DYNEGY INC /IL/
Form 10-K/A
January 18, 2005
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

Amendment No. 2

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

For the fiscal year ended December 31, 2003

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

For the transition period from to

Commission file number: 1-15659

DYNEGY INC.

(Exact name of registrant as specified in its charter)

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

1000 Louisiana, Suite 5800

Houston, Texas 77002

(Address of principal executive offices)

(Zip Code)

(713) 507-6400

(Registrant s telephone number, including area code)

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

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

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

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

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

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

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

The aggregate market value of the voting and non-voting equity held by non-affiliates of the registrant as of June 30, 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 $1,155,609,441, 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, 279,871,186 shares outstanding as of February 23, 2004; Class B common stock, no par value per share, 96,891,014 shares outstanding as of February 23, 2004.

DOCUMENTS INCORPORATED BY REFERENCE. Part III (Items 10, 11, 12, 13 and 14) incorporates by reference portions of the Notice and Proxy Statement for the registrant s 2004 Annual Meeting of Shareholders, which will be filed not later than 120 days after December 31, 2003.

Table of Contents

DYNEGY INC. FORM 10-K/A

INTRODUCTORY NOTE

Dynegy Inc. is filing this Amendment No. 2 on Form 10-K/A (Amendment No. 2) 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, 2003, which was originally filed on February 27, 2004 (the Original Filing):

An increase of $139 million to the $242 million goodwill impairment charge originally recorded in the fourth quarter 2003 and a previously unrecorded after-tax asset impairment charge of $120 million, in the fourth quarter 2003, each associated with the sale of Illinois Power and

A $154 million decrease to our deferred tax liability at December 31, 2003 resulting from our tax basis balance sheet review.

The aforementioned items are discussed in more detail in the Explanatory Note to the accompanying consolidated financial statements beginning on page F-8. The following Items of the Original Filing are amended by this Amendment No. 2:

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 9A. 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. 2.

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS AMENDMENT NO. 2, 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 REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004 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 FEBRUARY 27, 2004, INCLUDING OUR

QUARTERLY REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004, OUR CURRENT REPORTS ON FORM 8-K AND ANY AMENDMENTS THERETO.

Table of Contents

DYNEGY INC.

FORM 10-K/A

TABLE OF CONTENTS

Table of Contents

PART I

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS AMENDMENT NO. 2, 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 REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004 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 FEBRUARY 27, 2004, INCLUDING OUR QUARTERLY REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004, OUR CURRENT REPORTS ON FORM 8-K AND ANY AMENDMENTS THERETO.

DEFINITIONS

As used in this Amendment No. 2, the abbreviations contained herein have the meanings set forth in the glossary beginning on page F-88. Additionally, the terms Dynegy, we, us and our refer to Dynegy Inc. and its subsidiaries, unless the context clearly indicates otherwise.

Table of Contents

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.

As discussed in the Explanatory Note to the accompanying Consolidated Financial Statements, the accompanying Consolidated Financial Statements have been restated since the date of the Original Filing. Please read the Explanatory Note to the accompanying Consolidated Financial Statements for additional information about these restatements. The selected financial data that follows has been adjusted to reflect these restatements.

Dynegy s Selected Financial Data

	Year Ended December 31,				
	2003	**2002**	**2001**	**2000**	**1999**
	(in millions, except per share data) (Restated)				
Statement of Operations Data (1):					
Revenues	$ 5,787	$ 5,326	$ 9,124	$ 9,715	$ 4,821
General and administrative expenses	(366)	(325)	(420)	(312)	(208)
Depreciation and amortization expense	(454)	(466)	(452)	(386)	(114)
Asset impairment, abandonment and other charges	(200)	(190)			
Goodwill impairment	(311)	(814)			
Operating income (loss)	(569)	(1,058)	971	770	185
Interest expense	(509)	(297)	(255)	(247)	(77)
Income tax expense (benefit)	(246)	(352)	368	230	45
Net income (loss) from continuing operations	(688)	(1,190)	479	417	90
Income (loss) on discontinued operations (3)	(19)	(1,154)	(82)	27	44
Cumulative effect of change in accounting principles	40	(234)	2		
Net income (loss)	$ (667)	$ (2,578)	$ 399	$ 444	$ 134
Net income (loss) available to common stockholders	346	(2,908)	357	409	134
Earnings (loss) per share from continuing operations	$ 0.79	$ (4.16)	$ 1.29	$ 1.20	$ 0.39
Net income (loss) per share	0.84	(7.95)	1.05	1.29	0.58
Shares outstanding for diluted EPS calculation	423	370	340	315	230
Cash dividends per common share	$	$ 0.15	$ 0.30	$ 0.25	$ 0.04
Cash Flow Data:					
Cash flows from operating activities	$ 876	$ (25)	$ 550	$ 420	$ 40
Cash flows from investing activities	(266)	677	(3,828)	(1,539)	(391)
Cash flows from financing activities	(900)	(44)	3,450	1,131	399
Cash dividends or distributions to partners, net		(55)	(98)	(112)	(8)
Capital expenditures, acquisitions and investments	(338)	(981)	(4,687)	(2,415)	(521)

Table of Contents

	December 31,				
	2003	2002	2001	2000	1999
	(in millions) (Restated)				
Balance Sheet Data (2):					
Current assets	$ 3,030	$ 7,586	$ 8,956	$ 10,827	$ 2,658
Current liabilities	2,576	6,748	8,538	10,286	2,467
Property, plant and equipment, net	8,203	8,458	9,269	7,148	2,155
Total assets	12,961	20,029	25,083	22,572	6,491
Long-term debt (excluding current portion)	5,893	5,454	5,016	3,754	1,372
Notes payable and current portion of long-term debt	331	861	458	118	192
Non-recourse debt					35
Serial preferred securities of a subsidiary	11	11	46	46	
Subordinated debentures		200	200	300	200
Series B Preferred Stock (4)		1,212	882		
Series C convertible preferred stock	400				
Minority interest (5)	121	146	1,040	1,022	
Capital leases not already included in long-term debt		15	29	15	
Total equity	1,947	2,203	4,894	3,405	1,196

(1) The following acquisitions were accounted for in accordance with the purchase method of accounting and the results of operations attributable to the acquired businesses are included in our financial statements and operating statistics beginning on the acquisitions effective date for accounting purposes:

Northern Natural February 1, 2002;

BGSL December 1, 2001;

iaxis March 1, 2001;

Extant October 1, 2000; and

Illinova January 1, 2000.

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

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

Northern Natural (sold third quarter 2002);

U.K. Storage Hornsea facility (sold fourth quarter 2002) and Rough facility (sold fourth quarter 2002);

DGC (portions sold in fourth quarter 2002 and first and second quarters 2003);

Global Liquids (sold fourth quarter 2002); and

U.K. CRM (substantially liquidated in first quarter 2003).

