UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

Amendment No. 1

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

For the fiscal year ended December 31, 2002

¨ **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 **(State or other jurisdiction of incorporation or organization)**	**74-2928353** **(I.R.S. Employer Identification Number)**

1000 Louisiana, Suite 5800

Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

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

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 þ No ¨

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

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

The aggregate market value of the voting and non-voting equity held by non-affiliates of the registrant as of March 26, 2003, computed by reference to the closing sale price of the registrant s common stock on the New York Stock Exchange on such date, was $640,834,926, 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.

The aggregate market value of the voting and non-voting equity held by non-affiliates of the registrant as of June 28, 2002, computed by reference to the closing sale price of the registrant s common stock on the New York Stock Exchange on such date, was $1,946,041,481, 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, 275,026,449 shares outstanding as of March 24, 2003; Class B common stock, no par value per share, 96,891,014 shares outstanding as of March 24, 2003.

DOCUMENTS INCORPORATED BY REFERENCE. Part III (Items 10, 11, 12 and 13) incorporates portions of the Notice and Proxy Statement for the registrant s 2003 Annual Meeting of Shareholders to be filed not later than 120 days after December 31, 2002.

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DYNEGY INC. FORM 10-K/A

INTRODUCTORY NOTE

Dynegy Inc. is filing this Amendment No. 1 on Form 10-K/A (Amendment No. 1) to reflect the effect of the following items on our historical consolidated financial statements and related information, as reported in our Annual Report on Form 10-K for the fiscal year ended December 31, 2002, which was originally filed on April 11, 2003 (the Original Filing):

reclassifications necessary to present the results of our global communications and United Kingdom customer risk management businesses as discontinued operations for the three years in the period ended December 31, 2002 in accordance with Statement of Financial Accounting Standards (Statement) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, as a result of events that required us to begin accounting for such businesses as discontinued operations in the first quarter 2003;

reclassifications necessary to present our segment information for the three years in the period ended December 31, 2002 consistent with our current segment reporting structure, which structure was implemented beginning January 1, 2003, in order to better reflect our ongoing asset-based business operations;

the pro forma financial statement effect for each of the three years in the period ended December 31, 2002, as if we had adopted Statement No. 143, Accounting for Asset Retirement Obligations, as of January 1, 2000;

disclosures relating to the previously reported restatement of our 2000 and 2001 financial statements. These same disclosures were included in Amendment No. 2 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2001, which was filed on April 11, 2003 (the 2001 Form 10-K/A), and do not reflect additional restatements to the 2000 and 2001 financial statements as contained in the 2001 Form 10-K/A; and

other minor revisions.

None of the aforementioned items, which are discussed in more detail in the Explanatory Note to the accompanying consolidated financial statements beginning on page F-8, affect net income for any of the three years in the period ended December 31, 2002. Our periodic SEC reports, including this Amendment No. 1, remain subject to an ongoing review by the SEC Division of Corporation Finance.

The following Items of the Original Filing are amended by this Amendment No. 1:

Item 1. Business

Item 5. Market for Registrant s Common Equity and Related Stockholder Matters

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

Item 13. Certain Relationships and Related Transactions

Item 14. Controls and Procedures

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

Unaffected items have not been repeated in this Amendment No. 1.

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS AMENDMENT NO. 1, INCLUDING THE FINANCIAL STATEMENTS AND THE NOTES THERETO, DOES NOT REFLECT EVENTS OCCURRING AFTER THE DATE OF THE ORIGINAL FILING. SUCH EVENTS INCLUDE, AMONG OTHERS, THE EVENTS DESCRIBED IN OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED MARCH 31, 2003 AND THE EVENTS SUBSEQUENTLY DESCRIBED IN OUR CURRENT REPORTS ON FORM 8-K. FOR A DESCRIPTION OF THESE EVENTS, PLEASE READ OUR EXCHANGE ACT REPORTS FILED SINCE APRIL 11, 2003, INCLUDING OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED MARCH 31, 2003 AND OUR CURRENT REPORTS ON FORM 8-K.

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DYNEGY INC.

FORM 10-K/A

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PART I

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS AMENDMENT NO. 1, INCLUDING THE FINANCIAL STATEMENTS AND THE NOTES THERETO, DOES NOT REFLECT EVENTS OCCURRING AFTER APRIL 11, 2003 (THE DATE OF THE ORIGINAL FILING). SUCH EVENTS INCLUDE, AMONG OTHERS, THE EVENTS DESCRIBED IN OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED MARCH 31, 2003 AND THE EVENTS SUBSEQUENTLY DESCRIBED IN OUR CURRENT REPORTS ON FORM 8-K. FOR A DESCRIPTION OF THESE EVENTS, PLEASE READ OUR EXCHANGE ACT REPORTS FILED SINCE APRIL 11, 2003, INCLUDING OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED MARCH 31, 2003 AND OUR CURRENT REPORTS ON FORM 8-K.

DEFINITIONS

As used in this Amendment No. 1, the terms listed below are defined as follows:

Amendment No. 1	Amendment No. 1 to the Dynegy Inc. Form 10-K for the year ended December 31, 2002.
AmerGen	AmerGen Energy Company, LLC
Bcf/d	Billions of cubic feet per day.
BGSL	BG Storage Limited.
Btu	British thermal unit a measure of the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.
Cal ISO	The California Independent System Operator.
Cal PX	The California Power Exchange.
Catlin	Catlin Associates, L.L.C.
CBF	Cedar Bayou Fractionators, L.P., an entity in which we have an 88% ownership interest.
CDWR	The California Department of Water Resources.
CERCLA or Superfund	Comprehensive Environmental Response, Compensation and Liability Act.
CRM	Our customer risk management business segment.
DGC	Dynegy Global Communications, Inc.
DHI	Dynegy Holdings Inc., a wholly owned subsidiary of Dynegy Inc.
DMG	Dynegy Midwest Generation, Inc.
DMS	Dynegy Midstream Services.
DNE	Dynegy Northeast Generation.
DOT	The U.S. Department of Transportation.
EITF	Emerging Issues Task Force.
EWGs	Exempt Wholesale Generators.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
FPA	The Federal Power Act.
GAAP	Generally Accepted Accounting Principles.
GCF	Gulf Coast Fractionators, an entity in which we have a 23% ownership interest.
GEN	Our power generation business segment.
HLPSA	The Hazardous Liquid Pipeline Safety Act.
HP	Horsepower.
ICC	Illinois Commerce Commission.
Investor	Black Thunder Investors LLC.

IP	Illinois Power Company, a wholly owned subsidiary of Illinova.
kWh	Kilowatt hours.
LMP	Locational marginal pricing methodology.
LNG	Liquefied natural gas.
LPG	Liquefied petroleum gas.
MACT	Maximum Achievable Control Technology.
MBbls/d	Thousands of barrels per day.

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MGP	Manufactured Gas Plant.
MMBtu	Millions of Btu.
MMCFD	Millions of cubic feet per day.
MW	Megawatts.
NGA	The Natural Gas Act of 1938, as amended.
NGL	Our natural gas liquids business segment.
NGLs	Natural gas liquids.
NGPA	The Natural Gas Policy Act of 1978, as amended.
NGPSA	The Natural Gas Pipeline Safety Act.
NOV	Notice of Violation.
NSPS	New Source Performance Standards.
NYISO	New York Independent System Operator.
Original Filing	Dynegy Inc. s Form 10-K for the year ended December 31, 2002 filed on April 11, 2003.
OSHA	The Federal Occupational Safety and Health Act.
PJM	Pennsylvania-New Jersey-Maryland market.
Project Alpha	A structured natural gas transaction entered into by Dynegy in April 2001.
PUCT	Public Utility Commission of Texas.
PUHCA	The Public Utility Holding Company Act of 1935.
PURPA	The Public Utilities Regulatory Policies Act of 1978.
RCRA	The Resource Conversation and Recovery Act.
QFs	Qualifying facilities are power generation facilities that typically sell power to a single purchaser and are generally exempt from FERC ratemaking regulation.
REG	Our regulated energy delivery segment.
RTOs	Regional transmission organizations established by the FERC to control electric transmissions facilities within a particular region.
SEC	U.S. Securities and Exchange Commission.
SERC	Southeast Electric Reliability Council.
SFAS	Statement of Financial Accounting Standards.
T&D	Transmission and Distribution.
UCAP	Unforced capacity market.
VaR	Value at Risk.
Versado	Versado Gas Processors, L.L.C.
VESCO	Venice Energy Services Company, L.L.C.
VLGCs	Very Large Gas Carriers.
WECC	Western Electricity Coordinating Council.
WEN	Wholesale Energy Network.
West Seminole	West Seminole natural gas gathering system, a Dynegy joint venture.
WTI	West Texas Intermediate.

Additionally, the terms Dynegy, we, us and our refer to Dynegy Inc. and its subsidiaries, unless the context clearly indicates otherwise.

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Item 1. ***Business***

THE COMPANY

We are a holding company and conduct substantially all of our business operations through our subsidiaries. We own operating divisions engaged in power generation, natural gas liquids and regulated energy delivery. Through these operating divisions, we serve customers by delivering value-added solutions to meet their energy needs.

We are in the process of restructuring our company in response to events that have negatively impacted the merchant energy industry, and our company in particular, over the past year. This restructuring includes significant changes in our operations, primarily our exits from third-party risk management aspects of the marketing and trading business and the communications business. Our restructuring also includes significant financial transactions that have stabilized our liquidity position and began the process of decreasing our substantial financial leverage. Significant accomplishments include the following:

- The sale of Northern Natural Gas Company;
- The sale of our U.K. natural gas storage business;
- The sale of our global liquids business;
- Major progress towards our exit from the third-party marketing and trading, or customer risk management business, including the completion of our exit from European marketing and trading and the transition of ChevronTexaco Corporation s natural gas marketing business back to ChevronTexaco, and the reduction in associated collateral requirements;
- The sale of our European communications business;
- The execution of an agreement to sell our U.S. communications business;
- The extension of the maturity of our two primary bank credit facilities until February 2005 and the restructuring of our communications lease financing; and
- Considerable workforce reductions, which we expect will provide substantial general and administrative cost savings.

In our new, simplified operating structure, we intend to focus on being a low-cost producer of physical products and provider of services in each of our three main operating divisions. Our results also will continue to reflect our customer risk management business until the remaining obligations associated with this business have been satisfied or restructured.

Dynegy began operations in 1985 and became incorporated in the State of Illinois in 1999 in connection with the Illinova acquisition. 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.

Our SEC filings on Forms 10-K, 10-Q and 8-K (and amendments to such filings) are 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 Amendment No. 1.

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SEGMENT DISCUSSION

Beginning in 2003, we are reporting the financial results of the following four business segments:

- Power generation;
- Natural gas liquids;
- Regulated energy delivery; and
- Customer risk management.

Other reported results include corporate overhead and our discontinued communications operations. Set forth below is a discussion of each of our new business segments.

We have reported our historical segment results in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations beginning on page 59 of this Amendment No. 1 to reflect changes that we made to our reporting segments beginning January 1, 2003. In the Original Filing, we reported our historical segment results based on our 2002 business segments Wholesale Energy Network, Dynegy Midstream Services, Transmission and Distribution and Dynegy Global Communications. As described below, the power generation operations previously included in the Wholesale Energy Network segment now comprise the Power Generation segment. The Wholesale Energy Network segment s other former operations, to the extent such operations continue, comprise the Customer Risk Management segment. The remaining operations of our former Dynegy Global Communications segment are being reported within the Other category, together with corporate general and administrative expenses, income taxes and corporate interest expenses, all of which we previously allocated among our operating divisions. The natural gas liquids operations that previously comprised our Dynegy Midstream Services segment and the Illinois Power utility operations previously included within our Transmission and Distribution segment continue to be reported as their own respective segments.

Power Generation

We own or lease electric power generation facilities with an aggregate net generating capacity of 13,167 MW located in six regions of the United States, including one facility nearing completion of construction with approximately 800 MW of net generating capacity. 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, 2002)

Region/Facility	Location	Total Net Generating Capacity (MW)	Primary Fuel Type	Dispatch Type
Midwest-MAIN				
Baldwin	Baldwin, IL	1,751	Coal	Baseload
Havana:				
Havana Units 1-5	Havana, IL	238	Oil	Peaking
Havana Unit 6	Havana, IL	428	Coal	Baseload
Hennepin	Hennepin, IL	289	Coal	Baseload
Oglesby	Oglesby, IL	60	Gas	Peaking
Stallings	Stallings, IL	77	Gas	Peaking
Tilton(2)	Tilton, IL	176	Gas	Peaking
Vermillion	Oakwood, IL	186	Coal	Baseload
Wood River:				
Wood River Units 1-3	Alton, IL	139	Gas	Peaking
Wood River Units 4-5	Alton, IL	468	Coal	Baseload
Rocky Road(3)	East Dundee, IL	168	Gas	Peaking
Joppa(4)	Joppa, IL	232	Coal	Baseload
Combined		4,212		
Midwest-ECAR				
Michigan Power(3)	Ludington, MI	62	Gas	Baseload
Riverside	Louisa, KY	500	Gas	Peaking
Rolling Hills(5)	Wilkesville, OH	838	Gas	Peaking
Foothills	Louisa, KY	322	Gas	Peaking
Renaissance	Carson City, MI	690	Gas	Peaking
Bluegrass	Oldham Co., KY	500	Gas	Peaking
Combined		2,912		
Northeast-NPCC				
Roseton(6)	Newburgh, NY	1,200	Gas/ Oil	Intermediate
Danskammer:				
Danskammer Units 1 2	Newburgh, NY	130	Gas/ Oil	Peaking
Danskammer Units 3-4(6)	Newburgh, NY	370	Coal/Gas	Baseload
Combined		1,700		
Southeast-SERC				
Calcasieu	Lake Arthur, LA	323	Gas	Peaking
Heard County	Heard County, GA	500	Gas	Peaking
Rockingham	Rockingham, NC	818	Gas/ Oil	Peaking
Hartwell(3)	Hartwell, GA	150	Gas	Peaking
Commonwealth(3)	Chesapeake, VA	170	Gas	Peaking
Combined		1,961		
West-WECC				
Ferndale(7)	Ferndale, WA	12	Gas	Baseload
Long Beach(8)	Long Beach, CA	265	Gas	Peaking
Cabrillo I Encina(8)	Carlsbad, CA	483	Gas	Intermediate
Black Mountain(9)	Las Vegas, NV	43	Gas	Baseload
El Segundo:				

El Segundo Units 1-2(8)(10)	El Segundo, CA	175	Gas	Intermediate
El Segundo Units 3-4(8)	El Segundo, CA	335	Gas	Intermediate
Cabrillo II:				
Cabrillo II (4 units) (8)(10)	San Diego, CA	34	Gas	Peaking
Cabrillo II (9 units)(8)	San Diego, CA	93	Gas	Peaking
Combined		1,440		
Texas-ERCOT				
Paris(11)	Paris, TX	37	Gas	Baseload
Frontier(12)	Grimes Co., TX	83	Gas	Baseload
CoGen Lyondell	Houston, TX	610	Gas	Baseload
Oyster Creek(3)	Freeport, TX	212	Gas	Baseload
Combined		942		
TOTAL		13,167		

(1) We own 100% of each unit listed except as otherwise indicated.

(2) We lease this facility pursuant to an off-balance sheet lease arrangement that is further described in Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Off-Balance Sheet Arrangements beginning on page 48.

(3) We own a 50% interest in this facility.

(4) We own a 20% interest in this facility.

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(5) This facility is under construction, with completion expected in the second quarter 2003.
(6) We lease the Roseton facility and units 3 and 4 of the Danskammer facility pursuant to a leveraged lease arrangement that is further described in Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Off-Balance Sheet Arrangements beginning on page 48.
(7) We own a 5% interest in this facility.
(8) We own a 50% interest in each of these facilities through West Coast Power, L.L.C., a joint venture with NRG Energy.
(9) We own a 50% interest in this facility through a joint venture with ChevronTexaco.
(10) We shut these units down at the end of 2002 because we deemed them no longer commercially viable.
(11) We own a 16% interest in this facility.
(12) We own a 10% interest in this facility.

Midwest region Mid-America Interconnected Network Reliability Council (MAIN). At December 31, 2002, we owned or leased interests in ten generating facilities with an aggregate net generating capacity of 4,212 MW located in Illinois within the MAIN reliability area. Eight of these facilities, which we acquired as a result of the Illinova acquisition in February 2000, are currently owned by Dynegy Midwest Generation, Inc., one of our indirect subsidiaries. DMG pledged these facilities as collateral in connection with a July 2002 amendment to our Black Thunder financing. Please read Item 8, Financial Statements and Supplementary Data, Note 10 Debt DMG Secured Debt beginning on page F-53 for further discussion of this financing. We hold one of these facilities, the Tilton facility, through an off-balance sheet lease arrangement. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Off-Balance Sheet Arrangements beginning on page 48 for further discussion of this arrangement. The generating capacity of the MAIN facilities is approximately 80% baseload and 20% peaking and represents approximately 6% of the generating capacity within the MAIN region. The baseload capacity is primarily fueled by coal, with some ability to fire gas, while the remainder is primarily fueled by natural gas and oil.

DMG has a power purchase agreement with IP that provides the regulated utility with approximately 70% of its capacity requirements through December 2004. The contract provides for fixed capacity payments based on the megawatt capacity reserved. DMG also receives variable energy payments for each MW-hour of energy delivered under the contract based on DMG s cost of generation. As part of the power purchase agreement, DMG also supplies all ancillary services necessary for IP to serve its load and provide transmission services to its customers. The IP power purchase agreement provided a substantial portion of the operating income from our power generation business in 2002. DMG is not the sole supplier to IP, but bears ultimate responsibility for serving the load as the provider of last resort. The eight facilities that primarily provide the power under this agreement were formerly owned by IP and are in locations that are best suited for serving IP s native load.

In addition to the IP contract, the Rocky Road facility s 168 MW of peaking capacity is under long-term contract with another purchaser through May 2009. The contract is a tolling arrangement pursuant to which the facility receives fixed monthly payments and a variable fee based on the power that it actually generates.

Approximately 50% of the energy generated by our Illinois facilities is sold pursuant to the long-term contracts described above. The remainder of the power generated is sold primarily into wholesale markets in MAIN, the neighboring East Central Reliability Area, or ECAR, and the Pennsylvania-New Jersey-Maryland market, or PJM. The MAIN market includes all or portions of the states of Illinois, Wisconsin and Missouri. The ECAR market includes all or portions of the states of Indiana, Ohio, Michigan, Virginia, West Virginia, Tennessee, Maryland and Pennsylvania. MAIN and ECAR, like the rest of the country, are currently in a state of regulatory transition as each transmission provider in this region seeks to join regional transmission organizations, or RTOs, that operate the transmission system on a regional basis. Additionally, the RTOs implement the rules and requirements for competitive wholesale markets as set forth by the FERC. The Midwest Independent System Operator, or MISO, has been approved by the FERC to administer a substantial portion of the transmission facilities in this region, while PJM, another FERC-approved independent system operator, has been approved to administer other portions of the region. However, because state and federal regulators must approve these transfers, the timing for transmission providers to turn over control of their high-voltage power lines to the RTOs remains uncertain. Both the MISO and PJM continue to move forward with integrating those transmission facilities that have been approved for transfer to the RTOs, and are developing a plan to have a common energy market across their respective control areas by late 2005 or early 2006.

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PJM manages the transmission system and maintains competitive wholesale markets within its region. PJM historically covered the states of Pennsylvania, New Jersey and Maryland, but is poised to cover a larger geographic area as some midwestern companies seek to join the RTO. PJM operates the transmission grid for reliability purposes as well as managing the market for firm transmission rights, or FTRs, that determine the economics of congestion on the transmission system. Under a locational marginal pricing methodology, or LMP, PJM facilitates the competitive wholesale spot energy markets, which set the prices at which energy is bought and sold. It is also responsible for ensuring that adequate capacity is available for secure operations of the region, and it provides a capacity auction to facilitate this market. Much of the FERC s proposed Standard Market Design rulemaking utilizes the market structure for energy, transmission and capacity that PJM has implemented over the past few years. As mentioned above, PJM and MISO are seeking common energy markets that will be based on the LMP method of establishing prices at location; additionally, they plan to use similar FTRs and capacity markets.

We currently sell power from our facilities in the MAIN region to customers under short-term and long-term agreements. Many of the longer agreements are bilateral contracts that are generally non-standard with highly negotiated terms and conditions, while short-term sales usually occur through well-established existing commercial relationships. Our customers include municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities, industrial customers and power marketers. Some states within this region have restructured their electric power markets to competitive retail markets from traditional utility monopoly markets, which allow us to sell directly to retail and commercial end-users.

Midwest region ECAR. We own or lease interests in six generating facilities with an aggregate net generating capacity of 2,912 MW located in the states of Kentucky, Michigan and Ohio. One of these facilities, the Rolling Hills facility, is under construction with commercial operation expected to begin in the second quarter 2003. The Riverside facility is leased by one of our indirect subsidiaries, Riverside Generating Company, L.L.C. In addition, the Renaissance and Rolling Hills facilities are pledged as collateral to secure a financing originated in June 2002. Please read Item 8, Financial Statements and Supplementary Data, Note 10 Debt Renaissance and Rolling Hills Credit Facility beginning on page F-52 for further discussion of this financing. The generating capacity of the ECAR facilities is approximately 2% baseload and 98% peaking and represents approximately 2% of the generating capacity within the ECAR region. All units within the region are fueled by natural gas.

The majority of the power generated by our ECAR facilities is sold to wholesale customers in the MAIN, PJM and ECAR markets. Please read Midwest region Mid-America Interconnected Network Reliability Council (MAIN) above for a discussion of these markets. All 62 MW of baseload capacity, representing our net ownership interest in the Michigan Power facility, is under contract through December 2030.

Northeast region. At December 31, 2002, we owned or leased two generating facilities with an aggregate net generating capacity of 1,700 MW located in Newburgh, New York, 50 miles north of New York City. These facilities, acquired from Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. and Niagara Mohawk Power Corporation in January 2001, are referred to as the Dynegy Northeast Generation (DNE) facilities. The Danskammer facility has four generating units, two of which are owned and two of which are leased by one of our indirect subsidiaries, Dynegy Danskammer, L.L.C. The Roseton facility has two generating units, each of which is leased by another of our indirect subsidiaries, Dynegy Roseton, L.L.C. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Off-Balance Sheet Arrangements beginning on page 48 for further discussion of this off-balance sheet lease arrangement.

The generating capacity of these facilities represents approximately 5% of the generating capacity in the state of New York. Two of the Danskammer units use natural gas or fuel oil, while the other two Danskammer units are capable of burning both coal and natural gas. The two Roseton units are capable of burning fuel oil or natural gas or both simultaneously. The facilities sites are adjacent and share common resources such as fuel handling, a docking terminal, personnel and systems.

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We currently sell approximately 23% of the capacity from our DNE facilities to Central Hudson pursuant to a transitional power purchase agreement that expires in October 2004. We sell the remainder of the power generated by these facilities into the New York wholesale market, which is described below. We sell energy and ancillary services into both day ahead and real-time sales markets, and we sell capacity and energy forward (up to 1.5 years for capacity and 3 years for energy). Our customers include the members of the New York Independent System Operator, or NYISO, including municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities, retail electric providers and power marketers. We sell energy products to wholesale, commercial and industrial customers in New York under negotiated bilateral contracts. We also export power to neighboring regions, including PJM, Ontario and New England.

The New York wholesale market operates as a centralized power pool administered by the NYISO. Although the transmission infrastructure within this market is generally well developed and independently operated, significant transmission constraints exist. In particular, there is limited transmission capability from western New York to eastern New York and into New York City. Depending on the timing and nature of transmission constraints, market prices may vary between sub-regions of the market. For example, as a result of transmission constraints into eastern New York and New York City, power prices are generally higher in these areas than in other parts of the state. An unforced capacity market, or UCAP, has been established by the NYISO designed to ensure that there is enough generation capacity to meet retail energy demand and ancillary services requirements. All power retailers are required to demonstrate commitments for capacity sufficient to meet their forecast peak load plus a reserve requirement, currently set at 18 percent.

In addition to managing the transmission system, the NYISO is responsible for maintaining competitive wholesale markets, operating the day ahead, real time, ancillary service and UCAP markets and determining the market clearing price based on bids submitted by participating generators. The NYISO matches sellers with buyers within New York that meet specified minimum credit standards. The NYISO has protocols that provide the structure, rules and pricing mechanisms for various energy products and maintains FERC-approved rates, terms and conditions for transmission service in its control area. NYISO protocols allow energy demand, commonly referred to as load, to respond to high prices in emergency and non-emergency situations. The lack of programs, however, to implement load response to prices has been cited as one of the primary reasons for retaining wholesale energy bid caps, which are currently set at $1,000 per megawatt hour. Lower price caps are utilized in other regions.

The New York market is subject to significant regulatory oversight and control. Our operating results may be adversely affected by changes to the current regulatory structure. For additional discussion of the impact of current regulations on the New York market, please read Regulation Power Generation Regulation beginning on page 23.

Southeast region Southeast Electric Reliability Council (SERC). At December 31, 2002, we owned interests in five generating facilities with an aggregate net generating capacity of 1,961 MW located in the states of Georgia, Louisiana, North Carolina and Virginia. This capacity s primary fuel is natural gas, with some capability to burn fuel oil.

320 MW of the SERC capacity is under long-term contracts. A contract for the Commonwealth facility s 170 MW of capacity expires in May 2017, while a contract for the Hartwell facility s 150 MW of capacity expires in May 2019. The remainder of the power generated by our SERC facilities is generally sold to wholesale customers in the SERC market. This market includes all or portions of the states of Missouri, Kentucky, Arkansas, Tennessee, West Virginia, Virginia, North Carolina, South Carolina, Texas, Louisiana, Mississippi, Alabama, Georgia and Florida. There are several proposals to establish RTOs that would define the rules and requirements around which competitive wholesale markets in this region would develop. The FERC has provisionally approved proposals by SeTrans Grid Company L.L.C. and GridSouth Transco L.L.C. to administer a substantial portion of the transmission facilities in this region. As a result, the final market structure for this region remains uncertain. Currently, the transmission infrastructure in this market is generally owned and

managed by integrated utilities, some of which are our competitors. As a result, market anomalies may exist. Transmission constraints are present in this market. Transmission infrastructure owners are subject to tariffs and protocols administered by the FERC.

We currently sell power from our facilities in this region to customers under short-term and long-term agreements. Many of the longer agreements are bilateral contracts that are generally non-standard with highly negotiated terms and conditions, while short-term sales usually occur through well-established existing commercial relationships. Our customers include municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities and power marketers. To date, there has been no significant access granted to retail customers in SERC.

West region Western Electricity Coordinating Council (WECC). At December 31, 2002, we owned interests in six generating facilities with an aggregate net generating capacity of 1,440 MW located in the states of California, Nevada and Washington. The generating capacity of our WECC facilities is approximately 4% baseload, 69% intermediate and 27% peaking capacity and represents less than 1% of the generating capacity in the WECC region. This capacity is largely natural gas-fired, although two of the peaking facilities located in California can also burn fuel oil.

Of our 1,440 MW of net generating capacity in the WECC, 1,385 MW consists of our 50 percent share of the 2,770 MW portfolio of facilities owned by West Coast Power, L.L.C., a joint venture between Dynegy and NRG Energy. All of West Coast Power s facilities are located in southern California and the generation output of the facilities is substantially covered by a contract between one of our marketing subsidiaries, as agent for the facility owners, and the California Department of Water Resources, referred to as the CDWR, which expires in December 2004. The agreement provides for a firm commitment of 600 MW of on-peak capacity and 200 MW of off-peak capacity, in each case at a fixed price. The agreement also contains a contingent component pursuant to which the CDWR can elect to reserve up to an additional 1,500 MW of on-peak capacity and 1,500 MW of off-peak capacity, subject to required minimum reservation amounts of 500 MW and 200 MW, respectively. We receive a fixed capacity payment for any contingent amounts reserved as well as payments for contingent energy actually sold, which energy payments are based on fuel, operating and maintenance and start-up costs. We may also market the energy, capacity and ancillary services output of these facilities through bilateral contracts or sell into the markets operated by the California Independent System Operator, or Cal ISO. Please read the discussion of the California electricity market below as well as Item 8, Financial Statements and Supplementary Data, Note 14 Commitments and Contingencies FERC and Related Regulatory Investigations Western Long-Term Contract Complaints beginning on page F-68 for a discussion of the ongoing legal challenges to the CDWR contract. West Coast Power shut down two units at these facilities, representing an aggregate capacity of 209 MW, at the end of 2002 because we deemed them no longer commercially viable.

Approximately 55 MW of baseload capacity outside of California consists of our equity interests in QFs that are under long-term contracts. Of this capacity, the Ferndale facility s 12 MW of capacity is contracted through December 2011 and the Black Mountain facility s 43 MW of capacity is contracted through April 2023.

The WECC regional market includes all or parts of the states of Arizona, California, Oregon, Nevada, New Mexico, Colorado, Wyoming, Idaho, Montana, Texas, South Dakota, Utah and Washington. Generally, we sell the power generated by facilities that are not under long-term contracts to customers located in southern California. Our customers include power marketers, investor-owned utilities, electric cooperatives, municipal utilities and the Cal ISO, acting on behalf of load-serving entities. We sell power and ancillary services to these customers through a combination of bilateral contracts and sales made in the Cal ISO s day-ahead and hour- ahead ancillary services markets and its real-time energy market. Many of the longer agreements we enter into are bilateral contracts that are generally non-standard with highly negotiated terms and conditions, while short-term sales usually occur through well-established existing commercial relationships. Access to retail customers has been substantially curtailed in this region.

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Our operations in the California market are subject to numerous environmental and other regulatory restrictions. Permits issued by local air districts restrict the output of some of our generating facilities. In addition, the quantity of oxides of nitrogen emitted into the air from our California power generation facilities is regulated by local air districts in California. The specific regulations and procedures vary by district, but the air districts generally issue emissions allocations, which we refer to as emission credits, that allow us to produce specified quantities of emissions through the normal operations of our power generating facilities located within the respective air districts. If the quantities produced exceed those quantities that were allocated, we could be subject to mitigation fees. However, markets exist for the purchase and sale of emission credits and, 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.

In 1996 and 1997, the FERC issued a series of orders approving a wholesale market structure. This structure was administered by two independent non-profit corporations: the Cal ISO, responsible for operational control of the transmission system and balancing actual supply and demand in real-time, and the Cal PX, responsible for conducting auctions for the purchase or sale of electricity on a day-ahead or day-of basis. As part of this market restructuring, California s distribution utilities sold essentially all of their gas-fired plants to third parties. The utilities were required to sell their remaining generation into the Cal PX markets and purchase all of their power requirements from the Cal PX markets at market-based rates approved by the FERC. The Cal PX ceased operations in January 2001 and subsequently filed for bankruptcy. The Cal ISO currently is conducting a major market redesign process that, if approved by the FERC, could change the structure of the markets operated by the Cal ISO, including changes to market monitoring and mitigation, congestion management and capacity obligations. 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 Regulation Power Generation Regulation beginning on page 23 and Item 8, Financial Statements and Supplementary Data, Note 14 Commitments and Contingencies California Market Litigation beginning on page F-65 and FERC and Related Regulatory Investigations beginning on page F-66.

Texas region Electric Reliability Council of Texas (ERCOT). At December 31, 2002, we owned or leased interests in four generating facilities with an aggregate net generating capacity of 942 MW located in Texas. The CoGen Lyondell facility is leased by one of our indirect subsidiaries, CoGen Lyondell, Inc. The generating capacity of our ERCOT facilities consists entirely of baseload facilities and represents approximately 1% of the generating capacity in the ERCOT region. All facilities are fueled by natural gas.

Approximately 305 MW of baseload capacity in this region is under long-term contracts. The Paris facility s 37 MW of capacity is contracted through September 2005, 185 MW of the Oyster Creek facility s capacity is contracted through October 2014 and the Frontier facility s 83 MW of capacity is contracted through September 2020.

The ERCOT region is comprised of the majority of the state of Texas. As part of the transition to deregulation in Texas, ERCOT changed its operations from 10 control areas, managed by utilities in the state, to a single control area on July 31, 2001. ERCOT, as the independent system operator, is responsible for maintaining reliable operations of the bulk electric power supply system in the ERCOT market. It is responsible for facilitating information needed for retail customer choice. It ensures that electricity production and delivery are accurately accounted for among the generation resources and wholesale participants in the ERCOT market. Unlike independent systems operators in other regions of the country, ERCOT does not centrally dispatch resources in the region. Market participants are generally responsible for contracting for their requirements bilaterally. However, ERCOT does procure energy on behalf of market participants pursuant to relaxed Balanced Schedule Protocols implemented on November 1, 2002. ERCOT also serves as agent for procuring ancillary services for those who elect not to provide their own requirements.

Members of ERCOT include retail customers, investor and municipal owned electric utilities, rural electric cooperatives, river authorities, independent generators, power marketers and retail electric providers. The

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ERCOT market operates under the reliability standards set by the North American Electric Reliability Council. Unlike other regions of the U.S., the Public Utility Commission of Texas, or PUCT, has primary jurisdictional authority over the ERCOT market, rather than the FERC. Currently, the PUCT is evaluating the need to change ERCOT s market structure due to a variety of commercial and operational issues that have been uncovered in the first 18 months of operation. The market design rulemaking proceeding is expected to conclude during the first half of 2003. Implementation of market redesign would follow.

We currently sell power from our facilities in this region to customers under short-term and long-term agreements. Many of the longer agreements are bilateral contracts that are generally non-standard with highly negotiated terms and conditions, while short-term sales usually occur through well-established existing commercial relationships. Our customers include municipalities and electric cooperatives, which remain primarily integrated utilities, power marketers and retail electric providers. We also sell directly to commercial and industrial end users.

International. In addition to our U.S. generating assets, we own interests in five generating facilities with an aggregate net generating capacity of 192 MW located in Costa Rica, Panama, Jamaica, Honduras and Pakistan. All of these facilities were acquired as part of the merger with Illinova in February 2000. The capacity consists of natural gas, heavy fuel oil and wind projects. All of this capacity is under contract for terms ranging from five to 25 years. Our ownership interests in these international projects range from 16% to 100%.

Retail Supply Business. We selectively contract 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 marketing operations are directed towards Texas, Illinois and New York. We also have four contracts with The Kroger Co. to provide it with an aggregate of 100 MW of capacity in California. These contracts, which were executed by the parties during the first half of 2001, have terms of varying lengths, the longest of which extends through December 2006. Concurrently with our execution of these contracts, we entered into other contracts to provide us with the power supply to support our obligations to The Kroger Co. Please read Item 8, Financial Statements and Supplementary Data, Note 14 Commitments and Contingencies FERC and Related Regulatory Investigations Western Long-Term Contract Complaints beginning on page F-68 for discussion of The Kroger Co. s legal challenges to these four contracts.

Power Generation Segment Marketing and Trading Strategy. As previously announced, we are in the process of exiting third-party risk management aspects of the marketing and trading business. Please read Customer Risk Management Segment beginning on page 19 for further discussion of this exit. Our power generation segment will continue to manage price risk through the optimization of fuel procurement and the marketing of power generated from its owned and controlled assets. As part of our commercial strategy to optimize these assets (including agency and energy management agreements to which we are a party) and to mitigate any associated risk, we will enter into various financial and other transactions and instruments, including entering into and unwinding forward hedges related to our generating capacity. We may also purchase capacity and energy to serve more efficiently our supply obligations under various contracts in each of the regions in which we operate.

Natural Gas Liquids

Our natural gas liquids segment primarily 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 NGLs. We generate commodity and fee-based revenue in our upstream activities; we generate fee-based revenue downstream at our fractionation, storage, terminalling and distribution facilities; and we generate margin and commodity-based revenue in our natural gas liquids distribution and marketing operations.

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

Upstream business. Our upstream business comprises our natural gas gathering and processing operations. Natural gas processing includes the operations of refining raw natural gas into merchantable pipeline-quality natural gas by extracting NGLs and removing impurities. We own interests in 20 gas processing plants, including 12 plants we operate. We also operate 9,188 miles of natural gas gathering pipeline systems associated with the 12 operated facilities and 2 stand-alone gas gathering pipeline systems where gas is treated and/or processed at third-party plants. These assets are located in key producing areas of Louisiana, New Mexico and Texas. During 2002, we processed an average of 2.1 Bcf/d of natural gas and produced an average of 92,000 gross barrels per day of NGLs. We are also party to processing agreements with four third-party plants.

Our natural gas processing services are provided in two plant categories: field plants and straddle plants. Field plants aggregate volumes of unprocessed gas from multiple onshore producing wells through gathering systems. These volumes are aggregated into economically sufficient volumes to be processed to extract NGLs and to remove water vapor, solids and other contaminants. 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 natural gas markets.

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Our upstream assets are located in the high-growth oil and gas exploration and production areas of North Texas and Louisiana and the mature Permian basin. The following map depicts our upstream assets in their current locations, including our capacity, throughput and production levels by region.

We process natural gas under several types of contracts. Under percentage of liquids contracts, the producer delivers to us a percentage of the NGLs as our fee and retains the value of all remaining NGLs and natural gas at the processing plant tailgate. Under percentage of proceeds contracts, a producer delivers to us a percentage of the NGLs and a percentage of the natural gas as payment for our services and retains the value of the remaining NGLs and natural gas at the tailgate of the processing plant. Under both percentage of liquids and percentage of proceeds contracts, the producer will either take their share of the NGLs and natural gas in kind or have us sell the commodities and return the sale proceeds to them.

Under keep-whole processing arrangements, we extract NGLs 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 for processing. We retain the NGLs as our fee for processing and must purchase and return to the producer sufficient volumes of merchantable natural gas to replace the Btus that were removed through processing so that the producer is kept whole.

Under economic election contracts, when processing economics are unfavorable the producer generally has the election to either bypass the plant or pay us a per-unit fee to process the gas. In some of the more recent agreements, the election is automatic, depending on processing economics. In this situation, when the value of the NGLs is less than the value of gas on an equivalent Btu basis, the contract automatically converts to a fee-based processing arrangement. In both instances, this fee could be in the form of a percentage of the natural gas and/or NGLs processed or in cash. Under wellhead purchase contracts, we purchase unprocessed natural gas from a producer at the wellhead at a discount to the market value of the gas. This discount is our margin for gathering and processing.

In 2003, we estimate that approximately

56% of the volumes we process will be under percentage of liquids arrangements;

19% of the volumes will be under percentage of proceeds contracts;

15% of the volumes will be under keep-whole contracts;

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9% of the volumes will be under economic election contracts; and

the remaining 1% will be under wellhead purchase contracts.

Pursuant to agreements we have with ChevronTexaco, we have the right to process substantially all of ChevronTexaco s gas in North America. Generally, with respect to gas produced from all areas other than the Gulf of Mexico, we process the gas in field processing plants owned by us or owned by third parties. The gas processed in our field plants is processed on a percentage of proceeds basis and is based on a commitment of such production by ChevronTexaco for the life of the oil, gas and/or mineral 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 straddle plants in which we own an interest and in plants owned by third parties. The gas produced from the Gulf of Mexico area is processed on a percentage of liquids basis when processing is economical or is processed on a fee basis if processing is uneconomical. The oil, gas and/or mineral leases committed under this agreement are committed for the life of the prospect.

Both types of processing agreements with ChevronTexaco, our field processing agreements and our Gulf of Mexico processing agreement, allow either party to renegotiate the commercial terms effective as of September 1, 2006 and on each successive ten-year period thereafter, for ChevronTexaco gas processed in field processing plants, and five years thereafter, for gas produced from the Gulf of Mexico and processed in Louisiana straddle plants. These renegotiations are to assure that commercial terms are substantially similar to those which, as of the date of the renegotiation, each party could expect to obtain in a freely negotiated processing agreement providing for a commitment of gas of similar quantity and quality for a ten-year term, with respect to the field plants, and a life-of-lease commitment, with respect to the straddle plants. During 2002 and 2001, respectively, ChevronTexaco gas accounted for 27% and 22% of the total volume of gas we processed.

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Downstream business. In our downstream business, we use our integrated assets to fractionate, store, terminal, transport, distribute and market NGLs. Our downstream assets are generally connected to and supplied 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 in their current locations, including our capacity and throughput capabilities.

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

- ethane, or a mixture of ethane and propane known as EP mix;
- propane;
- normal butane;
- isobutane; and
- natural gasoline.

We fractionate volumes for customers, from both our own upstream operations and third parties, pursuant to contracts that typically include a base fee per gallon and other 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 2002, these facilities fractionated an aggregate average of 215,000 gross barrels per day. We also have an equity investment in a third fractionator located in Mont Belvieu, Texas.

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Storage. 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, these storage facilities are connected to marine, rail and truck loading and unloading facilities that provide service and products to our customers. We generate fee-based revenue from our storage business by providing long-term and short-term storage services and throughput capability to affiliated and third-party domestic customers. 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 in the storage wells the NGLs removed from storage. When large volumes of NGLs 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 well. When reduced volumes of NGLs are stored, we utilize the brine from our brine storage ponds to displace the volumes of NGLs removed and, if necessary, can produce additional brine from wells dedicated for that purpose through a process known as brine leaching.

Transportation and Logistics. Our natural gas liquids transportation and logistics infrastructure is made up of a wide range of transportation and distribution assets supporting the delivery requirements of our distribution and marketing business. These assets are deployed to serve our wholesale distribution terminals, fractionation facilities, underground storage facilities, pipeline injection terminals and many of the nation s crude oil refineries. Our marine terminals, located in Texas, Florida, Mississippi and Tennessee, offer importers and wholesalers a variety of methods for transporting products to the marketplace. Our transportation assets include:

- access to up to 2,000 railcars that we manage pursuant to a services agreement with ChevronTexaco;
- 87 transport tractors and 114 tank trailers;
- over 580 miles of gas liquids pipelines, primarily in the North Texas, Gulf Coast and Permian basin regions; and
- 21 pressurized LPG barges.

We maximize use of our transportation assets by providing fee-based transportation services to refineries and petrochemical companies in the Gulf of Mexico region and to the wholesale propane marketing business nationwide.

Distribution and Marketing Services. Our distribution and marketing services include:

- refinery services;
- wholesale propane marketing; and
- purchasing mixed NGLs 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.

Our refinery services business consists of providing LPG balancing services, purchasing natural gas liquids products from refinery customers and selling natural gas liquids products to various customers. In our LPG balancing operations, we use our storage, transportation, distribution and marketing assets to assist refinery customers in managing their natural gas liquids product inventories. This includes both feedstocks utilized in refinery processes and excess LPGs produced by those processes. We generally earn a margin in our refinery services operations by retaining a portion of the resale price of excess NGLs or a fixed minimum fee per gallon and by charging a fee for locating and supplying feedstocks to the refinery either based on a percentage of the cost in obtaining such supply or a minimum fee per gallon. Approximately 35% and 15% of this segment s natural gas liquids purchases in 2002 and 2001, respectively, were from ChevronTexaco. In 2002, we sold an average of 60,000 barrels per day through our refinery services business.

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We have contracts with each of ChevronTexaco s refineries situated in El Paso, Texas, El Segundo, California, Pascagoula, Mississippi, Richmond, California, Salt Lake City, Utah and Hawaii pursuant to which we provide refinery services. All of these contracts allow us to market excess NGLs produced during the refining process. In addition, with respect to all of the refineries except Hawaii, these agreements also provide for the supply by us of NGLs to ChevronTexaco, which are utilized in its refining process. Generally, these agreements provide that we obtain on behalf of the refineries any such natural gas liquids feedstocks that they need and, in return, we are reimbursed for the cost of acquiring such feedstocks and are paid a cents-per-gallon fee for providing such services. These agreements extend through August 2006.

Our wholesale propane marketing operations include the sale of propane and related logistical services to major multi-state retailers, independent retailers and other end users. Our propane supply comes from our refinery services operations and from our other owned and/or managed distribution and marketing assets. In addition, we also have the right to purchase or market substantially all of ChevronTexaco s NGLs (both mixed and raw) pursuant to a Master NGL Purchase Agreement that extends through August 31, 2006. We generally sell propane at a fixed or posted price at the time of delivery. In 2002, we sold an average of 40,000 barrels of propane per day. In January 2002, we purchased former Texaco s wholesale propane marketing business and integrated it into our existing wholesale business.

We market our own natural gas liquids production and also purchase natural gas liquids products from other natural gas liquids producers and marketers for resale. In 2002, our distribution and marketing services business sold an average of 303,000 barrels per day of NGLs in North America. We generally purchase mixed NGLs from producers 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 liquids products from producers under contract. We also earn margins by purchasing and reselling natural gas liquids products in the spot and forward markets.

In 2002, we marketed 96,000 barrels per day of LPG worldwide, using chartered large-hull ships. These operations consisted primarily of acquiring and marketing LPG from producing areas in the North Sea, West Africa, Algeria and the Arabian Sea, as well as from the U.S. Gulf Coast region. During the fourth quarter 2002, we decided to exit the global liquids business and sold our London-based international LPG trading and transportation business to Trammo Gas International Inc., a wholly owned subsidiary of Transammonia Inc. The transaction closed on December 13, 2002 and was effective on January 1, 2003. This sale is also consistent with our current strategy to focus our marketing activities on our North American physical assets. The sale of our international liquids business benefits liquidity by releasing significant amounts of previously posted collateral and removing lease obligations and parent guarantees related to shipping activities in the first quarter of 2003. We are in the process of finalizing a complete release of the ship lease, including the parent guarantee.

On an aggregate basis, this segment s marketing, wholesale and global operations sold approximately 499,000 barrels per day of NGLs to approximately 740 different customers in 2002. In 2002 and 2001, approximately 28% and 23%, respectively, of our 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 most 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 transmission and distribution segment consists of IP s operations, which we acquired in the Illinova acquisition in February 2000. IP is a regulated public utility based in Decatur, Illinois. IP 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. IP provides retail electric and natural gas service to residential, commercial and industrial consumers in substantial portions of northern, central and southern Illinois. IP also currently supplies electric transmission service to electric cooperatives, municipalities and power marketing entities in the state of Illinois. As described below, IP has previously announced an agreement to sell its electric transmission system.

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From February 1, 2002 through July 31, 2002, this segment also included the results of Northern Natural. We acquired Northern Natural from Enron in connection with our terminated merger and 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 Item 8, Financial Statements and Supplementary Data, Note 3 Dispositions, Discontinued Operations and Acquisitions Dispositions Discontinued Operations Northern Natural beginning on page F-27 for further discussion of Northern Natural.

Electric Business. IP supplies electric service at retail to an estimated aggregate population of 1,372,000 in 313 incorporated municipalities, adjacent suburban and rural areas, and numerous unincorporated communities. As of January 3, 2003, based on billable meters, IP served 592,692 active electric customers. IP owns an electric distribution system of 37,907 circuit miles of overhead and underground lines. For the year ended December 31, 2002, IP delivered a total of 19,144 million kWh of electricity.

IP owns, but has contracted to sell, its 1,672-circuit mile electric transmission system to Trans-Elect Inc., an independent transmission company, for $239 million. The closing of the sale, the contract for which was executed as of October 7, 2002, was conditioned on several matters, including the receipt of required approvals from the SEC under PUHCA, the Federal Trade Commission, the ICC and the FERC. With respect to the FERC, the sale was conditioned on its approving the levelized rates application filed by Trans-Elect seeking a 13% return on equity (based on a capital structure of equal portions of debt and equity), which would result in a significant increase in transmission rates over the rates IP currently charges. On February 20, 2003, the FERC voted to defer its approval of the transaction and set a hearing to establish the allowable transmission rates for Trans-Elect. Specifically, the FERC stated that the benefits of the transaction, including independent transmission ownership, may not justify the significant increase in rates sought. The FERC also limited the period for which IP may provide operational services to Trans-Elect to one year.

IP and Trans-Elect have withdrawn the rate filing at the FERC and requested a continuance of the hearing pending an order on rehearing and a FERC ruling on a new rate application. Pending resolution of these matters by the FERC, the ICC proceedings have also been withdrawn and continued. IP is in discussions with Trans-Elect to determine the impact of the FERC order on the transaction and to determine the course of action the parties will take. Under the sale agreement, if the transaction does not close on or before July 7, 2003, either party can terminate the agreement. Because of the lead time required to receive the necessary regulatory approvals, it is unlikely that the transaction could be closed by July 7th.

Regulators historically have determined IP s rates for electric service the ICC at the retail level and the FERC at the wholesale level. These rates are designed to recover the cost of service and to allow IP s shareholders the opportunity to earn a reasonable rate of return. Please read Regulation Illinois Power Company beginning on page 25 for further discussion of the regulatory environment in which IP operates, including the retail electric rate freeze that will remain in effect through 2006.

IP owns no significant generation assets and obtains the majority of the electricity that it supplies to its retail customers pursuant to long-term power purchase agreements with AmerGen and DMG. The AmerGen agreement was entered into in connection with the sale of the Clinton nuclear generation facility to AmerGen in December 1999. IP is obligated to purchase a predetermined percentage of Clinton s electricity output through 2004 at fixed prices that exceed current and projected wholesale prices. The AmerGen agreement does not obligate AmerGen to acquire replacement power for IP in the event of a curtailment or shutdown at Clinton.

IP obtains more than two-thirds of its electricity pursuant to its power purchase agreement with DMG that runs through 2004. The DMG agreement requires that IP compensate DMG for reserved capacity regardless of the amount of electricity purchased and that IP pay for any electricity actually purchased based on a formula that includes various cost factors, primarily related to the cost of fuel, plus a market price for amounts in excess of its reserved capacity. The agreement obligates DMG to provide power up to the amount IP reserves even if DMG has units unavailable. In addition, DMG bears ultimate responsibility for serving IP s load as the provider of last

resort. As a result, should IP be unable to obtain sufficient power to meet its load requirements from the DMG and AmerGen facilities, DMG is obligated to acquire such power for IP, likely through open market purchases at current market prices. IP is subject to market price risk with respect to such power purchases.

Gas Business. IP supplies retail natural gas service to an estimated population of 1,019,000 in 258 incorporated municipalities and adjacent areas. As of January 3, 2003, based on billable meters, IP served 414,333 active gas customers. IP owns 774 miles of natural gas transportation pipeline and 7,598 miles of natural gas distribution pipeline. IP purchases the gas that it sells at retail from various suppliers pursuant to contracts that generally have a duration of one to twelve months. IP attempts to manage its customers gas price risk by buying gas forward and injecting gas into storage at times when IP believes it is economic to do so, subject to ICC regulations and review.

The ICC determines rates that IP may charge for retail gas service. As with the rates that IP is allowed to charge for retail electric service, the rates that IP is allowed to charge for retail gas service are designed to recover the cost of service and to allow IP s shareholders the opportunity to earn a reasonable rate of return. IP s rate schedules contain provisions for passing through to its customers any increases or decreases in the cost of natural gas, subject to an annual prudency review by the ICC. For the year ended December 31, 2002, IP delivered a total of 773 million therms of natural gas.

IP owns seven underground natural gas storage fields with a total capacity of approximately 11.6 billion cubic feet and a total deliverability on a peak day of approximately 327 million cubic feet. To supplement the capacity of IP s seven underground storage fields, IP has contracted with natural gas pipelines for an additional 5.4 billion cubic feet of underground storage capacity, representing an additional total deliverability on a peak day of about 96 million cubic feet. The operation of these underground storage facilities permits IP to increase deliverability to its retail gas customers during peak load periods by extracting natural gas that was previously placed in storage during off-peak months.

Intercompany Note Receivable. In October 1999, IP transferred its wholly-owned fossil generating assets to Illinova in exchange for an unsecured note receivable of approximately $2.8 billion. These assets now comprise the generating fleet of DMG. The intercompany note matures in September 2009 and bears interest at an annual rate of 7.5%, payable semi-annually in April and October. At December 31, 2002, the principal outstanding under the note receivable was $2.3 billion. The intercompany note and the related interest income are eliminated in consolidation as intercompany transactions and, therefore, are not reflected in IP s segment results as reported herein.

Customer Risk Management

Our customer risk management, or CRM, segment consists of third-party marketing, trading and risk management activities unrelated to our generating assets. This segment provides these services to wholesale energy customers in North America, the United Kingdom and Continental Europe. In October 2002, we announced our exit from the CRM business, which has historically focused on the following activities:

- Purchases and sales of natural gas and power;
- Procurement of natural gas transportation services for our customers through pipelines owned by third parties;
- Storage of natural gas inventories in leased facilities for the purpose of offering peak delivery services to our customers;

Management of power tolling arrangements in which we pay a fee for access to power generated by facilities that are owned and operated by third parties; and

Execution of third-party, derivative financial instruments to manage the risks associated with commodity price fluctuations on behalf of our customers.

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Since announcing our exit from the CRM business, we have made substantial progress in winding down our marketing and trading portfolio, particularly in the United Kingdom. Following is a list of actions we have taken related to this exit:

- In September and November 2002, we sold the subsidiaries that owned our U.K. natural gas storage business;
- In November 2002, we sold a portion of our Canadian natural gas marketing business;
- In December 2002, we terminated a previously existing long-term power tolling arrangement; and
- In January 2003, we announced the sale of our Canadian retail electricity marketing business.

Also in January 2003, we announced an agreement with ChevronTexaco to end the existing natural gas purchase and sale contracts related to ChevronTexaco s North American production and consumption, effective February 1, 2003. Our CRM segment had purchased substantially all of ChevronTexaco s lower-48 U.S. natural gas and supplied the natural gas requirements of ChevronTexaco s corporate facilities through agreements that were to run until August 2006. We paid ChevronTexaco approximately $13 million in connection with ending the contracts, resolving balancing and other commercial matters and the transfer to ChevronTexaco of some related third-party contracts.

We have also taken various actions in the process of winding down our trading positions in this business. For example, we have sold all of our U.S. natural gas storage inventories. In an effort to reduce the size of our marketing and trading portfolio, we also have negotiated terminations of various marketing and trading agreements, or allowed them to expire, and generally have not entered into new transactions of this type. In our U.S. natural gas marketing and trading business, we have terminated or assigned all of our long-term storage arrangements and substantially all of our third-party sales arrangements. In the United Kingdom, we have terminated or sold all of our marketing and trading contracts in the region and have closed our U.K. office. The success of these efforts to date is reflected in, among other things, a significant reduction in our collateral requirements associated with this business. Since September 30, 2002, we have reduced our collateral obligations in this business by approximately $585 million.

