ENBRIDGE INC
Form 6-K
November 05, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 6-K

Report of Foreign Issuer

Pursuant to Rule 13a-16 or 15d-16 of

the Securities Exchange Act of 1934

Dated November 5, 2014

Commission file number 001-15254

ENBRIDGE INC.

(Exact name of Registrant as specified in its charter)

Canada	**None**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3000, 425 1st Street S.W.

Calgary, Alberta, Canada T2P 3L8

(Address of principal executive offices and postal code)

(403) 231-3900

(Registrants telephone number, including area code)

Indicate by check mark whether the Registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F	Form 40-F	ü

Indicate by check mark if the Registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1):

Yes	No	ü

Indicate by check mark if the Registrant is submitting the Form 6-K in paper as permitted by regulation S-T Rule 101(b)(7):

Yes	No	ü

Indicate by check mark whether the Registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes No ü

If Yes is marked, indicate below the file number assigned to the Registrant in connection with Rule 12g3-2(b):

N/A

THIS REPORT ON FORM 6-K SHALL BE DEEMED TO BE INCORPORATED BY REFERENCE IN THE REGISTRATION STATEMENTS ON FORM S-8 (FILE NO. 333-145236, 333-127265, 333-13456, 333-97305 AND 333-6436), FORM F-3 (FILE NO. 333-185591 AND 33-77022) AND FORM F-10 (FILE NO. 333-198566) OF ENBRIDGE INC. AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.

The following documents are being submitted herewith:

The following documents are being submitted herewith:

- Press Release dated November 5, 2014.
- Interim Report to Shareholders for the nine months ended September 30, 2014.

SIGNATURES

Pursuant to the requirements 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.

ENBRIDGE INC.
(Registrant)

Date: November 5, 2014

By: /s/ Tyler W. Robinson
Tyler W. Robinson
Vice President & Corporate Secretary

2

NEWS RELEASE

Enbridge reports third quarter adjusted earnings of $345 million or $0.41 per common share

HIGHLIGHTS

(all financial figures are unaudited and in Canadian dollars unless otherwise noted)

- Third quarter loss was $80 million and nine months earnings were $1,066 million, both including the impact of net unrealized non-cash mark-to-market gains and losses

- Third quarter and nine months adjusted earnings were $345 million and $1,165 million, respectively, or $0.41 and $1.41 per common share, respectively

- John Whelen became Chief Financial Officer of Enbridge Inc. on October 15, 2014

- Enbridge Inc. continued the execution of its sponsored vehicle strategy, with an agreement to transfer a package of assets and interests to Enbridge Income Fund for proceeds of $1.8 billion and also announced a proposed drop down of assets to Enbridge Energy Partners, L.P. for consideration of US$900 million

- Enbridge Inc. raised approximately $1.1 billion through a combination of public debt and preference share issuances and a further $2 billion of private note placements in support of its long-term financing plan during the third quarter of 2014

- Enbridge Inc. acquiring additional interests for $225 million in the Lac Alfred and Massif du Sud wind projects

- Enbridge Inc. released its 2014 Operational Reliability Report

- Enbridge Inc. named to 2014 Dow Jones Sustainability North American and World indices

CALGARY, ALBERTA November 5, 2014 Enbridge Inc. (Enbridge or the Company) (TSX:ENB) (NYSE:ENB) Enbridge adjusted earnings continued to accelerate in the third quarter as we progressed the execution of our record growth capital program, and we are on track to achieve full year adjusted earnings per share within our guidance range of $1.84 to $2.04 per share, said Al Monaco, President and Chief Executive Officer. We also rolled out our five-year strategic plan that now takes us through 2018 and includes our record $44 billion growth capital program, of which $33 billion is commercially secured and in execution. Projects secured over the past two years give us confidence in extending our anticipated average annual adjusted earnings per share growth rate of 10-12% to 2018 and provide visibility for continued growth beyond 2018.

Forward-Looking Information and Non-GAAP Measures

This news release contains forward-looking information and references to non-GAAP measures. Significant related assumptions and risk factors, as well as reconciliations are described under the Forward-Looking Information and Non-GAAP Measures sections of this news release, respectively.

In addition to the execution of the growth capital program, financing that growth is a key focus for Enbridge. In the third quarter, the Company issued $625 million in preference shares, bringing the total to $1.4 billion raised from the issuance of preference shares in 2014, and $2.4 billion of term debt financing for a total of $5.9 billion in 2014. The Company has also been active in utilizing its sponsored vehicles to support the funding program. In September, the Company announced a $1.8 billion transaction with Enbridge Income Fund (the Fund) to transfer a package of natural gas assets and diluent pipeline interests, which will provide a highly predictable cash flow stream to the Fund. This represents the largest transaction the Fund has undertaken since its inception in 2003. Enbridge also proposed to sell its 66.7% interest in the United States segment of the Alberta Clipper Pipeline to Enbridge Energy Partners, L.P. (EEP) for approximately US$900 million. EEP already owns the remaining 33.3% interest in the Alberta Clipper Pipeline. The proposed transfer and terms remain subject to review by an independent committee of EEP.

These transactions with our sponsored vehicles create value for Enbridge as sources of low-cost funding for our growth program and by maximizing the value of strong cash generating assets, said Mr. Monaco. Our sponsored vehicles are an important part of our overall financial strategy and we believe they will continue adding long-term value for our shareholders. The Fund has proven that it can raise capital on terms that are favourable to both Enbridge and the Fund. In the case of EEP, we expect this transaction to enhance its cash flow and help restore its effectiveness as a source of low-cost funding for Enbridge.

Enbridge advanced several projects in the third quarter as part of its objective of improving market access for western Canadian and Bakken crude. The Flanagan South Pipeline (Flanagan South), a key component of the $5.4 billion Western Gulf Coast Market Access program, is now mechanically complete and line fill arrangements have begun and will continue throughout November 2014. Flanagan South, along with the Seaway Crude Pipeline System twinning which was mechanically completed in July 2014, opens 585,000 barrels per day (bpd) of incremental capacity for Canadian and Bakken crude from Flanagan, Illinois to the key refining region at the United States Gulf Coast. The Company also advanced a key phase of its $3.2 billion Eastern Access program, with the completion of the Line 6B replacement and expansion project in September 2014. The project included replacing approximately 338 kilometres (210 miles) of existing pipeline in Indiana and Michigan and increased capacity in this section of the system to 500,000 bpd.

Timing for the in-service date for Enbridge s reversal and expansion of Line 9B has been delayed. The National Energy Board (NEB) had approved the project subject to conditions in March; however, the NEB has requested additional information from Enbridge relating to one of the conditions. That information has been provided. At this time, the Company is unable to estimate the length of the delay.

Our objective with the Line 9B project has always been to meet, if not exceed, regulatory requirements and to assure our stakeholders of our commitment to operate our pipeline safely and protect the environment, said Mr. Monaco. We have responded to the Board s request for clarification of our approach and additional information. We continue to work with the Board to understand and respond to its questions and to meet its requirements.

In July, the Ontario Energy Board (OEB) approved Enbridge Gas Distribution Inc. s (EGD) five-year customized Incentive Rate (IR) application, with modifications. The customized IR application establishes the methodology for determining rates for the distribution of natural gas over a five-year period from 2014 through 2018 and will allow EGD to recover its expected capital investment amounts, as well as an opportunity to earn above the allowed return on equity.