(4) The 2002 amount equals the $1.5 billion in proceeds related to the Series B Preferred Stock less the $660 million implied dividend recognized in connection with the beneficial conversion option plus $372 million in accretion of the implied dividend through December 31, 2002. The 2001 amount equals the $1.5 billion in proceeds less the $660 million implied dividend plus $42 million in accretion of the implied dividend through December 31, 2001. Please read Note 15 Redeemable Preferred Securities Series B Preferred Stock beginning on page F-54 for further discussion.

(5) The 2001 and 2000 amounts include amounts relating to the Black Thunder transaction discussed in Note 12 Debt Black Thunder Secured Financing beginning on page F-45.

Table of Contents

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

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

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS AMENDMENT NO. 2, 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 REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004 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 FEBRUARY 27, 2004, INCLUDING OUR QUARTERLY REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004, OUR CURRENT REPORTS ON FORM 8-K AND ANY AMENDMENTS THERETO.

OVERVIEW

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily in three areas of the energy industry: power generation; natural gas liquids; and regulated energy delivery. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. We also separately report the results of our customer risk management business, which primarily consists of our four remaining power tolling arrangements and related gas transportation contracts, as well as legacy gas and power trading positions. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization, but because of their nature, these items are not reported as a separate segment.

Following is a brief discussion of each of our four business segments, including a list of key factors that have affected, and are expected to continue to affect, their respective earnings and cash flows. We also present a brief discussion of our corporate-level expenses. This Overview section concludes with a summary of our current liquidity position and items that could impact our liquidity position in 2004 and beyond. Please note that this Overview section is merely a summary and should be read together with the remainder of Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, as well as the audited consolidated financial statements, including the notes thereto, and the other information included in this report.

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

The primary factors impacting our power generation earnings and cash flows are the prices for power and, to a lesser extent, natural gas, which in turn are largely driven by supply and demand. Demand for power can vary regionally due to, among other things, weather and general economic conditions. Power supplies similarly vary by region and are impacted significantly by available generating capacity, transmission capacity and federal and state regulation. We also are impacted by the relationship between prices for power and natural gas, commonly referred to as the spark spread, and its impact on the cost of generating electricity. However, we believe that our significant coal-fired and fuel oil generating facilities partially mitigate our sensitivity to changes in the spark spread, in that coal and fuel oil prices are relatively stable and insensitive to changes in gas prices, and position us for potential increases in earnings and cash flows in an environment where both power and gas prices increase. Please read Liquidity and Capital Resources Internal Liquidity Sources Cash Flows from Operations beginning on page 16 for a discussion of our views on the current pricing environment and its anticipated long-term recovery.

Table of Contents

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

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

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

our ability to enter into new sales contracts and to renew our existing contracts, particularly the CDWR and Illinois Power power purchase agreements that are scheduled to expire at the end of 2004. In connection with our recently announced agreement to sell Illinois Power to Ameren, we agreed, conditioned upon the closing of the sale, to sell 2,800 MWs of capacity and up to 11.5 million MWh of energy to Illinois Power at fixed prices for two years beginning in January 2005. The closing of the sale to Ameren, which is expected by the end of 2004, is subject to receipt of required regulatory approvals and other closing conditions. Please read Results of Operations Segment Discussion 2004 Outlook REG Outlook beginning on page 34 and Note 23 Subsequent Event beginning on page F-86 for further discussion.

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

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

The earnings and cash flows that we generate in this business are sensitive to natural gas and natural gas liquids prices and the relationship between the two, commonly referred to as the frac spread. In our upstream business, we continued the restructuring of our contract portfolio in 2003. As a result, our current contract mix has reduced our exposure to frac spread risk. Please read Item 1. Business Segment Discussion Natural Gas Liquids Upstream Business beginning on page 7 of our Original Filing for a detailed discussion of our current upstream contract mix.

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

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

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

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

a low frac spread environment and the resulting reduction in volumes available for fractionation, distribution and marketing;

the petrochemical industry s need for and utilization of our natural gas liquids feedstocks and related natural gas liquids facilities;

Table of Contents

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

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

Illinois Power is a regulated utility that serves more than 590,000 electricity customers and nearly 415,000 natural gas customers in portions of northern, central and southern Illinois. We generate earnings and cash flows in this business through sales of electric and gas service to residential, commercial and industrial customers.

The earnings and cash flows generated by this business are primarily driven by the volumes of electricity and natural gas that we sell and deliver. In terms of costs, retail electric rates are frozen through 2006, and gas costs are passed through to customers. The primary factors impacting sales volumes include:

- weather and its effect on demand for our services, particularly with respect to residential electric customers;
- the number of customers that choose another retail electric provider under the Illinois Customer Choice Law;
- our ability to control our capital expenditures, which primarily are limited to maintenance, safety and reliability projects, and other costs through disciplined management and safe, efficient operations; and
- general economic conditions and the resulting effect on demand for our services, particularly with respect to commercial and industrial customers.

We recently entered into an agreement to sell Illinois Power and our 20% interest in the Joppa power generation facility to Ameren for $2.3 billion. The transaction is expected to close by the end of 2004, subject to the receipt of required regulatory approvals and other closing conditions. Please read Note 23 Subsequent Event beginning on page F-86 for further discussion.

Customer Risk Management. Our customer risk management business primarily consists of our four remaining power tolling arrangements and related gas transportation contracts, as well as our legacy gas and power trading positions. We have significant, long-term fixed obligations associated with our tolling and gas transportation arrangements, which obligations substantially exceed the earnings and cash flows we expect to generate in connection with these arrangements. Our ability to mitigate partially the negative impact of these arrangements on our earnings and cash flows depends on the price of power and the spark spread in the regions where the tolling plants are located, as well as our ability to re-market the related capacity under the transportation arrangements. It also will be significantly impacted by our ability to restructure or terminate one or more of our power tolling arrangements, which we expect would require a significant cash payment.

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

Original Filing for further discussion.

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

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

Table of Contents

general and administrative costs, with respect to which we have implemented a number of initiatives expected to yield savings beginning in 2004; general and administrative costs also will be impacted by, among other things, (i) any future corporate-level litigation reserves or settlements and (ii) potential funding requirements under our pension plans; and

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

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

Liquidity. As of February 23, 2004, we had cash on hand of $397 million and available borrowing capacity of $866 million, for total liquidity of nearly $1.3 billion. During 2003, we substantially reduced our debt and other obligations while maintaining liquidity between $1.4 billion and $1.7 billion. Our ability to maintain our liquidity position in the future will depend on a number of factors, including our ability to consummate the Illinois Power sale to Ameren and, over the longer term, to generate cash flows from our asset-based energy businesses in relation to our substantial debt obligations and ongoing operating requirements.

For the next 12 months, assuming continuation of the current commodity pricing environment, we expect that our operating cash flows will be insufficient to satisfy our capital expenditures, debt maturities, increased interest expenses and operating commitments. When combined with our cash on hand, proceeds from anticipated asset sales and capacity under our $1.1 billion revolving credit facility, however, we believe we have sufficient capital resources to satisfy these obligations during this period. To further our deleveraging efforts, we also intend to explore other capital-raising activities, including potential public or private equity issuances. In addition, we will seek to renew or replace our $1.1 billion revolving credit facility, which is scheduled to mature on February 15, 2005. Our liquidity position will be materially adversely affected if we are unable to renew or replace this facility, with respect to which our ability to borrow and/or issue letters of credit could become increasingly important, on or before its scheduled maturity.

