at third-party storage facilities throughout North America. These distribution assets provide a variety of ways to transport and deliver products to our customers. Our transportation assets include:

More than 2,000 railcars owned or leased by ChevronTexaco that we manage pursuant to a services agreement with ChevronTexaco;

78 transport tractors and 114 tank trailers;

More than 550 miles of gas liquids pipelines, primarily in the Gulf Coast area; and

21 natural gas liquids pressurized barges with more than 320,000 barrels of capacity.

Distribution and Marketing Services. Our distribution and marketing services include: (1) Refinery services; (2) Wholesale propane marketing; and (3) Purchasing mixed natural gas liquids and natural gas liquids products from natural gas liquids producers and other sources and selling the natural gas liquids products to petrochemical manufacturers, refineries and other marketing and retail companies.

Refinery Services. In our refinery services business, we provide LPG balancing services, purchasing natural gas liquids products from refinery customers and selling natural gas liquids products to various customers. We also use our storage, transportation, distribution and marketing assets to assist refinery customers in managing their natural gas liquids product demand and production schedules. This includes both feedstocks consumed in refinery processes and the excess LPG produced by those same refining processes. Under our netback contracts, we generally retain a portion of the resale price of natural gas liquids sold or receive a fixed minimum fee per gallon on products sold. Also under netback contracts, fees are obtained for locating and supplying natural gas liquids feedstocks to the refineries either based on a percentage of the cost to obtain such supply or through a minimum fee per gallon. In 2004, we sold an average of 38,000 barrels of LPG per day through our refinery services business.

We have refinery services contracts with each of ChevronTexaco s refineries situated in El Segundo, California; Pascagoula, Mississippi; Richmond, California; Salt Lake City, Utah; and Barbers Point, Hawaii. All of these contracts allow us to market excess LPG produced during the refining process. With respect to all of the ChevronTexaco refineries, except Hawaii, these agreements also require us to supply to ChevronTexaco natural gas liquids utilized in their refining process as required by the refinery. The agreements require us to obtain, on behalf of the refineries, natural gas liquids feedstocks that each refinery requires on a daily basis. These agreements extend through August 2006. Approximately 47% and 44% of the business natural gas liquids volumes purchased in 2004 and 2003, respectively, were from ChevronTexaco.

Key factors impacting the results of our refinery services business include propane and butane prices, our ability to perform receipt, delivery and transportation services and refinery demand.

Wholesale Propane Marketing. Our wholesale propane marketing operations include the sale of propane and related logistics services to major multi-state retailers, independent retailers and other end users. Our propane supply primarily originates from both our refinery/gas supply contracts and our other owned and/or managed distribution and marketing assets. We generally sell propane at a fixed or posted price at the time of delivery. In 2004, we sold an average of 44,500 barrels of propane per day.

Our wholesale propane marketing business is significantly impacted by weather-driven demand, particularly in the winter, the price of propane in the markets we serve and our ability to deliver propane to customers to satisfy peak winter demand.

Distribution and Marketing Services. We market our own natural gas liquids production and also purchase natural gas liquid products from other natural gas liquids producers and marketers for resale. In 2004, our distribution and marketing services business sold an average of 200,000 barrels per day of natural gas liquids in North America. We generally purchase mixed natural gas liquids from producers

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at a monthly pricing index less applicable fractionation, transportation and marketing fees and resell these products to petrochemical manufacturers, refineries and other marketing and retail companies. This is primarily a physical business in which we earn margins from purchasing and selling natural gas liquid products from producers under contract. We also earn margins by purchasing and reselling natural gas liquids products in the spot and forward physical markets.

We also have the right to purchase or market substantially all of ChevronTexaco s natural gas liquids pursuant to a Master Natural Gas Liquids Purchase Agreement that extends through August 31, 2006.

This business is impacted by a number of factors, including our ability to prudently manage inventories during periods of market price movements and meeting our delivery obligations under term contracts.

In 2004 and 2003, approximately 35% and 32%, respectively, of our specification natural gas liquids sales were made to ChevronTexaco or one of its affiliates pursuant to the refinery agreements discussed above and pursuant to an agreement we have with Chevron Phillips Chemical Company. In the latter agreement, we supply a significant portion of Chevron Phillips Chemical s natural gas liquids feedstock needs in the Mont Belvieu area and collect a cents-per-barrel fee for storage and product delivery.

Regulated Energy Delivery

General. Our regulated energy delivery segment consisted of our former Illinois Power Company subsidiary, which we sold in September 2004. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23 for further discussion. Illinois Power is a regulated public utility based in Decatur, Illinois, and is engaged in the transmission, distribution and sale of electric energy and the distribution, transportation and sale of natural gas in the state of Illinois. Illinois Power provides retail electric and natural gas service to residential, commercial and industrial consumers in substantial portions of northern, central and southern Illinois. Illinois Power also currently supplies electric transmission service to electric cooperatives, municipalities and power marketing entities in the state of Illinois.

From February 1, 2002 through July 31, 2002, this segment also included the results of Northern Natural. We acquired Northern Natural from Enron Corp. in connection with our terminated merger and subsequently sold Northern Natural to MidAmerican Energy Holdings Company in August 2002. Northern Natural is accounted for as a discontinued operation in the accompanying financial statements. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Northern Natural beginning on page F-27 for further discussion.

Customer Risk Management

Our CRM segment is comprised largely of our three remaining power tolling arrangements (including the Gregory toll, which expires in July 2005, but excluding the Independence toll). Upon the closing of our Sithe Energies acquisition in January 2005, the Independence tolling arrangement was transformed into an intercompany obligation under our GEN segment, which now includes the Independence facility. In addition, we have mitigated the effect of our Kendall tolling arrangement through November 2008 by entering into a back-to-back power purchase agreement with a subsidiary of Constellation Energy, whereby we will receive payments which offset our obligations to LSP-Kendall.

Pursuant to these power tolling arrangements, we are obligated to make aggregate payments of approximately $1.3 billion to our counterparties in exchange for access to power generated by their facilities, resulting in a total obligation of $1.2 billion, net of $161 million to be received from Constellation. In addition to these tolling arrangements, our CRM segment includes gas transportation contracts and our remaining gas and power trading positions. We are actively pursuing opportunities to terminate, assign or renegotiate the terms of our contractual obligations related to our remaining obligations under these agreements.

The following table contains a listing of our power tolling arrangements, including the name and location of each related project, the term of each arrangement, the project capacity and our annual capacity payments, as well as other CRM fixed obligations.

CRM Obligations

				Annual Capacity Payments			
Project	**Location**	**Expiration Date**	**MWs**	**2005**	**2006**	**2007**	**2008 2017**
					(in millions)		
Sterlington/Quachita	Louisiana	9/2017(1)	835	$ 59	$ 61	$ 63	$ 627
Gregory	Texas	7/2005	335	13			
Kendall	Illinois	3/2017(1)(2)	578	39	41	42	374
Independence	New York	11/2014(3)	955	4			
Total annual capacity payments				115	102	105	1,001
Other fixed obligations				8	2	2	
Less: Payments to be received from Constellation (2)				(39)	(41)	(42)	(39)
Net cash commitments				$ 84	$ 63	$ 65	$ 962

(1) Includes a five-year extension option pursuant to which either party can elect to continue the arrangement depending on the market price for power at the expiration of the initial contract term.

(2) We have entered into an offsetting agreement with a subsidiary of Constellation Energy through November 2008, under which we will receive payments equal to those owed under our Kendall tolling arrangement.

(3) On January 31, 2005, we completed the Sithe Energies acquisition, which resulted in the transformation of our obligations under the Independence tolling arrangement and related derivative instrument into intercompany obligations under our GEN segment.

Regarding our legacy gas and power trading positions, we have substantially reduced the size of our mark-to-market portfolio since October 2002, when we initiated our efforts to exit the CRM business. As of December 31, 2004, we have exited approximately 90% of our physical and financial gas business. We expect to have effectively exited this business by the end of 2007, with the exception of a minimal number of physical gas transactions that expire between 2010 and 2017. Additionally, we have forward obligations to deliver emissions allowances. Currently, we own adequate allowances to satisfy the forward obligations. Our remaining CRM power business, exclusive of our power tolling arrangements, will be effectively exited by the end of 2005; with the exception of a minimum number of positions that will remain until 2010. We will continue our efforts to exit the remaining transactions as allowed by market liquidity and credit requirements.

Other

Our Other results include corporate governance roles and functions, which are managed on a consolidated basis, and specialized support functions such as finance, accounting, risk control, tax, legal, human resources, administration and technology. Corporate general and administrative expenses, income taxes and corporate interest expenses, which we previously allocated among our operating divisions, are included in our other reported results, as are corporate-related other income and expense items. Interest expense associated with borrowings incurred by our operating divisions, such as our power generation facility financings, will continue to be reflected in the appropriate business segment s results. Other results for the periods presented also include our discontinued global communications business.

The communications business was established during the fourth quarter 2000 and included an optically switched, mesh fiber-optic network with more than 16,000 route miles that reached 44 cities in the United States. During the first quarter 2003, we sold our European communications business, which operated a high-capacity, broadband network with access points in 32 cities throughout Western Europe. During the second quarter 2003, we sold our U.S. communications business. Since we have substantially completed our exit from the global communications business, we do not expect that this business will be included in our Other results for future periods.

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COMPETITION

Power Generation. Demand for power may be met by generation capacity based on several competing technologies, such as gas-fired, coal-fired or nuclear generation and 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 business competes with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities and other energy service companies in the development and operation of energy-producing projects. We believe that our ability to compete effectively in this business will be driven in large part by our ability to achieve and maintain a low cost of production, primarily by managing fuel costs, and to provide reliable service to our customers. We believe our primary competitors in this business consist of approximately 19 companies.

Natural Gas Liquids. Our natural gas liquids businesses face significant and varied competitors, including major integrated oil companies, major pipeline companies and their marketing affiliates and national and local gas gatherers, processors, fractionators, brokers, marketers and distributors of varying sizes and experience. The principal areas of competition include obtaining gas supplies for gathering and processing operations, obtaining supplies of raw product for fractionation, purchase and marketing of natural gas liquids, residue gas, condensate and sulfur, and transportation of natural gas and natural gas liquids and storage of natural gas liquids. Competition typically is based on location and operating efficiency of facilities, reliability of services, delivery capabilities and price. We believe our primary competitors in this business consist of approximately 21 companies.

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REGULATION

We are subject to regulation by various federal, state, local and foreign agencies, including the regulations described below.

Please read Environmental and Other Matters beginning on page 24 for a discussion of environmental regulations affecting our business.

Power Generation Regulation. The FERC has exclusive ratemaking jurisdiction over wholesale power sales in interstate commerce. Our power generation operations are subject to FERC regulation with respect to rates, the procurement and provision of certain services and operating standards. All of our current QF projects are qualifying facilities and, as such, are exempt from the ratemaking and other provisions of the FPA. Our EWGs, which are not QFs, have been granted market-based rate authority and comply with the FPA requirements governing approval of wholesale rates and subsequent transfers of project ownership interests. We are subject to the jurisdiction of the PUCT with respect to our operations in ERCOT.

In certain markets where we own power generation facilities, specifically California and New York, the FERC has, from time to time, approved temporary price caps on wholesale power sales or other market mitigation measures. In New York, the FERC approved and extended indefinitely an Automated Mitigation Procedure, or AMP, that caps bid prices based on the cost characteristics of power generating facilities, such as our DNE facilities and the Independence facility we acquired in January 2005. In January 2005, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion vacating and remanding the FERC s orders approving the AMP in the day-ahead market outside of New York City, where our DNE facilities and Independence facility are located. At this time it is not known whether the NYISO and others have sought reconsideration of this decision; consequently, the AMP currently remains in effect.

In February 2004, the FERC accepted, subject to certain modifications, the NYISO s proposed real-time scheduling software, but rejected the NYISO s proposal to extend the real-time AMP to areas outside New York City. On rehearing in August 2004, the FERC granted rehearing and allowed the NYISO to apply the real-time AMP in the area outside New York City.

As a consequence of the California energy crisis, which arose in 2000, generation within the Cal ISO is subject to mitigation consisting primarily of a $250/MWh offer cap and an AMP that under certain conditions limits the pricing of the electricity we generate in California. All power generating facilities in California fueled by fossil fuels, including all of our California facilities, are still obligated to offer all available output subject to these restrictions.

The energy crisis also precipitated a number of other FERC actions related to the California energy market, and the Western market generally, in addition to price caps and market mitigation measures. These actions included investigations concerning alleged manipulation of energy prices in the West, including claims of false reporting of trading data to publications that publish energy indices, and complaints requesting the FERC to reform or void various long-term power sales contracts. The FERC investigation with respect to us regarding false reporting to trade publications concluded in July 2003. Additionally, in October 2004, the FERC approved an agreement providing for the settlement of certain FERC claims relating to western energy market transactions that occurred from January 2000 through June 2001. Finally, we are awaiting the outcome of an appeal to the Ninth Circuit Court of Appeals regarding the validity of our CDWR contract, which expired in December 2004. Please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings FERC and Related Regulatory Investigations Requests for Refunds beginning on page F-59 for further discussion of the settlement.

We are also subject to the FERC s market behavior rules, which emerged from its consideration of market manipulation in the Western markets. The rules apply to sales in organized and bilateral markets and spot

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markets, as well as long-term sales. The remedies for violating the rules could include disgorgement of unjust profits, suspension or revocation of the authority to sell at market-based rates and penalties. The extent to which the rules will affect the costs or other aspects of our operations is uncertain. However, we believe that our entities subject to the FERC s market behavior rules, which consists of our entities with market-based rates for wholesale power sales and our entity with blanket natural gas sales certificate authority, are in compliance with these rules.

The FERC s market-based rate authority allows the sale of power at negotiated rates through the bilateral market or within an organized energy market, conditioned on periodic re-review. In April 2004, the FERC issued an order concerning the ability of companies to sell electricity at market-based rates. In this order, the FERC adopted two new tests for assessing generation market power. If an applicant for market-based rate authority is found to possess generation market power under these tests and is unsuccessful in challenging that finding, the applicant may either propose mitigation measures or adopt cost-based rates. If the FERC finds that the proposed mitigation measures fail to eliminate the ability to exercise market power, the applicant s market-based rate authority will be revoked and the applicant will be subject to cost-based default rates, or other cost-based rates proposed by the applicant and approved by the FERC. The FERC issued a follow up order in May 2004 which (i) addressed the implementation process for pending and new market-based rate applications and (ii) established a timeline for entities with FERC market-based rate authority to provide the FERC with their market power assessment. Despite challenges from numerous industry participants, in July 2004 the FERC upheld the April 2004 order. These orders require entities that were previously granted market-based rate authority by the FERC, including entities with pending applications for re-review, to resubmit their applications in accordance with the new directive. Consequently, Dynegy entities with applications pending since February 2002 timely resubmitted their applications to the FERC on February 7, 2005, as required. The entities we acquired in January 2005 in connection with the Sithe Energies acquisition previously submitted updated market-based rate applications in September 2004.

In December 2004, the FERC ruled that once the MISO becomes a single market and performs functions such as single central commitment and dispatch with FERC-approved market monitoring and mitigation (currently scheduled for April 1, 2005), MISO would be considered to have a single geographic market for purposes of assessing generation market power. This ruling will enlarge the geographic area in which our DMG facilities would be evaluated for generation market power for the relevant period. Although we cannot predict with any certainty whether our applications to renew our market based rate authority will be approved or the loss of revenues that would result from the imposition of cost-based rates, an adverse outcome with respect to these applications, and the resulting requirement that we charge cost-based rates, could have a material adverse effect on our financial condition, results of operations and cash flows.

Electricity Marketing Regulation. Our electricity marketing operations are regulated pursuant to the FPA by the FERC with respect to rates, terms and conditions of services and various reporting requirements. As discussed above, current FERC policies permit trading and marketing entities to market electricity at market-based rates.

Natural Gas Processing. Our natural gas processing operations could become subject to FERC regulation. While the FERC has found that its jurisdiction under the NGA applies to plants that perform processing necessary for the safe and efficient transportation of natural gas, the FERC has historically held that the extraction of liquid hydrocarbons for their economic value is not necessary for the safe and efficient transportation of gas. Thus, if a processing plant s primary function is the extraction of natural gas liquids for their economic value, the plant is not subject to the FERC s jurisdiction. We believe our gas processing plants are primarily involved in removing natural gas liquids for economic purposes and, therefore, are exempt from FERC jurisdiction. Nevertheless, the FERC has made no specific finding as to our gas processing plants. As such, no assurance can be given that all of our processing operations will remain exempt from FERC regulation.

Natural Gas Gathering. The NGA exempts gas gathering facilities from the jurisdiction of the FERC, while interstate transmission facilities remain subject to FERC jurisdiction, as described above. We believe our gathering facilities and operations meet the FERC s current tests for determining non-jurisdictional gathering

facility status, although the FERC s articulation and application of such tests have varied over time. Nevertheless, the FERC has made no specific findings as to the exempt status of any of our facilities. No assurance can be given that all of our gas gathering facilities will remain classified as such and, therefore, remain exempt from FERC regulation. Some states regulate gathering facilities to varying degrees; generally, rates are not state-regulated.

Illinois Power Company. During the period in which Illinois Power was a wholly-owned subsidiary of Illinova and Dynegy, it was an electric utility company as defined in PUHCA. As a result of such ownership, Illinova, the direct parent company of Illinois Power, and Dynegy were holding companies as defined in PUHCA. During this period Illinova and Dynegy were generally exempt from regulation under PUHCA based on their status as intrastate holding companies and on the application for exemption from PUHCA filed by Chevron Corporation and Chevron U.S.A. Inc. Upon the consummation of the sale of Illinois Power to Ameren in September 2004, Illinova and Dynegy were no longer holding companies as defined in PUHCA.

Natural Gas Regulation. The transportation, storage and sale for resale of natural gas in interstate commerce is subject to regulation by the FERC under the NGA and, to a lesser extent, the NGPA. The FERC regulates the rates interstate pipelines charge for interstate transportation and storage services. The FERC also has jurisdiction over, among other things, the construction and operation of pipeline and related facilities used in the transportation and storage of natural gas in interstate commerce, including the extension, expansion, acquisition, disposition, or abandonment of such facilities; maintenance of accounts and records; depreciation and amortization policies; and transactions with and conduct of interstate pipelines relating to affiliates. Venice Gathering System, in which we own a minority interest, is a regulated interstate pipeline. Like other interstate pipelines, Venice Gathering System must comply with FERC s open-access transportation regulations. The FERC continues to review and modify its open-access regulations and some appeals are pending.

State Regulatory Reforms. Our domestic power generation business is subject to various regulations from the states in which we operate. Proposed reforms to these regulations are proceeding in several states. In Illinois, both the regulators and the legislature are considering alternatives for the regulation of the retail electric markets, including how the procurement of power and energy by electric utilities will be handled following the expiration of the mandatory transition period at the end of 2006. In addition, in Texas, the PUCT has passed various rules regarding wholesale market re-design which will take effect during 2005 and 2006. In California, rules regarding resource adequacy requirements are expected to be determined by the California Public Utilities Commission, or CPUC, during 2005 and fully implemented in 2006. Although we are not regulated by the CPUC, the results of some or all of these reforms could have a material affect on our operations.

Legislation. The U.S. Congress is considering passage of comprehensive energy legislation that will impact us. We cannot predict with certainty if or when the U.S. Congress will finish its work on the energy legislation and send it to the President for signature or what effect any final legislation will have. Also, as noted above, in Illinois, both the regulators and the legislature are considering alternatives for the regulation of the retail electric markets, including how the procurement of power and energy by electric utilities will be handled following the expiration of the mandatory transition period at the end of 2006.

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ENVIRONMENTAL AND OTHER MATTERS

General. We incorporate environmental protection and stewardship as an integral part of the design, construction, operation and maintenance of our facilities. An important part of all of these strategies and actions is our commitment to conduct all business activities in an environmentally responsible manner.

Our operations are subject to extensive federal, state and local statutes, rules and regulations governing the discharge of materials into the environment or otherwise relating to environmental, health and safety protection. Environmental laws and regulations, including environmental regulators interpretations of these laws and regulations, are complex, change frequently and have become more stringent over time. Many environmental laws require permits from governmental authorities before construction on a project may commence or before wastes or other materials may be discharged into the environment. The process for obtaining necessary permits can be lengthy and complex, and can sometimes result in the establishment of permit conditions that make the project or activity for which the permit was sought either unprofitable or otherwise unattractive. Even where permits are not required, compliance with environmental laws and regulations can require significant capital and operating expenditures, and we may be required to incur costs to remediate contamination from past releases of wastes into the environment. Failure to comply with these statutes, rules and regulations may result in the assessment of administrative, civil and even criminal penalties. Furthermore, the failure to obtain or renew an environmental permit could prevent operation of one or more of our facilities.

In general, the construction and operation of our facilities are subject to federal, state and local environmental laws, regulations and permitting requirements governing the siting and operation of energy facilities, the discharge of pollutants and other materials into the environment, the protection of wetlands, endangered species, and other natural resources, the control and abatement of noise and other similar requirements. A variety of permits are typically required before construction of a project commences, and additional permits are typically required for facility operation.

Environmental Expenditures. Our aggregate expenditures for compliance with laws and regulations related to the protection of the environment were approximately $25 million in 2004, compared to approximately $51 million in 2003 and approximately $82 million in 2002. We estimate that total environmental expenditures (both capital and operating) in 2005 will be approximately $40 million. In 2005, the projected costs are associated primarily with enhanced air pollution controls and the handling of combustion byproducts. Changes in environmental regulations or the outcome of litigation could result in additional requirements that could necessitate increased future spending. Please read Environmental and Other Matters The Clean Air Act below for a discussion of the litigation brought by the Environmental Protection Agency against us relating to activities at our Baldwin generating station in Illinois.

The Clean Air Act. The Clean Air Act and comparable state laws and regulations relating to air emissions impose responsibilities on owners and operators of sources of air emissions, including requirements to obtain construction and operating permits and annual compliance and reporting obligations. In addition to the new source performance standards applicable to sulphur dioxide and nitrogen oxides, the Clean Air Act requires that fossil-fueled plants have sufficient sulphur dioxide and, in some geographical regions of the country, nitrogen oxides emission allowances, as well as meet certain pollutant emission standards. Our electric generation facilities are presently in compliance with these allowance and emission rate requirements. Although the impact of future air quality regulations cannot be predicted with certainty, these regulations are expected to become increasingly stringent, particularly for electric power generating facilities. Current Clean Air Act requirements include the following:

The Clean Air Act Amendments of 1990 required a two-phase reduction by electric utilities in emissions of sulfur dioxide and nitrogen oxides by 2000 as part of an overall plan to reduce acid rain in the eastern United States. Installation of control equipment and changes in fuel mix and operating practices have been completed at our facilities as necessary to comply with the emission reduction requirements of the acid rain provision of the Clean Air Act Amendment of 1990.

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In October 1998, the EPA issued a final rule on regional ozone control that required 22 eastern states and the District of Columbia to revise their State Implementation Plans to significantly reduce emissions of nitrogen oxides. The compliance deadline for implementation of these emission reductions was May 31, 2004. In January 2000, the EPA finalized another ozone-related rule under Section 126 of the Clean Air Act that has similar emission control requirements. The required capital expenditures and installation of the necessary emission control equipment to meet these requirements was completed before the compliance deadline; as a result, our power generation system met the specified compliance deadlines for implementation. Portions of our GEN and NGL businesses are also subject to similar ozone rules applicable to the Houston area. We have plans in place to satisfy these requirements and could incur capital expenditures of up to $23 million through 2007 pursuant to such plans**.**

Baldwin Station Litigation. Since November 1999, DMG has been the subject of an NOV from the EPA and a complaint filed by the EPA and the DOJ in federal district court alleging violations of the Clean Air Act and related federal and Illinois regulations related to certain maintenance, repair and replacement activities at our Baldwin generating station. We have reached agreement with the EPA, the DOJ, the State of Illinois and the environmental group intervenors on terms to settle the litigation. A consent decree was signed by all parties and lodged with the U.S. District Court for the Southern District of Illinois on March 7, 2005, and is subject to final approval of the Court following public comment. The consent decree requires us to (i) pay a $9 million civil penalty; (ii) fund several environmental projects in the additional aggregate amount of $15 million; and (iii) invest $321 million through 2010, and $224 million from 2011 through 2012, respectively, in emission control projects at our Baldwin, Vermilion and Havana plants. Please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings Baldwin Station Litigation beginning on page F-57 for further discussion of this lawsuit and consent decree.

Remedial Laws. We are also subject to environmental requirements relating to the handling and disposal of toxic and hazardous materials, including provisions of CERCLA and RCRA and similar state laws. CERCLA imposes liability, regardless of fault or the legality of the original conduct, on persons that contributed to the release of a hazardous substance into the environment. These persons include the current or previous owner and operator of a facility and companies that disposed, or arranged for the disposal, of the hazardous substance found at a 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 the costs of cleaning up the hazardous substances that have been released and for damages to natural resources from such responsible party. Further, it is not uncommon for neighboring landowners and other affected parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. CERCLA or RCRA could impose remedial obligations at a variety of our facilities.

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

As a result of their age, a number of our facilities contain quantities of asbestos insulation, other asbestos containing materials and lead-based paint. 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.

Pipeline Safety. In addition to environmental regulatory issues, the design, construction, operation and maintenance of some of our pipeline facilities are subject to the safety regulations established by the Secretary of the DOT pursuant to the NGPSA and the HLPSA, or by state regulations meeting the requirements of the NGPSA and the HLPSA, or to similar statutes, rules and regulations in other jurisdictions. In December 2000, the DOT adopted new regulations requiring operators of interstate pipelines to develop and follow an integrity management program that provides for continual assessment of the integrity of all pipeline segments that could

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affect so-called high consequence environmental impact areas, through periodic internal inspection, pressure testing or other equally effective assessment means. An operator s program to comply with the new rule must also provide for periodically evaluating the pipeline segments through comprehensive information analysis, remediating potential problems found through the required assessment and evaluation, and assuring additional protection for the high consequence segments through preventative and mitigative measures. Although the requirements of this DOT rule have increased the costs of pipeline operations, we do not believe that such costs are material to our financial condition or results of operations.

In the wake of the September 11, 2001 terrorist attacks on the United States, the Coast Guard has developed a security guidance document for marine terminals and has issued a security circular that defines appropriate countermeasures for protecting them and explains how the Coast Guard plans to verify that operators have taken appropriate action to implement satisfactory security procedures and plans. Using the guidelines provided by the Coast Guard, we have specifically identified certain of our facilities as marine terminals and therefore potential terrorist targets. In compliance with the Coast Guard guidance, we performed vulnerability analyses on such marine terminals. Future analyses of our security measures may result in additional measures and procedures, which measures or procedures have the potential for increasing our costs of doing business. Regardless of the steps taken to increase security, however, we cannot be assured that our marine terminals will not become the subject of a terrorist attack. Please read Operational Risks and Insurance beginning on page 29 for further discussion.

Health and Safety. Our operations are subject to the requirements of OSHA and other comparable federal, state and provincial statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the Superfund Amendments and Reauthorization Act and similar state statutes require that information be organized and maintained about hazardous materials used or produced in our operations. Some of this information must be provided to employees, state and local government authorities and citizens. We believe we are currently in substantial compliance, and expect to continue to comply in all material respects, with these rules and regulations.

Summary. Subject to final approval of the Baldwin consent decree announced in March 2005 and described in Note 16 Commitments and Contingencies Summary of Material Legal Proceedings Baldwin Station Litigation beginning on page F-57, management believes that it is in substantial compliance with, and is expected to continue to comply in all material respects with, applicable environmental statutes, regulations, orders and rules. Further, to management s knowledge, other than the previously referenced complaints, there are no existing, pending or threatened actions, suits, investigations, inquiries, proceedings or clean-up obligations by any governmental authority or third-party relating to any violations of any environmental laws with respect to our assets or pertaining to any indemnification obligations with respect to properties we previously owned or operated, which could reasonably be expected to have a material adverse effect on our operations, cash flows and financial condition.

Ongoing Environmental Initiatives

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

Multi-Pollutant Air Emission Initiatives. In recent years, various federal and state legislative and regulatory multi-pollutant initiatives have been introduced to replace multiple overlapping regulatory regimes with a limited number of programs and to streamline and simplify compliance planning.

There are currently numerous multi-pollutant initiatives being considered by state and federal governments which target many of the same pollutants but contain different compliance targets and timelines, such as the Clear Skies initiative, the Clean Air Interstate Rule, or CAIR, and the Clean Air Mercury Rule. The major issues addressed by these initiatives include the transportation of ozone and particulate matter, visibility impairment or Regional Haze and emissions of other pollutants, including mercury. These initiatives are aimed at long-term reductions of multiple pollutants produced from electric generating facilities. Some of these proposed initiatives, if enacted, would also impose controls on emissions of the greenhouse gas carbon dioxide, which is emitted by all combustion sources.

Additional EPA initiatives include designation of areas as attainment, non-attainment or non-classifiable for purposes of (i) the new particulate matter 2.5 standard, or PM 2.5 standard, and (ii) the new 8-hour ozone standard. The PM 2.5 standard is aimed at the reduction of fine (smaller than 2.5 microns in diameter) particulate matter, and would impose limitations on emissions of the precursor pollutants sulphur dioxide and nitrogen oxides. The new ozone standard may result in additional nitrogen oxides reductions from power generating facilities in affected locations. Fossil fuel-fired power plants in the U.S. would be affected by the adoption of these programs or other multi-pollutant legislation currently proposed by Congress addressing similar issues. Such programs would require compliance to be achieved either by the installation of pollution controls, the purchase of emission allowances, the curtailment of operations or some combination thereof. Based on court-ordered deadlines and Congressional activity, we anticipate that some of these new requirements will be finalized in 2005. The final requirements would specify the target emission or cap levels as well as the timeframe in which compliance must be achieved.

Water Issues. Our wastewater discharges are permitted under the Clean Water Act and analogous state laws. These permits are subject to review every five years. The state-issued water discharge permits associated with our DNE facilities expired in 1992. However, under New York State law, the authorization arising under these permits remains in effect and allows for continued operation under the terms of the original permit, provided that a timely and sufficient application requesting renewal has been filed as required. In May 1992, the then owner of the Danskammer facility filed a renewal application which we believe was timely and sufficient. In November 2002, several environmental groups filed suit in the Supreme Court of the State of New York seeking, among other things, a declaratory judgment that the Danskammer water intake and discharge permit expired because of alleged deficiencies in the renewal application process. In September 2004, the Court ruled that the water intake and discharge permit for our Danskammer facility is void, but stayed the enforcement of the decision pending further review by the Court or by the Appellate Division.

In October 2004, we filed our appeal of the Court s decision with the Appellate Division, and we intend to pursue vigorously our challenge to the Court s ruling voiding our permit. We will also continue to seek approval of our application to renew the water intake and discharge permit in proceedings before the New York State Department of Environmental Conservation. If our appeal is ultimately unsuccessful, we may be required to suspend operations at our Danskammer facility pending receipt of final approval of the renewal of our water intake and discharge permit. We cannot predict with any certainty the outcome of these proceedings; however, an adverse outcome, particularly a requirement that we suspend operations at our Danskammer facility for any period of time, could have a material adverse effect on our financial condition, results of operations and cash flows.

In February 2004, the EPA issued final rules, which we refer to as Rule 316(b), establishing national standards aimed at protecting aquatic life at power generating facilities with existing cooling water intake structures. This rule requires that final compliance plans be in place by January 2008. We believe that the requirements of Rule 316(b) are consistent with the provisions proposed in the Danskammer permit application. However, we expect that several of our other facilities will be impacted by the requirements of Rule 316(b), and we cannot predict what plant modifications may be necessary to comply with this rule.

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

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Global Climate Change. The international treaty relating to global warming (commonly known as the Kyoto Protocol) would have required reductions in emissions of greenhouse gases, primarily carbon dioxide and methane, by energy companies, including us, if adopted by the United States. As an alternative to Kyoto, which became effective (without ratification by the United States) in February 2005, current U.S. policy regarding greenhouse gases favors voluntary reductions, increased operating efficiency, and continued research and technology development. Although several bills have been introduced in Congress that would compel reductions in carbon dioxide emissions, none have advanced through the legislature and there are presently no federal mandatory greenhouse gas reduction requirements. The likelihood of any federal mandatory carbon dioxide emissions reduction program being adopted in the near future, and the specific requirements of any such program, are uncertain. However, a number of states in the Northeast and the West are in the process of developing regulatory programs to manage greenhouse gas emissions. The final program requirements and subsequent impact to our operations are not known at this time, but the Northeast states currently intend to finalize carbon dioxide emissions requirements for electric generating facilities during 2005. To the extent that any of the federal or state governments adopt or enact laws or regulations mandating a substantial reduction in greenhouse gas emissions, such mandatory reduction requirements could have far-reaching and significant implications for industry in those jurisdictions, particularly the energy industry in which we operate. Although we cannot predict the potential impact of such laws or regulations on our future financial condition, results of operations or cash flows, we will continue to monitor and participate in greenhouse gas policy developments in the regions in which we operate and will continue to assess and respond to the potential impact on our business operations.

For all of the ongoing environmental matters described above, it is difficult to predict the form that proposed rules will ultimately take and the impact that such rules, if approved, will have on our operations. It is possible that the result of these ongoing initiatives could require us and other similarly situated companies to incur material environmental compliance costs over a period of years, beginning as early as 2005.

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OPERATIONAL RISKS AND INSURANCE

We are subject to all risks inherent in the various businesses in which we operate. These risks include, but are not limited to, explosions, fires, terrorist attacks, product spillage, weather, nature, inadequate maintenance of rights-of-way and the public, which could result in damage to or destruction of operating assets and other property, or could result in personal injury, loss of life or pollution of the environment, as well as curtailment or suspension of operations at the affected facility. We maintain general public liability, property/boiler and machinery, and business interruption insurance in amounts that we consider to be appropriate for such risks. Such insurance is subject to deductibles that we consider reasonable and not excessive given the current insurance market environment. The costs associated with these insurance coverages have increased significantly during recent periods, and may continue to do so in the future. The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. While we currently maintain levels and types of insurance that we believe to be prudent under current insurance industry market conditions, our potential inability to secure these levels and types of insurance in the future could negatively impact our business operations and financial stability, particularly if an uninsured loss were to occur. No assurance can be given that we will be able to maintain these levels of insurance in the future at rates we consider commercially reasonable, particularly in the area of terrorism insurance should the Terrorism Risk Insurance Act of 2002 not be extended beyond December 2005.

In our CRM segment, we also face market, price, credit and other risks relative to our exit from the CRM business. Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk beginning on page 83 for further discussion of these risks.

In addition to these commercial risks, we also face the risk of damage to our reputation and financial loss as a result of inadequate or failed internal processes and systems. A systems failure or failure to enter a transaction properly into the records and systems may result in an inability to settle a transaction in a timely manner or cause a contract breach. Our inability to implement the policies and procedures that we have developed to minimize these risks could increase our potential exposure to damage to our reputation in the industries in which we compete and to financial loss. Please read Item 9A. Controls and Procedures beginning on page 85 for further discussion of our internal control systems.

SIGNIFICANT CUSTOMER

For the years ended December 31, 2004, 2003 and 2002, approximately 17%, 16% and 15%, respectively, of our consolidated revenues and approximately 22%, 22% and 44%, respectively, of our consolidated cost of sales were derived from transactions with ChevronTexaco and its subsidiaries. No other customer accounted for more than 10% of our consolidated revenues or consolidated cost of sales during 2004, 2003 or 2002.

EMPLOYEES

At December 31, 2004, we had approximately 643 employees at our administrative offices and approximately 1,580 employees at our operating facilities. Approximately 844 employees at Dynegy-operated facilities are subject to collective bargaining agreements with various unions. We believe relations with our employees are satisfactory.

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Item 1A. ***Executive Officers***

Set forth below are the names and positions of our executive officers as of March 11, 2005, together with their ages and years of service with us.

Name	Age	Position(s)	Served With the Company Since
Bruce A. Williamson	45	President, Chief Executive Officer and Chairman of the Board	2002
Alec G. Dreyer	46	Executive Vice President, Generation	2000
Stephen A. Furbacher	57	Executive Vice President, Natural Gas Liquids	1996
Nick J. Caruso	59	Executive Vice President and Chief Financial Officer	2002
Carol F. Graebner	51	Executive Vice President and General Counsel	2003
Peter J. Wilt	57	Vice President, Investor Relations	2004
R. Blake Young	46	Executive Vice President, Administration and Technology	1998

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

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

Alec G. Dreyer has served as Executive Vice President of our GEN segment since October 2002. Mr. Dreyer joined us in February 2000 upon consummation of the Illinova acquisition and has served various functions in our corporate finance department and power generation business. Prior to joining us, Mr. Dreyer served Illinova and its affiliates for 8 years, most recently as President of Illinova Generating Company and Senior Vice President of Illinova and Illinois Power. He was responsible for developing Illinova s spin off of its fossil-fueled generation fleet into an unregulated entity, which is now known as DMG.

Stephen A. Furbacher has served as Executive Vice President of our NGL segment since September 1996. He joined us in May 1996, just prior to our acquisition of Chevron s midstream business. Before joining us, he served as President of Warren Petroleum Company, the natural gas liquids division of Chevron U.S.A. He began his career with Chevron in August 1973 and served in positions of increasing responsibility before being named President of Warren Petroleum Company in July 1994.

Nick J. Caruso has served as our Executive Vice President and Chief Financial Officer since December 2002. Mr. Caruso is responsible for our internal audit, risk management, tax, treasury, accounting and finance functions. He was previously employed by Shell Oil Company from June 1969 to December 2001. He most recently served as that company s Vice President of Finance and Chief Financial Officer before retiring in December 2001. He was responsible for the controller s organization, treasury, insurance, auditing and retirement funds, interfacing with the board of directors on internal controls, and preparation of financial statements.

Carol F. Graebner has served as our Executive Vice President and General Counsel since March 2003. Prior to joining us, Ms. Graebner was employed by Duke Energy International, where she served as senior vice president and general counsel and was responsible for providing all legal, regulatory and governmental affairs

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services for that company s international merchant energy business. Prior to joining Duke Energy International in November 1998, she served in various positions of increasing responsibility at Conoco Inc., advancing over a 16-year period to general counsel of Conoco Global Power, Inc.

Peter J. Wilt has served as our Vice President, Investor Relations since April 2004. Mr. Wilt is responsible for serving as a liaison between our management, the investing public and the financial community, including portfolio managers and research analysts. He is also responsible for communicating our financial results, operational performance and business strategies to the investment community. Mr. Wilt previously served Duke Energy International as Executive Vice President, Europe from May 2002 through April 2004, and as Executive Vice President, Latin America, from November 1999 through May 2002.

R. Blake Young has served as our Executive Vice President of Administration and Technology since October 2002. Formerly President of Global Technology, Mr. Young is responsible for strategic planning, corporate technology, corporate communications, human resources, divestitures and corporate shared services. In addition, Mr. Young served as Executive Vice President and Chief Operating Officer of Illinois Power from February 2004 through April 2004, and as President of Illinois Power from April 2004 through September 2004. In these capacities he assumed the overall responsibility for Illinois Power and its transition to Ameren during the regulatory approval process. Prior to joining us in October 1998, he worked for Campbell Soup Company where he was responsible for technology deployment across its U.S. grocery division and served as head of global business systems strategy. Mr. Young was previously employed by Tenneco Energy for approximately 13 years, where he served as Vice President and Chief Information Officer.

Item 2. ***Properties***

We have included descriptions of the location and general character of our principal physical operating properties by segment in Item 1. Business beginning on page 1. Those descriptions are incorporated herein by this reference. Substantially all of our assets, including the physical operating properties we own, are pledged as collateral with respect to the DHI amended credit facility and the DHI second priority senior secured notes on a first lien and second lien, respectively. Please read Note 11 Debt beginning on page F-42 for further discussion of the amended credit facility.

Our principal executive office located in Houston, Texas is held under a lease that expires in December 2007. We also lease additional offices in the states of California, Colorado, Florida, Georgia, Illinois, Massachusetts, and Texas.

Item 3. ***Legal Proceedings***

For a description of our material legal proceedings, please read Note 16 Commitments and Contingencies beginning on page F-55, which is incorporated herein by reference.

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

No matter was submitted to a vote of our security holders during the fourth quarter 2004.

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PART II

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

Our Class A common stock, no par value per share, is listed and traded on the New York Stock Exchange under the ticker symbol DYN. The number of stockholders of record of our Class A common stock as of March 4, 2005, based upon records of registered holders maintained by our transfer agent, was 20,712.

Our Class B common stock, no par value per share, is neither listed nor traded on any exchange. All of the shares of Class B common stock are owned by Chevron U.S.A. Inc., which we refer to as Chevron.

The following table sets forth the high and low closing sales prices for the Class A common stock for each full quarterly period during the fiscal years ended December 31, 2004 and 2003, as reported on the New York Stock Exchange Composite Tape.

Summary of Dynegy s Common Stock Price

	High	Low
2004:		
Fourth Quarter	$ 5.86	$ 4.27
Third Quarter	4.99	3.93
Second Quarter	4.44	3.75
First Quarter	5.15	3.46
2003:		
Fourth Quarter	$ 4.35	$ 3.45
Third Quarter	4.65	2.85
Second Quarter	5.23	2.54
First Quarter	2.63	1.29

During the fiscal years ended December 31, 2004 and 2003, our Board of Directors did not elect to pay a common stock dividend. Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Dividends on Preferred and Common Stock beginning on page 48 for further discussion of our dividend policy and the impact of dividend restrictions contained in our financing agreements. Any decision to pay a dividend is at the discretion of the Board of Directors, but we do not expect to pay a common stock dividend in the foreseeable future.

Shareholder Agreement

In June 1999, Chevron, now a subsidiary of ChevronTexaco, entered into a shareholder agreement with us governing certain aspects of our relationship. The agreement was executed in February 2000, upon closing of the merger with Illinova, and reflected agreements negotiated between us and Chevron relating to Chevron s significant ownership interest in Dynegy. The agreement amended certain of the rights and obligations previously agreed between us and Chevron at the time of Chevron s initial investment in 1996. In August 2003, we entered into an amended and restated shareholder agreement with Chevron in connection with the consummation of the Series B Exchange. Please read Note 12 Related Party Transactions Series B Preferred Stock beginning on page F-47 for further discussion of the Series B Exchange. The material terms of this amended and restated shareholder agreement, which we refer to as the shareholder agreement, are described below.

The shareholder agreement grants Chevron preemptive rights to acquire shares of our common stock in proportion to its then-existing interest in our equity value whenever we issue any equity securities, including

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securities issued pursuant to employee benefit plans. Chevron agreed to waive its preemptive rights in respect of the equity securities we issued in connection with the Series B Exchange and our August 2003 refinancing and up to $250 million in equity securities we may issue in one or more future underwritten offerings.

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

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

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

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

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

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

- the issuance of new shares of stock where the aggregate consideration to be received exceeds the greater of $1 billion or one-quarter of our total market capitalization;
- any disposition of all or substantially all of our NGL business while substantial agreements between Chevron and us exist (except for a contribution of such liquids business to an entity in which we have a majority direct or indirect interest);

any merger, consolidation, joint venture, liquidation, dissolution, bankruptcy, acquisition of stock or assets, or issuance of common or preferred stock, any of which would result in payment or receipt of consideration having a fair market value exceeding the greater of $1 billion or one-quarter of our total market capitalization; or

any other material transaction or series of related transactions which would result in the payment or receipt of consideration having a fair market value exceeding the greater of $1 billion or one-quarter of our total market capitalization.

However, upon occurrence of one of these triggering events and in lieu of selling Class B common stock, Chevron may elect to retain the shares of Class B common stock but forfeit its right and the right of its Board

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designees to block the subject transaction. A block consists of a vote against a proposed transaction by either (a) all of Chevron s representatives on our Board of Directors present at the meeting where the vote is taken (if the transaction would otherwise be approved by our Board of Directors) or (b) any of the Class B common stock held by Chevron and its affiliates if the transaction otherwise would be approved by at least two-thirds of all other shares entitled to vote on the transaction, excluding shares held by our management, directors or subsidiaries.

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

- issuing any shares of Class B common stock to any person other than Chevron and its affiliates;
- adopting a shareholder rights plan, poison pill or similar device that prevents Chevron from exercising its rights to acquire shares of common stock or from disposing of its shares when required by us; and
- acquiring, owning or operating a nuclear power facility, other than being a passive investor in a publicly-traded company that owns a nuclear facility.

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

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2004 as it relates to our equity compensation plans for our Class A common stock, the only class with respect to which we offer equity compensation.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)

	(a)		
Equity compensation plans approved by security holders	7,506,236	$ 16.83	26,931,419
Equity compensation plans not approved by security holders (1)	3,856,434	$ 18.01	5,996,678
Total	11,362,670	$ 17.23	32,928,097

(1) The plans that were not approved by our security holders are as follows: Extant Plan, Dynegy 2001 Non-Executive Stock Incentive Plan and Dynegy UK Plan. Please read Note 18 Capital Stock Stock Options beginning on page F-71 for a brief description of our equity compensation plans, including these plans.

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

The selected financial information presented below was derived from, and is qualified by reference to, our Consolidated Financial Statements, including the notes thereto, contained elsewhere herein. The selected financial information should be read in conjunction with the Consolidated Financial Statements and related notes and Management s Discussion and Analysis of Financial Condition and Results of Operations. Earnings (loss) per share (EPS), shares outstanding for EPS calculation and cash dividends per common share have been adjusted for a two-for-one stock split on August 22, 2000 and, for all periods prior to February 1, 2000, the 0.69-to-one exchange ratio in the Illinova acquisition.

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As discussed in the Explanatory Note to the accompanying Consolidated Financial Statements, the historical information in the accompanying Consolidated Financial Statements has been restated. Please read the Explanatory Note to the accompanying Consolidated Financial Statements beginning on page F-10 for additional information about these restatements. The selected financial data that follows has been adjusted to reflect these restatements.

Dynegy s Selected Financial Data

	Year Ended December 31,				
	2004	2003	2002	2001	2000
		(Restated)	(Restated)	(Restated)	(Restated)
	(in millions, except per share data)				
Statement of Operations Data (1):					
Revenues	$ 6,153	$ 5,787	$ 5,326	$ 9,124	$ 9,715
Depreciation and amortization expense	(323)	(454)	(466)	(452)	(386)
Goodwill impairment		(311)	(814)		
Impairment and other charges	(83)	(225)	(190)		
General and administrative expenses	(352)	(346)	(325)	(420)	(312)
Operating income (loss)	192	(594)	(1,058)	971	770
Interest expense	(480)	(509)	(297)	(255)	(247)
Income tax benefit (expense)	89	246	343	(366)	(231)
Net income (loss) from continuing operations	(10)	(713)	(1,199)	481	416
Income (loss) from discontinued operations (3)	(5)	(19)	(1,154)	(82)	27
Cumulative effect of change in accounting principles		40	(234)	2	
Net income (loss)	$ (15)	$ (692)	$ (2,587)	$ 401	$ 443
Net income (loss) applicable to common stockholders	(37)	321	(2,917)	359	408
Basic earnings (loss) per share from continuing operations	$ (0.09)	$ 0.80	$ (4.18)	$ 1.35	$ 1.26
Basic net income (loss) per share	(0.10)	0.86	(7.97)	1.10	1.35
Diluted earnings (loss) per share from continuing operations	$ (0.09)	$ 0.73	$ (4.18)	$ 1.29	$ 1.21
Diluted net income (loss) per share	(0.10)	0.78	(7.97)	1.05	1.30
Shares outstanding for basic EPS calculation	378	374	366	326	302
Shares outstanding for diluted EPS calculation	504	423	370	340	315
Cash dividends per common share	$	$	$ 0.15	$ 0.30	$ 0.25
Cash Flow Data:					
Cash flows from operating activities	$ 5	$ 876	$ (25)	$ 550	$ 420
Cash flows from investing activities	262	(266)	677	(3,828)	(1,539)
Cash flows from financing activities	(115)	(900)	(44)	3,450	1,131
Cash dividends or distributions to partners, net	(22)		(55)	(98)	(112)
Capital expenditures, acquisitions and investments	(314)	(338)	(981)	(4,687)	(2,415)

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	December 31,				
	2004	2003	2002	2001	2000
		(Restated)	(Restated) (in millions)	(Restated)	(Restated)
Balance Sheet Data (2):					
Current assets	$ 2,752	$ 3,086	$ 7,586	$ 8,956	$ 10,827
Current liabilities	1,802	2,450	6,748	8,538	10,286
Property and equipment, net	6,130	8,178	8,458	9,269	7,148
Total assets	9,852	12,810	20,029	25,083	22,572
Long-term debt (excluding current portion)	4,332	5,893	5,454	5,016	3,754
Notes payable and current portion of long-term debt	34	331	861	458	118
Serial preferred securities of a subsidiary		11	11	46	46
Subordinated debentures			200	200	300
Series B Preferred Stock (4)			1,212	882	
Series C convertible preferred stock	400	400			
Minority interest (5)	106	121	146	1,040	1,022
Capital leases not already included in long-term debt			15	29	15
Total equity	1,867	1,886	2,167	4,867	3,376

(1) The following acquisitions were accounted for in accordance with the purchase method of accounting and the results of operations attributable to the acquired businesses are included in our financial statements and operating statistics beginning on the acquisitions effective date for accounting purposes:
- Northern Natural February 1, 2002;
- BGSL December 1, 2001;
- iaxis March 1, 2001;
- Extant October 1, 2000; and
- Illinova January 1, 2000.

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

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

(4) The 2002 amount equals the $1.5 billion in proceeds related to the Series B Preferred Stock less the $660 million implied dividend recognized in connection with the beneficial conversion option plus $372 million in accretion of the implied dividend through December 31, 2002. The 2001 amount equals the $1.5 billion in proceeds less the $660 million implied dividend plus $42 million in accretion of the implied dividend through December 31, 2001. Please read Note 12 Related Party Transactions Series B Preferred Stock beginning on page F-47 for further discussion.

(5) The 2001 and 2000 amounts include amounts relating to the Black Thunder Secured Financing. This financing involved (i) our investment of $100 million in June 2000 in Catlin Associates, L.L.C., an entity which holds indirect economic interests in some of our Midwest generation assets, including the coal-fired generation units in Illinois, and (ii) our obligation to purchase the $850 million interest held by a third party on or before June 2005. We repaid the balance owed under this financing in August 2003.

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

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

OVERVIEW

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily in two areas of the energy industry: power generation and natural gas liquids. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. As described below, our regulated energy delivery business, which was conducted through Illinois Power and its subsidiaries, was sold to Ameren Corporation in September 2004. We also separately report the results of our customer risk management business, which primarily consists of our three remaining power tolling arrangements (excluding the Independence toll, which is now part of our GEN segment) as well as our gas transportation contracts, and legacy gas and power trading positions. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and infrastructure depreciation and amortization, but because of their nature, these items are not reported as a separate segment.

Following is a brief discussion of each of our three current business 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 strategic growth opportunities and a summary of our current liquidity position and items that could impact our liquidity position in 2005 and beyond. 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.

Power Generation. Our power generation business owns or leases more than 12,700 MWs of net generating capacity located in six regions of the United States, including the facilities recently acquired in the Sithe Energies acquisition. Our power generating fleet is diversified by facility type (base load, intermediate and peaking), fuel source and geographic location. We generate earnings and cash flows in this business through sales of energy and capacity.

The primary factors impacting our power generation earnings and cash flows are the prices for power, natural gas and coal, which in turn are largely driven by supply and demand. Demand for power can vary regionally due to, among other things, weather and general economic conditions. Power supplies similarly vary by region and are impacted significantly by available generating capacity, transmission capacity and federal and state regulation. We also are impacted by the relationship between prices for power and natural gas, commonly referred to as the spark spread, and its impact on the cost of generating electricity. However, we believe that our significant coal-fired and fuel oil generating facilities partially mitigate our sensitivity to changes in the spark spread, in that coal and fuel oil prices are relatively stable and insensitive to changes in gas prices, and position us for potential increases in earnings and cash flows in an environment where both power and gas prices increase. We have entered into long-term coal supply and transportation agreements for our Midwest fleet. Please read Liquidity and Capital Resources Internal Liquidity Sources Cash Flows from Operations beginning on page 48 for a discussion of our views on the current pricing environment and its anticipated long-term recovery.

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

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

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our ability to optimize our assets through hedging activities and similar transactions, which is affected by general market liquidity and the need to satisfy counterparties collateral requirements given our non-investment grade credit ratings; and

our ability to enter into new sales contracts and to renew our existing contracts.

Natural Gas Liquids. Our natural gas liquids business owns natural gas gathering and processing, or upstream, assets in key producing areas of Louisiana, New Mexico and Texas. This business also owns integrated downstream assets used to fractionate, store, terminal, transport, distribute and market natural gas liquids. These downstream assets generally are connected to and supplied by our and third parties upstream assets and are located in Mont Belvieu, Texas, the hub of the U.S. natural gas liquids business, and West Louisiana.

We generate earnings and cash flows in the upstream business by selling our gathering, processing and treating services to producers. We generate earnings and cash flows in our downstream business through sales of our fractionation, storage, transportation and terminalling services and sales of natural gas liquids through our marketing operations.

The earnings and cash flows that we generate in this business are sensitive to natural gas and natural gas liquids prices and, to a lesser extent, the relationship between the two, commonly referred to as the frac spread. Our current contract mix has minimal exposure to frac spread risk. Please read Item 1. Business Segment Discussion Natural Gas Liquids Upstream Business beginning on page 10 for a detailed discussion of our current upstream contract portfolio.

In addition to commodity prices, other factors that have impacted, and are expected to continue to impact, the earnings and cash flows for this business include:

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

reduced market liquidity and our obligation to post collateral to or prepay counterparties because of our non-investment grade credit ratings, which limit our ability to contract forward physically for some of our natural gas liquids products;

producer drilling activity, which is significantly affected by commodity prices;

a varying frac spread environment and the resulting impact on volumes available for fractionation, distribution and marketing;

the petrochemical industry s need for and utilization of our natural gas liquids as feedstocks and related natural gas liquids facilities to provide distribution and logistics services;

our ability to manage our natural gas liquids inventories efficiently; and our ability to meet customer demands for timely delivery and transportation.

Regulated Energy Delivery. Our regulated energy delivery segment was comprised of our Illinois Power subsidiary prior to its sale to Ameren in September 2004. From February 2002 through July 2002, this segment, formerly called the Transmission and Distribution segment, also included the results of Northern Natural. Northern Natural s results for this period are reflected in Discontinued Operations in our consolidated statements of operations.

Customer Risk Management. Our customer risk management business primarily consists of the Gregory power tolling arrangement, which expires in July 2005, the Kendall power tolling arrangement, the effect of which we have mitigated through November 2008 and the Sterlington power tolling arrangement, as well as our gas transportation contracts and legacy gas and power trading positions. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Kendall beginning on page F-25 below for further discussion of the Kendall toll. Our Independence

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power tolling arrangement and the related gas transportation contracts, which were previously part of our CRM segment, were reclassified as intercompany transactions upon our consummation of the Sithe Energies acquisition, and, as of February 2005, are part of our GEN segment, as they relate to the operation of the power generation assets acquired from Exelon. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion. We have significant, long-term fixed obligations associated with our tolling arrangements, which obligations may substantially exceed the earnings and cash flows we expect to generate in connection with these arrangements. Our ability to mitigate partially the negative impact of these arrangements on our earnings and cash flows depends on the price of power and the spark spread in the regions where the plants covered by those tolls are located. It also will be significantly impacted by our ability to restructure or terminate one or more of our remaining power tolling arrangements, which we expect would require a significant cash payment.

Regarding our legacy gas and power trading positions, we have substantially reduced the size of our portfolio relative to when we were primarily a marketing and trading company. Please read Item 1. Business Segment Discussion Customer Risk Management beginning on page 18 for further discussion.

Other. Beginning January 1, 2003, Other includes corporate-level items that were previously allocated to our operating segments. Significant items impacting future earnings and cash flows include:

- interest expense, which increased beginning in 2003 as a result of our refinancing and restructuring activities and will continue to reflect our non-investment grade credit ratings;

- general and administrative costs, with respect to which we have implemented a number of initiatives that have yielded savings; general and administrative costs also will be impacted by, among other things, (i) any future corporate-level litigation reserves or settlements and (ii) potential funding requirements under our pension plans; and

- income taxes, with respect to which we currently only pay minimal state and foreign income taxes; income taxes will also be impacted by our ability to realize our significant deferred tax assets, including loss carryforwards.

In addition, dividends associated with our outstanding preferred stock will continue to affect our earnings available to our common shareholders.