A significant component of our CRM segment is the eight power tolling arrangements to which we are a party. Pursuant to these eight agreements, we are obligated to make aggregate payments of approximately $3.8 billion to our counterparties in exchange for access to power generated by their facilities. Given our decision to exit from third-party risk management aspects of the marketing and trading business, we no longer consider this access to power as key to our business strategy. We are actively pursuing opportunities to assign or renegotiate the terms of our contractual obligations related to some of these agreements.

The following table contains a listing of our power tolling arrangements, including the name and location of each related project, the plant heat rate, the plant capacity and the term over which these payments are due:

Tolling Agreements

Project	Location	Heat Rate	MW	Term
Dahlberg	Georgia	12,500	225	May 2005
Daniel	Mississippi	7,150	260	May 2011
Goat Rock(1)	Alabama	6,900	625	May 2030
Sithe Independence	New York	7,400	915	Nov. 2014
Sterlington/Quachita	Louisiana	6,950	835	Sept. 2017(2)
Kendall	Illinois	7,300	550	June 2012
Gregory	Texas	8,800	335	July 2005
Batesville	Mississippi	7,250	110	May 2010

(1) Project in development; contract begins in June 2005.
(2) 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.

Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Customer Risk Management CRM Outlook beginning on page 73 for further discussion of the potential impact of these power tolling agreements on our future results.

Corporate and 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, corporate legal, corporate human resources, administration and technology. Corporate general and administrative expenses, income taxes and corporate interest expenses, which we previously allocated among our operating divisions, will be included in our other reported results, as well as corporate-related other income and expense items. Interest expense associated with borrowings incurred by our operating divisions, such as IP mortgage bonds or power generation facility financings, will continue to be reflected in the appropriate business segment s results. Other results also include our discontinued global communications business.

The communications business was established during the fourth quarter of 2000 and includes an optically switched, mesh fiber-optic network that spans more than 16,000 route miles and reaches 44 cities in the United States. As previously announced, we have executed an agreement to dispose of our U.S. communications business to 360 networks. The transaction is expected to close in the second quarter 2003 and is subject to receipt of required regulatory approvals and other closing conditions.

During the first quarter 2003, we disposed of our European communications business, which operated a high-capacity, broadband network with access points in 32 cities throughout Western Europe. As a result of this sale, we eliminated approximately $150 million of our then-remaining operating commitments associated with our communications business.

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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 15 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 NGLs, residue gas, condensate and sulfur, and transportation and storage of natural gas and NGLs. 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 19 companies.

Regulated Energy Delivery. IP is authorized, by statute and/or certificates of public convenience and necessity, to conduct operations in the territories it serves. In addition, IP operates under franchises and license agreements granted it by the communities it serves.

With respect to IP s gas distribution business, absent extraordinary circumstances, potential competitors are barred from constructing competing systems in IP s service territories by a judicial doctrine known as the first in the field doctrine. In addition, the high cost of installing duplicate distribution facilities would render the construction of a competing system impractical. Additionally, competition in varying degrees exists between natural gas and other fuels or forms of energy available to consumers in IP s service territories.

IP s electric utility business faces significant competition brought about by the implementation of a customer choice structure in the state of Illinois. Under the Electricity Customer Choice and Rate Relief Law of 1997, commonly referred to as the Customer Choice Law, residential electricity customers were given a 15% decrease in their base electric rates beginning August 1, 1998 and an additional 5% decrease in base electric rates beginning May 1, 2002. The Customer Choice Law also implemented a return on equity collar that is further described below under Regulation Illinois Power Company . Additionally, the Customer Choice Law phased in a right of customers to choose their electricity suppliers, with specified non-residential customers being granted this right in October 1999, all then-remaining non-residential customers being granted this right beginning on December 31, 2000 and all residential customers being granted this right effective May 1, 2002. Customers who buy their electricity from a supplier other than the local electric utility are required to pay applicable transition charges to the utility through the year 2006. These charges are not intended to compensate the electric utilities for all revenues lost because of customers buying electricity from other suppliers.

Although no parties have requested certification from the ICC to provide residential electric service pursuant to the Customer Choice Law, this could change. Additionally, there are several registered energy providers for non-residential service. We face intense competition from these other energy providers and estimate that by the end of 2003, commercial and industrial customers representing approximately 16% of IP s eligible retail load will have switched to another such provider. Competition typically is based on price and service reliability. We believe IP has approximately eight primary competitors in its business.

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REGULATION

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

Power Generation Regulation. Our power generation assets include projects that are Exempt Wholesale Generators, or EWGs, qualifying facilities, or QFs, or foreign utility companies, or FUCOs. One form of EWG is a merchant plant, which operates independently from designated power purchasers and, as a result, will generate and sell power to markets when electricity sales prices exceed the cost of production. A QF typically sells the power it generates to a single power purchaser.

The FPA grants the FERC exclusive ratemaking jurisdiction over wholesale sales of electricity in interstate commerce. Our power generation operations also are subject to regulation by the FERC under PURPA with respect to rates, the procurement and provision of certain services and operating standards. Although facilities deemed QFs under PURPA are exempt from ratemaking and other provisions of the FPA and the Public Utilities Holding Company Act of 1935, or PUHCA, non-QF independent power projects that are not otherwise exempt and certain power marketing activities are subject to the FPA and the FERC s ratemaking jurisdiction, as well as PUHCA, and the Energy Policy Act of 1992. All of our current QF projects are qualifying facilities and, as such, under PURPA 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 ownership interests in such projects.

In certain markets where we own power generation facilities, specifically California and New York, the FERC has, from time to time, approved and subsequently extended temporary price caps on wholesale power sales, or other market mitigation measures. Due to concerns over potential short supply and high prices in the summer of 2001, the NYISO, the FERC-approved operator of electric transmission facilities and centralized electric markets in New York, filed an Automated Mitigation Procedure proposal with the FERC. The proposal caps bid prices based on the cost characteristics of power generating facilities in New York, such as our Central Hudson facilities. In an order issued on June 28, 2001, the FERC accepted the proposal for the summer of 2001. In a subsequent order issued on November 27, 2001, the FERC extended the proposal through April 30, 2002. In an order issued in May 2002, the FERC modified and extended the proposal indefinitely, until the NYISO implements the FERC s standard market design rules.

Price volatility and other market dislocations in the California market have precipitated a number of FERC actions related to the California market, and the Western market generally, in addition to price caps and market mitigation measures. These include an investigation of gas pipeline marketing affiliate abuse in the region, focused on whether, and to what extent, price refunds are owed by Dynegy and wholesale electricity suppliers serving California, and complaints requesting the FERC to reform or void various long-term power sales contracts. As a prelude to possible initiation of a new complaint proceeding, in the Spring of 2002, the FERC began investigating whether any entity has manipulated prices for electricity or natural gas in the West, since January 1, 2000, possibly resulting in unjust and unreasonable prices under long-term power sales contracts entered into since that time. On March 26, 2003, the FERC staff issued its Final Report on Price Manipulation in Western Markets, addressing a number of issues. The FERC staff also recommended that the FERC issue orders requiring that Dynegy and 36 other market participants be required to show cause why their activities did not violate the Cal ISO and Cal PX tariffs. Additional matters regarding our California operations are discussed in Item 8, Financial Statements and Supplementary Data, Note 14 Commitments and Contingencies FERC and Related Regulatory Investigations Other FERC and California Investigations beginning on page F-67.

On November 20, 2001, the FERC issued an order that would subject the prospective sales of all entities with market-based rate tariffs to refunds or other remedies in the event the seller engages in anti-competitive behavior or the exercise of market power. The FERC has postponed the effectiveness of this refund condition pending its consideration of comments submitted by interested parties. Dynegy and other similarly-situated

generators and power marketers have submitted comments in opposition to the proposed refund condition. It is uncertain how the FERC will act with respect to this matter. If the FERC were to establish the broad refund condition proposed, it would increase the risk inherent in electric marketing activities for all wholesale sellers of electricity, including us. Establishment of the proposed refund condition, together with a finding that we engaged in any of the specified activities, also could require us to refund some of the electricity payments we have collected.

Electricity Marketing Regulation. Our electricity marketing operations are regulated by the Federal Power Act and the FERC with respect to rates, terms and conditions of services and various reporting requirements. Current FERC policies permit trading and marketing entities to market electricity at market-based rates. While the FERC has affirmed its desire to move toward competitive markets with market-based pricing, it is currently reviewing the specifics of implementing this policy. For further discussion, please see Regulation Power Generation Regulation beginning on page 23 above.

In December 1999, the FERC issued Order No. 2000, which addressed a number of issues relating to the regional transmission of electricity. In particular, Order No. 2000 provided for regional transmission organizations, or RTOs, to control the transmission facilities within a particular region. After a period of progress toward voluntary creation of RTOs as envisioned by the FERC, activity has slowed due to controversy and uncertainty concerning required standards and structures for such entities. Recently, the FERC proposed new rules designed to result in the adoption of generally standardized market terms and conditions governing interstate transmission and RTO operation of markets. The FERC also proposed generic standards and procedures for the interconnection of generation to the transmission grid. These proposed rules are controversial, particularly with some legislators and state regulatory bodies, and have generated significant opposition. The FERC also has directed electric industry participants to establish a single organization to assist with the development of business practices and protocols that will be needed to implement such standardized terms and conditions. It is uncertain what rules the FERC may adopt as the result of these proceedings. The impact of these RTOs on our electricity marketing operations cannot be predicted. For further discussion, please see Regulation Illinois Power Company beginning on page 25.

Recently, the FERC announced a new policy concerning its approvals of utilities securities issuances, including debt, and to assume liabilities and obligations of others. Under the new policy, such approvals will be conditioned upon a requirement that any secured debt incurred follow the disposition of assets used to secure it, and if secured by public utility assets, must only be incurred for public utility purposes and if unsecured, must proportionately follow any assets financed with its proceeds if those assets are transferred.

Natural Gas Processing. Our natural gas processing operations could become subject to FERC regulation. The FERC has traditionally maintained that a processing plant used primarily for removal of NGLs for economic purposes is not a facility for transportation or sale for resale of natural gas in interstate commerce and, therefore, is not subject to jurisdiction under the NGA. However, the FERC considers a processing plant used primarily for purposes related to transportation safety and efficiency to be subject to such regulation. We believe our gas processing plants are primarily involved in removing NGLs 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 current tests used by the FERC to determine nonjurisdictional 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 regulated.

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Liquified Natural Gas (LNG) Terminals. LNG terminals operating in interstate commerce are subject to FERC jurisdiction and regulation of rates, terms and conditions of service. The FERC recently announced a new policy applicable to new LNG terminals, such as our proposed facility, which will apply less stringent regulation to such facilities as compared to that described above concerning interstate natural gas transportation and storage. Under this new policy, such LNG facilities need not operate on an open-access basis, and may offer rates, terms and conditions of service mutually agreed to with shippers, rather than as established by FERC. We recently received preliminary FERC approval to construct such a facility in Louisiana. We have entered into an agreement to sell this facility to Sempra LNG Corp., a subsidiary of San Diego-based Sempra Energy. The transaction is subject to the satisfaction of certain conditions and is expected to close in the early part of the second quarter.

Illinois Power Company. IP is an electric utility company as defined in PUHCA. Its direct parent company, Illinova, and Dynegy are holding companies as defined in PUHCA. Illinova and Dynegy remain subject to regulation under PUHCA with respect to the acquisition of certain voting securities of other domestic public utility companies and utility holding companies.

IP also is subject to regulation by the FERC under the FPA as to transmission rates, terms and conditions of service, the acquisition and disposition of transmission facilities and other matters. The FERC has declared IP exempt from the NGA and related FERC orders, rules and regulations.

IP is further subject to regulation by the State of Illinois and the Illinois Commerce Commission. The Illinois Public Utilities Act was significantly modified in December 1997 by the Electric Service Customer Choice and Rate Relief Law of 1997, or P.A. 90-561, but the ICC still has broad powers of supervision and regulation with respect to rates and charges and various other matters. Under P.A. 90-561, IP must continue to provide bundled retail electric services to all who choose to continue to take service at tariff rates and must provide unbundled electric distribution services to all eligible customers as defined by P.A. 90-561 and bundled rates were frozen at that time through December 31, 2004. P.A. 92-0537, enacted in June 2002, extended the rate freeze for bundled customers through December 31, 2006.

P.A. 90-561, as amended by P.A. 92-12, requires IP to participate in an Independent System Operator, or RTO. IP has announced its intention to join PJM Interconnection, L.L.C. On July 31, 2002, the FERC issued an order approving IP s proposal to join PJM, subject to certain conditions. In 2002, IP reached an agreement with Trans-Elect, Inc. pursuant to which IP agreed to sell its transmission assets. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Regulated Energy Delivery REG Outlook beginning on page 71 for further discussion of the proposed Trans-Elect transaction. Should the sale be consummated, Trans-Elect has announced its intention to place IP s transmission assets in the Midwest Independent Transmission System Operator, Inc. Any RTO in which IP ultimately participates will be subject to the outcome of the FERC s proceedings on standardized market terms and conditions.

IP s retail natural gas sales and distribution services also are regulated by the ICC. Such sales are currently priced under a purchased gas adjustment mechanism under which IP s gas purchase costs are passed through to its customers if such costs are determined prudent, subject to an annual prudency review by the ICC.

Natural Gas Regulation. The transportation (including storage) and sale for resale of natural gas in interstate commerce is subject to regulation by the FERC under the Natural Gas Act of 1938, as amended, and, to a lesser extent, the Natural Gas Policy Act of 1978, as amended. The rates charged by interstate pipelines for interstate transportation and storage services, and the terms and conditions for provision of such services, are regulated by the FERC, which generally also must approve any changes to these rates or terms and conditions prior to their implementation. 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. Our Venice Gathering System is a regulated interstate pipeline.

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Commencing in 1992, the FERC issued Order No. 636 and subsequent orders, which require interstate pipelines to provide transportation separate, or unbundled, from the pipelines sales of gas. These orders also require pipelines to provide open-access transportation on a basis that is equal for all shippers. The FERC intends for these orders to foster increased competition within all phases of the natural gas industry. Prior to our acquisition of the Venice Gathering System, these orders did not directly regulate any of our activities; however, like other interstate pipelines, Venice Gathering System must comply with FERC s open-access transportation regulations. The implementation of these orders has not had a material adverse effect on our results of operations. The courts have largely affirmed the significant features of these and numerous related orders pertaining to the individual pipelines, although some appeals remain pending and the FERC continues to review and modify its open-access regulations.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, these orders revised the FERC pricing policy by waiving price ceilings for short-term released interstate pipeline transportation capacity for a two-year period, and effected changes in the FERC regulations relating to interstate transportation scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. Most major aspects of these orders were upheld on judicial review, though some issues were remanded to the FERC, have been considered on remand and are pending rehearing at the FERC. It is uncertain whether and to what extent the FERC s market reforms will survive rehearing and further judicial review and, if so, whether the FERC s actions will achieve the goal of further increasing competition in natural gas markets.

The FERC has proposed to expand its existing rules governing the conduct of interstate pipelines and their marketing affiliates to include all energy affiliates. If adopted, the proposed rule would, among other things, preclude the exchange of transportation-related information among an interstate pipeline and any of its energy affiliates. The FERC has stated that one purpose of the proposal is to allow pipeline affiliates and non-affiliates to compete in energy markets on an even basis. It is uncertain whether or when the FERC may adopt the proposed rule, or the extent to which it may affect the cost or other aspects of our operations; however, we do not anticipate that our regulated transmission provider and its energy affiliates will be impacted any differently than other similar industry participants.

Pursuant to the NGPA and the Wellhead Decontrol Act of 1989, most sales of natural gas are no longer subject to price controls. However, the FERC retains jurisdiction over certain sales made by interstate pipelines or their affiliates. Currently, the FERC has authorized such sales to be made at unregulated prices, terms and conditions. While sales of natural gas can currently be made at market prices, and upon unregulated terms and conditions, there is no assurance that such regulatory treatment will continue indefinitely in the future. Congress or, as to sales remaining subject to its jurisdiction, the FERC, could re-enact price controls or other regulation in the future.

State Regulatory Reforms. Our domestic natural gas and power marketing, and power generation businesses are subject to various regulations from the states in which we operate. Proposed reforms to these regulations, and in some cases, repeal of measures implementing retail competition, are proceeding in several states, including California, the results of which could affect our operations.

Legislation. In the last legislative session, the United States Congress considered, but ultimately did not pass, a number of bills that could have impacted regulations applied to us and our subsidiaries, including bills that would repeal the PUHCA and portions of the PURPA and that would affect the FERC s regulatory authority over energy marketing, generation and trading. Recent market events including the California electricity crisis in late 2000 and the alleged manipulation of electricity prices by Dynegy and other wholesale electricity merchants have prompted questions about the wisdom of the PUHCA repeal and whether more stringent regulation may be needed. We cannot predict with certainty what energy legislation may be considered in the current legislative session, whether any such legislation will become law or what effect any such new legislation might have.

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ENVIRONMENTAL AND OTHER MATTERS

General. 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. In addition, development of projects in international markets creates exposure to and obligations under the national, provincial and local laws of each host country, including environmental standards and requirements imposed by these governments. Environmental laws and regulations, including environmental regulators interpretations of these laws and regulations, are complex, change frequently and have tended to become more stringent over time. Many environmental laws require permits from governmental authorities before construction on a project may be commenced 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 and regulations governing the siting 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 $82 million in 2002, compared to approximately $81 million in 2001 and approximately $121 million in 2000. We estimate that total environmental expenditures (both capital and operating) in 2003 will be approximately $52 million. A majority of our environmental expenditures relate to the federal Clean Air Act and comparable state laws and regulations. Management does not expect capital spending on environmental matters to increase materially over the near term; however, changes in environmental regulations or the outcome of litigation could result in additional requirements that could necessitate increased spending. Please read Environmental and Other Matters The Clean Air Act below for a discussion of the litigation brought by the Environmental Projection Agency against two Dynegy affiliates 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. Although the impact of air quality regulations cannot be predicted with certainty, these regulations are expected to become increasingly stringent, particularly for electric power generating facilities. 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 oxide 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.

- 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 oxide. The current compliance deadline for implementation of these emission reductions is 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

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installation of the necessary emission control equipment to meet these requirements has been largely completed; consequently, we expect the power generation system will meet the specified compliance deadlines for implementation. Portions of our NGL businesses are also subject to these rules. We have plans in place to satisfy these requirements and expect to incur capital expenditures of approximately $6.5 million pursuant to such plans.

Multi-Pollutant Air Emission Initiatives. Various multi-pollutant proposals have been introduced at the federal and state level. An example is the Clear Skies Initiative announced by the President in 2002. The Clear Skies proposal is aimed at long-term reductions of multiple pollutants produced from fossil fuel-fired power plants. Reductions averaging 70% are targeted for sulfur dioxide, NOx and mercury. In addition, the President has proposed a voluntary program for reducing greenhouse gas emissions such as carbon dioxide. The implementation of this initiative, if approved by Congress, would be via a market-based program, modeled after the Acid Rain Program, beginning in 2008 and phased full compliance by 2018. Fossil fuel-fired power plants in the United States would be affected by the adoption of this program, or other multi-pollutant legislation currently proposed by Congress addressing similar issues. Such programs would require compliance to be achieved by the installation of pollution controls, the purchase of emission allowances or curtailment of operations.

MACT. The EPA has announced its determination to regulate hazardous air pollutants including mercury, from coal-fired and oil-fired steam electric generating units under Section 112 of the Clean Air Act. The EPA plans to develop maximum achievable control technology standards for these types of units. The rulemaking for coal and oil-fired steam electric generating units is expected to be completed by December 2004. Compliance with the rules will likely be required within three or four years thereafter.

The MACT standards that will be applicable to the units cannot be predicted at this time and could have an adverse impact on our operations. As well, we cannot predict the additional impact that the MACT standard would have over and above any proposed multi-pollutant legislation. Although the impact of possible future environmental requirements cannot be predicted with any degree of certainty, any expenditures that are ultimately required are not anticipated to have a more significant effect on our operations or financial condition than on any similarly situated company that generates electricity through the burning of fossil fuels.

Baldwin Station Litigation. IP and DMG, referred to in this section as the Defendants, are currently the subject of a Notice of Violation, or NOV, from the EPA and a complaint filed by the EPA and the Department of Justice alleging violations of the Clean Air Act and the regulations promulgated under the Clean Air Act. Similar notices and complaints have been filed against a number of other utilities. Both the NOV and the complaint allege that certain equipment repairs, replacements and maintenance activities at the Defendants three Baldwin Station generating units in Illinois constituted major modifications under the Prevention of Significant Deterioration (PSD) and/or the New Source Performance Standards (NSPS) regulations. When activities that meet the definition of major modifications occur and are not otherwise exempt, the Clean Air Act and related regulations generally require that generating facilities meet more stringent emissions standards, which may entail the installation of potentially costly pollution control equipment. The Defendants filed an answer denying all claims and asserting various specific defenses and a trial date of June 3, 2003 has been set.

We believe that the Defendants have meritorious defenses to the EPA allegations and will vigorously defend against these claims. On February 18, 2003, the Court granted the Defendants motion for partial summary judgment based on the five-year statute of limitations. As a result of the Court s ruling, the EPA will not be able to seek any monetary civil penalties for claims related to construction without a permit under the PSD regulations. The Order also precludes monetary civil penalties for a portion of the claims under the NSPS regulations. The Company has recorded a reserve for potential penalties that could be imposed if the EPA were to prosecute its claims successfully. Please read Item 8, Financial Statements and Supplementary Data, Note 14 Commitments and Contingencies Baldwin Station Litigation beginning on page F-64 for further discussion of this lawsuit.

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On December 31, 2002, the EPA proposed several reforms to its regulations governing new source review. These reforms would clarify the routine maintenance, repair and replacement exclusion, provide more certainty in evaluating permit requirements and increase operational flexibility for affected facilities.

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 the DNE facilities expired in 1992. However, under New York State law, each permit remains in effect and allows for continued operation under the terms of the original permits, given that timely applications requesting renewal were filed as required. Although the renewal process has been underway from some time, joint legal action has been taken recently by several interested third parties. The petitioners in this matter are requesting that the permit renewal process be completed in an expeditious manner. In November 2001, the EPA promulgated rules that impose additional technology-based requirements on new cooling water intake structures. Draft rules for existing intake structures have also been issued. It is not known at this time what requirements the final rules for existing intake structures will impose or whether our existing intake structures will require modification as a result of such requirements.

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. The final impact on us as a result of these initiatives is unknown at this time; however, it is reasonable to assume that we would incur additional compliance costs as a result of the increased regulation of water quality.

Remedial Laws. We are also subject to environmental remediation requirements, including provisions of the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, and the corrective action provisions of the federal Resource Conservation and Recovery Act, or 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 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.

IP operated more than two dozen sites at which synthetic gas was manufactured from coal. Operation of these manufactured gas plant sites was generally discontinued in the 1950s when natural gas became available from interstate gas transmission pipelines. Many of these MGP sites were contaminated with residues from the gas manufacturing process and remediation of this historic contamination could be required under CERCLA or

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RCRA or analogous state laws. IP is in the process of cleaning up sites that it has identified as requiring remediation. Recovery of clean-up costs in excess of insurance proceeds is considered probable from IP s electric and gas customers.

Pipeline Safety. In addition to environmental regulatory issues, the design, construction, operation and maintenance of some of our pipeline facilities is subject to the safety regulations established by the Secretary of the U.S. Department of Transportation pursuant to the Natural Gas Pipeline Safety Act and the Hazardous Liquid Pipeline Safety Act, or by state regulations meeting the requirements of the NGPSA and the HLPSA, or to similar statutes, rules and regulations in Canada or 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 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. The requirements of this new DOT rule will likely increase the costs of pipeline operations. We believe that such costs will not be material to our financial position or results of operations.

In the wake of the September 11, 2001 terrorist attacks on the United States, the DOT has developed a security guidance document and has issued a security circular that defines critical pipeline facilities and appropriate countermeasures for protecting them, and explains how the DOT plans to verify that operators have taken appropriate action to implement satisfactory security procedures and plans. Using the guidelines provided by the DOT, we have specifically identified certain of our facilities as DOT critical facilities and therefore potential terrorist targets. In compliance with the DOT guidance, we are performing vulnerability analyses on such facilities. Additional security measures and procedures may be adopted or implemented upon completion of these analyses, and any such 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 facilities will not become the subject of a terrorist attack. Please read Operational Risks and Insurance beginning on page 31 for further discussion.

Health and Safety. Our operations are subject to the requirements of the Federal Occupational Safety and Health Act (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.

Subject to resolution of the complaints filed by the EPA and the DOJ against IP and DMG, which are described in Item 8, Financial Statements and Supplementary Data, Note 14 Commitments and Contingencies Baldwin Station Litigation beginning on page F-64, 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 previously owned or operated by us, which could reasonably be expected to have a material adverse effect on our operations and financial condition.

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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 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 adequate 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 increase into 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. In addition, the terrorist attacks on September 11, 2001 and the changes in the insurance markets attributable to those attacks have made some types of insurance, particularly terrorism and business interruption insurance, more difficult or costly to obtain. We may be unable to secure the levels and types of insurance we would otherwise have secured prior to September 11, 2001. 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 into 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.

In our CRM segment, we also face market, price, credit and other risks relative to our orderly exit from third-party risk-management aspects of the gas and power marketing and trading business. Please read Item 7A, Quantitive and Qualitative Disclosures About Market Risk for further discussion of these risks.

In addition to these commercial risks, we also face the risk of reputational damage 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 reputational damage in the industries in which we compete and to financial loss. Please read Item 14, Controls and Procedures beginning on page 84 for further discussion of our internal control systems and the efforts that we are undertaking with respect to such systems.

SIGNIFICANT CUSTOMER

For the years ended December 31, 2002, 2001 and 2000, approximately 15%, 10% and 13% of our consolidated revenues and approximately 42%, 45% and 41% 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 2002, 2001 or 2000.

EMPLOYEES

At December 31, 2002, we had approximately 1,524 employees at our administrative offices and approximately 3,102 employees at our operating facilities. Approximately 1,873 employees at Dynegy-operated facilities are subject to collective bargaining agreements with various unions. Management believes that its relations with Dynegy employees are satisfactory.

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PART II

Item 5. ***Market for Registrant s Common Equity and Related Stockholder Matters***

Our Class A common stock, no par value per share, is listed and traded on the New York Stock Exchange under the ticker symbol DYN . The number of stockholders of record of our Class A common stock as of February 28, 2003, based upon records of registered holders maintained by our transfer agent, was 23,151.

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.

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, 2002 and 2001, as reported on the New York Stock Exchange Composite Tape, and related dividends paid per share during these periods.

Summary of Dynegy s Common Stock Price and Dividend Payments

	High	Low	Dividend
2002:			
Fourth Quarter	$ 1.35	$ 0.68	$
Third Quarter	6.80	0.51	
Second Quarter	30.09	6.08	0.075
First Quarter	32.00	21.25	0.075
2001:			
Fourth Quarter	$ 46.94	$ 20.90	$ 0.075
Third Quarter	48.24	31.27	0.075
Second Quarter	57.95	42.00	0.075
First Quarter	53.15	39.25	0.075

Beginning with the third quarter 2002, our Board of Directors elected to cease payment of a common stock dividend. Payments of dividends for subsequent periods will be at the discretion of the Board of Directors, but we do not foresee reinstating the dividend in the near-term. Please read 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 56 for further discussion. Please also read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Bank Restructuring beginning on page 42 for a discussion of dividend limitations contained in our restructured credit facility.

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Shareholder Agreement

In June 1999, Chevron U.S.A., now a subsidiary of ChevronTexaco, entered into a shareholder agreement with us governing certain aspects of our relationship, the material provisions of which are discussed below. The agreement was executed in February 2000 upon closing of the Illinova acquisition 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. Before the Illinova acquisition, Chevron owned 38,789,876 shares of our common stock and 7,815,363 shares of our preferred stock. In connection with the Illinova acquisition, Chevron exchanged its common stock and preferred stock and paid $200 million in return for an aggregate of 40,521,250 shares of our Class B common stock.

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 securities issued pursuant to employee benefit plans. In addition, Chevron and its affiliates may acquire up to 40 percent of the total combined voting power of our outstanding voting securities without restriction in the shareholder agreement. If Chevron or its affiliates wish to acquire more than 40 percent 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 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 by Chevron; 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 liquids business or gas marketing 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 designees to block the transaction listed above. A block consists of a vote against a proposed transaction by either (a) all of Chevron s representatives on the Board of Directors present at the meeting where the vote is taken (if the transaction would otherwise be approved by the 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;

amending any provisions in our Articles of Incorporation or Bylaws which, in each case, contain or implement the special rights of holders of Class B common stock, without the consent of the holders of the shares of Class B common stock or the three directors elected by such holders;

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 percent 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.

Sales of Unregistered Securities

December 2001 Equity Purchases. In December 2001, ten members of our senior management purchased approximately 1,260,000 shares of 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 totaling approximately $25 million from us 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 percent 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.

Other Unregistered Common Stock Sales. In March 2001, we sold nearly 1.2 million shares of Class B common stock to Chevron at $34.93 per share in a private transaction under Section 4(2) of the Securities Act pursuant to the exercise of its pre-emptive rights under the shareholder agreement. The proceeds from this transaction were approximately $41 million.

During 2000, we sold approximately 4.2 million shares of Class B common stock to Chevron at a weighted average price per share of $25.65 in private transactions under Section 4(2) of the Securities Act pursuant to the exercise of its preemptive rights under the shareholder agreement. Additionally, Chevron purchased approximately 8.4 million shares of Class B common stock at $23.91 per share in a private transaction under Section 4(2) of the Securities Act concurrent with the acquisition of Illinova in February 2000. Total net proceeds to us from these 2000 sales approximated $310 million.

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Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2002 as it relates to our equity compensation plans.

Plan Category	Number of Securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	22,452,885	$ 19.38	14,694,779
Equity compensation plans not approved by security holders (1)	5,629,380	$ 26.16	4,574,539
Total	28,082,265	$ 20.74	19,269,318

(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 Item 8, Financial Statements and Supplementary Data, Note 16 Capital Stock Stock Options beginning on page F-81 for a brief description of our equity compensation plans, including these plans which were not approved by our security holders.

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

The selected financial information presented below was derived from, and is qualified by reference to, our Consolidated Financial Statements, including the notes thereto, contained elsewhere herein. The selected financial information should be read in conjunction with the Consolidated Financial Statements and related notes and 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.

The information contained in the table below has been revised primarily to reflect the reclassification relating to discontinued operations as further described in the Introductory Note to this Amendment No. 1. Please also read the Explanatory Note to the accompanying financial statements beginning on page F-8 for a discussion of the previously reported restatement of our 1998-2001 consolidated financial statements.

Dynegy s Selected Financial Data

	Year Ended December 31,				
	2002	**2001**	**2000**	**1999**	**1998(7)**
		(Restated)	**(Restated)**	**(Restated)**	**(Restated)**
	($ in millions, except per share data)				
Statement of Operations Data(1):					
Revenues(6)	$ 5,516	$ 8,878	$ 8,204	$ 4,695	$ 3,807
General and administrative expenses	325	420	312	208	175
Depreciation and amortization expense	466	456	390	115	113
Asset impairment, abandonment and other charges	190				10
Goodwill impairment	897				
Operating income (loss)	(1,141)	967	766	184	100
Interest expense	(297)	(255)	(247)	(77)	(75)
Income tax provision (benefit)	(276)	357	234	41	63
Net income (loss) from continuing operations	(1,349)	486	409	93	57
Income (loss) on discontinued operations(3)	(1,154)	(82)	27	44	30
Cumulative effect of change in accounting principle	(234)	2			
Net income (loss)	$ (2,737)	$ 406	$ 436	$ 137	$ 87
Net income (loss) available to common stockholders	(3,067)	364	401	137	87
Earnings (loss) per share from continuing operations	$ (4.59)	$ 1.31	$ 1.18	$ 0.41	$ 0.25
Net income (loss) per share	(8.38)	1.07	1.27	0.60	0.38
Shares outstanding for diluted EPS calculation	418	340	315	230	227
Cash dividends per common share	$ 0.15	$ 0.30	$ 0.25	$ 0.04	$ 0.04
Cash Flow Data:					
Cash flows from operating activities	$ (25)	$ 550	$ 420	$ 40	$ 251
Cash flows from investing activities	677	(3,828)	(1,539)	(391)	(295)
Cash flows from financing activities	(44)	3,450	1,131	399	50
Cash dividends or distributions to partners, net	(55)	(98)	(112)	(8)	(8)
Capital expenditures, acquisitions and investments	(981)	(4,687)	(2,415)	(521)	(478)

	December 31,				
	2002	**2001**	**2000**	**1999**	**1998**

		(Restated)	(Restated) ($ in millions)	(Restated)	(Restated)
Balance Sheet Data (2):					
Current assets	$ 7,586	$ 8,956	$ 10,827	$ 2,658	$ 2,117
Current liabilities	6,748	8,538	10,286	2,467	2,026
Property and equipment, net	8,389	9,201	7,081	2,090	1,932
Total assets	20,030	25,168	22,662	6,451	5,264
Long-term debt (excluding current portion)	5,454	5,016	3,754	1,372	953
Notes payable and current portion of long-term debt	861	458	118	192	135
Non-recourse debt				35	94
Serial preferred securities of a subsidiary	11	46	46		
Company obligated preferred securities of subsidiary trust	200	200	300	200	200
Series B convertible preferred securities(4)	1,212	882			
Minority interest(5)	146	1,040	1,022		
Capital leases not already included in long-term debt	15	29	15		
Total equity	2,087	4,937	3,441	1,240	1,073

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(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 August 2002);

UK Storage Hornsea facility (sold October 2002) and Rough facility (sold November 2002);

DGC Asia (sold November 2002); and

Global Liquids (sold December 2002).

In addition, during the first quarter 2003, we began to report the results of operations of our U.K. CRM operations and the remaining components of our global communications operations as discontinued operations in accordance with Statement No. 144. Accordingly, we have reclassified prior period amounts to reflect this accounting treatment. For further discussion, please read Item 8, Financial Statements and Supplementary Data, Note 3 Dispositions, Discontinued Operations and Acquisitions Discontinued Operations beginning on page F-27.

(4) The 2002 amount equals the $1.5 billion in proceeds related to the Series B convertible preferred securities 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 Item 8, Financial Statements and Supplementary Data, Note 13 Redeemable Preferred Securities Series B Convertible Preferred Securities beginning on page F-61 for further discussion.

(5) The 2001 and 2000 amounts include amounts relating to the Black Thunder transaction discussed in Item 8, Financial Statements and Supplementary Data, Note 10 Debt DMG Secured Debt beginning on page F-53.

(6) As further discussed in Item 8, Financial Statements and Supplementary Data, Note 2 Accounting Policies Revenue Recognition beginning on page F-21, revenue amounts have been restated to reflect the adoption of the net presentation provisions in EITF 02-03.

(7) The consolidated financial statements for the year ended December 31, 1998 were audited by other independent accountants who have ceased operations.

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

The following discussion and analysis should be read in conjunction with the consolidated financial statements of Dynegy Inc. (Dynegy, we, us or our) and the notes thereto included herein. As discussed in the Introductory Note to this Amendment No. 1, certain financial and other information contained herein has been revised to reflect the reclassifications and other revisions described in the Explanatory Note to the accompanying consolidated financial statements. Please read the Explanatory Note for a discussion of these items as well as the previously reported restatement of our 1998-2001 consolidated financial statements.

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS AMENDMENT NO. 1, INCLUDING THE FINANCIAL STATEMENTS AND THE NOTES THERETO, DOES NOT REFLECT EVENTS OCCURRING AFTER APRIL 11, 2003 (THE DATE OF THE ORIGINAL FILING). SUCH EVENTS INCLUDE, AMONG OTHERS, THE EVENTS DESCRIBED IN OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED MARCH 31, 2003 AND THE EVENTS SUBSEQUENTLY DESCRIBED IN OUR CURRENT REPORTS ON FORM 8-K. FOR A DESCRIPTION OF THESE EVENTS, PLEASE READ OUR EXCHANGE ACT REPORTS FILED SINCE APRIL 11, 2003, INCLUDING OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED MARCH 31, 2003 AND OUR CURRENT REPORTS ON FORM 8-K.

We are a holding company and conduct substantially all of our business operations through our subsidiaries. We own operating divisions engaged in power generation, natural gas liquids and regulated energy delivery. Through these operating divisions, we serve customers by delivering value-added solutions to meet their energy needs.

We are in the process of restructuring our company in response to events that have negatively impacted the merchant energy industry, and our company in particular, over the past year. This restructuring includes significant changes in our operations, primarily our exits from third-party risk management aspects of the marketing and trading business and the communications business. Our restructuring also includes significant financial transactions that have stabilized our liquidity position and begun the process of decreasing our substantial financial leverage. Significant accomplishments include the following:

- The sale of Northern Natural;
- The sale of our U.K. natural gas storage business;
- The sale of our global liquids business;
- Major progress towards our exit from the third-party marketing and trading, or customer risk management business, including the completion of our exit from European marketing and trading and the transition of ChevronTexaco s natural gas marketing business back to ChevronTexaco, and the reduction in associated collateral requirements;
- The sale of our European communications business;
- The execution of an agreement to sell our U.S. communications business;

The extension of the maturity of our two primary bank credit facilities until February 2005 and the restructuring of our communications lease financing; and

Considerable workforce reductions, which we expect will provide substantial general and administrative cost savings.

In our new, simplified operating structure, we intend to focus on being a low-cost producer of physical products and provider of services in each of our three main operating divisions. Our customer risk management business, including obligations relating to the eight long-term power tolling arrangements to which we remain a party, will continue to affect our future results of operations until the related obligations have been satisfied or restructured. Our results will also be significantly affected by higher borrowing costs.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

We faced significant challenges relating to our liquidity position in 2002. These challenges were caused by several factors affecting the merchant energy industry, and particularly our company, including the following:

- The application of more stringent credit standards to Dynegy and other energy merchants;
- Weak commodity prices, particularly for power;
- A reduction in liquidity and the amount of open trade credit available to counterparties in the marketing and trading business;
- The various lawsuits and governmental investigations involving our company, including matters relating to Project Alpha, our past trading practices and our activities in the California power market;
- Downgrades in our credit ratings to well below investment grade, resulting in substantial requirements to provide counterparties with collateral support in order to transact new business or avoid the termination of existing transactions; and
- The restatement of our 1999-2001 financial results, the related three-year re-audit and the unavailability of 2001 audited financial statements, all of which limited our ability to access the capital markets.

We also were negatively impacted by our inability to generate the expected return on the significant capital we had previously invested both in our communications business and, because of a weak pricing environment, new merchant generation facilities.

In relation to these events, we posted significantly higher amounts of collateral in the forms of cash and letters of credit than we had in the past. For example, at September 30, 2002, we had posted approximately $1.2 billion of letters of credit and cash collateral in support of our marketing and trading and asset-based businesses. This compares to the approximately $470 million in collateral that we had posted at December 31, 2001.

Since September 30, 2002, we have made marked progress in our exit from third-party risk management aspects of the marketing and trading business. The actions taken in this regard, particularly the transfer of the ChevronTexaco natural gas marketing business back to ChevronTexaco and the completion of our exit from U.K. marketing and trading, resulted in the return of approximately $250 million of collateral and the elimination of these collateral requirements going forward. However, our ongoing asset businesses will continue to manage commodity price risk and optimize commercial positions associated with their respective operations through, among other things, fuel procurement optimization and the marketing of power and NGLs. We expect to continue to post collateral to support these operations, the amount and term of which will be impacted by changes in commodity prices. At April 2, 2003, we had an aggregate of approximately $1,055 million of letters of credit and cash collateral outstanding. While the completion of our exit from third-party risk management aspects of the marketing and trading business will result in a reduction in the collateral requirements associated with that business, we expect an increase in the collateral requirements relating to fuel procurement for our asset-based businesses given our non-investment grade credit ratings and higher commodity prices.

We have also successfully completed a restructuring of our revolving credit facilities that were to expire in April and May of this year. By extending the maturity date of these obligations, which totaled approximately $1.3 billion at April 2, 2003, together with the successful execution of our other liquidity initiatives, we believe that we have provided our company with sufficient capital resources to meet our debt obligations and provide collateral support for our ongoing asset businesses and our continued exit from third-party marketing and trading through 2004. However, our success and future financial condition, including our ability to refinance our substantial debt maturities in 2005 and thereafter, will depend on our ability to successfully execute the remainder of our exit from third-party marketing and trading and to produce adequate operating cash flows from

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our continuing asset-based businesses to meet our debt and commercial obligations, including substantial increases in interest expense. Please read Uncertainty of Forward-Looking Statements and Information beginning on page 81 for additional factors that could impact our future operating results and financial condition.

Liquidity Sources

As described above, we faced severe strains on our liquidity during 2002. These strains were most severe in the middle of the year, prior to our completion of several initiatives, the proceeds of which have allowed us to stabilize our liquidity position. The most important of these initiatives was the sale of Northern Natural in August 2002 for $879 million in cash proceeds, net of working capital adjustments. Other important initiatives included the sale of our U.K. natural gas storage assets, the disposition of our global liquids business and, more recently, the disposition of our European communications business. The net proceeds from these initiatives and the reduction in related collateral requirements have enabled us to stabilize our liquidity position and to satisfy the collateral requirements of our suppliers, customers and trading counterparties.

These liquidity initiatives originated with our $1.25 billion capital program, which we announced in December 2001. This program included a $500 million reduction to our original 2002 capital spending program and common stock sales in December 2001 and January 2002 netting aggregate proceeds of approximately $744 million. However, with increasing collateral demands and significant near-term maturities, we adopted a number of additional restructuring objectives during the latter half of 2002.

The following table lists the liquidity initiatives that we have successfully executed since June 2002 (amounts reflect gross proceeds prior to reduction for applicable fees).

Date	Initiative
June 2002	$250 million interim financing secured by proceeds from the sale of our U.K. natural gas storage business
	Refinancing of West Coast Power debt, resulting in the release of $100 million in letters of credit previously posted by us on West Coast Power s behalf
	Reduction in workforce (325 employees)
July 2002	$200 million interim financing secured by interests in the Renaissance and Rolling Hills generating facilities
August 2002	Sale of Northern Natural for cash proceeds of $879 million, net of working capital adjustments
September 2002	Sale of Northern Natural senior notes for $96 million
	Sale of Hornsea (portion of U.K. natural gas storage business) for $189 million, the proceeds from which were used to partially repay the $250 million related interim financing
October 2002	Commencement of exit from third-party marketing and trading business
	Implementation of organizational restructuring
	Reduction in workforce (780 employees)

November 2002	Sale of Rough (then-remaining portion of U.K. natural gas storage business) for $500 million, with $61 million of the proceeds used to repay the remaining outstanding balance under the $250 million related interim financing
	Sale of portions of the Canadian marketing and trading business
December 2002	Extension of $106 million of the original $200 million Renaissance and Rolling Hills interim financing

Date	Initiative
	Sale of $550 million in IP mortgage bonds, $150 million of which were issued in January 2003 following ICC approval; and prepayment of $200 million of IP s $300 million term loan
January 2003	Disposition of European communications business resulting in significant reductions in operating commitments
	Disposition of global liquids business resulting in reduced collateral requirements and other operating commitments
	Termination of ChevronTexaco Gas Marketing Agreement
February 2003	Agreement to sell Hackberry LNG Project for $20 million, with additional contingent payments based upon project development milestones and performance
March 2003	Agreement to sell U.S. communications business, which is expected to result in reductions in operating commitments
	Completion of exit from European marketing and trading business
	Sale of equity interest in SouthStar Energy Services LLC for $20 million
April 2003	Restructuring of $1.66 billion in credit facilities

In addition, we received a tax refund on March 31, 2003 of approximately $110 million for U.S. federal income taxes paid in 2001 and 2000 as a result of the carryback of tax operating losses.

Because of our non-investment grade status and our limited ability to access the capital markets, we have relied, and expect to continue to rely, on cash proceeds from these liquidity initiatives, together with cash from operations and borrowings under our revolving credit facilities, to satisfy our capital requirements. The following table summarizes our consolidated credit capacity and liquidity position at December 31, 2002 and April 2, 2003, respectively.

	December 31, 2002	April 2, 2003(2)
	($ in millions)	
Total Credit Capacity	$ 1,400	$ 1,400
Outstanding Loans	(228)	(940)
Outstanding Letters of Credit	(872)	(405)
Unused Borrowing Capacity	300	55
Cash	757	1,665
Liquid Inventory (1)	258	2
Total Available Liquidity	$ 1,315	$ 1,722

(1) Consists principally of natural gas inventories that have largely been monetized in the first quarter 2003. The values presented are based on spot market prices as of December 31, 2002 and April 2, 2003, respectively.

(2)

Reflects an approximately $500 million increase in cash collateral, and a comparable reduction in letters of credit outstanding, since December 31, 2002. This temporary change resulted from our use of cash to collateralize our obligations, as opposed to letters of credit, late in the first quarter because the near-term nature of the maturity dates on our revolving credit facilities did not permit the issuance of letters of credit. In light of the restructuring of our revolving credit facilities, we expect to return to using letters of credit as opposed to cash to collateralize these obligations in the coming months. Also reflects $153 million of debt payments in the first quarter 2003, including a $94 million payment made in January 2003 on our $200 million Renaissance and Rolling Hills financing.

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Liquidity Uses

At December 31, 2002, we had posted approximately $1.2 billion of letters of credit and cash collateral relating to our marketing and trading business and our asset-based business. This compares to approximately $470 million of letters of credit and cash collateral that we had posted at December 31, 2001. Although we experienced a substantial increase in our liquidity usage for collateral requirements during 2002, the success of our restructuring efforts to date has improved our liquidity position and enabled us to generally satisfy the collateral requirements of our customers and counterparties.

The following table includes significant liquidity uses with respect to debt repayments in 2002:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
		(in millions)		
Payments on IP transitional funding trust notes	$ 22	$ 22	$ 22	$ 22
Payments on Project Alpha financing	11	17	17	14
Payments on Black Thunder financing		54	19	19
Payments on DHI revolving credit facilities, net	250		150	75
Payments on DHI commercial paper	5			
Payments on IP commercial paper	38			
Repurchase of Northern Natural senior notes		90		
Retirement of IP mortgage bonds at maturity			96	
Retirement of DHI senior notes at maturity			200	
Retirement of Canadian credit facility at maturity				40
Retirement of Illinova medium-term notes at maturity				20
Payments on U.K. storage interim financing				250
Pre-Payment on IP term loan				200
Retirement of Dynegy Inc. credit facility at maturity				83
Total	$ 326	$ 183	$ 504	$ 723

Bank Restructuring

On April 2, 2003, Dynegy s principal financing subsidiary, DHI, entered into a $1.66 billion credit facility consisting of:

- a $1.1 billion DHI secured revolving credit facility (the revolving facility) and a $200 million DHI secured term loan (Term A facility), each of which matures on February 15, 2005; and

- a $360 million DHI secured term loan (Term B facility) that matures on December 15, 2005.

The credit facility replaces, and preserves the commitment of each lender under, DHI s $900 million and $400 million revolving credit facilities, which had maturity dates of April 28, 2003 and May 27, 2003, respectively, and Dynegy s $360 million Polaris communications lease, which had a maturity date of December 15, 2005. The credit facility will provide funding for general corporate purposes. The revolving facility is also available for the issuance of letters of credit. Borrowings under the credit facility will bear interest, at Dynegy s option, at (i) a base rate plus 3.75% per annum or (ii) LIBOR plus 4.75% per annum. A letter of credit fee will be payable on the undrawn amount of each letter of credit outstanding at a percentage per annum equal to 4.75% of such undrawn amount. An unused commitment fee of 0.50% will be payable on the unused portion of the revolving facility.

Subject to restrictions contained in the credit facility, amounts repaid under the revolving facility may be reborrowed. The full amounts of the borrowings under the Term A facility and the Term B facility were borrowed at the closing, and borrowings repaid under these facilities may not be reborrowed.

The credit facility contains mandatory prepayment events. The credit facility must, subject to specified exceptions, be repaid and commitments permanently reduced with:

100% of the net cash proceeds of all non-ordinary course asset sales;

50% of the net cash proceeds from the issuance of equity or subordinated debt;

100% of the net cash proceeds from the issuance of senior debt; and

50% of extraordinary receipts.

The credit facility provides for no amortization of principal amounts outstanding prior to the maturity dates except upon the occurrence of such a prepayment event.

Subject to specified exceptions, DHI s obligations under the credit facility are guaranteed by Dynegy and substantially all of Dynegy s direct and indirect subsidiaries, excluding (i) IP and DGC and their respective subsidiaries, (ii) most foreign subsidiaries, dormant subsidiaries and subsidiaries with de minimus value and (iii) subsidiaries that are unable to become guarantors due to existing contractual or legal restrictions.

Subject to specified exceptions and permitted liens, the lenders under the credit facility received a first priority lien in substantially all the assets of Dynegy, DHI and certain of the subsidiary guarantors to the extent practicable and permitted by existing contractual arrangements, excluding IP and DGC and their respective subsidiaries. The lenders also received a first priority lien in the ownership interests in our direct and indirect subsidiaries, excluding (i) IP and DGC and their respective subsidiaries, (ii) most foreign subsidiaries, dormant subsidiaries and subsidiaries with de minimus value and (iii) subsidiaries whose ownership interests may not be pledged due to existing contractual or legal restrictions. The lenders also received a second priority lien in all material assets of DMG, subject to the first priority lien granted to the lenders under the Black Thunder financing. Our obligations under the Project Alpha transaction and CoGen Lyondell and Riverside generating facility leases were ratably secured with the same assets pledged to the lenders under the credit facility as required by the terms of such facilities.

The credit facility contains affirmative covenants relating to, among other things, financial statements; compliance and other certificates; notices of specified events; payment of obligations; preservation of existence; maintenance of properties; maintenance of insurance; compliance with laws; maintenance of books and records; inspection rights; use of proceeds; guarantee obligations and security; compliance with environmental laws; preparation of environmental reports; further assurances; material contracts; distribution of cash proceeds and extraordinary receipts by subsidiaries; and mortgaged property. The credit facility contains negative covenants relating to, among other things, liens; investments; indebtedness; fundamental changes; dispositions; restricted payments; changes in business; transactions with affiliates and non-loan parties; burdensome agreements; use of proceeds; amendments to organizational documents; accounting changes; prepayments of indebtedness; material contracts; swap contracts and off-balance sheet arrangements; formation of subsidiaries; the CoGen Lyondell and Riverside facilities; and amendments to the Series B preferred stock held by ChevronTexaco. The credit facility also contains financial and capital expenditure-related covenants, which are described in detail below.

The credit facility generally prohibits Dynegy and its subsidiaries, subject to various customary and other exceptions, from incurring additional debt. Notwithstanding this restriction, we may issue exchange debt, or debt issued in exchange for outstanding DHI senior unsecured debt. Any such exchange debt may provide for guarantees that result in such debt being structurally senior to DHI s outstanding senior unsecured debt. Any exchange debt issued would be subject to the following restrictions:

for exchange debt offered in respect of DHI senior unsecured debt maturing in 2005 and 2006,

if the maturity of the exchange debt is prior to March 15, 2007, then the aggregate principal amount of exchange debt issued generally cannot exceed 66% of the aggregate principal amount of the DHI senior unsecured debt exchanged; and

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- if the maturity of the exchange debt is on or after March 15, 2007, then the aggregate principal amount of exchange debt issued generally cannot exceed the aggregate principal amount of the DHI senior unsecured debt exchanged;

for exchange debt offered in respect of DHI senior unsecured debt maturing in 2011, 2012, 2018 and 2026,

- the aggregate principal amount of exchange debt issued generally cannot exceed the aggregate principal amount of the DHI senior unsecured debt exchanged; and

- the maturity of the exchange debt must be after December 31, 2009; and

the aggregate cash interest expense of any exchange debt cannot exceed the aggregate cash interest expense of the DHI senior unsecured debt exchanged.

The credit facility generally prohibits us from pre-paying, redeeming or repurchasing our outstanding debt or preferred stock. Notwithstanding this restriction, we may repurchase or redeem up to $300 million in DHI senior notes or Series B preferred stock held by ChevronTexaco subject to the following restrictions:

- the first $100 million in repurchases of DHI senior notes requires a concurrent permanent reduction in commitments under the credit facility of $100 million, the second $100 million in repurchases requires a concurrent permanent reduction in commitments under the credit facility of $200 million, and the third $100 million in repurchases requires a concurrent permanent reduction in commitments under the credit facility of $300 million;

- no concurrent permanent reduction in commitments under the credit facility is required if DHI senior notes are repurchased with net cash proceeds attributable to extraordinary receipts or the issuance of equity or subordinated debt; and

- only $50 million of the $300 million may be used to repurchase DHI senior notes that mature on or after April 1, 2011; and

- only $50 million of the $300 million may be used to redeem shares of the Series B preferred stock held by ChevronTexaco, and Dynegy must permanently reduce commitments under the credit facility concurrently by three times the amount used to redeem such shares.

Notwithstanding the foregoing, we must have $500 million of liquidity for ten days prior to and as of the date of the repurchase or redemption of DHI senior notes or the Series B preferred stock.

The financial covenants in the credit facility are described below. Dynegy and its subsidiaries, excluding IP and DGC and their respective subsidiaries, are prohibited from:

permitting their Secured Debt/EBITDA Ratio (as defined in the credit facility) from and after September 30, 2003 to be greater than the ratio set forth below:

Measurement Period Ending	Maximum Secured Debt/ EBITDA Ratio
September 30, 2003	7.8:1.0
December 31, 2003	7.8:1.0
March 31, 2004	7.2:1.0
June 30, 2004	6.8:1.0
September 30, 2004	6.0:1.0
December 31, 2004 and each fiscal quarter thereafter	5.6:1.0

the definition of EBITDA in the credit facility specifically excludes, among other items, (i) discontinued business operations (including third-party marketing and trading, communications and tolling arrangements), (ii) disclosed litigation, (iii) extraordinary gains or losses, (iv) any impairment, abandonment, restructuring or similar non-cash expenses, and (v) turbine cancellation payments up to $50 million in the aggregate;

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permitting their liquidity to be less than $200 million for a period of more than ten consecutive business days; or

making capital expenditures during the four fiscal quarter period ending on the applicable dates set forth below in an amount exceeding the amount set forth opposite such fiscal quarter:

Fiscal Quarter	Amount
December 31, 2003	$232 million
March 31, 2004	$202 million
June 30, 2004	$206 million
September 30, 2004	$208 million
December 31, 2004 and each fiscal quarter thereafter	$222 million

making capital expenditures in connection with the completion of the Rolling Hills facility in an aggregate amount exceeding $85 million.