Over the longer term, we believe that power prices will improve in some or all of the regions in which we operate as the supply-demand imbalance for power decreases. Much of the restructuring work that we did during 2003 extended a substantial portion of our debt maturities from 2005-2006 to 2008 and beyond, positioning us to benefit from earnings and growth opportunities associated with this expected recovery in the U.S. power markets. Conversely, although depressed frac spreads have negatively impacted our NGL segment s downstream operations, our upstream business is currently operating in a relatively favorable pricing environment. Our future financial condition and results of operations will be materially affected if the U.S. power markets fail to recover in accordance with our expectations or if we experience significant pricing deterioration in our NGL segment.

LIQUIDITY AND CAPITAL RESOURCES

Debt Maturities

During 2003, we consummated a series of refinancing and restructuring transactions comprised of the following:

Restructuring of $1.66 billion in credit facilities prior to their scheduled maturities, in connection with which we granted security interests in a substantial portion of the available assets and stock of our direct and indirect subsidiaries, excluding Illinois Power;

Issuance by DHI of $1.75 billion of senior notes at a weighted average interest rate of 9.71% and a weighted average yield to maturity of 9.65%, which notes are secured on a second priority basis by substantially the same collateral that secures the obligations under DHI s restructured credit facility;

Table of Contents

Issuance by Dynegy of $225 million of convertible subordinated debentures at an interest rate of 4.75%, which debentures are convertible into shares of our Class A common stock at $4.1210 per share, subject to certain adjustments, and guaranteed on a senior unsecured basis by DHI;

The purchase of approximately $282 million of DHI s $300 million 8.125% Senior Notes due 2005, virtually all of DHI s $150 million 6 3/4% Senior Notes due 2005 and approximately $177 million of DHI s $200 million 7.450% Senior Notes due 2006; and

Restructuring of the $1.5 billion in Series B Mandatorily Convertible Redeemable Preferred Stock previously held by a ChevronTexaco subsidiary, which we refer to as the Series B Preferred Stock. Under this restructuring, which we refer to as the Series B Exchange, the Series B Preferred Stock was exchanged for $225 million in cash, $225 million principal amount of our Junior Unsecured Subordinated Notes due 2016, which we refer to as the Junior Notes, and 8 million shares of our Series C Mandatorily Redeemable Convertible Preferred Stock due 2033 (liquidation preference $50 per share), which we refer to as the Series C preferred stock. The Series C preferred stock generally is convertible into shares of our Class B common stock at $5.78 per share, subject to shareholder approval, which approval we intend to solicit at our 2004 annual shareholder meeting.

We used the net cash proceeds from these transactions, together with approximately $300 million of cash on hand and additional funds received in the form of returned prepayments from ChevronTexaco under the Series B Exchange, to make the $225 million Series B Exchange payment, to purchase the DHI senior notes and to otherwise reduce our 2005 debt maturities as follows:

Prepay in full the $200 million Term A loan outstanding under DHI s restructured credit facility;

Prepay in full the $360 million Term B loan outstanding under DHI s restructured credit facility;

Prepay in full the $696 million of debt outstanding under the Black Thunder secured financing; and

Prepay in full the $170 million capital lease obligation associated with our CoGen Lyondell power generating facility.

For a more complete description of these transactions, including the increasing interest rate and conversion features of the securities issued in connection with the Series B Exchange, please read Note 11 Refinancing and Restructuring Transactions beginning on page F-39.

As a result of these transactions, we extended a substantial portion of our 2005-2006 maturities to 2008 and beyond. Our aggregate maturities for long-term debt are as follows:

Period	Total	Illinois Power (1)	Total Less Illinois Power (1)
		(in millions)	
2004 (2)	$ 331	$ 157	$ 174
2005	258	156	102
2006	130	86	44
2007	270	86	184

2008	311	86	225
Thereafter	4,924	1,366	3,558

(1) If the Ameren transaction closes as expected before the end of 2004, Ameren will assume Illinois Power s then outstanding indebtedness. Please read Note 12 Debt beginning on page F-41 for further discussion of our outstanding debt.

(2) Included in Illinois Power s 2004 maturities of $157 million is $71 million related to the Tilton capital lease. In October 1999, Illinois Power entered into a sublease with DMG pursuant to which DMG is obligated to make all payments under the lease.

8

Table of Contents

One important near-term maturity that remains is our $1.1 billion revolving credit facility, which is scheduled to mature on February 15, 2005. While we currently have no drawn amounts under this facility, our ability to borrow and/or issue letters of credit under a revolving credit facility could become increasingly important, particularly if we are unable to generate operating cash flows relative to our substantial debt obligations and ongoing operating requirements or to realize the asset sale proceeds we anticipate. We currently intend to renew or replace this facility during 2004, although we cannot guarantee that we will be successful.

While our restructuring and refinancing transactions have extended our significant debt maturities, they also resulted in significantly increased interest expenses, as further described under Results of Operations Interest Expense beginning on page 32. We also are subject to the more restrictive covenants that are contained in the related transaction agreements. Specifically, among other limitations, these covenants limit our ability to receive payments from DHI for the purpose of paying dividends on our common stock and otherwise, limit DHI s ability to incur additional indebtedness other than for refinancing purposes and require that a significant portion of proceeds from specified asset sales and equity issuances be used to pay down outstanding indebtedness. For example, upon closing of the agreed sale of Illinois Power to Ameren, we must use 75% of the net cash proceeds to repay the Junior Notes. We are required to use 25% of the net cash proceeds of the sale to reduce permanently or cash collateralize the commitments under the facility, subject to certain exceptions, to the extent the Junior Notes are repaid up to $100 million. If the Junior Notes are not outstanding, 100% of the net cash proceeds from asset sales are required to be used, subject to certain exceptions, to reduce the commitments under the revolver. While we are currently in compliance with these restrictive covenants, our future financial condition and results of operations could be significantly affected by our ability to execute our business and financial strategies within the confines of these restrictive covenants.

The following table depicts our consolidated third-party debt obligations, including the principle-like maturities associated with the DNE leveraged lease, and the extent to which they are secured as of December 31, 2003 and 2002:

	December 31, 2003	December 31, 2002
	(in millions)	
First Secured Obligations		
Dynegy Holdings Inc.	$ 1,127	$ 2,440
Dynegy Inc.		360
Illinois Power (1)	1,967	2,092
Total First Secured Obligations	3,094	4,892
Second Secured Obligations	1,750	
Unsecured Obligations	2,160	2,266
Subtotal	7,004	7,158
Preferred Obligations	411	1,711
Total Obligations	$ 7,415	$ 8,869
Less: DNE Lease Financing	(758)	(746)
Less: Preferred Obligations	(411)	(1,711)
Other (2)	(22)	(97)
Total Notes Payable and Long-term Debt	$ 6,224	$ 6,315

(1) Ameren will assume Illinois Power s debt obligations upon closing of our agreed sale of Illinois Power, which is anticipated to occur before the end of 2004, subject to receipt of required regulatory approvals and other closing conditions. Please read Note 23 Subsequent Event

beginning on page F-86 for further discussion.