Strategic Growth Opportunities. With only a few significant legacy matters remaining to be addressed, more of our company s resources are available to continue our efforts to operate our energy businesses safely, reliably and efficiently, to manage the costs across our organization and to deliver value to our investors. We are also continuing to focus on identifying and evaluating strategic growth opportunities, particularly organic or bolt-on projects, such as the conversion of our Havana power generating facility to lower-cost and lower-emission PRB coal, to improve the operational performance and efficiency of certain assets, enabling us to realize costs savings and to capture even more of the benefit of increases in commodity prices. Such opportunities may also include merger and acquisition activities, which we discuss and evaluate as part of our ongoing business strategy. In the power generation industry, in particular, we believe that consolidation is likely to occur within the next several years. We further believe that our efficient and scalable operations platform, together with our multi-fuel capabilities and multi-region presence, position us to benefit from opportunities that might arise in connection with any acquisition or consolidation transactions. However, our desire or ability to pursue in any such opportunities is subject to a number of factors beyond our control. As such, we cannot guarantee that any such opportunities will be available to us, nor can we predict with any degree of certainty the impact of any such opportunities on our financial condition or results of operations.

Liquidity. As of March 4, 2005, we had cash on hand of $365 million and available borrowing capacity of $611 million, for total liquidity of nearly $1 billion. During 2004, we continued to reduce our debt and other obligations while maintaining liquidity between $1.2 billion and $1.7 billion. The sale of Illinois Power provided significant cash proceeds and advanced our business strategy of focusing on our unregulated energy businesses. In January 2005, we used approximately $135 million of liquidity to pay the cash portion of the purchase price for the Sithe Energies acquisition.

For the next twelve months, assuming continuation of the current commodity pricing environment, we expect that our operating cash flows will be positive, but insufficient to satisfy our capital expenditures and debt maturities. However, we believe that our cash on hand and the $100 million deposited into escrow in connection with the sale of Illinois Power, which we expect to receive following approval of the Baldwin consent decree announced in March 2005, together with capacity under our $700 million revolving credit facility, will be

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sufficient to discharge these obligations. To further our deleveraging efforts, we may consider other capital-raising activities, including potential equity issuances.

Over the longer term and through the anticipated recovery of the U.S. power markets, we expect to maintain sufficient liquidity to satisfy our debt and commercial obligations and provide collateral support through operating cash flows, capacity under our revolving credit facility (or any refinancing thereof), as well as proceeds from anticipated refinancings of debt maturities.

Our ability to generate operating cash flows will be impacted by a number of factors, some of which are beyond our control, including weather, commodity prices, particularly for power and natural gas, and the success of our ongoing efforts to manage operating costs, particularly fuel requirements, and capital expenditures. Our ability to refinance our substantial debt maturities is primarily dependent upon our ability to generate operating cash flows, which is subject to the factors described in the preceding sentence. Over the longer term we believe that power prices will improve in some or all of the regions in which we operate as the supply-demand imbalance for power decreases. Much of our restructuring work has positioned us to benefit from earnings and growth opportunities associated with an expected recovery in the U.S. power markets. Additionally, our NGL business is currently operating in a highly favorable pricing environment. Our future financial condition and results of operations will be materially adversely affected if the U.S. power markets fail to recover in accordance with our expectations or if we experience significant, prolonged pricing deterioration below price levels experienced over the last few years in our NGL segment.

Our longer term liquidity position and financial condition will also be significantly impacted by the availability of, and our ability to pursue, strategic growth opportunities. However, our desire or ability to pursue any such opportunities is subject to a number of factors beyond our control. As such, we cannot guarantee that any such opportunities will be available to us, nor can we predict with any degree of certainty the impact of any such opportunities on our financial condition or results of operations.

Please read Uncertainty of Forward-Looking Statements and Information for additional factors that could impact our future operating results and financial condition.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, collateral requirements, fixed capacity payments and contractual obligations, capital expenditures, legal settlements and working capital needs. Examples of working capital needs include prepayments or cash collateral associated with purchases of commodities, particularly natural gas, coal and natural gas liquids, facility maintenance costs and other costs such as payroll. Our liquidity and capital resources are primarily derived from cash flows from operations, cash on hand, borrowings under our financing agreements, asset sale proceeds and proceeds from capital market transactions, to the extent that we engage in these activities prospectively.

Debt Obligations

During 2004, we continued our efforts to reduce our debt maturities and extend our maturity profile, which included the following transactions:

- Replacement of our $1.1 billion credit facility, scheduled to mature in February 2005, with a new $1.3 billion credit facility comprised of a revolving credit facility and a term loan, which are scheduled to mature in May 2007 and May 2010, respectively;

- Prepayment of all outstanding indebtedness and other amounts owed under the ABG Gas Supply Financing, primarily through use of $154 million in proceeds from the May 2004 term loan;

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Payment of $81 million in connection with the termination of the Tilton capital lease;

The sale of Illinois Power to Ameren Corporation, which eliminated Illinois Power s $1.8 billion in debt and preferred stock obligations from our consolidated balance sheet; and

Redemption of all outstanding ChevronTexaco junior notes, primarily through the use of $125 million of the proceeds from the Illinois Power sale.

As a result of our efforts, our aggregate maturities for long-term debt as of December 31, 2004 were reduced to $24 million in 2005, $28 million in 2006, $188 million in 2007 (excluding the maturity of our $700 million revolving credit facility), $231 million in 2008, $6 million in 2009 and approximately $3.9 billion thereafter. Maturities for 2005 represent our principal payments on our term loan and our 8.125% DHI senior notes and exclude the non-cash amortization of basis adjustments included in Notes payable and current portion of long-term debt on our consolidated balance sheets.

Furthermore, upon the closing of the Sithe Energies acquisition, our balance sheet will reflect the consolidation of the fair value of approximately $919 million in face value project debt. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion of this transaction.

We have incurred significant debt service obligations in the course of extending our debt maturities. We also are subject to covenants in the related transaction agreements that are substantially more restrictive than those typically found in financing agreements of borrowers with investment grade credit ratings, including covenants limiting our ability to incur additional debt and sell certain assets. We are currently in compliance with these restrictive covenants, but our future financial condition and results of operations could be materially adversely affected by our ability to comply with these restrictive covenants in the future.

The following table depicts our consolidated third-party debt obligations, including the principal-like maturities associated with the DNE leveraged lease, and the extent to which they are secured as of December 31, 2004 and 2003:

	December 31, 2004	December 31, 2003
	(in millions)	
First Secured Obligations		
Dynegy Holdings Inc.	$ 1,551	$ 1,127
Illinois Power (1)		1,967
Total First Secured Obligations	1,551	3,094
Second Secured Obligations	1,750	1,750
Unsecured Obligations	1,831	2,160
Subtotal	5,132	7,004
Preferred Obligations	400	411

Total Obligations	$ 5,532	$ 7,415
Less: DNE Lease Financing (3)	(771)	(758)
Less: Preferred Obligations	(400)	(411)
Other (2)	5	(22)
Total Notes Payable and Long-term Debt	$ 4,366	$ 6,224

(1) Ameren assumed Illinois Power s debt obligations on September 30, 2004 upon closing of our sale of Illinois Power. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23 for further discussion.

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(2) Consists of net premiums on debt of $5 million at December 31, 2004; net discounts on debt of $12 million at December 31, 2003; and the $10 million difference between the carrying value of the Tilton capital lease and the purchase obligation of $81 million at December 31, 2003.

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

Collateral Postings

We continue to use a significant portion of our capital resources, in the form of cash and letters of credit, to satisfy counterparty collateral demands. These counterparty collateral demands reflect our non-investment grade credit ratings and counterparties views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. The following table summarizes our consolidated collateral postings to third parties by segment at March 4, 2005, December 31, 2004 and December 31, 2003:

	March 4, 2005	December 31, 2004	December 31, 2003
		(in millions)	
By Segment:			
GEN	$ 176	$ 192	$ 136
CRM	80	94	121
NGL	167	167	179
REG	10	10	38
Other	9	7	8
Total	$ 442	$ 470	$ 482
By Type:			
Cash	$ 353	$ 376	$ 294
Letters of Credit	89	94	188
Total	$ 442	$ 470	$ 482

The increase in collateral postings for the GEN of $40 million is primarily a result of increased commodity prices, particularly the price of electricity, as well as increased coal purchases and collateral posted in connection with new electric capacity sales transactions. Additionally, as of February 2005, our Independence power tolling arrangement and financial derivative instrument and the related gas transportation contracts (and the collateral posted in connection with these obligations), which were previously part of our CRM segment, were transformed into intercompany obligations under our GEN segment. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion.

This increase in our collateral postings was offset by reductions in collateral postings in our other segments, including the $41 million reduction of collateral posted in support of our CRM segment primarily resulting from (i) the termination of the ABG Gas Supply contract in August 2004 and (ii) the execution of a master netting agreement with a significant counterparty, which were offset by $22.5 million of collateral posted in connection with an existing natural gas transaction. Additionally, the year end 2003 balance, in support of our NGL segment, included collateral posted with respect to the purchase of natural gas liquids inventory transported by barge. Finally, collateral postings at our REG segment have decreased by $28 million due to the sale of Illinois Power. We expect that the remaining $10 million of collateral relating to that segment will be eliminated in the first quarter 2005.

While the total amount of collateral posted decreased, we have increased the proportion of cash used to satisfy counterparty collateral demands. As of December 31, 2003, approximately 61% of the aggregate collateral posted (or approximately $294 million) consisted of cash, compared to approximately 80% cash

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collateral (or approximately $376 million) as of December 31, 2004 and 80% cash collateral (or approximately $353 million) as of March 4, 2005. This increase is the result of the termination of the ABG Gas Supply contract and our ongoing efforts to post cash collateral in lieu of letters of credit, to the extent economical, to avoid paying the 4.00% per annum letter of credit fee payable under our revolving credit facility.

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. Considering current commodity price estimates, our credit ratings, the timing of contract settlements, the anticipated level of new capacity sales agreements and forward hedging transactions, we believe that collateral requirements will be between $375 million and $400 million at year-end 2005. We believe that we have sufficient capital resources to satisfy counterparties collateral demands, including those for which no collateral is currently posted, for at least the next twelve months. Over the longer term, we expect to achieve incremental reductions associated with the completion of our exit from the CRM business.

Disclosure of Contractual Obligations and Contingent Financial Commitments

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

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2004. Cash obligations reflected are not discounted and do not include related interest, accretion or dividends.

	Payments Due by Period						
	Total	2005	2006	2007	2008	2009	Thereafter
Long-Term Debt (including Current Portion)	$ 4,366	$ 34	$ 28	$ 188	$ 231	$ 6	$ 3,879
Redeemable Preferred Securities	400						400
Operating Leases	1,622	93	93	141	158	161	976
Capacity Payments	2,242	208	191	194	200	201	1,248
Conditional Purchase Obligations	124	14	13	14	14	14	55
Pension Funding Obligations	73	28	19	26			
Total Contractual Obligations	$ 8,827	$ 377	$ 344	$ 563	$ 603	$ 382	$ 6,558

Long-Term Debt (including Current Portion). Total amounts of Long-Term Debt (including Current Portion) are included in the December 31, 2004 Consolidated Balance Sheet. For additional explanation, please read Note 11 Debt beginning on page F-42.

Additionally, we have entered into various joint ventures principally to share risk or optimize existing commercial relationships. These joint ventures maintain independent capital structures and, where necessary, have financed their operations on a non-recourse basis to us. Please read Note 9 Unconsolidated Investments beginning on page F-37 for further discussion of these joint ventures.

Redeemable Preferred Securities. Total amounts of Redeemable Preferred Securities are included in the December 31, 2004 Consolidated Balance Sheet. For additional explanation, please read Note 14 Redeemable Preferred Securities beginning on page F-54.

Operating Leases. Operating leases includes the minimum lease payment obligations associated with our DNE leveraged lease. For additional information, please read Liquidity and Capital Resources Off-Balance Sheet Arrangements DNE Leveraged Lease beginning on page 45. Amounts also include minimum lease payment obligations associated with office and office equipment leases.

In addition, we are party to two charter party agreements relating to VLGCs previously utilized in our global liquids business. The aggregate minimum base commitments of the charter party agreements are approximately $13 million each year for the years 2005 through 2007, and approximately $79 million through lease expiration. The charter party rates payable under the two charter party agreements float in accordance with market based rates for similar shipping services. The $13 million and $79 million numbers set forth above are based on the minimum obligations set forth in the two charter party agreements. The primary term of one charter is through August 2013 while the primary term of the second charter is through August 2014. On January 1, 2003, in connection with the sale of our global liquids business, we sub-chartered both VLGCs to a wholly owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter agreements. We are currently in negotiations with the owners of the VLGCs and their lenders to obtain a novation and release of our operating subsidiary from the two charter party agreements and partial releases of our parent guarantees. Until such time as the novations and partial releases are granted, 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.

Capacity Payments. Capacity payments include future payments aggregating $2.1 billion under our four remaining power tolling arrangements, including our Gregory tolling arrangement which expires in July 2005, as further described in Item 1. Business Segment Discussion Customer Risk Management beginning on page 18. This amount includes the fixed payments associated with a derivative instrument related to the Independence tolling arrangement, which is reflected at its fair value on our Consolidated Balance Sheets in Risk-Management Liabilities, as well as amounts relating to contracts that are accounted for on an accrual basis. At December 31, 2004, approximately $295 million of fixed payments have been reflected in the fair value of the Independence derivative instrument.

As a result of the Sithe Energies acquisition, which we completed in January 2005, we have reclassified approximately $747 million of our obligations under the Independence tolling arrangement and related derivative instrument as intercompany transactions within our GEN segment beginning February 1, 2005. Although this acquisition transformed the Independence toll and financial derivative instrument into intercompany agreements, those contracts currently remain in effect and we are still obligated to make all fixed capacity payments under those contracts that are reflected in the table above. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion.

In November 2004, we entered into a back-to-back power purchase agreement under which a subsidiary of Constellation Energy receives our rights to capacity and energy under the Kendall tolling arrangement for a four year term expiring effectively in November 2008. Although we are still obligated under the Kendall toll, we will receive approximately $161 million in aggregate cash payments from Constellation to offset our fixed payment obligations under the Kendall toll through November 2008, which payment obligations are reflected in the table above. We paid Constellation $117.5 million in cash in connection with this transaction. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Kendall beginning on page F-25 below for further discussion.

We are exploring opportunities to renegotiate or terminate one or more of our remaining long-term tolling arrangements on terms we consider economical. Please read Results of Operations 2005 Outlook CRM Outlook beginning on page 70 for further discussion of the anticipated effects of these arrangements on our future results of operations.

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In addition, capacity payments include fixed obligations associated with transmission, transportation and storage arrangements totaling approximately $170 million.

Conditional Purchase Obligations. Amounts relate to our co-sourcing agreement with Accenture Ltd. This 10-year agreement runs through 2013 and may be cancelled after two years upon the payment of a termination fee which ranges from $6 million for the first quarter 2005, declining to $2 million through 2013. This termination fee is in addition to amounts due for services provided through the termination date.

Pension Funding Obligations. Amounts include estimated defined benefit pension funding obligations for 2005 ($28 million), 2006 ($19 million) and 2007 ($26 million). Although we expect to incur significant funding obligations subsequent to 2007, such amounts have not been included in this table because our estimates are imprecise.

Contingent Financial Obligations

The following table provides a summary of our contingent financial obligations as of December 31, 2004 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)	$ 94	$ 94	$	$	$
Surety Bonds (2)(4)	54	54			
Guarantees (3)	4			4	
Total Financial Commitments	$ 152	$ 148	$	$ 4	$

(1) Amounts include outstanding letters of credit.
(2) Surety bonds are generally on a rolling 12-month basis.
(3) As part of the power purchase agreement with Constellation, under which Constellation effectively receives our rights to purchase approximately 570 MWs of capacity and energy arising from our tolling contract with Kendall, we have guaranteed Constellation the receipt of $3.5 million in reactive power revenues over the four year period of the power purchase agreement. Receipt of these reactive power revenues is predicated on, among other things, filing a reactive power tariff with the FERC.
(4) $40 million of the surety bonds were supported by collateral.

Off-Balance Sheet Arrangements

DNE Leveraged Lease. We established our presence in the Northeast region by acquiring 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 financing for our acquisition. In this transaction, which was structured as a sale-leaseback to minimize our operating cost of the facilities on an after-tax basis and to transfer ownership to the purchaser, we sold for approximately $920 million four of the six generating units comprising these facilities to Danskammer OL LLC and Roseton OL LLC, each of which was newly formed by an unrelated third-party investor, and we concurrently agreed to lease them back from these entities, which we refer to as the owner lessors. The owner lessors used $138 million in equity funding from the unrelated third-party investor to fund a portion of the purchase of the respective facilities. The remaining $800.4 million of the purchase price and the related transaction expenses was derived from proceeds obtained in a private offering of pass-through trust certificates issued by two of our subsidiaries, Dynegy Danskammer, L.L.C. and Dynegy Roseton, L.L.C., who

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serve as lessees of the applicable facilities. The pass-through trust certificate structure was employed, as it has been in similar financings historically executed in the airline and energy industries, to optimize the cost of financing the assets and to facilitate a capital markets offering of sufficient size to enable the purchase of the lessor notes from the owner lessors. The pass-through trust certificates were sold to qualified institutional buyers in a private offering and the proceeds were used to purchase debt instruments, referred to as lessor notes, from the owner lessors. The lease payments on the facilities support the principal and interest payments on the pass-through trust certificates, which are ultimately secured by a mortgage on the underlying facilities.

As of December 31, 2004, future lease payments are $60 million for 2005 and 2006, $108 million for 2007, $144 million for 2008 and $141 million for 2009, with $919 million in the aggregate due from 2010 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, 2004, the present value (discounted at 10%) of future lease payments was $771 million.

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

	2004	2003	2002
		(in millions)	
Lease Expense	$ 50	$ 50	$ 50
Lease Payments (Cash Flows)	$ 60	$ 60	$ 60

If one or more of the leases were to be terminated because of an event of loss, because it had become illegal for the applicable lessee to comply with the lease or because a change in law had made the facility economically or technologically obsolete, DHI would be required to make a termination payment in an amount sufficient to redeem the pass-through trust certificates related to the unit or facility for which the lease was terminated at par plus accrued and unpaid interest. As of December 31, 2004, the termination payment at par would be approximately $1 billion for all of the DNE facilities, which exceeds the $920 million we received on the sale of the facilities. If a termination of this type were to occur with respect to all of the DNE facilities, it would be difficult for DHI to raise sufficient funds to make this termination payment. Alternatively, if one or more of the leases were to be terminated because we determine, for reasons other than as a result of a change in law, that it has become economically or technologically obsolete or that it is no longer useful to our business, DHI must redeem the related pass-through trust certificates at par plus a make-whole premium in an amount equal to the discounted present value of the principal and interest payments still owing on the certificates being redeemed less the unpaid principal amount of such certificates at the time of redemption. For this purpose, the discounted present value would be calculated using a discount rate equal to the yield-to-maturity on the most comparable U.S. treasury security plus 50 basis points.

Capital Expenditures

We continue to tightly manage costs and capital expenditures. We had approximately $311 million in capital expenditures during 2004. Our 2004 capital spending by segment was as follows (in millions):

GEN	$ 145

NGL	61
REG	92
Other	13
Total	$ 311

Capital spending in our GEN segment primarily consisted of maintenance capital projects, as well as approximately $41 million spent on development capital. Development capital spending primarily related to the

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conversion of our Havana facility to PRB coal. Capital spending in our NGL segment primarily related to maintenance capital projects and wellconnects, as well as approximately $21 million in development capital. Development capital included approximately $13 million for gathering system expansion, additional compression and plant de-bottlenecking in North Texas related to increased gas from the Barnett Shale formation and approximately $8 million for a significant upgrade in compression technology and efficiencies at our Monument gas processing plant. Capital spending in our REG segment primarily related to projects intended to maintain system reliability and new business services.

We expect capital expenditures for 2005 to approximate $279 million. This primarily includes maintenance capital projects, environmental projects, contributions to equity investments and limited GEN and NGL development projects. The capital budget is subject to revision as opportunities arise or circumstances change. Estimated funds budgeted for the aforementioned items by segment in 2005 are as follows (in millions):

GEN	$ 190
NGL	78
Other	11
Total	$ 279

We anticipate increased capital spending in our GEN segment primarily due to an increase in long-term capital maintenance expenditures, including those at our newly acquired Independence facility. We anticipate increased capital spending in the NGL segment primarily due to $6 million for gathering system expansion, additional compression and plant de-bottlenecking in North Texas related to increased gas from the Barnett Shale formation and $20 million for a project under consideration at our Mont Belvieu facility.

As reflected in this section, the capital spending in our NGL segment includes 100% of the expenditures of our consolidated partnerships, Versado Gas Processors, LLC and Cedar Bayou Fractionators, LP. Our ownership percentages of these partnerships are 63% and 88%, respectively, and net funding equal to our ownership percentage is achieved through adjustments to partnership distributions. Adjusted for our partners share of capital expenditures, our expenditures would have been $52 million in 2004 and are expected to be $72 million in 2005.

Our capital expenditures in 2005 and beyond will continue to be limited by negative covenants contained in our debt instruments. These covenants place specific dollar limitations on our ability to incur capital expenditures. Please read Note 11 Debt DHI Term Loan and Credit Facility beginning on page F-43 for further discussion of these limitations. Our long term capital expenditures will also be significantly impacted by the Baldwin consent decree announced in March 2005. If ultimately approved by the Illinois federal district court, this consent decree would obligate us to, among other things, invest $321 million through 2010, and $224 million from 2011 through 2012, respectively, in emission control projects at our Baldwin, Vermilion and Havana plants. Please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings Baldwin Station Litigation beginning on page F-57 for further discussion of this consent decree.

Financing Trigger Events

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

Commitments and Contingencies

Please read Note 16 Commitments and Contingencies beginning on page F-55, which is incorporated herein by reference, for a discussion of our commitments and contingencies.

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Dividends on Preferred and Common Stock

Dividend payments on our common stock are at the discretion of our Board of Directors. We do not foresee a declaration of dividends in the near term, particularly given our financial condition and the dividend restrictions contained in our financing agreements. We have, however, continued to make the required dividend payments on our outstanding trust preferred securities.

The Series B Preferred Stock issued to ChevronTexaco in November 2001 had no dividend requirement. Because of ChevronTexaco s discounted conversion option, however, we accreted an implied preferred stock dividend over the redemption period, as required by GAAP. Please read Note 12 Related Party Transactions Series B Preferred Stock beginning on page F-47 for further discussion of this non-cash implied dividend and the Series B Exchange. In conjunction with the Series B Exchange, we recognized a gain of approximately $1.2 billion as a preferred stock dividend during 2003.

We accrue dividends on our Series C preferred stock at a rate of 5.5% per annum. We accrued and made dividend payments on the Series C preferred stock during the year ended December 31, 2004 totaling approximately $22 million. Dividends are payable on the Series C preferred stock in February and August of each year, but we may defer payments for up to 10 consecutive semi-annual periods. Please read Note 14 Redeemable Preferred Securities Series C Convertible Preferred Stock beginning on page F-54 for further discussion.

Internal Liquidity Sources

Our primary internal liquidity sources are cash flows from operations, cash on hand and available capacity under our $700 million revolving credit facility, which is scheduled to mature in May 2007.

Current Liquidity. The following table summarizes our consolidated revolver capacity and liquidity position at March 4, 2005, December 31, 2004 and December 31, 2003:

	March 4, 2005	December 31, 2004	December 31, 2003
		(in millions)	
Total Revolver Capacity	$ 700(1)	$ 700(1)	$ 1,100
Outstanding Letters of Credit Under Revolving Credit Facility	(89)	(94)	(188)
Unused Revolver Capacity	611	606	912
Cash	365(2)	628(2)	477
Total Available Liquidity	$ 976	$ 1,234	$ 1,389

(1) Please read Note 11 Debt DHI Term Loan and Credit Facility beginning on page F-43 for a discussion of our credit facility.
(2) The March 4, 2005 and December 31, 2004 amounts include approximately $46 million and $47 million, respectively, of cash that remains in Canada and the U.K. that is associated primarily with contingent liabilities relating to our former Canadian and U.K. marketing and trading operations.

Cash Flows from Operations. We had operating cash flows of $5 million in 2004. This consisted of $912 million in operating cash flows from our GEN, NGL and REG segments, reflecting positive earnings for the period offset by reductions in working capital from increased cash collateral postings. The cash flows from our operating segments were substantially offset by $907 million of cash outflows relating to our CRM business and corporate-level expenses. Please read Results of Operations Year Ended 2004 Compared to Year Ended 2003 Operating Income (Loss) beginning on page 56 and Cash Flow Disclosures beginning on page 71 for further discussion of factors impacting our operating cash flows for the periods presented.

For 2005, we have projected operating cash flows of $174 to $189 million. This projection, which is subject to change based on a number of factors, many of which are beyond our control, reflects $640 to $650 million in

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forecasted operating cash flows from our GEN and NGL business segments, offset by projected cash outflows of $66 million from our CRM business segment and $400 to $395 million in corporate-level expenses, including interest.

Over the longer term, our operating cash flows also will be impacted by, among other things, our ability to tightly manage our operating costs, including costs for fuel and maintenance. With respect to fuel costs, in January 2004, we entered into a new rail transportation contract that reduced the fees associated with fuel procurement at our coal-fired generation facilities in the Midwest; however, these fee reductions were substantially offset by increased coal prices in the Northeast and higher costs associated with the purchase of emission credits. Our ability to achieve fuel-related and other targeted cost savings in the face of industry-wide increases in labor and benefits costs, together with changes in commodity prices, will impact our future operating cash flows. Please read Results of Operations 2005 Outlook GEN Outlook beginning on page 67 for further discussion.

In addition, our CDWR power purchase agreement expired by its terms in December 2004. Please read Item 1. Business Segment Discussion Power Generation beginning on page 2 for a discussion of West Coast Power s current contractual arrangements. Our share of West Coast Power s earnings during 2004 totaled $165 million, excluding impairments of $85 million, approximately 70% of which was derived from the CDWR agreement. In California s current energy market, the West Coast Power generating facilities which previously supported the CDWR contract are significantly less profitable under the RMR contracts or as merchant facilities, and we may consider other alternatives if necessary, including shutting down units if we no longer consider them commercially viable. Based on our ongoing evaluation of strategic alternatives for our West Coast Power assets, we determined that it was not economically feasible to continue to operate our Long Beach generation facility beyond the expiration of the CDWR contract. Therefore, we retired the asset effective January 1, 2005. Please read Results of Operations 2005 Outlook GEN Outlook beginning on page 67 for further discussion of the CDWR agreement and the impairments relating to its expiration.

Cash on Hand. At March 4, 2005 and December 31, 2004, we had cash on hand of $365 million and $628 million, respectively, as compared to $477 million at the end of 2003. This increase in cash on hand at December 31, 2004 as compared to the end of 2003 is primarily attributable to the proceeds from our May 2005 term loan as well as proceeds from assets sales.

Revolver Capacity. In May 2004, DHI entered into a new $1.3 billion credit facility, consisting of a $600 million term loan and a $700 million revolving credit facility. This $700 million revolving credit facility, which is scheduled to mature in May 2007, is our primary credit facility. We currently have no drawn amounts under this facility, although as of March 4, 2005, we had $89 million in letters of credit issued under the facility. Our ability to borrow and/or issue letters of credit under a revolving credit facility could become increasingly important to our liquidity and financial condition, particularly if we are unable to generate operating cash flows relative to our substantial debt obligations and ongoing operating requirements. Please read Note 11 Debt DHI Term Loan and Credit Facility beginning on page F-43 for further discussion of our credit facility.

External Liquidity Sources

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

Asset Sale Proceeds. In an effort to maximize our return on investment and to further clarify our business strategy, we have sold assets that we do not consider core to our operations, including Illinois Power and our ownership interests in certain non-strategic domestic power generation facilities (e.g., Commonwealth, Hartwell, Joppa, Michigan Power and Oyster Creek) and international power generation facilities (e.g., Costa Rica and Jamaica), as well as our ownership interests in Indian Basin and our Sherman natural gas processing facility. As we have previously disposed of substantially all of our non-core assets, we do not currently anticipate receiving a material amount of proceeds from asset sales, if any, during 2005.

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The aggregate loss of earnings in 2004 associated with these assets (other than Illinois Power) was not material and was more than offset by net gains on sale in 2004. However, beginning in 2005, the lost earnings of approximately $15 million on an annual basis from such assets will no longer be offset by gains on sale.

During 2004, we received aggregate cash proceeds of $576 million from these asset sales, which includes the Illinois Power and Joppa sales proceeds of $316 million, net of transaction costs and cash retained by Illinois Power, but excludes the $100 million deposited by Ameren into escrow, which we expect to receive following approval of the Baldwin consent decree announced in March 2005. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23 for further discussion of this transaction.

Capital-Raising Transactions. As part of our ongoing efforts to develop a capital structure that is more closely aligned with the cash-generating potential of our asset-based businesses, each of which is subject to cyclical changes in commodity prices, we are continuing to explore additional capital-raising transactions both in the near- and long-term. The timing of any capital-raising transaction may be impacted by unforeseen events, such as legal judgments or regulatory requirements, as well as strategic decisions relating to litigation settlements or contract terminations (including settlement of one or more of our remaining power tolling arrangements), which would necessitate additional capital in the near-term.

These transactions may include capital markets transactions. Our ability to issue public securities is enhanced by our effective shelf registration statement, under which we have approximately $430 million in remaining availability. However, the receptiveness of the capital markets to a public offering cannot be assured and may be negatively impacted by, among other things, our non-investment grade credit ratings, significant debt maturities, long-term business prospects and other factors beyond our control. Any issuance of equity likely would have other effects as well, including shareholder dilution. Further, our ability to issue debt securities is limited by our financing agreements, including our credit facility. Please read Note 11 Debt DHI Term Loan and Credit Facility beginning on page F-43 for further discussion.

Conclusion

During 2004, we consummated the sale of Illinois Power, which reduced our debt and preferred stock obligations by $1.8 billion and generated $316 million in proceeds, net of transaction costs and cash retained by Illinois Power, excluding the $100 million escrowed funds we expect to receive following approval of the Baldwin consent decree announced in March 2005. We also received approximately $260 million in additional sale proceeds from the disposition of other non-core assets during the period. Further, we extended a significant debt maturity through the replacement of our $1.1 billion revolving credit facility, scheduled to mature in February 2005, with a $700 million revolving credit facility and $600 million term loan scheduled to mature in May 2007 and May 2010, respectively. Using proceeds from the $600 million term loan and the sale of Illinois Power, together with cash on hand, we extinguished some of our substantial debt obligations, including our ABG Gas Supply Financing and ChevronTexaco junior notes.

For the next twelve months, assuming continuation of the current commodity pricing environment, we expect that our operating cash flows will be positive, but insufficient to satisfy our capital expenditures, debt maturities and interest expenses. However, we believe that our cash on hand and the $100 million deposited into escrow in connection with the sale of Illinois Power, which we expect to receive following approval of the Baldwin consent decree announced in March 2005, together with capacity under our $700 million revolving credit facility, will be sufficient to discharge these obligations. To further our deleveraging efforts, we may consider other capital-raising activities, including potential equity issuances.

Over the longer term and through the anticipated recovery of the U.S. power markets, we expect to maintain sufficient liquidity to satisfy our substantial debt and commercial obligations and provide collateral support through operating cash flows, capacity under our revolving credit facility (or any refinancing thereof), as well as proceeds from anticipated refinancings of debt maturities. Our substantial debt and commercial obligations include increased interest expense, the fixed payment obligations associated with our remaining power tolling

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arrangements in our GEN and CRM businesses (which we expect will continue to reduce our operating cash flows absent early termination or settlement) and counterparty collateral requirements, as well as our significant potential payment obligations relating to our securities litigation and other legal and regulatory matters. We expect that our liquidity position will trend downward as these obligations are satisfied or extinguished.

Our ability to generate operating cash flows will be impacted by a number of factors, some of which are beyond our control, including weather, commodity prices, particularly for power and natural gas, and the success of our ongoing efforts to manage operating costs, particularly fuel requirements, and capital expenditures. Our ability to refinance our substantial debt maturities is primarily dependant upon our ability to generate operating cash flows, which is subject to the factors described in the preceding sentence. Over the longer term we believe that power prices will improve in some or all of the regions in which we operate as the supply-demand imbalance for power decreases. Much of our restructuring work has extended our significant debt maturities to 2007 and beyond, positioning us to benefit from earnings and growth opportunities associated with an expected recovery in the U.S. power markets. Additionally, our NGL business is currently operating in a highly favorable pricing environment. Our future financial condition and results of operations will be materially adversely affected if the U.S. power markets fail to recover in accordance with our expectations or if we experience significant, prolonged pricing deterioration below price levels experienced over the last few years in our NGL segment.

Our longer term liquidity position and financial condition will also be significantly impacted by the availability of, and our ability to pursue, strategic growth opportunities. However, as indicated above, our desire or ability to pursue any such opportunities is subject to a number of factors beyond our control. As such, we cannot guarantee that any such opportunities will be available to us, nor can we predict with any degree of certainty the impact of any such opportunities on our financial condition or results of operations.

Please read Uncertainty of Forward-Looking Statements and Information for additional factors that could impact our future operating results and financial condition.

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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 2004, 2003 and 2002. At the end of this section, we have included our 2005 outlook for each segment.

As reflected in this report, we have changed our reporting segments. Prior to 2003, we reported results for the following four business segments: WEN, DMS, T&D and DGC. Beginning January 1, 2003, we have been reporting our operations in the following segments: GEN, NGL, REG and CRM. Other reported results include corporate overhead and our discontinued communications business. All corporate overhead included in other reported results was allocated to our four former reporting segments prior to January 1, 2003. Beginning January 1, 2003, all direct general and administrative expenses and other income (expense) items incurred by us on behalf of our subsidiaries are charged to the applicable subsidiary as incurred. In addition, all interest expense was allocated to our four former reporting segments prior to January 1, 2003.

Prior to January 1, 2003, the GEN and CRM segments were operated together as an asset-based third-party marketing, trading and risk-management business, then referred to as the WEN segment. Please read Note 20 Segment Information beginning on page F-78 for a discussion of the impact of comparing segment results period over period. Regarding our results of operations for 2004, 2003 and 2002, the impact of acquisition and disposition activity reduces the comparability of some of our historical financial and volumetric data. Lastly, recent accounting pronouncements have affected our financial results, particularly those of our CRM business, so as to further reduce the comparability of some of our historical financial data. For example, the rescission of EITF Issue 98-10, effective January 1, 2003, has reduced the number of contracts accounted for on a mark-to-market basis in the 2004 and 2003 periods as compared to the 2002 period. Please read Results of Operations Year Ended 2004 Compared to Year Ended 2003 Cumulative Effect of Change in Accounting Principles beginning on page 61 for further discussion.

Summary Financial Information. The following tables provide summary financial data regarding our consolidated and segmented results of operations for 2004, 2003 and 2002, respectively. The financial data for the years ended December 31, 2003 and 2002 has been restated to reflect the effect of the items described in the Explanatory Note to the accompanying Consolidated Financial Statements. The restatements relate to an increased impairment charge associated with the sale of Illinois Power and our deferred income tax accounts. Please read the Explanatory Note beginning on page F-10 for further discussion of these restatement items.

Year Ended December 31, 2004

	GEN	NGL	REG	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$ 163	$ 287	$ 139	$ (118)	$ (279)	$ 192
Earnings from unconsolidated investments	192	10				202
Other items, net	1	(22)	3	(3)	8	(13)
Interest expense						(480)
Loss from continuing operations before taxes						(99)
Income tax benefit						89

Loss from continuing operations	(10)
Loss from discontinued operations, net of taxes	(5)
Net income	$ (15)

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Year Ended December 31, 2003

	GEN	NGL	REG	CRM	Other and Eliminations	Total
				(Restated) (in millions)		
Operating income (loss)	$ 194	$ 170	$ (327)	$ (385)	$ (246)	$ (594)
Earnings (losses) from unconsolidated investments	128	(2)		(2)		124
Other items, net	4	(17)		31	2	20
Interest expense						(509)
Loss from continuing operations before taxes						(959)
Income tax benefit						246
Loss from continuing operations						(713)
Loss from discontinued operations, net of taxes						(19)
Cumulative effect of change in accounting principles, net of taxes						40
Net loss						$ (692)

Year Ended December 31, 2002

	GEN	NGL	REG	CRM	Other and Eliminations	Total
				(Restated) (in millions)		
Operating income (loss)	$ (341)	$ 77	$ 157	$ (951)	$	$ (1,058)
Earnings (losses) from unconsolidated investments	(71)	14	(2)	(21)		(80)
Other items, net	(20)	(34)	(4)	(49)		(107)
Interest expense						(297)
Loss from continuing operations before taxes						(1,542)
Income tax benefit						343
Loss from continuing operations						(1,199)
Loss from discontinued operations, net of taxes						(1,154)
Cumulative effect of change in accounting principles, net of taxes						(234)
Net loss						$ (2,587)

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The following table provides summary segmented operating statistics for 2004, 2003 and 2002, respectively:

	Year Ended December 31,		
	2004	**2003**	**2002**
Power Generation			
Million megawatt hours generated gross	37.1	39.1	39.8
Million megawatt hours generated net	35.3	37.2	37.4
Average natural gas price Henry Hub ($/MMbtu) (1)	$ 5.89	$ 5.28	$ 3.35
Average on-peak market power prices ($/MWh)			
Cinergy	$ 43	$ 37	$ 27
Commonwealth Edison	42	37	26
Southern	49	41	30
New York Zone G	62	61	46
ERCOT	51	45	29
SP-15	55	52	35
Natural Gas Liquids			
Gross NGL production (MBbls/d):			
Field plants	57.3	59.6	56.0
Straddle plants	26.6	25.6	35.9
Total gross NGL production	83.9	85.2	91.9
Natural gas (residue) sales (Bbtu/d)	182.8	174.4	188.4
Natural gas inlet volumes (MMCFD):			
Field plants	535.6	591.0	569.3
Straddle plants	990.0	1,103.1	1,511.9
Total natural gas inlet volumes	1,525.6	1,694.1	2,081.2
Fractionation volumes (MBbls/d)	202.5	185.3	215.2
Natural gas liquids sold (MBbls/d)	282.5	311.7	498.8
Average commodity prices:			
Crude oil WTI ($/Bbl)	$ 41.43	$ 31.01	$ 25.75
Natural gas Henry Hub ($/MMbtu) (2)	$ 6.13	$ 5.38	$ 3.22
Natural gas liquids ($/Gal)	$ 0.71	$ 0.55	$ 0.40
Fractionation spread ($/MMBtu) daily	$ 2.18	$ 0.79	$ 1.13
Regulated Energy Delivery (5)			
Electric sales in KWH (millions)			
Residential	4,182	5,309	5,548
Commercial	3,389	4,413	4,415
Industrial	3,859	6,123	6,306
Transportation of customer-owned electricity	2,407	2,382	2,505
Other	287	374	370
Total electric sales	14,124	18,601	19,144
Gas sales in Therms (millions)			
Residential	214	337	323

Commercial	85	145	137
Industrial	40	70	80
Transportation of customer-owned gas	171	226	233
Total gas delivered	510	778	773
Cooling degree days Actual (3)	932	980	1,467
Cooling degree days 10-year rolling average	1,236	1,214	1,246
Heating degree days Actual (4)	3,145	5,256	5,118
Heating degree days 10-year rolling average	3,190	4,930	5,002

(1) Calculated as the average of the daily gas prices for the period.
(2) Calculated as the average of the first of the month prices for the period.

(3) A Cooling Degree Day (CDD) represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in our region. The CDDs for a period of time are computed by adding the CDDs for each day during the period.
(4) A Heating Degree Day (HDD) represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in our region. The HDDs for a period of time are computed by adding the HDDs for each day during the period.
(5) Operating statistics for REG for the year ended December 31, 2004 only include statistics through September 30, 2004, the date of the sale of Illinois Power to Ameren.

The following tables summarize significant items on a pre-tax basis, with the exception of the 2004 and 2003 tax items, affecting net loss for the periods presented.

	Year Ended December 31, 2004					
	GEN	NGL	REG	CRM	Other	Total
	(in millions)					
Discontinued operations	$	$ 1	$	$ 19	$ 3	$ 23
Kendall toll restructuring				(115)		(115)
Impairment of West Coast Power	(85)					(85)
Legal and settlement charges	(7)	2	(1)	(13)	(92)	(111)
Impairment of Illinois Power			(54)			(54)
Loss on sale of Illinois Power			(58)			(58)
Acceleration of financing costs					(14)	(14)
Gas transportation contracts				88		88
Gain on sale of Joppa	75					75
Taxes					24	24
Gain on sale of Indian Basin		36				36
Gain on sale of Hackberry LNG		17				17
Gain on sale of Sherman		16				16
Gain on sale of Oyster Creek	15					15
Total	$ (2)	$ 72	$ (113)	$ (21)	$ (79)	$ (143)

	Year Ended December 31, 2003					
	GEN	NGL	REG	CRM	Other	Total
	(in millions)					
Illinois Power goodwill impairment	$	$	$ (311)	$	$	$ (311)
Illinois Power asset impairment			(218)			(218)
Southern Power tolling settlement				(133)		(133)
Sithe power tolling contract				(121)		(121)
Legal charges					(50)	(50)
Batesville tolling settlement				(34)		(34)
Kroger settlement				(30)		(30)
Discontinued operations		(2)	(3)	(30)	7	(28)
Impairment of generation investments	(26)					(26)
Acceleration of financing costs					(24)	(24)
West Coast Power goodwill impairment	(20)					(20)

Impairment of equity investment		(12)				(12)
Taxes	(1)				34	33
Gain on sale of Hackberry LNG		25		2		27
Cumulative effect of change in accounting principles	24		(3)	43		64
Total	$ (23)	$ 11	$ (535)	$ (303)	$ (33)	$ (883)

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	Year Ended December 31, 2002					
	GEN	NGL	REG	CRM	Other	Total
	(in millions)					
Discontinued operations	$	$ (37)	$ (561)	$ (51)	$ (854)	$ (1,503)
Goodwill impairment	(489)			(325)		(814)
Restructuring costs	(42)	(19)	(23)	(73)		(157)
Impairment of generation investments	(144)					(144)
Generation equity earnings (loss)	(50)					(50)
Impairment of technology investments	(5)	(4)	(2)	(20)		(31)
Tolling settlement accrual				(25)		(25)
Illinois Power regulatory asset amortization expense			(23)			(23)
ChevronTexaco contract settlement				(22)		(22)
Enron settlement	(6)	(4)	(2)	(9)		(21)
Other (1)	(23)	(3)	(1)	(37)		(64)
Cumulative effect of change in accounting principle					(234)	(234)
Total	$ (759)	$ (67)	$ (612)	$ (562)	$ (1,088)	$ (3,088)

(1) Other includes a pre-tax charge of approximately $25 million related to the write-off of our investment in Dynegy*direct* and a pre-tax charge of approximately $14 million associated with the impairment of a generation turbine. These amounts are included in Impairment and other charges. Other also includes various other individually insignificant items.

Year Ended 2004 Compared to Year Ended 2003

Operating Income (Loss)

Operating income was $192 million in 2004, compared to a loss of $594 million in 2003.

GEN. Operating income for our GEN segment was $163 million in 2004, compared to $194 million in 2003.

In the Midwest region, where we produce approximately 60% of our generated volumes, results increased $27 million year over year. Increased prices contributed an additional $23 million for 2004 compared to 2003. Additionally, we experienced a $28 million reduction in coal transportation costs in the Midwest region, resulting from a transportation contract which took effect at the beginning of 2004. However, improved pricing was partially offset by an increase in operating expenses for the Midwest of approximately $12 million, resulting from the timing of maintenance expenditures, as well as increases in labor costs. Additionally, we reported $17 million less capacity revenue in 2004 as compared with 2003. Volumes were down slightly, from 21.1 million MWh for 2003 to 20.7 million MWh for 2004. This decrease was largely due to reduced production at our Havana facility, resulting from our management of fuel inventories in anticipation of our switch to PRB coal. Please read 2005 Outlook GEN Outlook beginning on page 67 for a discussion of the current fuel and transportation environment.

Improved earnings in the Midwest region were offset by the Northeast region, where results decreased from $49 million in 2003 to $20 million in 2004. This decrease was primarily the result of pricing effects year over year, as increased fuel costs more than offset an increase in power prices. This resulted in a $21 million reduction in earnings. Additionally, we realized $11 million less revenue in 2004 under a transitional power purchase agreement, which expired in October 2004. Operating expense in the Northeast was up $3 million year over year as a result of increased labor and tax expense. However, these reductions in earnings were partially offset by a 7% increase in volumes, which contributed an additional $6 million, largely the result of the dual fuel capabilities of our Roseton unit.

Results in the Southeast region were down $25 million, from $26 million in 2003 to $1 million in 2004. This reduction in earnings was primarily the result of the loss of capacity revenues related to a contract that expired at the end of 2003.

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Results in the ERCOT region decreased $11 million, from a loss of $8 million in 2003 to a loss of $19 million in 2004, primarily as a result of increased natural gas prices and the impact of these increased prices on a long-term power and steam sales contract.

GEN s reported operating income for 2004 also includes approximately $7 million of mark-to-market income related to purchases and sales that did not meet the criteria for hedge accounting under SFAS No. 133 and, therefore, were accounted for on a mark-to-market basis. GEN s results for 2003 include approximately $7 million of mark-to-market income related to derivative contracts that did not qualify as hedges. Mark-to-market income in 2004 included a $3 million charge to earnings in connection with hedge ineffectiveness.

In March 2004, we tested our CoGen Lyondell facility for an impairment based on the identification of a triggering event as defined by SFAS No. 144. After performing this test, we concluded that no impairment was necessary as the estimated undiscounted cash flows exceeded the book value of the asset.

NGL. Operating income for the NGL segment was $287 million in 2004, compared to $170 million in 2003.

The significant improvement in operating income was driven by natural gas, crude oil and natural gas liquids prices, which increased to historically high levels during periods of the year, and a frac spread sufficiently high to make natural gas liquids recovery profitable under all contract settlements during the last five months of 2004. During the entire year, we capitalized on the pricing opportunities presented through strong asset runtime across all NGL segments.

Significantly higher commodity prices contributed approximately $79 million to our results as compared to 2003. Of the increase, $52 million related to POP contracts in field processing, $24 million was derived from our POL contracts at our straddle processing plants and $3 million was generated from natural gas liquids marketing contracts.

Frac spreads were significantly higher in 2004 compared to 2003. During the last five months of 2004, the spread between natural gas liquids prices and natural gas prices reached levels sufficient to support increased liquids recovery industry-wide, reversing an eighteen-month trend. During the year, higher frac spreads generated incremental results of approximately $37 million as compared to 2003. The increase relates to the following: $2 million from additional volumes processed in our Stingray processing plant under economic keep-whole settlement terms; $24 million from contract settlements for existing gas volumes under hybrid contracts that switched from fee to percentage of liquids settlements; and $11 million due to increased industry-wide natural gas liquids recovery which brought additional volumes to our fee-based liquids gathering systems, fractionators, storage and distribution systems and marketing activities.

Gathering and processing operating results increased by $50 million for 2004 compared to 2003, primarily benefiting from 14% higher absolute commodity prices for natural gas and 29% higher absolute commodity prices for natural gas liquids year over year. At our field plants, results increased $42 million. Our current contract portfolio of nearly 99% POP and fee-based contracts benefited from higher prices. However, declines in gross and net natural gas liquids production due to sale of our non-operating joint interest in the Indian Basin plant in April 2004, sale of our Sherman plant in November 2004 and impacts of pipeline, compressor and process unit maintenance at our facilities partially offset the commodity price gains. At our straddle plants, operating results increased $8 million, due largely to the impact of higher natural gas liquids prices under our POL contract settlements. Additionally, during the last five months of 2004, higher frac spreads made it profitable to recover liquids under KW agreements and caused hybrid contracts to switch from fee to POL settlements. The Stingray facility, our only plant that settles under a keep-whole contract structure, operated from the end of July through the remainder of 2004, while it was idled during all of 2003.

Offsetting these increased volumes was the negative impact of Hurricane Ivan on producers volumes available to process at some of our straddle plants that resulted in a reduction in operating results of $17 million. Overall straddle plant inlet volumes decreased 10 % and net barrels produced increased 3%.

Results of our fractionation, storage and terminalling and transportation and logistics businesses increased $13 million for 2004 compared to 2003. Volumes increased at both of our fractionators due to industry-wide increased liquids production primarily as a result of higher frac spreads. These higher volumes also drove increased operating income in our supporting storage and natural gas liquids pipeline operations.

Wholesale marketing results were slightly favorable for 2004 compared to 2003 due to the impacts of higher natural gas liquids prices, offset by the loss of a refinery service contract. Results for 2003 benefited from extremely cold weather in the first quarter.

NGL marketing services and distribution results increased approximately $13 million for 2004 compared to 2003. Marketing fees were approximately $3 million higher due to the higher natural gas liquids prices year over year, offset by the impact of lower volumes primarily because of reduced market liquidity. As part of our normal operations, contractual terms with a natural gas liquids pipeline changed, and we terminated an inactive natural gas liquids sales contract. Both of these contractual changes reduced the amount of natural gas liquids volumes required to be held in reserve to serve our customers. Since the volumes held in reserve as deadstock were valued at below current market prices, the release of volumes required to be held in reserve allowed us to recognize an $8 million gain on sales at current market prices. Due to a sharp decline in prices during the last half of December 2004, distribution and marketing services recorded a negative non-cash lower of cost or market adjustment of $4 million compared to a similar negative adjustment of $9 million in 2003, for a positive variance of $5 million year over year.

Operating income for 2004 included pre-tax gains on sales of assets of $69 million, including a $36 million gain associated with the sale of our non-operating interest in the Indian Basin processing plant, a gain of $16 million from the sale of our Sherman processing plant and a $17 million gain on the sale of our final financial interest in our Hackberry LNG project, offset by increased depreciation expense of $6 million due to an adjustment to accumulated depreciation and an asset impairment of $5 million further discussed below. Operating income for 2003 included a $25 million gain on sale of our ownership interest in the Hackberry LNG facility and a $3 million gain associated with the expiration of an environmental indemnity obligation. Please see Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Hackberry LNG Project beginning on page F-26 for further discussion.

In the second quarter 2004, we tested certain of our assets for impairment based on identification of triggering events as defined by SFAS No. 144. After testing, we recorded a pre-tax impairment of $5 million for our Puckett gas treating plant and gathering system due to rapidly depleting reserves associated with that facility. We concluded that no impairment was necessary for any other facilities as estimated undiscounted cash flows exceeded facility book values.

REG. Operating income for the REG segment was $139 million in 2004, which included income prior to our sale of Illinois Power to Ameren on September 30, 2004, compared to a loss of $327 million in 2003. The 2004 period includes a $58 million charge related to the loss on the sale of Illinois Power and a $54 million impairment of Illinois Power assets. We also stopped depreciating our Illinois Power assets on February 1, 2004, as they were classified as held for sale, which resulted in a benefit to operating income of $111 million compared to the 2003 period. The 2003 period includes an operating loss for the fourth quarter 2003 of $485 million, which was not experienced in 2004, due to the September 2004 sale of Illinois Power. Included in the fourth quarter 2003 activity is a $529 million charge for the impairment of goodwill and other assets associated with this segment, as further described in Note 10 Goodwill beginning on page F-41 and $30 million of depreciation expense.

Operationally, residential and commercial electric sales volumes for the first nine months of 2004 were negatively impacted by warmer than average winter weather compared to 2003. Industrial electric sales were negatively affected by customers choosing alternate energy providers. These decreases were more than offset by lower overall operating costs, which were primarily due to the reimbursement of MISO exit fees and RTO development costs totaling approximately $10 million and lower departmental spending, partially offset by higher employee benefit costs. Residential and commercial electric sales volumes were relatively flat in 2004 as compared to 2003 due to cooler summer weather offset by warmer spring weather.

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CRM. Operating loss for the CRM segment was $118 million in 2004, compared to $385 million in 2003.

Results for 2004 were impacted by the following items:

- $88 million gain associated with the exit of four natural gas transportation agreements in support of our third-party marketing and trading business; and

- $115 million charge associated with our entry into a back-to-back power purchase agreement with a subsidiary of Constellation Energy in November 2004 to mitigate the effect of the Kendall tolling arrangement through November 2008.

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

Results for 2003 were impacted by the following pre-tax losses:

- $133 million charge associated with the settlement of power tolling arrangements with Southern Power, for which we paid $155 million;

- $121 million mark-to-market loss on contracts associated with the Independence power tolling arrangement;

- $34 million charge associated with the cash settlement of the Batesville tolling arrangement; and

- $30 million charge associated with the settlement of power supply agreements with Kroger, for which we received approximately $110 million.

Additionally, 2003 results include gains from the sale of natural gas inventories of $61 million, offset by charges associated with the settlement of legacy contracts of $21 million and changes in the value of our remaining marketing and trading activity.

Other. Other operating loss was $279 million in 2004, compared to $246 million in 2003. The losses in 2004 and 2003 primarily relate to general and administrative expenses and depreciation and amortization expenses which are incurred at a corporate level. The higher loss in 2004 related primarily to increased legal and settlement charges, costs related to compliance with Section 404 of the Sarbanes-Oxley Act and higher professional fees.

Operating loss for 2004 includes approximately $92 million of expenses related to legal and settlement charges. Please read Note 4 Restructuring and Impairment Charges Severance and Other Restructuring Costs beginning on page F-31 for a discussion of the settlement charges. Operating loss for 2003 includes legal charges of $50 million. The legal charges in both periods resulted from additional activities during each period that affected management s assessment of the probable and estimable loss associated with the applicable proceedings.

Earnings from Unconsolidated Investments.

Our earnings from unconsolidated investments were approximately $202 million during 2004 compared to $124 million in 2003. Both the 2004 and 2003 results include significant impairment charges related to these investments, primarily associated with our GEN segment.

GEN. GEN s earnings from unconsolidated investments were approximately $192 million during 2004 compared to $128 million in 2003.

Our West Coast Power investment was the primary driver of equity earnings for the two periods. Total earnings from the investment of $165 million in 2004 were partially offset by an impairment charge of $85 million triggered by the expiration of West Coast Power s CDWR contract, resulting in net earnings of $80 million. Please read Item 1. Business Segment Discussion Power Generation West region Western

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Electricity Coordinating Council (WECC) beginning on page 8 for further discussion of West Coast Power s CDWR contract. West Coast Power s equity earnings of approximately $137 million in 2003 were partially offset by a $20 million charge associated with our 50% share of a goodwill impairment charge recorded by West Coast Power in the fourth quarter 2003. Exclusive of impairments, results at our West Coast Power investment improved from 2003 to 2004 primarily as a result of higher realized margins resulting from hedges put in place in connection with the execution of our CDWR contract.

Earnings for 2004 also include gains of $75 million and $15 million on the sales of our 20% interest in the Joppa power generation facility and our 50% interest in the Oyster Creek facility, respectively. In addition to the gain on sale, we reported $5 million of earnings from the Oyster Creek investment. In July 2004, we sold our 50% interest in the Michigan Power generating facility. However, we recorded impairments of approximately $8 million related to the anticipated sale of Michigan Power, which offset our share of Michigan Power s earnings for 2004. The net loss related to Michigan Power recorded in 2004 was $2 million. In September 2004, we sold our 50% interest in the Hartwell facility, resulting in a gain of approximately $2 million. Our 2004 earnings from Hartwell, including this gain, were $4 million. Our 2004 earnings from Commonwealth were approximately $2 million. Our 2004 earnings also included $7 million from our investment in Rocky Road, as well as $5 million from our investment in Black Mountain.

Earnings for 2003 also include a $26 million impairment of U.S. and international investments.

NGL. NGL s earnings from unconsolidated investments were approximately $10 million during 2004 compared to a loss of $2 million in 2003. NGL s 2003 results were negatively impacted by a $12 million pre-tax impairment on our minority investment in GCF related to the difference between our book value and indicative bids received related to the possible sale of our minority investment.

CRM. CRM s losses from unconsolidated investments were zero during 2004 compared to $2 million in 2003. As of December 31, 2003, CRM has no material unconsolidated investments. As such, future results are expected to be immaterial.

Other Items, Net

Other items, net consists of other income and expense items, net, minority interest income (expense) and accumulated distributions associated with trust preferred securities. Other items, net totaled $(13) million and $20 million for 2004 and 2003, respectively.

The 2004 results included the following items:

- $25 million minority interest deduction; partially offset by

- $12 million in interest income.

The 2003 results included the following items:

- $17 million in interest income;
- $11 million gain on foreign currency transactions; offset by
- $8 million charge for accumulated distributions associated with trust preferred securities.

Interest Expense

Interest expense totaled $480 million for 2004, compared with $509 million for 2003.

The decrease in 2004, as compared to 2003, is primarily attributable to the following:

- Lower average principal balances in the 2004 period (approximately $44 million of the decrease);
- Decreased amortization of debt issuance costs (approximately $28 million of the decrease);

Lower letter of credit fees (approximately $12 million of the decrease). The lower letter of credit fees resulted from the restructuring of our credit facility in May 2004, with respect to which such fees are lower than those contained in our previous facility.