On the whole, we believe the Ontario Energy Board s decision is fair and balanced, said Mr. Monaco. The incentive plan provides opportunities to earn over and above an allowed rate of return through efficiencies and cost savings, which are also beneficial to rate payers over the long-term. The plan also allows for the necessary capital investment critical to the safety and reliability that our customers depend on .

In October, the Company released its 2014 Operational Reliability Report, which outlines progress on the performance of the Company as it strives for 100% safety and zero incidents. Safety and operational reliability remains Enbridge s number one priority, said Mr. Monaco. Our Operational Reliability Report provides our stakeholders and the public with an open and transparent view of our Company s performance. We ve made excellent progress on our operational risk management programs and the report highlights our progress towards our goal of industry leadership.

In September, Enbridge earned a place on both the 2014 Dow Jones Sustainability North American Index and the Dow Jones Sustainability World Index. Enbridge is one of only three energy industry companies on the World Index which overall includes just 11 companies from Canada out of 319 listed.

We re very proud of this recognition as it confirms that Enbridge is on the right path in terms of corporate responsibility performance and reporting, said Mr. Monaco. Our stakeholders look to us to deliver top notch financial, social and environmental performance. Being included on the Dow Jones indices is a significant accomplishment and acknowledgement that our business model and approach to managing the opportunities and risks that support the long-term sustainability of our Company are working.

Results of Operations

Enbridge 2014 third quarter adjusted earnings increased to $0.41 per share from $0.34 in the third quarter of 2013. Adjusted earnings for the nine months ended September 30, 2014 increased from $1.33 per share in the comparative 2013 period to $1.41 per share. The Company remains on track to deliver its 2014 full year adjusted earnings per share within its guidance range of $1.84 to $2.04 per share.

Third quarter adjusted earnings growth is predominately attributable to strong operating performance and the continued successful execution of the Company s growth capital program as demonstrated by new assets placed into service. This trend was particularly evident in Liquids Pipelines and Sponsored Investments. In Liquids Pipelines, Canadian Mainline continued its strong 2014 performance bolstered by higher throughput from growing crude oil supply in western Canada and higher downstream refinery demand, as well as successful efforts by the Company to optimize capacity and throughput and to enhance scheduling efficiency with shippers. Within Regional Oil Sands System, the Norealis Pipeline, which was placed into service in April 2014, and higher throughput on the Athabasca Mainline continued to be two key contributors of growth.

EEP provided strong adjusted earnings growth in the third quarter of 2014. New assets placed into service, primarily the Line 6B replacement and expansion, along with higher throughput on EEP s Lakehead and North Dakota systems were the primary growth drivers. Enbridge also benefitted from the completion of the Line 6B replacement and expansion through its 75% interest in the United States portion of the Eastern Access expansion projects held through Enbridge Energy, Limited Partnership (EELP).

The Company s other sponsored vehicle, the Fund, also contributed to adjusted earnings growth over the first nine months of 2014. However, the 2014 third quarter earnings decreased compared with the corresponding 2013 period due to higher income taxes.

EGD s five-year customized IR application was approved by the OEB in July 2014EGD operated the first half of 2014 under OEB approved interim distribution rates. On August 22, 2014, an OEB rate order (the Rate Order) under the IR mechanism approved the final rates with an effective date of January 1, 2014. EGD earnings increased slightly as the Rate Order resulted in a lower depreciation expense under a new approach for determining depreciation and future removal and site restoration reserves. However, this positive effect was partially offset by reduced final rates requiring a refund of a portion of the previously collected interim rates to customers.

Energy Services third quarter adjusted earnings were unfavourable compared with the corresponding 2013 quarter. The unfavourable trends experienced in the first half of the year, including narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, combined with associated unrecovered demand charges, continued to drive lower adjusted earnings. These unfavourable trends are expected to persist into the fourth quarter of 2014.

The adjusted earnings discussed above exclude the impact of unusual, non-recurring or non-operating factors, the most significant of which are changes in unrealized derivative fair value gains and losses from the Company s long-term hedging program and gains on the disposal of non-core assets and investments, as well as certain costs and related insurance recoveries arising from crude oil releases. See *Non-GAAP Measures.*

THIRD QUARTER 2014 OVERVIEW

For more information on Enbridge s growth projects and operating results, please see the Management s Discussion and Analysis (MD&A) which is filed on SEDAR and EDGAR and also available on the Company s website at www.enbridge.com/InvestorRelations.aspx.

- Loss attributable to common shareholders for the third quarter of 2014 was $80 million compared with earnings of $421 million in the third quarter of 2013. The decrease in earnings was primarily attributable to a number of unusual, non-recurring or non-operating factors, the most significant of which is changes in unrealized derivative fair value gains and losses. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price exposures. The changes in unrealized mark-to-market accounting impacts from this program create volatility in short-term earnings, but the Company believes over the long-term it supports reliable cash flows and dividend growth. The comparability of the Company s quarter-over-quarter earnings was also impacted by certain out-of-period adjustments recognized in the third quarter of 2013, including a non-cash adjustment of $37 million after-tax to defer revenues associated with make-up rights earned under certain long-term take-or-pay contracts within Regional Oil Sands System. Also in Regional Oil Sands System, there was an out-of-period adjustment of $31 million after-tax related to the recovery of income taxes under a long-term contract, partially offset by a related correction to deferred income tax expense. In addition, in the third quarter of 2013, in the Gas Distribution segment an out-of-year adjustment of $56 million after-tax was recognized reflecting an increase to gas transportation costs which had incorrectly been deferred. Finally, the Company s earnings for the three months ended September 30, 2014 reflected an accrual of US$51 million ($12 million after-tax attributable to Enbridge) recognized by EEP in respect of the 2010 Line 6B crude oil release.

- Enbridge s adjusted earnings increased from $278 million in the third quarter of 2013 to $345 million in the third quarter of 2014. Liquids Pipelines adjusted earnings reflected higher contributions from Canadian Mainline and Regional Oil Sands System. Canadian Mainline adjusted earnings reflected higher throughput, partially offset by lower average quarter-over-quarter Canadian Mainline International Joint Tariff Residual Benchmark Toll and the continued absence of revenues from Line 9B. Within Regional Oil Sands System, higher adjusted earnings were primarily attributable to contributions from the Norealis Pipeline and higher throughput on the Athabasca mainline. In July 2014, the OEB approved EGD s customized IR application, with modifications. EGD adjusted earnings increased and reflected the August 22, 2014 OEB Rate Order under the IR mechanism which approved the final rates with an effective date of January 1, 2014. EGD operated the first half of 2014 under OEB approved interim distribution rates. The Rate Order resulted in a lower depreciation expense under a new approach for determining depreciation and future removal and site restoration reserves. This positive effect was partially offset by reduced final rates requiring a refund of a portion of the previously collected interim rates to customers. Also impacting the comparability of quarter-over-quarter EGD adjusted earnings was a gas transportation adjustment related to the first half of 2013 recognized in the third quarter of 2013. Energy Services adjusted earnings declined in the third quarter of 2014 compared with a very strong comparative 2013 period due to narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, combined with associated unrecovered demand charges. This trend in Energy Services which also negatively impacted the first half of 2014 is expected to continue into the fourth quarter of 2014. EEP had a strong third quarter of 2014 owing to new assets placed into service, in particular the Line 6B replacement and expansion completed in phases during 2014. Line 6B is a key component of the Company s Eastern Access initiative. Higher throughput and tolls on the majority of EEP s major liquids pipelines also contributed to higher adjusted earnings. Enbridge also benefitted from the completion of Line 6B through its 75% interest in the United States portion of the Eastern Access expansion projects held through EELP. The Fund had lower adjusted earnings in the third quarter of 2014 principally driven by higher income taxes.