(2) Consists of net discounts on debt (totaling $12 million and $16 million at December 31, 2003 and December 31, 2002, respectively) and the $10 million difference between the carrying value of the Tilton capital lease

Table of Contents

and the purchase obligation of $81 million at December 31, 2003. At December 31, 2002, the Tilton lease was off-balance sheet as it was accounted for as an operating lease.

Collateral Postings

We have substantially reduced our collateral postings since the end of 2002. As detailed in the table below, total collateral postings are down by approximately $704 million as of February 23, 2004. The reduction is particularly pronounced in our CRM segment, which we commenced exiting in October 2002. Our collateral postings are down in that segment by more than $634 million since year-end 2002 and by more than $800 million from their peak at September 30, 2002.

The following table summarizes our consolidated collateral postings to third parties by operating division at February 23, 2004, December 31, 2003 and December 31, 2002:

	February 23, 2004	December 31, 2003	December 31, 2002
		(in millions)	
GEN	$ 146	$ 136	$ 168
CRM	172	121	806
NGL	144	179	166
REG	42	38	28
Other	8	8	48
Total	$ 512	$ 482	$ 1,216

As described in Note 12 Debt DHI Credit Facility beginning on page F-42, we incur a 0.15% fronting fee upon the issuance of letters of credit under our restructured credit facility. A letter of credit fee is also payable on the undrawn amount of each letter of credit outstanding at a percentage per annum equal to 4.75% of such undrawn amount. To reduce these fees, we have used, and expect to continue to use, cash on hand, as opposed to letters of credit, to satisfy our future collateral obligations where practicable. Our ability to continue this strategy depends to a large extent on the creditworthiness of our counterparties and the availability of cash on hand.

Going forward, we expect counterparties collateral demands to reflect changes in commodity prices, including seasonal changes in weather-related demand, as well as their view of our creditworthiness. We believe that we have sufficient capital resources to satisfy counterparties collateral demands, including those for which no collateral is currently posted, for at least the next 12 months. Over the longer term, we expect to achieve incremental reductions associated with the completion of our exit from the customer risk management business. Please see Results of Operations 2004 Outlook CRM Outlook beginning on page 35 for a discussion of the expected collateral roll-off from this business.

Table of Contents

Disclosure of Contractual Obligations and Contingent Financial Commitments

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

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2003. Cash obligations reflected are not discounted and do not include related interest, accretion or dividends.

	Payments Due by Period						
	Total	2004	2005	2006	2007	2008	Thereafter
	(in millions)						
Long-Term Debt (including Current Portion)	$ 6,153	$ 260	$ 258	$ 130	$ 270	$ 311	$ 4,924
Capital Leases	81	81					
Redeemable Preferred Securities	411						411
Operating Leases	1,588	81	81	81	127	147	1,071
Unconditional Purchase Obligations	53	53					
Capacity Payments	2,852	259	243	231	232	232	1,655
Conditional Purchase Obligations	766	222	158	207	127	38	14
Pension Funding Obligations	111	8	57	46			
Other Long-Term Obligations	7	6	1				
Total Contractual Obligations	$ 12,022	$ 970	$ 798	$ 695	$ 756	$ 728	$ 8,075

Long-Term Debt (including Current Portion). Total amounts of Long-Term Debt (including Current Portion) are included in the December 31, 2003 Consolidated Balance Sheet. For additional explanation, please read Note 12 Debt beginning on page F-41.

Additionally, we have entered into various joint ventures principally to share risk or optimize existing commercial relationships. These joint ventures maintain independent capital structures and, where necessary, have financed their operations on a non-recourse basis to us. Please read Note 9 Unconsolidated Investments beginning on page F-34 for further discussion of these joint ventures.

Capital Leases. Capital leases consist of our Tilton capital lease obligation. Of the $81 million obligation above, $71 million is included in the December 31, 2003 Consolidated Balance Sheet as a component of Notes Payable and Current Portion of Long-Term Debt. The $10 million difference will be accreted over the remaining term of the capital lease through a charge to interest expense with a corresponding increase to short-term debt. We began reflecting the Tilton facility and the related debt in our consolidated balance sheets in September 2003 as a result of our delivery of a notice of our intent to purchase the related turbines upon the lease expiration in September 2004. For additional explanation, please read Note 12 Debt Tilton Capital Lease beginning on page F-46.

Redeemable Preferred Securities. Total amounts of Redeemable Preferred Securities are included in the December 31, 2003 Consolidated Balance Sheet. For additional explanation, please read Note 15 Redeemable Preferred Securities beginning on page F-53.

Operating Leases. Operating leases includes the minimum lease payment obligations associated with our DNE leveraged lease. For additional information, please read Liquidity and Capital Resources Off-Balance Sheet Arrangements DNE Leveraged Lease beginning on page 13. Amounts also include minimum lease payment obligations associated with office and office equipment leases.

Table of Contents

Unconditional Purchase Obligations. Amounts include natural gas and power purchase agreements. For additional information, please read Note 17 Commitments and Contingencies Other Commitments and Contingencies Purchase Obligations beginning on page F-67.

Capacity Payments. Capacity payments include future payments aggregating $2.3 billion under our four remaining power tolling arrangements, as further described in Item 1. Business Segment Discussion Customer Risk Management beginning on page 18 of our Original Filing. This amount includes the fixed payments associated with a derivative instrument related to the Sithe tolling arrangement, which is reflected at its fair value on our Consolidated Balance Sheet in Risk-Management Liabilities, as well as amounts relating to contracts that are accounted for on an accrual basis. At December 31, 2003, approximately $325 million of fixed payments have been reflected in the fair value of the Sithe derivative instrument. We are exploring opportunities to renegotiate or terminate one or more of these arrangements on terms we consider economical. Please read Results of Operations 2004 Outlook CRM Outlook beginning on page 35 for further discussion of the anticipated effects of these arrangements on our future results of operations.

In addition, capacity payments include fixed obligations associated with transmission, transportation and storage arrangements totaling approximately $573 million.

Conditional Purchase Obligations. Amounts include our obligations as of December 31, 2003 to purchase 14 gas-fired turbines. 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 $479 million included herein assume all 14 turbines will be purchased. In February 2004, we terminated our conditional purchase obligation related to these gas fired turbines as part of a comprehensive settlement agreement with the manufacturer. No cash, other than $11 million previously paid to the manufacturer as a deposit, is expected to be provided as consideration for the termination.