These items were offset by higher average interest rates on borrowings (approximately $56 million), including the new notes issued in connection with our August 2003 refinancing.

Income Tax Benefit

We reported an income tax benefit from continuing operations of $89 million in 2004, compared to an income tax benefit from continuing operations of $246 million in 2003. These amounts reflect effective rates of 90% and 26%, respectively. The 2004 tax benefit includes a $40 million benefit related to a reduction in a deferred tax capital losses valuation allowance associated with gains on asset sales and a $12 million benefit primarily related to IRS and state audits and settlements and other items. The 2003 effective rate was impacted significantly by the $311 million goodwill impairment relating to the REG segment. As there was no tax basis in the goodwill impaired in 2003, there were no tax benefits associated with the charge. Additionally, the 2003 tax benefit includes a $33 million reduction in a valuation allowance associated with our capital loss carryforward as a result of capital gains recognized in 2003 or anticipated to be recognized in early 2004 related to various dispositions. Excluding these items from the 2004 and 2003 calculations would result in effective tax rates of 37% and 33%, respectively. In general, differences between these adjusted effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax basis differences.

Please see Note 13 Income Taxes beginning on page F-49 for further discussion of our income taxes.

Discontinued Operations

Discontinued operations include Northern Natural in our REG segment, our global liquids business in our NGL segment, our U.K. natural gas storage assets and our U.K. CRM business in the CRM segment and our communications business in Other and Eliminations.

The largest contributor to the pre-tax gain of $23 million ($5 million after-tax loss) for 2004 is the U.K. CRM business, primarily due to $20 million in tax expenses related to the conclusion of prior year tax audits partially offset by translation gains recognized on the repatriation of cash from the U.K. Please read Note 13 Income Taxes beginning on page F-49 for further discussion.

The largest contributor to the pre-tax loss of $28 million ($19 million after-tax) for 2003 is $30 million in pre-tax losses on operations of U.K. CRM and the U.K. natural gas storage assets. This loss is associated with costs relating to our exit from these foreign operations.

Cumulative Effect of Change in Accounting Principles

We reflected EITF Issue 02-03 s rescission of EITF Issue 98-10 effective January 1, 2003 as a cumulative effect of change in accounting principle. The net impact was a pre-tax benefit of $33 million ($21 million after-tax), of which a benefit of $43 million was recognized in our CRM segment and a charge of $10 million was recognized in our GEN segment. We also adopted SFAS No. 143 effective January 1, 2003 and recognized a pre-tax benefit of $54 million ($34 million after-tax) associated with its implementation. The $54 million benefit was split between our GEN ($57 million) and REG ($(3) million) segments. Finally, we adopted certain provisions of FIN No. 46R in the fourth quarter 2003 and recognized a pre-tax charge of $23 million ($15 million after-tax) in our GEN segment related to our CoGen Lyondell facility.

Please read Note 2 Accounting Policies beginning on page F-12 for further discussion of our adoption of recent accounting policies.

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Year Ended 2003 Compared to Year Ended 2002

Operating Loss

Operating loss was $594 million in 2003 and $1,058 million in 2002.

GEN. Operating income for the GEN segment was $194 million in 2003, compared with a loss of $341 million in 2002.

Operating loss for 2002 included the following charges:

- $489 million impairment of goodwill (please see Note 10 Goodwill beginning on page F-41 for further discussion);
- $42 million charge associated with this segment s allocated portion of costs incurred in connection with our corporate restructuring and related work force reductions (please see Note 4 Restructuring and Impairment Charges Severance and Other Restructuring Costs beginning on page F-31 for further discussion);
- $14 million associated with the impairment of a turbine; and
- $6 million associated with fees related to a voluntary action that altered the accounting for certain lease obligations.

Operating income for 2003 included general and administrative expense of $61 million and depreciation and amortization expense of $188 million. In comparison, operating loss for 2002 included general and administrative expense of $66 million and depreciation and amortization expense of $175 million. Please see Other beginning on page 64 for a consolidated discussion of general and administrative expense and depreciation and amortization expense.

Operating income in 2003 included a $34 million benefit related to pricing and a $51 million benefit due to generated volumes versus 2002. GEN s results for 2003 reflect higher power prices on average as compared to 2002. This was primarily driven by higher demand in the Midwest and Northeast regions given colder than expected weather conditions during the first half of 2003. Average on-peak prices in the Midwest and Northeast regions during 2003 increased 39% and 33%, respectively, from the corresponding prices for 2002. The earnings from our peaking generation facilities, which include both capacity and energy sales, were unfavorably impacted by compressed natural gas spark spreads and overcapacity in the generation marketplace. Overall, volumes remained relatively flat to 2002; however, the net MWh in the Midwest and Northeast were 21.1 million and 5.7 million, respectively, for 2003 compared to 20.4 million and 3.6 million, respectively, for 2002.

Operating loss for 2002 included approximately $30 million associated with favorable fuel supply contracts that expired in 2002. Additionally, revenues associated with the DNE facilities decreased approximately $20 million in 2003 as compared to 2002. This decrease primarily reflects reduced income recognized through amortization of a liability established for a transitional power purchase agreement acquired from the seller of the DNE facilities as part of their acquisition, which agreement expired in October 2004. Finally, 2003 operating income included an $11 million charge related to a comprehensive settlement agreement with a manufacturer of turbines in which we agreed in principle to forfeit a prepayment in the amount of $11 million.

GEN s reported operating income for the 2003 and 2002 periods included approximately $7 million and $8 million, respectively, of mark-to-market income related to derivative contracts that did not qualify as hedges.

In December 2003, we tested certain 100% owned assets for impairment in accordance with SFAS No. 144, based on the identification of certain trigger events. These triggers indicated that our Bluegrass, Calcasieu, Riverside, Rockingham and Rolling Hills peaking facilities could be impaired due to decreased spark spreads and other market factors. After performing these tests, we concluded that no impairment was necessary as the estimated undiscounted cash flows exceeded the book value of the respective asset.

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Operating loss for 2002 reflects the sale to our CRM segment of the fair value of GEN s generation capacity, forward sales and related trading positions at an internally determined transfer price. For 2003, operating income for the GEN segment reflects the sale of power to third parties at market prices.

NGL. Operating income for the NGL segment was $170 million in 2003, compared to $77 million in 2002. Operating income for 2003 included general and administrative expense of $37 million and depreciation and amortization expense of $81 million. 2003 operating income also included a $25 million gain associated with the sale of our Hackberry LNG project. Please see Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Termination Hackberry LNG Project beginning on page F-26 for further discussion. Operating income for 2002 included $19 million in charges relating to this segment s allocated portion of costs incurred in connection with our corporate restructuring and related work force reductions, as well as general and administrative expense of $36 million and depreciation and amortization expense of $88 million. Please see Other beginning on page 64 for a consolidated discussion of general and administrative expense and depreciation and amortization expense.

The increase in operating income in 2003 as compared to 2002 relates primarily to the upstream business. For 2003 we experienced higher natural gas and natural gas liquids prices, which resulted in a significant increase in processing plant margins at our field plants. In addition to favorable pricing, volumes of natural gas liquids produced at our field plants were 6% higher in 2003 as compared to 2002. This was primarily due to increased production in the highly active drilling area in North Texas. Our 2003 straddle plant volumes were much lower as compared to 2002 because of the low frac spread for 2003, which resulted in our decision to by-pass unprofitable gas or to shut-down some of our plants that are subject to significant frac spread risk and whose contract mix is substantially made up of KW contracts.

In our downstream business, volumes available for fractionation declined to 185 MBbls in 2003 compared to 215 MBbls per day in 2002 as a direct result of reduced natural gas liquids recovery from both our own and from third-party gas processing plants due to the low frac spread. Additionally, some of our competitors recent expansion of Mont Belvieu area fractionation capacity beyond the availability of raw natural gas liquids supplies has increased competition for supplies, leading to lower fees charged for fractionation service in the area.

In our wholesale marketing operations, profits were higher due to margin increases resulting from weather-driven propane sales in the first quarter of 2003 and the impact of higher commodity prices on contracts where we retain a percentage of the sales price as our fee for marketing natural gas liquids on behalf of others, such as in our refinery services agreements and our natural gas liquids marketing agreements with ChevronTexaco. NGL s marketing results declined from prior period levels as a result of reduced overall market liquidity and customer concerns relating to our liquidity and non-investment grade credit status. Finally, downstream operating income for 2002 included income of approximately $18 million related to our Canadian crude business, which was sold in August 2002. Although our marketed volumes declined from approximately 498,800 barrels per day in 2002 to approximately 311,700 barrels per day during 2003 due to reduced domestic marketing opportunities and the divestiture of our global liquids business, effective January 1, 2003, this decline had little impact on our operating income, as the financial impact of our global liquids business is included in discontinued operations for all periods presented. The global liquids business sold an average of 95,500 barrels per day in 2002.

REG. Operating loss for the REG segment was $327 million in 2003, compared to operating income of $157 million in 2002.

Operating loss for 2003 included a $529 million charge for the impairment of goodwill and other assets associated with this segment, as further described in Note 10 Goodwill beginning on page F-41, as well as general and administrative expense of $68 million and depreciation and amortization expense of $121 million. Operating income for 2002 included restructuring charges of $23 million, as well as general and administrative expense of $67 million and depreciation and amortization expense of $175 million. Please see Other beginning on page 64 for a consolidated discussion of general and administrative expense and depreciation and amortization expense.

We were negatively impacted in 2003 as compared to 2002 by cooler than normal spring and summer weather partially offset by colder than normal winter weather, which caused net decreases in residential and commercial electricity sales volumes and increases in residential and commercial gas sales volumes. Additionally, revenues during 2003 and 2002 attributable to the sale of electricity to residential customers were negatively impacted by a 5% rate reduction effective in May 2002.

CRM. Operating loss for the CRM segment was $385 million in 2003 compared to $951 million in 2002.

Results for 2003 were impacted by the following pre-tax losses:

- $133 million charge associated with the settlement of power tolling arrangements with Southern Power, for which we paid $155 million;
- $121 million mark-to-market loss on contracts associated with the Independence power tolling arrangement;
- $34 million charge associated with the cash settlement of the Batesville tolling arrangement; and
- $30 million charge associated with the settlement of power supply agreements with Kroger, for which we received approximately $110 million.

In addition, 2003 results include losses associated with fixed payments on power tolling arrangements in excess of realized margins on power generated and sold pursuant to these arrangements. These items were offset by gains totaling approximately $61 million associated with sales of natural gas in storage which had previously been recorded at fair value, partially offset by $21 million of charges associated with settlements of legacy contracts. Please read Note 2 Accounting Policies Revenue Recognition beginning on page F-17 for additional details.

Results for 2002 were impacted by the following items:

- $325 million charge for the impairment of goodwill (for further information, please see Note 10 Goodwill beginning on page F-41);
- $73 million in costs associated with our corporate restructuring and related work force reductions (for further information, please see Note 4 Restructuring and Impairment Charges Severance and Other Restructuring Costs beginning on page F-31);
- $25 million in charges associated with the settlement of tolling contracts;
- $25 million in charges associated with the write-off of our investment in Dynegy*direct*; and

$7 million in losses associated with the sale of our Canadian physical gas business to Seminole.

In addition, 2002 results included general and administrative expense of $154 million and depreciation and amortization expense of $28 million. Please see Other below for a consolidated discussion of general and administrative expense and depreciation and amortization expense. Finally, 2002 results were negatively impacted by reduced gas marketing volumes as a result of reduced market liquidity and our lower credit ratings.

During 2002, our CRM segment was actively managed as part of our ongoing strategy and its results included, in part, settlement with third parties of physical power and other trading positions purchased from our GEN segment at an internally determined transfer price. Please read Note 20 Segment Information beginning on page F-78 for further discussion.

Other. Other operating loss was $246 million in 2003, compared to zero in 2002. The loss in 2003 primarily relates to general and administrative expenses and depreciation and amortization expenses which are incurred at a corporate level. Prior to 2003, these costs were allocated to the segments.

Consolidated general and administrative expenses were $346 million in 2003, compared to $325 million in 2002. The $21 million increase year over year is principally the result of the $50 million second quarter 2003 litigation reserve and higher professional fees, offset by significantly lower compensation costs in the 2003 period resulting from the work force reductions.

Consolidated depreciation and amortization expenses were $454 million in 2003, compared to $466 million in 2002. The $12 million decrease year over year is primarily due to reduced depreciation in our REG segment, offset by increased depreciation of generation assets due to an increased asset base. Increases in our asset base include the construction of the Renaissance, Bluegrass and Foothills facilities in 2002 and the completion of Rolling Hills in 2003.

Earnings (Losses) from Unconsolidated Investments

Our earnings from unconsolidated investments were approximately $124 million during 2003 compared to losses of $80 million in 2002. Both 2002 and 2003 results include significant impairment charges related to these investments, primarily associated with the GEN segment.

GEN. GEN s earnings from unconsolidated investments were approximately $128 million during 2003 compared to a loss of $71 million in 2002.

Our West Coast Power investment was the primary driver of equity earnings for both periods. West Coast Power provided earnings of $117 million in 2003 compared to $17 million in 2002. Earnings for 2003 include a $20 million charge associated with our 50% share of a goodwill impairment charge recorded by West Coast Power in the fourth quarter 2003. Earnings for 2002 include a $50 million charge associated with our 50% share of a bad debt allowance recognized by West Coast Power, as well as a $33 million charge to write down our investment to fair value. Exclusive of these items, West Coast Power s improved results from 2002 to 2003 were driven by increased earnings under the CDWR contract.

In 2003, we recorded a $26 million impairment of our investments in Panama, Jamaica, Michigan Power, Commonwealth and Black Mountain, because of our determination that current market value was less than the book values of the investments. In 2002, we recorded a $144 million impairment of U.S. investments, of which $33 million related to West Coast Power, as discussed above. We assessed the carrying value of our generation portfolio on an asset-by-asset basis and determined that the fair value of some of our U.S. investments was less than our book value. The diminution in the fair value of these investments was primarily a result of depressed energy prices.

NGL. NGL s losses from unconsolidated investments were approximately $2 million during 2003 compared to earnings from unconsolidated investments of $14 million in 2002. NGL s 2003 results were negatively impacted by a $12 million pre-tax impairment on our minority investment in GCF related to the difference between our book value and indicative bids received related to the possible sale of our minority investment. In addition, WTLPS, which we sold to ChevronTexaco in August 2002, contributed approximately $6 million to our results for 2002.

CRM. CRM s losses from unconsolidated investments were $2 million during 2003 compared to $21 million in 2002. As of December 31, 2003, CRM had no material unconsolidated investments. As such, future results are expected to be immaterial. The 2002 loss is primarily comprised of charges allocated to the CRM segment for impairments associated with technology investments.

Other Items, Net

Other items, net consists of other income and expense items, net, minority interest income (expense) and accumulated distributions associated with trust preferred securities. Other items, net totaled $20 million and $(107) million for 2003 and 2002, respectively.

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The 2003 results included the following items:

- $17 million in interest income;
- $11 million gain on foreign currency transactions; offset by
- $8 million charge for accumulated distributions associated with trust preferred securities.

The 2002 results included the following items:

- $36 million in interest income;
- $36 million minority interest deduction, primarily related to ABG Gas Supply and Black Thunder;
- $22 million charge relating to the cancellation of our natural gas purchases and sales contract with ChevronTexaco;
- $21 million charge associated with the settlement of the Enron litigation relating to the termination of our proposed merger;
- $12 million charge for accumulated distributions associated with trust preferred securities;
- $10 million charge primarily related to our settlements with the CFTC ($4 million) and SEC ($3 million); and
- Remaining amounts consisting of individually insignificant items.

Interest Expense

Interest expense totaled $509 million for 2003, compared with $297 million for 2002. The significant increase in 2003, as compared to 2002, is primarily attributable to the following:

- Higher average interest rates on borrowings (approximately $70 million of the increase), including Illinois Power s new mortgage bonds and the new notes issued in connection with our August 2003 refinancing;

Interest expense for 2002 does not include approximately $65 million of interest expense which was allocated to our discontinued businesses;

Higher average principal balances in the 2003 period (approximately $30 million of the increase);

Increased amortization of debt issuance costs (approximately $35 million of the increase, of which approximately $24 million relates to accelerated amortization of previously incurred financing costs and the settlement value of the associated interest rate hedge instruments); and

Higher letter of credit fees (approximately $15 million of the increase). The higher letter of credit fees resulted from the restructuring of our credit facility in April 2003, with respect to which such fees are higher than those contained in our previous facility.

Income Tax Benefit

We reported an income tax benefit from continuing operations of $246 million in 2003, compared to an income tax benefit from continuing operations of $343 million in 2002. These amounts reflect effective rates of 26% and 22%, respectively. The effective rates were impacted significantly by the $311 million goodwill impairment relating to the REG segment in 2003 and the $814 million goodwill impairment relating the CRM and GEN segments in 2002. As there was no tax basis in the goodwill impaired in 2003 or $579 million of the goodwill impaired in 2002, there were no tax benefits associated with the charges. Additionally, the 2003 tax benefit includes a $33 million reduction in a valuation allowance associated with our capital loss carryforward as a result of capital gains recognized in 2003 or anticipated to be recognized in early 2004 related to various dispositions. Excluding these items from the 2003 and 2002 calculations would result in effective tax rates of

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33% in 2003 and 36% in 2002. In general, differences between these adjusted effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax basis differences.

Please see Note 13 Income Taxes beginning on page F-49 for further discussion of our income taxes.

Discontinued Operations

Discontinued operations include Northern Natural in our REG segment, our global liquids business in the NGL segment, our U.K. natural gas storage assets and our U.K. CRM business in the CRM segment and our communications business in Other and Eliminations.

The largest contributor to the pre-tax loss of $28 million ($19 million after-tax) for 2003 is $30 million in pre-tax losses on operations of U.K. CRM and the U.K. natural gas storage assets. This loss is associated with costs relating to our exit from these foreign operations.

During 2002, the $1,503 million pre-tax loss ($1,154 million after-tax) from discontinued operations was primarily comprised of $854 million in pre-tax losses ($538 million after-tax) from the global communications business and $561 million in pre-tax losses ($538 million after-tax) from Northern Natural. The global communications business recorded pre-tax charges of $635 million for the impairment of communications assets. The remaining $219 million in losses is related to approximately $48 million of impairments of technology investments and carrying costs associated with the business. In August 2002, we sold Northern Natural to MidAmerican and incurred a pre-tax loss of approximately $599 million associated with the sale. We recorded a valuation allowance against a portion of the tax benefit resulting from the sale, due to uncertainty as to the ability to generate capital gains in the future. Discontinued operations for the REG segment in 2002 also includes $38 million in pre-tax earnings associated with operating results from Northern Natural prior to its sale. The CRM pre-tax loss of $51 million ($49 million after-tax) consisted of $115 million in losses associated with the U.K. CRM business offset by $64 million in income from our U.K. natural gas storage assets. The global liquids pre-tax loss of $37 million ($29 million after-tax) included a pre-tax charge of approximately $12 million associated with the impairment of an LPG investment in the global liquids business. The remaining $25 million loss related to the write-off of a logistics and accounting computer system and other costs associated with the wind-down of the business.

Cumulative Effect of Change in Accounting Principles

We reflected EITF Issue 02-03 s rescission of EITF Issue 98-10 effective January 1, 2003 as a cumulative effect of a change in accounting principle. The net impact was a pre-tax benefit of $33 million ($21 million after-tax), of which a benefit of $43 million was recognized in our CRM segment and a charge of $10 million was recognized in our GEN segment. We also adopted SFAS No. 143 effective January 1, 2003 and recognized a pre-tax benefit of $54 million ($34 million after-tax) associated with its implementation. The $54 million benefit was split between our GEN ($57 million) and REG ($(3) million) segments. Finally, we adopted certain provisions of FIN No. 46R in the fourth quarter 2003 and recognized a pre-tax charge of $23 million ($15 million after-tax) in our GEN segment related to our CoGen Lyondell facility.

On January 1, 2002, we adopted SFAS No. 142. In connection with its adoption, we realized a cumulative effect loss of approximately $234 million associated with a write-down of goodwill associated with our discontinued communications business.

2005 Outlook

The following summarizes our 2005 outlook for our three remaining reportable segments.

GEN Outlook. We expect that this segment s future financial results will continue to reflect sensitivity to commodity prices and weather conditions. We will continue our efforts to manage price risk through the

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optimization of fuel procurement and the marketing of power generated from our assets, including through forward sales and related transactions, consistent with our views on market recovery in the regions we serve. Our sensitivity to commodity prices and our ability to manage this sensitivity is subject to a number of factors, including general market liquidity, particularly in forward years, our ability to provide necessary collateral support and the willingness of counterparties to transact business with us given our non-investment grade credit ratings. Additionally, because we may seek to manage price risk through forward sales and related transactions, at times we may be unable to capture opportunities presented by rising prices.

The operation of our generation facilities is highly dependent on our ability to procure coal as a fuel. Power generators in the Midwest and the Northeast have experienced significant pressures on available coal supplies that are either transportation or supply related. Our long-term supply and transportation agreements for our Midwest fleet mitigate these concerns. In the Northeast, we have accumulated sufficient inventories to allow us to operate our assets. While we believe our physical inventories and contractual commitments provide us with a stable fuel supply, we are subject to physical delivery risks outside of our control.

As discussed in Item 1. Business Segment Discussion Power Generation beginning on page 2, we enter into sales of capacity from our generation assets, which provide a revenue stream independent of energy sales. During 2004, we have seen increases in the market for capacity-related products from our peaking and intermediate generation facilities.

Throughout 2004, a substantial portion of our operating margin and earnings from unconsolidated investments was under contract or hedged. The primary contracts included the CDWR contract held by West Coast Power and the Illinois Power power purchase agreement, both of which terminated in December 2004. Our future results of operations will be significantly impacted by the expiration of the CDWR contract. West Coast Power, whose equity earnings were primarily derived from the CDWR contract, has been our largest contributor to earnings from unconsolidated investments. As a result of the expiration of the CDWR contract, future earnings from the investment will be substantially reduced. Please read Item 1. Business Segment Discussion Power Generation beginning on page 2 for a discussion of West Coast Power s current contractual arrangements. Based on our ongoing evaluation of strategic alternatives for our West Coast Power assets, we determined that it was not economically feasible to continue to operate our Long Beach generation facility beyond the expiration of the CDWR contract. Therefore, we retired the asset as of January 1, 2005. Additionally, the expiration of the CDWR contract in December 2004 had a negative impact on the fair value of our investment in West Coast Power. As a result, we recorded an impairment of $73 million in 2004. Our 2004 equity earnings also included a charge of $12 million, representing our 50% share of West Coast Power s impairment of certain generation assets. This impairment was also triggered by the expiration of the CDWR contract. Please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings FERC and Related Regulatory Investigations Request for Refunds beginning on page F-59 for further discussion of the legal challenges to the CDWR contract. Please also read Liquidity and Capital Resources Internal Liquidity Sources Cash Flows from Operations beginning on page 48 for a discussion of our efforts to seek a replacement of the CDWR contract.

Our former power purchase agreement between DMG and Illinois Power terminated in December 2004. In September 2004, in connection with the sale of Illinois Power to Ameren, DPM entered into a new two-year power purchase agreement with Illinois Power with expected volumes comparable to the former agreement. Under the terms of this new agreement, which became effective January 1, 2005, we have agreed to provide Illinois Power with up to 2,800 MWs of capacity at $48.00 per kW-yr and up to 11.5 million MWh of energy each year at a fixed price of $30 per MWh. Under the new agreement, we are no longer the provider of last resort for Illinois Power, which exposed us to volume and price uncertainties under the former agreement. Under the former agreement, we received contract revenues based on a higher fixed capacity payment and lower variable energy payments. Accordingly, GEN s operating income under the new agreement will be impacted more significantly by deviations from expected energy purchases by Illinois Power. We expect that any reduction in operating income under this new agreement will be mitigated by no longer serving as the provider of last resort.

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During 2004, we sold our 50% interests in the Oyster Creek, Michigan Power, Hartwell, and Commonwealth facilities, as well as our 20% interest in the Joppa facility. Additionally, we sold our 100% interest in Plantas Eolicas, S.A. de C.V. (Costa Rica) and 17.55% interest in Jamaica Energy Partners. Our 2004 results include an aggregate $99 million of earnings from these investments, including $82 million of net gains on sales. For 2003, these investments contributed $17 million to earnings. However, beginning in 2005, the lost earnings from these assets will no longer be offset by gains on sale.

On January 31, 2005, we acquired the 1,021 MW, combined-cycle Independence power generation facility, four natural gas-fired merchant facilities in New York and four hydroelectric generation facilities in Pennsylvania. GEN s 2005 results will include the results of this acquisition, including general and administrative costs associated with Sithe Energies New York City office, until such time as those costs can be mitigated. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion of this transaction.

NGL Outlook. The financial outlook for our NGL segment is sensitive to natural gas and natural gas liquids prices. The pricing environment for 2005 is expected to be strong with high volatility for commodities driving our market, similar to 2004, when we experienced high volatility in both natural gas and natural gas liquids prices. Provided the strong pricing environment persists throughout 2005, our upstream contract settlements under POP and POL contracts will continue to benefit. However, high natural gas prices without a comparable upward movement in natural gas liquids prices would reduce frac spreads to levels where it is no longer profitable to extract natural gas liquids. If frac spreads are reduced to unprofitable levels, our hybrid contracts, sensitive to frac spreads, will switch from POL settlements to fee settlements, which would negatively impact our earnings in a high natural gas liquids price environment. Frac spread volatility will impact natural gas liquids volumes produced from our own and third party natural gas processing plants as frac spread economics either do or do not support natural gas liquids extraction. In 2005, the U.S. and world economies are expected to grow, though not as rapidly as 2004. This growth will continue to support demand for products from the petrochemical industry, which experienced a dramatic improvement in 2004. The industry s improvement was due in part to strong world-wide ethylene and propylene demand, driving higher natural gas liquids feedstock consumption, and helping to improve frac spreads. This increased demand for natural gas liquids feedstocks will continue to benefit our results.

There seems to be a widely held belief that, long term, natural gas prices will remain high enough relative to natural gas liquids prices to depress the frac spread below levels required for liquids extraction, reducing natural gas liquid volumes requiring fractionation. As a result, there remains aggressive competition between fractionators for available volumes, driving fees paid for fractionation services to historic lows. In October 2004, we lost a substantial fractionation customer at our Mont Belvieu fractionator when the previous contract reached the end of its primary term. The customer had committed the volumes to a competitor as part of a larger asset sale. We continue to aggressively compete for replacement volumes albeit in a highly competitive market.

Straddle plant gas processing will continue to be impacted by uncertainty surrounding natural gas quality specifications for liquefiable hydrocarbons. Other than occasional short-term periods of favorable natural gas liquids extraction economics, market conditions for straddle plant gas processing have been generally poor since late 2000. Pipeline companies have operational and safety concerns related to the heavier natural gas liquids, like butane and natural gasoline, that are left in the natural gas entering their systems instead of being extracted. While industry stakeholders respond to recent FERC decisions directing pipeline companies to address this issue in their tariff, there is a lack of clarity around when and where processing is required, especially during periods of poor extraction economics. The result is a patchwork of pipeline policies and practices that leave producers and processors without clearly defined ground rules, making contracting gas supply and planning straddle plant operations difficult. Resolution of the issue is currently being pursued through the Natural Gas Council, FERC and other affected stakeholders.

Drilling for natural gas throughout our core processing areas in New Mexico, West Texas, North Texas and offshore Louisiana continues to increase, consistent with natural gas prices that have averaged $6/MMBtu.

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Continued exploration and production at these commodity price levels will benefit our upstream business by providing additional volumes for gathering and processing. In the Permian, continued property sales by major exploration and production companies to smaller independent producers will contribute to increased activity and exploration. If natural gas prices were to decline significantly in the future, resulting in reduced drilling activities, this segment s results could be adversely affected.

While we have not experienced significant turnover in customer contracts as a result of our non-investment grade credit ratings, we have been required to provide collateral or other adequate assurance of our obligations in connection with many of our commercial relationships. On occasion, we have been unable to satisfy efficiently a potential new customer s concerns about our credit ratings. We expect similar collateral requirements until such time as our credit ratings measurably improve.

At this time it is our strategy to not sell forward future natural gas liquids production; however, any change in this strategy resulting in a desire to hedge future natural gas liquids production during 2005 may again be limited by reduced market liquidity and our obligation to post collateral. As commodity prices rise, we are required by counterparties to post additional collateral.

We intend to continue prudently expanding our North Texas gathering system, working collaboratively with our producer customers. Additional compression and pipeline reach along with plant debottlenecking are expected to add volumes to our expanded Chico gas processing plant In addition, we continue to review our asset portfolio to maximize return on investment. In 2004, we identified and sold several assets that were not strategic to our core operations, including our final financial interest in Hackberry LNG, our interest in the Indian Basin plant and our Sherman facility. We may pursue sale of other assets if the price is sufficient to mitigate the anticipated impact on future earnings. Please see Liquidity and Capital Resources External Liquidity Sources Asset Sale Proceeds beginning on page 49 for further discussion.

CRM Outlook. Our CRM business future results of operations will be significantly impacted by our ability to complete our exit from this business. During 2004, we were successful in reaching agreements to exit four of our natural gas transportation agreements. In November 2004, we entered into a back-to-back power purchase agreement with a subsidiary of Constellation, under which we will receive $161 million in payments through November 2008 to offset our fixed payment obligations under our Kendall tolling arrangement, while positioning us to take advantage of the market recovery expected in 2008 and beyond. In January 2005, we completed the purchase from Exelon Corporation of all of the outstanding capital stock of ExRes SHC, Inc., the parent company of Sithe Energies and Independence. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion. As a result of this agreement, our Independence power tolling arrangement has been transformed into an intercompany agreement under our GEN segment, which now includes the Independence facility. This substantially eliminates its future financial statement impact. Our Gregory tolling arrangement expires by its terms in July 2005.

Our Sterlington tolling arrangement remains in place through 2017. We are exploring opportunities to assign or renegotiate the terms of this arrangement, but we cannot guarantee that we will be successful. If we do not renegotiate or terminate this remaining arrangement, it will continue to impact negatively our near- and long-term earnings and cash flows based on the current pricing environment. Any renegotiation or termination of this long-term contract would likely result in significant cash payments and a charge to earnings in the applicable period. For a discussion of our annual and long-term obligations under these arrangements, please read Disclosure of Contractual Obligations and Contingent Financial Commitments beginning on page 43 and Item 1. Business Segment Discussion Customer Risk Management beginning on page 18.

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CASH FLOW DISCLOSURES

The following tables include data from the operating section of the consolidated statements of cash flows and include cash flows from our discontinued operations, which are disclosed on a net basis in loss on discontinued operations, net of tax, in the consolidated statements of operations:

	GEN	NGL	REG	CRM	Other & Eliminations	Consolidated
				(in millions)		
Year Ended December 31, 2004	$ 421	$ 278	$ 213	$ (371)	$ (536)	$ 5
Year Ended December 31, 2003	$ 428	$ 186	$ 67	$ 496	$ (301)	$ 876
Year Ended December 31, 2002	$ 258	$ 24	$ 262	$ (318)	$ (251)	$ (25)

Operating Cash Flow. Our cash flow provided by operations totaled $5 million for the 12 months ended December 31, 2004. During the period, our GEN, NGL and REG segments provided positive cash flow from operations. GEN provided cash flow from operations of $421 million due primarily to positive earnings for the period and increased business activity, partially offset by increased cash collateral posted in lieu of letters of credit; NGL provided cash flow from operations of $278 million due primarily to positive earnings, partially offset by increased prepayments due to higher sales; and REG provided cash flow from operations of $213 million due primarily to positive earnings for the period. Our CRM segment used approximately $371 million in cash due primarily to fixed payments associated with the power tolling arrangements and related gas transportation agreements, a $117.5 million payment related to the restructuring of the Kendall toll, increased cash collateral posted in lieu of letters of credit and our exit from four long-term natural gas transportation contracts. Other & Eliminations includes a use of approximately $536 million in cash due primarily to interest payments to service debt, settlement payments and general and administrative expenses.

Cash provided in 2003 primarily relates to collateral returns, settlements of risk management assets and sales of natural gas storage in excess of $500 million from our CRM business, a $110 million income tax refund and solid operational performances from our GEN, NGL and REG segments. Despite a relatively weak commodity price environment, our GEN segment provided cash flows in excess of $400 million largely due to effective commercial and operational management and our coal- and dual-fired generation assets. Similarly, our NGL segment contributed cash flows from operations in excess of $180 million due to a strong commodity price environment, particularly in the upstream business, offset by increases in prepayments and lower downstream results due to industry-wide reductions in volumes available for fractionation. Our REG segment contributed operating cash flows in excess of $60 million, primarily from normal operating conditions, offset by working capital outflows due to increased injection of gas into storage, as well as an increase in prepayments. General and administrative costs, a $45 million litigation settlement and continued extinguishment of liabilities during our exit from our communications business offset these positive operational cash flows during 2003.

For 2002, our cash flow used in operations was $25 million. When compared to 2003, the primary driver of our operating cash outflows was our required posting during 2002 of significant amounts of collateral under the terms of our CRM commercial contracts due to the degradation of our credit ratings.

Capital Expenditures and Investing Activities. Net cash provided by investing activities during 2004 totaled $262 million. Capital spending of $311 million was comprised primarily of $145 million, $61 million and $92 million in the GEN, NGL and REG segments, respectively. The capital spending for our GEN segment related primarily to maintenance capital projects, as well as approximately $41 million related to developmental projects. Capital spending in our NGL segment related primarily to maintenance capital projects and wellconnects, as well as approximately $21 million on developmental projects. Capital spending in our REG segment related primarily to projects intended to maintain system reliability and new business services.

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

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

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

Cash used in investing activities for 2003 totaled $266 million. Our capital spending totaled $333 million and was primarily comprised of routine capital maintenance of our existing asset base. Of this amount, we spent approximately $40 million on the construction of Rolling Hills, which began commercial operations in June 2003. Our proceeds from asset sales totaled approximately $72 million and primarily relate to our sale of Hackberry LNG Terminal LLC ($35 million), SouthStar ($20 million), and generation equity investments ($25 million), which were offset by $10 million in cash outflows associated with the sale of our European communications business.

During 2002, cash provided by investing activities totaled $677 million. Our capital spending totaled $947 million and was primarily comprised of improvements to the existing asset base. Of this amount, we spent approximately $195 million on the construction of Rolling Hills. Additionally, we spent $83 million on our discontinued communications business and incurred $54 million in capital expenditures associated with information technology. Business acquisitions of $20 million relate to our acquisition of Northern Natural, net of cash acquired. We received $1.5 billion in proceeds from asset sales primarily from the sales of Northern Natural in August 2002 ($879 million), the Hornsea gas storage facility in September 2002 ($189 million) and the Rough gas storage facility in November 2002 ($500 million). Other investing activities include proceeds from the sale of Northern Natural bonds.

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

$223 million to redeem the outstanding ChevronTexaco junior notes;

$185 million under our ABG Gas Supply financing;

$95 million for a maturing series of Illinova senior notes;

$78 million on the Tilton capital lease; and

$65 million on Illinois Power s transitional funding trust notes.

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

During 2003, cash used for financing activities totaled $900 million. The following summarizes significant items:

Repayments of $128 million, net, under our revolving credit facilities.

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Long-term debt proceeds, net of issuance costs, for 2003 totaled $2.2 billion and consisted of: (1) $311 million associated with the October 2003 follow-on offering of the DHI notes; (2) $1,607 million associated with our August 2003 refinancing transaction, (3) $142 million from the delayed issuance of $150 million in Illinois Power 11.5% Mortgage Bonds due 2010 and (4) $159 million from the Term A loan drawn in connection with the April 2003 credit facility restructuring.

In connection with the Series B Exchange, we made a $225 million cash payment to ChevronTexaco.

Repayments of long-term debt totaled $2.7 billion and consisted of: (1) $696 million prepayment of the outstanding balance under the Black Thunder financing; (2) $609 million purchase of DHI s previously outstanding 2005/2006 senior notes; (3) $360 million prepayment of the Term B loan outstanding under DHI s April 2003 restructured credit facility; (4) $200 million prepayment of the Term A loan outstanding under DHI s April 2003 restructured credit facility; (5) $200 million in payments under the Renaissance and Rolling Hills interim financing; (6) $190 million in payments of Illinois Power mortgage bond maturities; (7) $100 million payment on Illinois Power s term loan; (8) $165 million payment in full for the GEN facility capital lease; (9) $86 million in payments on Illinois Power s transitional funding trust notes; (10) $74 million in payments under the ABG Gas Supply financing; (11) $62 million in payments under the Black Thunder secured financing prior to its prepayment; (12) $5 million purchase of Illinova senior notes on the open market; and (13) $2 million in payments on the ChevronTexaco junior notes.

Distributions to minority interest owners totaling $21 million.

During 2002, cash used for financing activities totaled $44 million. The following summarizes significant items:

Net long-term debt proceeds consisted primarily of the February 2002 issuance by DHI of $500 million of 8.75% senior notes due February 2012, the December 2002 issuance by Illinois Power of $400 million of 11.5% Mortgage bonds due 2010 and proceeds from the ABG Gas Supply financing;

Repayments of long-term borrowings consisted of: (1) $88 million in transitional funding notes relating to Illinois Power; (2) $90 million relating to the April 2002 purchase of Northern Natural s senior unsecured notes due 2005; (3) $92 million in principal payments related to the Black Thunder financing; (4) $200 million relating to the July 2002 DHI 6.875% senior note repayment; (5) $96 million relating to the July 2002 Illinois Power mortgage bond repayment; and (6) $59 million in repayments under the ABG Gas Supply financing;

In July 2002, we completed a $200 million interim financing secured by interests in our Renaissance and Rolling Hills merchant power generation facilities. In June 2002, we completed a $250 million interim financing representing an advance on a portion of the proceeds from the sale of our U.K. natural gas storage facilities. In September 2002, we sold the entity that owned the Hornsea storage facility, and, in October 2002, we repaid approximately $189 million of this interim financing with the proceeds. In November 2002, we sold the entities that owned the Rough facilities and repaid the remaining balance of this financing with a portion of the proceeds;

Repayments of commercial paper borrowings and revolving credit facilities of Dynegy and DHI totaled approximately $614 million in the aggregate and borrowings totaled an aggregate of approximately $136 million under the Dynegy and DHI revolving credit facilities. During the same period, repayments of commercial paper borrowings and revolving credit facilities for Illinois Power totaled approximately $238 million;

Proceeds from the sale of capital stock totaled $205 million related to ChevronTexaco s January 2002 purchase of approximately 10.4 million shares of Class B common stock pursuant to its preemptive rights under our shareholder agreement. Capital stock proceeds also included $24 million of cash inflows associated with cash received from senior management associated with a December 2001 private placement of shares of our Class A common stock;

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In March 2002, Illinova consummated a tender offer pursuant to which it paid $28 million in cash for approximately 73% of the then-outstanding shares of Illinois Power s preferred stock; and

We made dividend payments of $40 million to the holders of Class A common stock and $15 million to the holder of Class B common stock.

SEASONALITY

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

CRITICAL ACCOUNTING POLICIES

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

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

Revenue Recognition;

Valuation of Tangible and Intangible Assets;

Estimated Useful Lives;

Accounting for Contingencies, Guarantees and Indemnifications;

Accounting for Income Taxes; and

Valuation of Pension Assets and Liabilities.

Revenue Recognition

We utilize two comprehensive accounting models in reporting our consolidated financial position and results of operations as required by GAAP an accrual model and a fair value model. We determine the appropriate model for our operations based on guidance provided in applicable accounting standards and positions adopted by the FASB or the SEC. We have applied these accounting policies on a consistent basis during the three years in the period ended December 31, 2004, except as required by the adoption of EITF Issue 02-03, which rescinded EITF Issue 98-10.

The accrual model has historically been used to account for substantially all of the operations conducted in our GEN, NGL and REG segments. These segments consist largely of the ownership and operation of physical assets that we use in various generation, processing and delivery operations. The business of these segments includes the generation of electricity, the separation of natural gas liquids into their component parts from a stream of natural gas and the transportation or transmission of commodities through pipelines or over

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transmission lines. End sales from these businesses result in physical delivery of commodities to our wholesale, commercial, industrial and retail customers. We recognize revenue from these transactions when the product or service is delivered to a customer.

The fair value model has historically been used to account for certain forward physical and financial transactions, occurring primarily in the CRM and GEN segments, which meet criteria defined by the FASB or the EITF. The criteria are complex, but generally require these contracts to relate to future periods, to contain fixed price and volume components and to have terms that require or permit net settlement of the contract in cash or the equivalent. The FASB determined that the fair value model is the most appropriate method for accounting for these types of contracts. In part, this conclusion is based on the cash settlement provisions in these agreements, as well as the volatility in commodity prices, interest rates and, if applicable, foreign exchange rates, which impact the valuation of these contracts. Since these transactions may be settled in cash or the equivalent, the value of the assets and liabilities associated with these transactions is reported at estimated settlement value based on current prices and rates as of each balance sheet date.

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

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

Valuation of Tangible and Intangible Assets

We evaluate long-lived assets, such as property, plant and equipment, investments and goodwill, when events or changes in circumstances lead to a reduction in the estimated useful lives or estimated future cash flows sufficient to indicate that the carrying value of such assets may not be recoverable. Factors we consider important, which could trigger an impairment analysis, include, among others:

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

significant declines in stock value for a sustained period.

We assess the carrying value of our property, plant and equipment in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. If an impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the related discounted cash flows of the assets and recording a loss if the resulting estimated fair value is less than the book value. For assets identified as held for sale, the book value is compared to the estimated fair value, which may also include estimates based upon comparables or quoted market prices, to determine if an impairment loss is required. Please see Note 4 Restructuring and Impairment Charges beginning on page F-30 for discussion of impairment charges we recognized for 2004, 2003 and 2002.

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

We follow the guidance set forth in SFAS No. 142, Goodwill and Other Intangible Assets, when assessing the carrying value of our goodwill. Accordingly, we evaluate our goodwill for impairment on an annual basis or when certain events warrant an assessment. Our evaluation is based, in part, on our estimate of future cash flows. Please see Note 10 Goodwill beginning on page F-41 for discussion of impairment charges we recognized for 2003 and 2002.

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

Estimated Useful Lives

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

Accounting for Contingencies, Guarantees and Indemnifications

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

Liabilities are recorded when environmental assessment indicates that remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based, in part, on relevant past experience, currently enacted laws and regulations, existing technology, site-specific costs and cost-sharing arrangements. Recognition of any joint and several liability is based upon our best estimate of our final pro-rata share of such

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liability. These assumptions involve the judgments and estimates of management and any changes in assumptions could lead to increases or decreases in our ultimate liability, with any such changes recognized immediately in earnings.

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

Under the provisions of SFAS No. 143, Asset Retirement Obligations, we are required to record legal obligations to retire tangible, long-lived assets on our balance sheet as liabilities, which are recorded at a discount, when the liability is incurred. Significant judgment is involved in estimating our future cash flows associated with such obligations, as well as the ultimate timing of the cash flows. If our estimates on the amount or timing of the cash flow change, the change may have a material impact on our results of operations.

Accounting for Income Taxes

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

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

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

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

Please see Note 13 Income Taxes beginning on page F-49 for further discussion of our accounting for income taxes and any change in our valuation allowance.

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Valuation of Pension Assets and Liabilities

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

The discount rate is subject to change each year, consistent with changes in applicable high-quality, long-term corporate bond indices. Long-term interest rates declined during 2004. Accordingly, at December 31, 2004, we used a discount rate of 5.75%, a decline of 25 basis points from the 6.0% rate used as of December 31, 2003. This decline in the discount rate had an immaterial impact on the underfunded status of our pension plans.

The expected long-term rate of return on pension plan assets is selected by taking into account the expected duration of the projected benefit obligation for the plans, the asset mix of the plans and the fact that the plan assets are actively managed to mitigate downside risk. Based on these factors, our expected long-term rate of return as of January 1, 2005 is 8.25%, compared with 8.75% during 2004. This change did not impact 2004 pension expense, but it will adversely impact pension expense beginning in 2005. Although we expect 2005 pension expense to be lower than 2004 pension expense by approximately $13 million, primarily due to the sale of Illinois Power, the decrease will be partially offset by the decrease in the expected long-term rate of return, coupled with the decreased discount rate discussed above and the passage of time.

On December 31, 2004, our annual measurement date, the accumulated benefit obligation related to our pension plans exceeded the fair value of the pension plan assets (such excess is referred to as an unfunded accumulated benefit obligation). This difference is attributed to (1) an increase in the accumulated benefit obligation that resulted from the decrease in the discount rate and the expected long-term rate of return and (2) a decline in the fair value of the plan assets due to a sharp decrease in the equity markets through December 31, 2002, which was partially recovered during 2003 and 2004. As a result, in accordance with SFAS No. 87, Employers Accounting for Pensions, as of December 31, 2004, we have recognized a charge to accumulated other comprehensive loss of $13 million (net of taxes of $7 million), which decreases stockholders equity. The charge to stockholders equity for the excess of additional pension liability over the unrecognized prior service cost represents a net loss not yet recognized as pension expense.

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

	Impact on PBO, December 31, 2005	Impact on 2005 Expense
	(in millions)	
Increase in Discount Rate 50 basis points	$ (13.9)	$ (1.2)
Decrease in Discount Rate 50 basis points	15.5	1.3

Increase in Expected Long-term Rate of Return 50 basis points	(0.5)
Decrease in Expected Long-term Rate of Return 50 basis points	0.5

We expect to make $28 million in cash contribution related to our pension plans during 2005. In addition, it is likely that we will be required to continue to make contributions to the pension plan beyond 2005. Although it is difficult to estimate these potential future cash requirements due to uncertain market conditions, we currently expect that the cash requirements would be approximately $19 million in 2006 and $26 million in 2007.

Please see Note 19 Employee Compensation, Savings and Pension Plans beginning on page F-73 for further discussion of our pension related assets and liabilities.

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RECENT ACCOUNTING PRONOUNCEMENTS

See Note 2 Accounting Policies Accounting Principles Adopted beginning on page F-21 for a discussion of recently issued accounting pronouncements affecting us. Specifically, we adopted EITF 04-8, EITF 02-14 and certain provisions of FIN No. 46R on January 1, 2004, and we adopted other portions of FIN No. 46R effective December 31, 2003. We adopted SFAS No. 150 and EITF Issue 03-11 effective July 1, 2003. We adopted FIN No. 45 and SFAS No. 143 effective January 1, 2003. We adopted the net presentation provisions of EITF Issue 02-03 in the third quarter 2002 and we adopted the provision within EITF Issue 02-03 that rescinds EITF Issue 98-10 effective January 1, 2003.

RISK-MANAGEMENT DISCLOSURES

The following table provides a reconciliation of the risk-management data on the consolidated balance sheets, statements of operations and statements of cash flows:

	As of and for the Year Ended December 31, 2004 (in millions)
Balance Sheet Risk-Management Accounts	
Fair value of portfolio at January 1, 2004	$ (137)
Risk-management gains recognized through the income statement in the period, net	6
Cash paid related to risk-management contracts settled in the period, net	85
Changes in fair value as a result of a change in valuation technique (1)	
Non-cash adjustments and other (2)	(87)
Fair value of portfolio at December 31, 2004	$ (133)
Income Statement Reconciliation	
Risk-management gains recognized through the income statement in the period, net	$ 6
Physical business recognized through the income statement in the period, net (3)	(129)
Non-cash adjustments and other	13
Net recognized operating loss	$ (110)
Cash Flow Statement	
Cash paid related to risk-management contracts settled in the period, net	$ (85)
Estimated cash paid related to physical business settled in the period, net (3)	(129)
Timing and other, net (4)	54
Cash paid during the period	$ (160)
Risk-Management cash flow adjustment for the year ended December 31, 2004 (5)	$ (50)

(1) Our modeling methodology has been consistently applied.
(2) This amount primarily consists of changes in value associated with cash flow hedges on forward power sales.
(3) This amount includes capacity payments on our power tolling arrangements and the $115 million charge associated with our entry into a back-to-back power purchase agreement offset by the $88 million gain recognized by our exit from four gas transportation contracts.
(4) This amount consists primarily of cash received in connection with the settlement of cash flow hedges.
(5) This amount is calculated as Cash paid during the period less Net recognized operating loss.

The net risk management liability of $133 million is the aggregate of the following line items on the consolidated balance sheets: Current Assets Assets from risk-management activities, Other Assets Assets from risk-management activities, Current Liabilities Liabilities from risk-management activities and Other Liabilities Liabilities from risk-management activities.

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Risk-Management Asset and Liability Disclosures

The following table depicts the mark-to-market value and cash flow components, based on contract terms, of our net risk-management assets and liabilities at December 31, 2004. As opportunities arise to monetize positions that we believe will result in an economic benefit to us, we may receive or pay cash in periods other than those depicted below.

Net Risk-Management Asset and Liability Disclosures

	Total	2005	2006	2007	2008	2009	Thereafter
				(in millions)			
Mark-to-Market (1)	$ (96)	$ (7)	$ (8)	$ (48)	$ (21)	$ (10)	$ (2)
Cash Flow (2)	(99)	(5)	(7)	(51)	(23)	(12)	(1)

(1) Mark-to-market reflects the fair value of our risk-management asset position, which considers time value, credit, price and other reserves necessary to determine fair value. These amounts exclude the fair value associated with certain derivative instruments designated as hedges. The net risk-management liabilities at December 31, 2004 of $133 million on the consolidated balance sheets includes the $96 million herein as well as hedging instruments. Cash flows have been segregated between periods based on the delivery date required in the individual contracts.

(2) Cash Flow reflects undiscounted cash inflows and outflows by contract based on the tenor of individual contract position for the remaining periods. These anticipated undiscounted cash flows have not been adjusted for counterparty credit or other reserves. These amounts exclude the cash flows associated with certain derivative instruments designated as hedges.

The following table provides an assessment of net contract values by year as of December 31, 2004, based on our valuation methodology.

Net Fair Value of Risk-Management Portfolio

	Total	2005	2006	2007	2008	2009	Thereafter
				(in millions)			
Market Quotations (1)	$ (62)	$ (7)	$ (8)	$ (35)	$ (11)	$ (3)	$ 2
Prices Based on Models (2)	(34)			(13)	(10)	(7)	(4)
Total	$ (96)	$ (7)	$ (8)	$ (48)	$ (21)	$ (10)	$ (2)

(1) Prices obtained from actively traded, liquid markets for commodities other than natural gas positions. All natural gas positions for all periods are contained in this line based on available market quotations.

(2) See discussion of our use of long-term models in Critical Accounting Policies beginning on page 74.

Derivative Contracts

The absolute notional contract amounts associated with our commodity risk-management, interest rate and foreign currency exchange contracts are discussed in Item 7A. Quantitative and Qualitative Disclosures About Market Risk beginning on page 83.

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UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION

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 words of similar meaning. In particular, these include, but are not limited to, statements relating to the following:

- projected operating or financial results, including anticipated cash flows from operations;
- expectations regarding capital expenditures, interest expense and other payments;
- our ability to continue execution of the cost-savings measures we have identified;
- our beliefs and assumptions relating to our liquidity position, including our ability to satisfy or refinance our significant debt maturities and other obligations before or as they come due;
- our ability to access the capital markets as and when needed;
- our ability to address our substantial leverage;
- our ability to compete effectively for market share with industry participants;
- beliefs about the outcome of legal and administrative proceedings, including matters involving the western power and natural gas markets, shareholder claims and environmental and master netting agreement matters, as well as the investigations primarily relating to Project Alpha and our past trading practices;
- our ability to integrate the entities recently acquired in the Sithe Energies acquisition and their operations and to achieve our financial and operational goals associated with that acquisition; and
- our ability to complete our exit from the CRM business and the costs associated with this exit.

Any or all of our forward-looking statements may turn out to be wrong. They can be affected by inaccurate assumptions or by known or unknown risks, uncertainties and other factors including, among others:

the timing and extent of changes in weather and commodity prices, including the relationships between prices for power and natural gas or other power generating fuels, commonly referred to as the spark spread, and the frac spread;

the effects of competition in our asset-based business lines;

the effects of the Sithe Energies acquisition and the consolidation of the related project debt;

our ability to fund the environmental and emission control projects mandated by the Baldwin consent decree following its approval by the Illinois federal district court;

the condition of the capital markets generally, which will be affected by interest rates, foreign currency fluctuations and general economic conditions, and our ability to engage in capital-raising transactions;

our financial condition, including our ability to satisfy our significant debt maturities and debt service obligations;

our ability to realize our significant deferred tax assets, including loss carryforwards;

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- the effectiveness of our risk-management policies and procedures and the ability of our counterparties to satisfy their financial commitments;
- the liquidity and competitiveness of wholesale trading markets for energy commodities, particularly natural gas, electricity and natural gas liquids;
- operational factors affecting the start up or ongoing commercial operations of our power generation, natural gas and natural gas liquids facilities, including catastrophic weather-related damage, regulatory approvals, permit issues, unscheduled blackouts, outages or repairs, unanticipated changes in fuel costs or availability of fuel emission credits, the unavailability of gas transportation and the unavailability of electric transmission service or workforce issues;
- increased interest expense and restrictive covenants resulting from our non-investment grade credit rating;
- counterparties collateral demands and other factors affecting our liquidity position and financial condition;
- our ability to operate our businesses efficiently, manage capital expenditures and costs (including general and administrative expenses) tightly and generate earnings and cash flow from our asset-based businesses in relation to our substantial debt and other obligations;
- the direct or indirect effects on our business of any further downgrades in our credit ratings (or actions we may take in response to changing credit ratings criteria), including refusal by counterparties to enter into transactions with us and our inability to obtain credit or capital in amounts or on terms that are considered favorable;
- the costs and other effects of legal and administrative proceedings, settlements, investigations and claims, including legal proceedings related to the western power and natural gas markets, shareholder claims, claims arising out of our CRM business and environmental liabilities that may not be covered by indemnity or insurance, as well as the U.S. Attorney and other similar investigations primarily surrounding Project Alpha and our past trading practices;
- the effects of our efforts to improve our internal control structure, particularly with respect to the remediation of the deficiencies discussed under Item 9A Controls and Procedures;
- other North American regulatory or legislative developments that affect the demand and pricing for energy generally, that increase the environmental compliance cost for our facilities or that impose liabilities on the owners of such facilities; and
- general political conditions and developments in the United States and in foreign countries whose affairs affect our asset-based businesses including any extended period of war or conflict.

In addition, there may be other factors that could cause our actual results to be materially different from the results referenced in the forward-looking statements, some of which are included elsewhere in this Form 10-K. Many of these factors will be important in determining our actual future results. Consequently, no forward-looking statement can be guaranteed. Our actual future results may vary materially from those expressed or implied in any forward-looking statements.

All forward-looking statements contained in this Form 10-K are qualified in their entirety by this cautionary statement. Forward-looking statements speak only as of the date they are made, and we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this Form 10-K, except as otherwise required by applicable law.

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

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

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

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

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

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

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

The modeling of the risk characteristics of our mark-to-market portfolio involves a number of assumptions and approximations. We estimate VaR using a JP Morgan RiskMetrics approach assuming a one-day holding period. Inputs for the VaR calculation are prices, positions, instrument valuations and the variance-covariance matrix. While management believes that these assumptions and approximations are reasonable, there is no uniform industry methodology for estimating VaR, and different assumptions and/or approximations could produce materially different VaR estimates.

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

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

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

The following table sets forth the aggregate daily VaR of the mark-to-market portion of our risk-management portfolio primarily associated with the GEN and CRM segments.

Daily and Average VaR for Risk-Management Portfolio

	December 31, 2004	December 31, 2003
	(in millions)	
One Day VaR 95% Confidence Level	$ 5	$ 4
One Day VaR 99% Confidence Level	$ 7	$ 6
Average VaR for the Year-to-Date Period 95% Confidence Level	$ 4	$ 6

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

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

The following table represents our credit exposure at December 31, 2004 associated with the mark-to-market portion of our risk-management portfolio, on a net basis.

Credit Exposure Summary

	Investment Grade Quality	Non-Investment Grade Quality	Total
		(in millions)	
Type of Business:			
Financial Institutions	$ 146	$	$ 146

Commercial/Industrial/End Users	63	25	88
Utility and Power Generators	21		21
Oil and Gas Producers	4		4
Total	$ 234	$ 25	$ 259

Of the $25 million in credit exposure to non-investment grade counterparties, approximately 96% ($24 million) is collateralized or subject to other credit exposure protection.

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

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As of December 31, 2004, our fixed rate debt instruments as a percentage of total debt instruments was equal to 72%. Based on sensitivity analysis of the variable rate financial obligations in our debt portfolio as of December 31, 2004, it is estimated that a one percentage point interest rate movement in the average market interest rates (either higher or lower) over the 12 months ended December 31, 2005 would either decrease or increase income before taxes by approximately $15 million. Hedging instruments that impact such interest rate exposure are included in the sensitivity analysis. Over time, we may seek to reduce the percentage of fixed rate financial obligations in our debt portfolio through the use of swaps or other financial instruments.