- Effective October 15, 2014, the Company appointed John Whelen Executive Vice President and Chief Financial Officer. J. Richard Bird will remain Executive Vice President, Corporate Development until his retirement on December 31, 2014. Also, effective October 15, 2014, J. Herb England was appointed as the Chair of the Audit, Finance, and Risk Committee (AFRC) of the Board of Directors. David Leslie, the outgoing Chair of the AFRC will retire from the Board of Directors effective November 6, 2014.

- On September 23, 2014, the Company entered into an agreement to purchase additional interests in the 300-Megawatt (MW) Lac Alfred Wind Project (Lac Alfred) and the 150-MW Massif du Sud Wind Project (Massif du Sud) from existing partner, EDF EN Canada Inc. Under the agreement, Enbridge will invest approximately $225 million to acquire an additional 17.5% interest in Lac Alfred and an additional 30% interest in Massif du Sud. The Lac Alfred transaction closed in October 2014 and Enbridge now holds a 67.5% interest in Lac Alfred. The Massif du Sud transaction is expected to close in the fourth quarter of 2014 and Enbridge will hold an 80% interest in Massif du Sud upon closing of the transaction.

- On September 22, 2014, Enbridge and the Fund announced that they had entered into an agreement pursuant to which the Fund would acquire Enbridge s 50% interest in the United States segment of the Alliance Pipeline and would also subscribe for and purchase Class A units of Enbridge s subsidiaries that indirectly own the Canadian and United States segments of the Southern Lights Pipeline. The Class A units, which are non-voting and do not confer any governance or ownership rights in Southern Lights Pipeline, will provide a defined cash flow stream to the Fund. Total consideration for the proposed transaction is approximately $1.8 billion. Enbridge will receive on closing approximately $421 million in cash and $461 million in the form of preferred units of Enbridge Commercial Trust, a subsidiary of the Fund. Under the agreement, Enbridge has agreed to provide bridge debt financing to the Fund in the form of an $878 million long-term note payable by the Fund and bearing interest of 5.5% per annum. The note payable is expected to be repaid by the Fund on an expedited basis through the issuance of public debt by the Fund. The Fund will also issue $421 million of trust units to Enbridge Income Fund Holdings Inc. (ENF) to fund the cash component of the consideration. Enbridge will apply approximately $84 million of cash to acquire additional common share of ENF, thereby maintaining its 19.9% interest in ENF. The transaction is subject to customary regulatory approvals, including pursuant to competition legislation in Canada and the United States. If approved, the transaction is expected to provide Enbridge approximately $1.2 billion of net funding for its large growth capital investment program. The transaction is expected to close in the fourth quarter of 2014.

- On September 17, 2014, Enbridge and EEP announced Enbridge s proposal to transfer its current 66.7% interest in the United States segment of the Alberta Clipper pipeline, currently held through a wholly-owned Enbridge subsidiary in the United States, to EEP for approximately US$900 million. EEP currently owns the other 33.3% interest in Alberta Clipper. The proposed consideration includes cash of approximately US$300 million, plus approximately US$600 million in Class E equity units to be issued to Enbridge by EEP. The proposed transfer and terms are subject to review and recommendation by an independent committee of EEP. The transfer is targeted to close by the end of 2014. The Class E units to be issued to Enbridge would be entitled to the same distributions as the Class A units held by the public and would be convertible into Class A units on a one-for-one basis at Enbridge s option. The Class E units would be redeemable at EEP s option after 30 years, if not converted by Enbridge. The units would have a liquidation preference equal to their fair value on closing. Enbridge s economic interest in EEP would increase from approximately 34% to approximately 36% as a result of the transfer.

- Since June 30, 2014, the Company completed the following financing transactions:

- On September 30, 2014, Midcoast Energy Partners, L.P., completed a private placement of senior notes for gross proceeds of US$400 million.

- On September 23, 2014, Enbridge completed an offering of 11 million Cumulative Redeemable Preference Shares, Series 15 for gross proceeds of $275 million.

- On August 22, 2014, Enbridge issued medium term notes of $215 million with a ten-year maturity and $215 million with a 30-year maturity through its subsidiary EGD.

- On August 18, 2014, Enbridge completed private placements of senior notes for gross proceeds of $352 million and US$1,061 million to repay construction credit facilities on a dollar-for-dollar basis related to Southern Lights project financing.

5

• On July 17, 2014, Enbridge completed an offering of 14 million Cumulative Redeemable Preference Shares, Series 13 for gross proceeds of $350 million.

DIVIDEND DECLARATION

On October 22, 2014, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on December 1, 2014 to shareholders of record on November 14, 2014.

Common Shares	$0.35000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
Preference Shares, Series L	US$0.25000
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R	$0.25000
Preference Shares, Series 1	US$0.25000
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5	US$0.27500
Preference Shares, Series 7	$0.27500
Preference Shares, Series 9	$0.27500
Preference Shares, Series 11	$0.27500
Preference Shares, Series 13[1]	$0.41290
Preference Shares, Series 15[2]	$0.20790

1 This first dividend declared for the Preference Shares, Series 13 includes accrued dividends from July 17, 2014, the date the shares were issued. The regular quarterly dividend of $0.275 per share will take effect on March 1, 2015.

2 The first dividend declared for the Preference Shares, Series 15 includes accrued dividends from September 23, 2014, the date the shares were issued. The regular quarterly dividend of $0.275 per share will take effect on March 1, 2015.

CONFERENCE CALL

Enbridge will hold a conference call on Wednesday, November 5, 2014 at 9:00 a.m. Eastern Time (7:00 a.m. Mountain Time) to discuss the third quarter 2014 results. Analysts, members of the media and other interested parties can access the call toll-free at 1-800-708-4540 from within North America and outside North America at 1-847-619-6397, using the access code of 38270286#. The call will be audio webcast live at http://www.media-server.com/m/p/i49imvs7. A webcast replay and podcast will be available approximately two hours after the conclusion of the event and a transcript will be posted to the website within 24 hours. The replay will be available toll-free at 1-888-843-7419 within North America and outside North America at 1-630-652-3042 (access code 38270286#) until November 12, 2014.

The conference call will begin with presentations by the Company s President and Chief Executive Officer and the Chief Financial Officer, followed by a question and answer period for investment analysts. A question and answer period for members of the media will then immediately follow.