Amounts also include $205 million related to Illinois Power s long-term power purchase agreement with AmerGen. The agreement was entered into in connection with the sale of Illinois Power s former Clinton nuclear generation facility in December 1999. Illinois Power is obligated to purchase a predetermined percentage of Clinton s electricity output through 2004 at fixed prices that exceed current and projected wholesale prices. At the time of the sale of the nuclear generation facility, a liability was recorded related to the above-market portion of this purchase agreement, which is being amortized through 2004, based on the expected energy to be purchased from AmerGen.

Amounts also include $136 million related to our co-sourcing agreement with Accenture Ltd. This 10-year agreement may be cancelled after two years upon the payment of a termination fee.

Pension Funding Obligations. Amounts include estimated defined benefit pension funding obligations for 2004 ($8 million), 2005 ($57 million) and 2006 ($46 million). Although we expect to incur significant funding obligations subsequent to 2006, such amounts have not been included in this table because our estimates are imprecise. Under the terms of the sale of Illinois Power to Ameren, we will be required to accelerate certain of our 2005 cash funding requirements at closing of the sale.

Other Long-Term Obligations. Amounts include decommissioning costs related to Illinois Power s sale of its Clinton nuclear facility in 1999 and decontamination and decommissioning charges associated with Illinois Power s use of a facility that enriched uranium for the Clinton Power Station.

12

Table of Contents

Contingent Financial Obligations

The following table provides a summary of our contingent financial obligations as of December 31, 2003 on an undiscounted basis. These obligations represent contingent obligations that may require a payment of cash upon the occurrence of specified events.

		Expiration by Period			
	Total	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 Years**
			(in millions)		
Letters of Credit (1)	$ 188	$ 188	$	$	$
Surety Bonds (2)(4)	80	80			
Guarantees (3)	131	13	26	26	66
Total Financial Commitments	$ 399	$ 281	$ 26	$ 26	$ 66

(1) Amounts include outstanding letters of credit.
(2) Surety bonds are generally on a rolling 12-month basis.
(3) Amounts include two charter party agreements relating to VLGCs previously utilized in our global liquids business sub-chartered to a wholly owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter party agreements. We are currently in negotiations with the owners of the VLGCs and their lenders to obtain a novation/release of the two charter party agreements and a release of our guarantees.
(4) $45 million of the surety bonds were supported by collateral.

Off-Balance Sheet Arrangements

In September 2003, we delivered notice of our intent to exercise our option to purchase the Tilton assets upon the expiration of the operating lease in September 2004. As a result of this action, we began accounting for the related lease obligation, which we formerly reported as an off-balance sheet arrangement, as a capital lease. Following is a discussion of our remaining off-balance sheet arrangement.

DNE Leveraged Lease. As described in Item 1. Business Segment Discussion Power Generation Northeast region Northeast Power Coordinating Council (NPCC) beginning on page 5 of our Original Filing, we established our presence in the Northeast region by acquiring the DNE power generating facilities in January 2001 for $950 million from Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. and Niagara Mohawk Power Corporation.

In May 2001, we entered into an asset-backed sale-leaseback transaction relating to these facilities to provide us with long-term financing for our acquisition. In this transaction, which was structured as a sale-leaseback to 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 we concurrently agreed to lease them back from these entities, which we refer to as the owner lessors. The owner lessors used $138 million in equity funding from the unrelated third-party investor to fund a portion of the purchase of the respective facilities. The remaining $800.4 million of the purchase price and the related transaction expenses was derived from proceeds obtained in a private offering of pass-through trust certificates issued by two of our subsidiaries, Dynegy Danskammer, L.L.C. and Dynegy Roseton, L.L.C., who serve as lessees of the applicable facilities. The pass-through trust certificate structure was employed, as it has been in similar financings historically executed in the airline and energy industries, to optimize the cost of financing the assets and to facilitate a capital markets offering of sufficient size to enable the purchase of the lessor notes from the owner lessors. The pass-through trust certificates were sold to qualified institutional buyers in a private offering and the proceeds were used to purchase debt instruments, referred to as lessor notes, from the owner lessors. The lease payments on the facilities support the principal and interest payments on the pass-through trust certificates, which are ultimately secured by a mortgage on the underlying facilities.

Table of Contents

As of December 31, 2003, future lease payments are $60 million for each year 2004 through 2006, with $1.3 billion in the aggregate due from 2007 through lease expiration. The Roseton lease expires on February 8, 2035 and the Danskammer lease expires on May 8, 2031. We have no option to purchase the leased facilities at the end of their respective lease terms. DHI has guaranteed the lessees payment and performance obligations under their respective leases on a senior unsecured basis. At December 31, 2003, the present value (discounted at 10%) of future lease payments was $758 million.

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

	2003	2002	2001
		(in millions)	
Lease Expense	$ 50	$ 50	$ 34
Lease Payments (Cash Flows)	$ 60	$ 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. As of December 31, 2003, the termination payment at par would be $997 million for all of the DNE facilities, which exceeds the $920 million we received on the sale of the facilities. If a termination of this type were to occur with respect to all of the DNE facilities, it would be difficult for DHI to raise sufficient funds to make this termination payment. Alternatively, if one or more of the leases were to be terminated because we determine, for reasons other than as a result of a change in law, that it has become economically or technologically obsolete or that it is no longer useful to our business, DHI must redeem the related pass through trust certificates at par plus a make-whole premium in an amount equal to the discounted present value of the principal and interest payments still owing on the certificates being redeemed less the unpaid principal amount of such certificates at the time of redemption. For this purpose, the discounted present value would be calculated using a discount rate equal to the yield-to-maturity on the most comparable U.S. treasury security plus 50 basis points.

Capital Expenditures

In connection with our restructuring, we have undertaken various efforts to tightly manage costs and capital expenditures. We had approximately $333 million in capital expenditures during 2003. This is a significant reduction from the approximately $947 million in capital expenditures during 2002 and reflects our efforts to improve our capital efficiency without compromising the operational integrity of our facilities. Our 2003 capital spending by segment was as follows (in millions):

GEN	$ 151
NGL	51
REG	126
Other	5
Total	$ 333

Capital spending in our GEN segment primarily consisted of maintenance capital projects, as well as approximately $40 million spent on completing the construction of the Rolling Hills facility, which began commercial operation during the summer of 2003. Capital spending in our

NGL segment primarily related to maintenance capital projects and wellconnects, as well as $8 million in development capital at our Cedar Bayou Fractionators, LP. Capital spending in our REG segment primarily related to projects intended to maintain system reliability and new business services.

Table of Contents

We expect capital expenditures for 2004 to approximate $375 million. This primarily includes maintenance capital projects, environmental projects, contributions to equity investments and limited GEN and NGL development projects. The capital budget is subject to revision as opportunities arise or circumstances change. Estimated funds budgeted for the aforementioned items by segment in 2004 are as follows (in millions):

GEN	$ 150
NGL	75
REG	140
Other	10
Total	$ 375

Increased capital spending in the NGL segment is primarily due to $20 million for gathering system expansion, additional compression and plant de-bottlenecking in North Texas related to increased gas from the Barnett Shale formation and $7 million for a significant upgrade in compression technology and efficiencies at our Monument gas processing plant.