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

At December 31, 2004, our primary foreign currency exchange rate exposures were the Canadian Dollar and European Euro. Additionally, as further discussed in Liquidity and Capital Resources Internal Liquidity Sources Current Liquidity beginning on page 48, at December 31, 2004, approximately $47 million cash denominated in the U.K. Pound, the Euro and the Canadian Dollar remains in the U.K. and Canada.

Derivative Contracts. The absolute notional financial contract amounts associated with our commodity risk-management and interest rate contracts were as follows at December 31, 2004 and December 31, 2003, respectively:

Absolute Notional Contract Amounts

	December 31, 2004	December 31, 2003
Natural Gas (Trillion Cubic Feet)	1.084	2.364
Electricity (Million Megawatt Hours)	11.652	8.713
Fair Value Hedge Interest Rate Swaps (In Millions of U.S. Dollars)	$ 525	$ 25
Fixed Interest Rate Received on Swaps (%)	4.331	5.706
Cash Flow Hedge Interest Rate Swaps (In Millions of U.S. Dollars)	$	$ 405
Fixed Interest Rate Paid on Swaps (%)		3.448
Interest Rate Risk-Management Contract (In Millions of U.S. Dollars)	$ 25	$ 306
Fixed Interest Rate Paid (%)	5.998	5.570

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

Our financial statements and financial statement schedules are set forth at pages F-1 through F-110 inclusive, found at the end of this annual report, and are incorporated herein by reference.

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

Not applicable.

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

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). This evaluation included consideration of the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in our SEC reports is recorded,

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processed, summarized and reported within the time periods specified by the SEC. This evaluation also considered the work completed relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002, which is further described below.

Based on this evaluation, our CEO and CFO concluded that, as of December 31, 2004, as a result of the material weakness discussed below, our disclosure controls and procedures were not effective to ensure that the information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the requisite time periods. Due to the material weakness discussed below, in preparing our financial statements at and for the year ended December 31, 2004, we performed additional procedures relating to the tax provision designed to ensure that such financial statements were fairly presented in all material respects in accordance with generally accepted accounting principles.

Management s Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our management, including the CEO and CFO, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2004. In making this assessment, we used the criteria set forth by COSO in *Internal Control Integrated Framework.*

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of our annual or interim financial statements would not be prevented or detected. As of December 31, 2004, we did not maintain effective control over the calculation of the tax provision and deferred income tax balances in accordance with generally accepted accounting principles. Specifically, our processes, procedures and controls related to the preparation and review of the quarterly and annual tax provisions were not adequate to ensure that the deferred tax provision and classification of deferred tax balances were prepared in accordance with generally accepted accounting principles. This control deficiency resulted in year-end audit adjustments to correct the income tax benefit recognized in 2004 and the related deferred income tax asset account. Also, adjustments were identified relating to prior periods affecting a deferred tax liability that was erroneously included in the fourth quarter 2003 impairment calculation of Illinois Power, resulting in the impairment and the deferred tax liability being misstated. Additionally, errors were discovered in our previously completed tax basis balance sheet review which misstated the deferred tax liability account at December 31, 2003 and the corresponding tax benefit for 2003, 2002 and periods prior to 2002. As a result, we restated our 2003 and 2002 annual financial statements and 2004 and 2003 interim financial statements in this 2004 Annual Report on Form 10-K. Further, this control deficiency could have resulted in a misstatement of the tax provision and deferred tax balances resulting in a material misstatement to the annual or interim consolidated financial statements that may not have been prevented or detected. Therefore, we have concluded that this control deficiency constitutes a material weakness.

Based on our assessment, management has concluded that, as of December 31, 2004, we did not maintain effective internal control over our financial reporting due to the material weakness in our tax accounting and tax reconciliation processes, procedures and controls, as further described above.

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public

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accounting firm, as stated in their report (which expressed an unqualified opinion on management s assessment and an adverse opinion on the effectiveness of our internal control over financial reporting as of December 31, 2004), which appears on page F-00.

Changes in Internal Controls. Other than as noted below, there were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of our internal controls performed during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Prior to the fourth quarter 2004, we identified deficiencies in our tax accounting and tax reconciliation processes, procedures and controls. Although we had processes, procedures and controls in place relating to the preparation and review of the quarterly and annual tax provisions, we subsequently determined that such processes, procedures and controls were not adequate to ensure that the deferred tax provision and classification of deferred tax balances were prepared in accordance with generally accepted accounting principles. As a result, we restated our 2003 and 2002 annual financial statements and 2004 and 2003 interim financial statements in this 2004 Annual Report on Form 10-K. We have taken the following steps to improve our internal controls around our tax accounting and tax reconciliation processes, procedures and controls:

- Increased the levels of review in the preparation of the quarterly and annual tax provision;
- Formalized processes, procedures and documentation standards relating to income tax provisions; and
- Restructured our Tax Department to ensure appropriate segregation of duties regarding preparation and review of the quarterly and annual tax provision.

We believe we have taken steps necessary to remediate this material weakness relating to taxes, although certain of the corrective processes, procedures and controls were not in place as of December 31, 2004. Additionally, other processes, procedures and controls were not in place for an adequate period of time to conclude that they were operating effectively as of December 31, 2004. Accordingly, we will continue to monitor the effectiveness of these processes, procedures and controls and will make any changes management determines appropriate

In addition, during the course of completing the work relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002, we identified deficiencies in our internal control over financial reporting, including matters relating to system access and system implementation controls, segregation of duties and documentation of controls and procedures and their effective operation and monitoring. While we do not consider these deficiencies material weaknesses, we believe they should be remediated. Among other things, we have taken, and are taking, the following actions:

- Improved controls related to logging and system access; and
- Improved controls related to balance sheet classifications.

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

Baldwin Consent Decree. Since November 1999, DMG has been the subject of an NOV from the EPA and a complaint filed by the EPA and the DOJ in federal district court alleging violations of the Clean Air Act and related federal and Illinois regulations related to certain maintenance, repair and replacement activities at our Baldwin generating station. We have reached agreement with the EPA, the DOJ, the State of Illinois and the environmental group intervenors on terms to settle the litigation. A consent decree was signed by all parties and lodged with the U.S. District Court for the Southern District of Illinois on March 7, 2005, and is subject to final approval of the Court following public comment. The consent decree requires us to (i) pay a $9 million civil penalty; (ii) fund several environmental projects in the additional aggregate amount of $15 million; and (iii) invest $321 million through 2010, and $224 million from 2011 through 2012, respectively, in emission control projects at our Baldwin, Vermilion and Havana plants. Please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings Baldwin Station Litigation beginning on page F-57 for further discussion of this lawsuit and consent decree.

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PART III

Item 10. *Directors and Executive Officers of the Registrant*

Executive Officers. The information required by this Item 10 with respect to our executive officers is set forth in Part I of this annual report under the caption Item 1A. Executive Officers beginning on page 30**,** which information is incorporated herein by this reference.

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

Other Information. The other information required by this Item 10 will be contained in our definitive proxy statement for our 2005 annual meeting of shareholders under the headings Proposal 1 Election of Directors and Executive Compensation Section 16(a) Beneficial Ownership Reporting Compliance and is incorporated herein by reference. The proxy statement will be filed with the SEC not later than 120 days after December 31, 2004.

Item 11. *Executive Compensation*

Information with respect to executive compensation will be contained in the upcoming proxy statement under the heading Executive Compensation and is incorporated herein by reference.

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

Information regarding ownership of our outstanding securities will be contained in the upcoming proxy statement under the heading Principal Shareholders and is incorporated herein by reference.

Item 13. *Certain Relationships and Related Transactions*

Information regarding related party transactions will be contained in the upcoming proxy statement under the headings Principal Stockholders, Proposal 1 Election of Directors and Executive Compensation Employment Agreements and Change-in-Control Agreements and Certain Relationships and Related Transactions and is incorporated herein by reference.

Item 14. ***Principal Accountant Fees and Services***

Information regarding principal accountant fees and services will be contained in the upcoming proxy statement under the heading Independent Auditors and is incorporated herein by reference.

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PART IV

Item 15. ***Exhibits, Financial Statement Schedules***

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

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

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

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

Exhibit Number	Description
2.1	Purchase Agreement dated February 2, 2004 among Dynegy Inc., Illinova Corporation, Illinova Generating Company and Ameren Corporation (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on February 4, 2004, File No. 1-15659).
3.1	Amended and Restated Articles of Incorporation of Dynegy Inc. (incorporated by reference to Appendix A to the Definitive Proxy Statement on Schedule 14A of Dynegy Inc., File No. 1-15659, filed with the SEC on April 25, 2001).
3.2	Statement of Resolution Establishing Series of Series C Convertible Preferred Stock of Dynegy Inc. (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
3.3	Amended and Restated Bylaws of Dynegy Inc. (incorporated by reference to Exhibit 3.3 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
4.1	Indenture, dated as of December 11, 1995, by and among NGC Corporation, the Subsidiary Guarantors named therein and the First National Bank of Chicago, as Trustee (incorporated by reference to exhibits to the Registration Statement on Form S-3 of NGC Corporation, Registration No. 33-97368).
4.2	First Supplemental Indenture, dated as of August 31, 1996, by and among NGC Corporation, the Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1996 of NGC Corporation, File No. 1-11156).
4.3	Second Supplemental Indenture, dated as of October 11, 1996, by and among NGC Corporation, the Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1996 of NGC Corporation, File No. 1-11156).
4.4	

Subordinated Debenture Indenture between NGC Corporation and The First National Bank of Chicago, as Debenture Trustee, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).

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Exhibit Number	Description
4.5	Amended and Restated Declaration of Trust among NGC Corporation, Wilmington Trust Company, as Property Trustee and Delaware Trustee, and the Administrative Trustees named therein, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.6 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.6	Series A Capital Securities Guarantee Agreement executed by NGC Corporation and The First National Bank of Chicago, as Guarantee Trustee, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.7	Common Securities Guarantee Agreement of NGC Corporation dated as of May 28, 1997 (incorporated by reference to Exhibit 4.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.8	Registration Rights Agreement, dated as of May 28, 1997, among NGC Corporation, NGC Corporation Capital Trust I, Lehman Brothers, Salomon Brothers Inc. and Smith Barney Inc. (incorporated by reference to Exhibit 4.11 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.9	Fourth Supplemental Indenture among NGC Corporation, Destec Energy, Inc. and The First National Bank of Chicago, as Trustee, dated as of June 30, 1997, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.12 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1997 of NGC Corporation, File No. 1-11156).
4.10	Fifth Supplemental Indenture among NGC Corporation, The Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, dated as of September 30, 1997, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.18 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1997 of NGC Corporation, File No. 1-11156).
4.11	Sixth Supplemental Indenture among NGC Corporation, The Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, dated as of January 5, 1998, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.19 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1997 of NGC Corporation, File No. 1-11156).
4.12	Seventh Supplemental Indenture among NGC Corporation, The Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, dated as of February 20, 1998, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.20 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1997 of NGC Corporation, File No. 1-11156).
4.13	Indenture, dated as of September 26, 1996, restated as of March 23, 1998, and amended and restated as of March 14, 2001, between Dynegy Holdings Inc. and Bank One Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2000 of Dynegy Holdings Inc., File No. 0-29311).
4.14	Exchange and Registration Rights Agreement (Preferred Stock) dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).

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Exhibit Number	Description
4.15	Amended and Restated Registration Rights Agreement (Common Stock) dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.16	Amended and Restated Shareholder Agreement dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.17	Indenture dated as of August 11, 2003 among Dynegy Holdings Inc., the guarantors named therein, Wilmington Trust Company, as trustee, and Wells Fargo Bank Minnesota, N.A., as collateral trustee, including the form of promissory note for each series of notes issuable pursuant to the Indenture (incorporated by reference to Exhibit 4.8 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.18	Indenture dated August 11, 2003 between Dynegy Inc., Dynegy Holdings Inc. and Wilmington Trust Company, as trustee, including the form of debenture issuable pursuant to the Indenture (incorporated by reference to Exhibit 4.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.19	Registration Rights Agreement dated August 11, 2003 among Dynegy Inc., Dynegy Holdings Inc. and the initial purchasers named therein (incorporated by reference to Exhibit 4.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.20	First Supplemental Indenture dated July 25, 2003 to that certain Indenture, dated as of September 26, 1996, between Dynegy Holdings Inc. and Wilmington Trust Company, as trustee (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on July 28, 2003, File No. 1-15659).
4.21	Eighth Supplemental Indenture dated July 25, 2003 that certain Indenture, dated as of December 11, 1995, between Dynegy Holdings Inc. and Wilmington Trust Company, as trustee (incorporated by reference to Exhibit 99.3 to the Current Report on Form 8-K of Dynegy Inc. filed on July 28, 2003, File No. 1-15659).
**4.22	Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and IBJ Schroder Bank & Trust Company, as Trustee.
**4.23	First Supplemental Indenture dated as of January 1, 1993 to the Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and IBJ Schroder Bank & Trust Company, as Trustee.
**4.24	Second Supplemental Indenture dated as of October 23, 2001 to the Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and The Bank of New York, as Trustee.
	There have not been filed or incorporated as exhibits to this annual report, other debt instruments defining the rights of holders of our long-term debt, none of which relates to authorized indebtedness that exceeds 10% of our consolidated assets. We hereby agree to furnish a copy of any such instrument not previously filed to the SEC upon request.
10.1	Dynegy Inc. Amended and Restated 1991 Stock Option Plan (incorporated by reference to Exhibit 10.3 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156).

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Exhibit Number	Description
10.2	Dynegy Inc. 1998 U.K. Stock Option Plan (incorporated by reference to Exhibit 10.4 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156).
10.3	Dynegy Inc. Amended and Restated Employee Equity Option Plan (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156).
10.4	Dynegy Inc. 1999 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156).
10.5	Dynegy Inc. 2000 Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156).
10.6	Dynegy Inc. 2001 Non-Executive Stock Incentive Plan (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080).
10.7	Dynegy Inc. 2002 Long Term Incentive Plan (incorporated by reference to Appendix A to the Definitive Proxy Statement on Schedule 14A of Dynegy Inc., File No. 1-15659, filed with the SEC on April 9, 2002).
10.8	Extant, Inc. Equity Compensation Plan (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-47422).
10.9	Employment Agreement, effective October 23, 2002, between Bruce A. Williamson and Dynegy Inc. (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2002 of Dynegy Inc., File No. 1-15659).
10.10	Employment Agreement, effective March 11, 2003, between Carol F. Graebner and Dynegy Inc. (incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
10.11	Contract for Consulting Services dated March 19, 2004 between Dynegy Inc. and Daniel L. Dienstbier (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2004 of Dynegy Inc., File No. 1-15659).
10.12	Dynegy Inc. Deferred Compensation Plan for Certain Directors (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2000 of Dynegy Inc., File No. 1-15659).
10.13	Dynegy Inc. 401(k) Savings Plan, as amended and restated effective January 1, 2002 (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 383-76570).
10.14	First Amendment to the Dynegy Inc. 401(k) Savings Plan, effective February 11, 2002 (incorporated by reference to Exhibit 10.19 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
10.15	Second Amendment to the Dynegy Inc. 401(k) Savings Plan, effective January 1, 2002 (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).

Exhibit Number	Description
10.16	Third Amendment to the Dynegy Inc. 401(k) Savings Plan, effective October 1, 2003 (incorporated by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
10.17	Amendment to the Dynegy Inc. 401(k) Savings Plan, effective January 1, 2004 (incorporated by reference to Exhibit 10.18 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
10.18	Dynegy Inc. 401(k) Savings Plan Trust Agreement (incorporated by reference to Exhibit 10.2 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76570).
10.19	Dynegy Inc. Deferred Compensation Plan (incorporated by reference to Exhibit 4.6 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080).
10.20	Dynegy Inc. Deferred Compensation Plan Trust Agreement (incorporated by reference to Exhibit 4.7 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080).
10.21	Dynegy Inc. Short-Term Executive Stock Purchase Loan Program (incorporated by reference to Exhibit 10.19 to the Annual Report on Form 10-K for the Year Ended December 31, 2001 of Dynegy Inc., File No. 1-15659).
10.22	Dynegy Inc. Deferred Compensation Plan for Certain Directors (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.23	Dynegy Inc. Executive Severance Pay Plan, as amended effective September 30, 2003 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2003 of Dynegy Inc., File No. 1-15659).
10.24	Second Supplement to the Dynegy Inc. Executive Severance Pay Plan (incorporated by reference to Exhibit 10.28 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
**10.25	First Amendment to The Dynegy Inc. Executive Severance Pay Plan effective May 19, 2004.
10.26	Dynegy Inc. Mid-Term Incentive Performance Award Program (incorporated by reference to Exhibit 10.29 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
10.27	Dynegy Northeast Generation, Inc. Savings Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-111985).
10.28	Amendment to the Dynegy Northeast Generation, Inc. Savings Incentive Plan, effective January 1, 2004 (incorporated by reference to Exhibit 10.31 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
10.29	Dynegy Inc. Severance Pay Plan, as amended effective September 30, 2003 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2003 of Dynegy Inc., File No. 1-15659).
10.30	Lease Agreement entered into on June 12, 1996 between Metropolitan Life Insurance Company and Metropolitan Tower Realty Company, Inc., as landlord, and NGC Corporation, as tenant (incorporated by reference to Exhibit 10.69 to the Registration Statement on Form S-4 of Midstream Combination Corp., Registration No. 333-09419).

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Exhibit Number	Description
10.31	First Amendment to Lease Agreement entered into on June 12, 1996 between Metropolitan Life Insurance Company and Metropolitan Tower Realty Company, Inc., as landlord, and NGC Corporation, as tenant (incorporated by reference to Exhibit 10.70 to the Registration Statement on Form S-4 of Midstream Combination Corp., Registration No. 333-09419).
*10.32	Master Natural Gas Liquids Purchase Agreement, dated as of September 1, 1996, between Warren Petroleum Company, Limited Partnership and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1996 of NGC Corporation, File No. 1-11156).
10.33	Amended and Restated Credit Agreement dated as of May 28, 2004 among Dynegy Holdings Inc., as Borrower, Dynegy Inc., as Parent Guarantor, the Other Guarantors Party Thereto, the Lenders Party Thereto and Various Other Parties Thereto (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 1, 2004, File No. 1-15659).
10.34	Shared Security Agreement, dated April 1, 2003, among Dynegy Holdings, Inc., various grantors named therein, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.32 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659).
10.35	Non-Shared Security Agreement, dated April 1, 2003, among Dynegy Inc., various grantors named therein and Bank One, N.A. as collateral agent (incorporated by reference to Exhibit 10.33 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659).
10.36	Collateral Trust and Intercreditor Agreement, dated as of April 1, 2003, among Dynegy Holdings Inc., various grantors named therein, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.34 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659).
10.37	Amendment No. 1 to Collateral Trust and Intercreditor Agreement, dated as of May 28, 2004, among Dynegy Holdings Inc., various grantors named therein, JPMorgan Chase Bank, as collateral agent, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2004 of Dynegy Inc., File No. 1-15659).
10.38	Series B Preferred Stock Exchange Agreement dated as of July 28, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.39	Indemnity Agreement dated August 11, 2003 among Dynegy Inc., Dynegy Holdings Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.40	Intercreditor Agreement dated August 11, 2003 among Dynegy Holdings Inc., various grantors named therein, Wilmington Trust Company, as corporate trustee, John M. Beeson, Jr., as individual trustee, Bank One, NA, as collateral agent, and Wells Fargo Bank Minnesota, N.A., as collateral trustee (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.41	Second Lien Shared Security Agreement dated August 11, 2003 among Dynegy Holdings Inc., various grantors named therein and Wells Fargo Bank Minnesota, N.A., as collateral trustee (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).

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Exhibit Number	Description
10.42	Second Lien Non-Shared Security Agreement dated August 11, 2003 among Dynegy Inc., various grantors named therein and Wells Fargo Bank Minnesota, N.A., as collateral trustee (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.43	Purchase Agreement dated August 1, 2003 among Dynegy Inc., Dynegy Holdings Inc. and the initial purchasers named therein (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.44	Purchase Agreement dated August 1, 2003 among Dynegy Holdings Inc., the guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.45	Purchase Agreement dated September 30, 2003 among Dynegy Holdings Inc., the guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 15, 2003, File No. 1-15659).
10.46	Power Purchase Agreement dated September 30, 2004 between Illinois Power Company and Dynegy Power Marketing, Inc. (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2004 of Dynegy Inc., File No. 1-15659).
10.47	Escrow Agreement dated as of September 30, 2004 among Illinova Corporation, Ameren Corporation and JPMorgan Chase Bank, as escrow agent (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2004 of Dynegy Inc., File No. 1-15659).
**10.48	Stock Purchase Agreement dated as of November 1, 2004 among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc.
**10.49	Amendment to Stock Purchase Agreement (Special Payroll Payment) dated as of January 28, 2005 among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc.
**10.50	Amendment to Stock Purchase Agreement dated as of January 31, 2005 among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc.
**10.51	Amendment to Stock Purchase Agreement (Luz Sale) dated as of January 31, 2005 among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc.
**10.52	Tenth Amendment to Amended and Restated Base Gas Sales Agreement, dated as of June 29, 2001, by and between Enron North America Corp. and Sithe/Independence Power Partners, L.P.
**10.53	Power Purchase Agreement dated as of November 17, 2004, between Dynegy Power Marketing, Inc., as seller, and Constellation Energy Commodities Group, Inc., as purchaser.
**10.54	Assignment and Assumption Agreement dated as of November 17, 2004 between Dynegy Power Marketing, Inc. and Constellation Energy Commodities Group, Inc.
14.1	Dynegy Inc. Code of Ethics for Senior Financial Professionals (incorporated by reference to Exhibit 14.1 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1- 15659).
**21.1	Subsidiaries of the Registrant.
**23.1	Consent of PricewaterhouseCoopers LLP.

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Exhibit Number	Description
**23.2	Consent of PricewaterhouseCoopers LLP (West Coast Power LLC).
**31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Exhibit omits certain information that we have filed separately with the SEC pursuant to a confidential treatment request pursuant to Rule 406 promulgated under the Securities Act of 1933, as amended.

** Filed herewith

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

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SIGNATURES

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

DYNEGY INC.

Date: March 11, 2005

By: /s/ BRUCE A. WILLIAMSON

Bruce A. Williamson

President, Chief Executive Officer and

Chairman of the Board

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

/s/ BRUCE A. WILLIAMSON **Bruce A. Williamson**	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	March 11, 2005
/s/ NICK J. CARUSO **Nick J. Caruso**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 11, 2005
/s/ TERRY A. HART **Terry A. Hart**	Senior Vice President and Controller (Principal Accounting Officer)	March 11, 2005
/s/ CHARLES E. BAYLESS **Charles E. Bayless**	Director	March 11, 2005
/s/ DAVID W. BIEGLER **David W. Biegler**	Director	March 11, 2005
/s/ LINDA W. BYNOE **Linda W. Bynoe**	Director	March 11, 2005
/s/ THOMAS D. CLARK, JR. **Thomas D. Clark, Jr.**	Director	March 11, 2005

/s/ Barry J. Galt **Barry J. Galt**	Director	March 11, 2005
/s/ Patricia A. Hammick **Patricia A. Hammick**	Director	March 11, 2005
/s/ George L. Mazanec **George L. Mazanec**	Director	March 11, 2005
/s/ Robert C. Oelkers **Robert C. Oelkers**	Director	March 11, 2005
/s/ Howard B. Sheppard **Howard B. Sheppard**	Director	March 11, 2005
/s/ Joe J. Stewart **Joe J. Stewart**	Director	March 11, 2005
/s/ William L. Trubeck **William L. Trubeck**	Director	March 11, 2005
/s/ Raymond I. Wilcox **Raymond I. Wilcox**	Director	March 11, 2005

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DYNEGY INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

* West Coast Power s consolidated financial statements are included herein pursuant to Rule 3-09 of Regulation S-X.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Dynegy Inc:

We have completed an integrated audit of Dynegy Inc. s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedules

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Dynegy Inc. and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the accompanying index present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedules are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 16, the Company is the subject of substantial litigation. The Company s ongoing liquidity, financial position and operating results may be adversely impacted by the nature, timing and amount of the resolution of such litigation. The consolidated financial statements do not include any adjustments, beyond existing accruals applicable under Statement of Financial Accounting Standards No. 5, Accounting for Contingencies, that might result from the ultimate resolution of such matters.

As discussed in the Explanatory Note beginning on page F-10, the 2003 and 2002 consolidated financial statements have been restated to reflect adjustments to the deferred income tax accounts and to increase the impairment associated with the sale of Illinois Power.

As discussed in Note 2, the Company adopted the provisions of Emerging Issues Task Force Issue No. 04-8, The Effect of Contingently Convertible Instruments on Diluted Earnings per Share, as of January 1, 2004. As discussed in Note 2, the Company adopted certain provisions of Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities - an interpretation of ARB 51 (revised December 2003), as of January 1, 2004 and other portions effective December 31, 2003. As discussed in Note 2, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, as of January 1, 2003. As discussed in Note 2, the Company adopted the provisions of Statement of Financial Accounting Standards No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, as of July 1, 2003. As discussed in Note 2, the Company adopted the net presentation provisions of Emerging Issues Task Force Issue No. 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities as of January 1, 2002 and the provision related to the rescission of Emerging Issues Task Force Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, as of January 1, 2003. As discussed in Note 2, the Company adopted Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation using the prospective method of transition prescribed by Statement of Financial Accounting Standards No. 148, Accounting for Stock-Based Compensation - Transition and Disclosure as of January 1, 2003.

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Internal control over financial reporting

Also, we have audited management s assessment, included in Management s Report on Internal Control over Financial Reporting appearing under Item 9A, that Dynegy Inc. did not maintain effective internal control over financial reporting as of December 31, 2004, because the Company did not maintain effective control over the accounting for income taxes including the determination of deferred income tax assets and liabilities and the related income tax provision, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weakness has been identified and included in management s assessment. As of December 31, 2004, the Company did not maintain effective control over the calculation of the tax provision and deferred income tax balances in accordance with generally accepted accounting principles. Specifically, the Company s processes, procedures and controls related to the preparation and review of the quarterly and annual tax provisions were not adequate to ensure that the deferred tax provision and classification of deferred tax balances were prepared in accordance with generally accepted accounting principles. This control deficiency resulted in year-end audit adjustments to correct the income tax benefit recognized in 2004 and the related deferred income tax asset account. Also, adjustments were identified relating to prior periods, affecting a deferred tax liability that was erroneously included in the fourth quarter 2003 impairment calculation of Illinois Power, resulting in the impairment and the deferred tax liability being misstated. Additionally, errors were discovered in the Company s previously completed tax basis balance sheet review which misstated the deferred tax liability account at December 31, 2003 and the corresponding tax benefit for 2003, 2002 and periods prior to 2002. As a result, the Company restated its 2003 and 2002 annual financial statements and 2004 and 2003

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interim financial statements in this Annual Report on Form 10-K. Further, this control deficiency could have resulted in a misstatement of the tax provision and deferred tax balances resulting in a material misstatement to the annual or interim consolidated financial statements that may not have been prevented or detected. Therefore, the Company concluded that this control deficiency constitutes a material weakness. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2004 consolidated financial statements, and our opinion regarding the effectiveness of the Company s internal control over financial reporting does not affect our opinion on those consolidated financial statements.

In our opinion, management s assessment that Dynegy Inc. did not maintain effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in Internal Control - Integrated Framework issued by the COSO. Also, in our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, Dynegy Inc. has not maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control - Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

Houston, Texas

March 11, 2005

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DYNEGY INC.

CONSOLIDATED BALANCE SHEETS

See Explanatory Note

(in millions, except share data)

	December 31, 2004	December 31, 2003
		(Restated)
ASSETS		
Current Assets		
Cash and cash equivalents	$ 628	$ 477
Restricted cash		19
Accounts receivable, net of allowance for doubtful accounts of $159 and $184, respectively	810	1,010
Accounts receivable, affiliates	14	25
Inventory	233	279
Assets from risk-management activities	565	803
Deferred income taxes	74	182
Prepayments and other current assets	428	291
Total Current Assets	2,752	3,086
Property, Plant and Equipment	7,822	9,867
Accumulated depreciation	(1,692)	(1,689)
Property, Plant and Equipment, Net	6,130	8,178
Other Assets		
Unconsolidated investments	421	612
Assets from risk-management activities	313	434
Goodwill	15	15
Deferred income taxes	12	13
Other long-term assets	209	472
Total Assets	$ 9,852	$ 12,810
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 561	$ 597
Accounts payable, affiliates	23	22
Accrued interest	118	127
Accrued liabilities and other current liabilities	450	550
Liabilities from risk-management activities	616	823
Notes payable and current portion of long-term debt	34	245
Current portion of long-term debt to affiliates		86
Total Current Liabilities	1,802	2,450
Long-term debt	4,132	5,124
Long-term debt to affiliates	200	769

Long-Term Debt	4,332	5,893
Other Liabilities		
Liabilities from risk-management activities	395	551
Deferred income taxes	597	755
Other long-term liabilities	353	743
Total Liabilities	7,479	10,392
Minority Interest	106	121
Commitments and Contingencies (Note 16)		
Redeemable Preferred Securities, redemption value of $400 and $411 at December 31, 2004 and December 31, 2003, respectively (Note 14)	400	411
Stockholders Equity		
Class A Common Stock, no par value, 900,000,000 shares authorized at December 31, 2004 and December 31, 2003; 285,012,203 and 280,350,169 shares issued and outstanding at December 31, 2004 and December 31, 2003, respectively	2,859	2,848
Class B Common Stock, no par value, 360,000,000 shares authorized at December 31, 2004 and December 31, 2003; 96,891,014 shares issued and outstanding at December 31, 2004 and December 31, 2003	1,006	1,006
Additional paid-in capital	41	41
Subscriptions receivable	(8)	(8)
Accumulated other comprehensive loss, net of tax	(13)	(20)
Accumulated deficit	(1,950)	(1,913)
Treasury stock, at cost, 1,679,183 shares at December 31, 2004 and December 31, 2003	(68)	(68)
Total Stockholders Equity	1,867	1,886
Total Liabilities and Stockholders Equity	$ 9,852	$ 12,810

See the notes to the consolidated financial statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

See Explanatory Note

(in millions, except per share data)

	Year Ended December 31,		
	2004	**2003**	**2002**
		(Restated)	**(Restated)**
Revenues	$ 6,153	$ 5,787	$ 5,326
Cost of sales, exclusive of depreciation shown separately below	(5,214)	(5,074)	(4,596)
Depreciation and amortization expense	(323)	(454)	(466)
Goodwill impairment		(311)	(814)
Impairment and other charges	(83)	(225)	(190)
Gain on sale of assets, net	11	29	7
General and administrative expenses	(352)	(346)	(325)
Operating income (loss)	192	(594)	(1,058)
Earnings (losses) from unconsolidated investments	202	124	(80)
Interest expense	(480)	(509)	(297)
Other income and expense, net	12	25	(59)
Minority interest income (expense)	(25)	3	(36)
Accumulated distributions associated with trust preferred securities		(8)	(12)
Loss from continuing operations before income taxes	(99)	(959)	(1,542)
Income tax benefit	89	246	343
Loss from continuing operations	(10)	(713)	(1,199)
Loss from discontinued operations, net of tax benefit (expense) of $(28), $9 and $349, respectively (Note 3)	(5)	(19)	(1,154)
Loss before cumulative effect of change in accounting principles	(15)	(732)	(2,353)
Cumulative effect of change in accounting principles, net of tax expense of zero, $24 and zero, respectively (Note 2)		40	(234)
Net loss	(15)	(692)	(2,587)
Less: preferred stock dividends (gain) (Note 12)	22	(1,013)	330
Net income (loss) applicable to common stockholders	$ (37)	$ 321	$ (2,917)
Earnings (Loss) Per Share (Note 15):			
Basic earnings (loss) per share:			
Earnings (loss) from continuing operations	$ (0.09)	$ 0.80	$ (4.18)
Loss from discontinued operations	(0.01)	(0.05)	(3.15)

Cumulative effect of change in accounting principles		0.11	(0.64)
Basic earnings (loss) per share	$ (0.10)	$ 0.86	$ (7.97)
Diluted earnings (loss) per share:			
Earnings (loss) from continuing operations	$ (0.09)	$ 0.73	$ (4.18)
Loss from discontinued operations	(0.01)	(0.04)	(3.15)
Cumulative effect of change in accounting principles		0.09	(0.64)
Diluted earnings (loss) per share	$ (0.10)	$ 0.78	$ (7.97)
Basic shares outstanding	378	374	366
Diluted shares outstanding	504	423	370

See the notes to the consolidated financial statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

See Explanatory Note

(in millions)

	Year Ended December 31,		
	2004	**2003**	**2002**
		(Restated)	**(Restated)**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (15)	$ (692)	$ (2,587)
Adjustments to reconcile net loss to net cash flows from operating activities:			
Depreciation and amortization	356	525	613
Goodwill impairment		311	814
Impairment and other charges	83	225	847
(Earnings) losses from unconsolidated investments, net of cash distributions	(66)	33	232
Risk-management activities	(50)	382	638
Gain (loss) on sale of assets, net	(11)	(57)	620
Deferred income taxes	(74)	(258)	(697)
Cumulative effect of change in accounting principles (Note 2)		(40)	234
Reserve for doubtful accounts		19	68
Liability associated with gas transportation contracts	(148)		
Other	64	(9)	87
Changes in working capital:			
Accounts receivable	4	1,683	421
Inventory	(43)	93	3
Prepayments and other assets	(107)	726	(762)
Accounts payable and accrued liabilities	(13)	(2,017)	(454)
Changes in non-current assets	(15)	(24)	19
Changes in non-current liabilities	40	(24)	(121)
Net cash provided by (used in) operating activities	5	876	(25)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(311)	(333)	(947)
Investments in unconsolidated affiliates		(5)	(14)
Business acquisitions, net of cash acquired	(3)		(20)
Proceeds from asset sales, net	576	72	1,583
Other investing, net			75
Net cash provided by (used in) investing activities	262	(266)	677
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from long-term borrowings	581	2,219	969
Net proceeds from short-term borrowings			181

Repayments of borrowings	(650)	(2,749)	(623)
Net cash flow from commercial paper and revolving lines of credit		(128)	(724)
Payment to ChevronTexaco for Series B preferred stock restructuring		(225)	
Proceeds from issuance of capital stock	5	6	240
Purchase of serial preferred securities of a subsidiary			(28)
Purchase of treasury stock			(1)
Dividends and other distributions, net	(22)		(55)
Decrease (increase) in restricted cash		(2)	11
Other financing, net	(29)	(21)	(14)
Net cash used in financing activities	(115)	(900)	(44)
Effect of exchange rate changes on cash	(1)	10	(59)
Net increase (decrease) in cash and cash equivalents	151	(280)	549
Cash and cash equivalents, beginning of period	477	757	208
Cash and cash equivalents, end of period	$ 628	$ 477	$ 757

See the notes to the consolidated financial statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

See Explanatory Note

(in millions)

	Common Stock	Additional Paid-In Capital	Subscriptions Receivable	Accumulated Other Comprehensive Loss	Retained Earnings (Accumulated Deficit)	Treasury Stock	Total
December 31, 2001 (Restated)	$ 3,587	$ 688	$ (38)	$ (27)	$ 728	$ (71)	$ 4,867
Net loss (Restated)					(2,587)		(2,587)
Other comprehensive loss, net of tax				(28)			(28)
Differential of Series A Preferred purchase		7					7
Common Stock issued	205						205
Subscriptions receivable			26				26
Options exercised	22						22
Dividends and other distributions					(375)		(375)
401(k) plan and profit sharing stock	17						17
Options granted		11					11
Treasury stock		(1)				3	2
December 31, 2002 (Restated)	$ 3,831	$ 705	$ (12)	$ (55)	$ (2,234)	$ (68)	$ 2,167
Net loss (Restated)					(692)		(692)
Other comprehensive income, net of tax				35			35
Series B Preferred Stock restructuring		(660)			1,224		564
Subscriptions receivable			4				4
Options exercised	15	(6)					9
Dividends and other distributions					(211)		(211)
401(k) plan and profit sharing stock	8						8
Options granted		2					2
December 31, 2003 (Restated)	$ 3,854	$ 41	$ (8)	$ (20)	$ (1,913)	$ (68)	$ 1,886
Net loss					(15)		(15)
Other comprehensive income, net of tax				7			7
Options exercised	5	(6)					(1)
Dividends and other distributions					(22)		(22)
401(k) plan and profit sharing stock	6						6
Options and restricted stock granted		6					6
December 31, 2004	$ 3,865	$ 41	$ (8)	$ (13)	$ (1,950)	$ (68)	$ 1,867

See the notes to the consolidated financial statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

See Explanatory Note

(in millions)

	Year Ended December 31,		
	2004	2003	2002
		(Restated)	(Restated)
Net loss	$ (15)	$ (692)	$ (2,587)
Cash flow hedging activities, net:			
Unrealized mark-to-market gains (losses) arising during period, net	(62)	39	73
Reclassification of mark-to-market (gains) losses to earnings, net	36	(37)	(73)
Changes in cash flow hedging activities, net (net of tax benefit (expense) of $16, $(1) and zero, respectively)	(26)	2	
Foreign currency translation adjustments	(11)	24	31
Minimum pension liability (net of tax benefit (expense) of $(26), $(5) and $38, respectively)	44	9	(66)
Unrealized gains on securities, net Reclassification adjustments for losses realized in net loss, net of tax expense of zero, zero and $3, respectively			7
Other comprehensive income (loss), net of tax	7	35	(28)
Comprehensive loss	$ (8)	$ (657)	$ (2,615)

See the notes to the consolidated financial statements.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Explanatory Note

This Annual Report on Form 10-K for the fiscal year ended December 31, 2004 includes restatements of our consolidated financial statements for each of the two years ended December 31, 2003 and, in the case of our deferred income tax accounts, restatements prior to 2002. The restatements relate to an increased impairment associated with the sale of Illinois Power and our deferred income tax accounts. Although neither of these items were considered material to the periods to which they related, these items, in aggregate, are material to our 2004 results. We are required to restate prior periods in accordance with APB 20, Accounting Changes. Quarterly information in this Explanatory Note is unaudited. Specifically, the restatements are as follows:

Impairment of Illinois Power. As more fully discussed in Note 10 Goodwill beginning on page F-41, during 2003, the value of goodwill associated with Illinois Power was determined to be impaired, resulting in our recognizing a charge of $311 million. Additionally, Illinois Power s other assets were determined to be impaired, resulting in our recognizing a pre-tax charge of $193 million. Recently, while preparing our year-end 2004 tax provision, we identified a deferred tax liability that we erroneously included in our fourth quarter 2003 impairment analysis of Illinois Power. Our inclusion of this liability understated the net book value of the assets and, as a result, understated the asset impairment that had been recorded in the fourth quarter 2003. We concluded that an additional pre-tax impairment charge of approximately $25 million ($16 million after-tax) should have been reflected in the fourth quarter 2003. The aggregate effect of this restatement on our net loss for the twelve months ended December 31, 2003, is an increase in net loss of $16 million ($0.04 per diluted share). This restatement had no impact on our net loss for the year ended December 31, 2004 or our previously reported cash provided by (used in) operating activities, investing activities or financing activities.

The table below reflects the quarterly and year-to-date impact of the additional impairment on our net loss as originally reported in Amendment No. 2 to our Annual Report of Form 10-K for the year ended December 31, 2003.

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
				(in millions)		
2003	$	$	$	$	$	$ (16)

Deferred Income Tax Accounts. In Amendment No. 1 to our third quarter 2004 Form 10-Q, we detailed the steps implemented to improve our internal controls around our tax accounting and tax reconciliation controls and processes. Recently, during the preparation of our financial statements for inclusion in this Form 10-K, and as a result of these additional internal controls, we determined that adjustments related to our deferred income tax accounts in periods prior to 2004 were required. These adjustments, which primarily related to errors in our previously completed tax basis balance sheet review, resulted in a $45 million increase of our deferred tax liability at December 31, 2003. The aggregate effect of this restatement on our net loss for the twelve months ended December 31, 2003 is an increase in net loss of $9 million ($0.02 per diluted share). This restatement had no impact on our net loss for the year ended December 31, 2004 or our previously reported cash provided by (used in) operating activities, investing activities or financing activities.

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The table below reflects the quarterly and year-to-date impact of the correction to our previous accounting for income taxes on net loss as originally reported in Amendment No. 2 to our Annual Report of Form 10-K for the year ended December 31, 2003.

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
				(in millions)		
2001 and prior						$ (27)
2002	$	$	$	$	$	(9)
2003						(9)

Summary. A synopsis of the aggregate financial impact of these restatements on the amounts originally reported in Amendment No. 2 to our Annual Report of Form 10-K for the year ended December 31, 2003 is as follows:

RESTATED SELECTED BALANCE SHEET DATA

	December 31, 2003
	(in millions)
Property, Plant and Equipment, Net	
As previously reported	$ 8,203
Impairment of Illinois Power	(25)
As restated	$ 8,178
Total Assets	
As previously reported	$ 12,961
Reclassifications (1)	(126)
Impairment of Illinois Power	(25)
As restated	$ 12,810
Deferred income taxes	
As previously reported	$ 524

Reclassifications (1)		195
Impairment of Illinois Power		(9)
Deferred income tax accounts		45
As restated	$	755
Total Liabilities		
As previously reported	$	10,482
Reclassifications (1)		(126)
Impairment of Illinois Power		(9)
Deferred income tax accounts		45
As restated	$	10,392
Stockholders Equity		
As previously reported	$	1,947
Impairment of Illinois Power		(16)
Deferred income tax accounts		(45)
As restated	$	1,886

(1) Adjustment to our balances for total assets, deferred income taxes and total liabilities relate to reclassifications of December 31, 2003 balance sheet amounts to conform to the December 31, 2004 balance sheet presentation.

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RESTATED SELECTED RESULTS OF OPERATIONS DATA

	Year Ended December 31,	
	2003	2002
	(in millions)	
Impairment and other charges		
As previously reported	$ (200)	$ (190)
Impairment of Illinois Power	(25)	
As restated	$ (225)	$ (190)
Income tax benefit		
As previously reported	$ 246	$ 352
Impairment of Illinois Power	9	
Deferred income tax accounts	(9)	(9)
As restated	$ 246	$ 343
Net loss		
As previously reported	$ (667)	$ (2,578)
Impairment of Illinois Power	(16)	
Deferred income tax accounts	(9)	(9)
As restated	$ (692)	$ (2,587)
Net income (loss) applicable to common shareholders		
As previously reported	$ 346	$ (2,908)
Impairment of Illinois Power	(16)	
Deferred income tax accounts	(9)	(9)
As restated	$ 321	$ (2,917)
Net income (loss) per diluted share		
As previously reported	$ 0.84	$ (7.95)
Impairment of Illinois Power	(0.04)	
Deferred income tax accounts	(0.02)	(0.02)
As restated	$ 0.78	$ (7.97)

Note 1 Organization and Operations of the Company

Dynegy Inc. (together with our subsidiaries, we , us or our) is a holding company and conducts substantially all of our business through our subsidiaries. We own operating divisions engaged in power generation and natural gas liquids, and formerly owned an operating division engaged in regulated energy delivery. We also separately report the results of our customer risk management business. We had four reportable business segments in 2004: GEN, NGL, REG and CRM. We reported our results in these four business segments based on the diversity of their respective operations. Please see a description of abbreviations used in these footnotes beginning on page F-86.

Note 2 Accounting Policies

Our accounting policies conform to GAAP. Our most significant accounting policies are described below. The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and judgments that affect our reported financial position and results of operations. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

record the effect of any necessary adjustments prior to their publication. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) developing fair value assumptions, including estimates of future cash flows and discount rates, (2) analyzing tangible and intangible assets for possible impairment, (3) estimating the useful lives of our assets, (4) assessing future tax exposure and the realization of tax assets, (5) determining amounts to accrue for contingencies, guarantees and indemnifications and (6) estimating various factors used to value our pension assets and liabilities. Actual results could differ materially from our estimates.

Principles of Consolidation. The accompanying consolidated financial statements include our accounts and the accounts of our majority-owned or controlled subsidiaries, variable interest entities for which we are the primary beneficiary and our proportionate share of assets, liabilities, revenues and expenses of undivided interests in certain gas processing facilities. Intercompany accounts and transactions have been eliminated. Certain reclassifications have been made to prior-period amounts to conform with current-period financial statement classifications.

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

Restricted Cash. Restricted cash represents cash that is not readily available for general purpose cash needs. Restricted cash at December 31, 2003 reflected amounts reserved for use in retiring Illinois Power s Transitional Funding Trust Notes.

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

Investment in Unconsolidated Affiliates. Investments in affiliates over which we exercise significant influence, generally occurring in ownership interests of 20% to 50%, and also occurring in lesser ownership percentages due to voting rights or other factors, are accounted for using the equity method. Our share of net income from these affiliates is reflected in the consolidated statements of operations as earnings (losses) from unconsolidated investments. Any excess of our investment in affiliates, as compared to our share of the underlying equity that is not recognized as goodwill, is amortized over the estimated economic service lives of the underlying assets. Other investments over which we may not exercise significant influence and that have readily determinable fair values are considered available-for-sale and are recorded at quoted market values or at the lower of cost or net realizable value, if there are no readily determinable fair values. For securities with readily determinable fair values, the change in the unrealized gain or loss, net of deferred income tax, is recorded as a separate component of accumulated other comprehensive loss in the consolidated statements of comprehensive loss. Realized gains and losses on investment transactions are determined using the specific identification method. All investments in unconsolidated affiliates are periodically assessed for other-than-temporary declines in value, with write-downs recognized in earnings (losses) from unconsolidated investments in the consolidated statements of operations.

Concentration of Credit Risk. We sell our energy products and services to customers in the electric and gas distribution industries and to entities engaged in industrial and petrochemical businesses. These industry concentrations have the potential to impact our overall exposure to credit risk, either positively or negatively, because the customer base may be similarly affected by changes in economic, industry, weather or other conditions.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2004, our credit exposure as it relates to the mark-to-market portion of our risk management portfolio totaled $259 million. To reduce our credit exposure, we execute agreements that permit us to offset receivables, payables and mark-to-market exposure. We attempt to further reduce credit risk with certain counterparties by obtaining third-party guarantees or collateral as well as the right of termination in the event of default.

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

We enter into master netting agreements both to mitigate credit exposure and to reduce collateral requirements. In general, the agreements include our risk management subsidiaries and allow the aggregation of credit exposure, margin and set-off. As a result, we decrease a potential credit loss arising from a counterparty default.

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

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

Asset Group	Range of Years
Power Generation Facilities	28 to 40
Natural Gas Gathering Systems and Processing Facilities	15 to 25
Fractionation, Terminalling and Natural Gas Liquids Storage Facilities	15 to 25
Transportation Equipment	5 to 10
Regulated Gas Assets	3 to 25
Buildings and Improvements	10 to 40
Office and Miscellaneous Equipment	3 to 35

Gains and losses are not recognized for retirements of property, plant and equipment subject to composite rates until the asset group subject to the composite rate is retired. Gains and losses on sales of individual assets are reflected in gain on sale of assets, net in the consolidated statements of operations. We assess the carrying value of our property, plant and equipment in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. If an impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the related discounted cash flows of the assets and recording a loss if the resulting estimated fair value is less than the book value. For assets identified as held for sale, the book value is compared to comparable market prices, or the estimated fair value if comparable market prices are not readily available, to determine if an impairment loss is required. Please see Note 4 Restructuring and Impairment Charges beginning on page F-30 for a discussion of impairment charges we recognized in 2004, 2003 and 2002.

Asset Retirement Obligations. We adopted SFAS No. 143, Asset Retirement Obligations, effective January 1, 2003. Under the provisions of SFAS No. 143, we are required to record legal obligations to retire tangible, long-lived assets on our balance sheet as liabilities, which are recorded at a discount when the liability is incurred. Significant judgment is involved in estimating future cash flows associated with such obligations, as well as the ultimate timing of the cash flows. If our estimates on the amount or timing of the cash flow change, the change may have a material impact on our results of operations.

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As part of the transition adjustment in adopting SFAS No. 143, existing environmental liabilities in the amount of $73 million were reversed in the first quarter 2003. The fair value of the remediation costs estimated to be incurred upon retirement of the respective assets is included in the ARO and was recorded upon adoption of SFAS No. 143. Since the previously accrued liabilities exceeded the fair value of the future retirement obligations, the impact of adopting SFAS No. 143 was an increase in earnings, net of tax, of $34 million in the first quarter 2003, which is included in cumulative effect of change in accounting principles in the consolidated statements of operations. In addition to these liabilities, we also have potential retirement obligations for dismantlement of power generation facilities, a fractionation facility and natural gas storage facilities. Our current intent is to maintain these facilities in a manner such that they will be operated indefinitely. As such, we cannot estimate any potential retirement obligations associated with these assets. Liabilities will be recorded in accordance with SFAS No. 143 at the time we are able to estimate any new AROs.

Our AROs relate to activities such as ash pond and landfill capping, closure and post-closure costs, environmental testing, remediation, monitoring and land and equipment lease obligations. Annual amortization of the assets associated with the AROs was $2 million and $7 million in 2004 and 2003, respectively. A summary of changes in our AROs by reportable segment is as follows:

	GEN	NGL	REG	Total
		(in millions)		
Balance at December 31, 2002	$ 26	$ 9	$ 6	$ 41
Accretion expense	4	1		5
Other (1)			(5)	(5)
Balance at December 31, 2003	30	10	1	41
Accretion expense	4	1		5
Other (2)	1		(1)	
Balance at December 31, 2004	$ 35	$ 11	$	$ 46

(1) During 2003, we changed the estimated timing of our estimated cash flows associated with our ARO liability in the REG segment due to delivery of notice of our intention to exercise our option to purchase the Tilton turbines, as further described at Note 11 Debt Tilton Capital Lease beginning on page F-46 and reduced the liability accordingly. There were no additional AROs recorded or settled, nor were there any revisions to estimated cash flows associated with existing AROs, during 2003.

(2) During 2004, a land lease, and the related ARO, formerly held by our REG segment was transferred to our GEN segment. In addition, AROs totaling less than $1 million were removed following our sales of Sherman and our interest in Indian Basin. There were no additional AROs recorded or settled, nor were there any revisions to estimated cash flows associated with existing AROs, during 2004.

The following pro forma financial information has been prepared to give effect to the adoption of SFAS No. 143 for the year ended December 31, 2002 as if it had been adopted January 1, 2002 (in millions, except per share amounts):

Loss from continuing operations, as reported	$ (1,199)
Pro forma adjustments to reflect retroactive adoption of SFAS No. 143	(6)
Pro forma loss from continuing operations	$ (1,205)
Loss before cumulative effect of change in accounting principles, as reported	$ (2,353)
Pro forma adjustments to reflect retroactive adoption of SFAS No. 143	(6)
Pro forma loss before cumulative effect of change in accounting principles	$ (2,359)
Net loss, as reported	$ (2,587)
Pro forma adjustments to reflect retroactive adoption of SFAS No. 143	(4)
Pro forma net loss	$ (2,591)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	As Reported	Pro Forma
Basic loss per share:		
Loss from continuing operations	$ (4.18)	$ (4.19)
Loss from discontinued operations	(3.15)	(3.15)
Cumulative effect of change in accounting principles, net	(0.64)	(0.64)
Basic loss per share	$ (7.97)	$ (7.98)

	As Reported	Pro Forma
Diluted loss per share:		
Loss from continuing operations	$ (4.18)	$ (4.19)
Loss from discontinued operations	(3.15)	(3.15)
Cumulative effect of change in accounting principles, net	(0.64)	(0.64)
Diluted loss per share	$ (7.97)	$ (7.98)

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

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

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

Goodwill and Other Intangible Assets. Goodwill represents, at the time of an acquisition, the amount of purchase price paid in excess of the fair value of net assets acquired. We follow the guidance set forth in SFAS

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No. 142, Goodwill and Other Intangible Assets, when assessing the carrying value of our goodwill. Accordingly, we evaluate our goodwill for impairment on an annual basis and when events warrant an assessment. Our evaluation is based, in part, on our estimate of future cash flows. The estimation of fair value is highly subjective, inherently imprecise and can change materially from period to period based on, among other things, an assessment of market conditions, projected cash flows and discount rate. We currently perform our annual impairment test in the fourth quarter after our annual budgetary process, and we may record further impairment losses in future periods as a result of such test. Please see Note 10 Goodwill beginning on page F-41 for discussion of impairment charges we recognized for 2003 and 2002.

Revenue Recognition. We utilize two comprehensive accounting models in reporting our consolidated financial position and results of operations as required by GAAP an accrual model and a fair value model. We determine the appropriate model for our operations based on guidance provided in applicable accounting standards and positions adopted by the FASB or the SEC. We have applied these accounting policies on a consistent basis during the three years in the period ended December 31, 2004, except as required by the adoption of EITF Issue 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, which rescinded EITF Issue 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities.

The accrual model has historically been used to account for substantially all of the operations conducted in our GEN, NGL and REG segments. These segments consist largely of the ownership and operation of physical assets that we use in various generation, processing and delivery operations. The business of these segments includes the generation of electricity, the separation of natural gas liquids into their component parts from a stream of natural gas and the transportation or transmission of commodities through pipelines or over transmission lines. End sales from these businesses result in physical delivery of commodities to our wholesale, commercial, industrial and retail customers. We recognize revenue from these transactions when the product or service is delivered to a customer.

The fair value model has historically been used to account for forward physical and financial transactions, occurring primarily in the CRM and GEN segments, which meet criteria defined by the FASB or the EITF. The criteria are complex, but generally require these contracts to relate to future periods, to contain fixed price and volume components and to have terms that require or permit net settlement of the contract in cash or the equivalent. The FASB determined that the fair value model is the most appropriate method for accounting for these types of contracts. In part, this conclusion is based on the cash settlement provisions in these agreements, as well as the volatility in commodity prices, interest rates and, if applicable, foreign exchange rates, which impact the valuation of these contracts. Since these transactions may be settled in cash or the equivalent, the value of the assets and liabilities associated with these transactions is reported at estimated settlement value based on current prices and rates as of each balance sheet date.

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

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

In 2002, the EITF reached consensuses on several issues pursuant to Issue 02-03. First, the EITF concluded that all mark-to-market gains and losses on energy trading contracts (whether realized or unrealized) should be shown net in the income statement, regardless of whether the contract is physically or financially settled. In the third quarter 2002, we began presenting all mark-to-market gains and losses on a net basis in the consolidated statements of operations to reflect this change in accounting principle.

In October 2002, as an additional component of EITF Issue 02-03, the EITF rescinded EITF Issue 98-10, which previously required use of mark-to-market accounting for our energy trading contracts. While the rescission of EITF Issue 98-10 reduced the number of contracts accounted for on a mark-to-market basis, it did not eliminate mark-to-market accounting. All derivative contracts that either do not qualify, or are not designated, as hedges or as normal purchases or sales, as defined by SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, continue to be marked-to-market in the consolidated statements of operations in accordance with SFAS No. 133. Any earnings or losses previously recognized under EITF Issue 98-10 that would not have been recognized under SFAS No. 133 were reversed in 2003 pursuant to adopting the provisions of EITF Issue 02-03. The cumulative effect of this change in accounting principle resulted in after-tax earnings of $21 million in 2003 and comprised the following items that are no longer required to be recorded using mark-to-market accounting (in millions):

Removal of net risk-management assets representing the value of natural gas storage contracts	$ (176)
Removal of other net risk-management assets	(24)
Removal of net risk-management liabilities representing the value of power tolling arrangements	103
Net change in risk-management assets and liabilities	(97)
Addition of inventory previously included in risk-management assets (1)	130
Pre-tax gain recorded from change in accounting principle	33
Income tax provision	(12)
After-tax gain recorded in the consolidated statements of operations.	$ 21

(1) All of the natural gas inventory was sold during 2003.

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

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

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

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

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

Please see Note 13 Income Taxes beginning on page F-49 for further discussion of our accounting for income taxes and any change in our valuation allowance.

Earnings Per Share. Basic earnings per share represents the amount of earnings for the period available to each share of common stock outstanding during the period. Diluted earnings per share represents the amount of earnings for the period available to each share of common stock outstanding during the period plus each share that would have been outstanding assuming the issuance of common shares for all potentially dilutive common shares outstanding during the period.

EITF Issue 04-8, The Effect of Contingently Convertible Instruments on Diluted Earnings per Share, became effective for all reporting periods ending after December 15, 2004. EITF Issue 04-8 requires virtually all dilutive financial instruments, including contingently convertible instruments, be included in the calculation of fully diluted earnings per share. For purposes of this issue, contingently convertible instruments are instruments that have embedded conversion features that contingently convert based on market price triggers settled based on specified market conditions. None of our convertible instruments meet such conditions, and as such, the adoption of EITF Issue 04-8 resulted in no additional inclusion of potentially dilutive shares in the calculation of diluted earnings per share and did not change our diluted earnings per share for any of the periods presented.