Enbridge Inc., a Canadian Company, is a North American leader in delivering energy and has been included on the Global 100 Most Sustainable Corporations in the World ranking for the past six years. As a transporter of energy, Enbridge operates, in Canada and the U.S., the world s longest crude oil and liquids transportation system. The Company also has a significant and growing involvement in natural gas gathering, transmission and midstream businesses, and an increasing involvement in power transmission. As a distributor of energy, Enbridge owns and operates Canada s largest natural gas distribution company, and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a generator of energy, Enbridge has interests in more than 1,800 megawatts of renewable and alternative energy generating capacity and is expanding its interests in wind and solar energy and geothermal. Enbridge employs more than 10,000 people, primarily in Canada and the U.S. and is ranked as one of Canada s Top 100 Employers for 2014. Enbridge s common shares trade on the Toronto and New York stock exchanges under the symbol ENB. For more information, visit www.enbridge.com. None of the information contained in, or connected to, Enbridge s website is incorporated in or otherwise part of this news release.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this news release to provide the Company s shareholders and potential investors with information about the Company and its subsidiaries and affiliates, including management s assessment of Enbridge and its subsidiaries future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as anticipate , expect , project , estimate , forecast , plan , intend , target , b similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to: expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; estimated future dividends; and expected costs related to leak remediation and potential insurance recoveries.

Although Enbridge believes these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply of and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; expected exchange rates, inflation and interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for the Company s projects; anticipated in-service dates; and weather. Assumptions regarding the expected supply of and demand of crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as *they may impact current and future levels of demand for the Company s services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates and may impact levels of demand for the Company s services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings/(loss) or adjusted earnings/(loss) and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates and expected capital expenditures, include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction and in-service schedules.*

Enbridge s forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, changes in tax law and tax rate increases, exchange rates, interest rates, commodity prices and supply and demand for commodities, including but not limited to those risks and uncertainties discussed in this news release and in the Company s other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge s future course of action depends on management s assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this news release or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company s behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This news release contains references to adjusted earnings/(loss), which represent earnings or loss attributable to common shareholders adjusted for unusual, non-recurring or non-operating factors on both a consolidated and segmented basis. These factors, referred to as adjusting items, are reconciled and discussed in the financial results sections for the affected business segments in the Company s MD&A. Adjusting items referred to as changes in unrealized derivative fair value gains or loss are presented net of amounts realized on the settlement of derivative contracts during the applicable period. Management believes the presentation of adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, including setting the Company s dividend payout target, and to assess the performance of the Company. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by accounting principles generally accepted in the United States of America (U.S. GAAP) and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See Non-GAAP Reconciliations *for a reconciliation of the GAAP and non-GAAP measures.*

NON-GAAP RECONCILIATIONS

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Earnings/(loss) attributable to common shareholders	**(80)**	421	**1,066**	713
Adjusting items:				
Liquids Pipelines				
Canadian Mainline - changes in unrealized derivative fair value (gains)/loss[1]	**231**	(133)	**192**	125
Canadian Mainline - Line 9B costs incurred during reversal	**2**	-	**6**	-
Regional Oil Sands System - make-up rights adjustment	**(5)**	-	**(5)**	-
Regional Oil Sands System - make-up rights out-of-period adjustment	**-**	37	**-**	37
Regional Oil Sands System - leak insurance recoveries	**-**	-	**(4)**	-
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**4**	13	**4**	53
Regional Oil Sands System - long-term contractual recovery out-of-period adjustment, net	**-**	(31)	**-**	(31)
Southern Lights Pipeline - changes in unrealized derivative fair value loss[1]	**9**	-	**9**	-
Seaway Pipeline - make-up rights adjustment	**11**	-	**11**	-
Spearhead Pipeline - make-up rights adjustment	**-**	-	**1**	-
Feeder Pipelines and Other - make-up rights adjustment	**(1)**	-	**(3)**	-
Feeder Pipelines and Other - project development costs	**1**	-	**4**	-
Gas Distribution				
EGD - warmer/(colder) than normal weather	**2**	-	**(35)**	4
EGD - gas transportation cost cut-off-period adjustment	**-**	56	**-**	56
Gas Pipelines, Processing and Energy Services				
Energy Services - changes in unrealized derivative fair value gains[1]	**(71)**	(18)	**(288)**	(131)
Offshore - changes in unrealized derivative fair value loss[1]	**2**	-	**2**	-
Offshore - gain on sale of non-core assets	**-**	-	**(43)**	-
Other - changes in unrealized derivative fair value loss[1]	**1**	4	**3**	60
Sponsored Investments				
EEP - changes in unrealized derivative fair value loss[1]	**6**	6	**9**	3
EEP - make-up rights adjustment	**-**	-	**1**	-
EEP - leak remediation costs	**12**	5	**17**	35
EEP - leak insurance recoveries	**-**	-	**-**	(6)
EEP - tax rate differences/changes	**-**	-	**-**	3
The Fund - changes in unrealized derivative fair value gains[1]	**(3)**	-	**(3)**	-
The Fund - make-up rights adjustment	**1**	-	**1**	-
The Fund - drop down transaction costs	**2**	-	**2**	-
Corporate				
Noverco - changes in unrealized derivative fair value (gains)/loss[1]	**-**	(5)	**5**	(4)
Other Corporate - changes in unrealized derivative fair value (gains)/loss[1]	**221**	(77)	**227**	177
Other Corporate - gain on sale of investment	**-**	-	**(14)**	-
Other Corporate - foreign tax recovery	**-**	-	**-**	(4)
Other Corporate - impact of tax rate changes	**-**	-	**-**	(18)
Adjusted earnings	**345**	278	**1,165**	1,072

1 Changes in unrealized derivative fair value gains and losses are presented net of amounts realized on the settlement of derivative contracts during the applicable period.

9

HIGHLIGHTS

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars, except per share amounts)				
Earnings attributable to common shareholders				
Liquids Pipelines	**(31)**	301	**444**	381
Gas Distribution	**(11)**	(85)	**144**	49
Gas Pipelines, Processing and Energy Services	**88**	68	**386**	257
Sponsored Investments	**108**	75	**279**	189
Corporate	**(234)**	62	**(233)**	(163)
Earnings/(loss) attributable to common shareholders from continuing operations	**(80)**	421	**1,020**	713
Discontinued operations - Gas Pipelines, Processing and Energy Services	**-**	-	**46**	-
	(80)	421	**1,066**	713
Earnings/(loss) per common share	**(0.10)**	0.52	**1.29**	0.89
Diluted earnings/(loss) per common share	**(0.10)**	0.51	**1.27**	0.88
Adjusted earnings[1]				
Liquids Pipelines	**221**	187	**659**	565
Gas Distribution	**(9)**	(29)	**109**	109
Gas Pipelines, Processing and Energy Services	**20**	54	**106**	186
Sponsored Investments	**126**	86	**306**	224
Corporate	**(13)**	(20)	**(15)**	(12)
	345	278	**1,165**	1,072
Adjusted earnings per common share[1]	**0.41**	0.34	**1.41**	1.33
Cash flow data				
Cash provided by operating activities	**746**	830	**1,891**	2,560
Cash used in investing activities	**(2,525)**	(2,562)	**(8,154)**	(6,154)
Cash provided by financing activities	**1,594**	1,175	**6,549**	2,326
Dividends				
Common share dividends declared	**296**	261	**880**	774
Dividends paid per common share	**0.3500**	0.3150	**1.0500**	0.9450
Shares outstanding *(millions)*				
Weighted average common shares outstanding	**835**	814	**826**	803
Diluted weighted average common shares outstanding	**847**	824	**837**	814
Operating data				
Liquids Pipelines - Average deliveries *(thousands of barrels per day)*				
Canadian Mainline[2]	**2,039**	1,736	**1,970**	1,707
Regional Oil Sands System[3]	**690**	578	**697**	490
Spearhead Pipeline	**190**	172	**190**	174
Gas Distribution - Enbridge Gas Distribution (EGD)				
Volumes *(billions of cubic feet)*	**44**	44	**332**	299
Number of active customers *(thousands)*[4]	**2,076**	2,040	**2,076**	2,040
Heating degree days[5]				
Actual	**84**	89	**2,783**	2,378
Forecast based on normal weather	**61**	54	**2,299**	2,420
Gas Pipelines, Processing and Energy Services - Average throughput volume *(millions of cubic feet per day)*				
Alliance Pipeline US	**1,660**	1,514	**1,694**	1,569
Vector Pipeline	**1,201**	1,406	**1,434**	1,511
Enbridge Offshore Pipelines	**1,501**	1,458	**1,485**	1,420