As reflected in this section, the capital spending in our NGL segment includes 100% of the expenditures of our consolidated partnerships, Versado Gas Processors, LLC and Cedar Bayou Fractionators, LP. Our ownership percentages of these partnerships are 63% and 88%, respectively, and net funding equal to our ownership percentage is achieved through adjustments to partnership distributions. Adjusted for our partners share of capital expenditures, our expenditures would have been $45 million in 2003 and are expected to be $67 million in 2004.

Our capital expenditures in 2004 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 REG segment. Please read Note 11 Refinancing and Restructuring Transactions beginning on page F-39 for further discussion of these transactions.

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 ratings or other trigger events.

Commitments and Contingencies

Please read Note 17 Commitments and Contingencies beginning on page F-56, which is incorporated herein by reference, for a discussion of our commitments and contingencies.

Dividends on Preferred and Common Stock

Dividend payments on our common stock are at the discretion of our Board of Directors. We do not foresee a declaration of dividends in the near term, particularly given the dividend restrictions contained in our financing agreements. We have, however, continued to make the required dividend payments on our outstanding trust preferred securities. Please read Note 11 Refinancing and Restructuring Transactions beginning on page F-39 for a discussion of the dividend restrictions contained in our financing agreements.

Table of Contents

The Series B Preferred Stock issued to ChevronTexaco in November 2001 had no dividend requirement. Because of ChevronTexaco s discounted conversion option, however, we accreted an implied preferred stock dividend over the redemption period, as required by GAAP. Please read Note 15 Redeemable Preferred Securities beginning on page F-53 for further discussion of this non-cash implied dividend. In conjunction with the Series B Exchange, we recognized a gain of approximately $1.2 billion as a preferred stock dividend during 2003.

We accrue dividends on our Series C preferred stock at a rate of 5.5% per annum. We accrued $8 million in dividends during the year ended December 31, 2003. We did not make any dividend payments on the Series C preferred stock during the year ended December 31, 2003. However, we made the first semi-annual dividend payment of $11 million on February 11, 2004, as a result of which capacity under our revolving credit facility was reduced by $11 million. Dividends are payable on the Series C preferred stock in February and August of each year, but we may defer payments for up to 10 consecutive semi-annual periods. Please read Note 15 Redeemable Preferred Securities beginning on page F-53 for further discussion.

Internal Liquidity Sources

Our primary internal liquidity sources are cash flows from operations, cash on hand and available capacity under our $1.1 billion revolving credit facility, which is scheduled to mature on February 15, 2005.

Cash Flows from Operations. We had operating cash flows of $876 million in 2003, which included approximately $500 million associated with our CRM business and $110 million from a federal income tax refund, neither of which is expected to be repeated in 2004. For 2004, we have projected operating cash flows of $150 to $185 million. This projection, which is subject to change based on a number of factors, many of which are beyond our control, reflects $825 to $850 million in forecasted operating cash flows from our GEN, NGL and REG business segments, offset by projected cash outflows of $180 to $185 million from our customer risk management business and $485 to $490 million in corporate-level expenses, including interest.

Our operating cash flows are significantly impacted by commodity prices, particularly in our power generation and NGL businesses. Although the depressed frac spread is negatively impacting our NGL segment s downstream operations, our upstream business is currently operating in, and is expected to continue to operate in, a favorable pricing environment. However, our power generation business is currently operating in a relatively weak pricing environment due to overcapacity in the markets we serve. Management believes, however, that the U.S. power markets will improve and reach a state of equilibrium a condition where supply equals demand plus a reasonable reserve over the longer term. This belief is based on various market indicators, including projected supply-demand imbalances and the perceived reaction to the risk of supply interruption. If equilibrium were to occur in one or more of the regions in which we operate, we expect that the pricing environment in the applicable regions would significantly improve. As a result, baseload and dual-fuel plants would produce higher earnings and cash flows and peaking plants would be more economical to operate.

As described above, much of the restructuring work that we have done has extended our significant debt maturities to 2008 and beyond, positioning us to benefit from this expected long-term recovery in the U.S. power markets. Our future financial condition and results of operations will be materially adversely affected if the U.S power markets fail to recover in accordance with our expectations or if we experience significant price deterioration in the upstream portion of the NGL segment. Please read Item 1. Business Segment Discussion Power Generation beginning on page 2 of our Original Filing for a discussion of our current views on supply and demand in the regions where our power generation business operates.

Over the longer term, our operating cash flows also will be impacted by, among other things, our ability to tightly manage our operating costs and to renew or replace our CDWR agreement. With respect to costs, we launched a value creation project in early 2003, a company-wide initiative focused on identifying opportunities to improve our operational efficiencies. In connection with this project, we have undertaken a number of initiatives,

Table of Contents

including our October 2003 co-sourcing agreement with Accenture Ltd. and a centralized procurement program, designed to reduce costs across the company. We also have sharpened our focus on reducing operating costs and, in January 2004, entered into a new rail transportation contract that we anticipate will reduce the fees associated with fuel procurement at our coal-fired generation facilities. Our ability to achieve these cost savings in the face of industry-wide increases in labor and benefits costs will impact our future operating cash flows.

In addition, our CDWR power purchase agreement expires by its terms on December 31, 2004. Our share of West Coast Power s revenues under this agreement in 2003 totaled $305 million. If we are unable to renew or replace this agreement, we would seek to sell the associated energy and capacity into the open market, where our operating cash flows would be dependent on then prevailing market prices. We expect that the generating facilities supporting the CDWR contract would be significantly less profitable as merchant facilities.

Cash on Hand. At February 23, 2004 and December 31, 2003, we had cash on hand of $397 million and $477 million, respectively. We intend to continue our disciplined cash management practices to maintain our cash position. For example, we have been, and intend to continue, substituting more cash as collateral with certain high-credit quality counterparties than letters of credit under our revolving credit facility. This has resulted in reduced letter of credit fees relative to cash interest income. However, unforeseen events such as legal judgments or regulatory requirements, as well as litigation settlements or contract terminations, could negatively impact our ability to do so.

Revolver Capacity. Our primary credit facility is DHI s $1.1 billion revolving credit facility, which is scheduled to mature on February 15, 2005. We currently have no drawn amounts under this facility, although as of February 23, 2004, we had $222 million in letters of credit issued under the facility. Our ability to borrow and/or issue letters of credit under a revolving credit facility could become increasingly important, particularly if we are unable to generate operating cash flows relative to our substantial debt obligations and ongoing operating requirements or to realize the asset sale proceeds we anticipate. We currently plan to pursue such a renewal or replacement during 2004, although we cannot guarantee that we will be successful in this pursuit. We expect to incur significant fees in connection with any such renewal or replacement. Please see Note 11 Refinancing and Restructuring Transactions Credit Facility Restructuring beginning on page F-39 for a discussion of the fees we incurred in connection with our April 2003 credit facility restructuring.