Foreign Currency. For subsidiaries whose functional currency is not the U.S. Dollar, assets and liabilities are translated at year-end rates of exchange and revenues and expenses are translated at monthly average exchange rates. Translation adjustments for the asset and liability accounts are included as a separate component of accumulated other comprehensive loss in stockholders equity. Currency transaction gains and losses are recorded in other income and expense, net on the consolidated statements of operations and totaled gains of approximately $1 million, $12 million and $4 million for the years ended December 31, 2004, 2003 and 2002, respectively.

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Employee Stock Options. In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure. SFAS No. 148 amends SFAS No. 123, Accounting for Stock-Based Compensation, and provides alternative methods of transition (prospective, modified prospective or retroactive) for entities that voluntarily change to the fair value-based method of accounting for stock-based employee compensation in a fiscal year beginning before December 16, 2003. SFAS No. 148 requires prominent disclosure about the effects on reported net income of an entity s accounting policy decisions with respect to stock-based employee compensation. We transitioned to a fair value-based method of accounting for stock-based compensation in the first quarter 2003 and are using the prospective method of transition as described under SFAS No. 148.

Under the prospective method of transition, all stock options granted after January 1, 2003 are accounted for on a fair value basis. Options granted prior to January 1, 2003 continue to be accounted for using the intrinsic value method. Accordingly, for options granted prior to January 1, 2003, compensation expense is not reflected for employee stock options unless they were granted at an exercise price lower than market value on the grant date. We have granted in-the-money options in the past and continue to recognize compensation expense over the applicable vesting periods. No in-the-money stock options have been granted since 1999.

Please see Note 18 Capital Stock beginning on page F-69 for discussion of stock options and expense recognized for 2004, 2003 and 2002.

Had compensation cost for all stock options granted prior to 2003 been determined on a fair value basis consistent with SFAS No. 123, our net loss and basic and diluted earnings (loss) per share amounts would have approximated the following pro forma amounts for the years ended December 31, 2004, 2003 and 2002, respectively.

	Years Ended December 31,		
	2004	2003	2002
	(in millions, except per share data)		
Net loss as reported	$ (15)	$ (692)	$ (2,587)
Add: Stock-based employee compensation expense included in reported net loss, net of related tax effects	4	2	8
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(27)	(53)	(84)
Pro forma net loss	$ (38)	$ (743)	$ (2,663)

Earnings (loss) per share:			
Basic as reported	$ (0.10)	$ 0.86	$ (7.97)
Basic pro forma	$ (0.16)	$ 0.72	$ (8.18)
Diluted as reported	$ (0.10)	$ 0.78	$ (7.97)
Diluted pro forma	$ (0.16)	$ 0.66	$ (8.18)

Regulatory Assets and Liabilities. SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, allows companies whose service obligations and prices are regulated to maintain balance sheet assets representing costs they expect to recover from customers through inclusion in future rates. At December 31, 2003, Illinois Power, our former regulated utility subsidiary, had recorded regulatory assets in accordance with SFAS No. 71 of approximately $207 million, which were included in other long-term assets on our consolidated balance sheets. The investment tax credit related to regulatory assets is amortized over the lives of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the respective assets which gave rise to the investment tax credit. Additionally, rate-regulated companies subject to SFAS No. 71 are permitted to accrue the estimated cost of removal and salvage associated with certain of their assets through depreciation expense. At December 31, 2003, approximately $72 million of cost of removal, net of salvage, was included in regulatory liabilities.

Minority Interest. Minority interest on the consolidated balance sheets includes third-party investments in entities that we consolidate, but do not wholly-own. The net pre-tax results attributed to minority interest holders in consolidated entities are included in minority interest income (expense) in the consolidated statements of operations.

Accounting Principles Adopted

SFAS No. 150. In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity, which establishes how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. Instruments that have an unconditional obligation requiring the issuer to redeem the instrument by transferring an asset at a specified date are required to be classified as liabilities on the balance sheet. Instruments that require the issuance of a variable number of equity shares by the issuer generally do not have the risks associated with equity instruments and as such should also be classified as liabilities on the balance sheet. SFAS No. 150 was effective for contracts in existence or created or modified for the first interim period beginning after June 15, 2003. Upon adoption, we reclassified approximately $200 million of Subordinated Debentures, previously recorded in the mezzanine section of our balance sheet between liabilities and stockholders equity, to long-term liabilities. Accordingly, the interest related to this instrument is recorded as interest expense beginning July 1, 2003. Prior year amounts have not been reclassified to conform to this change. Previously, the preferred return on this instrument was reported in accumulated distributions associated with trust preferred securities in the consolidated statements of operations. Further, the $400 million in Series C convertible preferred stock issued in August 2003 in connection with the Series B Exchange is classified within the mezzanine section of our consolidated balance sheets due to the $5.78 per share substantive conversion option, which renders the mandatory redemption feature contingent upon the holder not exercising its conversion option.

EITF Issue 04-8. EITF Issue 04-8 became effective for all reporting periods ending after December 15, 2004. For further discussion, please see Earnings Per Share beginning on page F-19.

FIN No. 46R. In January 2003, the FASB issued FIN No. 46, Consolidation of Variable Interest Entities An Interpretation of ARB No. 51. In December 2003, the FASB issued the updated and final interpretation FIN No. 46R. FIN No. 46R requires that an equity investor in a variable interest entity have significant equity at risk (generally a minimum of 10%, which is an increase from the 3% required under previous guidance) and hold a controlling interest, evidenced by voting rights, and absorb a majority of the entity s expected losses, receive a majority of the entity s expected returns, or both. If the equity investor is unable to evidence these characteristics, the entity that retains these ownership characteristics is required to consolidate the variable interest entity as the primary beneficiary. FIN No. 46R was applicable immediately to variable interest entities created or obtained after January 31, 2003. While we have not entered into any arrangements in 2004 or 2003 that would be subject to FIN No. 46R, entities previously formed are impacted. FIN No. 46R was effective on December 31, 2003 for interests in entities that were previously considered special purpose entities under then existing authoritative guidance. We recorded a cumulative effect of change in accounting principle of $15 million after-tax related to our adoption of this portion of FIN No. 46R, as further described below.

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CoGen Lyondell, Inc. (CLI) was the lessee of the CoGen Facility, a 610 MW gas-fueled combined-cycle co-generation plant that sells steam and electricity to the Lyondell Chemical Complex and sells electricity to the open wholesale market in ERCOT. Additionally, CoGen Lessor was a synthetic lease entity which leased the CoGen Facility to CLI. Both entities were previously considered special purpose entities and also met the definition of a VIE because their equity holders did not have a controlling interest or significant equity investment at risk in the entity. We were considered the primary beneficiary of both entities as we held a fixed-price purchase option on the assets of the entities during the lease term and maintained a residual value guarantee for 97% of the facility on CoGen Lessor. FIN No. 46R did not impact our accounting for CLI, as we have always consolidated CLI. Additionally, we began accounting for our lease with CoGen Lessor as a capital lease in June 2002, and, therefore, began consolidating the generation facility and the associated debt. If we had adopted this provision of FIN No. 46R on January 1, 2002, our income (loss) before cumulative effect of change in accounting principles would have decreased by zero and $1 million for the years ended December 31, 2003 and 2002, respectively. Our net income (loss) would have increased (decreased) by $15 million and $(1) million for the years ended December 31, 2003 and 2002, respectively. Our basic and diluted earnings (loss) per share would have increased by $0.04 and zero for the years ended December 31, 2003 and 2002, respectively. The $15 million cumulative effect noted above is primarily a result of recording additional accumulated depreciation on the facility from June 1997, the inception of the leasing arrangement, through June 2002. We retired the $170 million capital lease obligation with proceeds received from our October 2003 follow-on notes offering further described in Note 11 Debt DHI Second Priority Senior Secured Notes beginning on page F-44.

We adopted the remaining provisions of FIN No. 46R on March 31, 2004. These provisions require that we review the structure of non-SPE legal entities in which we have an investment and other legal entities with whom we transact to determine whether such entities are VIEs, as defined by FIN No. 46R. With respect to each of the VIEs we identified, we assessed whether we are the primary beneficiary, as defined by FIN No. 46R. We concluded that we were not the primary beneficiary of any of these entities and, therefore, the adoption did not have an impact on our consolidated financial statements.

FIN No. 46R requires additional disclosures for entities which meet the definition of a VIE in which we hold a significant variable interest but are not the primary beneficiary. We own 50% equity interests in various generation facilities in Illinois and California, which are accounted for using the equity method and are included in unconsolidated investments in our consolidated balance sheets. We acquired or began involvement with these equity interests in 1997 and 1999. Total net generating capacity for these generating facilities ranges from 165 MW to 902 MW. As a result of various contractual arrangements into which these entities have entered, we have concluded that they are VIEs. As we do not absorb a majority of the expected losses or receive a majority of the expected residual returns, we are not considered the primary beneficiary of these entities. Our equity investment balance in the facilities totaled $324 million at December 31, 2004, and one of these entities has a loan outstanding to another of these entities, which totaled $20 million at December 31, 2004.

In July 2001, we entered into several agreements, including a power tolling agreement, a financial derivative instrument, an energy management agreement and a natural gas supply agreement, with Sithe Independence Power Partners, L.P., which we refer to as Independence and which owns and operates a 1,021 MW combined cycle natural gas generation facility near Scriba, New York. We had previously been unable to assess whether the entity was a VIE, but have subsequently received the necessary financial and contractual information related to the entity. As a result of various contractual arrangements into which this entity has entered, we have concluded that it is a VIE. However, as we do not absorb a majority of the expected losses or receive a majority of expected residual returns, we are not considered the primary beneficiary of the entity. On January 31, 2005, we completed the acquisition of ExRes SHC, Inc., the parent company of Sithe Energies and Independence. Please see Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion regarding this acquisition.

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Accounting Principles Not Yet Adopted

SFAS No. 123(R). In December 2004, the FASB issued SFAS No. 123(R), Share-Based Payment, which revises SFAS No. 123. SFAS No. 123(R) is effective July 1, 2005 for all calendar year-end companies and requires companies to expense the fair value of employee stock options and other forms of stock-based compensation. This expense will be recognized over the period during which an employee is required to provide services in exchange for the award.

As noted in Employee Stock Options above, we transitioned to a fair value based method of accounting for stock-based compensation in the first quarter 2003. Our share-based payments primarily consist of stock options and restricted stock awards. For stock options, we determine the fair value of each stock option at the grant date using a Black-Scholes model. For restricted stock awards, we consider the fair value to be the closing price of the stock on the grant date. We recognize the fair value of our share based payments over the vesting periods of the awards, which is typically a three-year service period. Prior to the issuance of SFAS No. 123(R), we adopted the modified prospective approach for expensing the fair value of stock options and restricted stock awards granted after January 1, 2003, and as such we do not expect the guidance under SFAS 123(R) to have a material impact on our consolidated statement of operations.

Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations

Acquisitions

Sithe Energies. On January 31, 2005, we completed the acquisition of ExRes SHC, Inc., the parent company of Sithe Energies and Independence. In exchange for $135 million in cash, subject to certain specified purchase price adjustments, and the assumption of $919 million of face value project debt, we acquired the 1,021 MW Independence power generation facility located near Scriba, New York, as well as four natural gas-fired merchant facilities in New York and four hydroelectric generation facilities in Pennsylvania. We will not consolidate these four natural gas-fired facilities or four hydroelectric generation facilities, according to the provisions of FIN No. 46R. In addition to these power plants, Dynegy acquired a 750-MW firm capacity sales agreement with Con Edison, a subsidiary of Consolidated Edison, Inc. This agreement, which runs through 2014, will provide us with annual cash receipts of $100 million.

Independence holds a power tolling contract and a gas supply agreement with another of our subsidiaries. Upon completion of our purchase of Independence, these contracts were settled, which will result in a first quarter 2005 charge equal to their fair values, in accordance with EITF Issue 04-01, Accounting for Pre-existing Contractual Relationships Between the Parties to a Purchase Business Combination. We estimate a first quarter 2005 pre-tax charge not to exceed $220 million on a consolidated basis.

Dispositions and Contract Terminations

Sale of Illinois Power. On September 30, 2004, we sold all of the outstanding common and preferred shares of Illinois Power Company, which formerly comprised our REG segment, owned by Illinova Corporation, our subsidiary, as well as our 20% interest in the Joppa power generation facility, to Ameren for $2.3 billion. The $2.3 billion sale price consisted of Ameren s assumption of $1.8 billion of Illinois Power s debt and preferred stock obligations, cash proceeds of approximately $375 million and an additional $100 million of cash placed in escrow. At December 31, 2004, we reflected the balance held in escrow in Prepayments and other current assets on our consolidated balance sheet. Under the escrow agreement, which we filed as an exhibit to our third quarter 2004 Form 10-Q, the $100 million deposited by Ameren will be released to us on the sooner of (i) December 31, 2010, (ii) the date on which DHI s senior unsecured debt achieves an investment grade rating from Standard & Poor s or Moody s Investor Services, Inc. or (iii) the occurrence of specified events relating to contingent

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

environmental liabilities associated with Illinois Power s former generating facilities. Once approved by the Illinois federal district court, we believe that the Baldwin consent decree announced in March 2005 will satisfy the third condition and entitle us to receive the $100 million in escrowed funds. Please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings Baldwin Station Litigation beginning on page F-57 for further discussion of this consent decree. During the time that these funds remain in escrow, we will receive quarterly payments equivalent to the interest income earned on such funds.

Also on September 30, 2004, we entered into a new two-year power purchase agreement with Illinois Power. Under the terms of this new agreement, which became effective January 1, 2005, we have agreed to provide Illinois Power with up to 2,800 MWs of capacity at $48.00 per kW-yr and up to 11.5 million MWh of energy each year at a fixed price of $30 per MWh. We also agreed to sell 300 MWs of capacity in 2005 and 150 MWs of capacity in 2006 to Illinois Power at a fixed price of $16 per KW-yr with an option to purchase energy at market-based prices.

During the first quarter 2004, Illinois Power met the held for sale classification requirements of SFAS No. 144, and continued to meet the requirements through the closing of the sale on September 30, 2004. SFAS No. 144 requires that long-lived assets not be depreciated or amortized while they are classified as held for sale. As such, we discontinued depreciation and amortization of Illinois Power s property, plant and equipment and regulatory assets, effective February 1, 2004. Depreciation and amortization expense related to Illinois Power totaled $10 million, $121 million and $175 million in the years ended December 31, 2004, 2003 and 2002, respectively. In addition, SFAS No. 144 requires a loss to be recognized by the amount Assets held for sale less Liabilities held for sale are in excess of fair value less costs to sell. Accordingly, we recorded a pre-tax loss on the sale of $112 million in the year ended December 31, 2004. $58 million of the charge is reflected in gain on sale of assets, net and $54 million of the charge is reflected in impairment and other charges on our consolidated statements of operations.

Further, pursuant to SFAS No. 144, we are not reporting the results of Illinois Power s operations as a discontinued operation. If we were to account for Illinois Power as a discontinued operation, its results of operations would be condensed into loss from discontinued operations, net of taxes, on our consolidated statements of operations, and prior periods would be required to be restated to conform to this presentation. To qualify for discontinued operations classification, SFAS No. 144 and subsequent interpretations, specifically EITF Issue 03-13, Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations, require that the seller have no significant continuing involvement with the business being sold. As noted above, we have contracted to sell capacity and energy to Illinois Power for two years beginning in January 2005. Consequently, because we still have significant continuing involvement with Illinois Power, we will continue to include the historical results of Illinois Power s operations as part of our continuing operations. Additionally, power sales to Illinois Power occurring subsequent to the disposition will be reported in our consolidated statements of operations as third party sales. Approximately $109 million of revenues, derived from power sales to Illinois Power occurring subsequent to the disposition, are reflected in our continuing operations for the period ending December 31, 2004.

Had the results of Illinois Power been excluded from our comparative results as though the sale had occurred at the beginning of each respective period noted below, our revenues; loss before cumulative effect of changes in accounting principles, net of tax; net income (loss) applicable to common stockholders; and associated basic and diluted earnings (loss) per share would have approximated the following pro forma amounts for the years ended December 31, 2004, 2003 and 2002, respectively.

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	Years Ended December 31,		
	2004	2003	2002
	(in millions, except per share data)		
Revenues:			
As reported	$ 6,153	$ 5,787	$ 5,326
Pro forma	5,360	4,767	4,324
Loss before cumulative effect of change in accounting principles, net of tax:			
As reported	$ (15)	$ (732)	$ (2,353)
Pro forma	(32)	(478)	(2,387)
Net income (loss) applicable to common stockholders:			
As reported	$ (37)	$ 321	$ (2,917)
Pro forma	(54)	576	(2,951)
Earnings (loss) per share Income (loss) before cumulative effect of change in accounting principles, net of tax:			
Basic as reported	$ (0.10)	$ 0.75	$ (7.33)
Basic pro forma	$ (0.14)	$ 1.43	$ (7.42)
Diluted as reported	$ (0.10)	$ 0.69	$ (7.33)
Diluted pro forma	$ (0.14)	$ 1.29	$ (7.42)
Earnings (loss) per share Net income (loss) applicable to common stockholders:			
Basic as reported	$ (0.10)	$ 0.86	$ (7.97)
Basic pro forma	$ (0.14)	$ 1.54	$ (8.06)
Diluted as reported	$ (0.10)	$ 0.78	$ (7.97)
Diluted pro forma	$ (0.14)	$ 1.39	$ (8.06)

Joppa. We recorded a pre-tax gain of $75 million upon closing of the sale of our 20% interest in the Joppa power generating facility. This gain is included in earnings (losses) from unconsolidated investments on our consolidated statements of operations.

Sherman. In November 2004, we sold our Sherman natural gas processing facility located in Sherman, Texas. This sale resulted in a pre-tax gain of approximately $16 million. This gain is included in gain on sale of assets, net on our consolidated statements of operations.

Indian Basin. In April 2004, we sold our 16% interest in the Indian Basin Gas Processing Plant for approximately $48 million, and we recognized a pre-tax gain on the sale of approximately $36 million. This gain is included in gain on sale of assets, net on our consolidated statements of operations.

PESA. In April 2004, we sold our interest in the Plantas Eolicas, S.A. de R.L. 20 MW wind-powered electric generation facility located in Costa Rica for approximately $11 million. We recognized a pre-tax loss of approximately $1 million on the sale. This loss is included in gain on sale of assets, net on our consolidated statements of operations.

Kendall. On November 18, 2004, DPM entered into a back to back power purchase agreement with Constellation Energy Commodities Group, Inc., or Constellation, under which Constellation will effectively receive DPM s rights to purchase approximately 570 MW of capacity and energy arising under DPM s tolling contract with LSP-Kendall Energy, LLC for a four-year term from December 2004 through November 2008. DPM will remain the primary obligor to the Kendall tolling contract, but will receive offsetting payments from Constellation during the four-year term.

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In connection with this transaction, DPM paid to Constellation $117.5 million in cash and effectively eliminated approximately $161 million in our future fixed payment obligations under the Kendall tolling contract through November 2008. We recognized a pre-tax charge of approximately $115 million ($72 million after-tax) related to this transaction. The charge is included in cost of sales on the consolidated statements of operations.

Gas Transportation Contracts. In June 2004, we agreed to exit four long-term natural gas transportation contracts whose purpose was to secure firm pipeline capacity through 2014 in support of our former third-party marketing and trading business. In exchange for exiting these obligations, we paid $20 million in June 2004, $16 million in December 2004 and will pay an additional $26 million in the first quarter 2005. This future payment obligation was recorded at its fair value of $40 million and will be accreted to $42 million over the period July 1, 2004 through March 31, 2005. Additionally, we reversed an aggregate liability of $148 million associated with the transportation contracts that was originally established in 2001 and recognized a pre-tax gain of $88 million ($55 million after-tax) related to these transactions. This gain is included in revenues on our consolidated statements of operations and is included in the results of our CRM segment. This agreement eliminated our obligation to make approximately $295 million in aggregate fixed capacity payments from April 2005 through 2014.

Batesville Tolling Arrangement. In December 2003, we reached an agreement with Virginia Electric and Power Company, a subsidiary of Dominion Resources, to terminate a wholesale power tolling contract totaling approximately 110 MWs. Under the terms of the agreement, we paid Virginia Power $34 million to end the arrangement. As a result, we eliminated approximately $63 million in future capacity payments as well as collateral obligations of $12.5 million. We recognized a pre-tax loss of approximately $34 million ($22 million after-tax) in connection with this agreement.

Kroger Company Settlement. In July 2003, we reached a settlement with Kroger related to four power supply contracts. Under the terms of the settlement agreement, which was approved by the FERC, Kroger paid us approximately $110 million to terminate two of the four power contracts and to restructure at current market prices the remaining two contracts through which we provide electricity to Kroger subsidiary stores in California. We also resolved an outstanding FERC dispute related to contract pricing as part of the settlement.

The four contracts were derivatives under SFAS No. 133 and were carried at their fair value on the consolidated balance sheets, with changes in fair value recognized in earnings. Our net risk management asset related to these contracts was approximately $140 million at June 30, 2003. Therefore, the $30 million difference between the settlement of $110 million and the carrying value of the net risk management asset was recorded as a pre-tax charge ($19 million after-tax). The two restructured contracts were carried at fair value with changes in fair value recognized in earnings through August 2003, when such contracts were terminated.

Southern Power Tolling Arrangements. In the second quarter 2003, we reached an agreement with Southern Power to terminate three power tolling arrangements among Dynegy, Southern Power and our respective affiliates covering an aggregate of 1,100 MWs. Under the terms of the agreement, we paid Southern Power $155 million to terminate these arrangements. The terminations resulted in $89 million of net collateral being returned to us and eliminated our obligation to make $1.7 billion of capacity payments to Southern Power over the next 30 years. The transaction closed in May 2003, and we recognized a pre-tax loss of approximately $133 million ($84 million after-tax).

Hackberry LNG Project. During the first quarter 2003, we entered into an agreement to sell our interest in Hackberry LNG Terminal LLC, the entity we formed in connection with our proposed LNG terminal/gasification project in Hackberry, Louisiana, to Sempra LNG Corp., a subsidiary of San Diego-based Sempra Energy. The

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transaction closed in April 2003. At closing, we received an initial payment of $20 million and recognized a pre-tax gain of approximately $12 million ($8 million after-tax). We retained the right to receive additional contingent payments based upon project development milestones. In October 2003, we received a $15 million payment associated with the completion of a project milestone and recognized a pre-tax gain of $15 million ($9 million after-tax). In March 2004, we sold our remaining financial interest in this project, which interest included rights to receive future contingent payments under the 2003 agreement, for $17 million and recognized a pre-tax gain of $17 million. These gains are included in gain on sale of assets, net on our consolidated statements of operations.

SouthStar Energy Services. During the first quarter 2003, we completed the sale of our 20% equity investment in SouthStar Energy Services LLC. We received approximately $20 million cash and recognized a pre-tax gain of approximately $1 million ($1 million after-tax). The gain is included in gain on sale of assets, net on our consolidated statements of operations.

Canadian Assets. In August and November 2002, we sold significant portions of our Canadian crude oil and natural gas marketing businesses to Seminole. The pre-tax loss on these sales was approximately $7 million.

Discontinued Operations

During 2002, we sold our ownership interests in Northern Natural, our U.K. natural gas storage business and our global liquids business. In addition, as part of our restructuring plan, we sold or liquidated additional portions of our operations during 2003, including our communications business and our U.K. CRM business, which have been accounted for as discontinued operations under SFAS No. 144, as further described below.

Northern Natural. In November 2001, we acquired 1,000 shares of Northern Natural Series A Preferred Stock for $1.5 billion. DHI concurrently acquired an option to purchase all of the equity of Northern Natural s indirect parent company. DHI exercised its option in November 2001 upon termination of a merger agreement with Enron, and closing of the option exercise occurred on January 31, 2002.

Consideration paid for the 2002 business acquisition of Northern Natural was as follows (in millions):

Cash purchase of stock	$ 1,565
Liabilities assumed	1,070
Total consideration	$ 2,635

On August 16, 2002, we sold Northern Natural to MidAmerican for $879 million in cash, net of working capital adjustments. Under the terms of this agreement, MidAmerican acquired all of the common and preferred stock of Northern Natural and assumed all of Northern Natural s $950 million of debt. We incurred a pre-tax loss in 2002 of $599 million ($561 million after-tax) associated with the sale, including adjustments for changes in working capital. Northern Natural s results of operations are included as a discontinued operation in our consolidated statements of operations, as part of our REG segment.

For federal income tax purposes, the sale resulted in a capital loss, which may be deducted solely against capital gains, if any, realized by us in our consolidated federal tax returns. There is a three-year carryback and a five-year carryforward for capital losses under existing federal statutes. For financial reporting purposes, we recorded a valuation allowance against a portion of the potential tax benefit because of uncertainty about our ability to generate future capital gains. Please see Note 13 Income Taxes beginning on page F-49 for further information about our capital loss carryforwards and related valuation allowance.

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Pursuant to the sale agreement, we are obligated to indemnify MidAmerican against any breaches of our representations and warranties contained therein. This indemnification obligation, which is capped at approximately $209 million, includes any potential tax liabilities we might have assumed when we acquired Northern Natural from the Enron consolidated group.

On September 30, 2002, DHI sold $90 million in Northern Natural 6.875% senior notes due May 2005 for approximately $96 million, including accrued interest of $2 million. DHI acquired the notes at par value in April 2002 pursuant to a tender offer that it agreed to effect in order to obtain a bondholder consent in connection with the acquisition of Northern Natural. The gain on sale of approximately $4 million is reflected in other income and expense, net on the accompanying 2002 consolidated statements of operations and is net of accrued interest.

U.K. Storage. On September 30, 2002, we sold a subsidiary that owned the Hornsea facility for net cash proceeds of approximately $189 million. There was no gain or loss recognized on this sale. On November 14, 2002, we sold the subsidiaries that owned the Rough offshore natural gas field and the Easington natural gas processing terminal for cash proceeds of approximately $500 million. We recognized a pre-tax gain on the sale of Rough of approximately $30 million ($5 million after-tax) in 2002.

Global Liquids. With our decision to exit the international LPG trading and transportation business, we sold our global liquids business in December 2002, which was included in our NGL segment, to Trammo Gas International Inc., a wholly owned subsidiary of Transammonia Inc. We did not receive any cash consideration at close. We have the right to receive contingent payments in the future, which are capped at $8 million. We recorded pre-tax write-downs and accruals totaling $27 million associated with this transaction in 2002, which is reflected in discontinued operations in the NGL segment.

Approximately $12 million of the $27 million charge noted above was our investment in EIOL. We had a 37.5% ownership interest in EIOL valued at $12 million that we accounted for using the equity method. We wrote down our investment in the EIOL project to zero at December 31, 2002 due to our expectation that we would receive no value or cash flows for our current investment in the project, and our exit from the EIOL project was completed in 2003. The remaining 2002 charges associated with this disposition included the write-off of a logistics and accounting computer system not acquired by the purchaser and other related restructuring costs.

Global Communications. In September 2000, we completed the acquisition of Extant, a privately held communications company. Our net investment consisted of $92 million in cash and 1.8 million shares of our Class A common stock. Following the transaction, we established DGC, a new segment that also owned 80% of a limited partnership called DynegyConnect, L.P., to conduct many of the activities previously conducted by Extant. In March 2003, we agreed to acquire the remaining 20% of DynegyConnect, L.P. effective September 19, 2001 in exchange for $45 million cash and settlement of a lawsuit. Additionally, in the first quarter 2001, we finalized the acquisition of iaxis, a European communications business, and created Dynegy Europe Communications.

DGC executed an agreement to sell a portion of its ownership in an entity that owns a Beijing communications data center. DGC retained a 20% ownership interest, which will be accounted for using the cost method. The sale of the Asian investments resulted in a $2 million pre-tax gain ($3 million after-tax) in the fourth quarter 2002, net of the impact of assets impaired in the second quarter 2002. In February 2005, we sold our remaining interest. We did not recognize a gain or loss on the sale.

During January 2003, we disposed of Dynegy Europe Communications to an affiliate of Klesch & Company, a London-based private equity firm. We recognized an after-tax gain on the sale of approximately $19 million in the first quarter 2003.

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During May 2003, we disposed of our U.S. communications network held by DynegyConnect, L.P. to an affiliate of 360networks Corporation. During the second quarter 2003, we recognized an after-tax gain on the sale of approximately $2 million. Approximately $12 million of undiscounted obligations with respect to this business remain following these sales.

U.K. CRM. We substantially completed our exit from the U.K. CRM business during the first quarter 2003. For the year ended December 31, 2003, we recognized an after-tax loss of $21 million, primarily as a result of selling and terminating all of our U.K. gas and power positions, as well as administrative expenses, depreciation and amortization, shut-down costs and currency translation losses. Collateral postings totaling $98 million were eliminated with the selling/terminations of these positions. We do not expect the U.K. CRM business to have a material impact on our future results.

The following table summarizes information related to our discontinued operations:

	Northern Natural	U.K. Storage	U.K. CRM	Global Liquids	DGC	Total
			(in millions)			
2004						
Income (loss) from operations before taxes (1)			19	1	3	23
Income (loss) from operations after taxes			(7)		2	(5)
2003						
Revenue	$	$	$ 21	$	$ 5	$ 26
Loss from operations before taxes			(31)	(2)	(26)	(59)
Loss from operations after taxes			(21)	(2)	(21)	(44)
Gain (loss) on sale before taxes	(3)	1			33	31
Gain (loss) on sale after taxes	(2)	1			26	25
2002						
Revenue	$ 201	$ 140	$ 16	$ 784	$ 22	$ 1,163
Income (loss) from operations before taxes (2)	38	34	(115)	(22)	(856)	(921)
Income (loss) from operations after taxes	23	23	(77)	(19)	(541)	(591)
Gain (loss) on sale before taxes	(599)	30		(15)	2	(582)
Gain (loss) on sale after taxes	(561)	5		(10)	3	(563)

(1) In the first quarter 2004, we recognized $17 million of pre-tax income related to translation gains on foreign currency in the U.K. Please see Note 5 Risk Management Activities and Financial Instruments Accounting for Derivative Instruments and Hedging Activities Net investment hedges in foreign operations beginning on page F-34 for further discussion. Also in the first quarter 2004, we recognized $3 million of pre-tax income associated with DGC s receipt of $3 million from a third party in settlement of a prior contractual claim. In the second quarter 2004, we recognized a tax expense of $20 million related to charges resulting from the conclusion of prior year tax audits. Please see Note 13 Income Taxes beginning on page F-49 for further discussion.

(2)

During the second quarter 2002, we reviewed DGC s long-lived assets for impairment in accordance with SFAS No. 144 and determined that future cash flows from DGC s operations were insufficient to recover the carrying value of its long-lived assets. As a result, a pre-tax impairment charge of $611 million was recorded in impairment and other charges and subsequently reclassified to discontinued operations. In addition, during the first quarter 2002 and third quarter 2002, $20 million and $4 million, respectively, of impairment charges were recorded for our discontinued communications business.

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Note 4 Restructuring and Impairment Charges

Prior period amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page F-10.

In 2004, we recorded charges relating to our sale of Illinois Power totaling $112 million. For further discussion, please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23. In addition, during 2004, we recorded a $5 million pre-tax charge related to the impairment of one of our NGL assets. Also during 2004, we recorded $85 million in pre-tax impairments of our investment in West Coast Power. For further discussion please see Note 9 Unconsolidated Investments GEN Investments beginning on page F-38.

In 2003, we recorded a goodwill impairment totaling $311 million and a pre-tax asset impairment totaling $218 million relating to our interest in Illinois Power. For further discussion, please see Note 10 Goodwill beginning on page F-41. In addition, during 2003, we recorded a $26 million pre-tax charge related to the impairment of some of our generation investments. For further discussion, please see Note 9 Unconsolidated Investments GEN Investments beginning on page F-38. Also, during 2003, we recorded a $12 million pre-tax charge related to the impairment of our investment in GCF. For further discussion, please see Note 9 Unconsolidated Investments NGL Investments beginning on page F-39.

In 2002, we recorded a goodwill impairment relating to our GEN and CRM segments totaling $814 million. For further discussion, please see Note 10 Goodwill beginning on page F-41.

In 2002, we recorded pre-tax restructuring and impairment charges of $1,129 million relating to various aspects of our operations. The table below provides the amounts of these charges by business area and the caption in which they are included in our consolidated statements of operations:

	Depreciation and Amortization Expense	Impairment and Other Charges	(Earnings) Losses from Unconsolidated Investments	Other	Discontinued Operations	Total Charge
			(in millions)			
Impairment of communications business	$	$	$	$	$ 635	$ 635
Severance and other restructuring costs	17	140		20	42	219
Impairment of generation investments			144			144
Impairment of technology investments			31		49	80

Impairment of other obsolete assets		50			1	51
	$ 17	$ 190	$ 175	$ 20	$ 727	$ 1,129

Impairment of Communications Business. During 2002, prospects for the communications sector continued to deteriorate as evidenced by an increased number of bankruptcies in the sector, continued devaluation of debt and equity securities, a lack of financing sources and further pricing pressures resulting from challenges faced by major industry participants. As a result of this deterioration, a continuing negative outlook for the industry and our desire to improve our liquidity, we began to take measures to reduce cash losses in the business, including reducing capital spending and lowering operating and administrative expenses.

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Our impairment analysis of our communications business, calculated in accordance with the guidelines set forth in SFAS No. 144, indicated future cash flows from DGC s operations were insufficient to recover the carrying value of its long-lived assets. As a result, impairments totaling $306 million ($199 million after-tax) were recorded. As all of these charges relate to our global communications business, they are reported in discontinued operations. In addition, assets related to communications leases were determined to be impaired, resulting in an additional impairment of $329 million ($214 million after-tax), which is also reported in discontinued operations.

Severance and Other Restructuring Costs. In the second quarter 2002, we recognized a $37 million pre-tax ($24 million after-tax) charge for severance benefits from a work force reduction that affected approximately 325 employees. In addition, in October 2002, we announced a restructuring plan designed to improve operational efficiencies and performance across our lines of business. As part of this restructuring, which included a further work force reduction of approximately 780 employees, we recognized a pre-tax charge of $182 million ($118 million after-tax) during the fourth quarter 2002. The total charge of $219 million ($142 million after-tax) is detailed below (in millions):

Cancellation fees and operating leases	$ 61
Severance	115
Asset impairments	15
Change in estimated useful lives of assets	28
	$ 219

In accordance with EITF Issue 94-3, we recognized $61 million in charges ($40 million after-tax) during 2002 associated with cancellation fees and accruals for the termination of operating leases. These accruals are not discounted.

In addition, we recognized charges of $115 million ($75 million after-tax) during 2002 for severance benefits for approximately 1,100 employees of various segments and all staffing levels, including our former chief executive officer, former president and former chief financial officer.

Following is a schedule of 2004, 2003 and 2002 activity for the liabilities recorded associated with the cancellation fees, operating leases and severance:

	Severance	Cancellation Fees and Operating Leases	Total

		(in millions)	
Balance at December 31, 2001	$	$	$
2002 charge	115	61	176
2002 cash payments	(44)		(44)
Balance at December 31, 2002	$ 71	$ 61	$ 132
2003 adjustments to liability	(8)	4	(4)
2003 cash payments	(40)	(35)	(75)
Balance at December 31, 2003	$ 23	$ 30	$ 53
2004 adjustments to liability	18	7	25
2004 cash payments	(38)	(12)	(50)
Balance at December 31, 2004	$ 3	$ 25	$ 28

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During 2003, the adjustment to the accrued liability primarily reflects reductions in the severance accrual for employees who will now be retained, as well as for employees of our foreign operations. In addition, we adjusted the liability for operating leases for revised estimates of potential income from subleasing the leased facilities.

During 2004, the adjustment to the accrued liability primarily reflects increases in the severance accrual due to changes in our estimate of the probable loss associated with the severance claims of our former chief executive officer and our former president. Cash payments during 2004 reflect payments made to our former chief executive officer and our former president. Please see Note 16 Commitments and Contingencies Summary of Material Legal Proceedings Severance Arbitrations beginning on page F-61 for further discussion regarding the status of these claims and settlement payments.

We expect the $25 million accrual as of December 31, 2004 associated with cancellation fees and operating leases to be paid by the end of 2007 when the leases expire.

Impairment losses of $15 million ($10 million after-tax) were also incurred in accordance with SFAS No. 144 as a result of the corporate restructuring plan for certain technology assets no longer being utilized. The remaining $28 million ($18 million after-tax) of the charge represents accelerated depreciation due to a change in the estimated useful life for leasehold improvements and technology assets related to the abandonment of those assets. This charge was included in depreciation and amortization expense, and $11 million was subsequently reclassified to discontinued operations.

Impairment of Generation Investments. In conjunction with our review of the carrying value of goodwill in the third quarter 2002 (see Note 10 Goodwill beginning on page F-41 for further discussion), we assessed the carrying value of our generation portfolio on an asset-by-asset basis. The generation portfolio includes wholly-owned generating facilities, which are reflected in property, plant and equipment, as well as investments in partnerships and limited liability companies that own generating facilities, which are reflected in unconsolidated investments. Based on this review, the carrying value associated with the wholly-owned generation facilities was considered realizable. However, some unconsolidated investments were considered impaired, resulting in a pre-tax charge of $144 million, which is reflected in earnings (losses) from unconsolidated investments on the consolidated statements of operations. The diminution in the fair value of these investments was primarily a result of depressed energy prices.

Impairment of Technology Investments. During the second quarter 2002, we recognized an impairment charge associated with certain technology investments. The $23 million pre-tax ($15 million after-tax) charge was recorded in earnings (losses) from unconsolidated investments, and $4 million of the charge ($3 million after-tax) was subsequently reclassified to discontinued operations. This is in addition to the first quarter 2002 pre-tax charge of $45 million ($30 million after-tax) resulting from unfavorable market conditions, which was recorded in earnings (losses) from unconsolidated investments and subsequently reclassified to discontinued operations.

These investments were re-evaluated at September 30, 2002 based on our inability to sell certain investments for their adjusted carrying values and the continued depressed conditions in the technology sector. Based on this assessment, the remaining carrying value of these investments was written-off, resulting in a pre-tax charge of $12 million ($8 million after-tax), which was recorded in earnings (losses) from unconsolidated investments. The cumulative pre-tax charge related to technology investments for the year ended December 31, 2002 was $80 million ($53 million after-tax), of which $49 million was subsequently reclassified to discontinued operations.

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Impairment of Other Obsolete Assets. As a result of our decision to exit the CRM business, our investment in Dynegy*direct* was written off in the third quarter 2002, resulting in a pre-tax charge of $25 million ($16 million after-tax). The charge was recorded in impairment and other charges in the consolidated statements of operations.

In the fourth quarter 2002, we also recognized a $14 million ($9 million after-tax) charge associated with the impairment of a generation turbine, as its fair value calculated in accordance with SFAS No. 144 was less than its carrying value. The charge was recorded in impairment and other charges in the consolidated statements of operations.

We recognized a pre-tax charge of $12 million ($8 million after-tax) in the second quarter 2002 related to the retirement of partially depreciated information technology equipment and software replaced during the quarter with new system applications and arrangements as well as miscellaneous deposits that are not expected to provide future value. The equipment and software was replaced during the second quarter 2002 with new system applications and arrangements. The charge was recorded in impairment and other charges, and $1 million of the charge ($1 million after-tax) was subsequently reclassified to discontinued operations.

Note 5 Risk Management Activities and Financial Instruments

Our operations are impacted by several factors, some of which may not be mitigated by risk management methods. These risks include, but are not limited to, commodity price, interest rate and foreign exchange rate fluctuations, weather patterns, counterparty credit risks, changes in competition, operational risks, environmental risks and changes in regulations.

We define market risk as changes to our earnings and cash flow resulting from changes in market conditions, including changes in commodity prices, interest rates and currency rates as well as the impact of volatility and market liquidity on such prices. We seek to manage market risk through diversification, controlling position sizes and executing hedging strategies.

Accounting for Derivative Instruments and Hedging Activities

We follow the accounting and disclosure requirements of SFAS No. 133, as amended. Under SFAS No. 133, all derivative instruments are recognized in the balance sheet at their fair values and changes in fair value are recognized immediately in earnings, unless such instruments qualify, and are designated, as hedges of future cash flows, fair values or net investments in foreign operations or qualify, and are designated, as normal purchases and sales. We distinguish between these hedges, which are further described below, as follows:

Cash flow hedges. Under these derivatives, the effective portion of changes in fair value is recorded as a component of accumulated other comprehensive loss until the related hedged items impact earnings. Any ineffective portion of a cash flow hedge is reported immediately as a component of other income and expense, net in the consolidated statements of operations.

Fair value hedges. Under these derivatives, changes in the fair value of the derivative and changes in the fair value of the related asset or liability are recorded in current period earnings.

Net investments in foreign operations. Under these derivatives, the effective portion of changes in the fair value of the derivative is recorded in the foreign currency translation adjustment, a component of accumulated other comprehensive loss. Any ineffective portion is reported immediately as a component of other income and expense, net in the consolidated statements of operations.

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Cash Flow Hedges. We enter into financial derivative instruments that qualify as cash flow hedges. The maximum length of time for which we hedge our exposure for cash flow hedges is through 2006. Instruments related to our GEN and NGL businesses are entered into for purposes of hedging future fuel requirements and sales commitments and locking in future margin. Interest rate swaps were previously used to convert the floating interest-rate component of some obligations to fixed rates.

During the year ended December 31, 2004, we recorded a $3 million charge related to ineffectiveness from changes in fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness related to the hedge of future cash flows. During the years ended December 31, 2003 and 2002, there was no material ineffectiveness from changes in fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness related to the hedge of future cash flows. During the years ended December 31, 2004, 2003 and 2002, we recorded charges of zero, less than $1 million and zero, respectively, related to the reclassification of earnings in connection with forecasted transactions that were no longer considered probable of occurring.

The balance in cash flow hedging activities, net at December 31, 2004 is expected to be reclassified to future earnings, contemporaneously with the related purchases of fuel, sales of electricity or natural gas liquids and payments of interest, as applicable to each type of hedge. Of this amount, after-tax losses of approximately $20 million are currently estimated to be reclassified into earnings over the 12-month period ending December 31, 2005. The actual amounts that will be reclassified to earnings over this period and beyond could vary materially from this estimated amount as a result of changes in market conditions and other factors.

Fair Value Hedges. We also enter into derivative instruments that qualify as fair value hedges. The maximum length of time for which we hedge our exposure for fair value hedges is through 2012. We use interest rate swaps to convert a portion of our non-prepayable fixed-rate debt into variable-rate debt. During the years ended December 31, 2004, 2003 and 2002, there was no ineffectiveness from changes in the fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness. During the years ended December 31, 2004, 2003 and 2002, we recorded gains of zero, $6 million and zero, respectively, related to the recognition of firm commitments that no longer qualified as fair value hedges.

Net investment hedges in foreign operations. Although we have exited a substantial amount of our foreign operations, we continue to have investments in foreign subsidiaries, the net assets of which are exposed to currency exchange-rate volatility. In the past, we used derivative financial instruments, including foreign exchange forward contracts and cross-currency interest rate swaps, to hedge this exposure. As of December 31, 2004 and 2003, we had no net investment hedges in place. For the year ended December 31, 2002, approximately $12 million of net losses related to these contracts were included in the foreign currency translation adjustment. This amount offsets the cumulative translation gains of the underlying net investments in foreign subsidiaries for the period the derivative financial instruments were outstanding.

During the year ended December 31, 2003, our efforts to exit the U.K. CRM business and the European communications business were substantially completed. As required by SFAS No. 52, Foreign Currency Translation, a significant portion of unrealized gains and losses resulting from translation and financial instruments utilized to hedge currency exposures previously recorded in stockholders equity were recognized in income, resulting in an after-tax loss of approximately $16 million. During the first quarter 2004, we repatriated a majority of our cash from the U.K. by repayment of intercompany loans, resulting in the substantial liquidation of our investment in the U.K. As such, we recognized approximately $17 million of pre-tax translation gains in income that arose since April 1, 2003 and had accumulated in stockholders equity.

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Accumulated Other Comprehensive Loss. Accumulated other comprehensive loss, net of tax, is included in stockholders equity on the consolidated balance sheets as follows:

	December 31,	
	2004	2003
	(in millions)	
Cash flow hedging activities, net	$ (16)	$ 10
Foreign currency translation adjustment	16	27
Minimum pension liability	(13)	(57)
Accumulated other comprehensive loss, net of tax	$ (13)	$ (20)

Notional Contract Amounts. The absolute notional contract amounts associated with the derivative instruments designated as hedges were as follows:

	December 31,	
	2004	2003
Fair Value Hedge Interest Rate Swaps (in Millions of U.S. Dollars)	$ 525	$ 25
Fixed Interest Rate Received on Swaps (Percent)	4.331	5.706
Cash Flow Hedge Interest Rate Swaps (in Millions of U.S. Dollars)	$	$ 405
Fixed Interest Rate Paid on Swaps (Percent)		3.448
Natural Gas Cash Flow Hedges (Trillion Cubic Feet)	0.023	0.073
Electricity Cash Flow Hedges (Million Megawatt Hours)	7.244	3.651
Fuel Oil Cash Flow Hedges (Million Barrels)	1.025	0.825

Fair Value of Financial Instruments. The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS No. 107, Disclosures About Fair Value of Financial Instruments. We have determined the estimated fair-value amounts using available market information and selected valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies could have a material effect on the estimated fair-value amounts.

The carrying values of current financial assets and liabilities approximate fair values due to the short-term maturities of these instruments. The carrying amounts and fair values of debt are included in Note 11 Debt beginning on page F-42. The carrying amounts and fair values of our other financial instruments were:

	December 31,			
	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Dynegy Inc.				
Series C Convertible Preferred Stock	$ 400	$ 421	$ 400	$ 316
Dynegy Holdings Inc.				
Fair Value Hedge Interest Rate Swap	5	5	3	3
Cash Flow Hedge Interest Rate Swap			(3)	(3)
Interest Rate Risk-Management Contracts	(3)	(3)	(4)	(4)
Commodity Cash Flow Hedge Contracts	(8)	(8)	17	17
Commodity Risk-Management Contracts	(86)	(86)	(86)	(86)
Illinois Power Company				
Serial Preferred Securities of a Subsidiary			11	10

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The fair value of our Serial Preferred Securities of a Subsidiary at December 31, 2003 were based on quoted market prices by financial institutions that actively trade these debt securities. The fair value of the Series C convertible preferred stock at December 31, 2004 and 2003 is based on an estimate provided by an external financial institution. The estimate reflects debt and equity market information for comparable securities and also incorporates the original lock-up period of the security, which expired in the first quarter 2005. The fair value stated above is the mid-point of the valuation range of $414 million to $428 million at December 31, 2004 and $287 million to $344 million at December 31, 2003. The fair value of interest rate and commodity risk-management contracts were based upon the estimated consideration that would be received to terminate those contracts in a gain position and the estimated cost that would be incurred to terminate those contracts in a loss position.

Note 6 Cash Flow Information

Following are supplemental disclosures of cash flow and non-cash investing and financing information:

	Year Ended December 31,		
	2004	2003	2002
		(in millions)	
Interest paid (net of amount capitalized)	$ 429	$ 428	$ 323
Taxes paid (refunds), net (1)	$ 4	$ (116)	$ (12)
Detail of business acquired (2):			
Current assets and other	$	$	$ 144
Fair value of non-current assets			2,491
Liabilities assumed, including deferred taxes			(1,070)
Cash balance acquired			(44)
Cash paid, net of cash acquired	$	$	$ 1,521
Other non-cash investing and financing activity:			
Series B Exchange	$	$ 1,224	$
Implied dividend on Series B Preferred Stock		(203)	(330)
Addition of a capital lease		66	170
Sale of West Texas LPG Pipeline Limited Partnership			45

(1) Based on 2002 operating results, we generated a significant current tax net operating loss that was carried back to reclaim certain U.S. federal income taxes paid in prior years. Accordingly, we received a tax refund in the first quarter of 2003 of approximately $110 million

for U.S. federal income taxes paid in 2001 and 2000.

(2) The business acquired in 2002 was Northern Natural. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Northern Natural beginning on page F-27 for more information regarding this acquisition. The $1,521 million paid to acquire Northern Natural includes $1,501 million paid in 2001.

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Note 7 Inventory

A summary of our inventories is as follows:

	December 31,	
	2004	2003
	(in millions)	
Natural gas in storage	$	$ 77
Natural gas liquids	60	40
Coal	49	37
Fuel oil	14	16
Emission allowances	27	11
Materials and supplies	83	98
	$ 233	$ 279

Note 8 Property, Plant and Equipment

Prior period amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page F-10.

A summary of our property, plant and equipment is as follows:

	December 31,	
	2004	2003
	(in millions)	
Generation assets	$ 5,838	$ 5,749
Natural gas liquids assets:		

Natural gas processing	1,058	1,067
Fractionation	230	231
Liquids marketing	30	22
Natural gas gathering and transmission	115	98
Terminals and storage	301	307
Barges	29	29
Regulated energy delivery assets		2,156
IT systems and other	221	208
	7,822	9,867
Accumulated depreciation	(1,692)	(1,689)
	$ 6,130	$ 8,178

Interest capitalized related to costs of projects in process of development totaled $4 million, $12 million and $16 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Note 9 Unconsolidated Investments

Our unconsolidated investments consist primarily of investments in affiliates that we do not control, but where we have significant influence over operations. Our principal equity method investments consist of entities that operate generation and natural gas liquids assets. We entered into these ventures principally to share risk and leverage existing commercial relationships. These ventures maintain independent capital structures and have

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financed their operations either on a non-recourse basis to us or through their ongoing commercial activities. We hold investments in joint ventures in which ChevronTexaco or its affiliates are investors. For additional information about these investments, please read Note 12 Related Party Transactions beginning on page F-47.

A summary of our unconsolidated investments is as follows:

	December 31,	
	2004	**2003**
	(in millions)	
Equity affiliates:		
GEN investments	$ 337	$ 518
NGL investments	78	82
Total equity affiliates	415	600
Other affiliates, at cost	6	12
Total unconsolidated investments	$ 421	$ 612

Cash distributions received from our equity investments during 2004, 2003 and 2002 were $136 million, $157 million and $91 million, respectively. Our investment balances include unamortized purchase price differences of $7 million and $73 million at December 31, 2004 and 2003, respectively. The unamortized purchase price differences represent the excess of our purchase price over our share of the investee s book value at the time of acquisition. Undistributed earnings from our equity investments included in accumulated deficit at December 31, 2004 and 2003 totaled $193 million and $161 million, respectively.

GEN Investments. Generation investments at December 31, 2004, include ownership interests in four joint ventures that own fossil fuel electric generation facilities, as well as a limited number of international ventures. Our ownership is 50% in the majority of these ventures. Our aggregate net investment of $337 million at December 31, 2004 represents approximately 1,010 MWs of net generating capacity.

Our most significant investment in generating capacity is our interest in West Coast Power, representing approximately 945 MWs of net generating capacity in California. Our net investment in West Coast Power totaled approximately $262 million and $291 million at December 31, 2004 and December 31, 2003, respectively. West Coast Power provided equity earnings of approximately $153 million, $117 million and $17 million in the years ended December 31, 2004, 2003 and 2002, respectively. Our West Coast Power related earnings for 2004 include a $12 million charge representing our share of an asset impairment. Earnings from unconsolidated investments for 2004 also include an impairment of $73 million on our investment in West Coast Power, primarily due to the expiration of the CDWR contract in December 2004. Our West Coast Power related earnings for 2003 include a $20 million charge representing our share of a goodwill impairment. Our West Coast Power related earnings for 2002 include an impairment charge of $33 million to write down our investment to fair value, as well as a $50 million charge representing our share of a bad debt allowance. A significant amount of West Coast Power s historical earnings related to the CDWR contract, which expired at the end of 2004.

Based on their significance, West Coast Power s audited consolidated financial statements are included herein beginning on page F-95.

In the fourth quarter 2004, we sold our unconsolidated investment in the Commonwealth generating facility. We did not recognize a material gain or loss on this sale.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In the third quarter 2004, we sold our unconsolidated investments in the Oyster Creek, Michigan Power and Hartwell generating facilities for aggregate net cash proceeds of approximately $132 million. We recognized gains of $15 million and $2 million related to our sales of Oyster Creek and Hartwell, but did not recognize any gain or loss on the sale of Michigan Power. However, during the year ended December 31, 2004, we recorded an impairment on our investment in Michigan Power totaling $8 million, to adjust our book value to the sale price.

In the third quarter 2004, as further discussed in Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23, we sold our 20% interest in the Joppa power generating facility.

During the first quarter 2004, we sold our interest in our power generating facility located in Jamaica. Net proceeds associated with the sale were approximately $5.5 million, and we did not recognize a gain or loss on the sale.

In the fourth quarter 2003, we evaluated our domestic and international interests in several power generation entities. We conducted this evaluation, which was required by GAAP, because of a surplus of both international and domestic investments being actively marketed for sale and a continued, sustained downturn in the independent power producer market. Through our evaluation, we determined that several of these equity investments experienced circumstances and events that indicated that the book value of our investment was no longer recoverable and that such decline in value was other than temporary. For some of our investments, we have entered into active discussions with either the owner of the entity or a third party, who, in some cases, has conducted extensive due diligence on the investment to determine an appropriate bid price. We believe that a bid price, or an external valuation, is the best determinant of fair value for these investments, if available. For other investments, we prepared internal valuation models to determine the fair value. After comparing the fair values of each of our investments to their book value, we recorded a pre-tax impairment charge of $26 million ($16 million after-tax) and included this charge in earnings (losses) from unconsolidated investments. The ultimate sale of these investments may result in additional charges.

In August and September 2003, we sold our interests in the Frontier, Paris and Ferndale domestic projects located in Texas and Washington (aggregate net generating capacity of approximately 130 MWs) and in two international projects located in Honduras and Pakistan (aggregate net generating capacity of approximately 110 MWs). Net proceeds associated with these sales were approximately $25 million. We recognized a $1 million after-tax loss on the transactions during 2003.

In addition to the charges related to our investment in West Coast Power described above, equity earnings during 2002 were negatively impacted by a pre-tax impairment of $111 million (net of the $33 million West Coast Power impairment) in multiple equity investments based on a fair value assessment, as further discussed in Note 4 Restructuring and Impairment Charges beginning on page F-30.

NGL Investments. At December 31, 2004, natural gas liquids investments included a 22.9% ownership interest in Venice Energy Services Company, L.L.C. (VESCO), a venture that operates a natural gas liquids processing, extraction, fractionation and storage facility in the Gulf Coast region as well as a 38.75% ownership interest in GCF, a venture that fractionates natural gas liquids on the Gulf Coast. In August 2002, we sold our investment in WTLPS to ChevronTexaco. Please read Note 12 Related Party Transactions beginning on page F-47 for further discussion of this transaction.

During the fourth quarter 2003, we determined that the fair value of our minority interest in GCF, based on bid prices received for a possible sale of the investment, was lower than the book value. As such, we recorded a

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pre-tax impairment charge in the fourth quarter of 2003 of $12 million ($8 million after-tax) and included this charge in earnings (losses) from unconsolidated investments.

Summarized Information. Summarized aggregate financial information for unconsolidated equity investments, exclusive of the West Coast Power information included beginning on page F-95, and our equity share thereof was:

	December 31,					
	2004		2003		2002	
	Total	Equity Share	Total	Equity Share	Total	Equity Share
	(in millions)					
Current assets	$ 166	$ 61	$ 272	$ 108	$ 504	$ 175
Non-current assets	137	68	1,404	605	1,441	607
Current liabilities	95	30	183	72	375	144
Non-current liabilities	96	46	649	300	720	330
Revenues	704	248	1,501	542	2,762	990
Operating income	137	54	234	90	337	105
Net income	107	40	154	53	239	70

Summarized aggregate financial information for West Coast Power, and our equity share thereof, was:

	December 31,					
	2004		2003		2002	
	Total	Equity Share	Total	Equity Share	Total	Equity Share
	(in millions)					
Current assets	$ 429	$ 215	$ 257	$ 129	$ 255	$ 128
Non-current assets	394	197	454	227	532	266
Current liabilities	82	41	55	28	112	56
Non-current liabilities	5	3	8	4	34	17
Revenues	726	363	696	348	585	293
Operating income	304	152	231	116	48	24

Net income	306	153	233	117	34	17

Earnings from unconsolidated investments of $202 million for the year ended December 31, 2004 include the $40 million above, $153 million from West Coast Power and gains on the sales of our 20% interest in the Joppa facility, our equity investment in Oyster Creek and our equity investment in Hartwell of $75 million, $15 million and $2 million, respectively. These gains were partially offset by a $73 million impairment of our investment in West Coast Power and an $8 million impairment of our Michigan Power equity investment, as well as $2 million primarily due to amortization of the difference between the cost of our unconsolidated investments and our underlying equity in their net assets.