1 *Adjusted earnings represent earnings attributable to common shareholders adjusted for unusual, non-recurring or non-operating factors. Adjusted earnings and adjusted earnings per common share are non-GAAP measures that do not have any standardized meaning prescribed by GAAP.*

2 Canadian Mainline includes deliveries ex-Gretna, Manitoba which is made up of United States and eastern Canada deliveries originating from western Canada.
3 Volumes are for the Athabasca mainline and Waupisoo Pipeline and exclude laterals on the Regional Oil Sands System.
4 Number of active customers is the number of natural gas consuming EGD customers at the end of the period.
5 Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in EGD s franchise area. It is calculated by accumulating, for the fiscal period, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto Area.

Enbridge Contacts:

Media
Graham White
(403) 508-6563 or Toll Free: 1-888-992-0997
Email: graham.white@enbridge.com

Investment Community
Adam McKnight
(403) 266-7922
Email: adam.mcknight@enbridge.com

ENBRIDGE INC.

MANAGEMENT S DISCUSSION AND ANALYSIS

September 30, 2014

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2014

This Management s Discussion and Analysis (MD&A) dated November 4, 2014 should be read in conjunction with the unaudited interim consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) as at and for the three and nine months ended September 30, 2014, prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). It should also be read in conjunction with the audited consolidated financial statements and MD&A contained in the Company s Annual Report for the year ended December 31, 2013. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

CONSOLIDATED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**(31)**	301	**444**	381
Gas Distribution	**(11)**	(85)	**144**	49
Gas Pipelines, Processing and Energy Services	**88**	68	**386**	257
Sponsored Investments	**108**	75	**279**	189
Corporate	**(234)**	62	**(233)**	(163)
Earnings/(loss) attributable to common shareholders from continuing operations	**(80)**	421	**1,020**	713
Discontinued operations - Gas Pipelines, Processing and Energy Services	**-**	-	**46**	-
Earnings/(loss) attributable to common shareholders	**(80)**	421	**1,066**	713
Earnings/(loss) per common share	**(0.10)**	0.52	**1.29**	0.89
Diluted earnings/(loss) per common share	**(0.10)**	0.51	**1.27**	0.88

Loss attributable to common shareholders was $80 million for the three months ended September 30, 2014, or a $0.10 loss per common share, compared with earnings attributable to common shareholders of $421 million or $0.52 per common share, for the three months ended September 30, 2013. The Company continued to deliver strong quarter-over-quarter earnings growth, as discussed in *Adjusted Earnings*; however, the Company s quarterly results are impacted by a number of unusual, non-recurring or non-operating factors, the most significant of which is changes in unrealized derivative fair value gains and losses. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price exposures. The changes in unrealized mark-to-market accounting impacts from this program create volatility in short-term earnings, but the Company believes over the long-term it supports reliable cash flows and dividend growth.

The comparability of the Company s quarter-over-quarter earnings was also impacted by certain out-of-period adjustments recognized in the third quarter of 2013, including a non-cash adjustment of $37 million after-tax to defer revenues associated with make-up rights earned under certain long-term take-or-pay contracts within Regional Oil Sands System. Also in Regional Oil Sands System, there was an out-of-period adjustment of $31 million after-tax related to the recovery of income taxes under a long-term contract, partially offset by a related correction to deferred income tax expense. In addition, in the third quarter of 2013, in the Gas Distribution segment an out-of-year adjustment of $56 million after-tax was recognized reflecting an increase to gas transportation costs which had incorrectly been deferred. Finally, the Company s earnings for the three months ended September 30, 2014 reflected an accrual of US$51 million ($12 million after-tax attributable to Enbridge) recognized by Enbridge Energy Partners, L.P. (EEP) in respect of the Line 6B crude oil release. See *Recent Developments Sponsored Investments Enbridge Energy Partners, L.P. Line 6B Crude Oil Release.*

1

Earnings attributable to common shareholders were $1,066 million for the nine months ended September 30, 2014, or $1.29 per common share, compared with $713 million, or $0.89 per common share, for the nine months ended September 30, 2013. The Company has delivered strong earnings growth in the first nine months of 2014; however, the magnitude of this growth and the comparability of the Company s results are impacted by changes in unrealized derivative fair value gains and losses, as well as the out-of-period adjustments noted above. In addition, earnings for the nine months ended September 30, 2014 also reflected a $43 million after-tax gain recognized on the disposal of non-core assets within Enbridge Offshore Pipelines (Offshore) and a $14 million after-tax gain on the sale of an Alternative and Emerging Technologies investment within the Corporate segment. Finally, the Company s earnings, for both 2014 and 2013, reflected certain costs and related insurance recoveries related to the Line 6B crude oil release, see *Recent Developments Sponsored Investments Enbridge Energy Partners, L.P. Line 6B Crude Oil Release,* as well as the Line 37 crude oil release which occurred in June 2013.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company s shareholders and potential investors with information about the Company and its subsidiaries and affiliates, including management s assessment of Enbridge and its subsidiaries future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as anticipate , expect , project , estimate , forecast , plan , intend , target , l similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to: expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; estimated future dividends; and expected costs related to leak remediation and potential insurance recoveries.

Although Enbridge believes these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply of and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; expected exchange rates, inflation and interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for the Company s projects; anticipated in-service dates; and weather. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company s services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates and may impact levels of demand for the Company s services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings/(loss) or adjusted earnings/(loss) and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates and expected capital expenditures, include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction and in-service schedules.