Current Liquidity. During 2003, we maintained a strong liquidity position, averaging total available liquidity of approximately $1.5 billion. The following table summarizes our consolidated credit capacity and liquidity position at February 23, 2004, December 31, 2003 and December 31, 2002:

	February 23, 2004	December 31, 2003	December 31, 2002
		(in millions)	
Total Revolver Capacity	$ 1,088(1)	$ 1,100(2)	$ 1,400
Outstanding Loans			(228)
Outstanding Letters of Credit Under Revolving Credit Facility	(222)	(188)	(872)
Unused Revolver Capacity	866	912	300
Cash (3)	397(4)	477	757
Liquid Inventory (5)			258
Total Available Liquidity	$ 1,263(6)	$ 1,389(6)	$ 1,315

(1)

The February 23, 2004 amount reflects $12 million of mandatory reductions of our revolving credit facility related to asset sales and dividend payments on the Series C preferred stock.

(2) Reflects the conversion of $200 million of credit capacity under the former DHI revolving credit facilities into the Term A loan in connection with the April 2003 restructuring of such facilities, as well as the May 2003 payment of the final $100 million then outstanding under Illinois Power s termed out revolving credit facility.

(3) Reflects $95 million repayment of Illinova senior notes on February 2, 2004.
(4) Includes approximately $40 million of cash that remains in Canada and the U.K. that is associated primarily with contingent liabilities relating to our former Canadian and U.K. marketing and trading operations.
(5) Amounts reflected for 2003 and 2004 periods do not include liquid inventory, as we have sold the natural gas inventories that comprised that item and converted them to cash.
(6) Includes approximately $71 million and $17 million, respectively, of liquidity at Illinois Power. Please read Item 1. Business Regulation beginning on page 21 of our Original Filing for a discussion of ICC regulations that restrict our ability to receive cash dividends from Illinois Power. Please also read Note 23 Subsequent Event beginning on page F-86 for a discussion of our pending sale of Illinois Power to Ameren.

External Liquidity Sources

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

Asset Sale Proceeds. As indicated above, assuming continuation of the current commodity pricing environment, our estimated operating cash flows for 2004 will be insufficient to satisfy our capital expenditures, debt maturities, increased interest expenses and operating commitments. Accordingly, the receipt of proceeds from asset sales that we are currently pursuing or considering will significantly impact our near-term financial condition.

In February 2004, we entered into an agreement to sell Illinois Power and our 20% interest in the Joppa power generation facility to Ameren for $2.3 billion. Upon closing of the transaction, which is subject to regulatory approval and other closing conditions, we would receive $400 million in cash, subject to working capital adjustments, and Ameren would put $100 million in escrow, subject to full release to us on December 31, 2010 or earlier upon the occurrence of specified events. Please read Note 23 Subsequent Event beginning on page F-86 for further discussion of the transaction, which is expected to close before the end of 2004, and the required use of proceeds.

In an effort to maximize our return on investment and to further clarify our business strategy, we are pursuing or considering sales of other assets that we do not consider core to our operations. These assets primarily include our ownership interests in certain non-strategic and international power generation facilities, as further described in Item 1. Business Segment Discussion Power Generation beginning on page 2 of our Original Filing, as well as our minority ownership interests in a gas processing plant and Gulf Coast Fractionators, a partnership that owns a fractionator in Mont Belvieu. The sales of these non-core assets, together with other potential payments relating to our prior sale of the Hackberry LNG project, are expected to generate aggregate cash proceeds of $255 to $270 million in 2004. These aggregate proceeds include approximately $5.5 million in proceeds received in January 2004 in connection with the sale of our Jamaica investment. Generally, the aggregate projected earnings impact of these transactions is not considered material and is expected to be offset substantially by net gains on sale in 2004.

We are in the late stages of negotiations to sell our remaining interest in the Hackberry LNG project. Commercial conditions affecting projects of this type have reduced the value of our interest, which primarily included rights to future earnings from the project. As a result, we could agree to a sale of our interest at a price that would reduce the $255 to $270 million in anticipated sale proceeds above by $30 to $35 million.

Our desire or ability to effect these transactions is subject to a number of factors, many of which are beyond our control, including the market for the subject assets and investments and the receipt of any regulatory and other approvals that may be required. Accordingly, we cannot make any guarantees that these sales will be consummated or that the expected proceeds will be received. In addition, if the sales are consummated while the Junior Notes remain outstanding, we are required to use: (i) 75% of the net cash proceeds from the sale of Illinois Power to pay down the

Junior Notes and 25% of the net cash proceeds to reduce the commitments of the revolver; (ii) 25% of the net cash proceeds from other sales to pay down the Junior Notes; and (iii) 25% of the net cash proceeds from other sales to reduce permanently or cash collateralize the commitments under our revolving credit facility up to a maximum of $100 million. If the Junior Notes are not outstanding, 100% of the net cash proceeds from asset sales are required to be used, subject to certain exceptions, to reduce the commitments under the revolver. We intend to use the remaining proceeds to pay transaction fees and expenses and to repay other outstanding debt.

Although no other asset sales or related transactions have been specifically identified, we discuss and evaluate merger and acquisition activities as part of our ongoing business strategy.

Capital-Raising Transactions. As part of our ongoing efforts to develop a capital structure that is more closely aligned with the cash-generating potential of our asset-based businesses, we intend to explore additional capital-raising transactions both in the near- and longer term. These transactions could include public or private equity issuances. Our ability to issue public equity is enhanced by our effective shelf registration statement, under which we have approximately $430 million in remaining availability. However, the receptiveness of the capital markets to a public equity issuance cannot be assured and may be negatively impacted by, among other things, our non-investment grade credit ratings, significant debt maturities, long-term business prospects and other factors beyond our control. Our ability to issue private equity could be similarly affected and, if such an issuance were completed, would likely be more costly, both in terms of required rates of return and other requirements typically associated with this type of transaction. Any issuance of equity likely would have other effects as well, including shareholder dilution.

The proceeds from any such issuance would be subject to the mandatory prepayment provisions of our revolving credit agreement and second secured senior notes indenture, which generally do not require prepayment for the first $250 million in proceeds, which may be used for repayment of the Junior Notes and for dollar-for-dollar commitment reduction under our revolving credit facility up to a maximum of $100 million. Please see Note 12 Debt DHI Credit Facility beginning on page F-42 for further discussion.

Conclusion

During 2003, we completed a series of refinancing and restructuring transactions that included sales of nearly $2.0 billion in DHI second priority senior secured notes and Dynegy convertible subordinated debentures. We used the net proceeds from these offerings, together with cash on hand, to repay approximately $2.0 billion in 2005-2006 debt maturities. We also made a $225 million cash payment to ChevronTexaco as part of the Series B Exchange. As a result of these transactions, we have extended a substantial portion of our debt maturities from 2005-2006 to 2008 and beyond and eliminated the uncertainty that surrounded the Series B Preferred Stock.