With respect to the quarterly restrictions on capital expenditures set forth above, we may (i) carryforward any amount not expended in the four fiscal quarter period in which it was permitted and (ii) carryback up to 50 percent of any amount permitted in a future four fiscal quarter period to any prior four fiscal quarter period and the amount related to the future four fiscal quarter period will be reduced accordingly. Further, Dynegy and its subsidiaries may make additional capital expenditures that are required to comply with applicable law.

The credit facility contains events of default relating to:

non-payment of principal when due, non-payment of interest or any commitment fee within three days or non-payment of any other amounts payable under applicable loan documents within five business days;

failure to comply with specified covenants and agreements, subject to applicable grace periods;

incorrect or materially misleading representations or warranties when made;

specified defaults under (i) any debt or guarantee obligation having an aggregate principal amount in excess of $50 million or (ii) certain swap contracts with a termination value owed to the counterparty in excess of $50 million;

specified insolvency proceedings that are not discharged or stayed within 60 days or the inability to pay debts as they become due;

the entry of a final, non-appealable judgment in excess of $50 million (net of insurance) that is not discharged or stayed within 60 days;

specified ERISA-related events involving in excess of $50 million; and any change of control.

Upon the occurrence of any event of default, upon the request of lenders representing more than 50 percent of borrowings outstanding under the credit facility, such lenders may, among other things, declare all borrowings outstanding (including letters of credit) under the credit facility immediately due and payable.

The foregoing description of the material terms of our new credit facility and related ancillary documents is qualified in its entirety by reference to the definitive agreements governing the credit facility, which are filed as exhibits to this Amendment No. 1.

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Debt Obligations. The following chart depicts our consolidated third-party debt obligations, including our DNE leveraged lease and Tilton lease obligations, relative to the primary entity under which those obligations reside as of April 2, 2003 (in millions):

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The following table lists our third-party debt obligations, including our DNE leveraged lease and Tilton lease, as of April 2, 2003, indicating whether such obligations are secured or unsecured (in millions):

DHI Revolving Credit Facility (1)	Secured	$ 1,045
DHI Term A Facility	Secured	200
DHI Term B Facility	Secured	360
ABG Gas Supply Credit Facility (Project Alpha)	Secured	250
CoGen Lyondell Credit Facility	Secured	170
DNE Lease Financing (3)	Secured	763
Dynegy Midwest Generation Financing (Black Thunder)	Secured	739
Riverside Credit Facility	Secured	190
Renaissance/Rolling Hills Credit Facility	Secured	106
Total Secured DHI Debt		3,823
DHI Senior Notes	Unsecured	2,000
Trust Preferred Securities	Unsecured	200
Total Unsecured DHI Debt		2,200
Total DHI Debt		6,023
IP Mortgage Bonds and Pollution Control Bonds	Secured	1,635
Transitional Funding Trust Notes	Secured	497
IP Bank Debt	Unsecured	100
Tilton Lease Financing	Secured	81
Total IP Debt		2,313
Illinova Corp. Senior Notes	Unsecured	95
Total Dynegy Third-Party Debt		$ 8,431(2)

(1) Includes $405 million in letters of credit outstanding.

(2) This approximately $8.4 billion in debt obligations reconciles to the approximately $6.3 billion in Long-Term Debt, Transitional Funding Trust Notes and Notes Payable and Current Portion of Long-Term Debt included in our Consolidated Balance Sheets as follows (in millions):

(3) Represents the present value of future lease payments using a 10% discount rate.

Notes payable and current portion of long-term debt (12/31/02)	$ 861
Long-term debt and Transitional funding trust notes (12/31/02)	5,454
	6,315
DNE lease financing	763
Tilton lease financing	81
Trust Preferred Securities	200
Issuance of $150 million of IP 11.5% mortgage bonds due 2010	150
Payments of debt maturities since 12/31/02	(153)
Letters of credit issued under restructured DHI bank credit facility	405
Additional borrowings under restructured DHI bank credit facility	840

Elimination of debt outstanding under former DHI revolving credit facilities	(128)
Other	(42)
Total Dynegy Third-Party Debt	$ 8,431

Debt Maturities. The restructuring and extension of our bank credit facilities has substantially reduced our 2003-2004 maturities.

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The following tables list our quarterly debt maturities through 2005 as of April 2, 2003 (amounts are approximated and presented in millions):

	2003 Maturities			
	2nd Quarter	3rd Quarter	4th Quarter	Total
IP Transitional Funding Trust Notes (1)	$ 22	$ 22	$ 22	$ 66
Black Thunder Financing (2)	22	22	22	66
Project Alpha Financing (3)	19	19	19	57
IP Mortgage Bonds		190		190
Renaissance/Rolling Hills Financing Facilities (4)	106			106
IP Bank Facility	100			100
	$ 269	$ 253	$ 63	$ 585

	2004 Maturities				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
IP Transitional Funding Trust Notes (1)	$ 22	$ 22	$ 22	$ 22	$ 88
Black Thunder Financing (2)	22	18	18	18	76
Project Alpha Financing (3)	20	20	20	20	80
Illinova 7.125% Senior Notes	95				95
IP Tilton Lease			81		81
	$ 159	$ 60	$ 141	$ 60	$ 420

	2005 Maturities				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Revolving and Term A Portion of Restructured Credit Facilities (5)	$ 1,245	$	$	$	$ 1,245
IP Transitional Funding Trust Notes (1)	22	22	22	22	88
Black Thunder Financing (2)	18	2	577		597
Project Alpha Financing (3)	21	21	21	22	85
DH1 8.125% Senior Notes	300				300
DH1 6.750% Senior Notes				150	150
IP 6.75% Mortgage Bonds	70				70
CoGen Lyondell Facility			170		170
Term B Portion of Restructured Credit Facilities (Formerly U.S. Communications Network Debt)				360	360
	$ 1,676	$ 45	$ 790	$ 554	$ 3,065

(1) Reflects required quarterly payments made with cash set aside from IP customer billings.
(2) Reflects required quarterly payments under Dynegy s Black Thunder financing as further described in Item 8, Financial Statements and Supplementary Data, Note 10 Debt DMG Secured Debt beginning on page F-53.
(3) Reflects required payments associated with Project Alpha as further described in Item 8, Financial Statements and Supplementary Data, Note 10 Debt ABG Gas Supply Credit Agreement beginning on page F-52.
(4) We recently agreed to prepay this $106 million on April 16, 2003.
(5) Includes $405 million of outstanding letters of credit.

Off-Balance Sheet Arrangements

As previously disclosed, in mid-2002 we restructured our Black Thunder minority interest transaction, which resulted in the reclassification of $796 million from Minority Interest to debt on our Consolidated Balance

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Sheet. We also voluntarily undertook specific actions, the effect of which altered the accounting for one of our lease obligations. As a result of those actions, together with accounting restatements we recently made affecting the accounting treatment of these and other similar arrangements, we now have two remaining off-balance sheet financings.

DNE Leveraged Lease. As described in Item 1. Business Power Generation Northeast Region beginning on page 7, we acquired the DNE power generating facilities in January 2001 from Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. and Niagara Mohawk Power Corporation. These facilities consist of a combination of base-load, intermediate and peaking facilities aggregating 1,700 MW and are located in Newburgh, New York, approximately 50 miles north of New York City. The aggregate purchase price for the facilities was approximately $950 million and included a transitional obligation to provide power to Central Hudson through October 2004.

In May 2001, we entered into a sale-leaseback transaction relating to these facilities in order to provide us with long-term financing for our acquisition, which established our physical presence as a generator in the Northeastern region of the United States. Pursuant to this transaction, which was structured as a sale-leaseback in order to maximize the value of the facilities 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 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 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 serve as lessees of the applicable facilities. 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, 2002, future lease payments are $60 million for each year 2003 through 2006, with $1.3 billion in the aggregate due during the period 2007 through lease expiration. The Roseton lease expires on February 8, 2035 and the Danskammer lease expires on May 8, 2031. We do not have an 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, 2002, the present value (discounted at 10%) of future lease payments was $763 million.

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

	($ in millions)	
	2002	**2001**
Lease Expense	$ 50	$ 34
Lease Payments (Cash Flows)	$ 60	$ 30

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. The current termination payment at par would be $999 million, which is in excess of the consideration we received on the sale of the facilities. The likelihood that DHI could make this termination payment would depend on the amount of cash it had on hand at the time such payment would be required as well as its ability to access the capital markets or to otherwise obtain the necessary financing within

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the confines of its recently restructured credit agreement. 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 would be required to 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.

Tilton Lease Arrangement. In September 1999, IP entered into an $81 million operating lease on four gas turbines located in Tilton, Illinois and a separate land lease at the Tilton site. These facilities consist of peaking units totaling 176 MW of capacity. The operating lease runs until September 2004. IP is providing a minimum residual value guarantee on the lease of approximately $70 million. At the expiration of the lease agreement IP has the option to purchase or sell the turbines to terminate the lease. If IP does not purchase the turbines it must deliver the turbines as prescribed under the lease and make a payment to the lessor to the extent the sales price is less than its residual value guaranty. If at the end of the operating lease term IP does not elect to purchase the leased assets, IP is also responsible for dismantling the facility for the benefit of the lessor. At the expiration of the land lease, we may have the obligation to restore the property to its original condition. We estimate the undiscounted costs of any such dismantling to be $8 million and the costs of any such land remediation to be $2 million and have included this amount in the cumulative effect adjustment relating to our adoption of Statement No. 143 effective January 1, 2003. In October 1999, IP sublet the turbines including all payment obligations under the lease to DMG.

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

	($ in millions)	
	2002	**2001**
Lease Expense	$ 2.7	$ 4.3
Lease Payments (Cash Flows)	$ 2.7	$ 4.3

Interest Expense

We have recognized interest expense of $297 million, $255 million and $247 million for the years 2002, 2001 and 2000, respectively. Our interest expense in 2003 and thereafter will reflect the increased cost of borrowing in our restructured credit facility. Generally, borrowings under the restructured credit facility will bear interest, at our option, at (i) a base rate plus 3.75% per annum or (ii) LIBOR plus 4.75% per annum. Pricing on letters of credit has increased from 50 basis points under DHI s former $400 million credit facility and 200 basis points under DHI s former $900 million credit facility to approximately 475 basis points under the restructured credit facility. Further contributing to our anticipated increase in interest expense in 2003 is our expectation that we will issue letters of credit in support of our marketing and trading obligations, which will be outstanding for the full year, as compared to the similar requirements that we faced beginning in mid-2002. Interest expense in 2003 will also reflect higher costs from IP s December 2002 issuance of $550 million in mortgage bonds (12% effective interest rate compared to average 2002 IP mortgage bond interest rate of 5.81%). We anticipate that we will recognize net interest expense of approximately $463 million in 2003.

Operating Cash Flows

Our net cash flows from operations for the years 2002, 2001 and 2000 were $(25) million, $550 million and $420 million, respectively. As discussed above, we posted significant amounts of collateral, particularly in the latter half of 2002, to support our marketing and trading and asset-based businesses. The amount of collateral posted increased from $470 million at the end of 2001 to $1.2 billion at the end of 2002. This increase is

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reflected in the cash flow statement as a reduction in operating cash flow. Operating cash flow in 2002 was also negatively impacted during 2002 by the factors that negatively affected our results of operations, particularly low power prices and decreased liquidity in trading markets. Please read Results of Operations beginning on page 59 for further discussion.

We expect that our exit from the third-party marketing and trading business will result in benefits to operating cash flow in 2003, particularly with respect to gas inventories held in storage that were sold in the first quarter. Our operating cash flows in 2003 and thereafter also will continue to reflect the expected negative cash flow associated with our eight power tolling arrangements. Please read Results of Operations Customer Risk Management CRM Outlook beginning on page 73 for further discussion of these arrangements. The cash flow of our asset-based operations will be significantly affected by the price realized for power and the relationship of prices for power and for natural gas or other generating fuels.

Disclosure of Financial Obligations and Contingent Financial Commitments

We have incurred various financial obligations and commitments in the normal course of our operations and financing activities. Financial obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. Financial commitments represent contingent obligations, which become payable only if certain pre-defined events occur, such as financial guarantees.

The following table provides a summary of our general financial obligations as of December 31, 2002. This table includes cash obligations related to outstanding debt, redeemable preferred stock and similar financing transactions. This table also includes cash obligations for minimum lease payments associated with general corporate services, such as office and equipment leases.

General Financial Obligations as of December 31, 2002

	Payments Due By Period ($ in millions)						
Cash Obligations*	**Total**	**2003**	**2004**	**2005**	**2006**	**2007**	**Thereafter**
Notes Payable and Current Portion of Long Term Debt (1)	$ 861	$ 861	$	$	$	$	$
Long Term Debt (1)	5,454		343	1,813	314	270	2,714
Series B Preferred Stock (1)	1,500	1,500					
Other Mezzanine Preferred Securities (1)	211						211
Operating Leases (2)	204	38	33	31	29	27	46
Other Long Term Obligations (3)	13	6	5	1	1		
Total General Financial Obligations	$ 8,243	$ 2,405	$ 381	$ 1,845	$ 344	$ 297	$ 2,971

* Cash obligations herein are not discounted and do not include related interest, accretion or dividends.

(1) Total amounts are included in the December 31, 2002 Consolidated Balance Sheet. For additional explanation, please read Item 8, Financial Statements and Supplementary Data, Note 10 Debt beginning on page F-47.
(2) Includes minimum lease payment obligations associated with office and office equipment leases.
(3) Includes decommissioning costs related to IP s sale of its Clinton nuclear facility in 1999 and decommissioning charges associated with IP s use of a facility that enriched uranium for the Clinton Power Station.

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The following table provides a summary of our contingent financial commitments as of December 31, 2002. These commitments represent contingent obligations that may require a payment of cash upon certain pre-defined events.

Contingent Financial Commitments as of December 31, 2002

			Expiration By Period ($ in millions)				
Contingent Obligations*	**Total**	**2003**	**2004**	**2005**	**2006**	**2007**	**Thereafter**
Letters of Credit (1)	$ 897	$ 897	$	$	$	$	$
Surety Bonds (2)	114	33	15			66	
Guarantees (3)	245	40	83	13	13	13	83
Total Financial Commitments	$ 1,256	$ 970	$ 98	$ 13	$ 13	$ 79	$ 83

* Contingent obligations are presented on an undiscounted basis.

(1) Amounts include outstanding letters of credit and uncommitted credit lines.
(2) Surety bonds are generally on a rolling twelve-month basis.
(3) Amounts include a $70 million residual value guarantee related to the Tilton lease arrangement. Based on the current estimated fair value of the underlying assets, the Company does not anticipate funding such amounts. Amounts also include two lease arrangements relating to VLGCs utilized in the NGL Segment that have been subchartered to a wholly owned subsidiary of Transammonia Inc. for the remaining lease term in connection with the sale of the global liquids business.

The table set forth below provides a summary of our commercial financial obligations, which are generally associated with revenue-producing activities. These arrangements provide us access to third-party owned assets for use in our asset-based lines of business. These obligations include certain unconditional purchase obligations associated with generation turbines and minimum lease payments associated with operating leases on assets used in our power generation and natural gas liquids businesses. The obligations also include capacity payments under power tolling arrangements and transportation, transmission and storage arrangements.

As described elsewhere in this annual report, we are in the process of exiting from third-party risk-management aspects of the marketing and trading business. Approximately $3.8 billion of the Capacity Payments included below represents the future value of capacity payments pursuant to the power tolling arrangements described in Item 1. Business Customer Risk Management beginning on page 19. The discounted value of these payments (based on a LIBOR-based discount rate) totaled $2.7 billion. Based on current estimates, the discounted fair value of the capacity payments under these arrangements exceeded the market value of electricity available for sale under these arrangements at December 31, 2002 by approximately $501 million. This amount includes tolling payments that are reflected at fair value on our Consolidated Balance Sheet in Risk-Management Assets or Risk-Management Liabilities for those contracts that are accounted for using mark-to-market accounting as well as amounts relating to contracts that are accounted for on an accrual basis, each as determined by the applicable contractual terms and in accordance with generally accepted accounting principles. At December 31, 2002, approximately 60 percent of the $3.8 billion of aggregate tolling capacity payments are accounted for on an accrual basis and approximately three-fourths of the $501 million noted above is attributable to contracts accounted for under the accrual method. Upon the adoption of EITF 02-03, as more fully described in Item 8, Financial Statements and Supplementary Data, Note 2 Accounting Policies Revenue Recognition beginning on page F-21, substantially all of our tolling arrangements will be accounted for on an accrual basis beginning January 1, 2003. We will continue our efforts to renegotiate or terminate some of these arrangements, which we will account for going forward in our CRM segment. Please read Results of Operations Customer Risk Management CRM Outlook beginning on page 73 for further discussion of the anticipated effects of these arrangements on our future results of operations.

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Commercial Financial Obligations as of December 31, 2002

	Payments Due By Period ($ in millions)						
Cash Obligations*	**Total**	**2003**	**2004**	**2005**	**2006**	**2007**	**Thereafter**
Operating Leases (1)	$ 1,558	$ 63	$ 63	$ 60	$ 60	$ 108	$ 1,204
Unconditional Purchase Obligations (2)	134	66	21	4	4	3	36
Capacity Payments (3)	4,437	327	302	309	323	324	2,852
Conditional Purchase Obligations (4)	483	6	111	116	121	104	25
Other Long Term Obligations	21	3	3	3	3	3	6
Total Commercial Financial Obligations	$ 6,633	$ 465	$ 500	$ 492	$ 511	$ 542	$ 4,123

* Cash obligations are presented on an undiscounted basis.

(1) Amounts include the minimum lease payment obligations associated with the lease arrangements relating to our DNE generation facilities and our Tilton generating facility.

(2) Amounts include natural gas, coal, systems design, various maintenance agreements and power purchase agreements.

(3) Capacity payments include future values of payments aggregating $3.8 billion under our power tolling arrangements. Other capacity payments totaling approximately $676 million include fixed obligations associated with transmission, transportation and storage arrangements.

(4) Amounts include our obligations as of December 31, 2002 to purchase 14 gas-fired turbines. Commitments under the turbine purchase orders are payable consistent with the delivery schedule. The purchase orders include milestone requirements by the manufacturer and provide us with the ability to cancel each discrete purchase order commitment in exchange for a fee, which escalates over time. The amounts herein assume all 14 turbines will be purchased. However, we can cancel these arrangements at any time, subject to a termination fee. If we had terminated the turbine purchase orders at December 31, 2002, the termination fee would have been approximately $48 million, reducing our conditional purchase commitment by $435 million. During the first quarter 2003, we renegotiated these turbine commitments. Under the new arrangements, cash obligations total $6 million in 2003, zero in 2004, $147 million in 2005, $193 million in 2006, $113 million in 2007 and $24 million in 2008. The termination payment remains at approximately $48 million through the first quarter 2004 and is subject to variable escalation thereafter.

IP has entered into other generating unit-specific contracts that stipulate fixed payments for the supply of power as well as variable payments for the reimbursement of operating costs. Because the costs associated with these arrangements are currently included in IP s revenue requirements under its rate-making process, we have not included the associated obligations in the table above.

We have entered into various joint ventures principally for the purpose of sharing risk or to optimize existing commercial relationships. These joint ventures maintain independent capital structures and have financed their operations on a non-recourse basis to us. Please read Item 8, Financial Statements and Supplementary Data, Note 8 Unconsolidated Investments, beginning on page F-42, for further discussion of these joint ventures.

ChevronTexaco Preferred Stock

In November 2001, in connection with entering into a merger agreement with Enron, we issued Series B preferred stock with a liquidation preference and redemption price of $1.5 billion to ChevronTexaco. We used the proceeds from this preferred stock issuance to purchase $1.5

billion of preferred stock in Northern Natural, which we later sold to MidAmerican in August 2002. The shares of Series B preferred stock are convertible prior to their redemption, at the holder s option, into shares of our Class B common stock at the conversion price of $31.64. The shares of Series B preferred stock also provide for a mandatory redemption on November 13, 2003. Our Board of Directors will evaluate this redemption obligation prior to November 13, 2003. Based on our

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substantial debt obligations, liquidity position, limitations under applicable state law and limitations in our restructured credit facility in respect of redemptions of equity securities, we currently do not expect to redeem the preferred shares in November 2003. Our restructured credit facility provides that we cannot redeem more than $50 million of the Series B preferred stock during the term of the facility and that we must permanently reduce borrowings under the credit facility by three times any amount repaid. Shares not redeemed will remain outstanding.

The failure to redeem the Series B preferred stock on the redemption date would not be a default under any of our bank borrowings, secured debt, senior notes or other debt obligations. The holder of the shares of Series B preferred stock are not entitled to a dividend in cash or in kind or Board representation either currently or upon a failure to make a redemption payment. We continue to engage in discussions with ChevronTexaco regarding a possible restructuring of the redemption obligations with respect to this preferred stock.

Capital Spending

The 2003 capital budget of $414 million primarily includes construction projects in progress, maintenance capital projects, environmental projects, contributions to equity investments and limited discretionary capital investment funds. The capital budget is subject to revision as opportunities arise or circumstances change. Funds budgeted for the aforementioned items by the various segments in 2003 are as follows:

2003 Budgeted Capital Expenditures

Segment or Category	($ in millions)
Power Generation	$ 206
Natural Gas Liquids	55
Regulated Energy Delivery	136
Other	17
	$ 414

Included within the Power Generation segment s capital budget are $60 million of funds to complete the Rolling Hills power plant, which is under construction and expected to begin commercial operation during the second quarter 2003. This natural gas-fired facility, located in Ohio, will provide 838 MW of generation capacity.

Our capital expenditures in 2003 and beyond will be limited by negative covenants contained in our restructured credit agreements. These covenants place specific dollar limitations on our ability to incur capital expenditures except in our Regulated Energy Delivery segment. Please read Bank Restructuring beginning on page 42 for further discussion.

During 2002, our actual capital expenditures were as follows:

2002 Actual Capital Expenditures

Segment or Category	($ in millions)
Power Generation	$ 554
Natural Gas Liquids	94
Regulated Energy Delivery	152
Other	147
	$ 947

Capital spending during 2002 for the GEN segment related primarily to our generation assets, the most significant of which were approximately as follows:

- Rolling Hills $195 million;
- Wood River $52 million;
- Baldwin $51 million;
- Renaissance $46 million;
- Bluegrass $33 million;
- Foothills $28 million; and
- Various other generation asset-related investments aggregating $149 million.

NGL segment capital expenditures of approximately $94 million were primarily related to gas plants and liquids marketing assets, the most significant of which were $29.2 million for the expansion of the Chico gas plant, $7.8 million at the Cedar Bayou fractionator, $6.9 million at the Mont Belvieu terminal and $6.3 million for the Hackberry LNG project, which we have agreed to sell to Sempra.

REG segment capital expenditures of approximately $152 million included $141 million of spending at IP and $11 million related to Northern Natural. For IP, $80 million was spent on electric and gas distribution, $18 million was spent on electric and gas transmission, $24 million was spent on information technology and $19 million was spent on other support and infrastructure.

Other consists of $83 million in capital expenditures associated with the communications business, of which $39 million relates to the U.S. fiber optic network and $44 million primarily relates to network hardware and software spending, including $27 million in the U.S., $14 million in Europe and $3 million in Asia. The remaining $64 million primarily relates to $54 million in spending on information technology and $10 million in our CRM segment.

Credit Rating Discussion

Credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing and the execution of our commercial strategies in a cost-effective manner. In determining our credit ratings, the rating agencies consider a number of factors. Quantitative factors that management believes are given significant weight include, among other things, EBITDA; operating cash flow; total debt outstanding; off balance sheet obligations and other commitments; fixed charges such as interest expense, rent or lease payments; distributions to stockholders; liquidity needs and availability and various ratios calculated from these factors. Qualitative factors appear to include, among other things, predictability of cash flows, business strategy, industry position, quality of management, equity value, litigation, regulatory investigations and other contingencies. Although these factors are among those considered by the rating agencies, each agency may calculate and weigh each factor differently.

Our credit ratings were lowered several times during 2002 by each of the major credit rating agencies. In taking these actions, including those made subsequent to the announcement of our capital plan, the rating agencies generally cited concerns over, among other things, the level of cash flows that we will be able to generate from our continuing businesses relative to our significant financial leverage, our ability to address our substantial near-term debt maturities, uncertainties surrounding our ongoing litigation and government investigations and the restatement of our 1999-2001 financial statements and the likelihood that the renewal of our revolving credit facilities would require a granting of collateral that would subordinate the unsecured bond holders. Most recently, on March 10, 2003, Fitch lowered its ratings on Dynegy and our subsidiaries, indicating that the downgrades anticipated the successful renewal and restructuring on a secured basis of our maturing

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credit facilities and U.S. communications network financing. Currently, our credit ratings are at least six notches below investment grade at Standard & Poor s, Moody s and Fitch. Additionally, our ratings remain on negative watch for further downgrade by both Standard & Poor s and Fitch; Moody s rates us with a negative outlook.

As of April 2, 2003, our senior unsecured debt ratings, as assessed by the three major credit rating agencies, were as follows:

Rated Enterprises	Standard & Poor s	Moody s	Fitch
Senior Unsecured Debt Rating:			
Dynegy Holdings Inc.(1)	CCC+	Caa2	CCC+
Dynegy Inc.(2)	CCC+	Ca	CCC+
Illinois Power(3)	Not Rated	Caa1	CCC+
Illinova Corporation(4)	CCC+	Caa2	CCC+

(1) Dynegy Holdings Inc. is the primary debt financing entity for the enterprise. This entity is a subsidiary of Dynegy Inc. and is a holding company that includes substantially all of the operations of the GEN, NGL and CRM segments.
(2) Dynegy Inc. is the parent holding company. This entity generally provides financing to the enterprise through issuance of capital stock.
(3) Illinois Power is a stand-alone entity from a financial credit perspective. This entity includes our regulated transmission and distribution business in Illinois.
(4) Illinova Corporation is the holding company for IP.

While we have substantially improved our liquidity position during the past several months and have made progress toward resolving many of the concerns cited by the rating agencies, we cannot be assured that our credit ratings will be improved. Our current, non-investment grade ratings have adversely affected our ability to access the capital markets and caused us to incur increased costs, including the granting of security, and more restrictive covenants in our recent refinancing activities. Should our ratings continue at their current levels, or should we be further downgraded, we would expect these negative effects to continue and, in the case of a downgrade, perhaps become more pronounced.

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, changes in law resulting in loss of tax-exempt status on certain bond issuances, 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 have not executed any transactions that require us to issue equity based on credit rating or other trigger events.

Commitments and Contingencies

Please read Item 8, Financial Statements and Supplementary Data, Note 14 Commitments and Contingencies beginning on page F-62, which is incorporated herein by reference, for a discussion of our commitments and contingencies.

Dividends on Preferred and Common Stock

Beginning with the third quarter 2002, our Board of Directors elected to cease payment of a dividend on our common stock. Payments of dividends for subsequent periods will be at the discretion of the Board of Directors, but we do not foresee reinstating the dividend in the near term. We have, however, continued to make the

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required dividend payments on our outstanding trust preferred securities. Please read Bank Restructuring beginning on page 42 for a discussion of the dividend limitations contained in our restructured credit facility.

There is no cash dividend required to be paid on the Series B preferred stock issued to ChevronTexaco in November 2001. Because of ChevronTexaco s discounted conversion option, we are required to accrete an implied preferred stock dividend over the redemption period, as required by GAAP. Please read Item 8, Financial Statements and Supplementary Data, Note 13 Redeemable Preferred Securities Series B Convertible Preferred Securities beginning on page F-61 for further discussion of this non-cash implied dividend.

FACTORS AFFECTING FUTURE OPERATING RESULTS

Our results of operations in 2003 and beyond may be significantly affected by the following factors, among others:

- the level of earnings and cash flows from our continuing asset-based businesses, which are subject to the effect of changes in commodity prices, particularly for power and the relationship between prices for power and for natural gas or other generating fuels, commonly referred to as the spark spread ;
- the negative cash flow expected from our tolling agreements and the effect that changes in power prices might have on our non-cash mark-to-market earnings associated with these arrangements;
- our ability to complete our exit of third-party risk management aspects of the marketing and trading business;
- our substantial level of leverage, which was reflected in approximately $7.0 billion of total debt and $405 million in letters of credit posted by us at April 2, 2003;
- our ability to address the $1.5 billion in Series B preferred stock held by ChevronTexaco;
- higher interest expense resulting from increased demand for collateral in our asset-based businesses and higher borrowing costs under our restructured credit facility;
- the effects of ongoing investigations and litigation relating to, among other things, our past trading practices, our activities in the California power market, shareholder claims and claims arising out of our legacy CRM business;
- our ability to operate our business within the confines of the increased borrowing rates and more restrictive covenants contained in our restructured bank credit facilities;
- our ability to access the capital markets given our non-investment grade credit ratings; and
- our ability to operate our business with a decentralized organizational structure and a reduced workforce.

Additionally, new accounting pronouncements will also impact our reported results of operations going forward. For example, during 2002, the EITF discussed Issue No. 02-03, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, and reached consensus on certain issues. EITF Issue 02-03 rescinds EITF 98-10, which required that energy trading contracts be accounted for at fair value, effective for any new contracts entered into after October 25, 2002. For energy trading contracts entered into through October 25, 2002, we continue to account for such contracts at fair value through December 31, 2002. Effective January 1, 2003, contracts that do not meet the accounting definition of derivatives are required to be accounted for under the accrual method and we will report all previously recorded unrealized income on these contracts as a cumulative effect of an accounting change. Our energy trading contracts that qualify as derivatives will continue to be accounted for at fair value under Statement No. 133. Please read Item 8, Financial Statements and Supplementary Data, Note 5 Commercial Operations, Risk Management Activities and Financial Instruments Accounting for Derivative Instruments and Hedging Activities, beginning on page F-38 for further discussion.

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In addition, we adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, effective as of January 1, 2003. Under Statement No. 143, asset retirement obligations are to be recorded at fair value in the period in which they are incurred by increasing the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the related asset. As part of the transition adjustment in adopting Statement No. 143, existing environmental liabilities in the amount of $73 million were reversed. The fair value of the remediation costs estimated to be incurred upon retirement of the respective assets is included in the asset retirement obligation and was recorded upon adoption of Statement No. 143. As such, we expect the impact of our adoption of Statement No. 143 will be an increase to earnings, net of tax, of approximately $33 million in the first quarter 2003 to be reflected as a cumulative effect of a change in accounting principle. The annual amortization of the assets created under this standard and the accretion of the liability to its fair value is estimated to be approximately $6 million in 2003. In addition to these liabilities, we also have potential retirement obligations for the dismantlement of power generation facilities, power transmission assets, a fractionation facility and natural gas storage facilities. It is our intent to maintain these facilities in a manner such that the facilities will be operational indefinitely. As such, we cannot estimate any potential retirement obligations associated with these assets. At the time we are able to estimate any new asset retirement obligations, liabilities will be recorded in accordance with Statement No. 143.

Please read Uncertainty of Forward Looking Statements and Information beginning on page 81 for additional factors that could impact our future operating results.

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RESULTS OF OPERATIONS

In this section, we discuss our results of operations, both on a consolidated basis and by segment, for the years 2002, 2001 and 2000. We historically presented the results for the following four reportable business segments:

- Wholesale Energy Network;
- Dynegy Midstream Services;
- Transmission and Distribution; and
- Dynegy Global Communications.

As described above under Item 1. Business Segment Discussion beginning on page 4, effective January 1, 2003, we began reporting our operations in the following segments:

- Power generation;
- Natural gas liquids;
- Regulated energy delivery; and
- Customer risk management.

Other reported results include our discontinued communications operations.

Reportable segments in this Amendment No. 1 have been reclassified to reflect the changes we made to our business reporting segments beginning January 1, 2003. As described in Note 18 to the accompanying consolidated financial statements beginning on page F-85, prior to January 1, 2003, the CRM and GEN segments were reported together in the WEN segment. In connection with our exit from the CRM business, we separated the contracts within the former WEN segment as of January 1, 2003 as being GEN contracts or CRM contracts, based on their terms and their importance to our GEN segment. The GEN and CRM businesses were operated together within the WEN segment as an asset-based third-party marketing, trading and risk-management business during all periods presented. Under this business model, the fair value of the GEN segment s generation capacity, forward sales and related trading positions were sold to the CRM segment each month at an internally determined transfer price. The CRM segment, together with all its other third-party marketing and trading positions unrelated to the GEN segment, would record revenue from the third-party contracts associated with the GEN segment during the month of settlement. The intersegment revenues for the GEN segment reflect this internal transfer price and do not represent amounts actually received for power sold to third parties. As such, the intersegment revenues do not include the effects of intra-month market price volatility.

Regarding our results of operations for 2002, 2001 and 2000, the impact of acquisition and disposition activity during the three-year period reduces the comparability of some of our historical financial and volumetric data.

Recent accounting pronouncements have also affected our financial results, particularly those of our third-party marketing and trading business, so as to further reduce the comparability of some of our historical financial data. For example, pursuant to EITF Issue 02-03, all mark-to-market gains and losses on energy trading contracts whether realized or unrealized, are shown net in the income statement, irrespective of whether the contract is physically or financially settled. In addition, pursuant to the transition provisions in EITF Issue 02-03, we have conformed the comparative period financial information contained in this annual report to reflect this change in accounting principle. We have historically classified net unrealized gains and losses from energy trading contracts as revenue in our consolidated statement of operations. However, physical transactions that were realized and settled were previously reflected gross in revenues and costs of sales. This change in accounting classification has no impact on our operating income, net income, earnings per share or operating cash flows.

For segment reporting purposes, all general and administrative expenses incurred by us on behalf of our subsidiaries have been charged to the applicable subsidiary as incurred. We have allocated indirect general and

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administrative expenses to our subsidiaries using a two-step formula that considers both payroll expense and total assets. Interest expense incurred by us on behalf of our subsidiaries has been allocated based on the subsidiaries capital structure. Other income (expense) items incurred by us on behalf of our subsidiaries are allocated equally among sub-components of our business segments.

The information presented below has been revised primarily to reflect the reclassifications relating to discontinued operations and segment reporting and other revisions described in the Introductory Note to this Amendment No. 1. Please also read the Explanatory Note to the accompanying financial statements beginning on page F-8 for a discussion of the previously reported restatement of our 1998-2001 financial statements. As discussed in the Explanatory Note, these previously reported restatements relate to the following items:

- the Project Alpha structured natural gas transaction,
- a balance sheet reconciliation project relating principally to our natural gas marketing business,
- corrections to our previous hedge accounting for certain contracts resulting in our accounting for these contracts pursuant to the mark-to-market method under Statement No. 133; in addition, we determined that we had incorrectly accounted for certain derivative transactions prior to the adoption of Statement No. 133,
- the valuation used in our 2000 acquisition of Extant, Inc.,
- the restatement of our forward power curve methodology to reflect forward power and market prices more closely,
- the recognition of additional assets, accrued liabilities and debt associated with certain lease arrangements, as well as impairment, depreciation and amortization expense for the related assets,
- a correction to the measurement date relating to the implied dividend we previously recorded related to the in-the-money beneficial conversion option in the $1.5 billion Series B preferred stock issued to ChevronTexaco in November 2001,
- the recognition of an other-than-temporary decline in value of a technology investment in the third quarter of 2001 rather than the second quarter of 2002,
- corrections to our previous accounting for income taxes, and
- other adjustments that arose during the re-audit of our 1999-2001 financial statements.

While certain of these items arose as the result of our consideration of differing interpretations of the applicable GAAP requirements between our former and current independent auditors, others, such as the restatements relating to Project Alpha, the natural gas marketing charge, hedge accounting under Statement No. 133, the valuation of the Extant acquisition, the Series B preferred stock and our previous accounting for income taxes, resulted from accounting errors. Please read Item 14. Controls and Procedures beginning on page 84 for a discussion of the measures we are taking relative to our internal control environment.

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Three Years Ended December 31, 2002

The following table provides summary financial data regarding our consolidated results of operations for 2002, 2001 and 2000, respectively.

Results of Operations

	2002	2001	2000
		(Restated)	(Restated)
		($ in millions)	
Operating Income (Loss)	$ (1,141)	$ 967	$ 766
Equity Earnings (Loss)	(80)	191	196
Interest Expense	(297)	(255)	(247)
Other Items, Net	(107)	(60)	(72)
Income Tax (Provision) Benefit	276	(357)	(234)
Income (Loss) from Continuing Operations	(1,349)	486	409
Discontinued Operations			
Income (Loss) from Discontinued Operations	(1,503)	(127)	38
Income Tax (Provision) Benefit	349	45	(11)
Income (Loss) on Discontinued Operations	(1,154)	(82)	27
Cumulative Effect of Change in Accounting Principle	(234)	2	
Net Income (Loss)	$ (2,737)	$ 406	$ 436

Net Income (Loss). We incurred a net loss of $2,737 million, or $8.38 per diluted share, in 2002. This compares with net income of $406 million, or $1.07 per diluted share, and $436 million, or $1.27 per diluted share, in 2001 and 2000, respectively. The following significant items contributed to our net loss for 2002:

- a charge of $897 million for the impairment of goodwill associated with our GEN and CRM segments;

- an after-tax loss of $1,154 million on our discontinued operations, primarily due to an after-tax loss of approximately $561 million on the sale of Northern Natural and an after-tax charge of approximately $413 million associated with the impairment of some of our communications assets;

- a loss of approximately $234 million associated with the write-down of goodwill in our communications business. This write-down was recognized as a cumulative effect of change in accounting principle upon our adoption of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets ;

- after-tax charges totaling approximately $142 million relating to our corporate restructuring and related workforce reductions, of which $28 million is included in discontinued operations;

- an after-tax charge of approximately $94 million related to the impairment of some of our generation investments;

- an after-tax charge of approximately $52 million related to the impairment of some of our technology investments, of which $32 million is included in discontinued operations; and

- other charges primarily associated with asset write-offs, losses on asset sales, contract and litigation settlements and the recognition of additional reserves.

In addition to these significant items, a weak pricing environment, especially for power, and reduced market liquidity contributed to lower operating results from our GEN, CRM and NGL segments in 2002. Please read our segment discussions below for further discussion of the changes in operating income during the periods presented.

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Our 2001 net income decreased to $406 million from $436 million in 2000. The following significant items impacted our 2001 results on an after-tax basis as follows:

approximately $84 million related to energy sales to Enron and its affiliates, which filed for bankruptcy during the fourth quarter 2001;

approximately $9 million associated with severance costs incurred as a result of an organizational restructuring at IP; and

approximately $7 million associated with costs incurred in connection with the terminated Enron merger.

These charges, together with increased interest expense, more than offset the $17 million pre-tax increase in operating income period over period.

Our 2000 net income of $436 million included aggregate gains of approximately $92 million associated with the sale of Accord and some QFs. These gains were partially offset by losses on sales of our crude oil business and our Mid-Continent gas processing assets, the impairment of a Canadian liquids asset and costs incurred in connection with our acquisition of Illinova.

The following table sets forth significant items affecting net income and diluted earnings per share for the periods presented.

	2002		2001		2000	
	Income	Diluted	Income	Diluted	Income	Diluted
($ in millions, except per share data)	(Charge)	EPS	(Charge)	EPS	(Charge)	EPS
Impairment of Goodwill	$ (897)	$ (2.45)	$	$	$	$
Discontinued Operations (1)	(1,154)	(3.15)	(82)	(0.25)	27	0.09
Cumulative Effect of Change in Accounting Principle	(234)	(0.64)	2	0.01		
Restructuring Costs	(101)	(0.27)				
Impairment of Unconsolidated Generation Investments	(94)	(0.26)				
Impairment of Technology Investments	(20)	(0.05)				
Generation Equity Earnings	(33)	(0.09)				
Tolling Settlement Accrual	(16)	(0.04)				
Enron Litigation Settlement	(14)	(0.03)				
ChevronTexaco Contract Settlement	(15)	(0.04)				
IP Regulatory Asset Amortization Expense	(15)	(0.04)				
Other (2)	(44)	(0.12)				
Enron bankruptcy exposure			(84)	(0.25)		
Illinois Power severance costs			(9)	(0.03)		
Terminated Enron merger related costs			(7)	(0.02)		
Gain on Sale Accord Energy Limited					58	0.18
Gain on Sale QFs					34	0.11
Loss on Sale Crude Business					(11)	(0.03)
Loss on Sale Mid-continent Assets					(6)	(0.02)
Impairment of a Liquids Asset					(16)	(0.05)

Illinova Acquisition Costs			(10)	(0.03)
Special Dividend (3)	(0.90)	(0.12)		(0.10)

(1) Included within this amount is $413 million ($1.13 per diluted share) of charges related to the impairment of communication assets, $28 million ($0.08 per diluted share) of restructuring costs, $32 million ($0.09 per diluted share) of charges related to the impairment of technology assets, $2 million ($0.01 per diluted share) of charges related to the Enron litigation settlement and $11 million ($0.03 per diluted share) of other charges.

(2) Includes various charges incurred in 2002, including the write-off of Dynegydirect, our former electronic trading platform, which resulted in an after-tax charge of approximately $16 million ($25 million pre-tax).

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(3) The special dividend in 2002 and 2001 relates to the accretion of the implied value of the beneficial conversion option in the Series B preferred stock held by ChevronTexaco. The special dividend in 2000 relates to a $32 million payment made to two of our former shareholders in the second quarter 2000 prior to the conversion of their preferred shares to Class A common stock.

Equity Earnings. Our share in the earnings (losses) of our unconsolidated investments contributed losses of approximately $80 million in 2002 and earnings of approximately $191 million and $196 million in 2001 and 2000, respectively. West Coast Power contributed approximately $17 million, $162 million and $122 million to equity earnings in 2002, 2001 and 2000, respectively. The decrease in earnings from West Coast Power in 2002 is due in part to a reduction in contingent capacity and energy sales under the CDWR contract. Please read Item 1, Business Segment Discussion Power Generation West Region Western Electricity Coordinating Council (WECC) beginning on page 9 for further discussion of this contract. Equity earnings from West Coast Power also include a pre-tax charge of $50 million ($33 million after-tax) related to our share of a reserve taken by West Coast Power to increase its allowance for doubtful accounts. The overall decrease in equity earnings in 2002 was primarily due to significant impairments of generation and technology investments recognized during 2002.

Cash distributions received from all unconsolidated investments in 2002, 2001 and 2000 approximated $91 million, $100 million and $118 million, respectively.

Interest Expense. Interest expense totaled $297 million for 2002, compared with $255 million and $247 million for 2001 and 2000, respectively. The increase in interest expense in 2002 was due primarily to increased principal borrowed to support our liquidity needs in 2002. Specifically, these additional principal amounts primarily relate to cash borrowings and letters of credit under our revolving credit facilities used to satisfy counterparty collateral demands. The effect of the increased interest expense relating to these additional principal amounts was partially offset by lower variable rates than in 2001. The increase in interest expense in 2001 from 2000 was due primarily to increased principal, partially offset by lower variable rates than in 2000.

Other Items. Net other income and expenses, net reduced 2002, 2001 and 2000 operating results by $107 million, $60 million and $72 million, respectively. The 2002 results were negatively impacted by the following:

- a charge of $14 million ($21 million pre-tax) associated with the settlement of the Enron litigation. The other $2 million ($4 million pre-tax) of the settlement is included in discontinued operations;
- a charge of $15 million ($22 million pre-tax) relating to the cancellation of our natural gas purchases and sales contract with ChevronTexaco;
- a charge of $4 million ($6 million pre-tax) associated with fees related to a voluntary action that we took that altered the accounting for some of our lease obligations;
- a charge of $4 million related to our settlement with the CFTC. The other $1 million of the $5 million settlement is included in discontinued operations; and
- a charge of $3 million related to our settlement with the SEC.

The remaining net amounts for all three years include the financial effects of minority shareholder investments in some of our operations, including interest and dividend income, foreign currency gains and losses, insurance proceeds and other similar items.

Income Tax (Provision) Benefit. We reported an income tax benefit of $276 million in 2002, compared to income tax provisions of $357 million and $234 million in 2001 and 2000, respectively. These amounts reflect effective rates of 17 percent, 42 percent and 36 percent, respectively. In general, differences between these effective rates and the statutory rate of 35 percent result primarily from permanent differences attributable to book-tax basis differences and certain liabilities; and the effect of certain foreign and state income taxes. In addition, the 2002 effective rate was impacted significantly by the $897 million goodwill impairment relating to the CRM and GEN segments. As there was no tax basis in the asset, there was no tax benefit associated with the charge. See Item 8, Financial Statements and Supplementary Data, Note 12 Income Taxes beginning on page F-58, which is incorporated herein by reference, for further discussion of our income taxes.

Discontinued Operations. Discontinued operations primarily include Northern Natural, our global liquids business, our U.K. natural gas storage assets, our U.K. CRM business and our global communications business. On August 16, 2002, we sold Northern Natural to MidAmerican for $879 million in cash, after adjustment for working capital changes. MidAmerican acquired all of the common and preferred stock of Northern Natural and assumed all of its $950 million of debt. We incurred a loss of approximately $561 million ($599 million pre-tax) associated with the sale, including the final adjustment for working capital changes. As noted above, during 2002, the global communications business recorded charges of $413 million for the impairment of communications assets. During 2002, we also recognized an after-tax charge of approximately $12 million associated with the impairment of an LPG investment in the global liquids business.

Cumulative Effect of Change in Accounting Principle. Effective January 1, 2002, we adopted Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets. In connection with the adoption, we realized a cumulative effect loss of approximately $234 million associated with a write-down of goodwill in our global communications business.

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Segment Results of Operations

Non-GAAP Financial Measures. Management uses Earnings Before Interest and Taxes, or EBIT, as one measure of financial performance of our business segments. EBIT is a non-GAAP financial measure and consists of operating income, earnings from unconsolidated investments, other income and expenses, net, minority interest income (expense), accumulated distributions associated with trust preferred securities, discontinued operations and the cumulative effect of a change in accounting principle. EBIT does not include interest expense and income taxes, each of which is evaluated on a consolidated level. Because we do not allocate interest expense and income taxes by segment, we believe that EBIT is a useful measurement of our segment performance for investors. EBIT should not be considered an alternative to, or more meaningful than, net income or cash flows from operations as determined in accordance with GAAP. Our segment EBIT may not be comparable to similarly titled measures used by other companies.

Power Generation

	Year Ended December 31,		
	2002	**2001**	**2000**
		(Restated)	**(Restated)**
	(in millions, except operating statistics)		
Total Operating Income (Loss)	$ (401)	$ 390	$ 337
Earnings (Losses) of Unconsolidated Investments	(71)	202	169
Other Items, net	(20)	(5)	(21)
Earnings (Losses) Before Interest and Taxes	$ (492)	$ 587	$ 485
Operating Cash Flow:			
Operating Cash Flows Before Changes in Working Capital	$ 349	$ 431	$ 257
Changes in Working Capital	(91)	71	(180)
Net Cash Provided By (Used In) Operating Activities	$ 258	$ 502	$ 77
Operating Statistics:			
Million Megawatt Hours Generated Gross	43.5	40.3	36.8
Million Megawatt Hours Generated Net	39.4	34.5	30.3
Average Natural Gas Price Henry Hub ($/MMbtu)	$ 3.22	4.26	$ 3.89
Average On-Peak Market Power Prices ($/MW hour)			
Cinergy	$ 27.21	$ 35.19	$ 36.43
TVA	27.56	34.87	39.73
PJM	36.00	40.76	39.96
New York Zone G	46.78	51.75	55.60
Platts SP15	34.64	121.04	113.51

GEN reported EBIT of $(492) million for 2002 compared to $587 million for 2001 and $485 million for 2000. EBIT consists of the following amounts reported by GEN for the periods presented: operating income (loss) of $(401) million, $390 million and $337 million, respectively; earnings (losses) of unconsolidated investments of $(71) million, $202 million and $169 million, respectively; and other items, net of $(20)

million, $(5) million and $(21) million, respectively.

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Results of operations during the three-year period were influenced either positively or negatively by the following:

- decreased equity earnings from West Coast Power from 2001 to 2002 as a result of lower volumes sold, an impairment of our investment and an increase in the allowance for West Coast Power s doubtful accounts;

- charges relating to our impairment of goodwill and generation equity investments in 2002;

- a weak pricing environment, particularly for power, causing reduced earnings from our generation facilities in 2002;

- increased earnings resulting from additional power generating capacity acquired or placed in service in 2002, 2001 and 2000;

- increased equity earnings from West Coast Power from 2000 to 2001, partially attributable to higher price realization for power purchased from West Coast Power; and

- aggregate after-tax gains of approximately $34 million on the sales of some of our QFs, offset by an allocated portion of Illinova acquisition costs, in 2000.

The new generating capacity in 2002 included the Renaissance, Bluegrass and Foothills facilities aggregating 1,512 MW. The new generating capacity in 2001 included the DNE power generating facilities in New York and development projects in Georgia, Kentucky and Louisiana aggregating 2,865 MW. The new capacity in 2000 included the generation assets from the Illinova acquisition and development projects in Illinois, Louisiana and North Carolina aggregating 8,091 MW.

Operating cash flows increased from 2000 to 2001 as a result of higher operating income from our asset businesses, reflecting added generation capacity and favorable power prices.

Total megawatt hours generated during 2002 aggregated 43.5 million compared to 40.3 million and 36.8 million during 2001 and 2000, respectively. Volumes for each period reflect the impact of additional generating capacity.

GEN Outlook

We expect that future financial results of our power generation business will continue to reflect a sensitivity to weather, power and natural gas prices, including the spark spread, and terms of contracts for contracted generation. We believe that our generation fleet s fuel diversity will help mitigate the extent to which this segment s future results are affected by changes in natural gas prices. We also expect that this business will continue its efforts to manage its price risk through the optimization of fuel procurement and the marketing of power generated from its assets. As part of our strategy of commercially optimizing our assets, including agency and energy management agreements to which we are a party, we enter into financial and other transactions, including forward hedges relating to our generating capacity. This segment s sensitivity to prices and our ability to manage this sensitivity is subject to a number of factors, including general market liquidity, our ability to provide necessary collateral support and the willingness of counterparties to transact business with us given our non-investment grade credit ratings. Other factors that could affect the prices at which transactions can be consummated and this segment s results of operations include transmission constraints, or the lack thereof, and governmental actions or excess generation capacity in the markets we serve.

Any events that negatively impact our significant long-term power sales agreements could likewise affect this segment s future results of operations. For example, equity earnings from West Coast Power are primarily derived from West Coast Power s long-term power sales contract with the CDWR. That contract, which runs through December 31, 2004, is the subject of various legal challenges as further described in Note 14 Commitments and Contingencies FERC and Related Regulatory Investigations Western Long-Term Contract Complaints beginning on page F-68. The success of any such challenges would negatively impact this segment s equity earnings from West Coast Power and, accordingly, its results of operations for the periods affected.

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Natural Gas Liquids

	Year ended December 31,		
	2002	2001	2000
		(Restated)	(Restated)
	($ in millions, except operating statistics)		
Operating Income:			
Upstream	$ 18	$ 82	$ 45
Downstream	59	51	35
Total Operating Income	77	133	80
Earnings of Unconsolidated Investments	14	13	24
Other Items, Net	(34)	(3)	(40)
Income (Loss) on Discontinued Operations	(37)	(2)	5
Earnings Before Interest and Taxes	$ 20	$ 141	$ 69
Operating Cash Flows:			
Operating Cash Flows Before Changes in Working Capital	$ 73	$ 147	$ 128
Changes in Working Capital	(49)	12	(54)
Net Cash Provided By Operating Activities	$ 24	$ 159	$ 74
Operating Statistics:			
Natural Gas Processing Volumes (MBbls/d):			
Field Plants	56.0	56.1	61.2
Straddle Plants	35.9	27.7	35.6
Total Natural Gas Processing Volumes	91.9	83.8	96.8
Fractionation Volumes (MBbls/d)	215.2	226.2	224.3
Natural Gas Liquids Sold (MBbls/d)	498.8	557.4	564.6
Average Commodity Prices:			
Crude Oil WTI ($/Bbl)	$ 25.75	$ 26.39	$ 28.97
Natural Gas Liquids ($/Gal)	0.40	0.45	0.55
Fractionation Spread ($/MMBtu)	1.26	0.89	2.40

NGL reported EBIT of $20 million for 2002, compared with EBIT of $141 million and $69 million in 2001 and 2000, respectively. EBIT consists of the following amounts reported by NGL for the periods presented: operating income of $77 million, $133 million and $80 million, respectively; earnings of unconsolidated investments of $14 million, $13 million and $24 million, respectively; other items, net of $(34) million, $(3) million and $(40) million, respectively; and income (loss) on discontinued operations of $(37) million, $(2) million and $5 million, respectively. The following influenced this segment s results of operations from 2002 compared to 2001:

a decline in processing plant margins caused by lower natural gas and realized natural gas liquids prices in 2002;

decreased profitability of our straddle plants in 2002 due to the negative effect of lower natural gas liquids prices and increased settlement costs related to volumes processed in 2002 that were processed on a slightly more profitable fee basis in 2001;

reduced domestic and foreign marketing volumes and margins in 2002 as a result of slow economic recovery, high industry-wide inventory levels, reduced market liquidity and Dynegy-specific credit limitations;

$12 million of after-tax charges allocated to this segment during 2002 associated with our restructuring;

$7 million of after-tax charges allocated to this segment during 2002 relating to technology investment impairments, the Enron settlement and other items; and the results of our discontinued operations in 2002, including a $12 million impairment of an LPG investment in India.

Results of operations from 2000 to 2001 were influenced either positively or negatively by:

Higher price realization in 2001, as compared to 2000, resulting from an active forward sales program and contract restructuring activities, despite a depressed pricing environment resulting from larger industry wide inventories;

Substantial focus on lowering costs throughout the two-year period;

Fluctuating world-wide demand for NGLs, particularly in Europe and Asia, enhanced 2000 revenues from global marketing operations;

Results for 2001 include approximately $2 million exposure to Enron (net of tax) as a result of that company s bankruptcy filing and an allocation of transaction costs associated with the terminated proposed merger with Enron; and

Results for 2000 include losses of approximately $17 million (net of tax) on sales of the Crude Oil Marketing and Trade business (which was sold in April 2000 and contributed approximately $9 million after tax in 1999) and Mid-Continent gas processing assets, an impairment of approximately $16 million (net of tax) relating to Canadian gas processing assets and an allocation of costs related to the Illinova acquisition.