Earnings from unconsolidated investments of $124 million for the year ended December 31, 2003 includes the $53 million above and $117 million from West Coast Power, offset by $45 million in impairments of investments and a $1 million loss on the sale of an investment.

Losses from unconsolidated investments of $80 million for the year ended December 31, 2002 consist primarily of the $70 million above and $17 million from West Coast Power, offset by impairments of generation and technology investments of $144 million and $31 million, respectively (see Note 4 Restructuring and Impairment Charges Impairment of Generation Investments beginning on page F-32 and Note 4 Restructuring and Impairment Charges Impairment of Technology Investments beginning on page F-32).

Other Investments. In addition to these equity investments, we hold interests in companies for which we do not have significant influence over the operations. These investments are accounted for by the cost method. Such investments totaled $6 million and $12 million at December 31, 2004 and 2003, respectively. We also owned securities that had a readily determinable fair market value and were considered available-for-sale. During 2002, we wrote down the remaining values of our available-for-sale securities. For further discussion, please see Note 4 Restructuring and Impairment Charges beginning on page F-30. The market value of these investments at December 31, 2004 and 2003 was estimated to be zero.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10 Goodwill

Historical amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page F-10.

The changes in the carrying amount of goodwill for each of our reporting units for the years ended December 31, 2004 and 2003 were as follows:

	GEN	NGL	REG	CRM	Other	Total
			(in millions)			
Balances as of December 31, 2002	$	$ 15	$ 311	$	$	$ 326
Goodwill impaired during 2003			(311)			(311)
Balances as of December 31, 2003 and 2004	$	$ 15	$	$	$	$ 15

During 2003, the value of goodwill associated with Illinois Power was determined to be impaired, resulting in our recognizing a charge of $311 million. Additionally, Illinois Power s other assets were determined to be impaired, resulting in our recognizing a pre-tax charge of $218 million. In determining the impairment amounts, the fair value of Illinois Power was determined based on the sales price allocation assigned to Illinois Power from the sale of Illinois Power and our Joppa investment announced in February 2004, as further described in Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23. The goodwill impairment charge and the asset impairment charge are reflected in goodwill impairment and impairment and other charges, respectively, in the consolidated statements of operations.

Significant components of the changes in goodwill during 2002 included the following:

We adopted SFAS No. 142 effective January 1, 2002, and, accordingly, tested for impairment all amounts recorded as goodwill. We determined that goodwill associated with our former DGC reporting segment was impaired and we therefore recognized a charge of $234 million for this impairment. The fair value of this reporting segment was estimated using the expected discounted future cash flows. The value was negatively impacted by continued weakness in the communications and broadband markets. The impairment charge is reflected in the consolidated statements of operations as a cumulative effect of change in accounting principle.

During 2002, the value of goodwill associated with our former WEN segment was determined to be impaired, resulting in our recognizing a charge of $814 million. The fair values of the respective components of this segment were estimated utilizing the expected discounted future cash flows. The primary factors leading to this impairment were: (1) the reduction in near-term power prices; (2) an increase in the rate of return required for investors to enter the energy merchant sector; and (3) our decision to exit third-party risk management aspects of the marketing and trading business. The impairment charge is reflected in the consolidated statements of operations as a goodwill impairment.

Also in 2002, $887 million of goodwill associated with the acquisition of Northern Natural was recorded in the REG segment and subsequently removed when Northern Natural was sold. See Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Northern Natural beginning on page F-27 for additional discussion of the sale of Northern Natural.

All charges related to goodwill during 2003 are the same on a pre-tax or an after-tax basis. Of the $814 million goodwill impairment recognized in 2002, $579 million related to goodwill for which there was no tax basis, and thus that portion of the impairment was the same on a pre-tax or an after-tax basis. The remaining impairment of the $235 million was $148 million on an after-tax basis.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 11 Debt

Notes payable and long-term debt consisted of the following:

	December 31,			
	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Dynegy Holdings Inc.				
Term Loan, floating rate due through 2010	$ 597	$ 604	$	$
Senior Notes, 8.125% due 2005	18	18	18	18
Senior Notes, 7.45% due 2006	22	23	22	24
Senior Notes, 6.875% due 2011	512	480	519	455
Senior Notes, 8.75% due 2012	501	522	500	501
Senior Debentures, 7.125% due 2018	176	154	179	147
Senior Debentures, 7.625% due 2026	177	150	181	147
Second Priority Senior Secured Notes, floating rate due 2008	225	247	225	225
Second Priority Senior Secured Notes, 9.875% due 2010	625	698	625	705
Second Priority Senior Secured Notes, 10.125% due 2013	900	1,028	900	1,035
Subordinated Debentures payable to affiliates, 8.316%, due 2027	200	165	200	164
ABG Gas Supply Credit Agreement, due through 2006			185	185
Generation Facility Debt, due 2007	183	183	184	184
Illinova				
Senior Notes, 7.125% due 2004			95	96
Illinois Power				
Mortgage Bonds, 6.75% due 2005			70	72
Mortgage Bonds, 7.5% due 2009			250	276
Mortgage Bonds, 11.5% due 2010			550	660
Mortgage Bonds, 7.5% due 2025			66	67
Transitional Funding Trust Notes payable to affiliates, 5.38% due through 2005			118	122
Transitional Funding Trust Notes payable to affiliates, 5.54% due through 2007			175	183
Transitional Funding Trust Notes payable to affiliates, 5.65% due through 2008			139	149
Floating Rate Pollution Control Revenue Refunding Bonds, due 2017			75	75
Adjustable Rate Pollution Control Revenue Refunding Bonds, due 2028			112	112
Adjustable Rate Pollution Control Revenue Refunding Bonds, due 2032			150	150
Pollution Control Revenue Refunding Bonds, 5.4% 7.4%, due 2024 through 2028			179	181
Tilton Capital Lease			71	71

Dynegy Inc.				
Convertible Subordinated Debentures, 4.75% due 2023	225	309	225	316
Junior Unsecured Subordinated Notes payable to affiliates, 9% 13.75% due 2016			223	223
	4,361		6,236	
Unamortized premium (discount) on debt, net	5		(12)	
	4,366		6,224	
Less: Amounts due within one year, including non-cash amortization of basis adjustments	34		331	
Total Long-Term Debt	$ 4,332		$ 5,893	

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Aggregate maturities of the principal amounts of all long-term indebtedness as of December 31, 2004 are as follows:

	Total	2006	2007(1)	2008	2009	Thereafter
			(in millions)			
Dynegy Holdings Inc.	$ 4,107	$ 28	$ 188	$ 231	$ 6	$ 3,654
Dynegy Inc. (2)	225					225
Total	$ 4,332	$ 28	$ 188	$ 231	$ 6	$ 3,879

(1) Excludes $700 million secured revolving credit facility, which matures on May 28, 2007. As of December 31, 2004, there were no borrowings outstanding under this facility and $94 million letters of credit outstanding.

(2) Maturities do not include the $919 million of face value project debt acquired on January 31, 2005 as part of the Sithe Energies acquisition. Please see Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23.

DHI Term Loan and Credit Facility. Effective May 28, 2004, DHI entered into a $1.3 billion credit facility consisting of:

- a $700 million secured revolving credit facility that matures on May 28, 2007; and
- a $600 million secured amortizing term loan that matures on May 28, 2010.

The credit facility replaced DHI s $1.1 billion revolving credit facility, which was scheduled to mature in February 2005.

The revolving credit facility provides funding for general corporate purposes and is also available for the issuance of letters of credit. Borrowings under the revolving credit facility bear interest, at DHI s option, at (i) a base rate plus 3.00% per annum or (ii) LIBOR plus 4.00% per annum. A letter of credit fee is payable on the undrawn amount of each letter of credit outstanding at a percentage per annum equal to 4.00% of such undrawn amount. We also incur additional fees for issuing letters of credit. An unused commitment fee of 0.50% is payable on the unused portion of the revolving credit facility.

During the year ended December 31, 2004, we reduced letters of credit under our revolving credit facilities by an aggregate amount of approximately $94 million, resulting in a total of $94 million outstanding at December 31, 2004. As of December 31, 2004, there were no borrowings outstanding under our $700 million revolving credit facility. During the period from December 31, 2004 through March 4, 2005, we reduced our outstanding letters of credit under this facility by $5 million.

Of the $600 million in proceeds from the term loan drawn at closing, a portion was used to post cash collateral in lieu of letters of credit, while approximately $19 million was used to pay fees and expenses incurred in connection with the new facility. These fees have been capitalized and are being amortized over the terms of the credit facility. In August 2004, $154 million of the proceeds from the $600 million term loan were used to pre-pay all outstanding indebtedness and other amounts owed in connection with the ABG Gas Supply financing. The remaining proceeds, subject to specified restrictions in the credit facility, are available for general corporate purposes. Borrowings under the term loan bear interest, at DHI s option, at (i) a base rate plus 3.00% per annum or (ii) LIBOR plus 4.00% per annum.

The credit facility contains mandatory prepayment events associated with specified asset sales and recovery events (i.e., certain payments in respect of insurance claims or condemnation proceedings). DHI must offer to repay the term loan or permanently reduce the revolving credit facility with 100% of the net cash proceeds of all

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

asset sales or any proceeds from recovery events, excluding (i) proceeds from sales of designated assets; (ii) up to $100 million of net cash proceeds from other asset sales as designated by DHI; and (iii) up to $900 million of proceeds from asset sales and recovery events that are reinvested in the business, subject to specified restrictions. Sales of assets over a specified threshold require written confirmation from both Standard & Poor s Ratings Service and Moody s Investors Service that the credit ratings of the credit facility will not be lowered as a result. Further, any sale of our Baldwin facility or all or substantially all of our NGL assets would require the written consent of a majority of the lenders under the credit facility.

The credit facility provides for no amortization of principal prior to the maturity dates except (i) upon the occurrence of a mandatory prepayment event and (ii) term loan amortization of 1% per annum.

The credit facility is secured by substantially the same collateral as the $1.1 billion facility it replaced, including a first priority interest in substantially all our assets and the assets of our subsidiaries and on substantially all of the equity of our subsidiaries in each case to the extent permitted by other applicable agreements. We and substantially all of our subsidiaries also guarantee this facility.

The credit facility contains affirmative and negative covenants, including negative covenants relating to the following which restrict DHI and its subsidiaries but do not restrict us: liens; investments; indebtedness; dispositions; restricted payments; burdensome agreements; amendments to organizational documents; prepayments of indebtedness; and swap contracts. The credit facility also contains the financial and capital expenditure-related covenants described below.

The credit facility generally prohibits DHI and its subsidiaries, subject to specified exceptions, from incurring additional debt. Notwithstanding this restriction, DHI may issue, to the extent permitted by the more restrictive covenants in the indenture governing the DHI second priority senior secured notes, (i) up to $700 million of additional second lien or junior secured debt or unsecured debt, provided such additional debt matures at least six months after the term loan, and (ii) permitted refinancing indebtedness.

The credit facility generally prohibits DHI and its subsidiaries from pre-paying, redeeming or repurchasing its outstanding debt or preferred stock. Notwithstanding this restriction, DHI may pre-pay, repurchase or redeem its remaining 2005 and 2006 senior notes and the Generation facility debt. DHI also may pre-pay, repurchase or redeem its other senior unsecured notes and its second priority senior secured notes, subject to specified conditions.

We and our subsidiaries are also prohibited from (i) permitting our Secured Debt/EBITDA Ratio (as defined in the credit facility) on and after September 30, 2004 to exceed specified ratios; (ii) permitting our liquidity to be less than $200 million for a period of more than ten consecutive business days; or (iii) making capital expenditures during each four fiscal quarter period in excess of a designated amount, subject to specified exceptions.

The terms and conditions of the credit facility are described in more detail in the definitive agreements governing the credit facility, which are filed and/or incorporated by reference as exhibits to our second quarter 2004 Form 10-Q.

DHI Senior Notes. The notes are unsecured and are not subject to a sinking fund.

DHI Second Priority Senior Secured Notes. In August 2003, DHI issued $1.45 billion in second priority senior secured notes, comprised of: (i) $225 million in floating rate notes due 2008 which accrue interest at a rate of LIBOR plus 650 basis points (reset on a quarterly basis); (ii) $525 million in 9.875% notes due 2010 with a yield to maturity of 10.0%; and (iii) $700 million in 10.125% notes due 2013 with a yield to maturity of 10.25%.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In October 2003, DHI consummated a follow-on offering of $300 million aggregate principal amount of additional second priority senior secured notes, comprised of: (i) $100 million of 9.875% second priority senior secured notes due 2010 issued at a premium to par of 104.25% with a yield to maturity of approximately 9.0%; and (ii) $200 million of 10.125% second priority senior secured notes due 2013 issued at a premium to par of 105.25% with a yield to maturity of approximately 9.3%. Each of these series of additional notes are treated as a single class with the corresponding series of DHI second priority senior secured notes that were originally issued in August 2003.

Each of DHI s existing and future wholly owned domestic subsidiaries that guarantee DHI s obligations under its credit facility also guarantee the obligations under the notes on a senior secured basis. In addition, Dynegy and its other subsidiaries that guarantee DHI s existing credit facility also guarantee the obligations under the notes on a senior secured basis. The notes and guarantees are senior obligations secured by a second-priority lien on, subject to certain exceptions and permitted liens, all of DHI s and its guarantors existing and future property and assets that secure DHI s obligations under its credit facility.

The indenture governing the notes contains restrictive covenants that limit the ability of DHI and its subsidiaries that guarantee the notes to, among other things: (1) redeem, repurchase or pay dividends or distributions on capital stock; (2) make investments or restricted payments; (3) incur or guarantee additional indebtedness; (4) create certain liens; (5) engage in sale and leaseback transactions; (6) consolidate, merge or transfer all or substantially all of its assets; or (7) engage in certain transactions with affiliates.

Subordinated Debentures. In May 1997, NGC Corporation Capital Trust I (Trust) issued, in a private transaction, $200 million aggregate liquidation amount of 8.316% Subordinated Capital Income Securities (Trust Securities) representing preferred undivided beneficial interests in the assets of the Trust. The Trust invested the proceeds from the issuance of the Trust Securities in an equivalent amount of DHI s 8.316% Subordinated Debentures (Subordinated Debentures). The sole assets of the Trust are the Subordinated Debentures. The Trust Securities are subject to mandatory redemption in whole, but not in part, on June 1, 2027, upon payment of the Subordinated Debentures at maturity, or in whole, but not in part, at any time, contemporaneously with the optional prepayment of the Subordinated Debentures, as allowed by the associated indenture. The Subordinated Debentures are redeemable, at DHI s option, at specified redemption prices. The Subordinated Debentures represent DHI s unsecured obligations and rank subordinate and junior in right of payment to all of DHI s senior indebtedness to the extent and in the manner set forth in the associated indenture. We have irrevocably and unconditionally guaranteed, on a subordinated basis, payment for the benefit of the holders of the Trust Securities the obligations of the Trust to the extent the Trust has funds legally available for distribution to the holders of the Trust Securities. Since the Trust is considered a SPE, FIN No. 46R was applied effective December 31, 2003. The holders of the Trust Securities absorb a majority of the Trust s expected losses. Accordingly, DHI s obligation is represented by the Subordinated Debentures payable to the deconsolidated Trust rather than the Trust Securities that were payable to the holders of the Trust Securities. This deconsolidation did not impact our consolidated balance sheets or consolidated statements of operations.

We may defer payment of interest on the Subordinated Debentures as described in the indenture, although we have not yet done so and have continued to pay interest as and when due. As of December 31, 2004 and 2003, the redemption amount associated with these securities totaled $200 million. In accordance with SFAS No. 150, on July 1, 2003, we reclassified these securities to long-term debt on the consolidated balance sheets. Prior year amounts have not been reclassified to conform to this change.

ABG Gas Supply Credit Agreement. In August 2004, we used $154 million in proceeds from our $600 million term loan to pre-pay all remaining indebtedness and other obligations under our ABG Gas Supply financing as required by the terms of our credit facility.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Generation Facility Debt. We previously entered into a lease arrangement for the purpose of constructing a generation facility located in Kentucky. As originally constituted, this arrangement required variable-rate interest only payments that include an option to purchase the related assets at maturity of the facility for a balloon payment equal to the principal balance on the financing. We have capitalized upfront fees with our generation facility lease arrangement and amortize these fees over the term of the arrangement. The generation lease arrangement expires in 2007 and bears interest at LIBOR plus 1.5% to 2.5%, depending on the tranche (3.976% and 2.713% at December 31, 2004 and 2003).

Illinova Senior Notes. In March 2003, we purchased on the open market $5 million in aggregate principal amount of Illinova s 7.125% Senior Notes due 2004. The repurchased notes were cancelled and are no longer outstanding. In the first quarter of 2004, we repaid the remaining $95 million in aggregate principal of these notes.

Illinois Power. As further described in Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23, in September 2004, we sold Illinois Power to Ameren. As a result, Ameren assumed Illinois Power s outstanding debt obligations.

Tilton Capital Lease. In September 1999, Illinois Power entered into an operating lease on four gas turbines located in Tilton, Illinois and a separate land lease at the Tilton site. This facility consists of peaking units totaling 176 MWs of capacity. Illinois Power sublet the turbines to DMG in October 1999. In September 2003, we delivered notice of our intent to exercise our option in order for DMG to purchase the turbines upon the expiration of the operating lease in September 2004. As a result of this action, we began accounting for the lease obligation as a capital lease. Accordingly, we recorded a $66 million increase to property, plant and equipment and a corresponding increase to short-term debt. The recorded amount of $66 million represents the fair market value of the leased assets at the inception of the capital lease. The difference between the recorded amount and the $81 million purchase price was accreted over the remaining term of the capital lease through a charge to interest expense with a corresponding increase to short-term debt.

In July 2004, Illinois Power terminated its lease arrangement, and DMG purchased the turbines for $81 million. This action resulted in a reduction of debt of $78 million. The difference between the purchase price and the debt balance was recorded as an increase to property, plant and equipment of $3 million in our consolidated balance sheets and represents the remaining accretion to the end of the term of the original lease agreement.

Convertible Subordinated Debentures. In August 2003, we issued $225 million in 4.75% convertible subordinated debentures due 2023. The debentures are convertible into shares of our Class A common stock at any time at a conversion price of $4.1210 per share, subject to specified adjustments for dividend payments and other actions. The debentures are subordinated to our existing and future senior indebtedness and effectively subordinated to all indebtedness and liabilities of our non-guarantor subsidiaries. The debentures are guaranteed on a senior unsecured basis by DHI. As of December 31, 2004, Dynegy Inc. has no material assets or operations other than ownership of its subsidiaries; the DHI guarantee is full and unconditional and all of Dynegy Inc. s subsidiaries other than DHI are minor. We filed, and the SEC has declared effective, a registration statement covering resale of the debentures.

Junior Unsecured Subordinated Notes. During September 2003, we used proceeds of approximately $2 million from the previously described sales of certain non-strategic generation investments to redeem a portion of the Junior Notes. During 2004, we made $98 million in pre-payments and used approximately $125 million of the proceeds from the sale of Illinois Power to mandatorily redeem the balance of the Junior Notes, as required by the indenture governing these notes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 12 Related Party Transactions

Transactions with ChevronTexaco. In connection with our previously announced exit from third-party risk management aspects of the marketing and trading business, we agreed with ChevronTexaco to terminate the natural gas purchase agreement between the parties and to provide for an orderly transition of responsibility for marketing ChevronTexaco s domestic natural gas production. This agreement did not affect our contractual agreements with ChevronTexaco relative to its U.S. natural gas processing and the marketing of its domestic natural gas liquids. The cancellation of the agreement was effective January 1, 2003. In accordance with the termination of the natural gas purchase agreement, we paid $13 million to ChevronTexaco. As part of the transition, we also provided scheduling, accounting and reporting services to ChevronTexaco through June 2003. In connection with the termination of the transition agreement, ChevronTexaco paid us $13.5 million in September 2003 as final settlement for the net payable and receivable balances.

In August 2002, we executed an agreement with ChevronTexaco pursuant to which the parties amended the existing gas purchase agreement, security agreement, netting agreement and certain related agreements. Under this new agreement, we accelerated our payment terms effective upon the closing of the sale of Northern Natural described in Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Northern Natural beginning on page F-27 above.

Also in August 2002, in partial satisfaction of certain of our obligations to ChevronTexaco under these agreements, we transferred our 39.2% ownership interest in WTLPS, valued at $45 million, to ChevronTexaco, the largest interest owner of WTLPS and operator of the pipeline. This non-cash transaction reduced accounts payable to affiliates and unconsolidated investments by $45 million.

Other transactions with ChevronTexaco result from purchases and sales of natural gas and natural gas liquids between our affiliates and ChevronTexaco. We believe that these transactions are executed on terms that are fair and reasonable. During the years ended December 31, 2004, 2003 and 2002, our marketing business recognized net purchases from ChevronTexaco of $23 million, $0.3 billion and $1.5 billion, respectively. In accordance with the net presentation provisions of EITF Issue 02-03, all of these transactions, whether physically or financially settled, have been presented net on the consolidated statements of operations. In addition, during the years ended December 31, 2004, 2003 and 2002, our other businesses recognized aggregate sales to ChevronTexaco of $1.1 billion, $0.9 billion and $0.8 billion, respectively, and aggregate purchases of $1.1 billion, $0.8 billion and $0.5 billion, respectively, which are reflected gross on the consolidated statements of operations. No other customer accounted for more than 10% of our consolidated revenues during 2004, 2003 or 2002, and these revenues relate to our GEN, NGL and CRM reportable segments.

Series B Preferred Stock. On November 13, 2001, ChevronTexaco purchased 150,000 shares of our Series B Preferred Stock for $1.5 billion. The proceeds from this issuance were used to finance our investment in Northern Natural, which is discussed in detail in Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Northern Natural beginning on page F-27. Each share of our Series B Preferred Stock was convertible, at the option of ChevronTexaco, for a period of two years into shares of our Class B common stock at the conversion price of $31.64. The $660 million intrinsic value of this beneficial conversion option was calculated using a commitment date of November 13, 2001, the date ChevronTexaco funded its preferred stock purchase and the preferred securities were issued.

We accreted an implied preferred stock dividend over the redemption period the Series B Preferred Stock was outstanding as required by GAAP. The shares of Series B Preferred Stock provided for a mandatory redemption on November 13, 2003.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In August 2003, we consummated a restructuring of the Series B Preferred Stock, which we refer to as the Series B Exchange. The following table summarizes the impact of this transaction on our consolidated balance sheets and consolidated statements of operations (in millions):

Series B Preferred Stock (previously included in redeemable preferred securities on the consolidated balance sheets)	$ 1,414
Implied dividend on Series B Preferred Stock (previously included in additional paid-in-capital on the consolidated balance sheets)	660
Total balance immediately prior to transaction	2,074
Issuance of Series C convertible preferred stock	(400)
Issuance of Junior Notes	(225)
Cash payment to ChevronTexaco	(225)
Gain related to Series B Exchange	1,224
Implied dividends on Series B Preferred Stock recorded in 2003	(203)
Dividends on Series C convertible preferred stock recorded in 2003	(8)
Net preferred stock dividend gain reflected on the consolidated statements of operations for the year ended December 31, 2003	$ 1,013

Series C Convertible Preferred Stock. In August 2003 we issued 8 million shares of our Series C convertible preferred stock due 2033 to Chevron U.S.A. Inc., a wholly owned subsidiary of ChevronTexaco which we refer to as Chevron, as a part of the Series B Exchange described above. We accrue dividends on our Series C convertible preferred stock at a rate of 5.5% per annum. For further information, see Note 14 Redeemable Preferred Securities Series C Convertible Preferred Stock beginning on page F-54.

Equity Investments. We hold investments in joint ventures in which ChevronTexaco or its affiliates are also investors. These investments include a 22.9% ownership interest in VESCO, which holds a pipeline gathering system, a processing plant, a fractionator and an underground natural gas liquids storage facility in Louisiana; and a 50% ownership interest in Nevada Cogeneration Associates #2, which holds our Black Mountain power generation facility. During the years ended December 31, 2004, 2003 and 2002, our portion of the net income from joint ventures with ChevronTexaco was approximately $13 million, $10 million and $17 million, respectively.

We also purchase and sell natural gas, natural gas liquids, crude oil, emissions and power and, in some instances, earn management fees from certain entities in which we have equity investments. During the years ended December 31, 2004, 2003 and 2002, our marketing business recognized net sales to affiliates related to these transactions of $0.3 billion, $0.7 billion and $1.0 billion, respectively. In accordance with the net presentation provisions of EITF 02-03, all of these transactions, whether physically or financially settled, have been presented net on the consolidated statements of operations. In addition, during the years ended December 31, 2004, 2003 and 2002, our other businesses recognized aggregate sales to these affiliates of $12 million, $25 million and $15 million, respectively, and aggregate purchases of $170 million, $177 million and $152 million, respectively, which are reflected gross on the consolidated statements of operations. Revenues were related to the supply of fuel for use at generation facilities, primarily West Coast Power, and the supply of natural gas sold by retail affiliates. Expenses primarily represent the purchase of natural gas liquids that are subsequently sold in our marketing operations.

Short-Term Executive Stock Purchase Loan Program. In July 2001, we established the Dynegy Inc. Short-Term Executive Stock Purchase Loan Program pursuant to which eligible employees were loaned funds to acquire Class A common stock through market purchases. We terminated this program as it related to new loans effective June 30, 2002. The notes bear interest at the greater of 5% or the applicable federal rate as of the loan date, are full recourse to the participants and matured on December 19, 2004.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In connection with our October 2002 restructuring, we offered to forgive 50% of the outstanding balance under loans established through this program effective as of January 15, 2003, April 15, 2003, July 15, 2003 or October 15, 2003, at the particular officer s election, in exchange for the payment of related federal income taxes by the particular officer. In order to provide incentives to those employees with outstanding loans under this program to remain with us post-restructuring, we agreed to forgive one-half of the remaining balance of each of their loans on or before December 31, 2003 and to forgive the then remaining balance under each such loan on or before December 19, 2004, subject to achievement of specified employment objectives. For employees terminated as part of the restructuring, the remaining balance outstanding under each loan matures and was due and payable on December 19, 2004. Interest rates charged under these loans remain unchanged.

Under this program, at December 31, 2004, approximately $8 million, which included accrued and unpaid interest, was owed to us. We are actively pursuing, through litigation and otherwise, repayment of the past due amounts owed to us under these loans. The loans are accounted for as subscriptions receivable within stockholders equity on the consolidated balance sheets and at December 31, 2004 are fully reserved.

December 2001 Equity Purchases. In December 2001, 10 members of our senior management purchased Class A common stock from us in a private placement pursuant to Section 4(2) of the Securities Act of 1933. These officers received loans from us totaling approximately $25 million to purchase the common stock at a price of $19.75 per share, the same price as the net proceeds per share received by us from a concurrent public offering. The loans bear interest at 3.25% per annum and are full recourse to the borrowers. Such loans are accounted for as subscriptions receivable within stockholders equity on the consolidated balance sheets. We recognized compensation expense in 2001 of approximately $1.2 million related to the shares purchased by these officers. This amount, which was recorded as general and administrative expense, is derived from the $1.00 per share discount these officers received based on the initial public offering price of $20.75 per share.

At December 31, 2004, one of our former executive officers, who resigned his position following our October 2002 restructuring, had a balance of approximately $480,000 remaining under the December 2001 equity purchase with an extended maturity date of September 30, 2007 for the loan. The extended loan bears interest at the same interest rate as the initial loan. The loan is accounted for as subscriptions receivable within stockholders equity on the consolidated balance sheets and at December 31, 2004 is fully reserved. No other December 2001 equity purchase loans are outstanding.

Note 13 Income Taxes

Prior period amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page F-10.

Income Tax Benefit. We are subject to U.S. federal, foreign and state income taxes on our operations. Components of loss from continuing operations before income taxes were as follows:

	Year Ended December 31,		
	2004	2003	2002
		(in millions)	
Loss from continuing operations before income taxes:			
Domestic	$ (75)	$ (945)	$ (1,513)
Foreign	(24)	(14)	(29)
	$ (99)	$ (959)	$ (1,542)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Components of income tax benefit related to loss from continuing operations were as follows:

	Year Ended December 31,		
	2004	2003	2002
	(in millions)		
Current tax benefit (expense):			
Domestic	$ (13)	$ (9)	$ 3
Foreign			(2)
Deferred tax benefit (expense):			
Domestic	103	256	356
Foreign	(1)	(1)	(14)
Income tax benefit	$ 89	$ 246	$ 343

Income tax benefits related to loss from continuing operations for the years ended December 31, 2004, 2003 and 2002, were equivalent to effective rates of 90%, 26% and 22%, respectively. Differences between taxes computed at the U.S. federal statutory rate and our reported income tax benefit were as follows:

	Year Ended December 31,		
	2004	2003	2002
	(in millions)		
Expected tax benefit at U.S. statutory rate (35%)	$ 35	$ 336	$ 540
State taxes	2	1	58
Foreign taxes	(1)	(8)	(9)
Valuation allowance	39	33	(9)
Goodwill permanent differences and impairments		(109)	(203)
IRS and state audits and settlements	8	1	27
Basis differentials and other	6	(8)	(61)
Income tax benefit	$ 89	$ 246	$ 343

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Deferred Tax Liabilities and Assets. Significant components of deferred tax liabilities and assets were as follows:

	December 31, 2004	December 31, 2003
	(in millions)	
Deferred tax assets:		
Current		
NOL carryforwards	$	$ 142
Reserves	52	31
Miscellaneous book/tax recognition differences	22	43
Subtotal	74	216
Less valuation allowance		(34)
Total current deferred tax assets	74	182
Non-current		
NOL carryforwards	373	378
AMT credit carryforwards	224	218
Capital loss carryforwards	125	194
Foreign tax credits	38	9
Other	29	36
Miscellaneous book/tax recognition differences	13	21
Subtotal	802	856
Less: valuation allowance	(164)	(136)
Total non-current deferred tax assets	638	720
Deferred tax liabilities:		
Depreciation and other property differences	1,208	1,283
Miscellaneous book/tax recognition differences	15	179
Total deferred tax liabilities	1,223	1,462
Net deferred tax liability	$ 511	$ 560

NOL Carryforwards. At December 31, 2004, we had approximately $929 million of regular federal tax NOL carryforwards after considering the effect of carryback to prior years and $1.7 billion of AMT NOL carryforwards. The federal and AMT NOL carryforwards will expire in 2023. Certain provisions of the Internal Revenue Code place an annual limitation on our ability to utilize tax carryforwards existing as of the date of a 2005 business acquisition. This limitation is not expected to have a material impact on our overall ability to utilize such tax carryforwards. If certain substantial changes in the Company s ownership should occur, there would be an annual limitation on the amount of the carryforwards which can be utilized. There was no valuation allowance established at December 31, 2004 for our federal NOL carryforwards, as management believes our NOL carryforward is more likely than not to be fully realized in the future based, among other things, on management s estimates of future taxable net income, future reversals of existing taxable temporary differences and tax planning.

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At December 31, 2004, state NOL carryforwards were as follows:

	Amount	Expiration Dates
	(in millions)	
States where we file unitary state income tax returns:		
Illinois	$ 303	2015 2022
California	44	2022 2023
New Mexico	35	2007 2008
States where we file separate state income tax returns:		
Louisiana	171	2020 2024
New York	167	2022 2024
Kentucky	156	2022 2024
Texas	61	2007 2009
North Carolina	56	2015 2019
Georgia	42	2022 2024
Ohio	41	2023 2024
Michigan	40	2011 2024
Pennsylvania	37	2022 2024
Other	21	2005 2024
	$ 1,174	

During 2004, we established a valuation allowance for certain state NOL carryforwards which management believes are not likely to be fully realized in the future based on our ability to generate gains in the respective state. See Change in Valuation Allowance below.

AMT Credit Carryforwards. At December 31, 2004, we had approximately $224 million of AMT credit carryforwards. The AMT credit carryforwards do not expire. There was no valuation allowance established at December 31, 2004 for our AMT credit carryforwards, as management believes the AMT credit carryforward is more likely than not to be fully realized in the future based, among other things, on management s estimates of future taxable net income and future reversals of existing taxable temporary differences.

Capital Loss Carryforwards. At December 31, 2004, we had approximately $337 million of capital loss carryforwards. The capital loss carryforwards expire during 2007 and 2008. At December 31, 2004, we had a full valuation allowance for our capital loss carryforwards, which management believes are not likely to be fully realized in the future based on our ability to generate capital gains.

Sale of Illinois Power and Joppa. On September 30, 2004, we sold our stock of Illinois Power and our 20% interest in the Joppa power generation facility to Ameren. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23 for further discussion. As a part of this transaction, we utilized approximately $735 million in net operating loss carryforwards and approximately $174 million in capital loss carryforwards to offset the gain on sale.

Foreign Tax Credits. At December 31, 2004, we had approximately $38 million of foreign tax credits. The foreign tax credits will expire in 2005 and 2006. At December 31, 2004, we had a full valuation allowance for our foreign tax credits, as we have disposed of or discontinued the majority of our foreign operations and management believes the foreign tax credits are not likely to be fully realized in the future based on our ability to generate foreign source income. Unless we generate foreign source income in 2005 and 2006, which we do not anticipate, we will write-off the $38 million of foreign tax credits and the related $38 million valuation allowance.

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Residual U.S. Income Tax on Foreign Earnings. We do not have any material undistributed earnings from our foreign operations. In addition, we have sufficient intercompany loans from our affiliates in both the U.K. and Canada, which will allow us the ability to repatriate any funds from those countries without incurring any income tax. Therefore, we have not provided any U. S. deferred taxes or foreign withholding taxes, if any, that might be payable on the actual or deemed remittance of any such earnings.

Change in Valuation Allowance. Realization of our deferred tax assets is dependent upon, among other things, our ability to generate taxable income of the appropriate character in the future. During 2004, we released valuation allowance related to completed sales that resulted in the realization of capital gains. We also established valuation allowance on certain foreign tax credits and a state net operating loss carryforward. At December 31, 2004 and 2003, valuation allowances related to capital loss carryforwards, foreign tax credit carryforwards and state NOL carryforwards have been established. The changes in the valuation allowance by attribute for the years ended December 31, 2004 and 2003 were as follows:

	Capital Loss Carryforwards	Foreign Tax Credits	State NOL Carryforwards	Total
		(in millions)		
Balance as of December 31, 2002	$ (194)	$ (9)	$	$ (203)
Changes in valuation allowance	33			33
Balance as of December 31, 2003	(161)	(9)		(170)
Changes in valuation allowance continuing operations	40	(29)	(1)	10
Changes in valuation allowance discontinued operations	(4)			(4)
Balance as of December 31, 2004	$ (125)	$ (38)	$ (1)	$ (164)

American Jobs Creation Act of 2004. On October 22, 2004, the American Jobs Creation Act of 2004 was signed into law. This legislation contains a number of changes to the Internal Revenue Code. We have analyzed the law in order to determine its effects. The two most notable provisions are those dealing with the reduced tax rate on the repatriation of money from foreign operations and the deduction for domestic-based manufacturing activity. We do not believe either of these provisions will impact us as we do not have significant funds overseas to take advantage of the reduced tax rate on repatriations, and we are projecting that we will continue to generate net operating losses for at least the next twelve months and, therefore, cannot take advantage of the domestic-based manufacturing deduction.

Various IRS and State Settlements and Settlement of Contingent Liability Transactions. On February 23, 2005, we settled our dispute with the IRS relating to our participation in three contingent liability transactions in 1996, 1997 and 1999. The settlement did not have a material impact on our financial results. We expect to pay penalty and interest of approximately $2 million in settlement of this matter in the first quarter 2005. Our federal income tax returns are routinely audited by the IRS, and provisions are routinely made in the financial statements in anticipation of the results of these audits. The IRS completed its audit of our 1998-2000 tax returns during 2004, including the settlement of the contingent liability transactions noted above. As a result of this settlement and various state settlements, we adjusted the tax provision by $8 million in 2004.

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Note 14 Redeemable Preferred Securities

Redeemable preferred securities consisted of the following:

	December 31,	
	2004	2003
	(in millions)	
Series C convertible preferred stock	$ 400	$ 400
Serial preferred securities of a subsidiary		11
Total redeemable preferred securities	$ 400	$ 411

Series C Convertible Preferred Stock. In August 2003, we issued 8 million shares of our Series C convertible preferred stock due 2033 to Chevron. Each share carries a liquidation preference of $50, and the aggregate redemption value is $400 million. Dividends are payable at a rate of 5.5% per annum in cash semi-annually. At our election, we may defer dividend payments for up to 10 consecutive semi-annual dividend payment periods. Upon termination of any deferral period, all accrued and unpaid amounts are due in cash. We may not pay dividends on our common stock during any deferral period. The shares of Series C convertible preferred stock generally are convertible, at the option of the holder, at a price of $5.78 per share. The initial holder of the Series C convertible preferred stock could not transfer the shares of the Series C convertible preferred stock (other than to affiliates) until 18 months following the closing of the Series B Exchange. On or after the third anniversary of this lock-up period, we may cause the Series C convertible preferred stock to be converted into shares of our Class B common stock at any time the closing price of our Class A common stock exceeds 130% of the conversion price then in effect for at least 20 trading days within any period of 30 consecutive trading days prior to such conversion. Upon any conversion of the Series C convertible preferred stock, we have the right to deliver, in lieu of shares of our Class B common stock, cash or a combination of cash and shares of our Class B common stock. At any time after the 10th anniversary of the closing of the Series B Exchange, we may redeem all of the shares of Series C convertible preferred stock for a redemption price equal to $50 per share plus accrued and unpaid dividends. We filed, and the SEC has declared effective, a registration statement covering the resale of the Series C convertible preferred securities as well as the Class B common stock into which it is convertible.

Serial Preferred Securities of a Subsidiary. Serial preferred securities of a subsidiary of approximately $11 million at December 31, 2003 consisted of six series of preferred stock issued by Illinois Power and owned by Illinova. As part of our sale of the stock of Illinois Power to Ameren, Ameren acquired the preferred securities owned by Illinova. For further discussion of the sale, please see Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23.

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Note 15 Earnings (Loss) Per Share

Prior period amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page F-10.

The reconciliation of basic earnings (loss) per share from continuing operations to diluted earnings (loss) per share from continuing operations is shown in the following table:

	Year Ended December 31,		
	2004	**2003**	**2002**
		(in millions, except per share amounts)	
Loss from continuing operations	$ (10)	$ (713)	$ (1,199)
Convertible preferred stock (dividends) gain	(22)	1,013	(330)
Income (loss) from continuing operations for basic earnings (loss) per share	(32)	300	(1,529)
Effect of dilutive securities:			
Interest on convertible subordinated debentures	7	3	
Dividends on Series C convertible preferred stock	22	8	
Income (loss) from continuing operations for diluted earnings (loss) per share	$ (3)	$ 311	$ (1,529)
Basic weighted-average shares	378	374	366
Effect of dilutive securities:			
Stock options	2	2	4
Convertible subordinated debentures	55	20	
Series C convertible preferred stock	69	27	
Diluted weighted-average shares	504	423	370
Earnings (loss) per share from continuing operations			
Basic	$ (0.09)	$ 0.80	$ (4.18)
Diluted (1)	$ (0.09)	$ 0.73	$ (4.18)

(1) When an entity has a net loss from continuing operations, SFAS No. 128, Earnings per Share, prohibits the inclusion of potential common shares in the computation of diluted per-share amounts. Accordingly, we have utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for the years ended December 31, 2004 and 2002.

Note 16 Commitments and Contingencies

Summary of Material Legal Proceedings

Set forth below is a description of our material legal proceedings. In addition to the matters described below, we are party to legal proceedings arising in the ordinary course of business. In management s opinion, the disposition of these ordinary course matters will not materially adversely affect our financial condition, results of operations or cash flows.

We record reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss is reasonably estimable under SFAS No. 5, Accounting for Contingencies. During 2004, we recorded pre-tax legal and settlement charges of $118 million, including cash

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payments made in the period in excess of our then-existing accruals. The charges recorded relate to contingencies for which, during 2004, either the amount of loss became probable and reasonably estimable or our previous loss estimates were adjusted.

For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated. Please read Note 2 Accounting Policies beginning on page F-12 for further discussion of our reserve policies. Environmental reserves do not reflect management s assessment of the insurance coverage that may be applicable to the matters at issue, whereas litigation reserves do reflect such potential coverage. We cannot make any assurances that the amount of any reserves or potential insurance coverage will be sufficient to cover the cash obligations we might incur as a result of litigation or regulatory proceedings, payment of which could be material.

With respect to some of the items listed below, management has determined that a loss is not probable or that any such loss, to the extent probable, is not reasonably estimable. In some cases, management is not able to predict with any degree of certainty the range of possible loss that could be incurred. Notwithstanding these facts, management has assessed each of these matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought and the probability of success. Management s judgment may, as a result of facts arising prior to resolution of these matters or other factors, prove inaccurate and investors should be aware that such judgment is made subject to the known uncertainty of litigation.

Shareholder Litigation. We are defending a class action lawsuit filed on behalf of purchasers of our publicly traded securities from January 2000 to July 2002 seeking unspecified compensatory damages and other relief. The lawsuit as filed principally alleged that we and certain of our current and former officers and directors violated the federal securities laws in connection with our disclosures, including accounting disclosures, regarding Project Alpha (a structured natural gas transaction entered into by us in April 2001), round-trip trading, the submission of false trade reports to publications that calculate natural gas index prices, the alleged manipulation of the California power market and the restatement of our financial statements for 1999-2001. The Regents of the University of California are lead plaintiff and Lerach Coughlin Stoia & Robbins, LLP is class counsel. The plaintiff filed an amended complaint in January 2004 and, in March 2004, we filed motions to dismiss. Briefing on our motions was completed in June 2004. The judge entered an order on our motion in October 2004 dismissing all claims brought by the plaintiff under the Securities Act of 1933, except those relating to Dynegy s March 2001 note offering and December 2001 common stock offering, and the Securities Exchange Act of 1934, except those dealing with Project Alpha and two alleged round-trip trades. Further, the judge scheduled the trial to commence in May 2005. Also in October 2004, the plaintiff voluntarily dismissed its claim under the Securities Act of 1933 relating to our March 2001 note offering. The parties filed motions on the class certification issue throughout the fourth quarter 2004. In December 2004, the court issued an order identifying the class period for the Exchange Act claims as June 21, 2001 through July 22, 2002, and the class period for the Securities Act claims to begin December 20, 2001. The court is taking discovery on the issue of the closing date for the Securities Act class period. We have been, and will continue to actively mediate this matter to reach a reasonable settlement if possible. However, we will be fully prepared for the trial scheduled for May 2005 in the event a settlement cannot be reached with the plaintiff. An adverse result in this litigation could have a material adverse effect on our financial condition, results of operations and cash flows. Reserves have been provided in connection with this litigation.

In addition, we are a nominal defendant in several derivative lawsuits brought by shareholders on Dynegy s behalf against certain of our former officers and current and former directors whose claims are similar to those described above. These lawsuits have been consolidated into two groups one pending in federal court and the other pending in state court. A hearing on our motion to dismiss the federal derivative claim was held in February

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2005, at which time the judge indicated his intent to stay or dismiss this matter pending the resolution of the shareholder litigation described above. Subsequently, in February 2005, the plaintiffs voluntarily dismissed this lawsuit. Discovery in the state derivative matter is ongoing. We do not expect to incur any material liability with respect to these claims.

ERISA/Dynegy 401(k) Litigation. We were defendants in a purported class action complaint filed in federal district court on behalf of participants holding Dynegy common stock in the Dynegy 401(k) Savings Plan during the period from April 1999 to January 2003. This complaint alleges violations of ERISA in connection with our 401(k) Savings Plan, including claims that our Board and certain of our former and current officers, past and present members of our Benefit Plans Committee, former employees who served on a predecessor committee to our Benefit Plans Committee, and Vanguard Fiduciary Trust Company and CG Trust Company (trustees of the trust that held Plan assets for portions of the class period) breached their fiduciary duties to the Plan s participants and beneficiaries in connection with the Plan s investment in Dynegy common stock in particular with respect to our financial statements, Project Alpha, round-trip trades and gas price index reporting. The lawsuit seeks unspecified damages for the losses to the Plan, as well as attorney s fees and other costs. In July 2003, we filed a motion to dismiss this action. The judge entered an order on our motion in March 2004, dismissing several of the plaintiff s claims and all of the defendants except Dynegy and the members of our Benefit Plans Committee from January 2002 to January 2003, the substantially reduced class period established by the order. In May 2004, in response to the plaintiff s request, the judge ordered the parties to engage in mediation. The parties mediated for two months, and ultimately reached a settlement under which the defendants agreed to pay $30.75 million to the plaintiff for a full and final release of all claims. In December 2004, the Court granted final approval of the agreement and the settlement was fully funded by insurance proceeds. Plaintiff s counsel is currently in the process of distributing the settlement funds to the class members.

ERISA/Illinois Power 401(k) Litigation. In January 2005, three Illinois Power employees and participants in the Illinois Power Company Incentive Savings Plan For Employees Covered Under a Collective Bargaining Agreement, which we refer to as the Illinois Power 401(k) Plan, purporting to represent all Illinois Power employees who held Dynegy common stock through the Illinois Power 401(k) Plan during the period from February 2000 through September 2004, filed a lawsuit in federal court in the Southern District of Illinois against us, Illinois Power, DMG and several individual defendants. The complaint alleges violations of ERISA in connection with the Illinois Power 401(k) Plan, including claims that certain of our former and current officers (who are past and present members of our Benefit Plans Committee) breached their fiduciary duties to the plan s participants and beneficiaries in connection with the plan s investment in Dynegy common stock in a manner similar to that alleged in the complaint filed with respect to the ERISA litigation we settled in December 2004 described above. The lawsuit seeks unspecified damages for the losses to the plan, as well as attorney s fees and other costs.

Baldwin Station Litigation. Since November 1999, DMG has been the subject of an NOV from the EPA and a complaint filed by the EPA and the DOJ in federal district court alleging violations of the Clean Air Act and related federal and Illinois regulations related to certain maintenance, repair and replacement activities at our Baldwin generating station. We have reached agreement with the EPA, the DOJ, the State of Illinois and the environmental group intervenors on terms to settle the litigation. A consent decree was signed by all parties and lodged with the U.S. District Court for the Southern District of Illinois on March 7, 2005. As required by the Clean Air Act, the consent decree will be posted in the Federal Register and the public will be given an opportunity to comment on the terms of the settlement. We expect that the consent decree will be approved and entered by the Court after the public comments have been considered and addressed by EPA and the DOJ. The consent decree provides for our payment of a civil penalty of $9 million and for our funding of several environmental projects in the additional aggregate amount of $15 million. It also requires us to install additional emission controls at our Baldwin, Vermilion and Havana plants. Under the terms of the settlement, we will invest

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$321 million in emission control projects through 2010, including the previously planned conversion of our Vermilion facility to low-sulfur PRB coal, with an additional $224 million in emission control projects in the 2011-2012 timeframe. The decree settles all claims in the litigation, as well as similar claims that might have been brought related to maintenance, repair and replacement activities at other DMG plants including Vermilion, Wood River, Hennepin and Havana.

Reserves have been provided in an aggregate amount adequate to cover the civil penalties and the environmental projects provided for under the consent decree.

The EPA previously requested information, which we provided, concerning maintenance, repair and replacement activities at our Danskammer and Roseton plants. The consent decree does not cover any activities at the Danskammer and Roseton plants. Although the EPA could eventually commence enforcement actions based on activities at these plants, we are unable to assess the likelihood of any such additional EPA enforcement actions.

California Market Litigation. We and numerous other power generators and marketers are the subject of numerous lawsuits arising from our participation in the western power markets during the California energy crisis. Eight of these lawsuits, which primarily allege manipulation of the California wholesale power markets and seek unspecified treble damages, were consolidated before a single federal judge. That judge dismissed two of the cases in the first quarter 2003 on the grounds of FERC preemption and the filed rate doctrine. The Ninth Circuit Court of Appeals affirmed these dismissals in June 2004 and September 2004, respectively. An appeal from the Ninth Circuit s affirmation of the September 2004 dismissal has been taken to the United States Supreme Court, and we filed our response brief in January 2005. Regarding the remaining six consolidated cases, the Ninth Circuit denied our appeal of a prior decision to remand those cases to state court and affirmed the remand in December 2004. We intend to file a motion to dismiss these cases in the state court in the first quarter 2005.

In addition to the eight consolidated lawsuits discussed above, nine other putative class actions and/or representative actions were filed in state and federal court on behalf of business and residential electricity consumers against us and numerous other power generators and marketers between April and October 2002. The complaints allege unfair, unlawful and deceptive practices in violation of the California Unfair Business Practices Act and seek an injunction, restitution and unspecified damages. While some of the allegations in these lawsuits are similar to the allegations in the eight lawsuits described above, these lawsuits include additional allegations relating to, among other things, the validity of the contracts between these power generators and the CDWR. The court dismissed eight of these nine actions, although the plaintiffs appealed, and the briefing on that appeal was completed in October 2004. In February 2005, the Ninth Circuit issued its decision affirming the denial of remand and dismissal of these cases. The ninth case was remanded to state court, where a newly added defendant filed a motion in February 2004 to remove the case back to federal court. In January 2005, following a hearing on the issue, the court denied the removal and returned the case to state court. We intend to file expeditiously a motion to dismiss this case.

In December 2002, two additional actions were filed with similar allegations on behalf of residents of Washington and Oregon. In May 2003, the plaintiffs voluntarily dismissed these actions and refiled them in California Superior Court as a class action complaint. The complaint, which was brought on behalf of consumers and businesses in Oregon, Washington, Utah, Nevada, Idaho, New Mexico, Arizona and Montana that purchased energy from the California market, alleges violations of the Cartwright Act and unfair business practices. We have removed the action from state court and consolidated it with existing actions pending before the United States District Court for the Northern District of California. The hearing on plaintiffs appeal to remand to state court occurred in February 2004. The judge stayed his ruling on the appeal pending the Ninth Circuit s ruling on the six consolidated cases referenced above.

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In May 2004, Wah Chang, a division of TDY Industries, Inc., filed suit in Oregon federal court against several energy companies, including Dynegy Power Marketing, Inc., seeking more than $30 million in compensatory damages resulting from alleged manipulation of the California wholesale power markets. In February 2005, at a hearing on our December 2004 motion to dismiss, the court granted our motion and dismissed this lawsuit.

In June 2004, the City of Tacoma public utility filed a lawsuit in Washington federal court against a number of energy companies, including us, alleging it paid inflated prices for electricity due to the defendants manipulation of the California wholesale power markets. In response to the defendants December 2004 motion, the court dismissed this lawsuit in February 2005.

In October 2004, Preferred Energy Services, an independent electric services provider in California, filed suit against us and several other defendants alleging that the defendants, in violation of the California anti-trust and unfair business practices statutes, engaged in unfair, unlawful and deceptive practices in the California wholesale energy market from May 2000 through December 2001. Plaintiff, which formerly sold electricity generated from renewable sources in the California market, claims to have been forced out of business by the defendants conduct and is seeking $5 million in compensatory damages, as well as treble damages. We have not yet been served with this lawsuit.

We believe that we have meritorious defenses to these claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability or estimate the range of possible loss, if any, that we might incur in connection with these lawsuits. However, given the nature of the claims, an adverse result in any of these proceedings could have a material adverse effect on our financial condition, results of operations and cash flows.

FERC and Related Regulatory Investigations Requests for Refunds. In October 2004, the FERC approved in all respects the agreement announced by Dynegy and West Coast Power in April 2004 which provides for the settlement of FERC claims relating to western energy market transactions that occurred from January 2000 through June 2001, including:

- the FERC s June 2003 order to show cause why the activities of certain participants in the California power markets from January 2000 to June 2001, including Dynegy, did not constitute gaming and/or anomalous market behavior as defined in the Cal ISO and Cal PX tariffs, which matter was resolved by the January 2004 settlement providing that West Coast Power will pay approximately $3 million into a fund for the benefit of California and Western electricity consumers. This January 2004 settlement was incorporated into the broader settlement described below; and

- the FERC s July 2001 hearings and October 2003 orders relating to the establishment of (i) refunds to electricity customers, or offsets against amounts owed to electricity suppliers, during the period of October 2000 through June 2001 and (ii) a methodology to calculate mitigated market clearing prices in the Cal ISO and the Cal PX markets.

The parties to this settlement other than Dynegy and West Coast Power include the FERC Office of Market Oversight and Investigations, NRG Energy, Inc., Pacific Gas and Electric Company, Southern California Edison, San Diego Gas & Electric Company, the CDWR, the California Electricity Oversight Board and the California Attorney General. Other market participants are permitted to opt into this settlement and share in the distribution of the settlement proceeds. Most of these other market participants have agreed to participate in the settlement. The entitlement to refund and/or the liability of each of the non-settling market participants will be determined by the Cal ISO. Under the terms of the settlement, we will have no further liability to these non-settling parties.

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As part of the settlement agreement, West Coast Power agreed to (i) forego its right to collect approximately $259 million in past-due receivables, plus interest, from the Cal ISO and the Cal PX related to the settlement period, (ii) forego natural gas cost recovery claims against the California settling parties related to the settlement period, and (iii) place into escrow accounts a total of $22.5 million, which includes the above-referenced $3 million settlement with the FERC staff, for subsequent distribution to various California energy purchasers. In exchange, the settling parties agreed to forego (i) all claims relating to refunds or other monetary damages for sales of electricity during the settlement period, and (ii) claims alleging receipt of unjust or unreasonable rates for the sale of electricity during the settlement period.

The settlement further provides that we are entitled to pursue claims for reimbursement of fuel costs against various non-settling market participants. We are currently pursuing these claims but are unable to predict the amounts that may be recovered from such parties.

The settlement does not apply to the ongoing civil litigation related to the California energy markets described above in which Dynegy and West Coast Power are defendants. The settlement also does not apply to the pending appeal by the CPUC and the California Electricity Oversight Board of the FERC s prior decision to affirm the validity of the West Coast Power-CDWR contract. We are currently awaiting a ruling on this appeal and related filings and cannot predict their outcome.

West Coast Power. Prior to the approval of the above-described settlement by the FERC in October 2004, our portion of the receivables owed to West Coast Power by the Cal ISO and Cal PX as of September 30, 2004 approximated $214 million. As part of the settlement, West Coast Power agreed to forego its right to collect these past due receivables. This change had no impact on our results, as our portion of these receivables was fully reserved.

Enron Trade Credit Litigation. Shortly before their bankruptcy filing in the fourth quarter 2001, we determined that Enron Corp. and its affiliates had net exposure to us, including certain liquidated damages and other amounts relating to the termination of commercial transactions among the parties, of approximately $84 million. This exposure was calculated by setting off approximately $230 million owed from Dynegy entities to Enron entities against approximately $314 million owed from Enron entities to Dynegy entities. The master netting agreement between Enron and us and the valuation of the commercial transactions covered by the agreement, which valuation is based principally on the parties assessment of market prices for such period, remain subject to some dispute. We have engaged in an ongoing process with Enron to reconcile the differences between our respective valuations of the transactions and accounts receivable. As a result of ongoing refinement of the values of past transactions, we reduced the $84 million amount that we originally believed we were owed by Enron to approximately $57 million, including the liabilities under the gas transportation agreement related to the Sithe Independence power tolling arrangement. This change in value had no impact on our results, as the net receivable was fully reserved in the fourth quarter 2001. In the event that Enron is victorious in its position that the master netting agreement is unenforceable, our exposure to Enron would be approximately $216 million, with as much as $220 million in unsecured Dynegy claims remaining to enforce against the bankruptcy estate. As required by the master netting agreement, we instituted arbitration proceedings against those Enron parties not in bankruptcy in 2002 and filed a motion with the Bankruptcy Court requesting that we be allowed to proceed to arbitration against those Enron parties that are in bankruptcy. The Enron parties opposed our request and filed an adversary proceeding against us, alleging that the master netting agreement should not be enforced and that the Enron companies should recover approximately $230 million from us. We have disputed such allegations and are vigorously defending our position regarding the setoff rights contained in the master netting agreement, although the Bankruptcy Court has yet to rule on the enforceability of the master netting agreement.

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In November 2003, we gave notice of our intent to pursue arbitration against Enron Canada Corp. as a non-bankrupt party to the master netting agreement. In response, Enron Canada Corp. filed a lawsuit in Canadian District Court to recover the amounts that it claims to be owed by our Canadian subsidiary under the master netting agreement, contingent upon a Bankruptcy Court ruling on the enforceability of the master netting agreement. In December 2003, Enron filed an application with the Bankruptcy Court for an injunction to prohibit this arbitration; the Bankruptcy Court ruled that the automatic stay of the bankruptcy applied to our request to pursue arbitration against Enron Canada Corp. under the master netting agreement. Consequently, we are currently prohibited from enforcing the master netting agreement by arbitration. In March 2004, we appealed the enforcement of the automatic stay and requested permission from the appellate court to proceed with arbitration against Enron Canada Corp. We also filed a motion with the Bankruptcy Court requesting a trial to determine the enforceability of the master netting agreement under the U.S. Bankruptcy Code. The appellate court denied our appeal as interlocutory in November 2004. We are currently awaiting a ruling by the Bankruptcy Court on our request for a trial date. The parties engaged in a second court-ordered mediation in November 2004, but did not reach a settlement.