Enbridge s forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, changes in tax law and tax rate increases, exchange rates, interest rates, commodity prices and supply and demand for commodities, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company s other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge s future course of *action depends on management s assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company s behalf, are expressly qualified in their entirety by these cautionary statements.*

NON-GAAP MEASURES

This MD&A contains references to adjusted earnings/(loss), which represent earnings or loss attributable to common shareholders adjusted for unusual, non-recurring or non-operating factors on both a consolidated and segmented basis. These factors, referred to as adjusting items, are reconciled and discussed in the financial results sections for the affected business segments. Adjusting items referred to as changes in unrealized derivative fair value gains or loss are presented net of amounts realized on the settlement of derivative contracts during the applicable period. Management believes the presentation of adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, including setting the Company s dividend payout target, and to assess the performance of the Company. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by U.S. GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See Non-GAAP Reconciliations *for a reconciliation of the GAAP and non-GAAP measures.*

ADJUSTED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**221**	187	**659**	565
Gas Distribution	**(9)**	(29)	**109**	109
Gas Pipelines, Processing and Energy Services	**20**	54	**106**	186
Sponsored Investments	**126**	86	**306**	224
Corporate	**(13)**	(20)	**(15)**	(12)
Adjusted earnings	**345**	278	**1,165**	1,072
Adjusted earnings per common share	**0.41**	0.34	**1.41**	1.33

Adjusted earnings were $345 million, or $0.41 per common share, for the three months ended September 30, 2014 compared with $278 million, or $0.34 per common share, for the three months ended September 30, 2013. Adjusted earnings were $1,165 million, or $1.41 per common share, for the nine months ended September 30, 2014 compared with $1,072 million, or $1.33 per common share, for the nine months ended September 30, 2013.

The following factors impacted adjusted earnings:

- Within Liquids Pipelines, higher throughput on Canadian Mainline drove an increase in adjusted earnings for the three and nine months ended September 30, 2014. The increase in throughput was attributable to several factors including: increased oil sands production; strong refinery demand in the midwest market partly due to a start-up of a midwest refinery s conversion to heavy oil processing in the second quarter of 2014; and successful efforts by the Company to optimize capacity and throughput and to enhance scheduling efficiency with shippers. Canadian Mainline earnings for the three and nine months ended September 30, 2014 reflected a lower average Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll compared with the corresponding 2013 periods. Finally, Canadian Mainline adjusted earnings continued to be impacted by the absence of revenues from Line 9B, which was idled in late 2013 while it is being reversed and expanded as part of the Company s Eastern Access initiative.

- Also within Liquids Pipelines, Regional Oil Sands System adjusted earnings increased due to contributions from the Norealis Pipeline, which was completed in April 2014, and higher throughput on the Athabasca mainline which were partially offset by higher operating and administrative, depreciation, interest and tax expenses.

- Within Gas Distribution, Enbridge Gas Distribution Inc. (EGD) adjusted earnings increased slightly and reflected the August 22, 2014 Ontario Energy Board (OEB) rate order (the Rate Order) under the incentive rate (IR) mechanism which approved the final rates with an effective date of January 1, 2014. EGD operated the first half of 2014 under OEB approved interim distribution rates. The Rate Order resulted in a lower depreciation expense under a new approach for determining depreciation and future removal and site restoration reserves. This positive effect was partially offset by reduced final rates requiring a refund of a portion of the previously collected interim rates to customers.

- Within Gas Pipelines, Processing and Energy Services, the decrease in adjusted earnings reflected weaker Energy Services results compared with a very strong 2013. Narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, combined with unrecovered demand charges, resulted in lower adjusted earnings for the first nine months of 2014. In addition to the trends noted above, adjusted earnings for the nine-month period of 2014 decreased as a result of losses realized in the first quarter of 2014 on certain financial contracts intended to hedge the value of committed transportation capacity, but which were not effective in doing so. Partially offsetting the decrease in adjusted earnings were favourable natural gas location differentials caused by abnormal winter weather conditions in the first quarter of 2014.

- Within Sponsored Investments, EEP adjusted earnings reflected increased contributions from EEP s liquids business due to new assets placed into service during 2013 and 2014, combined with higher throughput and tolls on EEP s major liquids pipelines. New assets placed into service include the replacement and expansion of Line 6B as part of Enbridge and EEP s Eastern Access initiative. Enbridge also benefitted from the completion of Line 6B replacement and expansion through its 75% interest in the United States portion of the Eastern Access expansion projects held through Enbridge Energy, Limited Partnership (EELP). Within EEP s natural gas and NGL businesses, which it holds directly and indirectly through its partially-owned subsidiary, Midcoast Energy Partners, L.P. (MEP), lower volumes had a negative impact on adjusted earnings.

- Also within Sponsored Investments, Enbridge Income Fund (the Fund) adjusted earnings reflected strong performance from the Fund s liquids business. Also contributing to period-over-period growth in adjusted earnings for the first nine months of 2014 was the absence of an after-tax charge of $12 million ($4 million after-tax attributable to Enbridge) related to the write-off of a regulatory deferral balance which occurred in the first quarter of 2013. Partially offsetting the adjusted earnings increase were higher income taxes, which also drove lower 2014 third quarter earnings.

- Within the Corporate segment, Noverco Inc. (Noverco) adjusted earnings for the nine months ended September 30, 2014 decreased compared with the corresponding 2013 period. Excluding the impact of a small one-time gain on sale of an investment in the first quarter of 2013 and an equity earnings true-up adjustment recognized in the first quarter of 2013, Noverco adjusted earnings were comparable between periods.

- Also within the Corporate segment, Other Corporate adjusted loss decreased for the three and nine months ended September 30, 2014 compared with the corresponding 2013 periods. The decreased loss reflected lower net corporate segment finance costs and lower income taxes partially offset by higher preference share dividends due to an increase in the number of preference shares outstanding.

RECENT DEVELOPMENTS

CHIEF FINANCIAL OFFICER SUCCESSION PLANS

On October 10, 2014, the Company announced the appointment of John Whelen to Executive Vice President and Chief Financial Officer, effective October 15, 2014. J. Richard Bird will remain Executive Vice President, Corporate Development until his retirement on December 31, 2014. The Company had previously announced on June 18, 2014, Mr. Bird s planned retirement and the split of his responsibilities into two separate roles of Chief Financial Officer and Chief Development Officer. Vern Yu was appointed Senior Vice President, Corporate Development effective July 1, 2014 and will continue to report to Mr. Bird.

4

LIQUIDS PIPELINES

Seaway Pipeline

Seaway Crude Oil Pipeline (Seaway Pipeline) filed an application for market-based rates in December 2011. Initially the Federal Energy Regulatory Commission (FERC) rejected the application in March 2012 and Seaway Pipeline appealed to the District of Columbia Circuit. In response, the FERC set the application for further proceedings and the appeal was stayed. Since the FERC had not issued a ruling on this application, Seaway Pipeline filed for initial rates in order to have rates in effect by the in-service date. The uncommitted rate on Seaway Pipeline was challenged by several shippers. During the evidentiary stage, FERC staff filed evidence stating that the committed and uncommitted rates are subject to review and adjustment. Seaway Pipeline filed a Petition for Declaratory Order (PDO) requesting the FERC confirm that it will honour and uphold existing contracts. The FERC issued a decision denying the PDO on procedural grounds but stated that it will uphold its longstanding policy of honouring contracts.

The FERC hearings concluded with all parties filing their respective briefs. In September 2013, a decision from the Administrative Law Judge (ALJ) was released finding that the committed and uncommitted rates on Seaway Pipeline should be reduced to reflect the ALJ s findings on the various cost of service inputs. Seaway Pipeline filed a brief with the FERC on October 15, 2013 challenging the ALJ s decision and asking for expedited ruling by the FERC on the committed rates. In February 2014, the FERC issued its decision upholding its policy to honour contracts and ordered the ALJ to revise her decision accordingly. On May 9, 2014, the ALJ issued an initial decision on remand reiterating her previous findings and did not change her decision. Briefings have concluded and the full record was sent to the FERC for its final decision, which is still pending.