NGL reported operating cash inflows of $24 million for 2002, compared with cash flows of $159 million and $74 million in 2001 and 2000, respectively. The following influenced operating cash flows period-to-period:

reduced 2002 EBIT as discussed above;

in 2002 prepayments were required to continue business with several customers and suppliers, which was a use of working capital of $57 million, as the result of Dynegy-specific credit limitations;

also in 2002, other movements in working capital items related to lower prices, which partially offset the increase in prepayments;

2001 cash flow exceeded 2000 cash flow due to increased earnings stemming from higher price realization in 2001 as discussed above; and

working capital provided $12 million in cash flow in 2001 primarily due to reducing the volume of natural gas liquids in inventory and a steep decline in inventory prices compared to the end of the year 2000.

Aggregate domestic NGLs fractionation volumes totaled 92 thousand gross barrels per day in 2002 compared to an average 84 thousand gross barrels per day and 97 thousand gross barrels per day in 2001 and 2000, respectively. Higher volumes processed in 2002 reflect volume growth from the Louisiana straddle plants and are the direct result of an increasing need to process Gulf of Mexico natural gas production to meet third-party downstream pipeline gas merchantability standards. In some cases, this has resulted in new contract terms that allow us to provide, on a temporary basis, processing services on a fee basis, thereby reducing our exposure to keep-whole processing margin risk. This is a trend that should continue as the volume of gas produced in the deep-water Gulf of Mexico increases. An increase in the volumes dedicated for processing by ChevronTexaco also contributed to the growth in Louisiana processing volumes during 2002. The reduction in volumes processed in 2001 compared to 2000 is due to the volume impacts from the sale of the Mid-Continent gas processing assets in 2000.

The average fractionation spread was $1.26 for 2002 compared to $0.89 and $2.40 in 2001 and 2000, respectively. Despite a slight increase in this spread in 2002, traditional keep-whole processing is still uneconomic at this level. Historically, the Louisiana straddle plants have not operated in this pricing environment.

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NGL Outlook

We expect that the general industry-wide contraction in trade credit in the wholesale energy markets, including limitations relating to our own credit issues, will continue in 2003. This contraction is evidenced by the fact that open or unsecured credit lines are generally no longer available, and our customers are more stringent in requiring credit support in the form of cash in advance, letters of credit or guarantees as a condition to transacting business above open credit limits. Beginning in the second quarter 2002, and as a result of the general contraction of trade credit as well as downgrades in our credit ratings, NGL has been required to provide letters of credit and cash prepayments to collateralize our net exposure to various counterparties in its distribution and marketing business. During 2002, our marketing volumes were negatively affected by the general uncertainty in the energy and capital markets. We expect this market uncertainty to continue during the foreseeable future. Counterparty credit concerns and the resulting industry-wide contraction in trade credit have increased the cost of transacting business in the wholesale energy markets. As a result of this increase, we have generally refrained from entering into lower volume, lower margin transactions. We anticipate that this contraction in credit will continue to affect our marketing volumes, the number of transactions we enter into and the number of counterparties with whom we transact business.

Due to the turmoil in the Middle East and Venezuela, crude prices, liquids prices and natural gas prices are well above 2002 prices. If these price levels continue, we would expect this segment to generate higher profits than in 2002, all other factors being equal. Even at higher liquids prices, we are experiencing a weak fractionation spread environment. The correlation of prices for propane relative to prices for oil has returned to historical levels, improving expected revenues for this segment in the current pricing environment over 2002 when the correlation was lower than historical levels. Drilling activity by independent producers has been increasing in the past several months in the producing regions NGL serves due to higher commodity prices. Major producers are responding with more drilling activity in these regions, albeit more slowly, as their drilling programs are normally determined several years in advance.

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Regulated Energy Delivery

	Year Ended December 31,		
	2002	2001	2000
		(Restated)	(Restated)
	($ in millions, except operating statistics)		
Total Operating Income	$ 157	$ 180	$ 206
Losses of Unconsolidated Investments	(2)		
Other Items, Net	(4)	2	(10)
Loss on Discontinued Operations	(561)		
Earnings (Losses) Before Interest and Taxes	$ (410)	$ 182	$ 196
Operating Cash Flows:			
Operating Cash Flows Before Changes in Working Capital	$ 371	$ 269	$ 252
Changes in Working Capital	(109)	(160)	50
Net Cash Provided By Operating Activities	$ 262	$ 109	$ 302
Operating Statistics:			
Electric Sales in kWh (Millions):			
Residential	5,548	5,202	5,046
Commercial	4,415	4,337	4,256
Industrial	6,306	6,353	8,324
Transportation of Customer-Owned Electricity	2,505	2,645	963
Other	370	373	412
Total Electricity Delivered	19,144	18,910	19,001
Gas Sales in Therms (Millions):			
Residential	323	315	337
Commercial	137	136	141
Industrial	80	88	96
Transportation of Customer-Owned Gas	233	246	259
Total Gas Delivered	773	785	833
Heating Degree Days	5,118	4,749	5,233
Cooling Degree Days	1,467	1,302	1,173

The REG segment includes the operations of IP, a regulated electric and gas energy delivery company serving customers across a 15,000-square-mile area of Illinois. As a result of our sale of Northern Natural in the third quarter 2002, Northern Natural is included in discontinued operations, as further discussed in Item 8, Financial Statements and Supplementary Data, Note 3 Dispositions, Discontinued Operations and Acquisitions Dispositions Discontinued Operations Northern Natural beginning on page F-27.

EBIT for the REG segment was $(410) million in 2002 compared with EBIT of $182 million and $196 million for 2001 and 2000, respectively. EBIT consists of the following amounts reported by REG for the periods presented: operating income of $157 million, $180 million and $206 million, respectively; losses of unconsolidated investments of $2 million, zero and zero, respectively; other items, net of $(4) million, $2 million and $(10) million, respectively; and loss on discontinued operations of $561 million, zero and zero, respectively. Reported 2002 EBIT for this segment included after-tax charges of $24 million, including restructuring and reorganization costs and additional regulatory asset amortization. Results were positively impacted in 2002 by weather-related increases in electric and gas residential and commercial sales volumes, offset by lower economic driven industrial sales and a 5% electric residential rate reduction effective May 1, 2002. In addition, electric revenue was positively affected by the resolution of a contingent liability for a bulk power billing dispute. Operating expenses were lower in 2002 due to reduced bad debt expense, a favorable resolution of a sales tax audit and a municipal utility tax adjustment. Discontinued operations included a pre-tax loss of $599 million related to the sale of Northern Natural in the third quarter.

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Segment results in 2001 include approximately $9 million of after-tax severance and early retirement charges related to a restructuring at IP, offset by an approximate $10 million after-tax credit related to IP s exit from a nuclear mutual insurance company. The 2000 results include an approximate $2 million after-tax merger cost charge related to the Illinova acquisition. In addition to the severance and early retirement charges, operating income decreased in 2001 as a result of decreased industrial electricity revenues resulting from increased competition and an economic downturn, offset by weather-driven sales from electric residential and commercial customers. Additionally, operating expenses were slightly higher due to fees paid in connection with an independent system operator and bad debt expense, offset by lower general and administrative expenses.

REG reported operating cash flow was $262 million for the year ended December 31, 2002, compared to $109 million and $302 million for the respective periods in 2001 and 2000. During 2002, non-cash losses increased from 2001 and 2000, primarily due to the $561 million after-tax loss on the sale of Northern Natural and corporate allocated severance and information technology asset impairment charges to IP. Over the three-year period, other non-cash items, such as depreciation, remained relatively flat, with the exception of additional regulatory asset amortization recorded during these periods.

Reported changes in working capital relating to Transmission and Distribution were a net use of $109 million in 2002, compared to a net use of $160 million in 2001 and a net source of $50 million in 2000, respectively. Fluctuations in working capital primarily relate to the timing of payments, such as the IP tax payment, or recognition of liabilities.

Working capital changes in 2001 exceeded those in 2002 primarily due to a payment during 2001 to DMG which was accrued at year end 2000. Conversely, working capital changes increased for the year ended December 31, 2000 primarily due to favorable IP power purchase agreements and an overall increase in trade accruals.

REG Outlook

Future results of operations for IP may be affected, either positively or negatively, by regulatory actions, general economic conditions, weather, overall economic growth, the demand for power and natural gas in IP s service area and interest rates. IP s future results also will be affected by its ability to consummate the previously announced sale of its transmission system to Trans-Elect. On February 20, 2003, the FERC voted to defer its approval of the transaction and set a hearing to establish the allowable transmission rates for Trans-Elect. Specifically, the FERC stated that the benefits of the transaction, including independent transmission ownership, may not justify the significant increase in rates sought. The FERC also limited the period for which IP may provide operational services to Trans-Elect to one year.

IP and Trans-Elect have withdrawn the rate filing at FERC, and requested a continuance of the hearing pending an order on rehearing and a ruling by FERC on the new rate application. Pending resolution of the FERC issues, the ICC proceeding has also been withdrawn and continued. IP is in discussions with Trans-Elect to determine the impact of the FERC order on the transaction and to determine the course of action the parties will take. Under the sale agreement, if the transaction does not close on or before July 7, 2003, either party can terminate the agreement. Because of the lead time required to receive the necessary regulatory approvals, it is unlikely that the transaction could be closed by July 7th. If we are unable to consummate the Trans-Elect transaction, IP will continue to recognize the revenues and expenses associated with its transmission assets. However, as described below, IP s liquidity position and future financial condition is not dependent on the receipt of proceeds associated with the pending transaction. If the Trans-Elect transaction cannot be consummated, we will explore other alternatives for IP s transmission assets, including potentially keeping those assets.

IP has a significant amount of leverage, with near-term maturities including a $100 million payment on its one-year term loan due in May 2003, $190 million in aggregate mortgage bond maturities due in August and

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September 2003 and quarterly payments of approximately $22 million due on its transitional funding trust notes. Please read Item 8, Financial Statements and Supplementary Information, Note 10 Debt Illinois Power Transitional Funding Trust Notes beginning on page F-54 for a discussion of the transitional funding trust notes. IP is required to make these quarterly payments on its transitional funding trust notes through 2008 and has a payment of up to $81 million due on its Tilton lease financing in the third quarter 2004. Because IP has no revolving credit facility and no access to the commercial paper markets, IP relies on cash on hand, cash from asset sales or other capital-raising transactions and cash flows from operations, including interest payments under its $2.3 billion intercompany note receivable from Illinova, to satisfy its debt obligations and to otherwise operate its business. In December 2002, IP sold $550 million of mortgage bonds, $150 million of which were issued in January 2003 following ICC approval. A portion of the proceeds were used to repay $200 million of IP s $300 million term loan and to refinance a $96 million mortgage bond maturity. The remaining proceeds from this offering are to be used to fund a significant portion of IP s remaining 2003 maturities. However, IP remains reliant on its ability to execute one or more other liquidity initiatives in order to satisfy its future debt and commercial obligations, including the remaining portion of its third quarter 2003 mortgage bond maturities. We expect these initiatives would include new bank borrowings or mortgage bond issuances or another type of initiative, including support from Dynegy, subject to availability and receipt of any required regulatory approval. Although Dynegy s recently restructured credit agreement prohibits prepayments of principal on our intercompany note receivable in excess of $200 million, it does not limit Dynegy s ability to prepay interest under our intercompany note receivable.

Customer Risk Management

	Year Ended December 31,		
	2002	2001	2000
		(Restated)	(Restated)
	(in millions, except operating statistics)		
Operating Income (Loss)	$ (974)	$ 264	$ 143
Earnings (Losses) of Unconsolidated Investments	(21)	(24)	3
Other Items, Net	(49)	(54)	(1)
Gain (Loss) on Discontinued Operations	(51)	(25)	52
Cumulative Effect of Change in Accounting Principle		3	
Earnings (Loss) Before Interest and Taxes	$ (1,095)	$ 164	$ 197
Operating Cash Flows:			
Operating Cash Flows Before Changes in Working Capital	$ 200	$ 180	$ 30
Changes in Working Capital	(518)	(476)	(50)
Net Cash Provided By (Used In) Operating Activities	$ (318)	$ (296)	$ (20)
Operating Statistics:			
Domestic Gas Marketing Volumes (Bcf/d)	7.4	8.2	7.5
Canadian Gas Marketing Volumes (Bcf/d)	2.3	3.0	2.2
European Gas Marketing Volumes (Bcf/d)	2.2	1.3	1.2
Total Gas Marketing Volumes	11.9	12.5	10.9
Coal Marketing Volumes (Millions of Tons)	38.2	43.0	10.4

CRM reported EBIT of $(1,095) million for 2002 compared to $164 million for 2001 and $197 million for 2000. EBIT consists of the following amounts reported by CRM for the periods presented: operating income (loss) of $(974) million, $264 million and $143 million, respectively; earnings (losses) of unconsolidated investments of $(21) million, $(24) million and $3 million, respectively; other items, net, of $(49) million, $(54) million and $(1) million; gain (loss) on discontinued operations of $(51) million, $(25) million and $52 million, respectively; and cumulative effect of change in accounting principle of zero, $3 million and zero.

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Results of operations during the three-year period were influenced either positively or negatively by the following:

- reduced gas marketing volumes during 2002 as a result of reduced market liquidity and our lower credit ratings;
- an increase in customer and risk-management activities in 2001, as compared to 2000, as a result of a long-term power agreement that contributed approximately $35 million of non-cash earnings in 2001;
- an increase in European and Canadian marketing operations due to increased customer origination and service demand during 2000 and 2001;
- an approximate $82 million after-tax charge relating to exposure to Enron as a result of that company s bankruptcy filing and an allocation of transaction costs associated with the terminated merger with Enron and the execution of Project Alpha in 2001; and
- aggregate after-tax gains of approximately $58 million on the sale of Accord, offset by an allocated portion of Illinova acquisition costs, in 2000.

Total natural gas volumes sold decreased to 11.9 billion cubic feet per day in 2002 from 12.5 billion cubic feet per day in 2001 and 10.9 billion cubic feet per day in 2000. The 2001 increase in natural gas volumes sold reflects greater market origination, including sales to commercial and industrial customers, sales volumes on Dynegy*direct* and increased gas marketing in Canada. The decrease in volumes in 2002 reflects market liquidity and credit concerns.

As a result of our declining credit ratings in 2002, we were required to post significant additional amounts of collateral under the terms of our commercial contracts. This use of working capital resulted in negative operating cash flows in 2002.

CRM Outlook

Our CRM business future results of operations will be significantly impacted by our ability to execute on our exit strategy. We are actively pursuing opportunities to assign or renegotiate the terms of our contractual obligations related to this business, particularly some of our power tolling arrangements. While we expect to complete a significant portion of our exit activities during the first half of 2003, some contracts, particularly our power tolling contracts, do not expire for up to 30 years and credit and market liquidity constraints could impact our ability to complete our exit plan and the timing thereof. If we are unsuccessful in our efforts to renegotiate or terminate some of the eight power tolling arrangements to which we remain a party, we would be required to pay an aggregate of approximately $3.8 billion in capacity payments under the related agreements through 2030, including $226 million in 2003 and $229 million in 2004. After applying a LIBOR-based discount rate, these capacity payments approximate $2.7 billion. The discounted fair value of the capacity payments under these arrangements exceeded the market value of electricity available for sale under these arrangements at December 31, 2002 by approximately $501 million. Even if we were successful in our efforts to renegotiate or terminate some of these arrangements, we could incur significant expenses relating to any such renegotiation or termination.

In addition, we have posted collateral to support a substantial portion of our obligations in this business, including approximately $121 million at April 2, 2003 posted in connection with some of our power tolling arrangements. While we have been working 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. Although we are current on all contract payments to these counterparties, we have received a notice of default from each such counterparty with regard to collateral. We are continuing to negotiate with both parties. Our annual net payments under these two arrangements approximate $67 million and $57 million, respectively, and the contracts extend through 2014 and 2012, respectively. If these counterparties were successful in pursuit of claims that we

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defaulted on these contracts, they could declare a termination of these contracts, which provide for termination payments based on the mark-to-market value of the contracts.

We have generally been successful in satisfying customer collateral requirements and have had few terminations or disputes relating to contracts in this segment. However, we are involved in litigation with some of our former counterparties relating to contract terminations with respect to which we were unable to agree on mutually acceptable collateral or other adequate assurance. There is a risk that we may be unable to agree with other counterparties on mutually acceptable forms and amounts of adequate assurance or other collateral, resulting in additional litigation and related expenses. Our ability to address these and other issues relating to collateral posted for ongoing CRM contracts could affect this business future results of operations.

We intend to manage actively our exit from the CRM business with the objective of maximizing the ultimate cash proceeds received and completing our exit plan in a timely and cost-effective manner. However, our failure to manage this exit successfully would negatively impact the CRM segment s results of operations.

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 natural gas, electricity and NGLs. Power marketing operations and electricity generating facilities have higher volatility and demand, respectively, in the summer cooling months, while the transmission and distribution business has higher seasonal gas sales in the winter and higher seasonal electricity sales in the summer. These trends 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; however, such factors typically have a greater impact on sales prices than on sales volumes.

CRITICAL ACCOUNTING POLICIES

Our Controller s Department is responsible for the development and application of accounting policy and control procedures for the organization s financial and operational accounting functions. This department conducts our activities independent of any active management of our risk exposures, is independent of revenue-producing units 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 regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. We have identified the following six critical accounting policies that require a significant amount of judgment and are considered to be the most 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;
- 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

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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, 2002, except as required by Financial Accounting Standard No. 133 (FAS No. 133), which was effective January 1, 2001, and the adoption of EITF 02-03, which rescinded EITF 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 businesses consist largely of the ownership and operation of physical assets that we use in various generation, processing and delivery operations. These processes include 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 and industrial and retail customers.

The fair value model has historically been used to account for forward physical and financial transactions in the CRM, GEN and NGL 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, 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 LIBOR-based time value of money adjustment and deduction of reserves for credit, price and market liquidity risks.

A key aspect of our operations and business strategy is our ability to provide customers with competitively priced bundled products and services that address their specific needs. Many of these customized products and services are not exchange-traded. In addition, the availability of reliable market quotations in certain regions and for certain commodities is limited as a result of liquidity and other factors. Consequently, we use a combination of market quotations, derivatives of market quotations and proprietary models to periodically value our portfolio as required by GAAP. Market quotations are validated against broker quotes, regulated exchanges or third-party information. Derivatives of market quotations use validated market quotes, such as actively traded power prices, as key inputs in determining market valuations.

In certain markets or for certain products, market quotes or derivatives of market quotes are not available or are not considered appropriate valuation techniques as a result of the newness of markets or products, a lack of liquidity in such markets or products or other factors. However, under GAAP, estimating the value of these types of contracts is required. Consequently, prior to the third quarter 2001, we used models principally derived from market research to estimate forward price curves for valuing positions in these markets. Our models generated pricing estimates primarily for regional power markets in the United States and Europe. Price curves were derived by incorporating a number of factors, including broker quotes, near-term market indicators and a proprietary model based on a required rate of return on investment in new generation facilities. We believed that new generation needs in the United States and Europe primarily would be met through the construction of new gas-fired generation. Power prices, over the long term, would thus reflect the cost of building new gas fired generation, the cost of natural gas fuel and a cost of capital return on new construction investment. Beginning in the third quarter 2001, we began to enter into longer-term power transactions in the United States with respect to which no broker quotes or other market data was available; consequently, we applied a proprietary model to estimate forward prices and, in turn, the fair market value of these longer-term power transactions.

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During January 2003, in connection with the re-audit of our 1999-2001 financial statements and an assessment of various accounting policies, we reconsidered the model-based methodology we used to value the portions of our marketing and trading portfolio for which broker quotes were not available. After reconsidering the appropriateness of our former methodology in light of changing industry circumstances and in connection with the re-audit, in late January 2003, we determined that, beginning with the third quarter 2001, a different forward power curve methodology would more appropriately reflect the value of our long-term power contracts.

Upon making this determination, we corrected the forward power curve methodology we used to estimate the fair market value of our U.S. power marketing and trading portfolio. This corrected methodology incorporates forward energy prices derived from broker quotes and values from executed transactions to estimate forward price curves for periods where broker quotes and transaction data cannot be obtained. Further, we determined that in order to adequately reflect our results, it was appropriate to restate our prior period financial statements, beginning with the third quarter 2001, to reflect the corrected methodology. Please read Item 8, Financial Statements and Supplementary Data, Explanatory Note Restatement Disclosures Restated Forward Power Curve Methodology beginning on page F-12 for further discussion.

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, 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 Statement of Financial Accounting Standards (Statement) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. If a long-lived asset is held and used, the determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. If an impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the fair value of the assets and recording a loss if the fair value was less than the book value. For assets identified as held for sale, the book value is compared to the estimated fair value to determine if an impairment loss is required.

We follow the guidance of APB 18, The Equity Method of Accounting for Investments in Common Stock and Statement No. 115, Accounting for Certain Investments in Debt and Equity Securities 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 loss is required. We would record a loss when the decline in value is considered other than temporary. We follow the guidance set forth in Statement 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. Fair value utilized in this assessment is also based on our estimate of future cash flows.

Our assessment regarding the existence of impairment factors is based on market conditions, operational performance and legal factors of our businesses. Our review of factors present and the resulting estimation of the appropriate carrying value of our property, plant and equipment, investments and goodwill are subject to judgments and estimates that management is required to make. Our fair value estimates are impacted significantly by the estimated useful lives of the assets, commodity prices, regulations and discount rate assumptions.

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Estimated Useful Lives

The estimated useful lives of our long-lived assets are used to compute depreciation expense and are also used for impairment testing. Estimated useful lives are based 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. These estimates could be impacted by future energy prices, environmental regulations and competition. If the useful lives of these assets were found to be shorter than originally estimated, depreciation charges would be accelerated.

Accounting for Contingencies

Environmental costs relating to current operations are expensed or capitalized, as appropriate, depending on whether such costs provide future economic benefit. Liabilities are recorded when environmental assessment indicates that remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based on relevant past experience, currently enacted laws and regulations, existing technology, site-specific costs and cost-sharing arrangements. Such liabilities may be recognized on a discounted basis if the amount and timing of anticipated expenditures for a site are fixed or reliably determinable; otherwise, such liabilities are recognized on an undiscounted basis. In assessing environmental 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. If our reserve balances were to either increase or decrease based on the factors mentioned above, the amount of the increase or decrease would be recognized immediately in earnings.

We are involved in numerous lawsuits, claims, proceedings and audits in the normal course of our operations. In accordance with Statement No. 5, we record a loss contingency for these matters when it is probable that an asset has been impaired or a liability has been incurred and the amount of the loss can be reasonably estimated. We review our loss contingencies on an on-going basis to ensure they are adequately reserved on the balance sheet. These reserves are based on judgments made by management with respect to the likely outcome of these matters and are adjusted as appropriate. Our 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 judgments were applied with respect to their matters, it is likely that reserves would be recorded for different matters and in different amounts.

Accounting for Income Taxes

We follow the guidance in Statement 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 income tax temporary differences. Please read Item 8, Financial Statements and Supplementary Data, Note 12 Income Taxes beginning on page F-58 for further discussion.

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 exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within our consolidated balance sheet.

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 recovery is not likely, we must establish a valuation allowance. Significant management judgment is required in determining our provision for income taxes, our deferred tax assets and liabilities and any valuation allowance recorded against our deferred tax assets. To the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or benefit within the tax provisions in the statements of operations.

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-

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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 2002. Accordingly, at December 31, 2002, we used a discount rate of 6.5%, a decline of 100 basis points from the 7.5% rate used as of December 31, 2001. This decline in the discount rate had the impact of increasing the underfunded status of our pension plans by approximately $72 million.

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 December 31, 2002 is 9%, compared with 9.47% at December 31, 2001. The reduction is primarily due to the decline in the rate of return on pension assets through 2002. This change did not impact 2002 pension expense, but it will adversely impact pension expense beginning in 2003. We expect the decrease in this assumption, coupled with the decreased discount rate discussed above and the passage of time, will increase pension expense by approximately $22 million over 2002 expense, exclusive of 2002 curtailment charges and special termination benefits charges.

On December 31, 2002, 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. As a result, in accordance with Statement of Financial Accounting Standards No. 87, Employers Accounting for Pensions , we recognized a charge to accumulated other comprehensive loss of $66 million (net of taxes of $38 million), which decreased 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.

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 (in millions):

	Impact on PBO, 12/31/2003	Impact on 2003 Expense
Increase Discount Rate 50 basis points	$ (46.0)	$ (3.9)
Decrease Discount Rate 50 basis points	48.8	4.0
Increase Expected Rate of Return 50 basis points		(3.2)
Decrease Expected Rate of Return 50 basis points		3.2

We expect to have minimal, if any, cash requirements related to our pension and post-retirement benefit plans during 2003. However, during 2004, it is likely that we will be required to make a contribution to the pension plan. Although it is difficult to estimate these potential 2004 cash requirements due to uncertain market conditions, we currently expect that the cash requirements would be approximately $43 million.

Accounting Pronouncements

See Item 8, Financial Statements and Supplementary Data, Note 2 Accounting Policies New Accounting Pronouncements beginning on page F-26, which is incorporated herein by reference, for a discussion of recently issued accounting pronouncements.

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RISK-MANAGEMENT DISCLOSURES

The following table provides a reconciliation of the risk management data on our balance sheet, statement of operations and statement of cash flow (in millions).

	As of and for the Twelve Months Ended December 31, 2002
Balance Sheet Risk-Management Accounts	
Fair value of portfolio at January 1, 2002	$ 935
Risk-management losses recognized through the income statement in the period, net (1)	(99)
Cash received related to contracts settled in the period, net (2)	(411)
Changes in fair value as a result of a change in valuation technique (3)	
Non-cash adjustments and other (4)	(62)
Fair value of portfolio at December 31, 2002 (9)	$ 363
Income Statement Reconciliation	
Risk-management losses recognized through the income statement in the period, net (1)	$ (99)
Physical business recognized through the income statement in the period, net	297
Non-cash adjustments and other (5)	(76)
Net recognized operating income (6)	$ 122
Cash Flow Statement	
Cash received related to risk-management contracts settled in the period, net (2)	$ 411
Estimated cash received related to physical business settled in the period, net	297
Timing and other, net (7)	52
Cash received during the period	$ 760
Risk Management cash flow adjustment for the year ended December 31, 2002 (8)	$ 638

(1) This amount includes approximately ($12) million representing management s estimate of the initial value of new contracts entered into during 2002.
(2) This amount includes cash settlements of hedging instruments, emission allowances and other non-trading amounts in addition to the cash settlement of trading contracts.
(3) Our modeling methodology was consistently applied during 2002.
(4) This amount consists primarily of changes in value and cash settlements associated with foreign currency and interest rate hedges.
(5) This amount consists primarily of changes in value of interest rate hedges.
(6) This amount consists primarily of CRM s operating income before the deduction of Depreciation and Amortization, Impairment and Other Charges and General and Administrative Expenses.
(7) This amount represents cash received for sales of emission credits and the settlement of fuel hedges and cash payments associated with foreign currency hedges.
(8) This amount is calculated as Cash received during the period less Net recognized operating income.
(9) The reduction in value of the portfolio from December 31, 2001 to December 31, 2002 is primarily due to the substantial liquidation of our European marketing portfolio and the accelerated settlement of our U.S. gas storage positions.

The net risk management asset of $363 million is the aggregate of the following line items on the Consolidated Balance Sheet: 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, 2002. 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	2003	2004	2005	2006	2007	Thereafter
				($ in millions)			
Mark-to-Market (1)	$ 363	$ 250	$ 24	$ 52	$ 27	$ (24)	$ 34
Cash Flow (2)	979	259	43	57	36	(15)	599

(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.
(2) Cash Flow reflects undiscounted cash inflows and outflows by contract based on the delivery date of individual contracts and has not been adjusted for counterparty credit or other reserves. These amounts exclude the cash flows associated with certain derivative instruments designated as hedges as well as other non-trading amounts.

The following table provides an assessment of net contract values by year based on our valuation methodology described above. Approximately 99 percent of our net risk-management asset value at December 31, 2002 was determined by market quotations or validation against industry posted prices.

Net Fair Value of Marketing Portfolio

	Total	2003	2004	2005	2006	2007	Beyond
				($ in millions)			
Market Quotations (1)	$ 213	$ 250	$ (45)	$ (2)	$ 2	$ (18)	$ 26
Other External Sources (2)	146		67	63	14		2
Prices Based on Models (3)	4		2	(9)	11	(6)	6
	$ 363	$ 250	$ 24	$ 52	$ 27	$ (24)	$ 34

(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) Mid-term prices validated against industry posted prices.
(3) See Critical Accounting Policies Revenue Recognition beginning on page 74 for a discussion of our use of long-term models.

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.

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UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION

This Amendment No. 1 includes statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as forward-looking 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, may, will, should, expect and other words of similar meaning. In part include, but are not limited to, statements relating to the following:

- Projected operating or financial results;
- Expectations regarding capital expenditures and other payments;
- Our beliefs and assumptions relating to our liquidity position, including our ability to satisfy or refinance our obligations as they come due;
- Our ability to execute additional capital-raising transactions or refinancings as necessary to enhance our liquidity position;
- Our ability to compete effectively for market share with industry participants;
- IP s ability to consummate capital-raising activities, including the proposed Trans-Elect transaction;
- Beliefs about the outcome of legal and administrative proceedings, including matters involving the California power market, shareholder class action lawsuits and environmental matters as well as the investigations primarily relating to Project Alpha and our trading practices; and
- Our ability to manage our exit from third-party risk management aspects of the marketing and trading business and the timing of the expected cash flow realization and release of collateral related to 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 and uncertainties, including the following:

- The timing and consummation of asset sales or other capital-raising activities;
- The timing and extent of changes in commodity prices for energy, particularly natural gas, electricity and NGLs;
- The extent and timing of the entry of additional competition in our asset-based business lines;

The condition of the capital markets generally, which will be affected by interest rates, foreign currency fluctuations and general economic conditions, and our financial condition, including our ability to satisfy our significant debt maturities and to maintain our credit ratings;

Developments in the California power markets, including, but not limited to, governmental intervention, deterioration in the financial condition of our counterparties, default on receivables due and adverse results in current or future investigations or litigation;

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 NGLs;

Operational factors affecting the start up or ongoing commercial operations of our power generation, natural gas, natural gas liquids or regulated energy delivery facilities, including catastrophic weather-related damage, regulatory approvals, permit issues, unscheduled outages or repairs, unanticipated changes in fuel costs or availability of fuel emission credits, the unavailability of gas transportation, the unavailability of electric transmission service or workforce issues;

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Increased interest expense and the other effects of our restructured credit facilities, including the security arrangements and restrictive covenants contained therein;

The availability of trade credit and other factors affecting our financing activities, including the effect of our restatement of our 1999-2001 financial statements and the other issues described in this annual report;

Our ability to generate sustainable earnings and cash flow from our assets and businesses;

Our ability to address the $1.5 billion in Series B preferred stock held by ChevronTexaco;

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;

Cost and other effects of legal and administrative proceedings, settlements, investigations and claims, including legal proceedings related to the California power market, shareholder claims, claims arising out of the CRM business and environmental liabilities that may not be covered by indemnity or insurance, as well as the FERC, U.S. Attorney and other similar investigations primarily surrounding Project Alpha and our trading practices;

Other North American regulatory or legislative developments that affect the regulation of the electric utility industry, the demand for energy generally, increase the environmental compliance cost for our facilities or 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 lines of business, including any extended period of war or conflict.

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 of our forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this annual report.

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS AMENDMENT NO. 1, INCLUDING THE FINANCIAL STATEMENTS AND THE NOTES THERETO, DOES NOT REFLECT EVENTS OCCURRING AFTER THE DATE OF THE ORIGINAL FILING. SUCH EVENTS INCLUDE, AMONG OTHERS, THE EVENTS DESCRIBED IN OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED MARCH 31, 2003 AND THE EVENTS SUBSEQUENTLY DESCRIBED IN OUR CURRENT REPORTS ON FORM 8-K. FOR A DESCRIPTION OF THESE EVENTS, PLEASE READ OUR EXCHANGE ACT REPORTS FILED SINCE APRIL 11, 2003, INCLUDING OUR QUARTERLY REPORT ON FORM 10-Q FOR THE PERIOD ENDED MARCH 31, 2003 AND OUR CURRENT REPORTS ON FORM 8-K.

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

Our financial statements and financial statement schedule are set forth at pages F-1 through F-98 inclusive, found at the end of this Amendment No. 1, and are incorporated herein by reference.

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PART III

Item 13. *Certain Relationships and Related Transactions*

Information regarding related party transactions is incorporated by reference to the 2003 annual meeting proxy statement under the headings Principal Stockholders, Proposal 1 Election of Directors and Executive Compensation Indebtedness of Management and Certain Relationship and Related Transactions. Except as otherwise disclosed therein, management believes such related party transactions were entered into on terms that were fair and reasonable.

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PART IV

Item 14. *Controls and Procedures*

Within the 90-day period immediately preceding the filing of this Amendment No. 1, 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 Rule 13a-14(c) under the Exchange Act). This evaluation included consideration of our establishment of a disclosure committee and the various processes that were carried out under the direction of this committee in an effort to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified by the SEC. This evaluation also included consideration of our internal controls and procedures for the preparation of our consolidated financial statements. While we have identified internal control weaknesses, which are discussed below, our evaluation indicated that these weaknesses did not impair the effectiveness of our overall disclosure controls and procedures.

In evaluating our internal controls we sought to determine whether there were any significant deficiencies and in particular whether there were any material weaknesses. Under the applicable accounting literature, significant deficiencies are referred to as reportable conditions, which are control issues that could have a significant adverse effect on our ability to record, process, summarize and report financial data in the financial statements. A material weakness is defined as a particularly serious reportable condition where the internal control does not reduce to a relatively low level the risk that (a) misstatements caused by the error may occur in amounts that would be material in relation to the financial statements and (b) that such misstatements would not be detected timely by employees in the normal course of performing their assigned functions.

Our management and the Audit Committee are aware of two reportable conditions relating to our operations, each of which was considered to be material weaknesses for the year ended December 31, 2002 under standards established by the American Institute of Certified Public Accountants. The first such condition related to the fact that inappropriate persons within our organization had access to record or revise entries in our accounting software system. We have taken action to test whether this access resulted in any inappropriate entries being recorded or revised and concluded that no such activities occurred. We are currently developing a technical solution to ensure that access to our accounting software system is limited to appropriate personnel, and we expect to implement this solution in the near term. In the interim, we have strengthened our monitoring policy with respect to the entries that are recorded or revised in this system to validate that all such entries are recorded or revised by appropriate personnel.

The second such condition related to the process whereby accrued estimates of volumes bought, sold, transported and stored in our natural gas marketing business were reconciled to the actual volumes. Due to the timing of the availability of transaction data, natural gas marketing transactions are initially recorded based on estimates of volumes bought, sold, transported and stored. These estimates are later adjusted to reflect actual purchases and sales based on a complex process of reconciling these estimates with our customers, suppliers and transportation and storage service providers which may occur over a period of months as new information is received. Such adjustments are a routine aspect of accounting for natural gas transactions and are typically immaterial to the estimated amounts recorded. Prior to 2002, we performed this process on a six-month delay due to system constraints to allow for an accumulation of all necessary data. In 2002, in connection with the implementation of process and systems enhancements to provide more timely and precise information, we identified balances in certain accounts in our natural gas marketing business unit that had not been adjusted or had been adjusted improperly in prior periods. As a result, in July 2002 we adopted additional procedures identifying and implementing specified key controls designed to improve the quality of our monthly monitoring and reconciliation process. A reconciliation has been completed and corrections resulting from this process are reflected in the audited consolidated financial statements included in this Amendment No. 1.

Additionally, we are undergoing a major organizational restructuring in connection with, among other things, our exit from third-party marketing and trading. We also have experienced significant changes in senior management and other accounting personnel over the past year. Our new management team is operating in an

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atmosphere of historic legislative, regulatory and accounting reform with respect to which there have been many new laws, regulations and accounting pronouncements that are expected to affect the business environment for years to come. In response to this new environment, we have undertaken a number of initiatives, including the following:

- engagement of a new Vice President of Internal Audit; and
- engagement of external consultants to assist us in a review of our internal control processes and procedures.

As part of this effort, we are currently developing and implementing a strategy for formalizing our internal controls and procedures for financial reporting in accordance with the SEC s proposed rules to implement the internal control report requirements included in Section 404 of the Sarbanes-Oxley Act. It is possible that additional changes will be made to our internal controls as a result of these efforts.

Item 15. *Exhibits, Financial Statement Schedules and Reports on Form 8-K*

(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
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 B Mandatorily Convertible Redeemable Preferred Stock of Dynegy Inc. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc., File No. 1-15659, dated November 9, 2001).
3.3	Amended and Restated Bylaws of Dynegy Inc.
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).

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Exhibit Number	Description
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).
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 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 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).

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.

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Exhibit Number	Description
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).
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. 1-11156).
10.10	Employment Agreement, effective February 1, 2000, between Charles L. Watson and Dynegy Inc. (incorporated by reference to Exhibit 10.9 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156)
10.11	Employment Agreement, effective February 1, 2000, between Stephen W. Bergstrom and Dynegy Inc. (incorporated by reference to Exhibit 10.10 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156).
10.12	Employment Agreement, effective as of September 16, 2002, between R. Blake Young and Dynegy Inc. (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2002 of Dynegy Inc., File No. 1-15659).
10.13	Employment Agreement, effective February 1, 2000, between Kenneth E. Randolph and Dynegy Inc. (incorporated by reference to Exhibit 10.12 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156).
10.14	Employment Agreement, effective February 1, 2000, between Matthew K. Schatzman and Dynegy Inc. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2000 of Dynegy Inc., File No. 1-15659).
10.15	Employment Agreement, effective February 1, 2000, between Alec G. Dreyer and Dynegy Inc.
10.16	Employment Agreement, effective December 2, 2002, between Nick J. Caruso and Dynegy Inc.
10.17	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).

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Exhibit Number	Description
10.18	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).
10.19	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).
10.20	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).
10.21	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).
10.22	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).
10.23	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 exhibits to the Registration Statement on Form S-4 of Midstream Combination Corp., Registration No. 333-09419).
10.24	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 exhibits to the Registration Statement on Form S-4 of Midstream Combination Corp., Registration No. 333-09419).
*10.25	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).
10.26	Shareholder Agreement of Energy Convergence Holding Company with Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K of Dynegy Inc., File No. 1-11156, dated June 14, 1999).
10.27	Dynegy Inc. Severance Pay Plan (incorporated by reference to Exhibit 10.41 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156).
10.28	Registration Rights Agreement Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.8 to the Current Report on Form 8-K of Dynegy Inc., File No. 1-11156, dated June 14, 1999).
10.29	First Amendment to Registration Rights Agreement Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.9 to the Current Report on Form 8-K of Dynegy Inc., File No. 1-15659, dated November 9, 2001).
10.30	Series B Preferred Stock Subscription Agreement dated as of November 9, 2001 by and between ChevronTexaco Corp. and Dynegy Inc. (incorporated by reference to Exhibit 10.8 to the Current Report on Form 8-K of Dynegy Inc., File No. 1-15659, dated November 9, 2001).
10.31	Credit Agreement, dated as of April 1, 2003, among Dynegy Holdings Inc., as borrower, Dynegy Inc., as parent guarantor, various subsidiary guarantors and the lenders party thereto.
10.32	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.
10.33	Non-Shared Security Agreement, dated April 1, 2003, among Dynegy Inc., various grantors named therein and Bank One, N.A. as collateral agent.
10.34	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.

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Exhibit Number	Description
21.1	Subsidiaries of the Registrant.
***23.1	Consent of PricewaterhouseCoopers LLP.
**99.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**99.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Previously filed
* 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.
** Furnished herewith
*** Filed herewith

(b) Reports on Form 8-K of Dynegy Inc. for the fourth quarter of 2002.

1. During the quarter ended December 31, 2002, we filed a Current Report on Form 8-K on October 2, 2002. Items 5 and 7 were reported and no financial statements were filed.

2. During the quarter ended December 31, 2002, we filed a Current Report on Form 8-K on October 22, 2002. Items 5, 7 and 9 were reported and no financial statements were filed.

3. During the quarter ended December 31, 2002, we filed a Current Report on Form 8-K on October 23, 2002. Items 5 and 7 were reported and no financial statements were filed.

4. During the quarter ended December 31, 2002, we filed a Current Report on Form 8-K on November 14, 2002. Items 5 and 7 were reported and no financial statements were filed.

5. During the quarter ended December 31, 2002, we filed a Current Report on Form 8-K on December 3, 2002. Items 5 and 7 were reported and no financial statements were filed.

6. During the quarter ended December 31, 2002, we filed a Current Report on Form 8-K on December 23, 2002. Items 5 and 7 were reported and no final statements were filed.

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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: July 25, 2003	By:	/s/ NICK J. CARUSO
		Nick J. Caruso Executive Vice President and Chief Financial Officer

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SECTION 302 CERTIFICATION

I, Bruce A. Williamson, certify that:

1. I have reviewed this Amendment No. 1 to the 2002 Annual Report on Form 10-K (Amendment No. 1) of Dynegy Inc. (Dynegy);

2. Based on my knowledge, this Amendment No. 1 does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Amendment No. 1;

3. Based on my knowledge, the financial statements, and other financial information included in this Amendment No. 1 fairly present in all material respects the financial condition, results of operations and cash flows of Dynegy as of, and for, the periods presented in this Amendment No. 1;

4. Dynegy s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for Dynegy and have:

(a) designed such disclosure controls and procedures to ensure that material information relating to Dynegy, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) evaluated the effectiveness of Dynegy s disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

(c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. Dynegy s other certifying officer and I have disclosed, based on our most recent evaluation, to Dynegy s auditors and the audit committee of Dynegy s board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect Dynegy s ability to record, process, summarize and report financial data and have identified for Dynegy s auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in Dynegy s internal controls; and

6. Dynegy s other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: July 25, 2003

/s/ BRUCE A. WILLIAMSON

Bruce A. Williamson

President and Chief Executive Officer

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SECTION 302 CERTIFICATION

I, Nick J. Caruso, certify that:

1. I have reviewed this Amendment No. 1 to the 2002 Annual Report on Form 10-K (Amendment No. 1) of Dynegy Inc. (Dynegy);

2. Based on my knowledge, this Amendment No. 1 does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Amendment No. 1;
3. Based on my knowledge, the financial statements, and other financial information included in this Amendment No. 1 fairly present in all material respects the financial condition, results of operations and cash flows of Dynegy as of, and for, the periods presented in this Amendment No. 1;

4. Dynegy s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for Dynegy and have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to Dynegy, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) evaluated the effectiveness of Dynegy s disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. Dynegy s other certifying officer and I have disclosed, based on our most recent evaluation, to Dynegy s auditors and the audit committee of Dynegy s board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect Dynegy s ability to record, process, summarize and report financial data and have identified for Dynegy s auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in Dynegy s internal controls; and
6. Dynegy s other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: July 25 , 2003

/s/ Nick J. Caruso

Nick J. Caruso

Executive Vice President and

Chief Financial Officer

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DYNEGY INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholders of Dynegy Inc.:

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, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and this financial statement schedule are the responsibility of the Company s management; our responsibility is to express an opinion on these financial statements and this financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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 14, 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.

See Note 13 for a discussion of the Company s plan with respect to the Series B Preferred Stock held by ChevronTexaco and its mandatory redemption date of November 13, 2003.

As discussed in the Explanatory Note, the consolidated financial statements include reclassifications relating to discontinued operations and segment reporting for each of the three years in the period ended December 31, 2002, additional pro forma disclosures relating to Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations , for each of the three years in the period ended December 31, 2002 and disclosures related to restatements of the consolidated financial statements for each of the two years in the period ended December 31, 2001 as previously contained in Amendment No. 2 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2001, which was filed on April 11, 2003.

As discussed in Note 2, the Company adopted the provisions of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets, and Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, as of January 1, 2002. As discussed in Note 2, the Company adopted certain provisions of Emerging Issues Task Force No. 02-03, Accounting for Contracts Involved in Energy Trading and Risk Management Activities. As discussed in Note 5, the Company adopted the provisions of Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities as of January 1, 2001.

PricewaterhouseCoopers LLP

Houston, Texas

April 9, 2003, except as to the matters discussed in the Explanatory Note captions Reclassifications Discontinued Operations and Reclassifications Revised Segments beginning on page F-8, as to which the date is July 18, 2003.

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DYNEGY INC.

CONSOLIDATED BALANCE SHEETS

(in millions, except share data)

	December 31, 2002	December 31, 2001
		(Restated)
ASSETS		
Current Assets		
Cash and cash equivalents	$ 757	$ 208
Restricted cash	17	28
Accounts receivable, net of allowance for doubtful accounts of $151 million and $113 million, respectively	2,791	3,083
Accounts receivable, affiliates	31	36
Inventories	236	256
Assets from risk-management activities	2,618	3,953
Prepayments and other assets	1,136	1,392
Total Current Assets	7,586	8,956
Property, Plant and Equipment	9,659	10,135
Less: accumulated depreciation	(1,270)	(934)
	8,389	9,201
Other Assets		
Unconsolidated investments	668	944
Investment in Northern Natural Gas Company		1,501
Assets from risk-management activities	2,529	2,214
Goodwill	396	1,561
Other assets	462	791
Total Assets	$ 20,030	$ 25,168
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 1,586	$ 2,064
Accounts payable, affiliates	65	38
Accrued liabilities and other	1,818	2,617
Liabilities from risk-management activities	2,418	3,361
Notes payable and current portion of long-term debt	861	458
Total Current Liabilities	6,748	8,538
Long-Term Debt	5,024	4,500
Other Liabilities		
Transitional funding trust notes	430	516
Liabilities from risk-management activities	2,366	1,871
Deferred income taxes	951	1,568

Other long-term liabilities	855	1,070
Total Liabilities	16,374	18,063
Minority Interest	146	1,040
Commitments and Contingencies (Note 14)		
Redeemable Preferred Securities, redemption value of $1,711 and $1,746, respectively (Note 13)	1,423	1,128
Stockholders Equity		
Class A common stock, no par value, 900,000,000 shares authorized at December 31, 2002 and 2001, 274,850,589 and 269,984,456 shares issued and outstanding at December 31, 2002 and 2001, respectively	2,825	2,786
Class B common stock, no par value, 360,000,000 shares authorized at December 31, 2002 and 2001, 96,891,014 and 86,499,914 shares issued and outstanding at December 31, 2002 and 2001, respectively	1,006	801
Additional paid-in capital	705	688
Subscriptions receivable (Note 16)	(12)	(38)
Accumulated other comprehensive loss, net of tax	(55)	(27)
Retained earnings (deficit)	(2,314)	798
Less: treasury stock, at cost 1,679,183 and 1,766,800 shares at December 31, 2002 and 2001, respectively	(68)	(71)
Total Stockholders Equity	2,087	4,937
Total Liabilities and Stockholders Equity	$ 20,030	$ 25,168

See Notes to Consolidated Financial Statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Year Ended December 31,		
	2002	2001	2000
		(Restated)	(Restated)
Revenues (Note 2)	$ 5,516	$ 8,878	$ 8,204
Cost of sales (exclusive of depreciation shown below) (Note 2)	4,786	7,071	6,785
Depreciation and amortization expense	466	456	390
Impairment and other charges	190		
Goodwill impairment	897		
Loss (gain) on sale of assets, net	(7)	(36)	(49)
General and administrative expenses	325	420	312
Operating income (loss)	(1,141)	967	766
Earnings (losses) of unconsolidated investments	(80)	191	196
Other income	48	55	45
Interest expense	(297)	(255)	(247)
Other expenses	(107)		(34)
Minority interest	(36)	(93)	(54)
Accumulated distributions associated with trust preferred securities	(12)	(22)	(29)
Income (loss) before income taxes	(1,625)	843	643
Income tax provision (benefit)	(276)	357	234
Income (loss) from continuing operations	(1,349)	486	409
Discontinued operations (Note 3):			
Income (loss) from discontinued operations	(1,503)	(127)	38
Income tax provision (benefit)	(349)	(45)	11
Income (loss) on discontinued operations	(1,154)	(82)	27
Income (loss) before cumulative effect of change in accounting principle	(2,503)	404	436
Cumulative effect of change in accounting principle (Notes 2 and 9)	(234)	2	
NET INCOME (LOSS)	$ (2,737)	$ 406	$ 436
Net income (loss)	$ (2,737)	$ 406	$ 436
Less: preferred stock dividends	330	42	35
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (3,067)	$ 364	$ 401

Net Income (Loss) Per Share:			
Basic earnings (loss) per share:			
Income (loss) from continuing operations	$ (4.59)	$ 1.37	$ 1.24
Income (loss) from discontinued operations	(3.15)	(0.26)	0.09
Cumulative effect of change in accounting principle, net	(0.64)	0.01	
Basic earnings (loss) per share	$ (8.38)	$ 1.12	$ 1.33
Diluted earnings (loss) per share:			
Income (loss) from continuing operations	$ (4.59)	$ 1.31	$ 1.18
Income (loss) from discontinued operations	(3.15)	(0.25)	0.09
Cumulative effect of change in accounting principle, net	(0.64)	0.01	
Diluted earnings (loss) per share	$ (8.38)	$ 1.07	$ 1.27
Basic shares outstanding	366	326	302
Diluted shares outstanding	418	340	315

See Notes to Consolidated Financial Statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year Ended December 31,		
	2002	2001	2000
		(Restated)	(Restated)
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ (2,737)	$ 406	$ 436
Items not affecting cash flows from operating activities:			
Depreciation and amortization	613	486	362
Impairment and other charges	847		
Goodwill impairment	897		
Earnings (losses) of unconsolidated investments, net of cash distributions	232	(117)	(87)
Risk-management activities	638	(17)	(145)
Deferred income taxes	(630)	242	170
Cumulative effect of change in accounting principle (Notes 6 and 9)	234	(2)	
Loss (gain) on asset sales, net	620	(36)	(132)
Reserve for doubtful accounts	68	55	45
Income tax benefit from stock option exercise and other	87	53	71
Change in assets and liabilities resulting from operating activities:			
Accounts receivable	421	1,622	(5,060)
Inventories	3	24	(129)
Prepayments and other assets	(762)	(183)	93
Accounts payable and accrued liabilities	(454)	(2,011)	4,870
Other, net	(102)	28	(74)
Net cash provided by (used in) operating activities	(25)	550	420
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(947)	(2,551)	(1,071)
Unconsolidated investments	(14)	(1,533)	(142)
Business acquisitions, net of cash acquired	(20)	(603)	(1,202)
Proceeds from asset sales	1,583	1,078	876
Other investing, net	75	(219)	
Net cash provided by (used in) investing activities	677	(3,828)	(1,539)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term borrowings	969	1,537	570
Repayments of long-term borrowings	(623)	(504)	(359)
Net proceeds from short-term borrowings	181		
Net cash flow from commercial paper and money market lines of credit	(724)	599	(906)
Decrease (increase) in restricted cash	11	(1)	(27)
Proceeds from sale of capital stock, options and warrants	240	604	1,216

Purchase of serial preferred securities of a subsidiary	(28)		
Proceeds from issuance of convertible preferred stock		1,500	
Purchase of treasury stock	(1)	(68)	(3)
Redemption of Illinois Power Preferred Securities		(100)	(93)
Dividends and other distributions, net	(55)	(98)	(112)
Minority interest contributions			843
Other financing, net	(14)	(19)	2
Net cash provided by (used in) financing activities	(44)	3,450	1,131
Effect of exchange rates on cash	(59)	(23)	(29)
Net increase (decrease) in cash and cash equivalents	549	149	(17)
Cash and cash equivalents, beginning of year	208	59	76
Cash and cash equivalents, end of year	$ 757	$ 208	$ 59

See Notes to Consolidated Financial Statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

(in millions)

	Preferred Stock	Common Stock	Additional Paid-In Capital	Subscriptions Receivable	Accumulated Other Comprehensive Loss	Retained Earnings (Deficit)	Treasury Stock	Total
December 31, 1999 (Restated)	$ 75	$ 1	$ 973	$	$	$ 208	$ (17)	$ 1,240
Net income (Restated)						436		436
Other comprehensive loss, net of tax (Restated)					(15)			(15)
Illinova acquisition	(75)	1,817	(973)				17	786
Common Stock issued		858						858
Extant acquisition (Restated)		67						67
Options exercised		157						157
Dividends and other distributions						(112)		(112)
401(k) plan and profit sharing stock		12						12
Options granted (Restated)			15					15
Treasury stock							(3)	(3)
December 31, 2000 (Restated)	$	$ 2,912	$ 15	$	$ (15)	$ 532	$ (3)	$ 3,441
Net income (Restated)						406		406
Other comprehensive loss, net of tax (Restated)					(12)			(12)
Common Stock issued		605						605
Subscriptions receivable (Restated)				(38)				(38)
Implied divided on Series B Preferred Stock (Restated)			660					660
Options exercised (Restated)		57						57
Dividends and other distributions						(140)		(140)
401(k) plan and profit sharing stock		13						13
Options granted (Restated)			13					13
Treasury stock (Restated)							(68)	(68)
December 31, 2001 (Restated)	$	$ 3,587	$ 688	$ (38)	$ (27)	$ 798	$ (71)	$ 4,937
Net loss						(2,737)		(2,737)
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	$	$ 3,831	$ 705	$ (12)	$ (55)	$ (2,314)	$ (68)	$ 2,087

See Notes to Consolidated Financial Statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions)

	Year Ended December 31,		
	2002	**2001**	**2000**
		(Restated)	**(Restated)**
Net income (loss)	$ (2,737)	$ 406	$ 436
Cash flow hedging activities, net:			
Cumulative effect of transition adjustment (net of tax provision of $18 million)		61	
Unrealized mark-to-market gains arising during period	73	4	
Reclassification to earnings, net	(73)	(57)	
Unrealized net gains (losses)		8	
Foreign currency translation adjustments	31	(21)	(7)
Minimum pension liability (net of tax benefit of $38 million)	(66)		
Unrealized losses on securities:			
Unrealized holding loss arising during period		(11)	(8)
Less: reclassification adjustments for losses realized in net loss	7	12	
Net unrealized gains (losses)	7	1	(8)
Other comprehensive loss, net of tax	(28)	(12)	(15)
Comprehensive income (loss)	$ (2,765)	$ 394	$ 421

See Notes to Consolidated Financial Statements

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(RESTATED)

PLEASE NOTE THAT THESE FINANCIAL STATEMENTS AND THE NOTES THERETO DO NOT REFLECT EVENTS OCCURRING AFTER APRIL 11, 2003 (THE DATE OF THE ORIGINAL FILING). FOR A DESCRIPTION OF THESE EVENTS, PLEASE READ OUR UNAUDITED EXCHANGE ACT REPORTS FILED SINCE APRIL 11, 2003, INCLUDING OUR QUARTERLY REPORT ON FORM 10-Q FOR THE QUARTER ENDED MARCH 31, 2003.