For the next 12 months, assuming continuation of the current commodity pricing environment, we expect that our operating cash flows will be insufficient to satisfy our capital expenditures, debt maturities, increased interest expenses and operating commitments. When combined with our cash on hand, proceeds from anticipated asset sales and capacity under our $1.1 billion revolving credit facility, however, we believe we have sufficient capital resources to discharge these obligations during this period. In order to further our deleveraging efforts, we also intend to explore other capital-raising activities, including potential public or private equity issuances. Our ability to raise additional funds may impact our ability to settle our significant ongoing litigation, as well as one or more of our four remaining power tolling arrangements, with respect to which we have substantial fixed payment obligations extending well into the future.

Over the longer term, our liquidity position and financial condition will be materially affected by a number of factors, including our ability to consummate the Illinois Power sale to Ameren and to generate cash flows from our asset-based energy businesses in relation to our debt and commercial obligations, including a substantial increase in interest expense, the fixed payment obligations associated with our CRM business and counterparty collateral requirements. The sale of Illinois Power would provide significant cash proceeds to repay outstanding debt and advance our business strategy of focusing on our unregulated energy businesses. Our future financial success is also substantially dependent on our ability to renew or replace our $1.1 billion revolving credit facility, which is scheduled to mature on February 15, 2005, with respect to which our ability to borrow and/or issue letters of credit could become increasingly important.

Our ability to generate operating cash flows from our asset-based energy businesses will be impacted by a number of factors, some of which are beyond our control, including weather, commodity prices, particularly for power and natural gas, and the success of our ongoing efforts to manage operating costs and capital expenditures. Over the longer term we believe that power prices will improve in some or all of the regions in which we operate as the supply-demand imbalance for power decreases. Much of the restructuring work that we did in 2003 has extended our significant debt maturities from 2005-2006 to 2008 and beyond, positioning us to benefit from earnings and growth opportunities associated with this expected recovery in the U.S. power markets. Conversely, although depressed frac spreads have negatively impacted our NGL segment s downstream operations, our upstream business is currently operating in a relatively favorable pricing environment. Our future financial condition and results of operations will be materially affected if the U.S. power markets fail to recover in accordance with our expectations or if we experience significant pricing deterioration in the NGL segment.

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

Table of Contents

RESULTS OF OPERATIONS

Overview and Discussion of Comparability of Results. In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for 2003, 2002 and 2001. At the end of this section, we have included our 2004 outlook for each segment.

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

Prior to January 1, 2003, the GEN and CRM segments were operated together as an asset-based third-party marketing, trading and risk-management business, then referred to as the WEN segment. Please read Note 21 Segment Information beginning on page F-79 for a discussion of the impact of comparing segment results period over period. Regarding our results of operations for 2003, 2002 and 2001, the impact of acquisition and disposition activity reduces the comparability of some of our historical financial and volumetric data. Lastly, recent accounting pronouncements have affected our financial results, particularly those of our CRM business, so as to further reduce the comparability of some of our historical financial data. For example, the rescission of EITF Issue 98-10, effective January 1, 2003, has reduced the number of contracts accounted for on a mark-to-market basis in the 2003 period as compared to the 2002 and 2001 periods. Please read Results of Operations Cumulative Effect of Change in Accounting Principles beginning on page 31 for further discussion.

Non-GAAP Financial Measures. Management uses EBIT as one measure of financial performance of our business segments. EBIT is a non-GAAP financial measure and consists of operating income (loss), earnings (losses) from unconsolidated investments, other income and expense, net, minority interest income (expense), accumulated distributions associated with trust preferred securities, discontinued operations and cumulative effect of change in accounting principles. EBIT does not include interest expense or income taxes, each of which is evaluated on a consolidated level. Because we do not allocate interest expense and income taxes by segment, management believes that EBIT is a useful measure of our segment s operating 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 and consolidated EBIT may not be comparable to similarly titled measures used by other companies.

Table of Contents

Summary Financial Information. The following tables provide summary financial data regarding our consolidated and segmented results of operations for 2003, 2002 and 2001, respectively (in millions). This financial data has been restated to reflect the items described in the Explanatory Note to the accompanying Consolidated Financial Statements. The restatements relate to an increased impairment associated with the sale of Illinois Power and our deferred income tax accounts. Please read this Explanatory Note for further discussion of these restatement items.

Year Ended December 31, 2003

	GEN	NGL	REG	CRM	Other and Eliminations	Total
				(Restated)		
Operating income (loss)	$ 194	$ 170	$ (302)	$ (385)	$ (246)	$ (569)
Earnings (losses) from unconsolidated investments	128	(2)		(2)		124
Other items, net	4	(17)		31	2	20
Discontinued operations		(2)	(3)	(30)	7	(28)
Cumulative effect of change in accounting principles	24		(3)	43		64
Earnings (loss) before interest and taxes	$ 350	$ 149	$ (308)	$ (343)	$ (237)	$ (389)
Interest expense						(509)
Pre-tax loss						(898)
Income tax benefit						231
Net loss						$ (667)

Year Ended December 31, 2002

	GEN	NGL	REG	CRM	Other and Eliminations	Total
				(Restated)		
Operating income (loss)	$ (341)	$ 77	$ 157	$ (951)	$	$ (1,058)
Earnings (losses) from unconsolidated investments	(71)	14	(2)	(21)		(80)
Other items, net	(20)	(34)	(4)	(49)		(107)
Discontinued operations		(37)	(561)	(51)	(854)	(1,503)
Cumulative effect of change in accounting principles					(234)	(234)
Earnings (loss) before interest and taxes	$ (432)	$ 20	$ (410)	$ (1,072)	$ (1,088)	$ (2,982)
Interest expense						(297)
Pre-tax loss						(3,279)
Income tax benefit						701
Net loss						$ (2,578)

Year Ended December 31, 2001						
	GEN	**NGL**	**REG**	**CRM**	**Other and Eliminations**	**Total**
				(Restated)		
Operating income	$ 391	$ 133	$ 182	$ 265	$	$ 971
Earnings (losses) from unconsolidated investments	202	13		(24)		191
Other items, net	(5)	(3)	2	(54)		(60)
Discontinued operations		(2)		(25)	(100)	(127)
Cumulative effect of change in accounting principles				3		3
Earnings (loss) before interest and taxes	$ 588	$ 141	$ 184	$ 165	$ (100)	$ 978
Interest expense						(255)
Pre-tax income						723
Income tax provision						(324)
Net income						$ 399

22

Table of Contents

The following table provides summary segmented operating statistics for 2003, 2002 and 2001, respectively:

	Year Ended December 31,		
	2003	**2002**	**2001**
Power Generation			
Million megawatt hours generated gross	39.1	39.8	40.3
Million megawatt hours generated net	37.2	37.4	34.5
Average natural gas price Henry Hub ($/MMbtu) (1)	$ 5.28	$ 3.35	$ 3.90
Average on-peak market power prices ($/MW hour)			
Cinergy	$ 37.26	$ 26.89	$ 34.85
Commonwealth Edison	36.73	26.45	34.15
Southern	41.27	30.10	38.30
New York Zone G	61.47	46.36	51.51
ERCOT	44.89	29.10	39.26
Natural Gas Liquids			