In relation to the original market based rate application, the FERC issued its decision rejecting Seaway Pipeline s application for market based rates in February 2014 and announced a new methodology for determining whether a pipeline has market power and invited Seaway Pipeline to refile its market based rate application consistent with the new policy. Seaway Pipeline is currently evaluating whether it will file a new market based rate application under the new methodology.

GAS DISTRIBUTION

Enbridge Gas Distribution Incentive Regulation

On July 17, 2014, the OEB approved EGD s five-year customized IR application, with modifications. The customized IR application establishes the methodology for determining rates for the distribution of natural gas over a five-year period from 2014 through 2018 and will allow EGD to recover its expected capital investment amounts, as well as an opportunity to earn above the allowed return on equity. The OEB decision also allowed for final 2014 rates to be implemented with the October 2014 Quarterly Rate Adjustment Mechanism with an effective date of January 1, 2014. EGD operated the first half of 2014 under OEB approved interim distribution rates. On August 22, 2014, an OEB Rate Order under the IR mechanism approved the final rates with an effective date of January 1, 2014.

The Rate Order approved a new approach for determining depreciation and future removal and site restoration reserves resulting in a lower depreciation expense. The Rate Order also approved reduced final rates requiring a refund of a portion of the previously collected interim rates to customers.

Enbridge Gas New Brunswick Regulatory Matter

In 2012, the Government of New Brunswick enacted final rates and tariff regulation that affected the franchise agreement between Enbridge Gas New Brunswick Inc. (EGNB) and the province of New Brunswick, including the ability for EGNB to recover a deferred regulatory asset.

Also in 2012, EGNB commenced legal proceedings against the Government of New Brunswick seeking damages for breach of contract and commenced a separate application to quash the Government of New Brunswick s rate and tariffs regulation. EGNB s appeal in the latter proceeding was ultimately successful in part, as the Court of Appeal ruled that the rates and tariffs regulation that caps rates according to a maximum revenue-to-cost ratio was beyond the regulation-making authority of the New Brunswick Lieutenant Governor in Council. The Court of Appeal upheld the portion of the regulation that requires EGNB to charge customers the lower of market or cost-based rates. EGNB s 2014 rate application was approved in April 2014 by New Brunswick Energy and Utilities Board (EUB). EGNB has filed its application for 2015 rates with the EUB and the rate case is ongoing.

On February 4, 2014, EGNB commenced a further legal proceeding against the Government of New Brunswick. The action seeks damages for improper extinguishment of the deferred regulatory asset that was previously eliminated from EGNB s Consolidated Statements of Financial Position.

There is no assurance that any of EGNB s legal proceedings against the Province of New Brunswick will be successful or will result in any recovery.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Lac Alfred and Massif du Sud Wind Projects

In September 2014, the Company entered into an agreement to purchase additional interests in the 300-Megawatt (MW) Lac Alfred Wind Project (Lac Alfred) and the 150-MW Massif du Sud Wind Project (Massif du Sud) from existing partner, EDF EN Canada Inc. Under the agreement, Enbridge will invest approximately $225 million to acquire an additional 17.5% interest in Lac Alfred and an additional 30% interest in Massif du Sud. The Lac Alfred transaction closed in October 2014 and Enbridge now holds a 67.5% interest in Lac Alfred. The Massif du Sud transaction is expected to close in the fourth quarter of 2014 and Enbridge will hold an 80% interest in Massif du Sud upon closing of the transaction.

SPONSORED INVESTMENTS ENBRIDGE ENERGY PARTNERS, L.P.

Sponsored Vehicle Transactions

In 2014, Enbridge and EEP undertook a series of actions with the objective of enhancing EEP s distributable cash flow and returns generated by investment opportunities and to increase its effectiveness as a sponsored vehicle and source of funding for Enbridge via future asset monetization.

Proposed Alberta Clipper Drop Down

In September 2014, Enbridge and EEP announced Enbridge s proposal to transfer its current 66.7% interest in the United States segment of the Alberta Clipper pipeline, currently held through a wholly-owned Enbridge subsidiary in the United States, to EEP for approximately US$900 million. EEP currently owns the other 33.3% interest in Alberta Clipper. The proposed consideration includes cash of approximately US$300 million, plus approximately US$600 million in Class E equity units to be issued to Enbridge by EEP. The proposed transfer and terms are subject to review and recommendation by an independent committee of EEP. The transfer is targeted to close by the end of 2014.

The Class E units to be issued to Enbridge would be entitled to the same distributions as the Class A units held by the public and would be convertible into Class A units on a one-for-one basis at Enbridge s option. The Class E units would be redeemable at EEP s option after 30 years, if not converted by Enbridge. The units would have a liquidation preference equal to their fair value on closing. Enbridge s economic interest in EEP would increase from approximately 34% to approximately 36% as a result of the transfer.

The United States segment of the Alberta Clipper Pipeline is a 36-inch diameter, 523-kilometre (325-mile) long crude oil pipeline from the United States border near Neche, North Dakota to Superior, Wisconsin. The initial capacity of the line is 450,000 barrels per day (bpd) and was constructed under the terms of a joint funding agreement under which Enbridge funded two-thirds of the capital costs in return for a corresponding economic interest in the earnings and cash flow from the investment. The line is being expanded in two phases to a capacity of 800,000 bpd through the addition of increased pumping horsepower. The required expansion investments are subject to separate joint funding arrangements between Enbridge and EEP. See *Growth Projects Commercially Secured Projects Sponsored Investments Enbridge Energy Partners, L.P. Lakehead System Mainline Expansion*.

Equity Restructuring

In June 2014, EEP and Enbridge announced an agreement to restructure EEP s equity. Effective July 1, 2014, Enbridge Energy Company, Inc., a wholly-owned subsidiary of Enbridge and the General Partner (GP) of EEP, irrevocably waived its then existing incentive distribution rights (IDR) in excess of its 2% GP interest in exchange for 66.1 million Class D units and 1,000 Incentive Distribution Units (IDU) (collectively, the Equity Restructuring). The GP share of incremental cash distributions decreased from 48% of all distributions in excess of US$0.4950 per unit per quarter down to 23% of all distributions in excess of EEP s quarterly distribution of US$0.5435 per unit per quarter. The Class D units carry a distribution equal to the quarterly distribution on the Class A common units. The third quarter 2014 distribution on the Class D units were adjusted to provide Enbridge with an aggregate distribution in 2014 equal to the distribution on its IDR as if the Equity Restructuring had not occurred. The IDU is not entitled to a distribution initially and in the event of any decrease in the Class A common unit distribution below US$0.5435 per unit in any quarter during the next five years, the distribution on the Class D units will be reduced to the amount which would have been received by Enbridge under the IDR as if the Equity Restructuring had not occurred.