EXPLANATORY NOTE

This Amendment No. 1 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2002 (this Amendment No. 1) includes reclassifications of our consolidated financial statements relating to discontinued operations and segment reporting for each of the three years in the period ended December 31, 2002, additional pro forma disclosures relating to Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (Statement No. 143), for each of the three years in the period ended December 31, 2002 and disclosures related to restatements of our consolidated financial statements for each of the two years in the period ended December 31, 2001 as previously contained in Amendment No. 2 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2001 (as amended, the 2001 Form 10-K/A), which was filed on April 11, 2003. Specifically, the changes are as follows:

Reclassifications Discontinued Operations

Beginning with the first quarter 2003, we were required to account for our global communications and U.K. CRM businesses as discontinued operations in accordance with Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets (Statement No. 144). The financial information contained in this Amendment No. 1 includes the results of these businesses, from which we exited after December 31, 2002, as discontinued operations for all periods presented. Detailed information regarding the results of operations of these two businesses is located in Note 3 Dispositions, Discontinued Operations and Acquisitions Dispositions Discontinued Operations Global Communications beginning on page F-29 and Note 3 Dispositions, Discontinued Operations and Acquisitions Dispositions Discontinued Operations U.K. CRM beginning on page F-29. In addition, the following related changes have been made to our consolidated financial statements and the notes thereto:

Consolidated Statements of Operations on page F-4 amounts have been adjusted to reflect the operations of the global communications and U.K. CRM businesses in discontinued operations rather than continuing operations;

Note 2 Accounting Policies Revenue Recognition beginning on page F-21 amounts in the table reconciling revenues and cost of sales have been adjusted to reflect the operations of the global communications and U.K. CRM businesses in discontinued operations rather than continuing operations;

Note 4 Restructuring and Impairment Charges beginning on page F-33 the amounts by income statement caption of various restructuring and impairment items included in the table have been adjusted to reflect charges incurred by the global communications and U.K. CRM businesses in discontinued operations;

Note 12 Income Taxes beginning on page F-58 amounts have been adjusted to remove the tax expense (benefit) related to the discontinued operations of the global communications and U.K. CRM businesses;

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Note 18 Segment Information beginning on page F-85 total segment results of operations have been adjusted to reflect the operations of the global communications and U.K. CRM businesses in discontinued operations rather than continuing operations; and

Note 19 Quarterly Financial Information (Unaudited) beginning on page F-90 quarterly revenues and operating income have been adjusted to remove the results of the global communications and U.K. CRM businesses.

Reclassifications Revised Segments

Beginning January 1, 2003, we revised our reporting segment structure. Our segment information for all periods included in this Amendment No. 1 has been presented based on this revised reporting segment structure. Detailed information regarding this revised reporting segment structure is located in Note 18 Segment Information beginning on page F-85. In addition, the following related changes have been made to our consolidated financial statements and the notes thereto:

Note 8 Unconsolidated Investments beginning on page F-42 the summary has been adjusted to reflect the revised reporting segment structure;

Note 9 Goodwill beginning on page F-45 the amounts in the table showing changes in the carrying amount of goodwill have been adjusted for the revised reporting segment structure;

Note 18 Segment Information beginning on page F-85 segment results of operations have been adjusted to reflect the revised reporting segment structure; and

Segment references throughout the financial statements have been conformed to the revised reporting segment structure.

FAS 143 Pro Forma Disclosures

On January 1, 2003, we adopted Statement No. 143. We have added unaudited pro forma financial information related to the adoption. Please see Note 2 Accounting Policies Other Contingencies beginning on page F-19.

Restatement Disclosures

This Amendment No. 1 includes disclosures relating to the restatement of our consolidated financial statements for each of the two years in the period ended December 31, 2001. These disclosures were previously included in the 2001 Form 10-K/A. The restatements relate to the following items:

- the Project Alpha structured natural gas transaction,
- a balance sheet reconciliation project relating principally to our natural gas marketing business,
- corrections to our previous hedge accounting for certain contracts resulting in accounting for these contracts pursuant to the mark-to-market method under Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (Statement No. 133); in addition, we determined that we had incorrectly accounted for certain derivative transactions prior to the adoption of Statement No. 133,
- the valuation used in our 2000 acquisition of Extant, Inc.,

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

the restatement of our forward power curve methodology to reflect forward power and market prices more closely,

the recognition of additional assets, accrued liabilities and debt associated with certain lease arrangements, as well as depreciation and amortization expense for the related assets,

a correction to the measurement date relating to the implied dividend we previously recorded related to the in-the-money beneficial conversion option in the $1.5 billion in Series B preferred stock issued to ChevronTexaco Corporation in November 2001,

the recognition of an other-than-temporary decline in value of a technology investment in the third quarter of 2001 rather than the second quarter of 2002,

corrections to our previous accounting for income taxes, and

other adjustments that arose during the re-audit of our 1999-2001 financial statements.

Quarterly information in this Explanatory Note is unaudited. Specifically, the restatements are as follows:

Project Alpha. We entered into the Project Alpha structured natural gas transaction in April 2001. As described in a Current Report on Form 8-K dated April 25, 2002 (the Alpha Form 8-K), we restated the cash flow associated with the related gas supply contract as a financing activity in our Consolidated Statement of Cash Flows for 2001. The effect of this restatement was to reclassify approximately $290 million of previously disclosed 2001 operating cash flow to financing cash flow. Following the disclosure in the Alpha Form 8-K and in connection with a further review of Project Alpha, Arthur Andersen LLP (Andersen) informed us that it could no longer support its tax opinion relating to the transaction. Andersen s change in position was based in part on its conclusion that the reclassification of cash flow from operations to cash flow from financing lessened the factual basis for the opinion. Our financial statement recognition of the tax benefit in 2001 was based principally on our assessment of the relevant issues, as corroborated by Andersen s tax opinion. After the withdrawal of Andersen s tax opinion, we concluded that sufficient support to include the income tax benefit for financial statement presentation purposes no longer existed, the effect of which was a reversal of approximately $79 million ($0.23 per diluted share) of tax benefit we previously recognized during the 2001 period. Andersen further advised us that its audit opinion relating to 2001 should no longer be relied upon as a result of the pending restatements relating to Project Alpha and such audit opinion has been withdrawn. We subsequently concluded that our 2001 restated consolidated financial statements would include the consolidation of ABG Gas Supply, LLC (ABG), one of the entities formed in connection with the transaction. The consolidation of ABG is included herein based on compilations of financial information received from an agent of ABG s equity holders. The most significant impact of this consolidation is to increase our consolidated indebtedness by approximately $280 million and to increase net risk management assets by $340 million, in each case at December 31, 2001. This $340 million increase reflects the recognition of ABG s net risk-management assets on our Consolidated Balance Sheet.

The table below reflects the quarterly and year-to-date impact of the Project Alpha restatements on net income as originally reported:

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Months Ended December 31	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
				($ in millions)			
2001	$ —	$ (27)	$ (36)	$ (16)	$ (27)	$ (63)	$ (79)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

***Balance Sheet Reconciliation Project*.** We recognized an after-tax charge of approximately $80 million ($124 million pre-tax) in the second quarter 2002 related to a balance sheet reconciliation project undertaken by us at the beginning of 2002. The charge related principally to our natural gas marketing business and was associated with the process of reconciling accrued to actual results. Accrual accounting for natural gas marketing involves the estimation of gas volumes bought, sold, transported and stored, as well as the subsequent reconciliation of estimated to actual volumes. We have restated our financial statements to allocate this $80 million charge from the second quarter 2002 back to the periods in which the transactions giving rise to the charge originally occurred. The table below reflects the impact on net income of this restatement.

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Months Ended December 31	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
				($ in millions)			
1999 and prior							$ (29)
2000	$ (7)	$ 3	$ 1	$ (35)	$ (4)	$ (3)	(38)
2001	22	(18)	(4)	(26)	4		(26)
2002	4	9			13	13	13
Total Re-allocation							$ (80)

The restatement decreased diluted earnings per share by $0.08 and decreased diluted earnings per share by $0.12 for the years ended December 31, 2001 and 2000.

***Corrected Hedge Accounting*.** We adopted Statement No. 133 effective January 1, 2001 and reflected certain contracts as cash flow hedges upon such adoption. Management has subsequently determined that following the initial adoption of Statement No. 133, the documentation of compliance requirements under the standard, particularly as it relates to documentation and the periodic assessment of hedge effectiveness, was inadequate to support the accounting method previously applied. In addition, we determined that we had incorrectly accounted for certain derivative transactions prior to the adoption of Statement No. 133. The resulting restatement reflects the accounting for these contracts on a mark-to-market basis rather than on the deferred basis previously employed. The correction in the accounting method for these contracts increased previously reported 2001 net income by approximately $45 million ($0.13 per diluted share) and decreased previously reported 2000 net income by approximately $19 million ($0.06 per diluted share). This correction had no impact on previously reported cash flows from operations in any period.

The table below reflects the impact of this restatement on net income as originally reported:

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Months Ended December 31	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
	($ in millions)						
1999 and prior							$ 2
2000	$ 19	$ 14	$ (14)	$ (38)	$ 33	$ 19	(19)
2001	15	(12)	5	37	3	8	45

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Valuation of Extant, Inc. Purchase. On September 29, 2000, we completed the acquisition of Extant, Inc., a privately held entity engaged in the communications business. The transaction was accounted for as a purchase. In 2000, we incorrectly valued the shares of Class A common stock issued as consideration for the acquisition at $49.59 per share, rather than $36.59 per share, which amount represented the average share price during the five days surrounding the announcement of the acquisition. The $49.59 per share originally utilized in the valuation was incorrectly based on the average closing price of our Class A common stock during the 30 days prior to the closing date, which was consistent with the valuation provisions in the merger agreement. As a result, the purchase price allocated to the assets acquired and liabilities assumed in the purchase was overstated by approximately $23 million in 2000. This error resulted in an overstatement of the amortization of goodwill acquired in the transaction during 2001 and 2000. The resulting restatement reflects an increase in net income in 2001 and 2000 by approximately $1 million and approximately $300,000, respectively. Additionally, as a result of this error, we overstated by $22 million the impairment of goodwill recorded in 2002 associated with our January 1, 2002 adoption of Statement of Financial Accounting Standard No. 142, Goodwill and Other Intangible Assets.

Restated Forward Power Curve Methodology. We value substantially all of our natural gas marketing, power marketing and portions of our natural gas liquids marketing operations under a mark-to-market accounting methodology. The estimated fair value of the marketing and trading portfolio is computed by multiplying all existing positions in the portfolio by estimated prices, reduced by a LIBOR-based time value of money adjustment and deduction of reserves for credit, price and market liquidity risks. We use a combination of market quotes, derivatives of market quotes and proprietary models to periodically value this portfolio as required by generally accepted accounting principles. Market quotes are used for near-term transactions, where such quotes are generally available; derivatives of market quotes are used for mid-term transactions, where broker quotes are only marginally available; and proprietary models are used for long-term transactions, where broker quotes or other objective pricing indicators typically are not available. Beginning in the third quarter 2001, we began to enter into longer-term power transactions in the United States with respect to which no broker quotes or other market data was available; consequently, we applied a proprietary model to estimate forward prices and, in turn, the fair market value of these longer-term power transactions.

During January 2003, in connection with the re-audit of our 1999-2001 financial statements and an assessment of various accounting policies, we reconsidered the model-based methodology used to value the portions of our power marketing and trading portfolio for which broker quotes were not available. Under our prior methodology, forward curves used to calculate the value of our long-term U.S. power contracts were derived from a proprietary model based on a required rate of return on investments in new generation facilities. This methodology had been confirmed by our former independent auditors prior to the withdrawal of their audit opinion for unrelated matters. The primary disadvantage of this methodology is that, in certain circumstances, it may not reflect true market prices in future years. After reconsidering the appropriateness of this methodology in light of changing industry circumstances and in connection with the re-audit, in late January 2003 we determined that, beginning with the third quarter 2001, a different forward power curve methodology would more appropriately reflect the value of our long-term power contracts.

Upon making this determination, we corrected the forward power curve methodology we used to estimate the fair market value of our U.S. power marketing and trading portfolio. This corrected methodology incorporates forward energy prices derived from broker quotes and values from executed transactions to estimate forward price curves for periods where broker quotes and transaction data cannot be obtained. Further, we determined that in order to adequately reflect our results, it was appropriate to restate our prior period financial statements, beginning with the third quarter 2001, to reflect the corrected methodology.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

This correction in the methodology resulted in a $94 million ($0.28 per diluted share) reduction to previously reported 2001 net income.

The table below reflects the impact of this restatement on net income as originally reported:

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Months Ended December 31	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
	($ in millions)						
2001	$	$	$ (25)	$ (69)	$	$ (25)	$ (94)

Restated Lease Accounting. We previously accounted for seven generation lease arrangements and one communications lease arrangement as operating leases. Our previous accounting treatment of these lease arrangements, which was confirmed by our former independent auditors prior to the withdrawal of their audit opinion for unrelated matters, reflected our belief that these arrangements satisfied the applicable generally accepted accounting principles (GAAP) requirements so as to justify their treatment as operating leases. However, these requirements are very technical and subject to a high degree of interpretation. During the course of the re-audit of our financial statements for 1999-2001, we analyzed our accounting for these arrangements and considered a variety of factors, including interpretations of the applicable GAAP requirements. Upon completion of this analysis and discussions with PricewaterhouseCoopers LLP, in January 2003, we determined it was necessary to correct our accounting for these lease arrangements to recognize on our balance sheet the related assets as of the inception of six of these arrangements. Although we previously amended the agreements relating to six generation lease arrangements so as to require them to be treated as capital leases in the second quarter 2002, the restatement of the accounting originally applied to these arrangement results in the recognition of the related assets as of an earlier date. Consequently, our previously reported net income for 2001 is reduced by approximately $9 million ($0.03 per diluted share), reflecting the recognition of depreciation and amortization expenses associated with the related assets. In addition, balance sheet amounts have been adjusted for this change as follows:

	December 31 2001
	($ in millions)
Restricted cash	$ 17
Property, plant and equipment	1,094
Accrued liabilities and other	(445)
Long-term debt	(666)

Please read Note 10 Debt Generation Facility Capital Lease, beginning on page F-53, for further discussion.

The table below reflects the impact of this restatement on net income as originally reported:

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Months Ended December 31	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
	($ in millions)						
2001	$	$	$ (2)	$ (7)	$	$ (2)	$ (9)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Change in Implied Preferred Dividends. In November 2001, we issued $1.5 billion in Series B preferred stock to ChevronTexaco. This preferred stock is convertible by ChevronTexaco into shares of our Class B common stock at a conversion price of $31.64. This conversion price represents an approximate 5% discount to our stock price on November 7, 2001, the date the conversion price was negotiated. Based on the implied value of this beneficial conversion option as of November 7, we recognized a $65 million preferred stock dividend to be amortized over the two-year period leading up to the mandatory redemption date for the shares. During the course of the three-year re-audit, we analyzed our accounting for the beneficial conversion option and determined it necessary to correct the commitment date used for valuing this beneficial conversion option to November 13, 2001, the date ChevronTexaco funded and consummated its preferred stock purchase and the preferred securities were issued. Our stock price increased significantly between November 7 and November 13 after the announcement of the proposed Enron Corp. merger. As a result of the increase in the implied value of ChevronTexaco s beneficial conversion option, the restated preferred stock dividend amount is calculated based on a two-year amortization of the beneficial conversion option s implied value of approximately $660 million an increase of approximately $595 million over the $65 million originally reported. Net income available to common stockholders as originally reported for 2001 is accordingly reduced by approximately $39 million ($0.11 per diluted share) as a result of this commitment date change.

The table below reflects the impact of this restatement on net income available to common stockholders as originally reported. The adjustment had no impact on net income or cash flows.

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Months Ended December 31	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
				($ in millions)			
2001	$	$	$	$ (39)	$	$	$ (39)

Valuation of Technology Investment. We acquired the common stock of a technology investment in the second quarter 2000. In the second quarter 2002, after several quarters of declines in the market price of the investment, we determined that the decline in value was other-than-temporary. As such, we recognized a $12 million after-tax charge ($0.04 per diluted share) during the second quarter 2002. Upon further review, we determined that we incorrectly delayed recognition of the charge associated with this investment, as the decline in value through September 30, 2001 met the other-than-temporary threshold. Therefore, we have restated the financial statements to record the impairment in the third quarter 2001.

The table below reflects the impact of this restatement on net income as originally reported:

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Months Ended December 31	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
				($ in millions)			
2001	$	$	$ (12)	$	$	$ (12)	$ (12)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Correction for Income Taxes. During the course of the re-audit of our 1999-2001 financial statements, we determined that we made errors in accounting for certain tax matters. These errors related to book-tax basis differences that were reflected as permanent differences as opposed to temporary differences, the failure to record differences between the amounts recognized as income tax provision and the amounts actually reflected in the applicable income tax returns, adjustments related to book and tax-basis balance sheet reconciliations and changes in estimates of tax contingencies. We have restated our financial statements to correct these errors, resulting in additional deferred tax expense as further detailed below.

The table below reflects the impact of these restatements on net income as originally reported:

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Months Ended December 31	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
1999 and prior							$ (21)
2000	$ (7)	$	$	$ (5)	$ (7)	$ (7)	(12)
2001	(5)	(3)	(3)	(26)	(8)	(11)	(37)

Other Adjustments Arising During the Re-Audit. We have restated our 1999-2001 financial statements to correct various errors in our historical financial statements that we discovered during the course of the re-audit. These restatements, which principally relate to the timing on which various transactions were recorded in the ordinary course of business, result in increases (reductions) to previously reported 2001 and 2000 net income of approximately $(30) million ($(0.09) per diluted share) and $4 million ($0.01 per diluted share), respectively.

The table below reflects the impact of these restatements on net income as originally reported:

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Months Ended December 31	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
				($ in millions)			
1999 and prior							$ (22)
2000	$ 9	$ 3	$ (13)	$ 5	$ 12	$ (1)	4

2001	(16)	(47)	29	4	(63)	(34)	(30)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

The following table reconciles selected financial data as reported in various filings:

	Form 10-K filed March 13, 2002	Adjustment and Reclassification(2)	Form 8-K filed November 14, 2002	Adjustment	Form 8-K filed January 31, 2003(1)	Adjustment	Form 10-K/ A filed February 14, 2003	Adjustment and Reclassification(3)	Form 10-K/A filed April 11, 2003(4)
	($ in millions, except earnings (losses) per diluted share)								
Selected Balance Sheet Data									
December 31, 2001									
Current Assets	$ 9,507	$ 437	$ 9,944			$ 40	$ 9,984	$ (1,028)	$ 8,956
Total Assets	24,874	841	25,715			586	26,301	(1,133)	25,168
Current Liabilities	8,555	637	9,192			414	9,606	(1,068)	8,538
Total Liabilities	17,396	1,016	18,412			707	19,119	(1,056)	18,063
Stockholders Equity	4,719	(185)	4,534			480	5,014	(77)	4,937
Results of Operations									
Year ended December 31, 2001									
Net Income (Loss)	$ 648	$ (109)	$ 539	$ (107)	$ 432	$ (11)	$ 421	$ (15)	$ 406
Net Income (Loss) Applicable to Common Stockholders	645	(109)	536	(145)	391	(12)	379	(15)	364
Earnings (Losses) Per Diluted Share	$ 1.90	$ (0.32)	$ 1.58	$ (0.43)	$ 1.15	$ (0.04)	$ 1.11	$ (0.04)	$ 1.07
Year ended December 31, 2000									
Net Income (Loss)	$ 501	$ (17)	$ 484			$ 10	$ 494	$ (58)	$ 436
Net Income (Loss) Applicable to Common Stockholders	466	(17)	449			10	459	(58)	401
Earnings (Losses) Per Diluted Share	$ 1.48	$ (0.05)	$ 1.43			$ 0.03	$ 1.46	$ (0.19)	$ 1.27
Selected Cash Flow Data									
Year ended December 31, 2001									
Operating Cash Flow	$ 811	$ (291)	$ 520			$ 15	$ 535	$ 15	$ 550
Investing Cash Flow	(3,413)		(3,413)			(423)	(3,836)	8	(3,828)
Financing Cash Flow	2,734	291	3,025			423	3,448	2	3,450
Year ended December 31, 2000									
Operating Cash Flow	$ 438	$	$ 438			$ (28)	$ 410	$ 10	$ 420
Investing Cash Flow	(1,304)		(1,304)			(254)	(1,558)	19	(1,539)
Financing Cash Flow	907		907			237	1,144	(13)	1,131

(1) The Form 8-K filed January 31, 2003 only included 2001 results of operations data. As a result, the only adjustments associated with such Form 8-K relate to 2001 results of operations.
(2) This column includes increases to the December 31, 2001 balances of current assets, total assets, current liabilities and total liabilities of $223 million, $301 million, $314 million and $313 million, respectively and a decrease to stockholders equity of $12 million related to reclassifications to the December 31, 2001 balance sheet to conform to December 31, 2002 balance sheet classifications.
(3) This column includes increases (decreases) to the operating cash flow, investing cash flow and financing cash flow data of $15 million, $8 million and $2 million, respectively, for the year ended December 31, 2001 and $30 million, $(1) million and $(13) million, respectively, for the year ended December 31, 2000 to conform to cash flow classifications for the year ended December 31, 2002.
(4) There have not been any changes to this data since Amendment No. 2 to the 2001 Form 10-K/A was filed April 11, 2003.

Please read Note 19 Quarterly Financial Information (Unaudited), beginning on page F-90, for a discussion of our 2002 quarterly financial statements, which reflect restatements of the financial statements included in our 2002 Quarterly Reports on Form 10-Q as originally filed. On May 14, 2003, we filed amended 2002 Quarterly Reports on Form 10-Q to reflect these restatements.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

NOTE 1 ORGANIZATION AND OPERATIONS OF THE COMPANY

Dynegy Inc. (together with our subsidiaries, we , us or our) is a holding company and conducts substantially all of its business through its subsidiaries. We own operating divisions engaged in power generation, natural gas liquids and regulated energy delivery. Prior to January 1, 2003, we had four reportable business segments: Wholesale Energy Network (WEN), Dynegy Midstream Services (DMS), Transmission and Distribution (T&D) and Dynegy Global Communications (DGC). Our operating segments for 2003 include Power Generation (GEN) , Natural Gas Liquids (NGL) , Regulated Energy Delivery (REG) and Customer Risk Management (CRM). Reportable segments in this report conform to the current segment presentation. We determined to report our results in these four business segments based on the diversity of their respective operations.

NOTE 2 ACCOUNTING POLICIES

Our accounting policies conform to generally accepted accounting principles in the United States of America (GAAP). Our more significant accounting policies are described below. The preparation of consolidated financial statements in conformity with GAAP requires management to develop estimates and to make assumptions that affect reported financial position and results of operation. These estimates and assumptions also impact the nature and extent of disclosure, if any, of contingent assets and liabilities. We review significant estimates affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. Judgments and estimates are based on our beliefs and assumptions derived from information available at the time such estimates are made. Adjustments made with respect to the use of these estimates often relate to information not previously available. Uncertainties with respect to such estimates and assumptions are inherent in the preparation of financial statements. Estimates are primarily used in (1) developing fair value assumptions, including estimates of future cash flows and discounts rates, (2) analyzing tangible and intangible assets for impairment, (3) estimating the useful lives of our assets, (4) assessing future tax exposure and the realization of tax assets, (5) determining the amounts to accrue related to contingencies and (6) the estimate of various factors impacting the valuation of our pension assets. Actual results could differ materially from any such estimates.

***Principles of Consolidation*.** The accompanying consolidated financial statements include our accounts and the accounts of our majority-owned or controlled subsidiaries, and our proportionate share of assets, liabilities, revenues and expenses of undivided interests in certain gas processing facilities, after elimination of intercompany accounts and transactions. Certain reclassifications have been made to prior-period amounts to conform with current-period financial statement classifications.

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

Restricted Cash. Restricted cash represents cash that is unavailable for general purpose cash needs. Included in restricted cash are amounts that have been reserved for use in retiring IP s Transitional Funding Trust Notes and cash received in excess of disbursements relating to a lease arrangement affecting our U.S. fiber optic network. These items are further discussed in Note 10 Debt beginning on page F-47.

Allowance for Doubtful Accounts. We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of the outstanding balance. We review collectibility and establish or adjust our allowance as necessary using the specific identification method.

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(RESTATED)

***Investment in Unconsolidated Affiliates*.** Investments in affiliates in which we have a significant ownership interest, generally 20 percent to 50 percent, are accounted for by the equity method. Prior to our adoption on January 1, 2002 of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets (Statement No. 142), any excess of our investment in affiliates was amortized over the estimated economic service lives of the underlying assets. Other investments less than 20 percent owned with readily determinable fair value are considered available-for-sale and are recorded at quoted market value or at the lower of cost or net realizable value, if there is no readily determinable fair value. For securities with a readily determinable fair value, the change in the unrealized gain or loss, net of deferred income tax, is recorded as a separate component of accumulated other comprehensive income (loss) in the consolidated statements of comprehensive income (loss). Realized gains and losses on investment transactions are determined using the specific identification method. These investments are periodically assessed for other-than-temporary declines in value, with related charges recognized within earnings (losses) of unconsolidated investments in the consolidated statements of operations.

***Concentration of Credit Risk*.** We provide multiple energy commodity solutions principally 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, in that the customer base may be similarly affected by changes in economic, industry, weather or other conditions.

***Inventories*.** Inventories consisted primarily of natural gas in storage of $49 million and $50 million, NGLs of $40 million and $49 million, coal of $49 million and $62 million and crude oil of $10 million and $19 million at December 31, 2002 and 2001, respectively. Such inventory is valued at the lower of weighted average cost or at market. Materials and supplies inventory of $88 million and $76 million at December 31, 2002 and 2001, respectively, is carried at the lower of cost or market using the specific identification method.

***Property, Plant and Equipment*.** Property, plant and equipment, which consists principally of gas gathering, processing, fractionation, terminaling and storage facilities, natural gas transportation and electric transmission lines, pipelines, power generating facilities and communications 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 facilities in operating condition are expensed. Depreciation is provided using the straight-line method over the estimated economic service lives of the assets, ranging from three to 50 years. Composite depreciation rates are applied to functional groups of property having similar economic characteristics. The estimated economic service lives are as follows:

Asset Group	Range of Years
Natural Gas Gathering Systems and Processing Facilities	14 to 25
Power Generation Facilities	27 to 40
Transportation Equipment	7 to 10

Regulated Assets	15 to 50
Buildings and Improvements	10 to 40
Office and Miscellaneous Equipment	3 to 35
Storage Assets	14 to 25

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(RESTATED)

Gains and losses are not recognized for retirements of property, plant and equipment subject to composite depreciation rates (composite rate) until the asset group subject to the composite rate is retired. Gains and losses on the sale of individual assets are reflected in loss (gain) on sale of assets in the consolidated statements of operations. Through December 31, 2001, we reviewed the carrying value of our long-lived assets in accordance with provisions of Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed of (Statement No. 121). In August 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets (Statement No. 144). Statement No. 144 addresses the accounting and reporting for the impairment or disposal of long-lived assets and supersedes Statement No. 121 and APB Opinion No. 30, Reporting the Results of Operations Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions. Under this standard, we evaluate an asset for impairment when events or circumstances indicate that a long-lived asset s carrying value may not be recovered. These events include market declines, changes in the manner in which we intend to use an asset or decisions to sell an asset and adverse changes in the legal or business environment. When we decide to exit or sell a long-lived asset or group of assets, we adjust the carrying value of these assets downward, if necessary, to the estimated sales price, less costs to sell. Our adoption of Statement No. 144 on January 1, 2002 did not have any impact on our financial position or results of operations. See Note 4 Restructuring and Impairment Charges, beginning on page F-33, for a discussion of impairment charges we recognized in 2002.

Other Contingencies. Environmental costs relating to current operations are expensed or capitalized, as appropriate, depending on whether such costs provide future economic benefit. Liabilities are recorded when environmental assessment indicates that 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. Such liabilities may be recognized on a discounted basis if the amount and timing of anticipated expenditures for a site are fixed or reliably determinable; otherwise, such liabilities are recognized on an undiscounted basis. Environmental liabilities incurred by providing indemnification in connection with assets that are 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 environmental 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.

In June 2001, the FASB issued Statement No. 143. We adopted this Statement effective January 1, 2003. Statement No. 143 provides accounting requirements for costs associated with legal obligations to retire tangible, long-lived assets. Under Statement No. 143, the asset retirement obligation is recorded at fair value in the period in which it is incurred by increasing the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the related asset. Effective upon our adoption, the cumulative effect of applying Statement No. 143 will be recognized as a change in accounting principle in the consolidated statements of operations.

As part of the transition adjustment in adopting Statement No. 143, existing environmental liabilities in the amount of $73 million were reversed. The fair value of the remediation costs estimated to be incurred upon retirement of the respective assets is included in the asset retirement obligation and was recorded upon adoption of Statement No. 143. As such, we expect the impact of adopting Statement No. 143 will be an increase in earnings, net of tax, of approximately $33 million, to be reflected as a cumulative effect of a change in accounting principle in the first quarter 2003. The annual amortization of the asset created under this standard and the accretion of the liability to its fair value is estimated to be approximately $6 million in 2003. In addition

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(RESTATED)

to these liabilities, we also have potential retirement obligations for the dismantlement of power generation facilities, power transmission assets, a fractionation facility and natural gas storage facilities. It is our intent to maintain these facilities in a manner such that the facilities will be operational indefinitely. As such, we cannot estimate any potential retirement obligations associated with these assets. At the time we are able to estimate any new asset retirement obligations, liabilities will be recorded in accordance with Statement No. 143.

The following unaudited pro forma financial information has been prepared to give effect to the adoption of Statement No. 143 as if it had been adopted on January 1, 2000:

	Years Ended December 31,		
	2002	2001	2000
	(in millions)		
Income (loss) from continuing operations, as reported	$ (1,349)	$ 486	$ 409
Pro forma adjustments to reflect retroactive adoption of Statement No. 143	(6)	(5)	(5)
Pro forma income (loss) from continuing operations	$ (1,355)	$ 481	$ 404
Income (loss) before cumulative effect of change in accounting principle, as reported	$ (2,503)	$ 404	$ 436
Pro forma adjustments to reflect retroactive adoption of Statement No. 143	(6)	(5)	(5)
Pro forma income (loss) before cumulative effect of change in accounting principle	$ (2,509)	$ 399	$ 431
Net income (loss), as reported	$ (2,737)	$ 406	$ 436
Pro forma adjustments to reflect retroactive adoption of Statement No. 143	(4)	(3)	(3)
Pro forma net income (loss)	$ (2,741)	$ 403	$ 433

	2002		2001		2000	
	As	Pro	As	Pro	As	Pro

	Reported	Forma	Reported	Forma	Reported	Forma
Basic earnings (loss) per share						
Income (loss) from continuing operations	$ (4.59)	$ (4.60)	$ 1.37	$ 1.36	$ 1.24	$ 1.23
Income (loss) from discontinued operations	(3.15)	(3.15)	(0.26)	(0.26)	0.09	0.09
Cumulative effect of change in accounting principle, net	(0.64)	(0.64)	0.01	0.01		
Basic earnings (loss) per share	$ (8.38)	$ (8.39)	$ 1.12	$ 1.11	$ 1.33	$ 1.32
Diluted earnings (loss) per share						
Income (loss) from continuing operations	$ (4.59)	$ (4.60)	$ 1.31	$ 1.30	$ 1.18	$ 1.17
Income (loss) from discontinued operations	(3.15)	(3.15)	(0.25)	(0.25)	0.09	0.09
Cumulative effect of change in accounting principle, net	(0.64)	(0.64)	0.01	0.01		
Diluted earnings (loss) per share	$ (8.38)	$ (8.39)	$ 1.07	$ 1.06	$ 1.27	$ 1.26

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(RESTATED)

The following table presents the detail of our asset retirement obligations which would have been included in other long-term liabilities in our consolidated balance sheet if Statement No. 143 had been adopted on January 1, 2000 (in millions):

	2002	2001	2000
Balance, beginning of year	$ 36	$ 30	$ 10
Liabilities incurred	1	2	17
Accretion expense	4	4	3
Balance, end of year	$ 41	$ 36	$ 30

Liabilities for other contingencies are recognized in accordance with Statement No. 5 upon identification of an exposure, which when fully analyzed indicates that it is both probable that an asset has been impaired or that a liability has been incurred and that such 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. When a range of probable loss exists, we accrue the lesser end of the range.

Goodwill and Other Intangible Assets. Prior to January 1, 2002, intangible assets, principally goodwill, were amortized on a straight-line basis over their estimated useful lives of 25 to 40 years. However, effective January 1, 2002, we adopted Statement No. 142 and, accordingly, we discontinued amortizing goodwill. In accordance with Statement No. 142, we subject goodwill to a fair value-based impairment test on at least an annual basis. As further discussed in Note 9 Goodwill beginning on page F-45, the adoption of Statement No. 142 and the resulting impairment test caused us to recognize a $234 million charge in our communications business associated with the cumulative effect of implementing this standard and an additional $897 million impairment in 2002 related to the CRM and GEN segments. 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. Accordingly, if conditions change in the future, we may record further impairment losses on an annual basis, absent any specific impairment indicators. We expect to perform our annual impairment test in the fourth quarter after the annual budgetary process.

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 appropriateness of application of one comprehensive accounting model over the other in accounting for our varied operations based on guidance provided by the FASB or the SEC.

The accrual model has historically been used to account for substantially all of the operations conducted in the GEN, NGL and REG segments. Ownership and operation of physical assets characterize these businesses. We use these physical assets in various generation, processing and delivery operations. These operations include the generation of electricity, the separation of natural gas liquids into their component parts from a stream of natural gas, the transportation or transmission of commodities through pipelines or over transmission lines and the delivery of data and voice bits over communication networks. End sales from these businesses result in physical delivery of commodities or services to our wholesale, commercial and industrial and retail customers.

Revenues for product sales and gas processing and marketing services are recognized when title passes to the customer or when the service is performed. Fractionation and transportation revenues are recognized based on volumes received in accordance with contractual terms. Revenues derived from power generation are

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

recognized upon output, product delivery or satisfaction of specific targets, all as specified by contractual terms. Our transmission and distribution revenues are recognized when services are provided to customers. Shipping and handling costs are included in revenue when billed to customers in conjunction with the sale of products.

Revenues derived from communications activities are recognized in the month in which the service is provided. Amounts billed in advance of providing services are recorded as unearned revenue until the period in which such services are either provided or expire unused. Revenue related to installation of service is recognized when equipment is delivered.

The fair value model is used to account for certain forward physical and financial transactions in the GEN, CRM and NGL segments, which meet criteria defined by the FASB or the Emerging Issues Task Force (EITF). These criteria require these contracts to be related 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 its equivalent. As these transactions may be settled in cash, 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. The net gains or losses resulting from the revaluation of these contracts during the period are recognized currently in our results of operations. Assets and liabilities associated with these transactions are reflected on our balance sheet as risk-management assets and liabilities, classified as short-term (i.e., current) or long-term pursuant to each contract s individual length.

We estimate the fair value of our marketing portfolio using a liquidation value approach assuming that our ability to transact business in the market remains at historical levels. The estimated fair value of our portfolio is computed by multiplying all existing positions in our portfolio by estimated prices, reduced by a LIBOR-based time value of money adjustment and deduction of reserves for credit, price and market liquidity risks.

A key aspect of our historical operations and business strategy has been our ability to provide customers with competitively priced bundled products and services that address customer specific energy and risk management needs. Many of these customized products and services are not exchange-traded. In addition, the availability of reliable market quotations in certain regions and for certain commodities is limited as a result of liquidity and other factors. We use a combination of market quotations, derivatives of market quotations and proprietary models to periodically value our portfolio as required by generally accepted accounting principles. Market quotations are validated against broker quotes, regulated exchanges or third-party information. Derivatives of market quotations use validated market quotes, such as actively traded natural gas or power prices, as key inputs in determining market valuations.

In certain markets or for certain products, market quotes or derivatives of market quotes are not available or are not considered appropriate valuation techniques as a result of the newness of markets or products, a lack of liquidity in such markets or products or other factors. However, under GAAP, estimating the value of these types of contracts is required. Consequently, prior to the third quarter 2001, we used models principally derived from market research to estimate forward price curves for valuing positions in these markets. Our models generated pricing estimates primarily for regional power markets in the United States and Europe. Price curves were derived by incorporating a number of factors, including broker quotes, near-term market indicators and a proprietary model based on a required rate of return on investment in new generation facilities. Power prices under this model, over the long term, would thus reflect the cost of building new gas fired generation, the cost of natural gas fuel and a cost of capital return on new construction investment.

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During January 2003, in connection with the re-audit of our 1999-2001 financial statements and an assessment of various accounting policies, we reconsidered the model-based methodology utilized to estimate forward power curves based on the increasing term length of contractual arrangements within our U.S. power portfolio in the third quarter 2001. Based on this assessment, we corrected our methodology utilized to estimate forward U.S. power curves effective for the third quarter 2001. The corrected power curve methodology incorporates forward energy prices derived from broker quotes and values from executed transactions to develop mathematical forward price curves for periods where broker quotes and transaction data cannot be obtained. While we believe our corrected pricing model is based on reasonable and sound assumptions, the application of forecasted pricing curves to contractual commitments may result in realized cash return on these commitments that vary significantly, either positively or negatively, from the estimated values. Please read Explanatory Note Restatement Disclosures Restated Forward Power Curve Methodology beginning on page F-12 for further discussion.

During 2002, the EITF reached consensuses on several issues pursuant to Issue 02-03, Accounting for Contracts Involved in Energy Trading and Risk Management Activities (EITF Issue 02-03). First, all mark-to-market gains and losses on energy trading contracts, whether realized or unrealized, are required to be shown net in the income statement, irrespective of whether the contract is physically or financially settled. We had historically classified net unrealized gains and losses from energy trading contracts as revenue in our consolidated statements of operations. Physical transactions that were realized and settled were previously reflected gross in revenues and costs of sales. This change in accounting classification has no impact on operating income, net income, earning per share or cash flow from operations. In accordance with the transition provisions in the consensus, comparative period financial statements have been conformed to reflect this change in accounting principle.

The following table reconciles the revenues and costs of sales as previously reported in Amendment No. 2 to the amounts reported herein. Amounts in this table have been adjusted to reflect the reclassification of our global communications and U.K. CRM businesses to discontinued operations. For further information, please see Explanatory Note Reclassifications Discontinued Operations beginning on page F-8 ($ in millions):

	Year Ended December 31,	
	2001	**2000**
Revenues as previously reported	$ 42,613	$ 29,327
Discontinued operations	(952)	(1,035)
Change in accounting principle	(32,783)	(20,088)
Revenues as reported herein	$ 8,878	$ 8,204
Cost of sales as previously reported	$ 40,812	$ 27,934

Discontinued operations	(958)	(1,061)
Change in accounting principle	(32,783)	(20,088)
Cost of sales as reported herein	$ 7,071	$ 6,785

Second, in October 2002, the EITF reached a consensus to rescind EITF Issue 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities (EITF 98-10), which was the guidance requiring us to use mark-to-market accounting for our energy trading contracts. While the rescission of EITF 98-10 will reduce the number of contracts accounted for on a mark-to-market basis, it does not eliminate

DYNEGY INC.

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(RESTATED)

mark-to-market accounting. All derivative contracts that either do not qualify, or are not designated, as hedges will continue to be marked-to-market in accordance with Statement of Financial Accounting Standard No. 133, Accounting for Derivative Instruments and Hedging Activities (Statement No. 133). Any earnings/losses previously recognized under EITF 98-10 that would not have been recognized under Statement No. 133 will be reversed in the first quarter 2003 as a cumulative effect of a change in accounting principle. The first quarter pre-tax income is expected to be approximately $35 million, primarily reflecting losses previously recognized prior to the settlement of power tolling arrangements offset by the reversal of mark-to-market earnings previously recognized prior to the settlement of natural gas storage contracts, transportation contracts and retail power sales.

A third issue addressed by the EITF in EITF Issue 02-03 deals with the recognition of unrealized gains and losses at inception of an energy trading contract (commonly referred to as dealer profit). The EITF did not reach a consensus on this issue.

We have historically entered into financial instrument contracts to hedge purchase and sale commitments, fuel requirements and inventories in our natural gas liquids, electricity and coal businesses in order to minimize the risk of changes in market prices in these commodities. We also monitor our exposure to fluctuations in interest rates and foreign currency exchange rates and may execute swaps, forward-exchange contracts or other financial instruments to manage these exposures. Gains and losses from hedging transactions are recognized in income in the periods for which the underlying commodity, interest rate or foreign currency transaction impacts earnings in the same line item as the underlying transaction on the consolidated statements of operations. If the underlying contract being hedged by the commodity, interest rate or foreign currency transaction is disposed of or otherwise terminated, the gain or loss associated with such contract is no longer deferred and is recognized in the period the underlying contract is eliminated. If the hedging transaction is terminated prior to the occurrence of the underlying transaction being hedged, the gain or loss associated with the hedging transaction is deferred and recognized in income in the period in which the underlying transaction being hedged occurs.

Cash inflows and outflows associated with the settlement of risk management activities are recognized in operating cash flows.

Income Taxes. We file a consolidated United States federal income tax return and, for financial reporting purposes, provide income taxes for the difference in the tax and financial reporting bases of our assets and liabilities in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes.

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 dilutive potential common shares outstanding during the period. Dilutive potential common shares for 2002 and 2001 consisted of approximately 4 million and 10 million common shares subject to stock options and preferred stock convertible into approximately 48 million and 4 million common shares. For 2000, dilutive potential common shares consisted of stock options to purchase approximately 13 million common shares.

All common shares outstanding, price per share, dividends per share and earnings per share amounts relating to transactions or periods prior to August 22, 2000 have been restated for the two-for-one stock split effected by means of a stock dividend distributed on August 22, 2000.

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(RESTATED)

When an entity has a net loss from continuing operations, Statement of Financial Accounting Standards 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 year ended December 31, 2002, since the effect of assuming conversion of these shares would be anti-dilutive.

Foreign Currency Translations. 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 income and totaled gains of $4 million, losses of $18 million and gains of $36 million for the years ended December 31, 2002, 2001 and 2000, respectively.

Employee Stock Options. We apply the provisions of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (APB No. 25) and related interpretations in accounting for our stock compensation plans. Accordingly, compensation expense is not recognized for employee stock options unless the options were granted at an exercise price lower than the 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. Since 2001, no in-the-money stock options have been issued.

Had compensation cost been determined on a fair value basis consistent with Statement No. 123, our net income and per share amounts would have approximated the following pro forma amounts for the years ended December 31, 2002, 2001 and 2000, respectively:

	Years Ended December 31,		
	2002	2001	2000
	(in millions, except per share data)		
Net income (loss) as reported	$ (2,737)	$ 406	$ 436
Pro forma compensation cost	(76)	(58)	(16)
Pro forma net income (loss)	$ (2,813)	$ 348	$ 420

Basic earnings (loss) per share as reported	$ (8.38)	$ 1.12	$ 1.33
Pro forma compensation cost per basic share	(0.21)	(0.18)	(0.05)
Pro forma basic earnings (loss) per share	$ (8.59)	$ 0.94	$ 1.28
Diluted earnings (loss) per share as reported	$ (8.38)	$ 1.07	$ 1.27
Pro forma compensation cost per diluted share	(0.21)	(0.17)	(0.05)
Pro forma diluted earnings (loss) per share	$ (8.59)	$ 0.90	$ 1.22

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 2002, 2001 and 2000: dividends per year of $0.15 for 2002 and $0.30 per share for 2001 and 2000; expected volatility of 74.3 percent, 46.4 percent and 42.1 percent, respectively; a risk-free interest rate of 4.2 percent, 4.3 percent and 6.1 percent, respectively; and an expected option life of ten years for all periods. As stated previously, we account for our stock option plan in accordance with APB No. 25 and plan to transition to a fair value-based method of accounting for stock option plans. We will use the prospective method of transition as described in Statement No. 148.

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(RESTATED)

Regulatory Assets. Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (Statement No. 71) allows companies whose service obligations and prices are regulated to maintain balance sheet assets representing costs they expect to recover through inclusion in future rates. Illinois Power Company (IP), our wholly owned utility subsidiary, records regulatory assets in accordance with Statement No. 71. Regulatory assets represent probable future revenues associated with costs that are expected to be recovered from customers through the rate-making process. The significant components of regulatory assets at December 31, 2002 and 2001 were approximately $256 million and $336 million, respectively, and are included in other long-term assets on our consolidated balance sheets.

Rate regulated companies subject to Statement No. 71 are permitted to accrue the estimated cost of removal and salvage associated with certain of their assets through depreciation expense. The amounts accrued in depreciation are not associated with asset retirement obligations in accordance with Statement No. 143. We estimate that as of December 31, 2002, approximately $68.7 million of cost of removal, net of salvage, allowed under rate regulation is included in accumulated depreciation.

Minority Interest. Minority interest on the consolidated balance sheets includes third-party investments in entities that are not wholly-owned consolidated entities. The net pre-tax results attributed to minority interest holders in consolidated entities are classified in minority interest in the consolidated statements of operations. In addition, minority interest at December 31, 2001 included $867 million related to Catlin Associates LLC, an entity formed in connection with our Black Thunder financing, which was reclassified to debt during 2002. Please see Note 10 Debt DMG Secured Debt beginning on page F-53, for further discussion.

New Accounting Pronouncements. As noted above, in June 2001, the FASB issued Statement No. 143, which we adopted January 1, 2003. See further discussion above in Other Contingencies beginning on page F-19.

As noted above, during 2002 the EITF reached consensus on several issues pursuant to EITF Issue 02-03. See further discussion above in Revenue Recognition beginning on page F-21.

In April 2002, the FASB issued Statement of Financial Accounting Standards No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections (Statement No. 145). The adoption of Statement No. 145 effective January 1, 2003 is not expected to impact us.

In July 2002, the FASB issued Statement of Financial Accounting Standards No. 146, Accounting for Exit or Disposal Activities (Statement No. 146). Statement No. 146 addresses issues regarding the recognition, measurement and reporting of costs that are associated with exit and disposal activities, including restructuring activities that are currently accounted for pursuant to the guidance that the EITF has set forth in EITF

Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring). Statement No. 146 requires costs to be accrued as incurred rather than when an approved plan is in place. The scope of Statement No. 146 also includes (1) costs related to terminating a contract that is not a capital lease and (2) termination benefits that employees who are involuntarily terminated received under the terms of a one-time benefit arrangement that is not an ongoing benefit arrangement or an individual deferred compensation contract. Statement No. 146 will be effective for exit or disposal activities that are initiated after December 31, 2002, although early adoption of the standard is encouraged. If we had adopted Statement No. 146 early, $45 million of our fourth quarter 2002 restructuring charge (see discussion in Note 4 Restructuring and Impairment Charges Severance and Other Restructuring Costs beginning on page F-34) would have been recognized in future periods.

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In November 2002, the FASB issued Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (FIN 45). FIN 45 elaborates on the disclosures to be made by a guarantor about its obligations under certain guarantees. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. As required by FIN 45, we adopted the disclosure requirements on December 31, 2002 (see Note 3 Dispositions, Discontinued Operations and Acquisitions beginning on page F-27, Note 10 Debt beginning on page F-47 and Note 14 Commitments and Contingencies beginning on page F-62), and we will adopt the initial recognition and measurement provisions on a prospective basis for guarantees issued or modified after December 31, 2002. We believe the adoption of the recognition/measurement provisions will not have a material impact on our financial statements.

In December 2002, the FASB issued Statement of Financial Accounting Standards No. 148, Accounting for Stock-Based Compensation Transition and Disclosure (Statement No. 148). Statement No. 148 amends FASB Statement No. 123, 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. Statement 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 are transitioning during 2003 to a fair value-based method of accounting for stock-based compensation and will use the prospective method of transition as described under Statement No. 148.

In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities an Interpretation of ARB No. 51 (FIN 46). FIN 46 addresses the consolidation of variable interest entities having certain characteristics. In summary, this interpretation increases the level of risk that must be assumed by equity investors in special purpose entities. FIN 46 requires that the equity investor have significant equity at risk (minimum of 10% with few exceptions, increased from 3% under previous guidance) and hold a controlling interest, evidenced by voting rights, risk of loss and the benefit of residual returns. If the equity investor is unable to evidence these characteristics, the entity that does retain these ownership characteristics will consolidate the variable interest entity. We are in the process of evaluating the impact of FIN 46. While we have not entered into any arrangements in 2003 that would be subject to FIN 46, we may have existing arrangements that are impacted. FIN 46 is applicable immediately to variable interest entities created or obtained after January 31, 2003. For variable interest entities acquired before February 1, 2003, FIN 46 is applicable as of July 1, 2003.

NOTE 3 DISPOSITIONS, DISCONTINUED OPERATIONS AND ACQUISITIONS

DISPOSITIONS

As part of our restructuring plan, significant portions of our operations were sold during 2002, many of which were accounted for as Discontinued Operations under Statement No. 144, as further discussed below.

Discontinued Operations

In 2002, the following operations were discontinued and subsequently sold:

Northern Natural. In November 2001, we acquired 1,000 shares of Series A Preferred Stock (Series A Preferred Stock) in Northern Natural Gas Company (Northern Natural) for $1.5 billion. DHI, our wholly owned subsidiary, concurrently acquired an option to purchase all of the equity of Northern Natural s indirect

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parent company. DHI exercised its option to acquire the indirect parent of Northern Natural in November 2001 upon termination of a merger agreement with Enron, and the closing of the option exercise occurred on January 31, 2002.

On August 16, 2002, we sold Northern Natural to MidAmerican Energy Holdings Company (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 of $599 million ($561 million after-tax) associated with the sale, including all adjustments for changes in working capital.

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 as a result of uncertainty as to the ability to generate capital gains in the future.

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 that we might have assumed when we acquired Northern Natural from the Enron consolidated group.

On September 30, 2002, DHI sold $90 million in 6.875 percent senior notes of Northern Natural 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 on the accompanying consolidated statements of operations and is net of accrued interest.

United Kingdom Storage. In the fourth quarter 2001, we completed the purchase of BG Storage Limited (BGSL), a wholly owned subsidiary of BG Group plc. Under the terms of the purchase agreement, we paid approximately £421 million (approximately $595 million at November 28, 2001) for BGSL and its existing assets. The assets, which are located in the United Kingdom (U.K.), consisted primarily of the Hornsea onshore gas storage facility in the U.K., the Rough offshore natural gas fields in the North Sea and the Easington natural gas processing terminal on the East Yorkshire coast.

BGSL s results of operations are included in our consolidated statement of operations beginning December 1, 2001 as part of our CRM segment. A condensed balance sheet as of the acquisition date is as follows ($ in millions):

Current assets	$ 57
Property, plant and equipment	792
Goodwill	9
Total assets acquired	858
Current liabilities	56
Long-term liabilities	207
Total liabilities assumed	263
Net assets acquired	$ 595

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On September 30, 2002, we sold a subsidiary that owned the Hornsea onshore natural gas storage facility in the U.K. for net cash proceeds of approximately $189 million. There was no gain/loss recognized on this sale. On November 14, 2002, we sold the subsidiaries that owned the Rough offshore natural gas field in the North Sea and the Easington natural gas processing terminal on the East Yorkshire coast for cash proceeds of approximately $500 million, thereby completing the disposition of all BGSL-related assets. We recognized a pre-tax gain on the sale of Rough of approximately $30 million ($5 million after-tax).

Global Liquids. As a result of our decision to exit the international LPG trading and transportation business, in December 2002 we sold our Dynegy Global Liquids business, which was included in our NGL segment, to Trammo Gas International Inc., a wholly owned subsidiary of Transammonia Inc. The effective date of the sale was January 1, 2003. Consideration for the sale will be a cash payment in 2007 based on a 12.5 percent share of actual cumulative EBITDA of the assets sold over the next five years (2003 through 2007), capped at $8 million. We recorded pre-tax write-downs and accruals totaling $27 million associated with this transaction in 2002.

Approximately $12 million of the $27 million charge noted above was our investment in Energy Infrastructure Overseas Limited (EIOL). We had a 37.5 percent ownership interest in EIOL valued at $12 million that we accounted for under the equity method. The success of the EIOL project, which was still in the development and financing phase, was dependent on its ability to raise additional debt and equity for completion of the project. Due to the generally poor prevailing worldwide investment conditions and depressed international market for development projects of this type, we expect to receive no value or cash flows for our current investment in the project. As a result, we wrote down our investment in this project to zero at December 31, 2002. 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. As part of our commitment to exit the communications business, DGC exited operations in Asia through the combination of a management buyout and sale of assets in November 2002. As part of the transaction, DGC retained a 20% interest in a Beijing data center. This retained interest 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 after taking into account the impact of assets impaired in the second quarter 2002.

During 2003, we disposed of Dynegy Europe Communications to an affiliate of Klesch & Company, a London-based private equity firm and we disposed of our U.S. communications network to an affiliate of 360 networks Corporation.

U.K. CRM. During the first quarter 2003, the wind-down efforts of the U.K. CRM business were substantially completed. We do not expect the U.K. CRM business to have a material impact on our results in the future.