If the setoff rights are modified or disallowed, either by agreement or otherwise, the amount available for our entities to set off against sums that might be due Enron entities could be reduced materially. In fact, we could be required to pay to Enron the full amount that it claims to be owed, while we would be an unsecured creditor of Enron to the extent of our claim. Reserves have been provided in an aggregate amount we consider reasonable with respect to Enron s claims. Given the size of the claims at issue, an adverse result could have a material adverse effect on our financial condition, results of operations and cash flows.

Severance Arbitrations. Our former CEO, Chuck Watson, former President, Steve Bergstrom, and former CFO, Rob Doty, each filed for arbitration pursuant to the terms of their employment/severance agreements. These former officers made arbitration claims seeking payments of up to approximately $28.7 million, $10.4 million and $3.4 million, respectively. In May 2004, pursuant to the decision of the arbitration panel, we paid Mr. Bergstrom $10.4 million plus attorneys fees, costs and interest in accordance with the arbitration panel s decisions. Shortly after the panel s decisions in the Bergstrom matter, we elected to enter into mediation with Mr. Watson. Through mediation, we agreed to pay Mr. Watson $22 million to settle his severance claims. We recorded an expense in the second quarter 2004 in the amount of the difference between this settlement amount and our severance accrual for this matter. Please read Note 4 Restructuring and Impairment Charges Severance and Other Restructuring Costs beginning on page F-31 for further discussion regarding the accrual relating to these former executive officers.

The arbitration with respect to Mr. Doty is scheduled to commence in May 2005. Mr. Doty s agreement is subject to interpretation, and we maintain that the amount owed is substantially lower than the amount sought. We recorded a severance accrual we consider reasonable relating to this proceeding.

Farnsworth Litigation. In August 2002, Bradley Farnsworth filed a lawsuit against us in state court claiming breach of contract and that he was demoted and ultimately fired from the position of Controller for refusing to participate in illegal activities. Specifically, Mr. Farnsworth alleged, in the words of his amended complaint, that certain of our former executive officers requested that he shave or reduce for accounting purposes the forward price curves associated with the natural gas business in the United Kingdom for the period of October 1, 2000 through March 31, 2001, in order to indicate a reduction in our mark-to-market losses. In March 2004, the judge dismissed Mr. Farnsworth s claim that he was asked to shave forward price curves. Under his remaining breach of contract and fraudulent inducement claims, Mr. Farnsworth alleged he was entitled to a termination payment under his employment agreement, which he estimated at $11 million, equal to 2.99 times the greater of his average base salary and incentive compensation for the highest three calendar years preceding termination or his base salary and target bonus amount for the year of termination. Trial on the breach of contract and fraud claims occurred in December 2004. Although the jury found that we did not breach the

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employment agreement, it found that Mr. Farnsworth was fraudulently induced to enter into the agreement. Consequently, the jury awarded the plaintiff $2.2 million in actual damages and $1.4 million in punitive damages. We subsequently settled this litigation and paid Mr. Farnsworth $1.4 million in exchange for a complete release. Our reserve for this litigation was adequate with respect to the settlement amount.

Apache Litigation. In May 2002, Apache Corporation filed suit in state court against Versado, as purchaser and processor of Apache s gas, and DMS, as operator of the Versado assets in New Mexico, seeking more than $9 million in damages. The plaintiff s petition, as amended, alleges (i) excessive field losses of natural gas from wells owned by the plaintiff, (ii) that Versado engaged in sham transactions with affiliates, resulting in Versado not receiving fair market value when it sells gas and liquids, and (iii) that the formula for calculating the amount Versado receives from its buyers of gas and liquids is flawed since it is based on gas price indexes that these same affiliates are alleged to have manipulated by providing false price information to the index publisher. At trial, the plaintiff s claim with respect to the alleged sham transactions and index manipulation, among others, were severed by the court and abated for a future trial, and the jury found in favor of the plaintiff on the remaining lost gas claim, awarding approximately $1.6 million in damages. In May 2004, our motion to set aside this judgment was granted by the court and the jury s award to the plaintiff was vacated. The plaintiff filed its notice of appeal with the court in October 2004 and its appellate brief in December 2004. We intend to file our response in the first quarter 2005. The parties attended mediation in February 2005, but did not reach a settlement. We do not believe that any liability we might incur as a result of this litigation would have a material adverse effect on our financial condition, results of operations or cash flows.

Gas Index Pricing Litigation. We are defending the following suits claiming damages resulting from the alleged manipulation of gas index publications and prices by us and others: *ABAG v. Sempra Energy et al.* (filed in state court in November 2004); *Ableman Art Glass v. Encana Corporation et al.* (class action filed in federal court in December 2004); *Benschiedt* (class action filed in state court in February 2004); *Bustamante v. The McGraw Hill Companies et al*. (class action filed in state court in November 2002); *City and County of San Francisco v. Dynegy Inc. et al.* (filed in state court in July 2004); *County of San Diego v. Dynegy Inc., Dynegy Marketing and Trade, West Coast Power, et al.* (filed in state court in July 2004); *County of San Mateo v. Sempra Energy et al.* (filed in state court in December 2004); *County of Santa Clara v. Dynegy Inc., Dynegy Marketing and Trade, West Coast Power, et al.* (filed in state court in July 2004); *Fairhaven Power Company v. Encana Corp. et al* (class action filed in federal court in September 2004); *In re Natural Gas Commodity Litigation* (class action filed in federal court in January 2004); *Leggett v. Duke Energy et al.* (class action filed in state court in January 2005); *Multiut v. Dynegy Inc.* (filed in federal court in December 2004); *Nelson Brothers LLC v. Cherokee Nitrogen v. Dynegy Marketing and Trade and Dynegy Inc.* (filed in state court in April 2003); *Nurserymen s Exchange v. Sempra Energy et al.* (filed in state court in October 2004); *Older v. Dynegy Inc. et al.* (filed in federal court in September 2004); *Owens-Brockway v. Sempra Energy at al.* (filed in state court in January 2005); *People of the State of Montana et al. v. Williams Energy Marketing et al.* (filed in federal court in July 2003); *Sacramento Municipal Utility District (SMUD) v. Reliant Energy Services, et al.* (filed in state court in November 2004); *School Project for Utility Rate Reduction v. Sempra Energy et al.* (filed in state court in November 2004); *Sierra Pacific Resources and Nevada Power Company v. El Paso Corp. et al.* (filed in federal court in April 2003)*; Tamco v. Dynegy Inc. et al.* (filed in state court in December 2004); *Texas-Ohio Energy, Inc. v. CenterPoint Energy Inc., et al.* (class action filed in federal court in November 2003); and *Utility Savings & Refund v. Reliant Energy Services, et al.* (class action filed in federal court in November 2004). In each of these suits, the plaintiffs allege that we and other energy companies engaged in an illegal scheme to inflate natural gas prices by providing false information to gas index publications, thereby manipulating the price. All of the complaints rely heavily on the FERC and CFTC investigations into and report concerning index-reporting manipulation in the energy industry. The plaintiffs generally seek unspecified actual and punitive damages relating to costs they claim to have incurred as a result of the alleged conduct. We have not been served in the *Montana* or *Leggett* cases.

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Pursuant to various motions filed by the parties to the litigation described above, the gas index pricing lawsuits pending in state court (except for *Nelson Brothers*) have been consolidated before a single judge in state court in San Diego. These cases are now entitled the Judicial Counsel Coordinated Proceeding (JCCP) 4221, 4224, 4226, and 4228, the Natural Gas Anti-Trust Cases, I, II, III, & IV , which we refer to as the Coordinated Gas Index Cases. A case management conference is expected in the next 60 days. The *Nelson Brothers* lawsuit, in which we have been brought in as a third party by the defendant, Cherokee Nitrogen, involves an alleged breach of a gas purchase contract and continues in state court in Alabama. The parties are presently engaged in discovery.

As to the gas index pricing lawsuits that have been filed in federal court, the *Sierra Pacific* case was dismissed in December 2004 on defendants motion. In *Texas-Ohio*, the defendants filed a motion to dismiss in May 2004, on which the court held a hearing in January 2005. We are awaiting the court s ruling. The parties are actively engaged in discovery in the *In re Natural Gas Commodity Litigation* matter, following denial of the appeal of the previous denial of defendants motion to dismiss. The *Multiut* case involves a counterclaim filed by the defendant, Multiut, against whom we have a pending breach of gas purchase contract claim. That case is proceeding in federal court in Illinois. The remaining federal court cases are pending transfer, or have already been transferred, to the federal judge in Nevada who is also currently presiding over the *Sierra Pacific* and *Texas-Ohio* matters.

We are analyzing all of these claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability in connection with these lawsuits. We do not believe that any liability that we might incur as a result of this litigation would have a material adverse effect on our financial condition, results of operations or cash flows.

Stand Energy Litigation (formerly Atlantigas Corp. Litigation). In November 2003, Atlantigas Corporation filed suit in Maryland against us and several other defendants alleging certain conspiracies between natural gas shippers and storage facilities. The complaint alleged that the interstate pipelines provided preferential storage and transportation services to their own unregulated marketing affiliate in return for percentages of the profits reaped by the marketing affiliate and that such conduct violated applicable FERC regulations and the federal antitrust laws and constituted common law tortious interference with contractual and business relations. In addition, the complaint claimed we conspired with the other defendants to receive preferential natural gas storage and transportation services at off-tariff prices. The complaint sought unspecified compensatory and punitive damages. In January 2004, the defendants filed motions to dismiss the plaintiff s claims. In July 2004, prior to the Court s ruling on the defendants motions, the plaintiff voluntarily dismissed the Maryland federal court action against all defendants. Shortly thereafter, plaintiff filed a class action lawsuit in a West Virginia state court against several defendants, excluding us, on similar grounds to the previous Maryland federal action. In October 2004, the plaintiff filed an amended class action complaint naming us as a defendant in the litigation. In response, Columbia, the primary defendant, filed a motion to strike the amended pleading as untimely and our participation in the suit will be delayed pending the resolution of this motion. We are analyzing these claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability in connection with these lawsuits. We do not believe that any liability that we might incur as a result of this litigation would have a material adverse effect on our financial condition, results of operations or cash flows.

Stumpf Litigation. We and two former subsidiaries are defendants in a lawsuit filed in New York by Stumpf AG and two of its affiliates stemming from the shutdown of our Vienna telecommunications office in the spring of 2001. The plaintiffs are seeking $29 million in compensatory and unspecified punitive damages, alleging breach of contract, tortious interference and alter ego-based claims primarily relating to the termination of real property leases to which our former Austrian subsidiary was a party. These claims are based on similar lawsuits filed in

Austria against our former Austrian subsidiary, which was sold to a third party in January 2003. This

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former subsidiary is in liquidation and, recently, one of its liquidators admitted, for purposes of the liquidation, the plaintiffs claims in the amount of $30 million. Although this lawsuit was initially stayed pending the Austrian insolvency proceeding, the stay was lifted and we filed our answer in May 2004. The parties are actively engaged in discovery. The plaintiffs filed a motion for summary judgment on this matter in December 2004, and our reply to that motion is due in the second quarter 2005.

We intend to oppose these claims vigorously and believe we have meritorious defenses. Although it is not possible to predict with certainty whether we will incur any liability in connection with these lawsuits, we do not believe that any liability we might incur as a result of these lawsuits would have a material adverse effect on our financial condition, results of operations or cash flows. Reserves have been provided in connection with this litigation.

Alleged Marketing Contract Defaults. We have posted collateral to support a portion of our obligations in our CRM business, including our obligations under one of our power tolling arrangements. While we worked with various counterparties to provide mutually acceptable collateral or other adequate assurance under these contracts, we have not reached agreement with Sithe Independence and Sterlington/Quachita Power LLC regarding a mutually acceptable amount of collateral in support of our obligations under our power tolling arrangements with either of these two parties. Although we are current on all contract payments to these counterparties, we previously received a notice of default from each such party with regard to collateral. Despite receiving these notices, all parties are continuing to perform and we have fulfilled our economic commitments under these contracts. Our average annual capacity payments under these two arrangements approximate $75 million and $63 million, respectively, and the contracts extend through 2014 and 2012, respectively, with a five-year extension option for Sterlington. If these two parties were successfully to pursue claims that we defaulted on these contracts, they could declare a termination of their respective contracts, which generally provide for termination payments based on the agreed mark-to-market value of the contracts. Because of the effects of changes in commodity prices on the mark-to-market value of these contracts, as well as the likelihood that we would differ with our counterparties as to the estimated value of these contracts, we cannot predict with any degree of certainty the amounts of termination payments that could be required under these two contracts. Disputes relating to these two contracts, if resolved against us, could materially adversely affect our financial condition, results of operations and cash flows.

U.S. Attorney Investigations. The U.S. Attorney s office in Houston is continuing its investigation of our actions relating to Project Alpha and our gas trade reporting practices. We have produced documents and witnesses for interviews in connection with this investigation. Seven of our natural gas traders were terminated in the fourth quarter 2002 for violating our Code of Business Conduct after an ongoing internal investigation conducted by our Audit and Compliance Committee in collaboration with independent counsel discovered that inaccurate information regarding natural gas trades had been reported to various energy industry publications. In January 2003, one of our former natural gas traders was indicted in Houston on three counts of knowingly causing the transmission of false trade reports used to calculate the index price of natural gas and four counts of wire fraud. In August 2003, however, several of these counts were dismissed as unconstitutional. Upon request by the U.S. Attorney s office for reconsideration of this ruling, the judge reinstated the dismissed counts. The case was originally set for trial in January 2004; however, both the U.S. Attorney s office and the defense have appealed the court s rulings regarding the dismissed and reinstated charges. The Fifth Circuit Court of Appeals heard argument on these matters in October 2004, and reinstated all of the charges against the defendant in December 2004. A trial date has not yet been set on this indictment. In addition, in December 2004, a second indictment was filed against this same former employee and other individuals alleging conspiracy to falsely report gas prices to various index publications. That indictment is scheduled for trial in October 2005.

In June 2003, three former Dynegy employees were indicted on charges of conspiracy, securities fraud and mail and wire fraud related to the Project Alpha transaction. Subsequently, two of these former employees pled

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guilty to conspiracy to commit securities fraud. These former employees have not been sentenced pending the completion of the government s investigation. Trial on the indictment against the third employee was held in November 2003. The defendant was convicted on all charges and, in March 2004, sentenced to a term of approximately 24 years in federal prison.

We are cooperating fully with the U.S. Attorney s office in its continuing investigation of these matters and cannot predict the ultimate outcome of these investigations.

Additionally, the United States Attorney s office in the Northern District of California issued a Grand Jury subpoena requesting information related to our activities in the California energy markets in November 2002. We have been, and intend to continue, cooperating fully with the U.S. Attorney s office in its investigation of these matters, including production of substantial documents responsive to the subpoena and other requests for information. We cannot predict the ultimate outcome of this investigation.

Department of Labor Investigation. In August 2002, the U.S. Department of Labor commenced an official investigation pursuant to Section 504 of ERISA with respect to the benefit plans we maintain and our ERISA affiliates. We cooperated with the Department of Labor throughout this investigation, which focused on a review of plan documentation, plan reporting and disclosure, plan recordkeeping, plan investments and investment options, plan fiduciaries and third-party service providers, plan contributions and other operational aspects of the plans. In February 2005, we received a letter from the Department of Labor indicating that, as a result of our recent settlement in the ERISA litigation, it intended to take no further action with respect to its investigation of the Dynegy Inc. 401(k) Plan. However, its investigation is ongoing as it relates to the Illinois Power 401(k) Plans, and the recent litigation relating to those plans described above.

Other Commitments and Contingencies

In conducting our operations, we have routinely entered into long-term commodity purchase and sale commitments, as well as agreements that commit future cash flow to the lease or acquisition of assets used in our businesses. These commitments have been typically associated with commodity supply arrangements, capital projects, reservation charges associated with firm transmission, transportation, storage and leases for office space, equipment, plant sites, power generation assets and LPG vessel charters. The following describes the more significant commitments outstanding at December 31, 2004.

Purchase Obligations. We have routinely entered into contracts for the purchase and sale of electricity, some of which contain fixed capacity payments. Such obligations are generally payable on a ratable basis, the terms of which extend through September 2017. In return for such fixed capacity payments, we receive the right to generate electricity, which we then may re-market. These types of arrangements are referred to as tolling arrangements. Fixed payments associated with these arrangements totaled approximately $2.1 billion at December 31, 2004. This amount includes the capacity payments on our remaining tolls as well as a cash obligation under a derivative contract related to the Independence tolling agreement.

We have other firm capacity payments related to storage and transportation of natural gas and transmission of electricity. Such arrangements are routinely used in the physical movement and storage of energy consistent with our business strategy. The total of such obligations was $170 million as of December 31, 2004.

In addition, we have conditional purchase obligations in the amount of $124 million related to our co-sourcing agreement with Accenture Ltd., which runs through 2013. This 10-year agreement may be cancelled after two years upon the payment of a termination fee, which ranges from $6 million for the first quarter 2005, declining to $2 million through 2013. This termination fee is in addition to amounts due for services incurred through the termination date.

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Advance Agreement. In 1997, we received cash from a gas purchaser as an advance payment under our agreement to make future natural gas deliveries over a ten-year period. As a condition of the agreement, we entered into a natural gas swap with a third party under which we became a fixed-price payer on identical volumes to those to be delivered under the agreement at prices based on current market rates. The cash receipt is included as deferred revenue in other long-term liabilities on the consolidated balance sheets and is ratably reduced as gas is delivered to the purchaser under the terms of the agreement. The balance at December 31, 2004 was approximately $42 million. The agreement contains specified non-performance penalties that impact both parties and, as a condition precedent, we purchased a surety bond in support of our obligations under the agreement.

Other Minimum Commitments. In the first quarter 2001, we acquired the DNE power generation facilities. These facilities consist of a combination of baseload, intermediate and peaking facilities aggregating approximately 1,700 MWs. The facilities are approximately 50 miles north of New York City and were acquired for approximately $903 million cash, plus inventory and certain working capital adjustments. In May 2001, two of our subsidiaries completed a sale-leaseback transaction to provide term financing for the DNE facilities. Under the terms of the sale-leaseback transaction, our subsidiaries sold plants and equipment and agreed to lease them back for terms expiring within 34 years, exclusive of renewal options.

Minimum commitments in connection with office space, equipment, plant sites and other leased assets, including the DNE sale-leaseback transaction discussed above, at December 31, 2004, were as follows: 2005- $93 million; 2006-$93 million; 2007-$141 million; 2008-$158 million; 2009- $161 million and beyond-$976 million.

Rental payments made under the terms of these arrangements totaled $82 million in 2004, $83 million in 2003 and $139 million in 2002.

We are party to two charter party agreements relating to VLGCs previously utilized in our global liquids business. The aggregate minimum base commitments of the charter party agreements are approximately $13 million each year for the years 2005 through 2007, and approximately $79 million through lease expiration. The charter party rates payable under the two charter party agreements float in accordance with market based rates for similar shipping services. The $13 million and $79 million numbers set forth above are based on the minimum obligations set forth in the two charter party agreements. The primary term of one charter is through August 2013 while the primary term of the second charter is through August 2014. On January 1, 2003, in connection with the sale of our global liquids business, we sub-chartered both VLGCs to a wholly owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter agreements. We are currently in negotiations with the owners of the VLGCs and their lenders to obtain a novation and release of our operating subsidiary from the two charter party agreements and a partial release of our parent guarantees. Until such time as the novations and partial releases are granted, 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.

Guarantees and Indemnifications. We routinely enter into contractual agreements that contain various representations, warranties, indemnifications and guarantees. Examples of such agreements include, but are not limited to, service agreements, equipment purchase agreements, engineering and technical service agreements, and procurement and construction contracts. Some agreements contain indemnities that cover the other party s negligence or limit the other party s liability with respect to third-party claims, in which event we will effectively be indemnifying the other party. Virtually all such agreements contain representations or warranties that are covered by indemnifications against the losses incurred by the other parties in the event such representations and

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warranties are false. While there is always the possibility of a loss related to such representations, warranties, indemnifications and guarantees in our contractual agreements, and such loss could be significant, in most cases management considers the probability of loss to be extremely remote.

During 2003, as part of our sale of Northern Natural, the Rough and Hornsea gas storage facilities and certain natural gas liquids assets, we provided indemnities to third parties regarding environmental, tax, employee and other representations. Maximum recourse under these indemnities is limited to $209, $857 and $28 for the Northern Natural, Rough and Hornsea gas storage facilities and natural gas liquids assets, respectively. We have also entered into similar indemnifications regarding environmental, tax, employee and other representations when completing other asset sales such as, but not limited to, Hackberry LNG Project, SouthStar Energy Services and various Canadian assets. We carry reserves for existing environmental, tax and employee liabilities and have incurred no other expense relating to these indemnities.

During 2004, as part of our sale of Illinois Power and our interest in Joppa, we provided indemnifications to third parties regarding environmental, tax, employee and other representations. There is no limit to recourse under these indemnities and $100 million of the sale proceeds is being held in escrow pending settlement of environmental litigation or an improvement in our credit rating, although we expect to receive these escrowed funds following approval of the Baldwin consent decree announced in March 2005. Additionally, we have indemnified third parties against losses resulting from possible adverse regulatory actions taken by the ICC that could prevent Illinois Power from recovering costs incurred in connection with purchased gas and investments in specified items. Our maximum liability under this indemnity is 50% of these losses. Illinois Power had not sustained any such losses in recent years and, at the time of the sale of Illinois Power to Ameren, our management considered the probability of any such loss under this indemnity remote. Consequently, the value of the indemnification was deemed to be insignificant. In February 2005, the ICC staff proposed $8 million of disallowances that potentially fall within the scope of the indemnity. We have also been notified of a separate $3 million disallowance proposed by the ICC staff in a different case that also potentially falls within the scope of the indemnity. Further disallowances and other events which fall within the scope of the indemnity may still occur; however, we are not required to incur an expense in connection with these indemnifications as management at this time considers the probability of an adverse outcome as only reasonably possible. We intend to contest vigorously the proposed disallowances.

We have also entered into various indemnifications regarding environmental, tax, employee and other representations when completing other asset sales such as, but not limited to Michigan Power, Oyster Creek, Hartwell, Commonwealth, Sherman, Indian Basin and PESA. We carry reserves for existing environmental, tax and employee liabilities and have incurred no other expense relating to these indemnities.

During 2004, as part of entering into a back-to-back power purchase agreement with Constellation, under which Constellation will effectively receive our rights to purchase approximately 570 MW of capacity and energy arising under our Kendall tolling contract, we have guaranteed Constellation an aggregate $3.5 million in reactive power revenues over the four year term of the power purchase agreement. We have established a liability of $0.3 million reflecting the fair value of this guarantee, but have made no payments or incurred any other expense relating to this guarantee.

Through one of our subsidiaries, we hold a 50% ownership interest in Nevada Cogeneration Associates #2. Nevada Cogeneration, in which our partner is a ChevronTexaco subsidiary, owns the Black Mountain power generation facility and has a power purchase agreement with a third party that extends through April 2023. In connection with the power purchase agreement, pursuant to which Nevada Cogeneration receives payments which decrease in amount over time, we agreed to guarantee 50% of certain payments that may be due to the purchaser under a mechanism designed to protect it from early termination of the agreement. At December 31,

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2004, if an event of default had occurred under the terms of the mortgage on the facility entered into in connection with the power purchase agreement, we could have been required to pay the purchaser $45 million under the guarantee. In addition, while there is a question of interpretation regarding the existence of an obligation to make payments calculated under this mechanism upon the scheduled termination of the agreement, management does not expect that any such payments would be required.

Note 17 Regulatory Issues

We are subject to regulation by various federal, state, local and foreign agencies, including extensive rules and regulations governing transportation, transmission and sale of energy commodities as well as the discharge of materials into the environment or otherwise relating to environmental protection. Compliance with these regulations requires general and administrative, capital and operating expenditures including those related to monitoring, pollution control equipment, emission fees and permitting at various operating facilities and remediation obligations. In addition, the U.S. Congress has before it a number of bills that could impact regulations or impose new regulations applicable to us and our subsidiaries. We cannot predict the outcome of these bills or other regulatory developments or the effects that they might have on our business.

Danskammer Water Permit. Our wastewater discharges are permitted under the Clean Water Act and analogous state laws. These permits are subject to review every five years. The state-issued water discharge permits associated with the DNE facilities expired in 1992. However, under New York State law, the authorization arising under these permits remains in effect and allows for continued operation under the terms of the original permit, provided that a timely and sufficient application requesting renewal has been filed as required. In May 1992, the then owner of the Danskammer facility filed a renewal application which we believe was timely and sufficient. In November 2002, several environmental groups filed suit in the Supreme Court of the State of New York seeking, among other things, a declaratory judgment that the Danskammer water intake and discharge permit expired because of alleged deficiencies in the renewal application process. In September 2004, the Court ruled that the water intake and discharge permit for our Danskammer facility is void, but stayed the enforcement of the decision pending further review by the Court or by the Appellate Division.

In October 2004, we filed our appeal of the Court s decision with the Appellate Division, and we intend to pursue vigorously our challenge to the Court s ruling voiding our permit. We will also continue to seek approval of our application to renew the water intake and discharge permit in proceedings before the New York State Department of Environmental Conservation. If our appeal is ultimately unsuccessful, we may be required to suspend operations at our Danskammer facility pending receipt of final approval of the renewal of our water intake and discharge permit. We cannot predict with any certainty the outcome of these proceedings; however, an adverse outcome, particularly a requirement that we suspend operations at our Danskammer facility for any period of time, could have a material adverse effect on our financial condition, results of operations and cash flows.

FERC Market-Based Rate Authority. The FERC s market-based rate authority allows the sale of power at negotiated rates through the bilateral market or within an organized energy market, conditioned on periodic re-review. In April 2004, the FERC issued an order concerning the ability of companies to sell electricity at market-based rates. In this order, the FERC adopted two new tests for assessing generation market power. If an applicant for market-based rate authority is found to possess generation market power under these tests and is unsuccessful in challenging that finding, the applicant may either propose mitigation measures or adopt cost-based rates. If the FERC finds that the proposed mitigation measures fail to eliminate the ability to exercise market power, the applicant s market-based rate authority will be revoked and the applicant will be subject to cost-based default rates, or other cost-based rates proposed by the applicant and approved by the FERC. The FERC issued a follow

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up order in May 2004, which it upheld in July 2004, (i) addressing the implementation process for pending and new market-based rate applications and (ii) establishing a timeline for entities with FERC market-based rate authority to provide the FERC with their market power assessment. These orders required entities that were previously granted market-based rate authority by the FERC, including entities with pending applications for re-review, to resubmit their applications in accordance with the new directive. Consequently, our entities with applications pending since February 2002, including the entities we acquired in January 2005 in connection with the Sithe Energies acquisition, timely resubmitted their applications to the FERC.

In December 2004, the FERC ruled that once the Midwest Independent System Operator, Inc., or MISO, becomes a single market and performs functions such as single central commitment and dispatch with FERC-approved market monitoring and mitigation (currently scheduled for April 2005), MISO would be considered to have a single geographic market for purposes of assessing generation market power. This ruling will enlarge the geographic area in which our DMG facilities would be evaluated for generation market power for the relevant period. Although we cannot predict with any certainty whether our applications to renew our market based rate authority will be approved or the loss of revenues that would result from the imposition of cost-based rates, an adverse outcome with respect to these applications, and the resulting requirement that we charge cost-based rates, could have a material adverse effect on our financial condition, results of operations and cash flows.

Note 18 Capital Stock

At December 31, 2004, we had authorized capital stock consisting of 900,000,000 shares of Class A common stock, 360,000,000 shares of Class B common stock and 70,000,000 shares of preferred stock.

Preferred Stock. Our preferred stock may be issued from time to time in one or more series, the shares of each series to have such designations and powers, preferences, rights, qualifications, limitations and restrictions thereof as specified by our Board of Directors.

Please read Note 14 Redeemable Preferred Securities Series C Convertible Preferred Stock beginning on page F-54 for a discussion of Series C convertible preferred stock we issued to Chevron.

Common Stock. At December 31, 2004, there were 381,903,217 shares of Class A and B common stock issued in the aggregate and 1,679,183 shares were held in treasury. During 2004 and 2003, no quarterly cash dividend payments were made. During 2002, we paid quarterly cash dividends on our common stock of $0.075 per share for the first and second quarters and none thereafter, or $0.15 per share on an annual basis.

Pursuant to the terms of the Illinova acquisition, we split our common shares into two classes, Class A and Class B. All of the Class B common stock is owned by Chevron. Generally, holders of Class A and Class B common stock are entitled to one vote per share on all matters to be voted upon by the shareholders. Holders of Class A common stock may cumulate votes in connection with the election of directors. The election of directors and all other matters will be by a majority of shares represented and entitled to vote, except as otherwise provided by law. Holders of Class B common stock vote together with holders of Class A common stock as a single class on every matter acted upon by the shareholders except for the following matters:

- the holders of Class B common stock vote as a separate class for the election of up to three of our directors, while the holders of Class A common stock vote as a separate class for the remaining directors;

- any amendment to the special corporate governance rights associated with the Class B common stock must be approved by a majority of the directors elected by holders of Class B common stock and a

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majority of all of our directors or by a 66 $^{2}/3$% of the outstanding shares of Class B common stock voting as a separate class, and the affirmative vote of a majority of the shares of Class A and Class B common stock, voting together as a single class; and

any amendment to the provision of the Amended and Restated Articles of Incorporation addressing the voting rights of holders of Class A and Class B common stock requires the approval of 66 $^{2}/3$% of the outstanding shares of Class B common stock voting as a separate class, and the affirmative vote of a majority of the shares of Class A and Class B common stock, voting together as a single class.

Subject to the preferences of preferred stock, holders of Class A and Class B common stock have equal and ratable rights to dividends, when and if dividends are declared by the Board of Directors. Holders of Class A and Class B common stock are entitled to share ratably, as a single class, in all of our assets available for distribution to holders of shares of common stock upon the liquidation, dissolution or winding up of our affairs, after payment of our liabilities and any amounts to holders of preferred stock, if any.

A share of Class B common stock automatically converts into a share of Class A common stock if it is transferred to any person other than an affiliate of ChevronTexaco. Additionally, each share of Class B common stock automatically converts into a share of Class A common stock if the holders of all Class B common stock cease to own collectively at least 15% of our outstanding common stock. Conversely, any shares of Class A common stock acquired by ChevronTexaco or its affiliates will automatically convert into shares of Class B common stock, so long as ChevronTexaco and its affiliates continue to own 15% or more of the outstanding voting power of Dynegy.

Holders of Class A and Class B common stock generally are not entitled to preemptive rights, subscription rights, or redemption rights, except that Chevron is entitled to preemptive rights under the amended and restated shareholder agreement. The rights and preferences of holders of Class A common stock are subject to the rights of any series of preferred stock we may issue.

In January 2002, Chevron purchased approximately 10.4 million shares of Class B common stock in a private transaction, pursuant to the exercise of its preemptive rights under the shareholder agreement. The proceeds from this sale were approximately $205 million.

Common stock activity for the three years ended December 31, 2004 was as follows:

	Class A Common Stock		Class B Common Stock	
	Shares	**Amount**	**Shares**	**Amount**

		(in millions)		
December 31, 2001	269	$ 2,786	86	$ 801
Common stock issued			10	205
Options exercised	3	22		
401(k) plan and profit sharing	3	17		
December 31, 2002	275	$ 2,825	96	$ 1,006
Options exercised	2	15		
401(k) plan and profit sharing	3	8		
December 31, 2003	280	$ 2,848	96	$ 1,006
Options exercised	3	5		
401(k) plan and profit sharing	2	6		
December 31, 2004	285	$ 2,859	96	$ 1,006

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Treasury Stock. During 2002, Class A common stock shares purchased from the open market and placed into treasury totaled 41,929. During 2002, 129,546 shares were issued out of treasury stock. There were no purchases or issuances of treasury stock in 2004 and 2003.

Restricted Stock. During the first and second quarter 2004, we awarded an aggregate 945,055 shares of restricted stock. The closing stock price of our Class A common stock was $4.48 and $3.85, respectively on the dates of grants. These restricted shares vest on the third anniversary from the date of grant. In years prior to 2002, we awarded 47,088 shares of restricted stock, of which 21,392 were outstanding, but not vested, at December 31, 2004. The shares awards were awarded pursuant to the terms of the Dynegy 2000 and 2001 Non-Executive Plans, which are described in Stock Options below.

Stock Options. We have nine stock option plans, all of which contain authorized shares of our Class A common stock. Each option granted is exercisable an option price, which ranges from $0.88 per share to $57.95 per share for options currently outstanding. A brief description of each plan is provided below:

NGC Plan. Created early in our history and revised prior to Dynegy becoming a publicly traded company in 1996, this plan contains 13,651,802 authorized shares, has a 10-year term, and expires in May 2006. All option grants are vested.

Employee Equity Plan. This plan expired in May 2002 and is the only plan in which we granted options below the fair market value of Class A common stock on the date of grant. This plan contains 20,358,802 authorized shares, and grants from this plan vest on the fifth anniversary from the date of the grant. All option grants are vested.

Illinova Plan. Adopted by Illinova prior to the merger with Dynegy, this plan expired upon the merger date in February 2000 and contains 3,000,000 authorized shares. All option grants are vested.

Extant Plan. Adopted by Extant prior to its acquisition by Dynegy, this plan expired in September 2000 and contains 202,577 authorized shares. Grants from this plan vest at 25% per year. All option grants are vested.

UK Plan. This plan contains 276,000 authorized shares and has been terminated. All option grants are vested.

Dynegy 1999 Long-Term Incentive Plan (LTIP). This annual compensation plan contains 6,900,000 authorized shares, has a 10-year term and expires in 2009. All option grants are vested.

Dynegy 2000 LTIP. This annual compensation plan, created for all employees upon the merger of Illinova and Dynegy, contains 10,000,000 authorized shares, has a 10-year term and expires in February 2010. Grants from this plan vest in equal annual installments over a three-year period.

Dynegy 2001 Non-Executive LTIP. This plan is a broad-based plan and contains 10,000,000 authorized shares, has a ten-year term and expires in September 2011. Grants from this plan vest in equal annual installments over a three-year period.

Dynegy 2002 LTIP. This annual compensation plan contains 10,000,000 authorized shares, has a 10-year term and expires in May 2012. Grants from this plan vest in equal annual installments over a three-year period.

All of our option plans cease vesting for employees who are terminated for cause. For voluntary and involuntary termination, disability, retirement or death, continued vesting and/or an extended period in which to exercise vested options may apply, dependent upon the terms of the grant agreement in which a specific grant was awarded. Options awarded to our executive officers and others who participate in our Executive Severance Pay Plan vest immediately upon the occurrence of a change in control in accordance with the terms of the Second Supplemental Amendment to the Executive Severance Pay Plan.

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Compensation expense related to options granted and restricted stock awarded totaled $6 million, $4 million and $11 million for the years ended December 31, 2004, 2003 and 2002, respectively. We recognize compensation expense ratably over the vesting period of the respective awards. Of the total compensation expense recognized for the year ended December 31, 2002, $2 million related to the extension of the exercise period and acceleration of vesting for various stock options associated with divestitures of certain operations and provisions of certain executive employment agreements. No accelerated compensation expense recognition occurred during the years ended December 31, 2004 and 2003. Total options outstanding and exercisable for 2004, 2003 and 2002 were as follows:

	Year Ended December 31,					
	2004		2003		2002	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(options in thousands)					
Outstanding at beginning of period	17,595	$ 18.70	28,035	$ 20.74	33,873	$ 21.39
Granted	1,503	$ 4.47	1,985	$ 1.78	2,284	$ 2.83
Exercised	(2,129)	$ 2.37	(1,958)	$ 2.87	(3,007)	$ 2.95
Cancelled or expired	(5,606)	$ 24.06	(10,467)	$ 23.98	(5,115)	$ 27.54
Outstanding at end of period	11,363	$ 17.23	17,595	$ 18.66	28,035	$ 20.74
Exercisable at end of period	8,444	$ 22.18	12,876	$ 21.28	17,620	$ 19.69
Weighted average fair value of options granted during the period at market		$ 4.47		$ 0.81		$ 1.22

During the three-year period ended December 31, 2004, we granted no options at an exercise price less than the market price on the date of grant.

Options outstanding as of December 31, 2004 are summarized below:

Range of Exercise Prices	Options Outstanding: Number of Options Outstanding at December 31, 2004	Options Outstanding: Weighted Average Remaining Contractual Life (Years)	Options Outstanding: Weighted Average Exercise Price	Options Exercisable: Number of Options Exercisable at December 31, 2004	Options Exercisable: Weighted Average Exercise Price
	(options in thousands)				
$0.88-$2.15	2,609	7.8	$ 1.32	1,080	$ 1.21
$2.16-$5.15	1,951	6.9	$ 4.37	582	$ 4.14
$5.16-$11.59	749	3.4	$ 9.75	736	$ 9.79
$11.60-$23.18	1,543	3.8	$ 15.58	1,540	$ 15.58
$23.19-$23.98	2,138	6.2	$ 23.78	2,138	$ 23.78
$23.99-$34.77	693	4.8	$ 33.75	688	$ 33.79
$34.78-$40.57	152	5.9	$ 37.55	152	$ 37.55
$40.58-$46.36	78	5.9	$ 43.80	78	$ 43.80
$46.37-$52.16	1,376	5.4	$ 47.26	1,376	$ 47.26
$52.17-$57.95	74	4.5	$ 55.71	74	$ 55.71
	11,363			8,444	

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Pursuant to terms of the Illinova acquisition, certain vesting requirements on outstanding options were accelerated and the option shares and strike prices were subject to the exchange ratios applicable in the acquisition.

The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions used for grants in 2004, 2003 and 2002: dividends per year of zero for 2004 and 2003 and $0.15 for 2002; expected volatility of 87.5%, 89.6%, and 74.3%, respectively; a risk-free interest rate of 4.1%, 3.9%, and 4.2%, respectively; and an expected option life of 10 years for all periods.

Note 19 Employee Compensation, Savings and Pension Plans

Short-Term Incentive Plan. We maintain a discretionary incentive compensation plan to provide employees with rewards for the achievement of corporate goals and individual, professional accomplishments. Specific awards are at the discretion of the Compensation and Human Resources Committee of the Board of Directors.

In addition, in 2003 we adopted the Mid-Term Incentive Plan. This special compensation program is limited to select employees who are eligible to receive cash compensation of up to 200% of their annual base salary, payable in two installments over a two-year period, based on the performance of our Class A common stock during the last 30 trading days in 2004 and over the entire year in 2005. The first performance period ended December 31, 2004. The first installment in the aggregate amount of approximately $0.6 million was approved by the Compensation and Human Resources Committee of the Board of Directors and will be paid during the first quarter 2005. We account for this cash plan using variable plan accounting and recognized an aggregate amount of approximately $1 million in compensation expense during 2004 and 2003 associated with the plan.

401(k) Savings Plan. During the 12-months ended December 31, 2004, our employees participated in four 401(k) savings plans, all of which meet the requirements of Section 401(k) of the Internal Revenue Code and are defined contribution plans subject to the provisions of ERISA. The following summarizes the plans:

Dynegy Inc. 401(k) Savings Plan this plan and the related trust fund are established and maintained for the exclusive benefit of participating employees in the United States. All employees of designated Dynegy subsidiaries are eligible to participate in the plan. Employee pre-tax contributions to the plan are matched 100%, up to a maximum of 5% of base pay, subject to IRS limitations. Vesting in our contributions is based on years of service at 25% per full year of service. We may also make annual discretionary contributions to employee accounts, subject to our performance. Matching and discretionary contributions, if any, are allocated in the form of units in the Dynegy common stock fund. During the years ended December 31, 2004, 2003 and 2002, we issued approximately 1 million, 1.8 million and 2.7 million shares, respectively, of our common stock in the form of matching contributions to fund the plan. No discretionary contributions were made for any of the years in the three-year period ended December 31, 2004;

Dynegy Midwest Generation, Inc. 401(K) Savings Plan (formerly the Illinois Power Company Incentive Savings Plan) and Dynegy Midwest Generation, Inc. 401(K) Savings Plan for Employees Covered Under a Collective Bargaining Agreement (formerly the Illinois Power Company Incentive Savings Plan for Employees Covered Under A Collective Bargaining Agreement) we match 50% of employee contributions to the plans, up to a maximum of 6% of compensation, subject to IRS limitations. Employees are immediately 100% vested in our contributions. Matching contributions to the plans are allocated in the form of units in the Dynegy common stock fund. During the years ended December 31, 2004, 2003 and 2002, we issued 0.6 million, 1.2 million and 1.1 million shares, respectively, of our common stock in the form of matching contributions to the plans; and

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Dynegy Northeast Generation, Inc. Savings Incentive Plan under this plan, which is for union and non-union employees, we match 24% of employee contributions up to 6% of base salary for union employees and 50% of employee contributions up to 8% of base salary for non-union employees, in each case subject to IRS limitations. Employees are immediately 100% vested in our contributions. Matching contributions to this plan are made in cash and invested according to the employee investment discretion.

During the years ended December 31, 2004, 2003 and 2002, we recognized aggregate costs related to these employee compensation plans of $7 million, $8 million and $17 million, respectively.

Pension and Other Post-Retirement Benefits.

We have various defined benefit pension plans and post-retirement benefit plans. All domestic employees participate in the pension plans, but only some of our domestic employees participate in the other post-retirement medical and life insurance benefit plans. Our pension plans are in the form of a cash balance plan and more traditional career average or final average pays formula plans. We use a December 31 measurement date for all of our plans.

Obligations and Funded Status. The following tables contain information about the obligations and funded status of these plans on a combined basis:

	Pension Benefits		Other Benefits	
	2004	2003	2004	2003
	(in millions)			
Projected benefit obligation, beginning of the year	$ 693	$ 626	$ 202	$ 161
Service cost	20	21	5	5
Interest cost	33	39	10	11
Plan amendments	4	1		
Actuarial (gain) loss	14	40	25	33
Curtailment loss	(590)		(189)	
Participant contributions			1	1
Benefits paid	(21)	(34)	(8)	(9)
Projected benefit obligation, end of the year	$ 153	$ 693	$ 46	$ 202
Fair value of plan assets, beginning of the year	$ 571	$ 501	$ 79	$ 67

Actual return on plan assets	15	104		14
Curtailment and settlement (loss)	(485)		(73)	
Employer contributions	8			6
Participant contributions			1	1
Benefits paid	(21)	(34)	(7)	(9)
Fair value of plan assets, end of the year	$ 88	$ 571	$	$ 79
Funded status	$ (65)	$ (122)	$ (46)	$ (123)
Unrecognized prior service costs	6	7		
Unrecognized actuarial (gain) loss	45	267	21	103
Net amount recognized $	$ (14)	$ 152	$ (25)	$ (20)

As a result of the sale of Illinois Power to Ameren, which closed on September 30, 2004, the number of participants in our various defined benefit pension plans and post-retirement benefit plans was reduced

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substantially. As a result, we recognized curtailment and settlement losses in 2004, which are included in our loss on sale. For further information, see Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23. In addition, in connection with the sale, we agreed to transfer a portion of the assets in certain of our defined benefit plans and post-retirement plans to other plans maintained by Ameren. An initial asset transfer of $411 million was made on November 1, 2004 and an additional transfer of approximately $74 million is expected to be made in the first quarter 2005.

Amounts recognized in the consolidated balance sheets consist of:

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2004	2003	2004	2003
	(in millions)			
Prepaid benefit cost	$	$ 122	$	$
Accrued benefit liability	(40)	(65)	(25)	(20)
Intangible asset	6	5		
Accumulated other comprehensive income	20	90		
Net amount recognized	$ (14)	$ 152	$ (25)	$ (20)

The accumulated benefit obligation for all defined benefit pension plans was $125 million and $615 million at December 31, 2004 and 2003, respectively.

On December 31, 2004 and December 31, 2003, our annual measurement date, the accumulated benefit obligation related to certain of our pension plans exceeded the fair value of the pension plan assets. As a result, in accordance with SFAS No. 87, Employers Accounting for Pensions, we have recorded a minimum pension liability, with an offset to accumulated other comprehensive loss. The following summarizes information for pension plans with an accumulated benefit obligation in excess of plan assets:

	December 31,	
	2004	2003

	(in millions)	
Projected benefit obligation	$ 153	$ 386
Accumulated benefit obligation	125	336
Fair value of plan assets	88	273

The following summarizes the change to accumulated other comprehensive loss associated with the minimum pension liability:

	2004	2003	2002
		(in millions)	
Change in minimum liability included in other comprehensive income (loss) (net of tax benefit (expense) of $(26) million, $(5) million and $38 million, respectively)	$ (44)	$ (9)	$ 66

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Components of Net Periodic Benefit Cost. The components of net periodic benefit cost were:

	Pension Benefits			Other Benefits		
	2004	2003	2002	2004	2003	2002
	(in millions)					
Service cost benefits earned during period	$ 20	$ 21	$ 19	$ 5	$ 5	$ 3
Interest cost on projected benefit obligation	33	39	38	10	11	10
Expected return on plan assets	(38)	(53)	(59)	(5)	(6)	(7)
Amortization of prior service costs	1	1	1			
Recognized net actuarial loss	12	9		4	5	3
Net periodic benefit cost (income)	$ 28	$ 17	$ (1)	$ 14	$ 15	$ 9
Additional early retirement window benefits			2			
Additional cost due to curtailment	146			(9)		
Total net periodic benefit cost	$ 174	$ 17	$ 1	$ 5	$ 15	$ 9

Assumptions. The following weighted average assumptions were used to determine benefit obligations:

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2004	2003	2004	2003
Discount rate	5.75%	6.00%	5.75%	6.00%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%

The following weighted average assumptions were used to determine net periodic benefit cost:

	Pension Benefits	Other Benefits

	Year Ended December 31,			Year Ended December 31,		
	2004	2003	2002	2004	2003	2002
Discount rate	5.97%	6.50%	7.50%	5.98%	6.50%	7.50%
Expected return on plan assets	8.75%	9.00%	9.50%	8.75%	9.00%	9.50%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%

Our expected long-term rate of return on plan assets for the year ended December 31, 2005 will be 8.25%. This figure begins with a blend of asset class-level returns developed under a theoretical global capital asset pricing model methodology conducted by an outside consultant. In development of this figure, the historical relationships between equities and fixed income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long-term. Current market factors such as inflation and interest rates are also incorporated in the assumptions. The figure also incorporates an upward adjustment reflecting the plan s use of active management and favorable past experience.

The following summarizes our assumed health care cost trend rates:

	December 31,	
	2004	2003
Health care cost trend rate assumed for next year	10.1%	10.1%
Ultimate trend rate	5.36%	5.47%
Year that the rate reaches the ultimate trend rate	2011	2009

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Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The impact of a one percent increase/decrease in assumed health care cost trend rates is as follows:

	Increase	Decrease
	(in millions)	
Aggregate impact on service cost and interest cost	$ 0.9	$ (0.8)
Impact on accumulated post-retirement benefit obligation	$ 7.5	$ (6.3)

Plan Assets. We employ a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. The intent of this strategy is to minimize plan expenses by outperforming plan liabilities over the long run. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks as well as growth, value, and small and large capitalization. Other assets such as real estate and private equity may be used judiciously to enhance long-term returns while improving portfolio diversification.

Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives may not be used to leverage the portfolio beyond the market value of the underlying investment. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, periodic asset/liability studies, and annual liability measurement.

Our pension plans weighted-average asset allocations by asset category were as follows:

	December 31,	
	2004	2003
Equity securities	72%	64%
Debt securities	28%	28%
Real estate		5%
Other		3%
Total	100%	100%

Equity securities did not include any of our common stock at December 31, 2004 or 2003.

Our other postretirement benefit plans weighted-average asset allocations by asset category were as follows:

	December 31,	
	2004	2003
Equity securities		75%
Debt securities		25%
Total		100%

As of December 31, 2004, our other postretirement benefit plan assets were zero. Following the sale of Illinois Power to Ameren, these postretirement assets were transferred to Ameren as a condition to the sale agreement. Equity securities did not include any of our common stock at December 31, 2003.

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Contributions. Under the terms of our agreement to sell Illinois Power to Ameren, we accelerated approximately $7 million of future cash funding requirements in September 2004. In 2005, we expect to contribute $28 million to our pension plans and $0.3 million to our other postretirement benefit plans.

Our expected benefit payments for future services for our pension and other postretirement benefits are as follows:

	Pension Benefits	Other Benefits
	(in millions)	
2005	$ 2.8	$ 0.3
2006	2.8	0.5
2007	3.8	0.7
2008	4.9	1.0
2009	6.1	1.4
2010 2014	52.5	13.6

Medicare Prescription Drug, Improvement and Modernization Act of 2003. On December 8, 2003, President Bush signed into law a bill that expands Medicare, primarily adding a prescription drug benefit for Medicare-eligible retirees starting in 2006. We anticipate that the benefits that we will pay after 2005 will be lower as a result of the new Medicare provisions. The December 31, 2004 accumulated post-retirement benefit obligation reflects the new Medicare program as required by FASB Staff Position 106-2. The accumulated post-retirement benefit obligation was reduced by approximately $1 million by reflecting the new Medicare prescription drug program.

Note 20 Segment Information

Prior period amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page F-10.

In 2002, we reported results for the following four business segments: WEN, DMS, T&D and DGC. Beginning January 1, 2003, we are reporting our operations in the following segments: GEN, NGL, REG and CRM. All corporate overhead included in other reported results was allocated to our four former reporting segments prior to January 1, 2003. Beginning January 1, 2003, all direct general and administrative expenses and other income (expense) items incurred by us on behalf of our subsidiaries are charged to the applicable subsidiary as incurred. In addition, all interest expense was allocated to our four former reporting segments prior to January 1, 2003.

Prior to January 1, 2003, the GEN and CRM segments were operated together as an asset-based third-party marketing, trading and risk-management business, referred to as the WEN segment. Most, but not all, of the WEN third-party purchase and sale contracts were held by a subsidiary that became part of the CRM segment. Under this previous business model, the net fair value of most of GEN s generation capacity, forward sales and related trading positions were sold to the CRM segment monthly at an internally determined transfer price. The internal transfer price was primarily comprised of the option value of generation capacity and executed forward sales contracts based on then-current forward prices of power and fuel. GEN intersegment revenues for the year ended December 31, 2002 reflect this internal transfer price and do not represent amounts actually received for power sold to third parties. As such, the GEN intersegment revenues for the year ended December 31, 2002 do not include the effect of intra-month market price volatility. The CRM segment recorded net unaffiliated revenue from these third-party contracts, together with all of its other third-party marketing and trading positions unrelated to the GEN segment.

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In connection with our exit from the third-party marketing and trading business, individual contracts within the former WEN segment were identified on January 1, 2003 as either GEN contracts, as they were determined to be part of our continuing operations, or CRM contracts. Under this new business segment model, CRM continued to transact with third parties on behalf of GEN. When transacting on behalf of GEN and our other segments, CRM would record third party revenue related to GEN and our other segments, together with its other third-party marketing and trading positions unrelated to the our other segments. Transfer pricing between CRM and our other segments was set at the actual amount received or paid for the purchases and sales to the third parties. Therefore, our other segments intersegment revenues included the effects of intra-month market price volatility, and represented amounts actually received from or paid to third parties.

Effective July 1, 2004, GEN began transacting directly with third parties on its own behalf. Therefore, certain generation capacity, forward sales, and related market positions previously sold by GEN to CRM are now sold by GEN directly to third parties. The GEN segment now records revenues for such third party sales as unaffiliated revenues.

Prior to January 1, 2003, consolidated revenue associated with the retail power business represented energy trading activity that was recorded on a net basis. The GEN segment purchased from the CRM segment a portion of the physical power that was used to fill these retail power sales contracts. The revenues from retail power sales were presented gross in GEN unaffiliated revenues, with the corresponding power purchases from the CRM segment presented in GEN intersegment revenues. Beginning January 1, 2003, pursuant to the rescission of EITF Issue 98-10, retail power sales are presented gross in consolidated revenue. Any purchases of physical power by the GEN segment from the CRM segment are classified as cost of sales in the GEN segment and are presented in CRM intersegment revenues. These differences affect the comparability of the results for the years ended December 31, 2004, 2003 and 2002.

Revenues from third-party sales in which a GEN entity is the legal party to the third-party sales contracts are presented gross in GEN unaffiliated revenues for the years ended December 31, 2004, 2003 and 2002.

Pursuant to EITF Issue 02-03, all gains and losses on third-party energy trading contracts in the CRM segment, whether realized or unrealized, are presented net in the consolidated statements of operations. For the purpose of the segment data presented below, intersegment transactions between CRM and our other segments are presented net in CRM intersegment revenues but are presented gross in the intersegment revenues of our other segments, as the activities of our other segments are not subject to the net presentation requirements contained in EITF Issue 02-03. If transactions between CRM and our other segments result in a net intersegment purchase by CRM, the net intersegment purchases and sales are presented as negative revenues in CRM intersegment revenues. In addition, intersegment hedging activities are presented net pursuant to SFAS No. 133.

Prior to January 1, 2003, our natural gas liquids operations comprised our DMS segment. Beginning January 1, 2003, these operations comprise the NGL segment. Additionally, prior to January 1, 2003, we reported our Illinois Power utility operations and, for the first three quarters of 2002 prior to its sale, the operations of Northern Natural in our T&D segment. Beginning January 1, 2003, our Illinois Power utility operations comprise the REG segment. Results associated with the former DGC segment are included in discontinued operations in Other and Eliminations due to the sale of our communications businesses. Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the years ended December 31, 2004, 2003 and 2002 is presented below.

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Dynegy s Segment Data for the Year Ended December 31, 2004

(in millions)

	GEN	NGL	REG	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 704	$ 3,450	$ 1,146	$ 937	$	$ 6,237
Other		3		(87)		(84)
	704	3,453	1,146	850		6,153
Intersegment revenues	880	300	19	(672)	(527)	
Total revenues	$ 1,584	$ 3,753	$ 1,165	$ 178	$ (527)	$ 6,153
Depreciation and amortization	$ (191)	$ (88)	$ (10)	$ (1)	$ (33)	$ (323)
Impairment and other charges		(5)	(54)		(24)	(83)
Operating income (loss)	$ 163	$ 287	$ 139	$ (118)	$ (279)	$ 192
Earnings from unconsolidated investments	192	10				202
Other items, net	1	(22)	3	(3)	8	(13)
Interest expense						(480)
Loss from continuing operations before taxes						(99)
Income tax benefit						89
Loss from continuing operations						(10)
Loss from discontinued operations, net of taxes						(5)
Net loss						$ (15)
Identifiable assets:						
Domestic	$ 6,497	$ 1,599	$ 18	$ 1,238	$ 300	$ 9,652
Other	5	5		190		200
Total	$ 6,502	$ 1,604	$ 18	$ 1,428	$ 300	$ 9,852
Unconsolidated investments	$ 343	$ 78	$	$	$	$ 421
Capital expenditures	$ (145)	$ (61)	$ (92)	$	$ (13)	$ (311)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Dynegy s Segment Data for the Year Ended December 31, 2003

(in millions)

	GEN	NGL	REG	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 354	$ 2,999	$ 1,542	$ 937	$	$ 5,832
Other	1	3		(49)		(45)
	355	3,002	1,542	888		5,787
Intersegment revenues	1,255	250	28	(1,015)	(518)	
Total revenues	$ 1,610	$ 3,252	$ 1,570	$ (127)	$ (518)	$ 5,787
Depreciation and amortization	$ (188)	$ (81)	$ (121)	$	$ (64)	$ (454)
Goodwill impairment			(311)			(311)
Impairment and other charges	(13)		(218)	(1)	7	(225)
Operating income (loss)	$ 194	$ 170	$ (327)	$ (385)	$ (246)	$ (594)
Earnings (losses) from unconsolidated investments	128	(2)		(2)		124
Other items, net	4	(17)		31	2	20
Interest expense						(509)
Loss from continuing operations before taxes						(959)
Income tax benefit						246
Loss from continuing operations						(713)
Loss from discontinued operations, net of taxes						(19)
Cumulative effect of change in accounting principles, net of taxes						40
Net loss						$ (692)
Identifiable assets:						
Domestic	$ 6,298	$ 1,635	$ 4,900	$ 2,078	$ (2,440)	$ 12,471
Other	49	1		259	30	339
Total	$ 6,347	$ 1,636	$ 4,900	$ 2,337	$ (2,410)	$ 12,810
Unconsolidated investments	$ 530	$ 82	$	$	$	$ 612
Capital expenditures and investments in unconsolidated affiliates	$ (154)	$ (51)	$ (126)	$ (2)	$ (5)	$ (338)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Dynegy s Segment Data for the Year Ended December 31, 2002

(in millions)

	GEN	NGL	REG	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 452	$ 2,530	$ 1,488	$ 308	$	$ 4,778
Other	6	723		(181)		548
	458	3,253	1,488	127		5,326
Intersegment revenues	920	165	33	(258)	(860)	
Total revenues	$ 1,378	$ 3,418	$ 1,521	$ (131)	$ (860)	$ 5,326
Depreciation and amortization	$ (175)	$ (88)	$ (175)	$ (28)	$	$ (466)
Goodwill impairment	(489)			(325)		(814)
Impairment and other charges	(58)	(18)	(19)	(95)		(190)
Operating income (loss)	$ (341)	$ 77	$ 157	$ (951)	$	$ (1,058)
Earnings (losses) from unconsolidated investments	(71)	14	(2)	(21)		(80)
Other items, net	(20)	(34)	(4)	(49)		(107)
Interest expense						(297)
Loss from continuing operations before taxes						(1,542)
Income tax benefit						343
Loss from continuing operations						(1,199)
Loss from discontinued operations, net of taxes						(1,154)
Cumulative effect of change in accounting principles, net of taxes						(234)
Net loss						$ (2,587)
Identifiable assets:						
Domestic	$ 5,440	$ 2,088	$ 3,808	$ 6,309	$ 69	$ 17,714
Other	281	5		2,012	17	2,315
Total	$ 5,721	$ 2,093	$ 3,808	$ 8,321	$ 86	$ 20,029
Unconsolidated investments	$ 564	$ 102	$	$ 3	$ (1)	$ 668
Capital expenditures and investments in unconsolidated affiliates	$ (589)	$ (105)	$ (170)	$ (14)	$ (83)	$ (961)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 21 Quarterly Financial Information (Unaudited)

Prior period amounts in this footnote have been restated. For further information, please see the Explanatory Note on beginning on page F-10.