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The following table summarizes information related to our discontinued operations. Amounts in this table have been adjusted to reflect the reclassification of our global communications and U.K. CRM businesses to discontinued operations. For further information, please see Explanatory Note Reclassifications Discontinued Operations beginning on page F-8 ($ in millions):

	Northern Natural	UK Storage	UK CRM	Global Liquids	DGC	Total
2002						
Revenue	$ 201	$ 140	$ 16	$ 784	$ 22	$ 1,163
Income (loss) from operations before taxes	38	34	(115)	(22)	(856)	(921)
Gain (loss) on sale before taxes	(599)	30		(15)	2	(582)
Gain (loss) on sale after taxes	(561)	5		(10)	3	(563)
2001						
Revenue	$	$ 15	$ 20	$ 890	$ 27	$ 952
Income (loss) from operations before taxes		6	(31)	(2)	(100)	(127)
2000						
Revenue	$	$	$	$ 1,033	$ 2	$ 1,035
Income (loss) from operations before taxes			52	5	(19)	38

Other Significant Dispositions

Illinois Power Transmission. During the fourth quarter 2002, IP announced an agreement to sell its 1,672-circuit mile high-voltage electric transmission system to Trans-Elect Inc., an independent transmission company, for $239 million. The purchase price is subject to adjustment with respect to certain items, including a final determination of the transmission assets to be sold, any variance in the assumed amount of inventory on hand and the amount of accounts payable at closing. A change in interest rates from those estimated by Trans-Elect in contemplating its financing for the sale also could cause an adjustment to the purchase price or postponement of the closing, at IP s option. The closing of the sale, the contract for which was executed as of October 7, 2002, was conditioned on several matters, including the receipt of required approvals from the SEC under the Public Utility Holding Company Act, the Federal Trade Commission, the Illinois Commerce Commission (ICC) and the Federal Energy Regulatory Commission (FERC). With respect to the FERC, the sale was conditioned on its approving the levelized rates application filed by Trans-Elect seeking a 13% return on equity (based on a capital structure of equal portions of debt and equity), which would result a significant increase in transmission rates over the rates IP currently charges. On February 20, 2003, the FERC voted to defer its approval of the transaction and set a hearing to establish the allowable transmission rates for Trans-Elect. Specifically, the FERC stated that the benefits of the transaction, including independent transmission ownership, may not justify the significant increase in rates sought. The FERC also limited the period for which IP may provide operational services to Trans-Elect to one year.

IP and Trans-Elect have withdrawn the rate filing at the FERC and requested a continuance of the hearing pending an order on rehearing and a FERC ruling on a new rate application. Pending resolution of these matters by the FERC, the ICC proceedings have also been withdrawn and continued. IP is in discussions with Trans-Elect to determine the impact of the FERC order on the transaction and to determine the course of action the parties will take. Under the sale agreement, if the transaction does not close on or before July 7, 2003, either party can terminate the agreement. Because of the lead time required to receive the necessary regulatory approvals, it is unlikely that the transaction could be closed by July 7th.

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Canadian Assets. In August 2002, we completed the sale of a significant portion of our Canadian crude oil business to The Seminole Group Inc. In November 2002, we completed the sale of a portion of our Canadian natural gas marketing business to The Seminole Group Inc. The pre-tax loss on the sale was approximately $7 million. The remaining Canadian business consists primarily of existing power marketing positions and physical gas in storage.

Hackberry Terminal. Consistent with our restructuring plan, in early 2003 we entered into an agreement to sell 100 percent of our membership 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 transaction is subject to the completion of specified closing conditions. Under the terms of the agreement, Sempra LNG Corp. will make an initial payment of $20 million to us, with additional contingent payments based upon project development milestones. Additionally, we are entitled to a portion of the return on the project if performance targets are achieved in the future. The planned facility will be capable of sending out 1.5 billion cubic feet per day of natural gas and will have two docks and storage capability of 10.4 billion cubic feet equivalent. Pending further approvals, commercial operation is expected as early as 2007.

2000 Dispositions. In the first quarter 2000, we sold our domestic crude oil marketing and trading business, which was included in the results of our NGL segment prior to its sale. We recognized an after-tax loss on the sale of $11 million, which is included in loss (gain) on sale of assets on our consolidated statements of operations. Also in the first quarter 2000, we sold our Mid-Continent gas processing assets, the results of which were included in the results of the NGL segment prior to the sale, and recognized a $6 million after-tax loss, which is included in loss (gain) on sale of assets on our consolidated statements of operations. In the third quarter 2000, we sold our 25% participating preferred interest in Accord, which was included in the results of our CRM segment prior to its sale. We received cash proceeds of $95 million, and recognized an after-tax gain of $58 million. The gain is included in loss (gain) on sale of assets on our consolidated statements of operations. Finally, during 2000 we sold interests in certain Qualifying Facilities, which were included in the results of our GEN segment prior to their sale, pursuant to statutory requirements related to the Illinova acquisition described below. We received cash proceeds of $257 million on those sales and recognized an after-tax gain of $34 million. The gain is included in loss (gain) on sale of assets on our consolidated statements of operations.

ACQUISITIONS

DNE. In the first quarter 2001, we acquired DNE power generation facilities in New York. The DNE facilities consist of a combination of base load, intermediate and peaking facilities aggregating 1,700 MW. The facilities are located 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 the term financing with respect to 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.

Illinova and Illinois Power. We completed our acquisition of Illinova on February 1, 2000. This involved the creation of a new holding company, now known as Dynegy Inc. We accounted for the acquisition as a purchase of Illinova with an effective date of January 1, 2000. This accounting treatment was based on various factors present in the merger, including the majority ownership and voting control of our shareholders following the merger, the role of our management following the merger and the influence of Chevron because of the size of its ownership interest and its rights under the shareholder agreement, articles of incorporation and bylaws.

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Pursuant to the merger agreement, our shareholders, other than Chevron, NOVA and BG, elected to exchange each former Dynegy share for 0.69 of a share of Dynegy Class A common stock, based on a fixed exchange ratio, or elected to receive $8.25 per share in cash consideration, subject to proration. In exchange for their respective shares of former Dynegy common stock, NOVA and the parent of BG each received a combination of cash, subject to proration, and shares of Dynegy Series A Convertible Preferred Stock. Chevron received 0.69 of a share of Dynegy Class B common stock in exchange for each share of former Dynegy common stock and Series A Participating Preferred Stock it owned. Additionally, as part of the transaction, Chevron purchased $200 million of additional Dynegy Class B common stock. Each share of Illinova common stock was converted into one share of Dynegy Class A common stock.

Approximately 60 percent of the consideration received by existing Dynegy shareholders was in the form of Dynegy stock and 40 percent was cash. In the aggregate, the cash portion of the consideration approximated $1.1 billion. We financed the cash component of the acquisition initially with borrowings under a debt facility and the issuance of $200 million of Class B common stock to Chevron. On a long-term basis, we financed the acquisition of Illinova through a combination of sales of common equity, the disposition of certain non-strategic assets, the refinancing of Illinova s unregulated generation assets and cash flow from operations.

Global Communications. On September 29, 2000, we completed the acquisition of Extant, Inc. (Extant), a privately held communications solutions company. Our net investment consisted of $92 million in cash and 1.8 million shares of Class A common stock. Following the transaction, we established DGC, a new segment that also owns 80 percent of a limited partnership called DynegyConnect, L.P., which conducts many of the activities previously conducted by Extant. On March 14, 2003, we agreed to acquire the remaining 20 percent of DynegyConnect L.P. effective as of September 19, 2001 in exchange for $45 million in cash and settlement of a lawsuit. See Telstra Litigation on page F-71 for additional details about this lawsuit. In the first quarter 2001, we finalized the acquisition of iaxis, Limited (iaxis), a London-based communications company.

Consideration Paid for Acquisitions. Consideration paid for the above described 2002, 2001 and 2000 business acquisitions was as follows ($ in millions):

	NNG	BGSL	iaxis	Extant	Ilinova
Cash purchase of stock	$ 1,565	$ 595	$ 40	$ 91	$ 1,111
Capital stock and stock options issued				76	1,817
Liabilities assumed	1,070	263	83	75	4,674
Subordinated capital assumed					239
Total consideration	$ 2,635	$ 858	$ 123	$ 242	$ 7,841

In both the Illinova and Extant acquisitions, we issued stock as a component of the total consideration paid. The value of this consideration for the Extant acquisition was determined based on the average of our quoted market price for the five trading days surrounding the announcement date, which was August 2, 2000 (average stock price). This period includes the announcement date and the two trading days just prior to and after the announcement date. Pursuant to the terms of the merger agreement, each share of Extant common stock was converted into Dynegy Class A common stock at the agreed upon exchange ratio of $7.50 divided by the average stock price. Each share of Extant preferred stock was exchanged for $7.50 in cash.

The value of the stock consideration for the Illinova acquisition was based on a fixed exchange ratio whereby each share of Illinova common stock was converted to one share of Dynegy Class A common stock and

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each Dynegy share held by a shareholder other than BG, NOVA and Chevron was converted into the right to receive 0.69 shares of Dynegy Class A common stock. (See above for a discussion of the exchange provisions that impacted these shareholders.) These fixed exchange ratios were set prior to the circulation of the joint proxy statement/prospectus for the merger in September 1999. This method of valuing the stock consideration was used since management did not believe market quotes were a reliable indicator of fair value. The reasons for this belief included, but were not limited to, marketplace takeover rumors, Dynegy s stock being thinly traded prior to the announcement and the merger being premised on leveraging an unregulated generation capacity position in a deregulating environment. The cash component of the consideration was deemed to be a more reliable indicator of fair value. Thus, an implied value for the stock consideration was calculated by dividing the $16.50 per share (not adjusted herein for the two-for-one stock split which occurred on August 22, 2000) cash price by the 0.69 stock exchange ratio.

NOTE 4 RESTRUCTURING AND IMPAIRMENT CHARGES

Amounts in this footnote reflect the reclassification of our global communications and U.K. CRM businesses to discontinued operations. For further information, please see Explanatory Note Reclassifications Discontinued Operations beginning on page F-8.

In 2002, we recorded pre-tax restructuring and impairment charges of $1,109 million relating to various areas of our operations. The table below provides the amounts of such charges by business area and the caption in which such charges are reflected in the consolidated statements of operations ($ in millions):

	Depreciation and Amortization Expense	Impairment and Other Charges	(Earnings) Losses of Unconsolidated Investments	Discontinued Operations	Total Charge
Impairment of communications business	$	$	$	$ 635	$ 635
Severance and other restructuring costs	17	140		42	199
Impairment of generation investments			144		144
Impairment of technology investments			31	49	80
Impairment of other obsolete assets		50		1	51
	$ 17	$ 190	$ 175	$ 727	$ 1,109

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.

Our impairment analysis of our communications business, calculated in accordance with the guidelines set forth in Statement No. 144, indicated future cash flows from DGC s operations were insufficient to cover the carrying value of its long-lived assets. As a result, non-cash impairment charges 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, we restated the treatment of certain communication leases, as discussed in Explanatory Note Restatement Disclosures Restated Lease Accounting, beginning on page F-13. As such, the assets related to the communications leases were also determined to be impaired resulting in an additional impairment charge of $329 million ($214 million after-tax), which was recorded in impairment and other charges and subsequently reclassified to discontinued operations.

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Severance and Other Restructuring Costs. In October 2002, we announced a restructuring plan designed to improve operational efficiencies and performance across our lines of business, including the adoption of a decentralized business structure consisting of a streamlined corporate center and operating units in power generation, natural gas liquids and regulated energy delivery. As part of the restructuring, we also announced we would exit third-party risk management aspects of the marketing and trading business. The decision to exit this business is expected to reduce our collateral requirements and overall corporate expenses. During the restructuring period and thereafter, we will maintain the resources and make the necessary arrangements to meet our customer commitments, including retaining personnel and risk management capabilities. This decision to exit third-party risk management aspects of the marketing and trading business will not change the commercial activities of our midstream or generation businesses. The midstream business will continue to manage commodity price risk associated with its operations related to fuel procurement and the marketing of natural gas liquids. The generation business will continue to manage commodity price risk existing in its physical asset positions through optimizing fuel procurement and the marketing of power.

In addition, in the second quarter 2002, we recognized a charge for severance benefits.

As a result of these items, we recognized a charge of $219 million ($142 million after-tax) during 2002, as detailed below ($ in millions):

Cancellation fees and operating leases	$ 61
Severance	115
Asset impairments	15
Change in estimated useful life of assets	28
	$ 219

In accordance with EITF 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring), we recognized $61 million in charges ($40 million after-tax) associated with cancellation fees and accruals for the termination of operating leases. These accruals are not discounted.

In addition, we recognized severance charges of $115 million ($75 million after-tax) related to severance benefits for approximately 973 employees who were from various segments and included all staffing levels, including our former Chief Executive Officer, former President and former Chief Financial Officer. Approximately $4 million was reclassified to Discontinued Operations in the third quarter related to the sale of Northern Natural.

A substantial amount of the balance at December 31, 2002 relates to severance that has not been paid to our former Chief Executive Officer, former President and former Chief Financial Officer, each of whom has instituted an arbitration proceeding against us related to this severance. Please read Note 14 Commitments and Contingencies Severance Arbitrations beginning on page F-72 for further discussion.

In April 2003, we made a payment to the Internal Revenue Service associated with a tax obligation incurred by our former Chief Executive Officer in relation to a May 2002 stock option exercise. This exercise was effected by a family limited partnership controlled by Mr. Watson to which he had previously transferred approximately 2.4 million options to acquire Dynegy stock. The April 2003 payment was made in response to an Internal Revenue Service inquiry arising from the fact that no tax withholdings were made at the time of the

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exercise. It is intended that this payment to the Internal Revenue Service will be offset against any other payments determined to be owed to Mr. Watson as a result of the ongoing arbitration proceedings between the parties. This payment does not impact our results of operations because the amount of the severance accrual we previously established for Mr. Watson in connection with his 2002 resignation exceeds the amount of such payment.

The following is a schedule of 2002 activity for the liabilities recorded associated with these charges ($ in millions):

Balance at December 31, 2001	$
Severance:	
2002 provision	115
Cash utilization	(44)
	71
Cancellation fees and operating leases	41
Balance at December 31, 2002	$ 112

Impairment losses of $15 million ($10 million after-tax) were also incurred as a result of the corporate restructuring plan for certain technology assets no longer being utilized in accordance with Statement No. 144. 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. These charges are included in depreciation and amortization expense.

Impairment of generation investments. In conjunction with our review of the carrying value of goodwill in the third quarter 2002 (see Note 9 Goodwill beginning on page F-45 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 investments were considered impaired, resulting in a pre-tax charge of $144 million. The diminution in the fair value of these investments is primarily a result of depressed energy prices.

Impairment of technology investments. During the first six months of 2002, the valuations of technology investments were assessed in light of our decision to pursue partnership and sale opportunities for our communications business. These investments were originally entered into in order to leverage existing commercial relationships or as a means of expanding new communications relationships. Historically, we viewed these investments as strategic and core to our communications strategy. Accordingly, we expected to hold these investments for the long term and viewed trends in the sector as cyclical. These investments include ownership in public and private companies and investment funds focused in the technology sector. The continued downturn in the technology sector during the second quarter 2002 combined with our change in strategy resulted in an impairment charge relative to these investments. We recorded a charge of $45 million ($29 million after-tax) for devaluation of investments resulting from unfavorable market conditions in the first quarter and an additional $23 million ($15 million after-tax) charge in the second quarter 2002.

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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 values of these investments were written off, resulting in a charge of $12 million ($8 million after-tax). The cumulative charge related to technology investments for the year ended December 31, 2002 was $80 million ($52 million after-tax).

Impairment of other obsolete assets. As a result of our decision to exit third-party risk management aspects of the marketing and trading 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). 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 Statement No. 144 was less than its carrying value. 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.

NOTE 5 COMMERCIAL OPERATIONS, RISK MANAGEMENT ACTIVITIES AND FINANCIAL INSTRUMENTS

Our operations and periodic returns 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 risk, management estimations, strategic investment decisions, changes in competition, operational risks, environmental risks and changes in regulations.

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

- Commodity price risks result from exposures to changes in spot prices, forward prices and volatilities of commodities, such as electricity, natural gas 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.

- Currency rate risks result from exposures to changes in spot prices, forward prices and volatilities of currency rates.

We seek 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 or our inability to transact as a result of reduced credit capacity or other factors. We cannot guarantee the ultimate effectiveness of our risk management activities.

We generally attempt to balance our fixed-price physical and financial purchase and sales commitments in terms of contract volumes, and the timing of performance and delivery obligations. However, we may, at times, have a bias in the market within guidelines established by management and by our Board of Directors, resulting from the management of our portfolio. In addition, as a result of marketplace illiquidity, our creditworthiness and other factors, we may, at times, be unable to hedge our portfolio fully for certain market risks.

The financial performance and cash flow derived from certain merchant generating capacity (e.g., peaking facilities) are impacted annually, either favorably or unfavorably, by changes in, and the relationship between, the cost of the commodity fueling the facilities and electricity prices, which in turn influences the volume of electricity generated by these assets.

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Operating results associated with natural gas gathering, processing and fractionation activities are sensitive to changes in natural gas liquids prices and the availability of inlet volumes. In addition, similar to peaking electricity generating facilities, straddle processing plants are impacted by changes in, and the relationship between, natural gas and natural gas liquids prices, which in turn influence the volumes of gas processed at these facilities. The impact from changes in natural gas liquids prices on upstream operations results principally from the nature of contractual terms under which natural gas is processed and products are sold. The availability of inlet volumes directly affects the utilization and profitability of this segment s businesses. Commodity price volatility may also affect operating margins derived from our natural gas liquids marketing operations.

Purchases of electricity and natural gas used in the transmission and distribution business to supply service to our customers may be impacted by commodity price fluctuations. IP has contracted for electricity volumes from various suppliers under contracts having various terms. Certain of these contracts do not obligate the supplier to provide replacement power to IP in the event of a curtailment or shutdown of operating facilities. If the commodity volumes supplied from these agreements are inadequate to cover IP s native load, IP will be required to purchase its supply needs in open-market purchases at prevailing market prices. Such purchases would expose IP to commodity price risk. Price risk associated with the gas utility operations of IP is mitigated through contractual terms applicable to the business, as allowed by the ICC.

Quantitative and Qualitative Market Risk Disclosures. In addition to applying business judgment, we use a number of quantitative tools to manage our exposure to market risk. These tools include:

- Risk limits based on a summary measure of market risk exposure, referred to as VaR; and

- Stress and scenario analyses as performed daily that measure the potential effects of various market events, including substantial swings in volatility factors, absolute commodity price changes and the impact of interest rate movements.

VaR represents the potential loss in value of our enterprise-wide marketing portfolio due to adverse market movements over a defined time horizon with a specified confidence level.

The modeling of the risk characteristics of our various portfolios involves a number of assumptions and approximations. We estimate VaR using a JP Morgan RiskMetrics approach assuming a one-day holding period and a 95 percent confidence level. 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, these historical data are weighted to give greater importance to more recent observations. Given its reliance on historical data, VaR is most 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.

Credit and Market Reserves. In connection with the market valuation of our energy commodity contracts, we maintain certain reserves for a number of risks associated with these future commitments. Among others, these include reserves for credit risks based on the financial condition of counterparties, reserves for price and product location (basis) differentials and consideration of the time value of money for long-term contracts. Counterparties in our marketing portfolio consist principally of commercial and industrial companies, utility and

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

power generators, financial institutions and oil and gas producers. The creditworthiness of these counterparties may impact overall exposure to credit risk, either positively or negatively. However, with regard to our counterparties, we maintain credit policies that management believes minimize overall credit risk. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings, financial condition and collateral requirements. When applicable, we employ standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty.

Based on these policies, our current exposures and our credit reserves, we do not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance. As a result of Enron s bankruptcy, we reserved an after-tax amount of $84 million in the fourth quarter 2001 related to our net exposure for commercial transactions with that entity. For further discussion of this matter, see Note 14 Commitment and Contingencies Enron Trade Credit Litigation beginning on page F-71.

Accounting for Derivative Instruments and Hedging Activities. The Financial Accounting Standards Board issued, and subsequently amended, Statement No. 133, which became effective January 1, 2001. Provisions in Statement No. 133, as amended, affect our accounting and disclosure of certain contractual arrangements and operations. Under Statement No. 133, as amended, 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, net investments or qualify, and are designated, as normal purchases and sales. For derivatives treated as hedges of future cash flows, 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 in earnings immediately. For derivatives treated as fair value hedges, 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. For derivatives treated as hedges of net investment in foreign operations, 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. Derivatives treated as normal purchases or sales are recorded and recognized in income using accrual accounting.

We recorded the impact of the adoption of Statement No. 133, as amended, as a cumulative effect adjustment in our consolidated results on January 1, 2001. The amounts recorded are as follows ($ in millions):

	Net Income	Other Comprehensive Income
Adjustment to fair value of derivatives	$ 3	$ 105
Income tax effects	(1)	(44)
Total	$ 2	$ 61

DYNEGY INC.

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(RESTATED)

Accumulated other comprehensive loss, net of tax is included in stockholders equity on the consolidated balance sheets as follows ($ in millions):

	December 31	
	2002	2001
Cash Flow Hedging Activities, Net	$ 8	$ 8
Foreign Currency Translation Adjustment	3	(28)
Minimum Pension Liability	(66)	
Unrealized Loss on Available-for-Sale Securities, Net		(7)
Accumulated Other Comprehensive Loss, Net of Tax	$ (55)	$ (27)

Additional disclosures required by Statement No. 133, as amended, are provided in the following paragraphs.

From time to time, we may enter into various financial derivative instruments that qualify as cash flow hedges. Instruments related to our power generation and midstream liquids businesses are entered into for purposes of hedging forward fuel requirements for power generation and fractionation facilities and locking in future margin in the domestic midstream liquids and power marketing businesses. In addition, prior to exiting the global liquids business, we utilized these instruments to hedge price risks associated with this business. Interest rate swaps are used to convert the floating interest-rate component of some obligations to fixed rates.

During the years ended December 31, 2002 and 2001, 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. Additionally, no amounts were reclassified to earnings in connection with forecasted transactions that were no longer considered probable of occurring.

The balance in other comprehensive income at December 31, 2002 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, approximately $10 million of after-tax losses is estimated to be reclassified into earnings during 2003. The actual amounts that will be reclassified to earnings over the next year and beyond could vary materially from this estimated amount as a result of changes in market conditions.

From time to time, we may also enter into derivative instruments that qualify as fair-value hedges. We used interest rate-swaps to convert a portion of our nonprepayable fixed-rate debt into variable-rate debt. During the twelve months ended December 31, 2002 and 2001, 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 recognized in relation to firm commitments that no longer qualified as fair-value hedge items.

We have investments in foreign subsidiaries, and the net assets of these subsidiaries are exposed to currency exchange-rate volatility. We use derivative financial instruments, including foreign exchange forward contracts and cross currency interest rate swaps, to hedge this exposure. For the years ended December 31, 2002 and 2001, approximately $12 million and $29 million of net losses related to these contracts were included in the cumulative translation adjustment, respectively. This amount neutralizes the cumulative translation gains of the underlying net investments in foreign subsidiaries for the period the derivative financial instruments were outstanding.

DYNEGY INC.

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(RESTATED)

Fair Value of Financial Instruments. The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of Statement of Financial Accounting Standards 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 10 Debt beginning on page F-47. The carrying amounts and fair values of our other financial instruments were ($ in millions):

	December 31,			
	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Dynegy Inc.				
Series B Convertible Preferred Securities (1)	$ 1,500	$ 365	$ 1,500	$ 1,418
Foreign Currency Risk-Management Contracts	3	3	(11)	(11)
Dynegy Holdings Inc.				
Preferred Securities of a Subsidiary Trust	200	14	200	159
Fair Value Hedge Interest Rate Swap	73	73	(7)	(7)
Cash Flow Hedge Interest Rate Swap	(16)	(16)	1	1
Interest Rate Risk-Management Contracts	(74)	(74)	6	6
Commodity Risk-Management Contracts	(43)	(43)	293	293
Illinois Power Company				
Serial Preferred Securities of a Subsidiary	11	4	46	39
Dynegy Global Communications				
Investment in Warrants			37	37

(1) Carrying value at December 31, 2002 represents $1,212 million included in Series B Convertible Preferred Securities, $660 million in Additional paid-in-capital and $(372) million in Retained earnings (deficit) in the Consolidated Balance Sheets. Carrying value at December 31, 2001 represents $882 million included in Series B Convertible Preferred Securities, $660 million in Additional paid-in-capital and $(42) million in Retained earnings in the Consolidated Balance Sheets.

The fair value of our Preferred Securities of a Subsidiary Trust were based on quoted market prices by financial institutions that actively trade these debt securities. The fair value of the Series B Convertible Preferred Securities reflects management s estimate of the realizable value of such securities based on an estimate of our enterprise value. This enterprise value estimate reflects information derived from the debt and equity markets and, as a result, is highly sensitive to the market prices at which our public debt and equity securities trade. The fair value of interest rate, foreign currency 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. The investment in warrants was recorded at fair value estimated using the Black-Scholes valuation methodology.

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(RESTATED)

The absolute notional contract amounts associated with the derivative instruments designated as hedges were as follows:

ABSOLUTE NOTIONAL CONTRACT AMOUNTS

	December 31,	
	2002	2001
Fair Value Hedge Interest Rate Swaps (in Millions of U.S. Dollars)	$ 601	$ 206
Fixed Interest Rate Received on Swaps (Percent)	5.616	5.284
Cash Flow Hedge Interest Rate Swaps (in Millions of U.S. Dollars)	$ 1,566	$ 100
Fixed Interest Rate Paid on Swaps (Percent)	2.824	4.397
U.K. Pound Sterling Net Investment Hedges (in Millions of U.S. Dollars)	$	$ 906
Average U.K. Pound Sterling Contract Rate (in U.S. Dollars)	$	$ 1.4233

NOTE 6 CASH FLOW INFORMATION

Following are supplemental disclosures of cash flow and non-cash investing and financing information ($ in millions):

	Year Ended December 31,		
	2002	2001	2000
Interest paid (net of amount capitalized)	$ 323	$ 248	$ 238
Taxes paid (net of refunds)	$ 12	$ 79	$ 40
Detail of businesses acquired:			
Current assets and other	$ 144	$ 62	$ 648
Fair value of non-current assets	2,491	903	7,509
Liabilities assumed, including deferred taxes	(1,070)	(346)	(4,782)

Subordinated capital assumed			(239)
Capital stock issued and options exercised			(1,884)
Cash balance acquired	(44)	(16)	(50)
Cash paid, net of cash acquired	$ 1,521	$ 603	$ 1,202
Other non-cash investing and financing activity:			
Implied dividend on Series B Convertible Preferred Securities	$ (330)	$ (42)	$
Addition of a capital lease	170		
Sale of West Texas LPG Pipeline Limited Partnership	45		

The businesses acquired included: 2002 Northern Natural; 2001 BGSL and iaxis; and 2000 Extant and Illinova. See Note 3 Dispositions, Discontinued Operations and Acquisitions beginning on page F-27 for more information regarding these acquisitions. The $1,521 million paid to acquire Northern Natural includes $1,501 million paid in 2001, which is included in unconsolidated investments in the consolidated statement of cash flows for the year ended December 31, 2001.

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DYNEGY INC.

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(RESTATED)

NOTE 7 PROPERTY, PLANT AND EQUIPMENT

Investments in property, plant and equipment consisted of ($ in millions):

	December 31	
	2002	2001
Power Generation	$ 5,428	$ 4,757
CRM (including U.K. gas storage facilities)	14	795
Natural Gas Liquids:		
Natural gas processing	992	944
Fractionation	221	201
Liquids marketing	33	25
Natural gas gathering and transmission	176	196
Terminals and storage	254	234
Barges	29	29
Regulated Energy Delivery	2,053	1,993
Dynegy Global Communications	126	544
IT Systems and Other	333	417
	9,659	10,135
Less: accumulated depreciation	(1,270)	(934)
	$ 8,389	$ 9,201

Interest capitalized related to costs of projects in process of development totaled $16 million, $20 million and $31 million for the years ended December 31, 2002, 2001 and 2000, respectively.

NOTE 8 UNCONSOLIDATED INVESTMENTS

Our unconsolidated investments consist primarily of investments in affiliates that we do not control but where we have significant influence over operations. These investments are accounted for by the equity method of accounting. Our share of net income from these affiliates is reflected in the consolidated statements of operations as earnings (losses) of unconsolidated investments. Our principal equity method investments consist of entities that operate power generation assets and natural gas liquids assets. We entered into these ventures principally for the purpose of sharing risk and leveraging existing commercial relationships. These ventures maintain independent capital structures and have financed their operations either on a non-recourse basis to us or through their ongoing commercial activities. We hold investments in joint ventures in which ChevronTexaco or its affiliates are investors. For additional information about these investments, please read Note 11 Related Party Transactions Transactions with ChevronTexaco beginning on page F-55.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

A summary of our unconsolidated investments is as follows. Amounts in this footnote reflect the revision of our reportable segments. For further information, please see Explanatory Note Reclassifications Revised Segments beginning on page F-9 ($ in millions):

	December 31	
	2002	2001
Equity affiliates:		
GEN investments	$ 542	$ 682
CRM investments	4	2
NGL investments	102	146
Total equity affiliates	648	830
Other affiliates, at cost	20	91
Other investments		23
Total unconsolidated investments	$ 668	$ 944

Cash distributions received from our equity investments during 2002, 2001 and 2000 were $91 million, $100 million and $118 million, respectively. Our investment balances include unamortized purchase price differences of $65 million and $151 million at December 31, 2002 and 2001, respectively. The unamortized purchase price differences represent the difference between our purchase price and our share of the investee s book value at time of acquisition. Undistributed earnings from our equity investments included in retained earnings (deficit) at December 31, 2002 and 2001 totaled $161 million and $138 million, respectively.

GEN Investments. Power generation investments include ownership interests in eight joint ventures that own fossil fuel electric generation facilities as well as a limited number of international ventures. Our ownership is 50 percent in the majority of these ventures. Our aggregate net investment of $546 million at December 31, 2002 represents approximately 2,400 MW of net generating capacity. Our most significant investment in generating capacity is our interest in West Coast Power, representing approximately 1,400 MW of net generating capacity in California. Our net investment in West Coast Power totaled approximately $287 million and $330 million at December 31, 2002 and December 31, 2001, respectively. West Coast Power provided equity earnings of approximately $17 million, $162 million and $122 million in the years ended December 31, 2002, 2001 and 2000, respectively. Equity earnings during 2002 were negatively impacted by a $100 million increase ($50 million net to us) in West Coast Power s allowance for doubtful accounts as well as a pre-tax impairment of $144 million in multiple equity investments based on a fair value assessment, as further discussed in Note 4 Restructuring and Impairment Charges Impairment of Generation Investments beginning on page F-35. On November 22, 2002, a petition was filed by several former officers of NRG Energy, Inc. (NRG), the parent company of our partner in West Coast Power and another joint venture, to put NRG in involuntary bankruptcy. NRG and the original petitioners reached a settlement agreement on February 17, 2003, in which the original petitioners agreed to cooperate with NRG to secure dismissal of the petition. One intervening petitioning creditor remains who did not withdraw its objection to NRG s motion to dismiss. A hearing was held on April 10, 2003 on the motion to dismiss, after which the Judge took the matter under advisement and indicated he would have a decision shortly. We cannot predict with certainty the effects of these or similar actions by NRG on the operations or collateral obligations of these two joint ventures.

During the first quarter 2003, we completed the sale of our 20% equity investment in Southstar Energy Services LLC. We received cash proceeds of approximately $20 million and recognized a pre-tax gain on the sale of approximately $1.5 million.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

CRM Investments. Our CRM investments include an ownership interest in a retail energy joint venture.

NGL Investments. At December 31, 2002, natural gas liquids investments included a 23 percent ownership interest in a venture that operates a natural gas liquids processing, extraction, fractionation and storage facility in the Gulf Coast region as well as a 39 percent ownership interest in a venture that fractionates NGLs on the Gulf Coast. Our midstream investments at December 31, 2001 also included our investment in West Texas LPG Pipeline Limited Partnership (WTLPS), which was sold to ChevronTexaco in August 2002. Please read Note 11 Related Party Transactions Transactions with ChevronTexaco beginning on page F-55 for further discussion of this transaction.

Summarized aggregate financial information for the GEN, CRM and NGL investments and our equity share thereof was ($ in millions):

	December 31,					
	2002		2001		2000(1)	
	Total	Equity Share	Total	Equity Share	Total	Equity Share
Current assets	$ 1,108	$ 477	$ 1,008	$ 415	$ 1,029	$ 374
Non-current assets	1,943	858	2,247	913	2,934	1,233
Current liabilities	840	376	592	241	734	276
Non-current liabilities	720	330	1,153	443	1,363	520
Revenues	3,591	1,404	4,000	1,548	3,988	1,568
Operating margin	666	232	909	350	857	324
Net income	273	87	544	223	481	196

(1) The financial data for 2000 is exclusive of amounts attributable to our investment in Accord as data was unavailable for these periods. For competitive reasons, Accord was unwilling to provide to us detailed financial information concerning its operations. We contractually agreed not to require the production of such information in our negotiations with Accord. Our share of Accord earnings for the year ended December 31, 2000 totaled $9 million. We sold our investment in Accord in the third quarter 2000.

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 $20 million and $91 million at December 31, 2002 and 2001, respectively. We also owned securities that had a readily determinable fair market value and were considered available-for-sale. The market value of these investments at December 31, 2002 and 2001 was estimated to be zero and $23 million, respectively. During 2001, we recognized an $19 million pre-tax loss on a technology investment due to impairments that were determined by management to be other-than-temporary. During 2002, we wrote down the remaining values of our available-for-sale securities. See Note 4 Restructuring and

Impairment Charges Impairment of Technology Investments beginning on page F-35.

In November 2001, we acquired 1,000 shares of Series A Preferred Stock in Northern Natural for $1.5 billion. Dividends of $8 million and $13 million are reflected in Other Income on the 2002 and 2001 Consolidated Statements of Operations, respectively. We exercised our option to acquire the indirect parent of Northern Natural in November 2001 upon termination of the merger agreement with Enron and closed the acquisition on January 31, 2002. See further discussion on this transaction and the subsequent sale of Northern Natural under Note 3 Dispositions, Discontinued Operations and Acquisitions Dispositions Discontinued Operations Northern Natural beginning on page F-27.

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DYNEGY INC.

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(RESTATED)

NOTE 9 GOODWILL

The changes in the carrying amount of goodwill for each of our reportable business segments for the year ended December 31, 2002 were as follows ($ in millions):

	GEN	CRM	NGL	REG	Other	Total
Balances as of January 1, 2002	$ 549	$ 381	$ 16	$ 381	$ 234	$ 1,561
Cumulative effect of change in accounting principle					(234)	(234)
Goodwill acquired during the period				887		887
Purchase price adjustments		(33)		(28)		(61)
Goodwill impaired during the period	(549)	(348)				(897)
Sale of Canadian Crude business			(1)			(1)
Sale of Northern Natural				(859)		(859)
Balances as of December 31, 2002	$	$	$ 15	$ 381	$	$ 396

As discussed in Explanatory Note Reclassifications Revised Segments, beginning on page F-9, reportable segments in this report conform to the 2003 segment classification. Accordingly, goodwill which was previously associated with the former WEN segment has been allocated between the GEN and CRM segment. Goodwill which was previously associated with the former DGC segment is included in the Other classification.

Significant components of the changes in goodwill during 2002 included the following:

We adopted Statement 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 statement 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 $897 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 statement of operations as a goodwill impairment.

Also in 2002, goodwill associated with the acquisition of Northern Natural was recorded and removed when Northern Natural was sold. See Note 3 Dispositions, Discontinued Operations and Acquisitions Dispositions Discontinued Operations Northern Natural beginning on page F-27 for additional discussion of the sale of Northern Natural.

All charges related to goodwill during 2002 are the same on a pre-tax or an after-tax basis.

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(RESTATED)

The following table shows what our net income and earnings per share (EPS) would have been in 2001 and 2000 if goodwill had not been amortized during those periods, compared to the net loss and loss per share we recorded for 2002 ($ in millions, except per share data).

	2002	2001	2000
Reported net income (loss)	$ (2,737)	$ 406	$ 436
Add back: Goodwill amortization		46	36
Adjusted net income (loss)	$ (2,737)	$ 452	$ 472
Less: preferred stock dividends	330	42	35
Net income (loss) available to common stockholders	$ (3,067)	$ 410	$ 437
Basic EPS:			
Reported net income (loss)	$ (8.38)	$ 1.12	$ 1.33
Goodwill amortization		.14	.12
Adjusted net income (loss)	$ (8.38)	$ 1.26	$ 1.45
Diluted EPS:			
Reported net income (loss)	$ (8.38)	$ 1.07	$ 1.27
Goodwill amortization		.14	.11
Adjusted net income (loss)	$ (8.38)	$ 1.21	$ 1.38

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DYNEGY INC.

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(RESTATED)

NOTE 10 DEBT

Notes payable and long-term debt consisted of the following at December 31 ($ in millions):

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Dynegy Holdings Inc.				
Commercial Paper	$	$	$ 6	$ 6
Revolving Credit Facilities	128	128	600	600
Canadian Credit Agreements			40	40
Renaissance and Rolling Hills Credit Facility, due 2003	200	200		
Senior Notes, 6.875% due 2002			200	198
Senior Notes, 6.75% due 2005	150	54	150	134
Senior Notes, 8.125% due 2005	300	114	300	275
Senior Notes, 7.45% due 2006	206	70	200	177
Senior Notes, 6.875% due 2011	522	158	493	422
Senior Notes, 8.75% due 2012	500	170		
Senior Debentures, 7.125% due 2018	190	47	175	141
Senior Debentures, 7.625% due 2026	198	46	175	140
ABG Gas Supply Credit Agreement, due through 2004	259	252	282	267
DMG Secured Debt, due through 2005	758	758		
Generation Facility Debt	184	184	342	342
Generation Facility Capital Lease	165	165		
Illinova Corporation				
Senior Notes, 7.125%, due 2004	100	43	102	100
Medium Term Notes, 6.46% due 2002			20	20
Illinois Power Company				
Commercial Paper			38	38
Term Loan, due 2003	100	100	240	240
Mortgage Bonds, 6.25% due 2002			96	96
Mortgage Bonds, 6.5% due 2003	100	97	100	100
Mortgage Bonds, 6.0% due 2003	90	87	90	90
Mortgage Bonds, 6.75% due 2005	70	66	70	70
Mortgage Bonds, 7.5% due 2009	250	215	250	238
Mortgage Bonds, 11.5% due 2010	400	388		
Mortgage Bonds, 7.5% due 2025	66	52	66	56
Transitional Funding Trust Notes, 5.31% due 2002			31	31

Transitional Funding Trust Notes, 5.34% due through 2003	30	30	85	86
Transitional Funding Trust Notes, 5.38% due through 2005	175	178	175	177
Transitional Funding Trust Notes, 5.54% due through 2007	175	182	175	174
Transitional Funding Trust Notes, 5.65% due through 2008	139	153	139	138
Floating Rate Pollution Control Revenue Refunding Bonds, due 2017	75	75	75	75
Adjustable Rate Pollution Control Revenue Refunding Bonds, due 2028	112	112	112	112
Adjustable Rate Pollution Control Revenue Refunding Bonds, due 2032	150	150	150	150
Pollution Control Revenue Refunding Bonds, 5.4%-7.4%, due 2024 through 2028	179	177	179	183
Dynegy Inc.				
DGC secured debt	360	360	324	324
	6,331		5,480	
Less: Unamortized discount on debt	16		6	
Less: Amounts due within one year	861		458	
Total Long-Term Debt	$ 5,454		$ 5,016	

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Aggregate maturities of the principal amounts of all long-term indebtedness are: 2003 $861 million; 2004 $343 million; 2005 $1,813 million; 2006 $314 million; 2007 $270 million and beyond $2,714 million.

DHI Revolvers and Commercial Paper. On April 29, 2002, DHI closed a $900 million unsecured revolving credit agreement with a syndicate of commercial banks. This facility was scheduled to mature on April 28, 2003 but has been restructured and extended as described below. Generally, borrowings under this credit agreement bore interest at a Eurodollar rate plus a margin determined based on our unsecured debt ratings. Facility fees were payable on the full amount of the facility and were determined based on unsecured debt ratings. As of December 31, 2002, amounts outstanding under this facility included $128 million of borrowings and $624 million in letters of credit. An additional $248 million in letters of credit was outstanding at December 31, 2002 under the DHI $400 million revolving credit agreement. The facility did not contain a term-out provision permitting extension of the maturity for borrowings under the facility beyond the facility s April 28, 2003 maturity date. As such, the amounts outstanding under this facility were classified as current at December 31, 2002.

At December 31, 2002, we had no outstanding commercial paper. The weighted average interest rate at December 31, 2001 on the $6 million outstanding under DHI s commercial paper program was 3.2 percent.

During the year ended December 31, 2002, we repaid commercial paper borrowings and revolving credit facilities for Dynegy and DHI of approximately $614 million in the aggregate and borrowed an aggregate of approximately $136 million under the Dynegy and DHI revolving credit facilities. Additionally, during the year ended December 31, 2002, Dynegy and DHI issued an aggregate of $495 million of letters of credit under their revolving credit facilities.

On April 2, 2003, Dynegy s principal financing subsidiary, DHI, entered into a $1.66 billion credit facility consisting of:

- a $1.1 billion DHI secured revolving credit facility (the revolving facility) and a $200 million DHI secured term loan (Term A facility), each of which matures on February 15, 2005; and

- a $360 million DHI secured term loan (Term B facility) that matures on December 15, 2005.

The credit facility replaces, and preserves the commitment of each lender under, DHI s $900 million and $400 million revolving credit facilities, which had maturity dates of April 28, 2003 and May 27, 2003, respectively, and Dynegy s $360 million DGC secured debt, which had a maturity date of December 15, 2005. The credit facility will provide funding for general corporate purposes. The revolving facility is also available for the issuance of letters of credit. Borrowings under the credit facility will bear interest, at Dynegy s option, at (i) a base rate plus 3.75% per annum or (ii) LIBOR plus 4.75% per annum. A letter of credit fee will be payable on the undrawn amount of each letter of credit outstanding at a percentage per annum equal to 4.75% of such undrawn amount. An unused commitment fee of 0.50% will be payable on the unused portion of the revolving facility.

Subject to restrictions contained in the credit facility, amounts repaid under the revolving facility may be reborrowed. The full amounts of the borrowings under Term A facility and Term B facility were borrowed at the closing, and borrowings repaid under these facilities may not be reborrowed.

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(RESTATED)

The credit facility contains mandatory prepayment events. Amounts borrowed under the credit facility must, subject to specified exceptions, be repaid and commitments permanently reduced with:

100% of the net cash proceeds of all non-ordinary course asset sales;

50% of the net cash proceeds from the issuance of equity or subordinated debt;

100% of the net cash proceeds from the issuance of senior debt; and

50% of extraordinary receipts

The credit facility provides for no amortization of principal amounts outstanding prior to the maturity dates except upon the occurrence of such a prepayment event.

Subject to specified exceptions, DHI s obligations under the credit facility are guaranteed by Dynegy and substantially all of Dynegy s direct and indirect subsidiaries, excluding (i) IP and DGC and their respective subsidiaries, (ii) most foreign subsidiaries, dormant subsidiaries and subsidiaries with de minimus value and (iii) subsidiaries that are unable to become guarantors due to existing contractual or legal restrictions.

Subject to specified exceptions and permitted liens, the lenders under the credit facility received a first priority lien in substantially all the assets of Dynegy, DHI and certain of the subsidiary guarantors to the extent practicable and permitted by existing contractual arrangements, excluding IP and DGC and their respective subsidiaries. The lenders also received a first priority lien in the ownership interests in our direct and indirect subsidiaries, excluding (i) IP and DGC and their respective subsidiaries, (ii) most foreign subsidiaries, dormant subsidiaries and subsidiaries with de minimus value and (iii) subsidiaries whose ownership interests may not be pledged due to existing contractual or legal restrictions. The lenders also received a second priority lien in all material assets of DMG, subject to the first priority lien granted to the lenders under the Black Thunder financing. Our obligations under the Project Alpha transaction and CoGen Lyondell and Riverside generating facility leases were ratably secured with the same assets pledged to the lenders under the credit facility as required by the terms of such facilities.

The credit facility contains affirmative covenants relating to, among other things, financial statements; compliance and other certificates; notices of specified events; payment of obligations; preservation of existence; maintenance of properties; maintenance of insurance; compliance with laws; maintenance of books and records; inspection rights; use of proceeds; guarantee obligations and security; compliance with environmental laws; preparation of environmental reports; further assurances; material contracts; distribution of cash proceeds and extraordinary receipts by subsidiaries; and mortgaged property. The credit facility contains negative covenants relating to, among other things, liens; investments; indebtedness; fundamental changes; dispositions; restricted payments; changes in business; transactions with affiliates and non-loan parties; burdensome agreements; use of proceeds; amendments to organizational documents; accounting changes; prepayments of indebtedness; material contracts; swap contracts and off-balance sheet arrangements; formation of subsidiaries; the CoGen Lyondell and Riverside facilities; and amendments to the Series B preferred stock held by ChevronTexaco. The credit facility also contains financial and capital expenditure related covenants, which are described in detail below.

The credit facility generally prohibits Dynegy and its subsidiaries, subject to various customary and other exceptions, from incurring additional debt. Notwithstanding this restriction, we may issue exchange debt, or debt issued in exchange for outstanding DHI senior unsecured debt. Any such exchange debt may provide for guarantees that result in such debt being structurally senior to DHI s outstanding senior unsecured debt. Any exchange debt issued would be subject to the following restrictions:

- for exchange debt offered in respect of DHI senior unsecured debt maturing in 2005 and 2006,

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- if the maturity of the exchange debt is prior to March 15, 2007, then the aggregate principal amount of exchange debt issued generally cannot exceed 66% of the aggregate principal amount of the DHI senior unsecured debt exchanged; and
- if the maturity of the exchange debt is on or after March 15, 2007, then the aggregate principal amount of exchange debt issued generally cannot exceed the aggregate principal amount of the DHI senior unsecured debt exchanged;

for exchange debt offered in respect of DHI senior unsecured debt maturing in 2011, 2012, 2018 and 2026,

- the aggregate principal amount of exchange debt issued generally cannot exceed the aggregate principal amount of the DHI senior unsecured debt exchanged; and
- the maturity of the exchange debt must be after December 31, 2009; and

the aggregate cash interest expense of any exchange debt cannot exceed the aggregate cash interest expense of the DHI senior unsecured debt exchanged.

The credit facility generally prohibits us from pre-paying, redeeming or repurchasing our outstanding debt or preferred stock. Notwithstanding this restriction, we may repurchase or redeem up to $300 million in DHI senior notes or Series B preferred stock held by ChevronTexaco subject to the following restrictions:

- the first $100 million in repurchases of DHI senior notes requires a concurrent permanent reduction in commitments under the credit facility of $100 million, the second $100 million in repurchases requires a concurrent permanent reduction in commitments under the credit facility of $200 million, and the third $100 million in repurchases requires a concurrent permanent reduction in commitments under the credit facility of $300 million;
- no concurrent permanent reduction in commitments under the credit facility is required if DHI senior notes are repurchased with net cash proceeds attributable to extraordinary receipts or the issuance of equity or subordinated debt; and
- only $50 million of the $300 million may be used to repurchase DHI senior notes that mature on or after April 1, 2011; and
- only $50 million of the $300 million may be used to redeem shares of the Series B preferred stock held by ChevronTexaco, and Dynegy must permanently reduce commitments under the credit facility concurrently by three times the amount used to redeem

such shares.

Notwithstanding the foregoing, we must have $500 million of liquidity for ten days prior to and as of the date of the repurchase or redemption of DHI senior notes or the Series B preferred stock.

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The financial covenants in the credit facility are described below. Dynegy and its subsidiaries, excluding IP and DGC and their respective subsidiaries, are prohibited from:

permitting their Secured Debt/EBITDA Ratio (as defined in the credit facility) from and after September 30, 2003 to be greater than the ratio set forth below:

Measurement Period Ending	Maximum Secured Debt/ EBITDA Ratio
September 30, 2003	7.8:1.0
December 31, 2003	7.8:1.0
March 31, 2004	7.2:1.0
June 30, 2004	6.8:1.0
September 30, 2004	6.0:1.0
December 31, 2004 and each fiscal quarter thereafter	5.6:1.0

the definition of EBITDA in the credit facility specifically excludes, among other items, (i) discontinued business operations (including third-party marketing and trading, communications and tolling arrangements), (ii) disclosed litigation, (iii) extraordinary gains or losses, (iv) any impairment, abandonment, restructuring or similar non-cash expenses, and (v) turbine cancellation payments up to $50 million in the aggregate;

permitting their liquidity (as defined) to be less than $200 million for a period of more than ten consecutive business days; or

making capital expenditures during the four fiscal quarter period ending on the applicable dates set forth below in an amount exceeding the amount set forth opposite such fiscal quarter:

Fiscal Quarter	Amount
December 31, 2003	$232 million
March 31, 2004	$202 million
June 30, 2004	$206 million
September 30, 2004	$208 million
December 31, 2004 and each fiscal quarter thereafter	$222 million

making capital expenditures in connection with the completion of the Rolling Hills facility in an aggregate amount exceeding $85 million.

With respect to the quarterly restrictions on capital expenditures set forth above, we may (i) carryforward any amount not expended in the four fiscal quarter period in which it was permitted and (ii) carryback up to 50 percent of any amount permitted in a future four fiscal quarter period to any prior four fiscal quarter period and the amount related to the future four fiscal quarter period will be reduced accordingly. Further, Dynegy and its subsidiaries may make additional capital expenditures that are required to comply with applicable law.

The credit facility contains events of default relating to:

non-payment of principal when due, non-payment of interest or any commitment fee within three days or non-payment of any other amounts payable under applicable loan documents within five business days;

failure to comply with specified covenants and agreements, subject to applicable grace periods;

incorrect or materially misleading representations or warranties when made;

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specified defaults under (i) any debt or guarantee obligation having an aggregate principal amount in excess of $50 million or (ii) certain swap contracts with a termination value owed to the counterparty in excess of $50 million;

specified insolvency proceedings that are not discharged or stayed within 60 days or the inability to pay debts as they become due;

the entry of a final, non-appealable judgment in excess of $50 million (net of insurance) that is not discharged or stayed within 60 days;

specified ERISA-related events involving in excess of $50 million; and

any change of control.

Upon the occurrence of any event of default, upon the request of lenders representing more than 50 percent of borrowings outstanding under the credit facility, such lenders may, among other things, declare all borrowings outstanding (including letters of credit) under the credit facility immediately due and payable.

The foregoing description of the material terms of our new credit facility and related ancillary documents is a summary of certain provisions of the definitive agreements governing the credit facility and should be read in conjunction with such agreements, which are filed as exhibits to this Amendment No. 1.

Renaissance and Rolling Hills Credit Facility. In July 2002, we completed a $200 million interim financing, bearing interest at LIBOR plus 1.38 percent. This loan was scheduled to mature in January 2003 and was secured by interests in our Renaissance and Rolling Hills merchant power generation facilities. In January 2003, we repaid $94 million of this facility and refinanced the remaining $106 million. The maturity date on the remaining $106 million was extended to October 15, 2003 and the interest rate on the remaining balance was changed to LIBOR plus five percent. We recently agreed to prepay the remaining $106 million on April 16, 2003.

Interim Financing. In June 2002, we completed a $250 million interim financing, bearing interest at LIBOR plus 1.75 percent. This loan was scheduled to mature in June 2003 and represented an advance on a portion of the proceeds from the sale of our United Kingdom 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 net 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 therefrom.

DHI Senior Notes. In July 2002, DHI repaid its $200 million 6.875% senior notes. On February 21, 2002, DHI issued $500 million of 8.75% senior notes due 2012. Interest on the notes is due on February 15 and August 15 of each year, beginning August 15, 2002. The notes are unsecured and are not subject to a sinking fund.

ABG Gas Supply Credit Agreement. On April 10, 2001, ABG Gas Supply entered into a credit agreement with a consortium of lenders in order to provide financing associated with Project Alpha. Advances under the agreement allowed ABG Gas Supply to purchase NYMEX natural gas contracts with the underlying physical gas supply to be sold to Dynegy Marketing and Trade under an existing natural gas purchase and sale agreement. The credit agreement requires ABG Gas Supply to repay the advances in monthly installments commencing February 2002 through December 2004 from funds received from Dynegy Marketing and Trade under the natural gas purchase and sale agreement. The advances bear interest at a Eurodollar rate plus a margin as defined in the agreement (2.715% at December 31, 2002). Advances of $259 million and $282 million were outstanding under this agreement at December 31, 2002 and 2001, respectively.

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DMG Secured Debt. In June 2000, Dynegy and Black Thunder Investors LLC (Investor) invested in Catlin Associates, L.L.C. (Catlin), an entity that we consolidated, with the Investor s ownership in Catlin reflected as minority interest on the consolidated balance sheets at December 31, 2001. We invested $100 million in Catlin and the Investor contributed $850 million. As a result of its investment, the Investor received a preferred interest in Catlin, which holds indirect economic interests in some of our Midwest generation assets, including the coal-fired generation units in Illinois. This preferred interest is a passive interest and generally is not entitled to management rights.

Originally, on or before June 29, 2005, we were effectively obligated to purchase the Investor s preferred interest for $850 million unless the Investor agreed to extend or refinance this obligation. Alternatively, we could liquidate Catlin s assets, including DMG s generating assets, to satisfy this obligation.

We completed an amendment to this transaction in June 2002 that permanently removed a $270 million obligation that could have been triggered by declines in our credit ratings. The amended agreement requires one of our subsidiaries to make periodic payments totaling $275 million over the remaining three years of the transaction with $577 million due in June 2005. At December 31, 2002, this subsidiary had already paid approximately $92 million of this total. Quarterly maturities are approximately $20 million through the first quarter 2005. Balances outstanding incur interest based on market conditions in accordance with the agreement. In addition, we agreed to grant mortgages on the Midwest generation assets covered by the transaction, post a letter of credit to secure a contingent obligation that expired on December 31, 2002 and to make certain structural changes to enhance the security of the third-party lenders involved in the transaction. As a result of this amendment, $796 million related to Catlin was reclassified from minority interest to debt on our consolidated balance sheets.

DGC Secured and Generation Facility Debt. We executed lease arrangements for the purpose of constructing two generation facilities located in Georgia and Kentucky as well as our domestic fiber optic network. As originally constituted, these arrangements require 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. In December 2002, we repaid the principal balance under one of the generation facility lease arrangements. The remaining generation lease arrangement expires in 2007 and bears interest at LIBOR plus 1.5% to 2.5%, depending on the tranche. We restructured the arrangement relating to our domestic fiber optic network in March 2003 in connection with the restructuring of our revolving credit facilities. Please read DHI and Revolvers and Commercial Paper above for a discussion of our restructured credit facilities.

Generation Facility Capital Lease. In response to the initiatives currently underway at the FASB, on June 28, 2002, we unilaterally undertook certain actions, the effect of which altered the accounting for one of our existing lease obligations. These actions included the delivery of a guarantee of the lessor debt in the lease of a power generation facility. As a result of these actions, the lease is now accounted for as a capital lease and approximately $165 million of generation assets and the associated debt were brought on-balance sheet. We have the option to purchase the related assets at lease maturity in 2005. This obligation bears interest at a rate of LIBOR plus 1.5% to 2.75%, depending on the tranche.

This non-cash action resulted in an increase to property, plant and equipment and a corresponding increase in long-term debt on our condensed consolidated balance sheets. This obligation was previously disclosed as a lease obligation in the footnotes to our financial statements and in the Commercial Financial Obligations and Contingent Financial Commitments tables in our 2001 Form 10-K/A.

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The following is a schedule of future minimum lease payments under the capital lease together with the present value of the net minimum lease payments as of December 31, 2002 ($ in millions):

Year ending December 31:	
2003	$ 5
2004	7
2005	176
Total minimum lease payments	188
Less: Amount representing interest	23
Present value of net minimum lease payments	$ 165

Illinois Power Revolvers and Commercial Paper. During the year ended December 31, 2002, we repaid commercial paper borrowings and revolving credit facilities for IP of approximately $238 million in the aggregate and borrowed an aggregate of approximately $60 million under IP s revolving credit facility. The weighted average interest rates on amounts outstanding under IP s commercial paper program and revolving credit facility were 3.3% and 2.7%, respectively at December 31, 2001.

On May 17, 2002, IP exercised the term-out provision contained in its $300 million 364-day revolving credit facility, which was scheduled to mature on May 20, 2002. In connection with this conversion, IP borrowed the remaining $60 million available under this facility. The exercise of the term-out provision converted the facility to a one-year term loan that matures in May 2003. As such, the amounts outstanding under this loan are classified as current. Borrowings of $100 million were outstanding under this loan at December 31, 2002, reflecting a $200 million pre-payment that was made in December 2002. IP pays facility fees of 0.25% of the outstanding balance. The weighted average interest rate of this borrowing was 2.7% at December 31, 2002.

Illinois Power Mortgage Bonds. During December 2002, IP sold $550 million 11.5% Mortgage bonds due 2010. Of the $550 million, IP issued $400 million in December, while the remaining $150 million was issued on a delayed delivery basis subject to ICC approval. In January 2003, IP received the ICC approval and closed on the remaining $150 million of bonds. The effective interest rate on these bonds is 12 percent, as they were issued at a $10 million discount. IP used the December proceeds from the issuance to refinance the maturity of its $95.7 million 6.25% Mortgage bonds and to pay $200 million on its $300 million term loan as discussed above. Because of IP s non-investment credit ratings, these bonds were sold pursuant to a supplemental mortgage indenture that includes various triggering events. IP is generally required to redeem the bonds upon the occurrence of a triggering event. These triggering events include, among other things, IP s incurrence of certain additional indebtedness and payment of dividends on its capital stock.

Various other IP bonds were issued at a discount. At December 31, 2002 and 2001, the unamortized discount balance totaled $15 million and $6 million, respectively.

Illinova Senior Notes. As of December 31, 2002, Illinova had approximately $100 million of its 7.125% Senior Notes due 2004 outstanding. In March 2003, DHI purchased $5 million in aggregate principal amount of these notes on the open market. The notes have been cancelled and are no longer outstanding, such that $95 million in aggregate principal amount of the notes were outstanding at March 31, 2003.

Illinois Power Transitional Funding Trust Notes. The Illinois Electric Utility Transition Funding Law permits Illinois utilities to issue transitional funding notes in connection with that state s transition to customer

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choice. These notes are issued through a special purpose trust, and a specified amount per kWh of cash received from customer electricity delivery service billings is earmarked for distribution to the trust and payment of the notes. Illinois Power Special Purpose Trust, a special purpose trust formed by IP for this express purpose, issued $864 million of transitional funding notes in December 1998. During 2002, IP paid down approximately $88 million of transitional funding trust notes and expects to continue to pay approximately $88 million on such notes annually through 2008. At December 31, 2002, Illinois Power Special Purpose Trust had $519 million in transitional funding notes outstanding, including $89 million of such notes that were classified as current portion of long-term debt.

Other Obligations.   In connection with five fully collateralized generation lease arrangements, we had recorded a construction agency liability as of December 31, 2001. The construction agency liability was included in accrued liabilities and other in the accompanying consolidated balance sheets, and totaled $445 million, at December 31, 2001. The construction agency liability was secured by a note receivable owed to us, which was included in prepayments and other assets on the accompanying consolidated balance sheets at December 31, 2001. During 2002, we terminated the generation lease arrangements. Under the terms of this agreement we received title to the leased assets and assigned the note receivable to the lessor in exchange for forgiveness of the construction agency liability.

We incurred upfront fees aggregating approximately $39 million in connection with the interim financings, Black Thunder amendment and other transactions described above. Such amounts have been capitalized and are amortized over the term of the respective financing transactions.

NOTE 11 RELATED PARTY TRANSACTIONS

Transactions with ChevronTexaco.   In March 2002, we agreed with ChevronTexaco to expand our commercial relationships to include substantially all of the natural gas and domestic mixed NGLs and natural gas liquid products produced or controlled by the former Texaco.

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 agreed to accelerate payment to the month of delivery for a portion of the natural gas we purchase from ChevronTexaco, with the amount of the accelerated payment generally being equal to 75 percent of the value of the prior month s gas deliveries, after reduction pursuant to a netting agreement between us and ChevronTexaco. This payment arrangement was effective upon the closing of the sale of Northern Natural described in Note 3 Dispositions, Discontinued Operations and Acquisitions Dispositions Discontinued Operations Northern Natural beginning on page F-27 above. The accelerated payment totaled $176 million at December 31, 2002.

Also in August 2002, in partial satisfaction of certain of our obligations to ChevronTexaco under these agreements, we sold to ChevronTexaco our 39.2 percent ownership interest in WTLPS, which is the owner of West Texas LPG Pipeline. ChevronTexaco was already the owner of the largest interest in WTLPS and the operator of the pipeline. The interest sold to ChevronTexaco was valued at $45 million. This non-cash transaction reduced accounts payable to affiliates and unconsolidated investments by $45 million.

In connection with our announced exit from third-party risk management aspects of the marketing and trading business, we have 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 will not affect our contractual agreements with ChevronTexaco relative to ChevronTexaco s U.S. natural gas processing and the marketing of ChevronTexaco s domestic NGLs. The

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cancellation of the agreement was effective January 1, 2003. In accordance with the termination of the natural gas purchase agreement, we paid ChevronTexaco $13 million. As part of the transition, we also agreed to provide scheduling, accounting and reporting services to ChevronTexaco through April 2003. We were obligated to purchase any gas not sold under the ChevronTexaco agreements for February and March 2003 at index.

Other transactions with ChevronTexaco Inc. result from purchases and sales of natural gas, NGLs and crude oil between our affiliates and ChevronTexaco. We believe that these transactions are executed at prevailing market rates. During the years ended December 31, 2002, 2001 and 2000, our marketing business recognized net purchases from ChevronTexaco of $1.5 billion, $2.7 billion and $2.1 billion. 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, 2002, 2001 and 2000, our other businesses recognized aggregate sales to ChevronTexaco of $0.8 billion, $0.9 billion and $1.1 billion and aggregate purchases of $0.5 billion, $0.5 billion and $0.7 billion, which are reflected gross on the consolidated statements of operations.

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 Venice Energy Services Company, L.L.C., 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, 2002, 2001 and 2000, our portion of the net income from joint ventures with ChevronTexaco was approximately $17 million, $14 million and $17 million, respectively.

We also purchase and sell natural gas, NGLs, crude oil and power and, in some instances, earn management fees from certain entities in which we have equity investments. During the years ended December 31, 2002, 2001 and 2000, our marketing business recognized net sales to affiliates related to these transactions of $1.0 billion, $1.8 billion and $0.7 billion. 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, 2002, 2001 and 2000, our other businesses recognized aggregate sales to these affiliates of $15 million, $19 million and $16 million and aggregate purchases of $152 million, $185 million and $130 million, 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 Cost Power, and the supply of natural gas sold by retail affiliates. Expenses primarily represent the purchase of NGLs that are subsequently sold in our marketing operations.

Also during 2001, we earned approximately $8 million of interest income related to cash loaned to West Coast Power. The loan was created as a result of natural gas fuel costs owed by West Coast Power to one of our subsidiaries. As of December 31, 2001, West Coast Power had repaid in full all amounts owed to us. We have guaranteed $13 million of estimated environmental obligations and possible forfeiture of our rights to dividends previously received if collateral requirements under the agreement are not met. At December 31, 2002, the maximum exposure under the guarantee is $16 million.

At December 31, 2002, we had two financing arrangements, which originated during 2001, under which we were owed an aggregate of approximately $12 million from one of our equity investees, Nicor Energy, L.L.C. Under a gas purchase agreement, Nicor was obligated to purchase a total of 3.5 million MMBtu over the fifteen-month period October 2001 through December 2002 at a contract price of $18 million. Approximately $4 million of the $18 million per the agreement was outstanding at December 31, 2002. Additionally, under a loan

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agreement, which bears interest at a rate of prime plus two percent, we advanced $8.2 million to Nicor to satisfy a third-party debt all of which was outstanding at December 31, 2002. During the first quarter of 2003, substantially all of the operations of Nicor Energy have been sold and we expect to liquidate the Company in the second quarter of 2003. We anticipate that all amounts due to us from Nicor Energy will be repaid with the proceeds of this liquidation.

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 five percent or the applicable federal rate as of the loan date, are full recourse to the participants and mature on December 19, 2004. At December 31, 2002 and 2001, approximately $12 million and $13 million, respectively, which included accrued and unpaid interest, was owed to us under this program. The loans are accounted for as subscriptions receivable within stockholders equity on the consolidated balance sheets and are assessed for collectibility with our other receivables.

In connection with our organizational restructuring, we offered to forgive 50 percent of the outstanding balance under each loan established through this program to non-executive officers effective as of January 15, 2003, April 15, 2003, July 15, 2003 or October 15, 2003, at the officers election. In order to provide incentives to those employees with outstanding loans under this program to remain with us post-restructuring, we have 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 is due and payable on December 19, 2004. Interest rates charged under these loans remain unchanged.

December 2001 Equity Purchases. In December 2001, ten 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 totaling approximately $25 million from us 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 percent 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.

In October 2002, three executive officers with loans then outstanding for December 2001 equity purchases and under the Short-Term Executive Stock Purchase Loan Program resigned their positions. Two of these former executive officers paid an aggregate of approximately $1.5 million to retire their outstanding December 2001 equity purchase loans as part of their severance arrangements. These former executive officers outstanding loans under the Short-Term Executive Stock Purchase Loan Program, which aggregated approximately $2 million, were then extended to September 2007. The severance arrangement with the third former executive officer included a similar pay down of 50 percent of an outstanding December 2001 equity purchase loan and an extension of the maturity date for the $512,000 remaining outstanding under that loan, from September 15, 2002 to September 30, 2007. The extended loans bear interest at the same interest rate as the initial loans.

Two other executive officers with loans outstanding under each program, one of whom has since left Dynegy, repaid an aggregate of $1 million to retire their December 2001 equity purchase loans during the third

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quarter 2002. These executive officers used proceeds from a special bonus payment paid by us as part of their re-negotiated employment contracts to make these loan payments. These executive officers outstanding loans under the Short-Term Executive Stock Purchase Loan Program, which aggregate approximately $883,000 as of December 31, 2002, remain outstanding and mature on December 19, 2004.

NOTE 12 INCOME TAXES

Amounts in this footnote reflect the reclassification of our global communications and U.K. CRM businesses as discontinued operations. For further information, please see Explanatory Note Reclassifications Discontinued Operations beginning on page F-8.

General. We are subject to U.S. federal, foreign and state income taxes on our operations. Components of income tax expense (benefit) related to income (loss) from continuing operations were ($ in millions):

	Year Ended December 31,		
	2002	**2001**	**2000**
Current tax expense (benefit):			
Domestic	$ 1	$ 97	$ 28
Foreign	2	11	51
Deferred tax expense (benefit):			
Domestic	(299)	253	196
Foreign	20	(4)	(41)
Income tax provision (benefit):	$ (276)	$ 357	$ 234

Components of income (loss) from continuing operations before income taxes were as follows ($ in millions):

Year Ended December 31,

	2002	2001	2000
Income (loss) before income taxes:			
Domestic	$ (1,596)	$ 841	$ 660
Foreign	(29)	2	(17)
	$ (1,625)	$ 843	$ 643

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Deferred income taxes are provided for the temporary differences between the tax basis of our assets and liabilities and their reported financial statement amounts. Significant components of deferred tax liabilities and assets were ($ in millions):

	December 31,	
	2002	2001
Deferred tax assets:		
NOL carryforwards	$ 224	$ 128
AMT credit carryfowards	268	138
Capital loss carryforward	223	
Book/tax differences from liabilities	172	173
Miscellaneous book/tax recognition differences	446	402
Subtotal	1,333	841
Less: valuation allowance	(180)	
Total deferred tax assets	1,153	841
Deferred tax liabilities:		
Investments	659	767
Depreciation and other property differences	1,246	1,510
Miscellaneous book/tax recognition differences	199	132
Total deferred tax liabilities	2,104	2,409
Net deferred tax liability	$ 951	$ 1,568

Realization of the aggregate deferred tax asset is dependent on our ability to generate taxable earnings and regular tax in excess of tentative minimum tax in the future. At December 31, 2002, $171 million of the valuation allowance relates to capital loss carryforwards arising from the sale of Northern Natural and $9 million relates to foreign tax credit carryforwards, which management believes are not more likely than not to be fully realized in the future based on our ability to generate capital gains and foreign income. The financial statement impact of the valuation allowance against the capital loss carryforward has been reflected in discontinued operations. There was no valuation allowance established at December 31, 2002 for net operating loss carryforwards, as management believes the net operating loss carryforwards are more likely than not to be fully realized in the future based on management s estimates of future net income and related taxes.

Income tax provisions on continuing operations for the years ended December 31, 2002, 2001 and 2000, were equivalent to effective rates of 17 percent, 42 percent and 36 percent, respectively. Differences between taxes computed at the U.S. federal statutory rate and our reported income tax provision were ($ in millions):

	Year Ended December 31,		
	2002	2001	2000
Expected tax at U.S. statutory rate	$ (569)	$ 295	$ 225
State taxes	(32)	18	14
Foreign taxes	9	7	6
Valuation allowance	9		
Goodwill impairments	314		
Basis differentials and other	(7)	37	(11)
Income tax provision (benefit)	$ (276)	$ 357	$ 234

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At December 31, 2002, we had approximately $607 million of regular federal tax net operating loss carryforwards after considering the effect of carryback to prior years, $268 million of AMT credit carryforwards and $1,059 million of AMT net operating loss carryforwards. The federal net operating loss carryforwards expire from 2009 through 2022. The AMT credit carryforwards do not expire. 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 1995 and a 2000 business acquisition. These are not expected to have an impact on our overall ability to utilize such tax carryforwards. State net operating loss carryforwards in states where we file unitary state income tax returns are $30 million in California, $97 million in Illinois and $12 million in New Mexico. These state net operating loss carryforwards expire in 2012, 2022 and 2007, respectively. We believe such carryforwards will be fully realized prior to expiration.

Based on 2002 operating results, we have generated a significant current tax net operating loss that is available for carryback or carryforward 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 as a result of such carryback of tax losses.

We plan to reinvest the earnings of foreign subsidiaries indefinitely and no U.S. taxes or foreign withholding taxes were provided on these earnings in 2002, 2001 or 2000. It is not practicable to estimate the amount of unrecognized U.S. deferred taxes or foreign withholding taxes, if any, that might be payable on the actual or deemed remittance of such earnings. As of December 31, 2002, we have no material undistributed earnings of foreign subsidiaries.

As more fully discussed in Explanatory Note Restatement Disclosures Project Alpha beginning on page F-10, we entered into the Project Alpha structured natural gas transaction in April 2001. We have not recognized the permanent tax benefit related to Project Alpha in our 2002 or 2001 U.S. consolidated federal income tax return or financial statements.

Contingent Liability Transactions. We entered into three contingent liability transactions in 1996, 1997 and 1999. These transactions involved the transfer of an aggregate of $182 million in contingent liabilities primarily assumed by us in prior acquisitions of three separate companies. The three companies to which these contingent liabilities were transferred subsequently sold preferred or restricted common stock to various purchasers. Two of the companies sold stock to an aggregate of 15 non-executive Dynegy employees with positions of influence over the contingent liabilities held in such companies; the purchaser of the stock of the third company is an unaffiliated third party. The stock purchased by these non-executive employees was later redeemed under the terms of the applicable purchase agreements. The average redemption prices and dividends paid to these present and former employees, which related to their successful management of the subject contingent liabilities and exceeded the amounts paid by such employees for the stock they acquired, was $62,000 and no such employee received more than $81,000.

On January 18, 2001, the IRS issued Notice 2001-17 in which it identified these types of transactions as listed transactions or tax shelters. Pursuant to a settlement initiative described in IRS Revenue Procedure 2002-67, we are currently resolving with the IRS any issues in dispute related to these liability management companies. We expect that the settlement will have no material impact on our financial statements.

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NOTE 13 REDEEMABLE PREFERRED SECURITIES

Redeemable preferred securities consisted of the following ($ in millions):

	December 31,	
	2002	2001
Serial Preferred Securities of a Subsidiary	$ 11	$ 46
Company Obligated Preferred Securities of a Subsidiary Trust	200	200
Series B Convertible Preferred Securities	1,212	882
Total Redeemable Preferred Securities	$ 1,423	$ 1,128

Serial Preferred Securities of a Subsidiary. Serial Preferred Securities of a Subsidiary of approximately $11 million and $46 million, at December 31, 2002 and 2001, respectively, consists of six series of preferred stock issued by IP, with interest rates ranging from 4.08% to 7.75%. Certain series are redeemable at the option of IP, in whole or in part. On March 28, 2002, IP completed a solicitation of consents from its preferred stockholders to amend its Restated Articles of Incorporation to eliminate a provision restricting its ability to incur unsecured debt. Concurrently, Illinova completed a tender offer pursuant to which it paid approximately $35 million to acquire 662,924 shares, or approximately 73 percent, of IP s preferred stock. As a result, the NYSE has delisted each of the series of preferred stock that was subject to the tender offer and previously listed thereon. As of December 31, 2002 and 2001, the redemption amount associated with these securities totaled $11 million and $46 million, respectively.

Company Obligated Preferred Securities of a Subsidiary Trust. 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, in whole at any time or in part from time to time, at formula-based redemption prices, as defined in the indenture. 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, as described in the indenture. We may defer payment of interest on the subordinated debentures as described in the indenture.

As of December 31, 2002 and 2001, the redemption amount associated with these securities totaled $200 million.

Series B Convertible Preferred Securities. On November 13, 2001, ChevronTexaco purchased 150,000 shares of our Series B Mandatorily Convertible Redeemable Preferred Stock (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 Dispositions, Discontinued Operations and Acquisitions Dispositions Discontinued Operations Northern Natural, beginning on page F-27. Each share of our Series B preferred stock is convertible, at the option of ChevronTexaco, for a period of two years into shares of our Class B common

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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 are accreting an implied preferred stock dividend over the redemption period the Series B preferred stock is outstanding as required by GAAP. The shares of Series B preferred stock provide for a mandatory redemption on November 13, 2003. Our Board of Directors will evaluate this redemption obligation prior to November 13, 2003. Based on our substantial debt obligations, liquidity position, limitations under applicable state law and limitations in our restructured credit facility in respect of redemptions of equity securities, we do not currently expect to redeem the preferred shares in November 2003. Our restructured credit facility provides that we cannot redeem more than $50 million of the Series B preferred stock during the term of the facility and we must permanently reduce borrowings under the credit facility by three times any amount repaid. Shares not redeemed will remain outstanding. As of December 31, 2002 and 2001, the redemption amount associated with these securities totaled $1.5 billion.

The failure to redeem the Series B preferred stock on the redemption date would not be a default under any of our bank borrowings, secured debt, senior notes or other debt obligations. The shares of Series B preferred stock are not entitled to a dividend in cash or in kind or Board representation either currently or upon a failure to make a redemption payment. We continue to engage in discussions with ChevronTexaco regarding a possible restructuring of the redemption obligations with respect to this preferred stock.

Trust Originated Preferred Securities. Illinois Power Financing Inc. (IPFI) is a statutory business trust in which IP serves as sponsor. In 1996, IPFI issued $100 million aggregate liquidation amount of 8% Trust Originated Preferred Securities (TOPrS) in a private transaction. The TOPrS were to mature on January 31, 2045 and could be redeemed at IP s option, in whole or in part, from time to time on or after January 31, 2001. On September 30, 2001, IP redeemed all $100 million of the TOPrS. The redemption was financed with $85 million cash and $15 million in commercial paper.

NOTE 14 COMMITMENTS AND CONTINGENCIES

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 the opinion of management, the disposition of these ordinary course matters will not have a material adverse effect on 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 in accordance with Statement of Financial Accounting Standards No. 5, Accounting for Contingencies. For environmental matters, we record liabilities when environmental assessment indicates that remedial efforts are probable and the costs can be reasonably estimated. Please read Note 2 Accounting Policies Other Contingencies beginning on page F-19 for further discussion.

With respect to several of the items listed below, we have determined that a loss is not probable or that any such loss, to the extent probable, is not reasonably estimable. Notwithstanding the foregoing, our management has assessed the matters described below based on currently available information and made an informed judgment concerning the likely outcome of such matters, 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.

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Shareholder Litigation. Since April 2002, a number of class action lawsuits have been filed on behalf of purchasers of our publicly traded securities generally during the period between April 2001 and April 2002. These lawsuits principally assert that Dynegy and certain of our executive officers violated the federal securities laws in connection with our accounting treatment and disclosure of Project Alpha. These lawsuits have been consolidated in the United States District Court for the Southern District of Texas. On October 28, 2002, the court in which the cases have been consolidated appointed the Regents of the University of California as lead plaintiff and the law firm of Milberg Weiss as class counsel. Plaintiffs have until June 6, 2003 to file a consolidated amended complaint, which may differ materially from the complaints presently on file. We expect that the amended complaint will include additional allegations relating to Project Alpha, particularly in light of our settlement with the SEC which is described below, as well as allegations relating to round-trip trading, the submission of false trade reports to publications that calculate natural gas index prices, alleged manipulation of the California power market and the restatement of Dynegy s financial statements for periods since 1999. The original complaint covered a class period from April 2001 to April 2002. We expect the amended complaint to cover a longer period, particularly in light of our previously announced restatements. It is not possible to 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. An adverse result could have a material adverse effect on our financial condition and results of operations.

In addition, three derivative lawsuits have been filed in which we are a nominal defendant. The lawsuits relate to Project Alpha, round-trip trades and alleged manipulation of the California power market. The lawsuits seek recovery on behalf of Dynegy from various present and former officers and directors. We are analyzing these claims and, because of the nature of these derivative lawsuits, do not expect to incur any material liability with respect to these derivative claims.

ERISA/401(k) Litigation. On August 15, 2002, a purported class action complaint was filed against us in the United States District Court for the Southern District of Texas (Houston Division) alleging violations of the Employee Retirement Income Securities Act. The lawsuit concerns the Dynegy Inc. 401(k) Savings Plan and claims that our Board of Directors and certain former and current officers involved in the administration of the 401(k) Plan breached their fiduciary duties to the Plan s participants and beneficiaries in connection with the Plan s holdings of Dynegy common stock. The lawsuit seeks unspecified damages for the losses to the Plan resulting from the alleged breaches of fiduciary duties, as well as attorney s fees and certain other costs. The putative class was defined as participants holding Dynegy common stock in the plan as of April 17, 2001 or later. On February 12, 2003, the plaintiffs filed an amended complaint, which extended the putative class period back to April 27, 1999. Additional past Board members were named as defendants, as were past and present members of our Benefit Plans Committee. The amended complaint alleges that our earnings and business conditions were misstated from 1999 forward and that, during such period, Dynegy and members of the Board, including members of the Compensation and Human Resources Committee of the Board, breached fiduciary duties by failing to disclose to the Benefit Plans Committee information regarding risks associated with our business due to misstatements about our revenues, earnings and operations, which information was material to the appropriateness of Dynegy common stock as an investment option, and by failing to monitor the Benefit Plans Committee. The amended complaint further alleges that the Benefit Plans Committee breached fiduciary duties by failing to disclose complete and accurate information with respect to the suitability of investing in Dynegy common stock and by failing to eliminate Dynegy common stock as a Plan investment option, and that the Benefit Plans Committee breached their duty of loyalty to discharge their duties to the Plan solely in the interest of the participants and beneficiaries. The amended complaint also alleges that we breached co-fiduciary duties under ERISA and, to the extent it is found not to be a fiduciary, that we benefited by knowingly participating in fiduciary breaches by others. The plaintiff filed a second amended complaint on April 7, 2003, which names as

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additional defendants certain former employees who served on a predecessor committee to the Benefit Plans Committee. The plaintiff also included in this second amended complaint allegations relating to Project Alpha, round trip trades and the gas price index investigation.

We are analyzing these claims and intend to defend against them vigorously. As with the shareholder class action lawsuits described above, it is not possible to predict with certainty whether we will incur any liability or to estimate the damages, if any, that might be incurred in connection with this lawsuit. However, an adverse outcome could have a material adverse effect on our financial condition and results of operations.

Baldwin Station Litigation. IP and Dynegy Midwest Generation, Inc., collectively referred to in this section as the Defendants, are currently the subject of a Notice of Violation (NOV) from the EPA and a complaint filed by the EPA and the Department of Justice alleging violations of the Clean Air Act, the regulations promulgated thereunder and certain Illinois regulations adopted pursuant to the Clean Air Act. Eight similar notices and complaints were filed against other owners of coal-fired power plants. Both the NOV and the complaint allege that certain equipment repairs, replacements and maintenance activities at the Defendants three Baldwin Station generating units constituted major modifications under the Prevention of Significant Deterioration (PSD), the New Source Performance Standard (NSPS) regulations and the applicable Illinois regulations, and that the Defendants failed to obtain required operating permits under the applicable Illinois regulations. When activities that meet the definition of major modifications occur and are not otherwise exempt, the Clean Air Act and related regulations generally require that the generating facilities at which such activities occur meet more stringent emissions standards, which may entail the installation of potentially costly pollution control equipment. The Defendants filed an answer denying all claims and asserting various specific defenses, and a trial date of June 3, 2003 has been set.

We have undertaken activities to significantly reduce emissions at the Baldwin Station since the complaint was filed in 1999. In 2000, the Baldwin Station was converted from high to low sulfur coal, resulting in sulfur dioxide emission reductions of over 90% from 1999 levels. Furthermore, selective catalytic reduction equipment has been installed at two of the three units at Baldwin Station, resulting in significant emission reductions of nitrogen oxides. However, the EPA may seek to require the installation of the best available control technology, or the equivalent, at the Baldwin Station. Current estimates indicate that we could incur capital expenditures of up to $410 million if the installation of best available control technology were required. The EPA also has the authority to seek penalties for the alleged violations at the rate of up to $27,500 per day for each violation.

On February 19, 2003, the Court granted our motion for partial summary judgment based on the five-year statute of limitations. As a result, the EPA will not be permitted to seek any monetary civil penalties for claims related to construction without a permit under the PSD regulations. The Court s ruling also precludes monetary civil penalties for a portion of the claims under the NSPS regulations and the applicable Illinois regulations. We believe that we have meritorious defense against the remaining claims and will vigorously defend against them. We have recorded a reserve for potential penalties that could be imposed if the EPA were to prosecute successfully its remaining claims for penalties.

None of the Defendants other facilities are covered in the complaint and NOV, but the EPA has officially requested information, and we have provided such information, concerning activities at the Defendants Vermilion, Wood River and Hennepin Plants as well as the Danskammer and Roseton plants operated by other Dynegy subsidiaries. The EPA could eventually commence enforcement actions based on activities at these plants.

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***California Market Litigation*.** Six class action lawsuits were filed in 2000-2001 against various Dynegy entities based on the events occurring in the California power market. The complaints allege violations of California s Business and Professions Code, Unfair Trade Practices Act and other related statutes. The plaintiffs allege that the defendants, including the owners of in-state generation and various power marketers, conspired to manipulate the California wholesale power market to the detriment of California consumers. Included among the acts forming the basis of the plaintiffs claims are the alleged improper sharing of generation outage data, improper withholding of generation capacity and the manipulation of power market bid practices. The plaintiffs seek unspecified treble damages.

All six lawsuits were consolidated before Judge Sammartino, Superior Court Judge for the County of San Diego. Subsequent to this consolidation, two of the defendants filed cross-complaints against a number of corporations and governmental agencies that sold power in California s wholesale energy markets. Four cross-defendants removed the six cases to the United States District Court for the Southern District of California (San Diego) and the cases were returned to Multi-District Litigation Proceeding 1405, referred to as the California Wholesale Electricity Antitrust Litigation. The original plaintiffs in the six consolidated complaints filed motions to remand the consolidated cases back to state court, which motions were granted. Some of the cross-defendants then appealed that ruling and, prior to the remand taking effect, the Ninth Circuit Court of Appeals granted review and stayed the remand order. A ruling by the Ninth Circuit is not expected until late this year at the earliest.

On January 6, 2003, the Federal Judge in the California Wholesale Electricity Antitrust Litigation dismissed with prejudice one of the cases, *Public Utility District No. 1 of Snohomish County*, based upon the filed rate doctrine and federal preemption principles. On January 27, 2003, the plaintiffs in that case filed a notice of appeal of the Court s decision.

In addition to the six consolidated lawsuits discussed above, ten other putative class actions and/or representative actions have been filed on behalf of business and residential electricity consumers. The lawsuits were filed in various state courts and in the United States District Court for the Northern District of California. The defendants named in these lawsuits are various power generators and marketers, including Dynegy and some of our affiliates. The complaints allege unfair, unlawful and deceptive practices in violation of the California Unfair Business Practices Act and seek to enjoin illegal conduct, restitution and unspecified damages. While some of the allegations in these lawsuits are similar to the allegations in the other six lawsuits, these lawsuits include additional allegations based on events occurring subsequent to the filing of the other six lawsuits. These additional allegations include allegations similar to those made by the California Attorney General in the March 11, 2002 lawsuit described below as well as allegations that contracts between these power generators and the CDWR constitute unfair business practices resulting from market manipulation. The lawsuits filed in state court were removed to federal courts and ultimately all of these cases have been added to the California Wholesale Electricity Antitrust Litigation. The plaintiffs in all but one of these cases have filed motions to remand the cases to state court. The oral argument on these motions to remand was heard on March 26, 2003 before Judge Whaley, and the matters are under submission.

Two other actions have recently been filed with allegations similar to those in the California Wholesale Electricity Antitrust Litigation on behalf of residents of the State of Washington and residents of the State of Oregon. *Symonds v. Dynegy* was filed in the United States District Court for the Western District of Washington. *Lodewick v. Dynegy* was originally filed in the State Court of Oregon and has since been removed to the

United States District Court for the District of Oregon. Defendants in these matters sought to have these actions included in the California Wholesale Electricity Antitrust Litigation; however, the Multi-District Litigation panel indicated

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that since Judge Whaley was a resident of the State of Washington, it is unlikely that the cases would be assigned to the California Wholesale Electricity Antitrust Litigation. A motion by some of the defendants has been filed with the Multi-District Litigation panel seeking to have the assignment of these two cases to the Honorable Vaughn Walker in the Northern District of California, who has pending before him those cases filed by the California Attorney General as referred to below.

On March 11, 2002, the California Attorney General filed, on behalf of the People of the State of California, complaints in San Francisco Superior Court against several owners of power generation facilities, including subsidiaries of West Coast Power. The complaints allege that since June 1998, these power generators sold power in the open market that should have been held in emergency reserve for the State. In the aggregate, the complaints seek more than $150 million in penalties, restitution and return of profits from the generators. These lawsuits were subsequently removed to the United States District Court for the Northern District of California. The California Attorney General filed motions to remand the cases back to state court. By Order issued on August 6, 2002, Judge Walker denied the motions to remand, thus keeping the cases in federal court. On March 25, 2003, Judge Walker dismissed this action based upon the filed rate doctrine and federal preemption principles. The California Attorney General has appealed this decision and is seeking an expedited briefing schedule.

On November 20, 2002, a new class action was filed in the Superior Court of the State of California for the County of Los Angeles styled *Cruz Bustamante v. The McGraw Hill Companies, Inc., et al.* on behalf of purchasers of natural gas and electricity in the State of California. Plaintiffs allege damages as the result of the defendants alleged false reporting of pricing and volume information regarding natural gas transactions. Pursuant to a stipulation of the parties, the Court has issued a briefing schedule for defendants responsive pleadings in this action. The Court has ordered that the hearing on any such motions will be held on June 18, 2003.

We believe that we have meritorious defenses to these claims and intend to vigorously defend against them. We are unable to estimate the range of possible loss that could be incurred with respect to these lawsuits. However, an adverse result in any of these proceedings could have a material adverse effect on our financial condition and results of operations.

FERC and Related Regulatory Investigations

Requests for Refunds. On July 25, 2002, the FERC initiated a hearing to establish refunds to electricity customers, or offsets against amounts owed to electricity suppliers, during the period of October 2, 2000 through June 19, 2001. In particular, the FERC established a methodology to calculate mitigated market clearing prices in the Cal ISO and the Cal PX markets. During March 2002 and August 2002, hearings on this matter were held before an administrative law judge. On December 12, 2002, the administrative law judge issued his recommendations regarding the appropriate level of refunds or offsets. Those recommendations, however, do not fully reflect proposed refund or offset amounts for individual companies. In order to determine such amounts, the Cal ISO and Cal PX must rerun their settlement processes in a compliance stage of the proceeding. We subsequently filed briefs with the FERC supporting certain aspects of the administrative law judge s decision and opposing others. The matter now is awaiting a decision from the FERC.

In August 2002, the FERC requested comments on a proposal made by the FERC staff to change the method for determining natural gas prices for purposes of computing the mitigated market-clearing price that it intends to utilize in calculating refunds for sales of power in California power markets during the period from October 2,

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2000 to June 19, 2001. The proposal replaces the gas prices used in the computation, thus reducing the mitigated market clearing price for power and increasing calculated refunds, subject to a provision that generally would provide full recoverability of gas costs paid by the generators to unaffiliated third parties. This proposal was adopted by the FERC on March 26, 2003. We expect that proceedings at FERC to determine final calculated refund amounts, net of any adjustments for actual gas costs incurred by generators, will commence during the second quarter 2003.

On March 27, 2003, the FERC issued a decision in the refund case in which it essentially adopted the FERC staff s proposal to change the gas pricing component of the refund calculations. The FERC did, however, recognize that many generators paid higher prices for gas than would be reflected in this new calculation and provided a mechanism whereby generators can submit evidence of their actual out-of-pocket spot gas purchase costs and have those costs deducted from the refund calculations. We intend to vigorously pursue relief under this procedure. The FERC otherwise affirmed the decision by the administrative law judge, and indicated that it expected to have specific refund or offset calculations by the end of the Summer 2003. We intend to seek rehearing of the FERC s decision changing the gas pricing methodology.

On November 20, 2002, the FERC granted a motion filed jointly by the People of the State of California, *ex rel.* Bill Lockyer, Attorney General, the California Electricity Oversight Board, the Public Utilities Commission of the State of California, Pacific Gas and Electric Company, and Southern California Edison Company, referred to in this section as the California Parties, to reopen the record in the refund proceeding to allow 100 days of discovery into allegations of market manipulation. The California Parties submitted the results of their discovery effort on March 3, 2003. Other parties also made such submissions. The California Parties sought increased refunds for the period from October 2, 2000 to June 19, 2001 based on, among other things, the adoption of the FERC staff s proposal to change the gas prices used in computing refunds. The California Parties also sought refunds for the period from May 1, 2000 through October 1, 2000. We submitted our response on March 20, 2003. We believe that we have meritorious defenses against these claims and intend to vigorously defend against them. Please read West Coast Power below for a discussion of the reserves recorded by West Coast Power relative to its exposure in the California power market.

Other FERC and California Investigations. On February 13, 2002, the FERC initiated an investigation of possible manipulation of natural gas and power prices in the western United States during the period from January 2001 through the present. On May 8, 2002, in response to three memoranda discovered by the FERC allegedly containing evidence of market manipulation by others in California, the FERC issued requests for information to all sellers in the Cal ISO and Cal PX markets during 2000 and 2001 seeking information with respect to whether those sellers engaged in trading strategies described in the three memoranda. We responded to these requests, indicating that we did not engage in the trading strategies described in the three memoranda. In August 2002, the FERC staff issued its preliminary report on its investigation into trading practices in the three memoranda. We continued to provide the FERC with additional information relevant to its investigation.

On March 26, 2003, the FERC staff issued its Final Report on Price Manipulation in Western Markets, addressing a number of issues. In its report, the FERC staff indicated that it appears a majority of public utility entities, and some non-public utilities, engaged in some of the above-referenced trading strategies during the two-year review period. The FERC staff also recommended that the FERC issue orders requiring that Dynegy and 36 other market participants be required to show cause why their activities did not violate the Cal ISO and Cal PX tariffs. Potential penalties for violation of the tariff could include disgorgement of unjust profits from activities found to be in violation of the tariff. Many of these allegations have already been raised and were answered in large part in our FERC filing of March 20, 2003. We intend to defend against them vigorously.

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On May 21, 2002, the FERC issued requests for information to all sellers of wholesale electricity or ancillary services in the Western Electricity Coordinating Council (WECC) and, on May 22, 2002, the FERC issued requests for information to all sellers of natural gas in the WECC or Texas, seeking information with respect to whether those sellers engaged in wash, round-trip or sale/buyback transactions during 2000-2001.

We responded to each of these requests. Based on our investigation to date, we believe that our trading practices are consistent with applicable law and tariffs. We will continue to cooperate fully with these investigations. Please read SEC Settlement below for a discussion of our round-trip energy trades with CMS Energy.

On August 13, 2002, the FERC staff issued its preliminary report on its investigation into wash, round-trip or sale/buyback transactions. In the FERC staff s March 26, 2003 Final Report on Price Manipulation in Western Markets, it recommended that the FERC establish specific rules banning any form of prearranged wash trading activities, but made no recommendations regarding wash transactions specifically with respect to us.

Requests for similar information regarding the above-referenced trading strategies and wash trades with respect to electric power trading activities within the ERCOT were received from the Texas Public Utility Commission (Texas PUC) in June 2002. We responded to each of these requests. Based on our investigation to date, we believe that our trading practices are consistent with applicable law and tariffs. The Texas PUC has not issued findings on its investigation and we cannot predict with certainty how the investigation will be resolved.

On September 17, 2002, California Public Utilities Commission President Loretta Lynch released a report indicating that Dynegy and five other energy firms did not produce all available power on days in which the State of California experienced power service interruptions between November 1, 2000 and May 31, 2001. No mention is made of prosecuting the named firms in the report. However, the SEC and FERC staffs requested additional information and comment with respect to the report. On March 26, 2003, the FERC staff issued its analysis of the report and found that it was incomplete and overstated the amount of power withheld. The FERC staff s analysis further stated that there was no evidence that we withheld any material amounts of power or that we were responsible for any service interruptions.

Trade Press. In September 2002, the FERC staff issued requests for information on issues related to reporting of information on natural gas and electricity trades to energy industry publications that compile and report index prices. We responded to these requests and cooperated with the FERC staff in connection with this matter. In its Final Report on Price Manipulation in Western Markets, the FERC staff made several recommendations in order to ensure the integrity and accuracy of energy price indices in the future. The staff also recommended that the FERC issue orders requiring Dynegy and ten other companies to show cause that employees involved in improper index reporting have been disciplined; that a clear code of conduct is in place for reporting price information; that all trade data reporting is done by an entity within the company that does not have a financial interest in the published index; and that the company is fully cooperating with any government agency investigating its past price reporting. We believe that we are in compliance with each of these recommended requirements.

Western Long-Term Contract Complaints. On February 25, 2002, the California Public Utilities Commission and the California Electricity Oversight Board filed complaints with the FERC asking that it void or reform power supply contracts between the CDWR and, among others, West Coast Power. The complaints allege that prices under the contracts exceed just and reasonable prices permitted under the Federal Power Act. The

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FERC set these complaints for evidentiary hearing. On January 10, 2003, the FERC granted a motion by Dynegy and other defendants for the administrative law judge to issue a partial initial decision on certain threshold legal issues, and for the FERC itself to resolve the issues on the basis of the record developed at hearing. On January 16, 2003, the administrative law judge issued a decision adopting our view on the threshold legal issue. The complainants have appealed that decision to the FERC. Both sides of the case also have filed briefs before the FERC and the case is awaiting decision. Additionally, on March 3, 2003, the complainants filed supplemental testimony requesting that the FERC void or reform the power supply contracts at issue based on the allegations of market manipulation submitted by the California Parties. On March 20, 2003, Dynegy and other the defendants filed responses to this submission. While we believe the terms of our contracts are just and reasonable and do not reflect alleged market manipulation, we cannot predict the outcome of this matter.

In a related complaint, The Kroger Co. filed a complaint with the FERC in August 2002 asking that the four wholesale contracts between Dynegy Power Marketing, Inc. and AES New Energy, Inc., which provides retail service to The Kroger Co., be declared void for their remaining terms, and that the FERC set just and reasonable rates for prior periods. Alternatively, The Kroger Co. asks that the FERC allow for an annual review procedure to reset the contract prices. The complaint alleges that but for the dysfunctional California electricity markets, it would not have entered into the contracts for delivery of energy through December 2006. On March 14, 2003, the FERC issued an order setting The Kroger Co. s complaint for hearing, establishing hearing procedures and holding the hearing in abeyance pending proceedings for a FERC settlement judge. Settlement proceedings are currently being conducted by the settlement judge. We believe that we have meritorious defenses against these claims and intend to vigorously defend against them.

West Coast Power. Through our interest in West Coast Power, we have credit exposure for past transactions to the Cal ISO and Cal PX, which primarily relied on cash payments from California utilities to in-turn pay their bills. West Coast Power currently sells directly to the CDWR pursuant to a long-term sales agreement. Please see Western Long-Term Contracts Complaints above for discussion of the actions taken by various parties with respect to this agreement.

At December 31, 2002, our portion of the receivables owed to West Coast Power by the Cal ISO and Cal PX approximated $200 million. Management is continually assessing our exposure, as well as our exposure through West Coast Power, relative to our California receivables and establishes reserves for contingent liabilities where the amount of potential loss is determined to be probable and estimable. During 2002, 2001 and 2000, our pre-tax share of reserves recorded by West Coast Power totalled $49.0 million, $122.5 million and $24.5 million, respectively. Our share of the total reserve at December 31, 2002 and 2001 was $200.8 million and $151.8 million, respectively.

Enron Merger Termination Litigation. Dynegy and DHI were sued on December 2, 2001 by Enron and Enron Transportation Services Co. in the United States Bankruptcy Court for the Southern District of New York, Adversary Proceeding No. 01-03626 (AJG). Enron claimed that Dynegy materially breached the Merger Agreement dated November 9, 2001 between Enron and Dynegy and related entities by wrongfully terminating that Agreement on November 28, 2001. Enron also claimed that DHI wrongfully exercised its option to take ownership of Northern Natural under an Option Agreement dated November 9, 2001. Enron sought damages in excess of $10 billion and declaratory relief against Dynegy for breach of the Merger Agreement. Enron also sought unspecified damages against Dynegy and DHI for breach of the Option Agreement. We filed an answer on February 4, 2002, denying all material allegations. On April 12, 2002, the Bankruptcy Court granted our motion to transfer venue in the proceeding to the United States District Court for the Southern District of Texas (Houston Division).

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On August 15, 2002, we entered into an agreement with Enron to settle this lawsuit. Under the terms of the settlement agreement, we agreed to pay Enron $25 million, $10 million of which was paid to Enron upon approval of the settlement agreement by the Bankruptcy Court, with the remaining $15 million escrowed until approval of the settlement becomes final. In addition, we agreed with Enron to exchange mutual releases of any and all claims related to the terminated merger and to dismiss the related litigation. We also agreed not to pursue any claims for working capital adjustments relating to our acquisition of Northern Natural. The terms of the settlement were approved by the Bankruptcy Court on August 29, 2002. On September 6, 2002, an appeal of the Bankruptcy Court s approval was filed by the plaintiffs who had filed the class action lawsuits described below. On February 6, 2003, the District Court affirmed Judge Gonzalez s order approving the settlement agreement. On April 7, 2003, following the expiration of the time period during which these plaintiffs could have filed a further appeal, we and Enron filed with the United States District Court for the Southern District of Texas (Houston Division) a joint motion for dismissal of Enron s claims with prejudice. Upon the courts approval of such motion, our settlement with Enron will be effective and their lawsuit will be formally dismissed.

Ann C. Pearl and Joel Getzler filed a suit against Dynegy and DHI in the United States District Court for the Southern District of New York. Plaintiffs filed the lawsuit as a purported class action on behalf of all persons or entities that owned Enron common stock as of November 28, 2001. A similar suit was filed by Bernard D. Shapiro and Peter Strub in the 129th Judicial District Court for Harris County, Texas. Plaintiffs in each case alleged that they are intended third-party beneficiaries of the Merger Agreement dated November 9, 2001 among Enron, Dynegy and related entities. Plaintiffs claimed that we materially breached the Merger Agreement by, among other things, wrongfully terminating that agreement. Plaintiffs also claimed that we breached the implied covenant of good faith and fair dealing. Plaintiffs sought unspecified damages and other relief. Enron moved for an order of the Bankruptcy Court in the Southern District of New York directing that the Pearl and Shapiro plaintiffs be enjoined from prosecuting their actions and that their actions be immediately dismissed. The Bankruptcy Court held that the claims asserted by the Pearl and Shapiro plaintiffs were the exclusive property of the Enron bankruptcy estate and that the plaintiffs lacked standing to sue as third-party beneficiaries of the Merger Agreement. Accordingly, by an order entered on April 19, 2002, the Bankruptcy Court granted Enron s motion, enjoined the prosecution of both actions and directed that they be dismissed. The Pearl and Shapiro plaintiffs thereafter complied with that order, but filed an appeal to the United States District Court for the Southern District of New York. On October 22, 2002, the District Court reversed the Bankruptcy Court s determination, holding that the Pearl and Shapiro plaintiffs do have standing to sue as third-party beneficiaries, and that their claims are not the exclusive property of the bankruptcy estate. Shortly after this ruling, certain Enron shareholders filed an action against Dynegy for wrongful termination of the Merger Agreement in the United States District Court for the Southern District of New York.

On October 28, 2002, Dynegy and DHI filed a declaratory action in Harris County Judicial District Court relating to the Shapiro action. The action seeks to reinstate the Shapiro action in the 129th Judicial District Court that is no longer stayed. The action also seeks affirmative declarations to the effect that Dynegy did not wrongfully terminate the Merger Agreement, that the termination did not breach any duty owed to the Shapiro plaintiffs or to Enron s shareholders generally and that neither the Shapiro plaintiffs nor Enron s shareholders generally have a right to enforce or to make claims under the Merger Agreement.

On April 9, 2003, we executed a settlement agreement with the former Enron stockholder plaintiffs relating to the purported class action lawsuits described above. Pursuant to the settlement agreement, which is subject to court approval, we have agreed to pay $6 million to settle the claims asserted on behalf of the class of all Enron shareholders who held Enron stock at the time the merger was terminated. We have a unilateral right to terminate the settlement agreement if any class members opt out of the settlement class or if the court fails to approve any material provision of the settlement agreement.

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We believe that we have meritorious defenses against these claims and, subject to the finalization of the settlements described above, intend to vigorously defend against them. An adverse result in any of these proceedings, however, could have a material adverse effect on our financial position and results of operations.

Enron Trade Credit Litigation. As a result of Enron s bankruptcy filing, we recognized in our fourth quarter 2001 financial statements a pre-tax charge related to our net exposure for commercial transactions with Enron. As of December 31, 2002, our net exposure to Enron, inclusive of certain liquidated damages and other amounts relating to the termination of the transactions, was approximately $84 million and was calculated by setting off approximately $230 million owed from various Dynegy entities to various Enron entities against approximately $314 million owed from various Enron entities to various Dynegy entities. The master netting agreement between us and Enron 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 dispute by Enron with respect to which there have been negotiations between the parties. These negotiations have focused on the scope of the transactions covered by the master netting agreement and the parties valuations of those transactions. If any disputes cannot be resolved by the parties, the agreements call for arbitration. We have instituted arbitration proceedings against those Enron parties not in bankruptcy and have 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 have responded by opposing our request to enforce the arbitration requirement and filing an adversary proceeding against us. Both the opposition to the arbitration request and the adversary proceeding allege 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 provided for in the master netting agreement. No ruling has been made by the Bankruptcy Court, and the Court has referred the disputes to non-binding mediation. If the setoff rights were modified or disallowed, either by agreement or otherwise, the amount available for Dynegy entities to set off against sums that might be due Enron entities could be reduced materially.

Telstra Litigation. On January 25, 2002, Telstra Corporation, Ltd. and Telstra Wholesale Inc. (collectively, Telstra) filed suit in Delaware Chancery Court against DynegyConnect, L.P. (DynegyConnect), a limited partnership in which Dynegy acquired a combined 80% interest, as well as some of our other affiliates. DynegyConnect is a vehicle established by us to participate in the U.S. telecommunications business. Telstra Wholesale originally acquired the remaining 20% interest in DynegyConnect pursuant to a limited partnership agreement that was executed in October 2000 and details the partners rights and obligations. Under the agreement, Telstra Wholesale was granted a put option permitting it to require Dynegy or its designee, at any time on or before September 20, 2002, to purchase its 20% partnership interest for a purchase price equal to the value of Telstra Wholesale s capital account in DynegyConnect, subject to certain adjustments. The plaintiffs brought this action in connection with Telstra Wholesale s attempted exercise of this put option. The plaintiffs alleged breach of contract and bad faith, among other things, in connection with the valuation of Telstra Wholesale s capital account and, as a result, the put option purchase price, as well as the administration of the partnership. The plaintiffs sought approximately $50 million plus interest in damages together with fees and other litigation expenses. Previously, Minority Interest on our consolidated balance sheets included amounts relating to Telstra Wholesale s investment in DynegyConnect, which amounts equaled the fair value of Telstra Wholesale s put option. During the fourth quarter 2002, based on the status of the litigation, this Minority Interest liability was reclassified to a current liability, which reclassification had no impact on net income, and we accrued an additional $15 million legal expense.

Telstra filed a motion for summary judgment on December 6, 2002, and the court partially granted Telstra s motion on March 4, 2003. The court ruled against Dynegy on Telstra s breach of contract claim and in favor of

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Dynegy on Telstra s bad faith claim and set a trial date on the issue of damages. On March 14, 2003, the parties agreed to settle this lawsuit. Pursuant to the terms of the settlement agreement, we agreed to acquire Telstra Wholesale s minority interest in DynegyConnect effective as of September 19, 2001 in exchange for $45 million in cash, $10 million of which was paid on March 14, 2003 and the remaining $35 million of which is due on April 13, 2003.

Severance Arbitrations. Dynegy s former CEO, Chuck Watson, former President, Steve Bergstrom, and former CFO, Rob Doty, have each filed for arbitration pursuant to the terms of their employment/severance agreements. In each case, the parties disagree as to the amounts that may be owed pursuant to their respective agreements. These former officers have made arbitration claims that seek payments from us of up to approximately $28.7 million, $10.4 million and $3.4 million, respectively. These agreements are subject to interpretation and we believe that the amounts owed are substantially lower than the amounts sought. In particular, the severance agreement with Mr. Bergstrom provides that the amounts identified in the agreement are not due him if material financial restatements have occurred or allegations of wrongdoing are made against him by a state or federal law enforcement agency. However, we cannot predict with any degree of certainty the amounts that may be determined to be owed as a result of the pending arbitration proceedings. Please read Note 4 Restructuring and Impairment Charges Severance and Other Restructuring Costs beginning on page F-34 for discussion of the accruals we have recorded with respect to our estimated severance obligations.

Modesto Litigation. On August 3, 1998, the Modesto Irrigation District filed a lawsuit against PG&E and Destec Energy, Inc. (now known as Dynegy Power Corp.), which was previously acquired by Dynegy, in federal court for the Northern District of California, San Francisco division. The lawsuit alleges violations of federal and state antitrust laws and state law tort and breach of contract claims against Destec relating to a power sale and purchase arrangement with the plaintiff in the City of Pittsburg, California. While the plaintiff s pleadings indicate that it cannot measure its alleged damages with specificity, it has indicated that the actual damages sought from PG&E and Destec may exceed $25 million. Plaintiff also seeks a trebling of any portion of damages related to its antitrust claims. After the District Court dismissed the plaintiff s antitrust claims on August 20, 1999 and refused to assert pendent jurisdiction over the state law claims, the plaintiff filed an appeal with the Ninth Circuit Court of Appeals and re-filed its state claims in state court. Plaintiff then agreed to execute a tolling agreement on the state law claims and to dismiss the state court case until the federal appeal was decided. Plaintiff subsequently filed in the state court a request for dismissal, which the court granted on October 25, 2000.

Although PG&E filed a Chapter 11 bankruptcy proceeding on April 6, 2001, the automatic stay applicable in the proceeding was lifted to permit the Ninth Circuit to decide the pending appeal. On December 6, 2002, the Ninth Circuit reversed the District Court s order dismissing the plaintiff s antitrust claims. Plaintiff has not taken any action with respect to this action since December 6, 2002. We believe that we have meritorious defenses to these claims and we intend to vigorously defend against them. However, if the plaintiff were to successfully prosecute its claims, we could be required to fund a judgment in excess of $25 million.

Farnsworth Litigation. On August 2, 2002, Bradley Farnsworth filed a lawsuit against us in Texas state district 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 alleges, in the words of his 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. Mr. Farnsworth, who seeks unspecified actual and exemplary damages and other compensation, also alleges that he is

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entitled to a termination payment under his employment agreement 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 (currently estimated at a range of approximately $700,000 to $1,200,000). The parties have commenced discovery in this lawsuit. We believe that we have meritorious defenses against these claims and intend to vigorously defend against them. 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 or results of operations.