The following is a summary of our unaudited quarterly financial information for the years ended December 31, 2004 and 2003:

	Quarter Ended			
	March 2004	June 2004	September 2004	December 2004
	(in millions, except per share data)			
Revenues	$ 1,657	$ 1,440	$ 1,650	$ 1,406
Operating income (loss)	108	133	138	(187)
Net income (loss) before cumulative effect of change in accounting principles	70	8	78	(171)
Net income (loss)	70	8	78	(171)
Net income (loss) per share before cumulative effect of change in accounting principles	0.14	0.00	0.16	(0.47)
Net income (loss) per share	$ 0.14	$ 0.00	$ 0.16	$ (0.47)

	Quarter Ended			
	March 2003	June 2003	September 2003	December 2003
	(in millions, except per share data)			
Revenues	$ 1,879	$ 1,067	$ 1,385	$ 1,456
Operating income (loss)	187	(374)	101	(508)
Net income (loss) before cumulative effect of change in accounting principles	92	(290)	5	(539)
Net income (loss)	147	(290)	5	(554)
Net income (loss) per share before cumulative effect of change in accounting principles	0.02	(1.00)	3.17	(1.45)
Net income (loss) per share	$ 0.17	$ (1.00)	$ 3.17	$ (1.49)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A synopsis of the aggregate financial impact of the restatements on the amounts originally reported in Amendment No. 2 to our Annual Report of Form 10-K for the year ended December 31, 2003 is as follows:

RESTATED RESULTS OF OPERATIONS BY QUARTER

	Quarter Ended			
	March 31, 2003	**June 30, 2003**	**September 30, 2003**	**December 31, 2003**
	(in millions)			
Operating income (loss)				
As previously reported	$ 187	$ (374)	$ 101	$ (483)
Restatement effect				(25)
As restated	$ 187	$ (374)	$ 101	$ (508)
Net income (loss) before cumulative effect of change in accounting principles				
As previously reported	$ 92	$ (290)	$ 5	$ (514)
Restatement effect				(25)
As restated	$ 92	$ (290)	$ 5	$ (539)
Net income (loss)				
As previously reported	$ 147	$ (290)	$ 5	$ (529)
Restatement effect				(25)
As restated	$ 147	$ (290)	$ 5	$ (554)
Net income (loss) per share before cumulative effect of change in accounting principles				
As previously reported	$ 0.02	$ (1.00)	$ 3.17	$ (1.38)
Restatement effect				(0.07)
As restated	$ 0.02	$ (1.00)	$ 3.17	$ (1.45)
Net income (loss) per share				
As previously reported	$ 0.17	$ (1.00)	$ 3.17	$ (1.42)

Restatement effect				(0.07)
As restated	$ 0.17	$ (1.00)	$ 3.17	$ (1.49)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

RESTATED SELECTED BALANCE SHEET DATA BY QUARTER

	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003
		(in millions)		
Total Assets				
As previously reported	$ 17,296	$ 15,185	$ 13,771	$ 12,961
Reclassifications (1)				(126)
Restatement effect				(25)
As restated	$ 17,296	$ 15,185	$ 13,771	$ 12,810
Total Liabilities				
As previously reported	$ 13,371	$ 11,514	$ 10,761	$ 10,482
Reclassifications (1)				(126)
Restatement effect	36	36	36	36
As restated	$ 13,407	$ 11,550	$ 10,797	$ 10,392
Stockholders Equity				
As previously reported	$ 2,290	$ 1,955	$ 2,475	$ 1,947
Restatement effect	(36)	(36)	(36)	(61)
As restated	$ 2,254	$ 1,919	$ 2,439	$ 1,886

(1) Adjustment to our balances for total assets and total liabilities relate to reclassifications of December 31, 2003 balance sheet amounts to conform to the December 31, 2004 balance sheet presentation.

Note 22 Subsequent Events

On January 31, 2005, we completed the acquisition of ExRes SHC, Inc., the parent company of Sithe Energies and Independence. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion.

On March 7, 2005, we reached agreement with the EPA regarding our Baldwin Station litigation. Please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings Baldwin Station Litigation beginning on page F-57 for further discussion.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DEFINITIONS

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

AMP	Automated mitigation procedure
ARO	Asset retirement obligation
Bcf/d	Billion cubic feet per day
Cal ISO	The California Independent System Operator
Cal PX	The California Power Exchange
CDWR	California Department of Water Resources
CERCLA	The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFTC	Commodity Futures Trading Commission
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CRM	Our customer risk management business segment
DGC	Dynegy Global Communications
DGC-Asia	Dynegy Global Communications-Asia, our former Asian communications business
DHI	Dynegy Holdings Inc., our primary financing subsidiary
DMG	Dynegy Midwest Generation, Inc
DMS	Dynegy Midstream Services
DMT	Dynegy Marketing and Trade
DNE	Dynegy Northeast Generation
DOJ	The Department of Justice
DOT	Department of Transportation
DPM	Dynegy Power Marketing Inc
EIOL	Energy Infrastructure Overseas Limited
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas, Inc.
ERISA	The Employee Retirement Income Security Act of 1974, as amended
EWG	Exempt Wholesale Generators
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FPA	Federal Power Act of 1935, as amended
FTC	U.S. Federal Trade Commission
FUCOs	Foreign Utility Companies
GAAP	Generally Accepted Accounting Principles of the United States of America
GEN	Our power generation business segment
GCF	Gulf Coast Fractionators
HLPSA	Hazardous Liquid Pipeline Safety Act of 1979, as amended
ICC	Illinois Commerce Commission
ISO	Independent System Operator
KW	Keep-whole

KWH	Kilowatt hour
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MBbls/d	Thousands of barrels per day
Mcf	Thousand cubic feet
MISO	Midwest ISO Regional Transmission Organization

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

MMBtu	Millions of British thermal units
MMCFD	Million cubic feet per day
MW	Megawatts
MWh	Megawatt hour
NERC	North American Electric Reliability Council
NGA	Natural Gas Act of 1938, as amended
NGL	Our natural gas liquids business segment
NGPA	Natural Gas Policy Act of 1978, as amended
NGPSA	Natural Gas Pipeline Safety Act of 1968, as amended
NOL	Net operating loss
NOV	Notice of Violation issued by the EPA
NYISO	New York Independent System Operator
NYDEC	New York Department of Environmental Conservation
PCAOB	Public Company Accounting Oversight Board (United States)
PJM	Pennsylvania-New Jersey-Maryland Interconnection, LLC
POL	Percentage of liquids
POP	Percentage of proceeds
PRB	Powder River Basin coal
PUCT	Public Utility Commission of Texas
PUHCA	The Public Utility Holding Company Act of 1935, as amended
QFs	Qualifying Facilities
RCRA	The Resource Conservation and Recovery Act of 1976, as amended
REG	Our regulated energy delivery business segment
RMR	Reliability Must Run
RTO	Regional Transmission Organization
SEC	U.S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SPE	Special Purpose Entity
T&D	Our former transmission and distribution energy delivery business segment
VaR	Value at Risk
VIE	Variable Interest Entity
VLGC	Very large gas carrier
WECC	Western Electricity Coordinating Council
WEN	Our former wholesale energy network business segment
WTLPS	West Texas LPG Pipeline Limited Partnership, the owner of West Texas LPG Pipeline

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Schedule I

DYNEGY INC.

CONDENSED BALANCE SHEETS OF THE REGISTRANT

See Explanatory Note

(in millions)

	December 31, 2004	December 31, 2003 (Restated)
ASSETS		
Current Assets		
Cash and cash equivalents	$ 374	$ 124
Intercompany accounts receivable	1,498	1,923
Prepayments and other current assets	23	1
Total Current Assets	1,895	2,048
Other Assets		
Investments in affiliates	3,145	3,621
Other long-term assets	9	10
Total Assets	$ 5,049	$ 5,679
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 7	$ 8
Accrued liabilities and other current liabilities	19	2
Total Current Liabilities	26	10
Long-Term Debt	225	448
Intercompany long-term debt	2,243	2,243
Other long-term liabilities	288	692
Total Liabilities	2,782	3,393
Commitments and Contingencies (Note 3)		
Redeemable Preferred Securities, redemption value of $400 at December 31, 2004 and December 31, 2003	400	400
Stockholders Equity		
	2,859	2,848

Class A Common Stock, no par value, 900,000,000 shares authorized at December 31, 2004 and December 31, 2003; 258,012,203 and 280,350,169 shares issued and outstanding at December 31, 2004 and December 31, 2003, respectively		
Class B Common Stock, no par value, 360,000,000 shares authorized at December 31, 2004 and December 31, 2003; 96,891,014 shares issued and outstanding at December 31, 2004 and December 31, 2003	1,006	1,006
Additional paid-in capital	41	41
Subscriptions receivable	(8)	(8)
Accumulated other comprehensive loss, net of tax	(13)	(20)
Accumulated deficit	(1,950)	(1,913)
Treasury stock, at cost, 1,679,183 shares at December 31, 2004 and December 31, 2003	(68)	(68)
Total Stockholders Equity	1,867	1,886
Total Liabilities and Stockholders Equity	$ 5,049	$ 5,679

See Notes to Registrant s Financial Statements and Dynegy Inc. s Consolidated Financial Statements

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Schedule I

DYNEGY INC.

CONDENSED STATEMENTS OF OPERATIONS OF THE REGISTRANT

See Explanatory Note

(in millions)

	Year Ended December 31,		
	2004	2003	2002
		(Restated)	(Restated)
Operating income (loss)	$ (2)	$ (2)	$ 3
Losses from unconsolidated investments	(52)	(872)	(2,720)
Interest expense	(22)	(16)	(1)
Other expense, net		(24)	(56)
Loss from continuing operations before income taxes	(76)	(914)	(2,774)
Income tax benefit	61	222	703
Loss from continuing operations	(15)	(692)	(2,071)
Loss from discontinued operations, net of taxes			(516)
Net loss	(15)	(692)	(2,587)
Less: preferred stock dividends (gain)	22	(1,013)	330
Net income (loss) applicable to common stockholders	$ (37)	$ 321	$ (2,917)

See Notes to Registrant s Financial Statements and Dynegy Inc. s Consolidated Financial Statements

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Schedule I

DYNEGY INC.

CONDENSED STATEMENTS OF CASH FLOWS OF THE REGISTRANT

See Explanatory Note

(in millions)

	Year Ended December 31,		
	2004	**2003**	**2002**
		(Restated)	**(Restated)**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Operating cash flow, exclusive of intercompany transactions	$ (20)	$ (466)	$ (91)
Intercompany transactions	510	584	(103)
Net cash provided by (used in) operating activities	490	118	(194)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from long-term borrowings		225	
Net repayments of long-term borrowings	(223)		
Payment to ChevronTexaco for Series B preferred stock restructuring		(225)	
Proceeds from issuance of capital stock	5	6	240
Purchase of treasury stock			(1)
Dividends and other distributions, net	(22)		(55)
Net cash provided by (used in) financing activities	(240)	6	184
Net increase (decrease) in cash and cash equivalents	250	124	(10)
Cash and cash equivalents, beginning of period	124		10
Cash and cash equivalents, end of period	$ 374	$ 124	$
SUPPLEMENTAL CASH FLOW INFORMATION			
Interest paid (net of amount capitalized)	29		1
Taxes paid (net of refunds)	4	(116)	12

See Notes to Registrant s Financial Statements and Dynegy Inc. s Consolidated Financial Statements

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Schedule I

DYNEGY INC.

NOTES TO REGISTRANT S FINANCIAL STATEMENTS

Explanatory Note

These condensed parent company financial statements included restatements for each of the two years in the period ended December 31, 2003. Please see the Explanatory Note beginning on page F-10 of our consolidated financial statements for further information.

Note 1 Background and Basis of Presentation

These condensed parent company financial statements have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X, as the restricted net assets of Dynegy Inc. s subsidiaries exceeds 25% of the consolidated net assets of Dynegy Inc. These statements should be read in conjunction with the Consolidated Statements and notes thereto of Dynegy Inc.

We are a holding company and conduct substantially all of our business operations through our subsidiaries. We began operations in 1985 and became incorporated in the state of Illinois in 1999 in anticipation of our February 2000 merger with Illinova Corporation.

Note 2 Debt

For a discussion of our debt facilities, see Note 11 Debt beginning on page F-42 of our consolidated financial statements. All of our debt obligations outstanding are due subsequent to 2008.

Note 3 Commitments and Contingencies

For a discussion of our commitments and contingencies, see Note 16 Commitments and Contingencies beginning on page F-55 of our consolidated financial statements.

For a discussion of our guarantees, see Note 11 Debt beginning on page F-42 of our consolidated financial statements and Note 16 Commitments and Contingencies Other Commitments and Contingencies Guarantees beginning on page F-65 of our consolidated financial statements.

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Schedule II

DYNEGY INC.

VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2004, 2003 and 2002

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
2004					
Allowance for doubtful accounts	$ 184	$ (7)	$ (5)	$ (13)	$ 159
Allowance for risk management assets (1)	11			(5)	6
Deferred tax asset valuation allowance	170	(6)			164
2003					
Allowance for doubtful accounts	151	25	31	(23)	184
Allowance for risk management assets (1) (2)	244			(233)	11
Deferred tax asset valuation allowance (3)	203			(33)	170
2002					
Allowance for doubtful accounts	113	47		(9)	151
Allowance for risk management assets (1)	248	(4)			244
Deferred tax asset valuation allowance		203			203

(1) Changes in price and credit reserves related to risk management assets are offset in the net mark-to-market income accounts reported in revenues.

(2) Deduction of $233 million primarily relates to the rescission of EITF Issue 98-10, which resulted in changing the accounting for certain tolling arrangements from the mark-to-market method to the accrual method. As such, the related reserves associated with the mark-to-market value were removed from the allowance for risk management assets.

(3) Decrease in our deferred tax asset valuation relates to our release of a deferred tax capital gains valuation allowance.

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WEST COAST POWER LLC

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Members of West Coast Power LLC:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, members equity and comprehensive income and cash flows present fairly, in all material respects, the financial position of West Coast Power LLC (the Company) at December 31, 2004 and 2003, and the results of its operations and its cash flows for the three years ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the Standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 9, the Company is the subject of substantial litigation. The Company s ongoing liquidity, financial position and operating results may be adversely impacted by the nature, timing and amount of the resolution of such litigation. The consolidated financial statements do not include any adjustments, beyond existing accruals applicable under Statement of Financial Accounting Standards No. 5, Accounting for Contingencies , that might result from the ultimate resolution of such matters.

As discussed in Note 2, effective January 1, 2002, the Company adopted the provisions of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets . As discussed in Note 2, effective January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations .

PricewaterhouseCoopers LLP

Houston, Texas

March 11, 2005

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WEST COAST POWER LLC

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2004	December 31, 2003
ASSETS		
Current Assets		
Cash and cash equivalents	$ 208,730	$ 124,245
Accounts receivable, net of allowance for doubtful accounts of $1,032 and $391,819, respectively	113,794	57,844
Inventory	21,318	25,626
Prepaid expenses	52,121	41,000
Assets from risk-management activities	33,231	8,740
Total Current Assets	429,194	257,455
Property, Plant and Equipment	596,776	610,534
Accumulated depreciation	(203,060)	(157,017)
Property, Plant and Equipment, Net	393,716	453,517
Total Assets	$ 822,910	$ 710,972
LIABILITIES AND MEMBERS EQUITY		
Current Liabilities		
Accounts payable	$ 1,694	$ 1,032
Accounts payable, affiliates	33,529	19,242
Accrued liabilities and other current liabilities	10,132	26,241
Liabilities from risk-management activities	36,790	8,740
Total Current Liabilities	82,145	55,255
Asset retirement obligation	5,223	7,632
Total Liabilities	87,368	62,887
Total Members Equity	735,542	648,085
Total Liabilities and Members Equity	$ 822,910	$ 710,972

See the notes to the consolidated financial statements.

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WEST COAST POWER LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands)

	Year Ended December 31,		
	2004	**2003**	**2002**
Revenues	$ 725,626	$ 695,964	$ 585,307
Affiliate operating costs, exclusive of depreciation shown separately below	(316,632)	(302,954)	(456,526)
Non-affiliate operating costs, exclusive of depreciation shown separately below	(42,191)	(62,372)	(29,039)
Depreciation and amortization expense	(39,456)	(31,693)	(27,227)
Goodwill impairment		(38,998)	
Impairment charges	(24,348)		(13,451)
Gain on sale of assets	689		
General and administrative expenses	(198)	(28,858)	(10,638)
Operating income	303,490	231,089	48,426
Interest expense	(82)	(176)	(15,410)
Interest income	2,539	1,327	1,129
Income before cumulative effect of change in accounting principle	305,947	232,240	34,145
Cumulative effect of change in accounting principle		1,030	
Net income	$ 305,947	$ 233,270	$ 34,145

See the notes to the consolidated financial statements.

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WEST COAST POWER LLC

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in thousands)

	Accumulated Other Comprehensive Income (Loss)	Members Equity	Comprehensive Income
Balance at December 31, 2001	$ (4,527)	$ 653,152	
Net income		34,145	$ 34,145
Amounts reclassified into income	4,527		
Other comprehensive income	4,527	4,527	4,527
Comprehensive income			$ 38,672
Contributions		13,516	
Distributions		(64,525)	
Balance at December 31, 2002	$	$ 640,815	
Net income		233,270	$ 233,270
Comprehensive income			$ 233,270
Distributions		(226,000)	
Balance at December 31, 2003	$	$ 648,085	
Net income		305,947	$ 305,947
Comprehensive income			$ 305,947
Contributions		5,000	
Distributions		(217,245)	
Other distributions		(6,245)	
Balance at December 31, 2004	$	$ 735,542	

See the notes to the consolidated financial statements.

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WEST COAST POWER LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2004	**2003**	**2002**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 305,947	$ 233,270	$ 34,145
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	39,456	31,693	27,227
Goodwill impairment		38,998	
Impairment charges	24,348		13,451
Risk-management activities	3,559		
Gain on sale of assets	(689)		
Cumulative effect of change in accounting principle		(1,030)	
Other, non-cash and adjustments	(1,313)		
Changes in working capital:			
Accounts receivable, net	(55,950)	3,127	164,278
Inventory	1,281	1,164	11,617
Prepaid expenses	(11,584)	(30,338)	2,226
Accounts payable	14,949	(20,690)	(17,269)
Accrued liabilities and other current liabilities	(18,654)	20,571	5,729
Other	(1,512)	3,744	2,489
Net cash provided by operating activities	299,838	280,509	243,893
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(1,386)	(25,709)	(21,652)
Decrease (increase) in restricted cash		69,362	(69,362)
Proceeds from asset sales, net	3,278		
Net cash provided by (used in) investing activities	1,892	43,653	(91,014)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repayments of borrowings		(10,000)	(140,057)
Contributions			13,516
Distributions	(217,245)	(226,000)	(64,525)
Net cash used in financing activities	(217,245)	(236,000)	(191,066)
Net increase (decrease) in cash and cash equivalents	84,485	88,162	(38,187)
Cash and cash equivalents, beginning of period	124,245	36,083	74,270
Cash and cash equivalents, end of period	$ 208,730	$ 124,245	$ 36,083

Supplemental Disclosure of Cash Flow Information:			
Interest paid	82	178	4,336
Other non-cash investing and financing activity:			
Contribution of El Segundo Power II LLC by NRG	5,000		

See the notes to the consolidated financial statements.

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WEST COAST POWER LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization and Operations of the Company

Effective June 30, 1999, Dynegy Power Corp. (DPC), an indirect wholly owned subsidiary of Dynegy Holdings Inc. (Dynegy), and NRG Energy, Inc. (NRG), a subsidiary of Xcel Energy, Inc (collectively, the Sponsors) formed WCP (Generation) Holdings LLC (Holdings) and West Coast Power LLC (WCP , we , us or our), both of which are Delaware limited liability companies. The Sponsors have an equal interest in Holdings and share in profits and losses equally. WCP is wholly owned by Holdings and serves as a holding company for El Segundo Power, LLC (ESP), El Segundo Power II LLC (ESP II), Long Beach Generation LLC (LBG), Cabrillo Power I LLC (Cabrillo I) and Cabrillo Power II LLC (Cabrillo II). NRG became an independent public company upon its emergence from bankruptcy on December 5, 2003 and no longer has any material affiliation or relationship with Xcel Energy.

Upon formation of WCP, the assets and liabilities of ESP, LBG, Cabrillo I and Cabrillo II (collectively, the LLCs) were contributed to WCP by the Sponsors and were recorded at their historical costs because the transfer represented a reorganization of entities under common control. Operations are governed by the executive committee, which consists of two representatives from each Sponsor.

From March 2001 through December 2004, WCP s facilities operated under a contract with the California Department of Water Resources (CDWR). Sales to CDWR represented a substantial portion of WCP s capacity.

ESP owns a 670-megawatt (MW) plant located in EI Segundo, California, consisting of two operating steam electric generating units. The facility has operated as a merchant plant, selling energy and ancillary services through the deregulated California wholesale electric market and other western markets. In December 2004, the California Independent System Operator (Cal ISO), pursuant to its tariff, designated ESP units 3 and 4 as Reliability Must Run (RMR) units for the calendar year 2005. On December 21, 2004, ESP filed with the Federal Energy Regulatory Commission (FERC), an application for approval of its rates as an RMR designated facility. ESP made the election to collect rates as a Condition 2 plant, effective January 1, 2005. On February 11, 2005, FERC issued an order that accepted the rates for filing, subject to refund, set the matter for hearing, and held the hearing in abeyance to permit the parties to continue to engage in negotiations and resolve any outstanding issues. ESP expects that FERC will issue an order approving its rates in the third quarter of 2005.

In October 2004, the FERC approved WCP s settlement of FERC claims relating to western energy market transactions that occurred from January 2000 through June 2001. (See Note 9 Commitments and Contingencies for further discussion of this settlement). Included in this settlement was a payment of $22,544,942. In order to provide the funds for this settlement, Dynegy agreed to forego approximately $17,000,000 of distributions from WCP, and NRG agreed to forego approximately $5,500,000 of distributions and contribute El Segundo Power II LLC, valued at $5,000,000, to WCP. The contribution of these assets is reflected as a contribution in the Consolidated Statements of Changes in Equity. $6,244,942 of the settlement was paid by WCP on behalf of Dynegy in accordance with the settlement agreement, and is recorded as a reduction in Dynegy s member s equity on the Consolidated Statements of Changes in Equity.

On December 30, 2004, NRG West Coast LLC, a Delaware limited liability company, assigned its right, title, and interest in El Segundo Power II LLC to Holdings, which in turn assigned its interest to WCP, as part of the funding of the settlement agreement with the FERC. On February 3, 2005, the California Energy Commission approved the certificate for the construction and operation of a proposed 630-megawatt combined-cycle facility by ESP II on the site previously used by ESP units 1 and 2. ESP II became 100% owned by WCP on December 30, 2004. No date has been set to commence construction, although California state law requires that construction commence five years after the issuance of the certificate.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On January 27, 2005, Dynegy Power Marketing Inc, an affiliate of ESP, acting as its fully authorized agent, entered into a power purchase agreement with a major California utility for a term commencing May 1, 2005 and ending December 31, 2005. As part of that agreement, ESP is required to obtain certain consents and waivers from Cal ISO and to file for an application with FERC to change from Condition 2 to Condition 1 under the Cal ISO tariff. Once all approvals are obtained, the utility will acquire all dispatch rights from ESP for the term of the agreement and assume responsibility for all Cal ISO grid reliability dispatches as permitted under the RMR contract (See Note 7 for a more detailed explanation).

LBG owns a 560-MW plant located in Long Beach, California. On January 1, 2005, after due notice to the Cal ISO, the plant was shut down and the operator began decommissioning and environmental remediation of the plant site and equipment salvage and investment recovery efforts.

Cabrillo I owns a 970-MW Plant located in Carlsbad, California, consisting of five steam electric generating units and one combustion turbine. The facility has operated as a merchant plant, selling energy and ancillary services through the deregulated California wholesale electric market and other western markets. Cabrillo I was designated as a RMR unit by the Cal ISO for 2004 and 2005. Pursuant to an uncontested settlement agreement filed in December 2004 with the Cal ISO and various interveners in FERC Docket No. ER04-308, RMR rates for the years 2004 through 2006 were agreed upon between the parties. As a part of that settlement, Cabrillo chose to collect rates as a Condition 2 plant, effective January 1, 2005 (See Note 7 below for a more detailed explanation). On February 14, 2005, FERC issued an order approving these rates. Rates for 2006 will only be effective if the Cabrillo I units are designated RMR units by the Cal ISO in the third or fourth quarter of 2005.

Cabrillo II owns 13 combustion turbines with an aggregate capacity of 202-MW located throughout San Diego County, California. The facility has operated as a merchant plant, selling energy and ancillary services through the deregulated California wholesale electric market and other western markets. Cabrillo II combustion turbines were designated as RMR units by the Cal ISO for 2004 and 2005. Pursuant to an uncontested settlement agreement filed in December 2004 with the Cal ISO and various interveners in FERC Docket No. ER04-308, RMR rates for the years 2004 through 2006 were agreed upon between the parties. As a part of that settlement, Cabrillo II chose to continue collecting rates as a Condition 2 plant, effective January 1, 2005 (See Note 7 below for a more detailed explanation). On February 11, 2005, FERC issued an order approving these rates. Rates for 2006 will only be effective if the Cabrillo II units are designated RMR units by the CAISO in the third or fourth quarter of 2005.

Note 2 Accounting Policies

Our accounting policies conform to GAAP. Our most significant accounting policies are described below. The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and judgments that affect our reported financial position and results of operations. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) developing fair value assumptions, including estimates of future cash flows and discounts rates, (2) analyzing tangible and intangible assets for possible impairment, (3) estimating the useful lives of our assets and (4) determining amounts to accrue for contingencies, guarantees and indemnifications.

Principles of Consolidation. The accompanying consolidated financial statements include our accounts after eliminating intercompany accounts and transactions. Certain reclassifications have been made to prior-period amounts to conform with current-period financial statement classifications.

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WEST COAST POWER LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Accounts Receivable and Allowance for Doubtful Accounts. We establish provisions for losses on accounts receivable if it becomes probable we will not collect all or part of outstanding balances. Trade accounts receivable are recorded at the invoiced amount and do not bear interest. We review collectibility and establish or adjust our allowance as necessary using the specific identification method. As of December 31, 2004 and 2003, we have reserved $1,032,466 and $391,819,281, respectively, as an allowance for doubtful accounts relating to receivables owed to us by the CDWR, the Cal ISO and the California Power Exchange (PX). As described in Note 9, in October 2004, we settled our historical disputes with FERC parties.

Concentration of Credit Risk. We sell our electricity production to purchasers of electricity in California, which includes the Cal ISO and Dynegy Power Marketing, Inc. (DYPM). These industry and geographical concentrations have the potential to impact our overall exposure to credit risk either positively or negatively, because the customer base may be similarly affected by changes in economic, industry, weather or other conditions.

Inventory. Inventories are valued at the lower of market or cost using the last-in, first-out (LIFO) or the average cost methods and are comprised of the following:

	December 31,	
	2004	**2003**
	(in thousands)	
Emissions credits (average cost)	$ 4,496	$ 5,366
Materials and supplies (average cost)	3,446	6,418
Fuel oil (LIFO)	13,376	13,842
	$ 21,318	$ 25,626

In conjunction with the retirement of the Long Beach facility, a lower of cost or market analysis was performed on the facility s materials and supplies balance. The vast majority of the materials and supplies were designed for use specifically at the Long Beach facility or are otherwise obsolete. As a result, an adjustment of $3,027,613, which is included in Operating costs on the consolidated statement of operations, was made to reduce the inventory to net realizable value as of December 31, 2004.

Emission credits represent costs paid by us to acquire additional NOx credits. We use these credits to comply with emission caps imposed by various environmental laws under which we must operate. As individual credits are used, costs are recognized as operating expense. See additional discussion below at Other Contingencies.

Property, Plant and Equipment. Property, plant and equipment, which consists primarily of power generating facilities, furniture and fixtures and computer equipment, is recorded at historical cost. Expenditures for major replacements, renewals and major maintenance are capitalized. We consider major maintenance to be expenditures incurred on a cyclical basis in order to maintain and prolong the efficient operation of our assets. Expenditures for repairs and minor renewals to maintain assets in operating condition are expensed. Depreciation is provided using the straight-line method over the estimated economic service lives of the assets, ranging from 3 to 25 years. The estimated economic service lives of our asset groups are as follows:

Asset Group	**Range of Years**
Power Generation Facilities	7 to 25
Furniture and Fixtures	3 to 5
Other Miscellaneous	5 to 20

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Gains and losses on sales of individual assets are reflected in gain on sale of assets in the consolidated statements of operations. We assess the carrying value of our plant and equipment in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. If an impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the related discounted cash flows of the assets and recording a loss if the resulting estimated fair value is less than the book value. For assets identified as held for sale, the book value is compared to comparable market prices or the estimated fair value if comparable market prices are not readily available to determine if an impairment loss is required.

On September 30, 2004, the WCP executive committee consented to a plan to retire the Long Beach facilities effective January 1, 2005. The revision of the expected useful life of Long Beach is a change in accounting estimate, per the guidance in APB 20, Accounting Changes. This change is accounted for in the current and future periods if the change affects both. The remaining asset value, excluding land, as of September 30, 2004, was $9.9 million. The depreciation was accelerated so that the Long Beach facilities were fully depreciated by December 31, 2004.

Asset Retirement Obligations. We adopted SFAS No. 143, Asset Retirement Obligations, effective January 1, 2003. Under the provisions of SFAS No. 143, we are required to record legal obligations to retire tangible, long-lived assets on our balance sheet as liabilities, which are recorded at a discount when the liability is incurred. Significant judgment is involved in estimating future cash flows associated with such obligations, as well as the ultimate timing of the cash flows. If our estimates on the amount or timing of the cash flow change, the change may materially affect earnings.

Upon adoption of SFAS No. 143, existing environmental liabilities in the amount of $5,200,000 were reversed in the first quarter 2003. The fair value of the remediation costs estimated to be incurred upon retirement of the respective assets is included in the asset retirement obligation (ARO) and was recorded upon adoption of SFAS No. 143. Since the previously accrued liabilities exceeded the fair value of the future retirement obligations, the impact of adopting SFAS No. 143 was an increase in earnings of $1,029,756 in 2003, which is the cumulative effect of change in accounting principle in the consolidated statement of operations.

The following pro forma financial information has been prepared to give effect to the adoption of Statement No. 143 as if it had been adopted January 1, 2002:

	Year Ended December 31, 2002
Net income, as reported	$ 34,144,995
Pro forma adjustments to reflect retroactive adoption of Statement No. 143	(1,224,171)
Pro forma net income	$ 32,920,824

During 2004, the timing or fair value of the estimated cost to be incurred upon retirement related to the dismantlement and remediation changed for four of the Cabrillo II facilities. These changes resulted in an $896,809 decrease in our ARO liability. Since the change in the ARO liability associated with one of the facilities exceeded the asset retirement cost net of accumulated depreciation, an increase in earnings of $641,236 was recorded during 2004, which is included in Non-affiliate operating costs on the consolidated statements of operations.

At January 1, 2004, our ARO liabilities totaled $7,631,979, which includes monitoring charges related to El Segundo Units 1 and 2 as well as dismantlement and remediation at the Cabrillo II facilities since these assets reside on leased property. Annual depreciation of the ARO assets resulting from adoption of this standard and the accretion of the liability towards the ultimate obligation amount were $404,559 and $628,290, respectively,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

during 2004. Annual depreciation of the ARO assets and the accretion of the liability towards the ultimate obligation amount were $644,483 and $697,472, respectively, during 2003. During 2004, we settled $2,140,550 relating to our ARO. At December 31, 2004, our ARO liabilities totaled $5,222,910.

In addition to these liabilities, we also have potential retirement obligations for dismantlement of our other power generation facilities. Our current intent is to maintain these facilities in a manner such that they will be operated indefinitely. Liabilities will be recorded in accordance with SFAS No. 143 at such time as our operations change and a liability is incurred.

Other Contingencies. Environmental costs relating to current operations are expensed or capitalized, as appropriate, depending on whether they provide future economic benefit. Liabilities are recorded when environmental assessment indicate remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based on currently enacted laws and regulations, existing technology and site-specific costs. Liabilities incurred by providing indemnification in connection with assets sold or closed are recognized upon such sale or closure to the extent they are probable, can be estimated and have not previously been reserved. In assessing liabilities, no offset is made for potential insurance recoveries. Recognition of any joint and several liability is based upon our best estimate of our final pro rata share of such liability.

Liabilities for other contingencies are recognized in accordance with SFAS No. 5, Accounting for Contingencies, upon identification of an exposure, which, when fully analyzed, indicates that it is both probable a liability has been incurred and the loss amount can be reasonably estimated. Non-capital costs to remedy such contingencies or other exposures are charged to a reserve, if one exists, or otherwise to current-period operations. We accrue the lesser end of the range when a range of probable loss exists.

Goodwill. Goodwill represents, at the time of an acquisition, the amount of purchase price paid in excess of the fair value of net assets acquired. We follow the guidance set forth in SFAS No. 142, Goodwill and Other Intangible Assets, when assessing the carrying value of our goodwill. Accordingly, we evaluate our goodwill for impairment on an annual basis or when events warrant an assessment. Our evaluation is based, in part, on our estimate of future cash flows. The estimation of fair value is highly subjective, inherently imprecise and can change materially from period to period based on, among other things, an assessment of market conditions, projected cash flows and discount rate. In 2003, all goodwill was impaired (See Note 3).

Revenue Recognition. Revenues from the sale of energy and ancillary services are recorded based upon output delivered and/or service provided priced at market or by contract. Revenues received from the RMR agreement with the Cal ISO are primarily derived from availability payments and amounts based on reimbursing variable costs. Revenues identified as being subject to future resolution are accounted for as discussed above at Allowance for Doubtful Accounts.

Federal Income Taxes. We are not a taxable entity for federal income tax purposes. Accordingly, there is no provision for income taxes in the accompanying consolidated financial statements.

Fair Value of Financial Instruments. Our financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable and derivative instruments to hedge commodity price and interest rate risk. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable are representative of their respective fair values due to the short-term maturities of these instruments. Additionally, we had entered into fair value hedges and electricity options. The fair value of these instruments is discussed in Note 5.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounting for Derivative Instruments. We may enter into various derivative instruments to hedge the risks associated with changes in commodity prices and interest rates. We use physical forward contracts to hedge a portion of our exposure to price fluctuations of natural gas and electricity.

Under SFAS No. 133, as amended, we recognize all derivative instruments on the balance sheet at their fair values, and changes in fair value are recognized immediately in earnings, unless the derivatives qualify, and are designated, as hedges of future cash flows or fair values, or qualify, and are designated, as normal purchases and sales. For derivatives treated as hedges of future cash flows, we record the effective portion of changes in the fair value of the derivative instrument in other comprehensive income until the related hedged items impact earnings. Any ineffective portion of a cash flow hedge is reported in earnings immediately. For derivatives treated as fair value hedges, we record changes in the fair value of the derivative and changes in the fair value of the hedged risk attributable to the related asset, liability or firm commitment in current period earnings. Derivatives treated as normal purchases or sales are recorded and recognized in income using accrual accounting.

Note 3 Goodwill

We recognized a $39 million impairment charge in 2003 based on our annual goodwill impairment test. We calculated our fair value using a discounted future cash flows methodology. Fair value was negatively impacted by the expiration of the CDWR contract in December 2004 coupled with decreasing power prices and current market conditions. Please read Note 7. The impairment charge is included in goodwill impairment on the consolidated statements of operations.

Note 4 Impairment of Long-Lived Assets

In December 2004, we tested our long-lived assets for impairment in accordance with SFAS No. 144. As a result of the expiration of the CDWR contract (See Note 7), our impairment analysis of our Cabrillo II facility indicated future cash flows were insufficient to recover the carrying value of the long-lived assets. As a result, we recorded an impairment of $24,348,534, which is included in impairment and other charges on the consolidated statements of operations.

In July 2002, we were notified that land leases associated with four Cabrillo II combustion turbines would not be renewed. We determined that these turbines would be sold rather than relocated to an alternate site for continued use. As a result, an impairment charge of $13,400,000 was recognized in 2002 and represented the difference between the carrying value of the four turbines and the estimated net proceeds from their prospective sale. In addition, a $5,200,000 liability was recorded for the estimated cost of restoring the land on which the turbines are located to its original condition. This reserve was reversed upon adoption of SFAS No. 143 on January 1, 2003. Please read Note 2 Accounting Policies Asset Retirement Obligations. During 2004, three of these turbines were sold. We recognized a gain of $689,144.

Note 5 Derivatives and Hedging

We entered into a series of fixed price electricity purchases to hedge a portion of the fair value of our fixed price CDWR Power Purchase Agreement (PPA). During the years ended December 31, 2004, 2003 and 2002, there was no ineffectiveness from changes in fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness. Additionally, no amounts were reclassified to earnings in connection with forecasted transactions that were no longer considered probable.

The value of the fair value hedges at December 31, 2004 and 2003, were approximately zero and $(8,739,539) and is included in liabilities from risk-management activities on the consolidated balance sheets. The corresponding value of the hedged risk is approximately zero and $8,739,539 and is included in assets from risk-management activities on the consolidated balance sheets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Upon acceptance of RMR Condition 2 on December 31, 2004, we are not exposed to the variability of cash flow from sales of power on a merchant basis. Please read Note 7.

We have also entered into interest rate swap agreements, which effectively exchanged variable interest rate debt for fixed interest rate debt. The agreements were used to reduce the exposure to possible increases in interest rates. We entered into these swap agreements with major financial institutions. On June 28, 2002, we terminated the interest rate swap agreements concurrently with the refinancing of our debt. Brokerage fees of approximately $5,200,000 were expensed at the time of refinancing. No interest rate swaps were outstanding at December 31, 2004 or 2003.

Note 6 Related Parties

We purchase fuel for our plants under full requirement natural gas supply agreements (GSAs) with Dynegy Marketing and Trade (DMT), one of our affiliates. Charges for fuel are based upon similar terms and conditions as could be obtained from unrelated third parties. Fuel purchases from DMT are included in affiliated operating costs in the consolidated statement of operations.

We contracted with DYPM to provide all power scheduling, power marketing and risk management for us under an energy management agreement (the EMA). Sales of power under the EMA through DYPM were $502,554,381, $617,370,571, and $540,114,356 for the years ended December 31, 2004, 2003, and 2002 respectively. Additionally, we contracted with DMT to provide all scheduling of fuel supply.

We entered into Operation and maintenance (O&M) agreements with NRG Cabrillo Power Operations Inc. and NRG El Segundo Operations Inc., two of our affiliates, for Cabrillo I and Cabrillo II effective May 2001 and for ESP and LBG effective April 2000. Their fees for services primarily include recovery of the costs of operating the plant as approved in the annual budget as well as a base monthly fee. When NRG became operator, we contracted with NRG Development Company, Inc., one of our affiliates, to provide services under the Administrative Management Agreement (the AMA). Services they provided under the AMA included environmental, engineering, legal and public relations services not covered under the O&M agreements. Fees for such services are subject to executive committee approval if the amounts exceed a certain percentage of the applicable annual approved budget.

We entered into an administrative services management agreement (the ASMA) with Dynegy Power Management Services, L.P., one of our affiliates, under which Dynegy Power Management Services, L.P. provides administrative services such as business management and accounting to us. Fees for such services are subject to executive committee approval if the amounts exceed a certain percentage of the applicable annual approved budget.

In addition to the related-party transactions listed above, we made $14,200,000 in interest payments in 2002 to DMT under a forbearance agreement with DMT with respect to noncompliance with the GSA. The effective interest rate on the deferred balance was prime rate plus 2%. All amounts due under the forbearance agreement have been paid and the forbearance agreement terminated. In 2004 and 2003, no interest was paid to DMT.

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WEST COAST POWER LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As described above, our affiliates provide various services for us. Charges for these services are included in our operating and general and administrative expenses in the consolidated statements of operations and consisted of the following costs:

	Years Ended December 31,		
	2004	2003	2002
		(in thousands)	
Dynegy s Related Cost			
Fuel	$ 267,844	$ 258,134	$ 401,650
EMA Charges	9,216	9,141	10,346
ASMA Charges	55	207	
Charges included in operating costs	$ 277,115	$ 267,482	$ 411,996
ASMA fees included in general and administrative expenses	$ 1,209	$ 1,331	$ 1,298
NRG s Related Cost			
O&M and AMA charges included in operating costs	$ 39,517	$ 35,472	$ 44,531

Note 7 Power Purchase Agreement

We entered into a long-term Power Purchase Agreement with the CDWR in March 2001. From January 2002 through December 31, 2004, the CDWR contracted for fixed price firm energy and system contingent capacity and energy representing a substantial portion of WCP s capacity. Sales to CDWR constituted approximately 71%, 88%, and 93% of revenues, net of reserves, in 2004, 2003 and 2002, respectively.

The CDWR contract expired by its terms on December 31, 2004. For 2005, all of our assets will be operating under RMR Condition 2 contracts with the Cal ISO, except for the Long Beach facility, which was retired effective January 1, 2005 (See Note 2 Accounting Policies Property, Plant and Equipment). Under the terms of these RMR contracts, Cal ISO reimburses WCP for 100% of approved costs plus a rate of return specified in the contracts. When the facilities are instructed to provide power by the Cal ISO, they are reimbursed for their variable production costs. Under RMR Condition 2, the facilities are 100% committed to the Cal ISO and, therefore, do not experience changes in market conditions through bilateral energy or capacity sales to third parties that might otherwise be entered. The RMR contracts are effective for calendar year 2005. The Cal ISO may renew or terminate the RMR contracts at its sole option on an annual basis as of the first of the following year.

In addition, ESP has entered into a power sales agreement with a major California utility for 100% of the capacity and associated energy from the El Segundo facility from May 2005 through December 2005. During the term of this agreement, the utility will be entitled to primary energy dispatch right for the facility s generating capacity. The agreement is subject to an amendment to the El Segundo RMR agreement to switch to RMR Condition I and to permit the utility to exercise primary dispatch rights under the agreement while preserving Cal ISO s ability to call on the El Segundo facility as a reliability resource under the RMR agreement, if necessary. The agreement will be accounted for as an operating lease of the facility under the requirements of EITF Issue 01-8.

Note 8 Debt

In August 1999, we entered into a credit agreement with a five-year, $322,500,000 amortizing term loan with a balloon payment and a $40,000,000 working capital facility line of credit (the Credit Agreement). The Credit Agreement was scheduled to mature in June 2004.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In September 1999, we entered into two interest rate swap agreements related to the Credit Agreement. One agreement effectively fixed the interest rate at 6.435% for the first $60,000,000 and matured in June 2002. The second agreement effectively fixed the interest rate at 6.230% for an incremental $40,000,000 and was scheduled to mature in June 2003. These swaps were designated as hedges of the future cash outflows associated with interest payments on the debt. The second agreement was terminated in 2002 as part of the refinancing discussed below, and the remaining deferred loss was reclassified from other comprehensive income to interest expense.

In June 2002, we refinanced our Credit Agreement with a 364-day bank facility consisting of a $100,000,000 letter of credit line, a $10,000,000 term loan commitment and a $10,000,000 working capital loan commitment (the Refinanced Credit Agreement). In conjunction with the refinancing, $3,400,000 of deferred financing costs related to the original Credit Agreement were expensed. We incurred additional debt issuance costs of $4,900,000 in connection with the refinancing. Such costs were capitalized and amortized over the remaining term of the Credit Agreement and are included in prepaid expenses and other current assets.

In June 2003, we replaced the Refinanced Credit Agreement with an 18-month $50,000,000 letter of credit facility. With the replacement of the Refinanced Credit Agreement, we are no longer required to maintain restricted cash funds. This agreement requires us to post equal amounts of cash collateral for all letters of credit issued. This letter of credit facility incurs fees at the rate of 0.50% on any outstanding letters of credit plus a commitment fee at the rate of 0.25% on any unused amount of the commitment.

In November 2004, the letter of credit facility was extended until December 31, 2005 and increased from $50,000,000 to $85,000,000 effective January 1, 2005. We incurred financing costs of $275,000 in connection with the renewal of the agreement. Such costs have been capitalized and will be amortized over the remaining term of the renewed agreement and are included in prepaid expenses and other current assets. At December 31, 2004, our deposit for collateral was $35,300,000. Of this deposit, $28,450,000 was issued in letters of credit.

Our interest costs on the term loans, working capital loans and interest rate swaps (including swap termination costs and amortization costs, which are included in depreciation and amortization on the consolidated statements of operations) totaled approximately $500,000, $2,900,000, and $15,400,000 for 2004, 2003, and 2002 respectively.

Note 9 Commitments and Contingencies

Set forth below is a description of our material legal proceedings. In addition to the matters described below, we are party to legal proceedings arising in the ordinary course of business. In management s opinion, the disposition of these matters will not materially adversely affect our financial condition, results of operations, or cash flows.

We record reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss is reasonably estimable under SFAS No. 5. For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated. Please see Note 2 for further discussion. Environmental reserves do not reflect management s assessment of the insurance coverage that may be applicable to the matters at issue. We cannot guarantee that the amount of any reserves will cover any cash obligations we might incur as a result of litigation or regulatory proceedings, payment of which could be material.

With respect to some of the items listed below, management has determined that a loss is not probable or that any such loss, to the extent probable, is not reasonably estimable. In some cases, management is not able to predict with any degree of certainty the range of possible loss that could be incurred. Notwithstanding these facts,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

management has assessed these matters based on current information and made a judgment concerning their potential outcome, giving due consideration to the nature of the claim, the amount and nature of damages sought and the probability of success. Management s judgment may, as a result of facts arising prior to resolution of these matters or other factors, prove inaccurate and investors should be aware that such judgment is made subject to the known uncertainty of litigation.

California Market Litigation. We and numerous other power generators and marketers were the subject of numerous lawsuits arising from our participation in the western power markets during the California energy crisis. Eight of these lawsuits, which primarily alleged manipulation of the California wholesale power markets and sought unspecified treble damages, were consolidated before a single federal judge. WCP was identified as a defendant in one of those lawsuits, which was dismissed, together with another of the eight lawsuits, in the first quarter 2003 on the grounds of FERC preemption and the filed rate doctrine. The Ninth Circuit Court of Appeals affirmed this dismissal in June 2004. The plaintiffs have not appealed.

In addition to the lawsuit discussed above, WCP and/or the LLCs were named as defendants in eight other putative class actions and/or representative actions that were filed in state and federal court on behalf of business and residential electricity consumers against numerous power generators and marketers between April and October 2002. The complaints alleged unfair, unlawful and deceptive practices in violation of the California Unfair Business Practices Act and sought an injunction, restitution and unspecified damages. While some of the allegations in these lawsuits were similar to the allegations in the eight lawsuits described above, these lawsuits included additional allegations relating to, among other things, the validity of the contracts between these power generators and the CDWR. The court dismissed these actions, although the plaintiffs have appealed, and the briefing on that appeal was completed in October 2004. The Ninth Circuit affirmed the denial of remand and dismissal of these lawsuits in February 2005.

In December 2002, two additional actions naming WCP and/or the LLCs as defendants were filed with similar allegations on behalf of residents of Washington and Oregon. In May 2003, the plaintiffs voluntarily dismissed these actions and refiled them in California Superior Court as a class action complaint. The complaint, which was brought on behalf of consumers and businesses in Oregon, Washington, Utah, Nevada, Idaho, New Mexico, Arizona and Montana that purchased energy from the California market, alleges violations of the Cartwright Act and unfair business practices. We have removed the action from state court and consolidated it with existing actions pending before the United States District Court for the Northern District of California. The hearing on plaintiffs appeal to remand to state court occurred in February 2004. The judge stayed his ruling on the appeal pending the Ninth Circuit s ruling on the six remaining lawsuits described in the first paragraph above.

In June 2004, the City of Tacoma public utility filed a lawsuit in Washington federal court against a number of energy companies, including us, alleging it paid inflated prices for electricity due to the defendants manipulation of the California wholesale power markets. The defendants filed a motion to dismiss this case in December 2004. On February 11, 2005, defendants motion to dismiss was granted.

We believe that we have meritorious defenses to these claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability or estimate the range of possible loss, if any, that we might incur in connection with these lawsuits. However, given the nature of the claims, an adverse result in any of these proceedings could have a material adverse effect on our financial condition, results of operations and cash flows.

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FERC and Related Regulatory Investigations Requests for Refunds and RMR Complaints. In October 2004, the FERC approved in all respects the agreement announced by Dynegy and WCP in April 2004 which provides for the settlement of FERC claims relating to western energy market transactions that occurred from January 2000 through June 2001, including:

- FERC s June 2003 order to show cause why the activities of certain participants in the California power markets from January 2000 to June 2001, including WCP, did not constitute gaming and/or anomalous market behavior as defined in the ISO and PX tariffs, which matter was resolved by the January 2004 settlement providing that WCP will pay approximately $3 million into a fund for the benefit of California and Western electricity consumers, which January 2004 settlement was incorporated into the broader settlement described below; and

- FERC s July 2001 hearings and October 2003 orders relating to the establishment of (i) refunds to electricity customers, or offsets against amounts owed to electricity suppliers, during the period of October 2000 through June 2001 and (ii) a methodology to calculate mitigated market clearing prices in the ISO and the PX markets.

The parties to this settlement other than Dynegy and WCP include NRG Energy, Inc., FERC Office of Market Oversight and Investigations, Pacific Gas and Electric Company, Southern California Edison, San Diego Gas & Electric Company, the CDWR, the California Electricity Oversight Board and the California Attorney General. Other market participants are permitted to opt into this settlement and share in the distribution of the settlement proceeds. Most of these other market participants have agreed to participate in the settlement. The entitlement to refund and/or the liability of each of the non-settling market participants will be determined by the Cal ISO. Under the terms of the settlement, WCP will have no further liability to these non-settling parties.

As part of the settlement agreement, WCP agreed to (i) forego its right to collect approximately $259 million in past-due receivables, plus interest, from the Cal ISO and the PX related to the settlement period, (ii) forego natural gas cost recovery claims against the California settling parties related to the settlement period, and (iii) place into escrow accounts a total of $22.5 million, which includes the above-referenced $3 million settlement with the FERC staff, for subsequent distribution to various California energy purchasers. In exchange, the settling parties agreed to forego (i) all claims relating to refunds or other monetary damages for sales of electricity during the settlement period, and (ii) claims alleging receipt of unjust or unreasonable rates for the sale of electricity during the settlement period.

The settlement further provides that WCP is entitled to pursue claims for reimbursement of fuel costs against non-settling market participants. WCP is currently pursuing these claims but is unable to predict the amounts that may be recovered from such parties.

The settlement does not apply to the ongoing civil litigation related to the California energy markets described above in which Dynegy and WCP are defendants. The settlement also does not apply to the pending appeal by the CPUC and the California Electricity Oversight Board of the FERC s prior decision to affirm the validity of the CDWR contract. We are currently awaiting a ruling on this appeal and related filings and cannot predict their outcome.

In Docket Nos. EL02-15-000 and EL03-22-000 there is a dispute regarding various payment provisions in previous RMR Contracts with Cabrillo I and II. Certain California parties and the California ISO have proposed to apply to the Cabrillo RMR Contracts, any changes required by the Commission in similar agreements entered into between the ISO and Mirant Corporation, a matter which is pending in Docket Nos. ER98-495-000, et al. In a settlement between Mirant and the California parties filed in February, 2005, Mirant and the California parties have requested that the FERC rule on the initial decision in the ER98-495 docket. An adverse ruling by FERC could have an material adverse impact on WCP in Dockets Nos. EL02-15-000 and EL03-22-000.

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We are unable to predict with any certainty how FERC may ultimately decide ER98-495 and to what extent such ruling might have an adverse impact on WCP.

Gas Index Pricing Litigation. We are defending the following suits claiming damages resulting from the alleged manipulation of gas index publications and prices by WCP and/or the LLCs and numerous other power generators and marketers: *ABAG v. Sempra Energy et al.* (filed in state court in November 2004); *Bustamante v. The McGraw Hill Companies et al.* (class action filed in state court in November 2002); *City and County of San Francisco v. Dynegy Inc. et al.* (filed in state court in July 2004); *County of San Diego v. Dynegy Inc., Dynegy Marketing and Trade, West Coast Power, et al.* (filed in state court in July 2004); *County of San Mateo v. Sempra Energy et al.* (filed in state court in December 2004); *County of Santa Clara v. Dynegy Inc., Dynegy Marketing and Trade, West Coast Power, et al.* (filed in state court in July 2004); *Fairhaven Power Company v. Encana Corp. et al.* (class action filed in federal court in September 2004); *Nurserymen s Exchange v. Sempra Energy et al.* (filed in state court in October 2004); *Older v. Dynegy Inc. et al*. (filed in federal court in September 2004); *Sacramento Municipal Utility District (SMUD) v. Reliant Energy Services, et al.* (filed in state court in November 2004); *Texas-Ohio Energy, Inc. v. CenterPoint Energy Inc., et al.* (class action filed in federal court in November 2003); and *Utility Savings & Refund v. Reliant Energy Services, et al*. (class action filed in federal court in November 2004). In each of these suits, the plaintiffs allege that we and other energy companies engaged in an illegal scheme to inflate natural gas prices by providing false information to gas index publications, thereby manipulating the price. All of the complaints rely heavily on the FERC and CFTC investigations into and report concerning index-reporting manipulation in the energy industry. The plaintiffs generally seek unspecified actual and punitive damages relating to costs they claim to have incurred as a result of the alleged conduct.

Pursuant to various motions filed by the parties to the litigation described above, the gas index pricing lawsuits pending in state court have been consolidated before a single judge in state court in San Diego. These cases are now entitled the Judicial Counsel Coordinated Proceeding (JCCP) 4221, 4224, 4226, and 4228, the Natural Gas Anti-Trust Cases, I, II, III, & IV , which we refer to as the Coordinated Gas Index Cases. A case management conference is expected in the next 60 days.

As to the gas index pricing lawsuits that have been filed in federal court, in *Texas-Ohio*, the defendants filed a motion to dismiss in May 2004, on which the court held a hearing in January 2005. We are awaiting the court s ruling. The remaining federal court cases are pending transfer, or have already been transferred, to the federal judge in Nevada who is also currently presiding over the *Texas-Ohio* matter.

We are analyzing all of these claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability or to estimate the damages, if any, that might be incurred in connection with these lawsuits. We do not believe that any liability that we might incur as a result of this litigation would have a material adverse effect on our financial condition, results of operations or cash flows.

U.S. Attorney Investigations. The United States Attorney s office in the Northern District of California issued a Grand Jury subpoena requesting information related to our activities in the California energy markets in November 2002. We have been, and intend to continue, cooperating fully with the U.S. Attorney s office in its investigation of these matters, including production of substantial documents responsive to the subpoena and other requests for information. We cannot predict the ultimate outcome of this investigation.

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