Apache Litigation. In May 2002, Apache Corporation filed suit in Harris County, Texas district court against Versado Gas Processors, LLC as purchaser and processor of Apache s gas, and against Dynegy Midstream Services, Limited Partnership as operator of the Versado assets in New Mexico. The suit, which followed an Apache audit of Versado s books and records relating to the parties commercial transactions, originally sought approximately $3.9 million in damages. Under an agreed court order, Versado analyzed the results of the Apache audit and voluntarily paid approximately $1.35 million to Apache in the third quarter 2002. Apache has since amended its petition to allege Versado still owes it a total of more than $9 million. These new claims include allegations that Versado engages in sham transactions with affiliates, which result in Versado not receiving the true fair market values when it sells the gas and liquids. They also allege, among other things, that the formula for calculating the amount Versado receives from the buyers of the 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. Versado intends to vigorously defend against these claims and believes it has meritorious defenses. Trial in the matter is scheduled for late third quarter 2003. 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 or results of operations.

Triad Energy Litigation. On March 18, 2003, Triad Energy Resources Corp. and five other alleged representatives of two plaintiffs classes filed a putative antitrust class action against NiSource Inc. and other defendants, including Dynegy Inc., in the United States District Court for the District of Columbia. The plaintiffs purport to represent classes of purchasers, marketers, wholesalers, managers, sellers and shippers of natural gas that allegedly were damaged by an illegal gas scheme devised by three federally regulated interstate pipeline systems: Columbia Gas Transmission Corporation, Columbia Gulf Transmission Company, and The Cove Point LNG Limited Partnership all of which now are owned by NiSource, and certain shippers on these pipelines.

The complaint alleges violations of the federal antitrust laws and common law tortious interference with contractual and business relations. It alleges that the interstate pipelines provided preferential storage and transportation services to their own unregulated marketing affiliate in violation of FERC regulations and, in return, received percentages of the profits reaped by the marketing affiliate. The complaint also alleges that certain shippers, including us, having learned of the Columbia arrangements, demanded and received similar preferential storage and transportation services that were not available to all shippers.

Although this alleged scheme was the subject of a FERC order issued on October 25, 2000, which order required the Columbia companies to pay $27.5 million to certain customers of Columbia Gas and Columbia Gulf, plaintiffs claim that the FERC order did not remedy the competitive injury to plaintiffs caused by the scheme. The complaint seeks aggregate damages of approximately $1.716 billion (divided approximately $1.034 billion and $682 million between two plaintiffs classes). Under the federal antitrust laws, damages are subject to trebling. We are analyzing these claims, which only recently were made, and intend to vigorously defend against them. It is not possible to predict with certainty whether we will incur any liability or to estimate the damages, if any, that we might incur in connection with this lawsuit.

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Alleged Marketing Contract Defaults. We have posted collateral to support a substantial portion of our obligations in our customer risk management business, including our obligations under some of our power tolling arrangements. While we have been working 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 have received a notice of default from each such party with regard to collateral and are continuing to negotiate the issue. Our annual net payments under these two arrangements approximate $67 million and $57 million, respectively, and the contracts extend through 2014 and 2012, respectively. If these two parties were to successfully pursue claims that we defaulted on these contracts, they could declare a termination of their respective contracts, which 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 and results of operations.

In addition, we are involved in litigation with some of our former counterparties relating to contract terminations with respect to which we were unable to agree on mutually acceptable collateral or other adequate assurance. We intend to vigorously defend against these claims and do not expect that any liability we might incur in connection with these contract terminations will materially adversely affect our financial condition or results of operations.

U.S. Attorney Investigations. The U.S. Attorney s office in Houston has commenced an investigation of our actions relating to Project Alpha, roundtrip trades with CMS Energy and our gas trade reporting practices. We have produced documents and witnesses for interviews in connection with this investigation. Six of our natural gas traders were dismissed in October 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. On January 27, 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. We are cooperating fully with the U.S. Attorney s office in its investigation of these matters and cannot predict the ultimate outcome of this investigation.

Additionally, the United States Attorney s office in the Northern District of California has issued a subpoena to us requesting information related to the California energy markets. 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.

SEC Settlement. On September 24, 2002, we announced a settlement with the SEC of allegations made against us in connection with the previously disclosed investigation relating to Project Alpha and round-trip electricity trades with CMS Energy. In the settlement, the SEC found that we engaged in securities fraud in connection with our disclosures and accounting for Project Alpha, and negligently included materially misleading information about the round-trip energy trades with CMS Energy in two press releases we issued in early 2002. In settlement of the SEC s enforcement action, Dynegy, without admitting or denying the SEC s findings, agreed to the entry of a cease-and-desist order and to pay a $3 million penalty in a related civil suit filed

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in the United States District Court in Houston, Texas. We are continuing to cooperate with the SEC s ongoing investigation of others related to Project Alpha.

Nicor Energy Investigations. We own a 50% interest in Nicor Energy, L.L.C., a joint venture with Nicor Inc. that markets retail gas and electricity in the Midwest. During the first quarter of 2003, substantially all of the operations of Nicor Energy have been sold and we expect to liquidate the company in the second quarter of 2003. We have historically provided gas and electricity to Nicor Energy for resale to its retail customers; however, we ceased to provide gas to Nicor Energy effective March 31, 2003 in connection with our exit from third-party marketing and trading and will cease to provide electricity to Nicor Energy in connection with its assignment of our wholesale electricity contracts to the purchasers of its retail electricity business. On March 10, 2003, Nicor Inc. publicly announced that it expects the SEC to bring civil charges against Nicor Energy based on alleged violations of standard financial reporting relating to unbilled revenues and unrecorded liabilities, including fraud and maintaining false books and records. The U.S. Attorney for the Northern District of Illinois has also notified Nicor Energy that it is conducting an inquiry on these same matters, and that a grand jury is also reviewing these matters. We intend to cooperate with these investigations and cannot predict their ultimate outcomes.

Nicor Inc. previously revealed irregularities in accounting at Nicor Energy. We have reflected a $5.6 million pre-tax charge in the fourth quarter 2001 relating to our investment in Nicor Energy as a result of these matters. We intend to divest our ownership interest in Nicor Energy consistent with our previously announced exit from third-party marketing and trading.

CFTC Investigation. The CFTC commenced an investigation in June 2002 relating to our past trading activities. The investigation covers Dynegy*direct* and round-trip trading and was expanded to cover our practices with respect to furnishing information regarding natural gas trades to various energy industry publications that compile and report index prices. During an internal review of our trading activities that was conducted in connection with the CFTC investigation, we discovered that certain employees in our trading business had furnished inaccurate information to various industry publications. We are one of many energy industry participants who routinely provide trade data to the publications; consequently, we cannot determine whether the inaccurate data had any impact on the published indices. In response to these findings, we now require that all price information provided to industry publications be verified by the office of our Chief Risk Officer. In addition, in October 2002, we dismissed six employees and disciplined seven others in our natural gas trading business as a result of an investigation conducted by our Audit and Compliance Committee and in collaboration with independent counsel. Settlement with the CFTC was reached on December 18, 2002 regarding the gas price index issues, pursuant to which we agreed to pay a $5 million fine and neither admitted nor denied the CFTC s allegations of false reporting, attempted gas price manipulation and inadequate recordkeeping. The CFTC settlement also applied to West Coast Power, our 50-50 joint venture with NRG Energy. We have separately agreed to indemnify NRG Energy with respect to any liability that it might incur as a result of these issues.

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 maintained by us and our ERISA affiliates. We have cooperated with the Department of Labor throughout this investigation, which remains ongoing. As of this date, the investigation has 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. We have not yet received the Department of Labor s definitive findings resulting from its investigation.

Purchase Obligations. 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

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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, ships, power generation assets and long-haul fiber optic and metropolitan networks. The following describes the more significant commitments outstanding at December 31, 2002.

We have routinely entered into supply and market 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 May 2030. In return for such fixed capacity payments, we receive the right to generate electricity at agreed prices, which we then may re-market. These types of arrangements are referred to as tolling arrangements. These fixed capacity payments totaled approximately $3.8 billion at December 31, 2002.

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 $676 million as of December 31, 2002, with $327 million of the $676 million due after 2007.

We have $165 million of unconditional purchase obligations related to the purchase of power, gas, coal and systems design. Pursuant to our capital asset expansion program we entered into purchase orders to acquire at least 14 gas-fired turbines, representing a capital commitment of approximately $483 million. Commitments under these purchase orders are generally payable consistent with the delivery schedule. Approximately 95% are scheduled to be delivered by the end of 2006. The purchase orders include milestone requirements by the manufacturer and provide us with the ability to cancel each discrete purchase order commitment in exchange for a fee, which escalates over time. At December 31, 2002, we could have paid approximately $48 million to cancel all 14 purchase orders.

***Advance Agreement**.* In 1997, we received cash from a gas purchaser as an advance payment for future natural gas deliveries over a ten-year period (Advance Agreement). As a condition of the Advance 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 Advance 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 Advance Agreement. The balance at December 31, 2002 approximated $57 million. The Advance 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 Advance Agreement.

***Other Minimum Commitments**.* We have a commitment to pay decommissioning costs of approximately $5 million a year for the years 2003 to 2004 related to the sale of the Clinton nuclear facility in 1999. This sale occurred prior to our acquisition of Illinova in 2000; thus we were not involved with the sale. However, we assumed this decommissioning obligation in connection with our acquisition of Illinova. See Note 2 Accounting Policies Other Contingencies page F-19, for further discussion of our accounting policies surrounding asset retirement obligations.

We also have a total of approximately $9 million in future minimum commitments outstanding over the next several years to EnerTech Capital Partners II, L.P., a venture capital fund investing in energy and communication portfolio companies. These commitments relate to an initial commitment of $15 million of capital made by us in a prior year to serve as a strategic fund investor prior to our change to the current restructuring business model.

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We have not made our most recent cash capital call to EnerTech and are in negotiations to find a buyer for our investment in EnerTech.

Minimum commitments in connection with office space, equipment, plant sites and other leased assets, including the DNE sale-leaseback transaction discussed in Note 3 Dispositions, Discontinued Operations and Acquisitions Acquisitions DNE beginning on page F-31, at December 31, 2002, were as follows: 2003 $104 million; 2004 $169 million, 2005 $95 million; 2006 $92 million; 2007 $137 million and beyond $1.3 billion.

Rental payments made under the terms of these arrangements totaled $139 million in 2002, $132 million in 2001 and $75 million in 2000.

We are party to two lease agreements relating to VLGCs previously utilized in our global liquids business. The aggregate base commitments of the lease agreements are $13 million each year for the years 2003 through 2007, and $83 million through lease expiration. 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 leases to a wholly owned subsidiary of Transammonia Inc. The terms of the sub-charter are identical to the base commitments of the original lease agreements.

Guarantees. As discussed in Note 2, Statement No. 45 requires disclosure of information relating to guarantees issued. These guarantees include letters of credit, indemnities and other forms of guarantees provided by the Company to third parties.

Guarantees included letters of credits of $897 million and surety bonds totaling $114 million. At December 31, 2002, $20 million of the $114 million in surety bonds were supported by letters of credit. Approximately $33 million of the contingent financial commitments related to the surety bonds expire in 2003; however, these bonds are generally renewed on a rolling twelve-month basis.

As part of the acquisition of Illinois Power in 2000, we assumed a lease arrangement associated with the Tilton natural gas-fired generating facility, which is accounted for as an operating lease. Under the terms of this arrangement, we have provided a residual value guarantee of approximately $70 million associated with the leased asset. Pursuant to this guarantee, we have the option to acquire, at the end of the lease term, the leased assets for a purchase price determined at lease inception and estimated to represent fair market value at the end of the lease term. If we do not choose to purchase the leased asset, we must perform under the terms of the residual value guarantee. At lease inception, we guaranteed to the owner of the leased asset that the leased asset would maintain a value equal to at least 85% of its originally estimated fair value. If the value of the asset at lease termination is less than 85% of the originally estimated fair market value, we are obligated to pay the owner the difference. If at the end of the lease term we do not elect to purchase the leased assets, we are also responsible for dismantling the facility for the benefit of the lessor.

We have indemnified various parties against specific liabilities that third parties might incur in connection with acquisitions, divestitures and leasing arrangements that we enter into. These indemnities are contingent upon the other party incurring liabilities that are not recoverable from other third parties and reach a certain threshold. Indemnities provided under such contracts are customary in these types of arrangements, particularly for the Rough and Hornsea sales contract, where it is common practice in Europe to cap such indemnities at the purchase price paid. The indemnities relate to breach of warranties and terms of contracts, tax indemnifications, performance guarantees, compliance with laws and regulations, environmental and employee-related matters. At December 31, 2002, we do not expect any of the indemnities provided to third parties to have a material impact

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on the Company s financial statements. However, if a liability is brought against us under such indemnity in the future, it may have a material adverse effect to the consolidated financial position.

In connection with the sale of Northern Natural, the Hornsea gas storage facility, Illinois Power Transmission and certain NGL assets, we have provided certain indemnities to third parties acquiring the assets. Environmental liability indemnities provided in connection with the sale of certain NGL assets have a maximum loss threshold of $28 million. Indemnities provided in connection with the sale of other assets relate to environmental, tax, employee and other representations provided by the company. Maximum recourse under such indemnities under the Northern Natural, Rough and Hornsea storage facilities total $209 million, £316 million (approximately $510 million at December 31, 2002) and £130 million (approximately $210 million at December 31, 2002), respectively. As of December 31, 2002, we are not aware of any circumstance that would lead to future indemnity claims in connection with these transactions.

We have also provided a performance and replacement cost guarantee under a power purchase agreement related to our Rockingham power generation facility. The $21 million guarantee secures our obligation to deliver capacity from energy to a third party under the terms of the agreement.

NOTE 15 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 United States 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.

NOTE 16 CAPITAL STOCK

At December 31, 2002, 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 described in the Company s Amended and Restated Articles of Incorporation.

Pursuant to the terms of the Illinova acquisition, we established a series of preferred stock, designated as Series A Convertible Preferred Stock, which was issued to British Gas Atlantic (BG) and NOVA Corporation (NOVA) in accordance with the exchange ratios provided in the acquisition documents. On the effective date of the acquisition, BG and NOVA held an aggregate 6.7 million shares of this Series A Convertible Preferred Stock. All of these shares were converted into shares of Class A common stock in the second quarter of 2000. In addition 8,000,000 shares of preferred stock, previously designated as Dynegy Series A Participating Preferred Stock (Series A Preferred), were converted to shares of Class B common stock on a 0.69-for-one exchange ratio. No such preferred stock was outstanding at December 31, 2002 or 2001.

Please read Note 13 Redeemable Preferred Securities Series B Convertible Preferred Securities beginning on page F-61 for a discussion of the Series B preferred stock we issued to ChevronTexaco in November 2001, which preferred stock remains outstanding.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Common Stock. At December 31, 2002, there were 371,741,603 shares of Class A and B common stock issued in the aggregate and 1,679,183 shares were held in treasury. 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 majority of all of our directors or by a 66 $^{2}/3$ percent 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 $^{2}/3$ percent 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 ratable rights to dividends, when and if dividends are declared by the Board of Directors. Holders of Class A and Class B common stock are entitled to share ratably, as a single class, in all of our assets available for distribution to holders of shares of common stock upon the liquidation, dissolution or winding up of our affairs, after payment of our liabilities and any amounts to holders of preferred stock, if any.

A share of Class B common stock automatically converts into a share of Class A common stock if it is transferred to any person other than an affiliate of Chevron. Additionally, each share of Class B common stock automatically converts into a share of Class A common stock if the holders of all Class B common stock cease to own collectively 15 percent of our outstanding common stock. Conversely, any shares of Class A common stock acquired by Chevron or its affiliates will automatically convert into shares of Class B common stock, so long as Chevron and its affiliates continue to own 15 percent 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 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 pre-emptive rights under the shareholder agreement. The proceeds from this sale were approximately $205 million.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

In December 2001, 27.5 million shares of Class A common stock were sold through a public offering resulting in proceeds of approximately $539 million, net of underwriting commission and expenses of approximately $32 million. Concurrent with the public offering, members of our senior management purchased approximately 1.2 million shares of Class A common stock from us in a private placement. The net proceeds from these equity sales were used to reduce indebtedness under DHI s revolving credit facility by approximately $539 million and the remainder of the proceeds were used for general operating purposes.

In March 2001, approximately 1.2 million shares of Class B common stock were sold to Chevron in a private transaction pursuant to the exercise of its pre-emptive rights under the shareholder agreement. The proceeds from this transaction were approximately $41 million.

During 2000, we sold approximately 22.6 million shares of common stock. The offerings included approximately 18.4 million shares of Class A common stock sold to the public and approximately 4.2 million shares of Class B common stock sold to Chevron. Total net proceeds to us from these sales approximated $858 million, net of underwriting commissions and expenses of approximately $10 million. Additionally, Chevron purchased $200 million of Class B common stock concurrent with the acquisition of Illinova.

Concurrent with the acquisition of Illinova, BG and NOVA were issued preferred shares which were convertible into Class A common stock. In the second quarter of 2000, a non-recurring special dividend payment of $32 million was made to BG and NOVA prior the conversion of their preferred shares to Class A common stock.

Common stock activity (in millions) for the three years ended December 31, 2002 was as follows:

	Common Stock		Class A Common Stock		Class B Common Stock	
	Shares	Amount	Shares	Amount	Shares	Amount
December 31, 1999	217	$ 1		$		$
Illinova acquisition	(217)	(1)	195	1,168	81	650
Common Stock issued			19	748	4	110
Preferred Stock conversion			12			
Extant acquisition			2	67		
Options exercised			9	157		
401(k) plan and profit sharing			1	12		

December 31, 2000		$	238	$ 2,152	85	$ 760
Common stock issued			28	564	1	41
Options exercised			3	57		
401(k) plan and profit sharing				13		
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

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Treasury Stock. During 2002, 2001 and 2000, Class A common stock shares purchased from the open market and placed into treasury totaled 41,929, 1,696,800 and 70,000, respectively. During 2002, 129,546 shares were issued out of treasury stock.

Stock Options. Each option granted is valued at an option price, which ranges from $0.88 per share to $57.95 per share at date of grant. The difference, if any, between the option price and the common stock s fair value on the date of grant, which is referred to as the options s intrinsic value, is recorded as compensation expense over the respective vesting period.

We have eight stock option plans all of which contain authorized shares of our Class A common stock. 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 ten-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.

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 grants are vested.

Extant Plan. Adopted by Extant prior to the acquisition by Dynegy, this plan expired in September 2000 and contains 202,577 authorized shares. Grants from this plan vest at 25% per year.

UK Plan. This plan contains 276,000 authorized shares and has been terminated. All grants are vested.

Dynegy 1999 Long-Term Incentive Plan (LTIP). This annual compensation plan contains 6,900,000 authorized shares, has a ten-year term and expires in 2009. All grants are vested.

Dynegy 2000 LTIP. This annual compensation plan, created for all employees upon the merger date of Illinova and Dynegy, contains 10,000,000 authorized shares, has a ten-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. Created at the discretion of our Board of Directors, this plan 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 ten-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, or death, all of our option plans cease vesting, with the exception of the Employee Equity Plan, which contains partial vesting provisions for the events noted above, exclusive of voluntary terminations.

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DYNEGY INC.

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(RESTATED)

Compensation expense related to options granted totaled $11.2 million, $12.7 million and $15.4 million for the years ended December 31, 2002, 2001 and 2000, respectively. Compensation expense in 2002, 2001 and 2000 included $2 million, $1 million and $7 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. Total options outstanding and exercisable for 2002, 2001 and 2000 were as follows (options in thousands):

	Year Ended December 31,					
	2002		2001		2000	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding at beginning of period	33,920	$ 21.39	21,264	$ 10.65	28,651	$ 8.71
Granted	2,284	$ 2.83	15,820	$ 34.14	1,959	$ 31.48
Exercised	(3,007)	$ 2.95	(2,543)	$ 8.77	(8,329)	$ 8.52
Cancelled or expired	(5,115)	$ 27.54	(621)	$ 30.26	(1,017)	$ 13.45
Outstanding at end of period	28,082	$ 20.74	33,920	$ 21.39	21,264	$ 10.65
Exercisable at end of period	17,620	$ 19.69	12,516	$ 10.11	12,878	$ 8.03
Weighted average fair value of options granted during the period at market		$ 1.22		$ 19.41		$ 19.01
Weighted average fair value of options granted during the period at below market		$		$		$ 26.90
Weighted average exercise price of options granted during the period at below market		$		$		$ 29.33

Options outstanding as of December 31, 2002 (options in thousands) are summarized below:

Range of Exercise Prices	Options Outstanding: Number of Options Outstanding at December 31, 2002	Options Outstanding: Weighted Average Remaining Contractual Life (Years)	Options Outstanding: Weighted Average Exercise Price	Options Exercisable: Number of Options Exercisable at December 31, 2002	Options Exercisable: Weighted Average Exercise Price
$0.88-$2.15	3,531	6.9	$ 1.14	1,171	$ 1.48
$2.16-$5.15	3,397	3.2	$ 4.15	2,199	$ 4.18
$5.16-$11.59	2,152	4.1	$ 9.84	2,074	$ 9.94
$11.60-$23.18	5,538	4.8	$ 15.70	5,515	$ 15.68
$23.19-$28.98	6,631	6.7	$ 23.87	3,119	$ 23.87
$28.99-$34.77	1,776	6.2	$ 34.40	923	$ 34.44
$34.78-$40.57	237	7.3	$ 37.61	140	$ 37.38
$40.58-$46.36	306	3.2	$ 43.84	202	$ 43.66
$46.37-$52.16	4,366	5.9	$ 47.22	2,153	$ 47.23
$52.17-$57.95	148	5.5	$ 55.85	124	$ 56.17
	28,082			17,620	

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

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 described in the acquisition documents. Additionally, we instituted new option plans on the effective date of the acquisition.

NOTE 17 EMPLOYEE COMPENSATION, SAVINGS AND PENSION PLANS

Short-Term Bonus Incentive Plan. We maintain a discretionary incentive plan to provide employees with what we believe to be competitive and meaningful rewards for reaching corporate and individual objectives. Specific awards are at the discretion of the Compensation Committee of the Board of Directors (Compensation Committee).

401(k) Savings Plan. We established the Dynegy Inc. 401(k) Savings Plan (Dynegy Plan), which meets the requirements of Section 401(k) of the Internal Revenue Code, and is a defined contribution plan subject to the provisions of the Employee Retirement Income Security Act of 1974 (ERISA). The Plan and related trust fund are established and maintained for the exclusive benefit of participating employees in the United States and certain expatriates. Similar plans are available to other employees resident in foreign countries and are subject to the laws of each country. All employees of certain entities are eligible to participate in the Plan. Employee pre-tax contributions to the Plan are matched 100%, up to a maximum of five percent 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 discretionary contributions to employee accounts, subject to our performance. Matching contributions to the Plan and discretionary contributions are made in Dynegy common stock. During the years ended December 31, 2002, 2001 and 2000, we issued approximately 2.6 million, 0.3 million and 0.5 million shares, respectively, of Dynegy common stock to fund the plan. We discontinued the additional 5% profit sharing contribution to active employee accounts in 2001. However, active employees who normally would have received the profit sharing contribution under the Dynegy Plan began participating in the pension plan in 2001 (see below).

Certain eligible employees participate in the Illinois Power Company Incentive Savings Plan and Illinois Power Company Incentive Savings Plan for Employees Covered Under A Collective Bargaining Agreement (IP Plans), which meet the requirements of Section 401(k) of the Internal Revenue Code and are defined contribution plans subject to the provisions of ERISA. We match 50% of employee contributions to the IP Plans, up to a maximum of six percent of compensation, subject to IRS limitations. Employees are immediately 100% vested in our contributions. Matching contributions to the Plan are made in Dynegy common stock. During the years ended December 31, 2002, 2001 and 2000, we issued 723,999, 72,700 and 202,175 shares, respectively, of Dynegy common stock to fund the plan.

Certain eligible employees participate in the Dynegy Northeast Generation, Inc. Savings Incentive Plan (Northeast Plan), which meets the requirements of Section 401(k) of the Internal Revenue Code and is a defined contribution plan subject to the provisions of ERISA. Under the Northeast Plan, for representative (union) employees, we match 24% of employee contributions up to 6 percent of base salary. For non-representative (non-union) employees, we match 50% of employee contributions up to 8 percent of base salary. Our guaranteed match is subject to a maximum of six or eight percent of base pay, subject to IRS limitations. Employees are immediately 100% vested in our contributions. Matching contributions to the Northeast Plan are made in cash.

During the years ended December 31, 2002, 2001 and 2000, we recognized aggregate costs related to these employee compensation plans of $17 million, $27 million and $35 million, respectively.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

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. We added a cash balance feature effective for 2001 and thereafter with respect to employees who would have otherwise received a profit sharing contribution under the Dynegy Plan for 2001 and thereafter (the contribution credit under such cash balance feature shall generally be six percent of base pay). The following tables contain information about these plans on a combined basis ($ in millions):

	Pension Benefits		Other Benefits	
	2002	2001	2002	2001
Projected benefit obligation, beginning of the year	$ 524	$ 448	$ 140	$ 100
Business combination		14		5
Service cost	19	10	3	2
Interest cost	38	34	10	8
Plan amendments		8		
Actuarial (gain) loss	74	30	15	31
Special termination benefits	1	9		
Curtailment (gain) loss	2			
Participant contributions			1	
Benefits paid	(32)	(29)	(8)	(6)
Projected benefit obligation, end of the year	$ 626	$ 524	$ 161	$ 140
Fair value of plan assets, beginning of the year	$ 584	$ 627	$ 79	$ 83
Business combination		16		
Actual return on plan assets	(52)	(30)	(11)	(8)
Employer contributions	1		6	9
Participant contributions			1	1
Benefits paid	(32)	(29)	(8)	(6)
Fair value of plan assets, end of the year	$ 501	$ 584	$ 67	$ 79
Funded status	$ (125)	$ 60	$ (94)	$ (61)
Unrecognized prior service costs	6	8		
Unrecognized actuarial (gain) loss	288	101	84	55
Net amount recognized	$ 169	$ 169	$ (10)	(6)

Amounts recognized in the consolidated balance sheets consist of:				
Prepaid benefit cost	$ 127	$ 174	$	$
Accrued benefit liability	(68)	(5)	(10)	(6)
Intangible asset	6			
Accumulated other comprehensive income	104			
Net amount recognized	$ 169	$ 169	$ (10)	$ (6)

	Pension Benefits			Other Benefits		
	2002	2001	2000	2002	2001	2000
Weighted Average Assumptions:						
Discount rate at December 31	6.50%	7.50%	7.99%	6.50%	7.50%	8.00%
Expected return on plan assets as of January 1	9.00%	9.47%	9.47%	9.00%	9.50%	9.50%
Rate of compensation increase	4.50%	4.48%	4.48%	4.50%	4.50%	4.50%
Medical trend initial trend				9.44%	10.09%	6.70%
Medical trend ultimate trend				5.47%	5.48%	5.50%
Medical trend year of ultimate trend				2009/2015	2009/2015	2005

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

The changes in the projected benefit obligation and in plan assets attributable to business combination in 2000 are the result of the acquisition of Illinova. The changes in the projected benefit obligations and in plan assets attributable to business combination in 2001 are the result of the DNE acquisition. Special termination benefits of approximately $9 million in 2001 reflect the additional expense of the early retirement window related to the Illinois Power Company Retirement Income Plan for Salaried Employees. Curtailment losses of $2 million during 2002 relate to the 2002 severance plans (see Note 4 Restructuring and Impairment Charges Severance and Other Restructuring Costs, beginning on page F-34, for further discussion).

On December 31, 2002, our annual measurement date, the accumulated benefit obligation related to our pension plans exceeded the fair value of the pension plan assets. This difference is attributed to (1) an increase in the accumulated benefit obligation that resulted from a 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. As a result, in accordance with Statement of Financial Accounting Standards No. 87, Employers Accounting for Pensions , we recognized a charge to accumulated other comprehensive loss of $66 million (net of taxes of $38 million), which decreased stockholders equity.

The components of net periodic benefit cost were (in millions):

	Pension Benefits			Other Benefits		
	2002	**2001**	**2000**	**2002**	**2001**	**2000**
Service cost benefits earned during period	$ 19	$ 10	$ 10	$ 3	$ 2	$ 2
Interest cost on projected benefit obligation	38	34	33	10	8	7
Expected return on plan assets	(59)	(57)	(53)	(7)	(7)	(7)
Amortization of prior service costs	1					
Recognized net actuarial (gain)/loss			(1)	3	1	
Net periodic benefit cost (income)	$ (1)	$ (13)	$ (11)	$ 9	$ 4	$ 2
Additional early retirement window benefits	2	9				
Additional cost due to curtailment						
Total net periodic benefit cost (income)	$ 1	$ (4)	$ (11)	$ 9	$ 4	$ 2

Impact of a one percent increase/decrease in medical trend (in millions):

	Increase	Decrease
Aggregate impact on service cost and interest cost	$ 2	$ 2
Impact on accumulated post-retirement benefit obligation	$ 18	$ 16

NOTE 18 SEGMENT INFORMATION

Amounts in this footnote reflect our global communications and U.K. CRM businesses as discontinued operations. For further information, please see Explanatory Note Reclassifications Discontinued Operations beginning on page F-8.

We changed our reporting segments in the first quarter 2003. Prior to January 1, 2003, we reported results for the following four business segments:

Wholesale Energy Network, or WEN;

Dynegy Midstream Services, or DMS;

Transmission and Distribution, or T&D; and

Dynegy Global Communications, or DGC.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Beginning January 1, 2003, we began reporting our operations in the following segments:

- Power generation, or GEN;
- Natural gas liquids, or NGL;
- Regulated energy delivery, or REG; and
- Customer risk management, or CRM.

Our segment information for all periods included in this Amendment No. 1 has been presented based on our 2003 segment presentation. GEN includes the operations of owned or leased electric power generation facilities located in six regions of the United States. This segment is focused on optimizing our portfolio of energy assets and related contracts, as well as direct commercial and industrial sales. NGL consists of our North American natural gas gathering and processing, natural gas liquids fractionation and marketing businesses and transportation operations. REG is engaged in the transmission, distribution and sale of electricity and natural gas to customers across a 15,000-square-mile area of Illinois. CRM consists of third-party marketing, trading and risk-management activities unrelated to our generating assets. Other reported results include corporate governance roles and functions, which are managed on a consolidated basis, and specialized support functions. All costs associated with other reported results were allocated to the four operating segments prior to January 1, 2003.

Prior to January 1, 2003, the WEN segment was comprised of the current GEN segment and the current CRM segment. 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 a part of our continuing operations, or CRM contracts.

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. Under this business model, the fair value of GEN s generation capacity, forward sales and related trading positions were sold to the CRM segment each month at an internally determined transfer price based on then-current market prices. The CRM segment would record revenue from the third-party contracts associated with the GEN segment, together with all of its other third-party marketing and trading positions unrelated to the GEN segment, during the month of settlement. The intersegment revenues presented for the GEN segment reflect this internal transfer price and do not represent amounts actually received by GEN for power sold to third parties. As such, the GEN intersegment revenues do not include the effects of intra-month market price volatility.

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 due to the sale of our communications businesses.

As further described in Note 3 Dispositions, Discontinued Operations and Acquisitions beginning on page F-27, in the fourth quarter 2002, the NGL segment sold its global liquids business, the CRM segment sold its UK storage business and DGC Asia was sold; and in August 2002, the REG segment sold its Northern Natural operations. Furthermore, in the first quarter 2003, all remaining communications businesses were sold. The results of all of these sold businesses are presented as discontinued operations in the consolidated statements of operations. During the first quarter 2003, the wind-down efforts of the UK CRM business, which is included in the CRM segment, were substantially completed. As such, this business is also presented as discontinued operations in the accompanying consolidated statements of operations.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the years ended December 31, 2002, 2001 and 2000 is presented in the following tables:

DYNEGY S SEGMENT DATA FOR THE YEAR ENDED DECEMBER 31, 2002

(in millions)

	GEN	NGL	REG	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 385	$ 2,530	$ 1,488	$ 384	$	$ 4,787
Canadian		723				723
Other	6					6
	391	3,253	1,488	384		5,516
Intersegment revenues	486	154	31	388	(1,059)	
Total revenues	$ 877	$ 3,407	$ 1,519	$ 772	$ (1,059)	$ 5,516
Depreciation and amortization	(175)	(88)	(175)	(28)		(466)
Goodwill impairment	(549)			(348)		(897)
Impairment and other charges	(58)	(18)	(19)	(95)		(190)
Operating income (loss)	$ (401)	$ 77	$ 157	$ (974)	$	$ (1,141)
Other items, net	(20)	(34)	(4)	(49)		(107)
Earnings (losses) of unconsolidated investments	(71)	14	(2)	(21)		(80)
Interest expense						(297)
Income tax benefit						276
Loss from continuing operations						$ (1,349)
Loss on discontinued operations, net of taxes						(1,154)
Cumulative effect of a change in accounting principle						(234)
Net loss						$ (2,737)

Identifiable assets:						
Domestic	$ 5,440	$ 2,088	$ 3,809	$ 6,309	$ 69	$ 17,715
Canadian		5		365		370
European and other	281			1,647	17	1,945
Unconsolidated investments	564	102		3	(1)	668
Capital expenditures and unconsolidated investments	(589)	(105)	(170)	(14)	(83)	(961)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

DYNEGY S SEGMENT DATA FOR THE YEAR ENDED DECEMBER 31, 2001

(in millions)

	GEN	NGL	REG	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 491	$ 3,910	$ 1,593	$ 1,421	$	$ 7,415
Canadian		1,463				1,463
Other						
	491	5,373	1,593	1,421		8,878
Intersegment revenues	460	237	25	125	(847)	
Total revenues	$ 951	$ 5,610	$ 1,618	$ 1,546	$ (847)	$ 8,878
Depreciation and amortization	(164)	(84)	(173)	(35)		(456)
Operating income	$ 390	$ 133	$ 180	$ 264	$	$ 967
Other items, net	(5)	(3)	2	(54)		(60)
Earnings (losses) of unconsolidated investments	202	13		(24)		191
Interest expense						(255)
Income tax provision						(357)
Income from continuing operations						$ 486
Loss on discontinued operations, net of taxes						(82)
Cumulative effect of a change in accounting principle						2
Net income						$ 406
Identifiable assets:						
Domestic	$ 7,287	$ 2,308	$ 4,500	$ 6,910	$ 816	$ 21,821
Canadian		130		773		903
European and other	224			1,972	248	2,444
Unconsolidated investments	1,301	422	568	47	107	2,445
Capital expenditures and unconsolidated investments	(2,191)	(391)	(701)	(305)	(496)	(4,084)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

DYNEGY S SEGMENT DATA FOR THE YEAR ENDED DECEMBER 31, 2000

(in millions)

	GEN	NGL	REG	CRM	Other and Eliminations	Total
Unaffiliated revenues:						
Domestic	$ 854	$ 4,089	$ 1,581	$ 439	$	$ 6,963
Canadian		1,224		1		1,225
Other	16					16
	870	5,313	1,581	440		8,204
Intersegment revenues	558	178	27	185	(948)	
Total revenues	$ 1,428	$ 5,491	$ 1,608	$ 625	$ (948)	$ 8,204
Depreciation and amortization	(120)	(105)	(156)	(9)		(390)
Operating income	$ 337	$ 80	$ 206	$ 143	$	$ 766
Other items, net	(21)	(40)	(10)	(1)		(72)
Earnings of unconsolidated investments	169	24		3		196
Interest expense						(247)
Income tax provision						(234)
Income from continuing operations						$ 409
Income on discontinued operations, net of taxes						27
Net income						$ 436
Identifiable assets:						
Domestic	$ 5,093	$ 2,104	$ 3,569	$ 9,828	$ 302	$ 20,896
Canadian		299		750		1,049

European	219			425	73	717
Unconsolidated investments	582	174		43		799
Capital expenditures and unconsolidated investments	(825)	(114)	(158)	(53)	(63)	(1,213)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

NOTE 19 QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Amounts in this footnote reflect the reclassification of our global communications and U.K. CRM businesses as discontinued operations. For further information, please see Explanatory Note Reclassifications Discontinued Operations beginning on page F-8.

The following is a summary of our unaudited quarterly financial information for the years ended December 31, 2002 and 2001.

	Quarter Ended			
	March 2002	June 2002	September 2002	December 2002
	(in millions, except per share data)			
Revenues	$ 1,439	$ 1,364	$ 1,396	$ 1,317
Operating income (loss)	85	(143)	(882)	(201)
Net loss before cumulative effect of accounting change	(13)	(561)	(1,651)	(278)
Net loss	(247)	(561)	(1,651)	(278)
Net loss per share before cumulative effect of accounting change	(0.27)	(1.76)	(4.71)	(0.98)
Net loss per share	(0.91)	(1.76)	(4.71)	(0.98)

	Quarter Ended			
	March 2001	June 2001	September 2001	December 2001
	(in millions, except per share data)			
Revenues	$ 2,997	$ 1,766	$ 2,269	$ 1,846
Operating income	320	174	420	53
Net income (loss) before cumulative effect of accounting change	153	39	238	(26)
Net income (loss)	155	39	238	(26)
Net income (loss) per share before cumulative effect of accounting change	0.45	0.12	0.71	(0.20)
Net income (loss) per share	0.46	0.12	0.71	(0.20)

These amounts reflect previously reported restatements. For further discussion of the restatements, see the Explanatory Note Restatement Disclosures beginning on page F-9.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

The table below reflects the impact of each restatement on net income and diluted earnings per share as originally reported in the applicable 2002 quarterly reports.

	Three Months Ended March 31	Three Months Ended June 30	Six Months Ended June 30	Three Months Ended September 30	Nine Months Ended September 30
			(in millions, except share data)		
Net Income (Loss) 2001					
Project Alpha	$	$ (27)	$ (27)	$	$
Balance Sheet Reconciliation Project	22	(18)	4	(28)	36
Corrected Hedge Accounting	15	(12)	3	5	28
Valuation of Extant, Inc. Purchase					
Restated Forward Power Curve Methodology				(25)	(25)
Restated Lease Accounting				(2)	(2)
Change in Implied Preferred Dividends					
Valuation of Technology Investment				(12)	(12)
Correction for Income Taxes	(5)	(3)	(8)	(3)	(11)
Other Adjustments Arising During Re-Audit	(16)	(47)	(63)	29	(34)
Total	$ 16	$ (107)	$ (91)	$ (36)	$ (20)
Net Income (Loss) 2002					
Project Alpha	$	$	$	$	$
Balance Sheet Reconciliation Project	4	89	93		8
Corrected Hedge Accounting	(27)	5	(22)	(2)	(24)
Valuation of Extant, Inc. Purchase	22		22		
Restated Forward Power Curve Methodology	(74)	(128)	(202)	133	(69)
Restated Lease Accounting	(14)	(214)	(228)	13	(215)
Change in Implied Preferred Dividends(1)					
Valuation of Technology Investment		10	10	2	12
Correction for Income Taxes	(3)	(1)	(4)	(3)	(7)
Other Adjustments Arising During Re-Audit	(15)	6	(9)	10	1
Total	$ (107)	$ (233)	$ (340)	$ 153	$ (294)
Diluted Earnings (Loss) per Share 2001					
Project Alpha	$	$ (0.08)	$ (0.08)	$	$
Balance Sheet Reconciliation Project	0.07	(0.05)	0.01	(0.08)	0.11
Corrected Hedge Accounting	0.04	(0.04)	0.01	0.01	0.08
Valuation of Extant, Inc. Purchase					
Restated Forward Power Curve Methodology				(0.07)	(0.07)
Restated Lease Accounting					(0.01)
Change in Implied Preferred Dividends					

Valuation of Technology Investment				(0.03)	(0.04)
Correction for Income Taxes	(0.01)		(0.02)	(0.01)	(0.03)
Other Adjustments Arising During Re-Audit	(0.05)	(0.14)	(0.19)	0.08	(0.10)
Total	$ 0.05	$ (0.31)	$ (0.27)	$ (0.10)	$ (0.06)
Diluted Earnings (Loss) per Share 2002					
Project Alpha	$	$	$	$	$
Balance Sheet Reconciliation Project	0.01	0.24	0.25		0.02
Corrected Hedge Accounting	(0.07)	0.01	(0.06)	(0.01)	(0.07)
Valuation of Extant, Inc. Purchase	0.06		0.06		
Restated Forward Power Curve Methodology	(0.20)	(0.35)	(0.55)	0.36	(0.19)
Restated Lease Accounting	(0.04)	(0.58)	(0.63)	0.04	(0.58)
Change in Implied Preferred Dividends	(0.20)	(0.20)	(0.41)	(0.20)	(0.61)
Valuation of Technology Investment		0.03	0.03	0.01	0.03
Correction for Income Taxes	(0.01)		(0.01)	(0.01)	(0.02)
Other Adjustments Arising During Re-Audit	(0.05)	0.01	(0.02)	0.02	
Total	$ (0.50)	$ (0.84)	$ (1.34)	$ 0.21	$ (1.42)

(1) The adjustment to change implied preferred dividends decreased net income (loss) available to common stockholders by $75 million, $74 million, $149 million, $75 million and $224 million for the three months ended March 31, 2002, the three months ended June 30, 2002, the six months ended June 30, 2002, the three months ended September 30, 2002 and the nine months ended September 30, 2002, respectively.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

A synopsis of the aggregate financial impact of these restatements on the amounts originally reported in the 2002 Forms 10-Q for the quarterly periods ended September 30, 2002, June 30, 2002 and March 31, 2002, filed on November 15, 2002, August 14, 2002 and May 15, 2002, respectively, is set forth in the following tables (in millions). On May 14, 2003, we filed amended 2002 Forms 10-Q to reflect these restatements.

RESTATED SELECTED BALANCE SHEET DATA BY QUARTER

	2002		
	March 31	**June 30**	**September 30**
		($ in millions)	
Current Assets			
As Reported	$ 10,608	$ 9,692	$ 9,424
Restatement Effect	(781)	(834)	(626)
As Restated	$ 9,827	$ 8,858	$ 8,798
Total Assets			
As Reported	$ 28,047	$ 28,989	$ 25,147
Restatement Effect	199	(1,043)	(1,427)
As Restated	$ 28,246	$ 27,946	$ 23,720
Current Liabilities			
As Reported	$ 9,946	$ 10,833	$ 9,323
Restatement Effect	(41)	(470)	(612)
As Restated	$ 9,905	$ 10,363	$ 8,711
Total Liabilities			
As Reported	$ 20,516	$ 22,644	$ 20,669
Restatement Effect	657	(365)	(978)
As Restated	$ 21,173	$ 22,279	$ 19,691
Stockholders Equity			

As Reported	$ 4,800	$ 4,471	$ 2,590
Restatement Effect	39	(254)	(87)
As Restated	$ 4,839	$ 4,217	$ 2,503

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

RESTATED RESULTS OF OPERATIONS BY QUARTER

	Three Months Ended March 31,	Three Months Ended June 30,	Six Months Ended June 30,	Three Months Ended September 30,	Nine Months Ended September 30,
	(in millions, except per share amounts)				
2002					
Revenues:					
As Reported	$ 8,652	$ 9,906	$ 18,558	$ 1,720	$ 4,769
Adjustment for discontinued operations and EITF 02-03(1)	(6,987)	(8,312)	(15,299)	(309)	(83)
Restatement Effect(2)	(226)	(230)	(456)	(15)	(487)
As Restated	$ 1,439	$ 1,364	$ 2,803	$ 1,396	$ 4,199
Operating Income:					
As Reported	$ 252	$ (271)	$ (19)	$ (1,160)	$ (1,255)
Adjustment for discontinued operations(1)	6	635	641	71	803
Restatement Effect(2)	(173)	(507)	(680)	207	(488)
As Restated	$ 85	$ (143)	$ (58)	$ (882)	$ (940)
Net Income (Loss) before Cumulative Effect of Accounting Change:					
As Reported	$ 116	$ (328)	$ (212)	$ (1,804)	$ (1,931)
Restatement Effect(2)	(129)	(233)	(362)	153	(294)
As Restated	$ (13)	$ (561)	$ (574)	$ (1,651)	$ (2,225)
Net Income (Loss):					
As Reported	$ (140)	$ (328)	$ (468)	$ (1,804)	$ (2,165)
Restatement Effect(2)	(107)	(233)	(340)	153	(294)
As Restated	$ (247)	$ (561)	$ (808)	$ (1,651)	$ (2,459)
Net Income (Loss) Available to Common Stockholders:					
As Reported	$ (148)	$ (336)	$ (484)	$ (1,812)	$ (2,189)
Restatement Effect	(182)	(307)	(489)	78	(518)

As Restated	$ (330)	$ (643)	$ (973)	$ (1,734)	$ (2,707)
Earnings (Loss) Per Diluted Share before Cumulative Effect of Accounting Change:					
As Reported	$ 0.26	$ (0.92)	$ (0.55)	$ (4.92)	$ (5.36)
Restatement Effect(2)	(0.53)	(0.84)	(1.48)	0.21	(1.42)
As Restated	$ (0.27)	$ (1.76)	$ (2.03)	$ (4.71)	$ (6.78)
Earnings (Loss) Per Diluted Share:					
As Reported	$ (0.41)	$ (0.92)	$ (1.33)	$ (4.92)	$ (6.00)
Restatement Effect(2)	(0.50)	(0.84)	(1.34)	0.21	(1.42)
As Restated	$ (0.91)	$ (1.76)	$ (2.67)	$ (4.71)	$ (7.42)

(1) Information included within our Form 10-Q filed on November 14, 2002, which included results for the three- and nine-month periods ended September 30, 2002, presented revenues net in accordance with EITF 02-03. In addition, this Form 10-Q included the results of operations of Northern Natural and UK storage in discontinued operations.

(2) Certain adjustments were already reflected in the Form 10-Q filed on November 14, 2002, which included results for the three- and nine-month periods ended September 30, 2002.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

	Three Months Ended March 31	Three Months Ended June 30,	Six Months Ended June 30,	Three Months Ended September 30,	Nine Months Ended September 30,
	(in millions, except per share amounts)				
2001					
Revenues:					
As Reported	$ 14,168	$ 10,812	$ 24,980	$ 2,329	$ 7,323
Adjustment for discontinued operations and EITF 02-03 (1)	(11,267)	(9,112)	(20,379)	(87)	(545)
Restatement Effect (2)	96	66	162	27	254
As Restated	$ 2,997	$ 1,766	$ 4,763	$ 2,269	$ 7,032
Operating Income:					
As Reported	$ 255	$ 198	$ 453	$ 417	$ 744
Adjustment for discontinued operations (1)	9	52	61	40	100
Restatement Effect (2)	56	(76)	(20)	(37)	70
As Restated	$ 320	$ 174	$ 494	$ 420	$ 914
Net Income (Loss) before Cumulative Effect of Accounting Change:					
As Reported	$ 137	$ 146	$ 283	$ 274	$ 450
Restatement Effect (2)	16	(107)	(91)	(36)	(20)
As Restated	$ 153	$ 39	$ 192	$ 238	$ 430
Net Income (Loss):					
As Reported	$ 139	$ 146	$ 285	$ 274	$ 452
Restatement Effect (2)	16	(107)	(91)	(36)	(20)
As Restated	$ 155	$ 39	$ 194	$ 238	$ 432
Net Income (Loss) Available to Common Stockholders:					
As Reported	$ 139	$ 146	$ 285	$ 274	$ 452
Restatement Effect	16	(107)	(91)	(36)	(20)
As Restated	$ 155	$ 39	$ 194	$ 238	$ 432

Earnings (Loss) Per Diluted Share before Cumulative Effect of Accounting Change:					
As Reported	$ 0.41	$ 0.43	$ 0.83	$ 0.81	$ 1.33
Restatement Effect (2)	0.04	(0.31)	(0.27)	(0.10)	(0.06)
As Restated	$ 0.45	$ 0.12	$ 0.56	$ 0.71	$ 1.27
Earnings (Loss) Per Diluted Share:					
As Reported	$ 0.41	$ 0.43	$ 0.84	$ 0.81	$ 1.34
Restatement Effect (2)	0.05	(0.31)	(0.27)	(0.10)	(0.06)
As Restated	$ 0.46	$ 0.12	$ 0.57	$ 0.71	$ 1.28

(1) Information included within our Form 10-Q filed on November 14, 2002, which included results for the three- and nine-month periods ended September 30, 2001, presented revenues net in accordance with EITF 02-03. In addition, this Form 10-Q included the results of operations of Northern Natural and UK storage in discontinued operations.

(2) Certain adjustments were already reflected in the Form 10-Q filed November 14, 2002, which included results for the three- and nine-month periods ended September 30, 2001.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

RESTATED SELECTED CASH FLOW DATA BY QUARTER

	Three Months Ended March 31,	Six Months Ended June 30,	Nine Months Ended September 30,
		(in millions)	
2002			
Operating Cash Flows:			
As Reported	$ 293	$ 375	$ 261
Restatement Effect	(40)	(47)	1
As Restated	$ 253	$ 328	$ 262
Investing Cash Flows:			
As Reported	$ (371)	$ (597)	$ 412
Restatement Effect	(41)	(56)	(62)
As Restated	$ (412)	$ (653)	$ 350
Financing Cash Flows:			
As Reported	$ 330	$ 417	$ 48
Restatement Effect	79	102	53
As Restated	$ 409	$ 519	$ 101
2001			
Operating Cash Flows:			
As Reported	$ 265	$ 371	$ 452
Restatement Effect	9	5	6
As Restated	$ 274	$ 376	$ 458
Investing Cash Flows:			
As Reported	$ (1,166)	$ (577)	$ (852)
Restatement Effect	(127)	(318)	(556)
As Restated	$ (1,293)	$ (895)	$ (1,408)

Financing Cash Flows:			
As Reported	$ 1,056	$ 644	$ 548
Restatement Effect	133	331	564
As Restated	$ 1,189	$ 975	$ 1,112

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

The following table reconciles selected financial data as reported in various filings.

	Form 8-K Filed January 31, 2003	Adjustments	2002 Form 10-K Filed April 11, 2003(2)
Results of Operations			
Year ended December 31, 2002			
Net Income (Loss)	$ (2,802)	65	(2,737)
Net Income (Loss) Applicable to Common Stockholders	$ (3,132)	65	(3,067)
Earnings (Loss) per Diluted Share	$ (8.56)	0.18	(8.38)
Selected Cash Flow Data			
Year ended December 31, 2002			
Operating Cash Flow	$ (26)	1	(25)
Investing Cash Flow	(1)		677
Financing Cash Flow	(1)		(44)

(1) Financial data not included in the January 31, 2003 Form 8-K.
(2) There have not been any changes to this data since the 2002 Form 10-K filed April 11, 2003.

NOTE 20 LIQUIDITY

We faced significant challenges relating to our liquidity position in 2002. These challenges were caused by several factors affecting the merchant energy industry, and particularly our company, including the following:

The application of more stringent credit standards to Dynegy and other energy merchants;

Weak commodity prices, particularly for power;

A reduction in liquidity and the amount of open trade credit available to counterparties in the marketing and trading business;

The various lawsuits and governmental investigations involving our company, including matters relating to Project Alpha, our past trading practices and our activities in the California power market;

Downgrades in our credit ratings to well below investment grade, resulting in substantial requirements to provide counterparties with collateral support in order to transact new business or avoid the termination of existing transactions; and

The restatement of our 1999-2001 financial results, the related three-year re-audit and the unavailability of 2001 audited financial statements, all of which limited our ability to access the capital markets.

We also were negatively impacted by our inability to generate the expected return on the significant capital we had previously invested both in our communications business and, because of a weak pricing environment, new merchant generation facilities.

In relation to these events, we posted significantly higher amounts of collateral in the forms of cash and letters of credit than we had in the past. For example, at September 30, 2002, we had posted approximately $1.2 billion of letters of credit and cash collateral in support of our marketing and trading and asset-based businesses. This compares to the approximately $470 million in collateral that we had posted at December 31, 2001.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Since September 30, 2002, we have made marked progress in our exit from third-party risk management aspects of the marketing and trading business. The actions taken in this regard, particularly the transfer of the ChevronTexaco natural gas marketing business back to ChevronTexaco and the completion of our exit from U.K. marketing and trading, resulted in the return of approximately $250 million of collateral and the elimination of these collateral requirements going forward. However, our ongoing asset businesses will continue to manage commodity price risk and optimize commercial positions associated with their respective operations through, among other things, fuel procurement optimization and the marketing of power and NGLs. We expect to continue to post collateral to support these operations, the amount and term of which will be impacted by changes in commodity prices. While the completion of our exit from third-party risk management aspects of the marketing and trading business will result in a reduction in the collateral requirements associated with that business, we expect an increase in the collateral requirements relating to fuel procurement for our asset-based businesses given our non-investment grade credit ratings and higher commodity prices.

We have also successfully completed a restructuring of our revolving credit facilities that were to expire in April and May of this year. By extending the maturity date of these obligations, which totaled approximately $1.3 billion at April 2, 2003, together with the successful execution of our other liquidity initiatives, we believe that we have provided our company with sufficient capital resources to meet our current debt obligations and provide collateral support for our ongoing asset businesses and our continued exit from third-party marketing and trading. However, our long term success and future financial condition, including our ability to refinance our substantial debt maturities in 2005 and thereafter, will depend on our ability to successfully execute the remainder of our exit from third-party marketing and trading and to produce adequate operating cash flows from our continuing asset-based businesses to meet our debt and commercial obligations, including substantial increases in interest expense.

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Schedule II

DYNEGY INC.

VALUATION AND QUALIFYING ACCOUNTS

(RESTATED)

Years Ended December 31, 2002, 2001, and 2000

DESCRIPTION	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
2002					
Allowance for doubtful accounts	$ 113	$ 47	$	$ (9)	$ 151
Allowance for risk management assets(1)	248	(4)			244
Deferred tax asset valuation allowance		180			180
2001					
Allowance for doubtful accounts	69	92	(2)	(46)	113
Allowance for risk management assets(1)	146	102			248
2000					
Allowance for doubtful accounts	24	52		(7)	69
Allowance for risk management assets(1)	38	108			146

(1) Changes in price and credit reserves related to risk management activities are offset in the net mark-to-market income accounts reported in revenues.