The Class D units have a notional value per unit equivalent to the closing market price of the Class A Common units on June 17, 2014 (Notional Value) and have the same voting rights as the Class A units. The Class D units are convertible on a one-for-one basis into Class A common units at any time on or after the fifth anniversary of the closing date, at the holder s option. In the event of a liquidation event (or any merger or other extraordinary transaction), the Class D unitholders will have a preference in liquidation equal to 20% of the Notional Value, with such preference being increased by an additional 20% on each anniversary of the closing date, resulting in a liquidation preference equal to 100% of the Notional Value on the fourth anniversary of the closing date. The Class D units will be redeemable in 30 years in whole or in part at EEP s option for either a cash amount equal to the Notional Value per unit or newly issued Class A common units with an aggregate market value at redemption equal to 105% of the aggregate Notional Value of the Class D units being redeemed.

EEP Drop Down of Additional Interest to Midcoast Energy Partners, L.P.

On July 1, 2014, EEP completed the sale of an additional 12.6% limited partnership interest in its natural gas and NGL midstream business to MEP for cash proceeds of US$350 million. Upon finalization of this transaction, EEP retains an approximate 48% direct interest in entities or partnerships holding the natural gas and NGL midstream operations, with the remaining ownership held by MEP. The balance of EEP s interest in the natural gas and NGL midstream operations is held indirectly through ownership of a GP interest, an approximate 52% limited partner interest and all IDR of MEP. The completion of this transaction resulted in a partial monetization of EEP s natural gas and NGL midstream business through sale to noncontrolling interests (being MEP s public unitholders). The proceeds from the drop down provided EEP a cost-effective funding alternative to execute its current liquids pipeline organic growth program.

Line 6B Crude Oil Release

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. On March 14, 2013, EEP received an order from the Environmental Protection Agency (EPA) which defined the scope requiring additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. EEP submitted its initial proposed work plan required by the EPA on April 4, 2013 and resubmitted the work plan on April 23, 2013 and again on May 1, 2013 based on EPA comments. The EPA approved the Submerged Oil Recovery and Assessment (SORA) work plan with modification on May 8, 2013. EEP incorporated the modification and submitted an approved SORA on May 13, 2013. At this time, EEP has completed substantially all of the SORA.

EEP is also working with the Michigan Department of Environmental Quality (MDEQ) to transition submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities from the EPA to the MDEQ, through a Kalamazoo

River Residual Oil Monitoring and Maintenance Work Plan.

As at September 30, 2014, EEP s total cost estimate for the Line 6B crude oil release was US$1.2 billion ($198 million after-tax attributable to Enbridge), which is an increase of US$86 million ($17 million after-tax attributable to Enbridge) as compared with December 31, 2013 and an increase of US$51 million ($12 million after-tax attributable to Enbridge) as compared with June 30, 2014. On May 28, 2014, the MDEQ s Water Resource Division approved EEP s Schedule of Work for the remainder of 2014. Of the total cost increase of US$51 million during the three months ended September 30, 2014, US$33 million is primarily related to the MDEQ approved Schedule of Work and completion of the dredge activities near Ceresco and Morrow Lake and US$18 million is related to an increase of estimated civil penalties under the Clean Water Act of the United States (Clean Water Act), as described below under *Legal and Regulatory Proceedings*.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at September 30, 2014. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews throughout the year. On May 1 of each year, the insurance program is up for renewal and includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents excluding costs for fines and penalties.

A majority of the costs incurred in connection with the crude oil release for Line 6B are covered by Enbridge s comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Including EEP s remediation spending through September 30, 2014, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. As at September 30, 2014, EEP has recorded total insurance recoveries of US$547 million ($80 million after-tax attributable to Enbridge) for the Line 6B crude oil release out of the US$650 million aggregate limit. EEP will record receivables for additional amounts it claims for recovery pursuant to its insurance policies during the period it deems recovery to be probable.

In March 2013, EEP and Enbridge filed a lawsuit against the insurers for the then remaining US$145 million coverage, as one particular insurer is disputing the recovery eligibility for costs related to EEP s claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of the recovery from that insurer. EEP received a partial recovery payment of US$42 million from the other remaining insurers. Of the remaining US$103 million coverage limit, US$85 million is the subject matter of the lawsuit Enbridge filed in March 2013 against one particular insurer who is disputing EEP s recovery eligibility for costs related to its claim on the Line 6B crude oil release. The recovery of the remaining US$18 million is awaiting resolution of this lawsuit. While EEP believes those costs are eligible for recovery, there can be no assurance that EEP will prevail in this lawsuit.

Enbridge renewed its comprehensive property and liability insurance programs under which the Company is insured through April 30, 2015 with a liability aggregate limit of US$700 million, including sudden and accidental pollution liability. The deductible applicable to oil pollution events was increased to US$30 million per event, from the previous US$10 million. In the unlikely event multiple insurable incidents which in aggregate exceed coverage limits occur within the same insurance period, the total insurance coverage will be allocated among Enbridge entities on an equitable basis based on an insurance allocation agreement among Enbridge and its subsidiaries.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately 10 actions or claims are pending against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, the Company does not expect the outcome of these actions to be material.

At September 30, 2014, included in EEP s estimated costs related to the Line 6B crude oil release is US$48 million in fines and penalties. Of this amount, US$3.7 million related to civil penalties assessed by the Pipeline and Hazardous Materials Safety Administration, which EEP paid during the third quarter of 2012. The total also included an amount of US$40 million related to civil penalties under the Clean Water Act. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$40 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Injunctive relief is likely to include measures directed toward enhancing spill prevention, leak detection, emergency response to environmental events and the cost of compliance with such measures could be significant. Discussions with governmental agencies regarding fines, penalties and injunctive relief are ongoing.

SPONSORED INVESTMENTS ENBRIDGE INCOME FUND

Proposed Natural Gas And Diluent Pipeline Interests Transfer

In September 2014, Enbridge and the Fund announced that they had entered into an agreement pursuant to which the Fund would acquire Enbridge s 50% interest in the United States segment of the Alliance Pipeline and would also subscribe for and purchase Class A units of Enbridge s subsidiaries that indirectly own the Canadian and United States segments of the Southern Lights Pipeline. The Class A units, which are non-voting and do not confer any governance or ownership rights in Southern Lights Pipeline, will provide a defined cash flow stream to the Fund. Total consideration for the proposed transaction is approximately $1.8 billion. Enbridge will receive on closing approximately $421 million in cash and $461 million in the form of preferred units of Enbridge Commercial Trust, a subsidiary of the Fund. Under the agreement, Enbridge has agreed to provide bridge debt financing to the Fund in the form of an $878 million long-term note payable by the Fund and bearing interest of 5.5% per annum. The note payable is expected to be repaid by the Fund on an expedited basis through the issuance of public debt by the Fund. The Fund will also issue $421 million of trust units to Enbridge Income Fund Holdings Inc. (ENF) to fund the cash component of the consideration. Enbridge will apply approximately $84 million of cash to acquire additional common share of ENF, thereby maintaining its 19.9% interest in ENF. The transaction is subject to customary regulatory approvals, including pursuant to competition legislation in Canada and the United States. If approved, the transaction is expected to provide Enbridge approximately $1.2 billion of net funding for its large growth capital investment program. The transaction is expected to close in the fourth quarter of 2014.

CORPORATE

Preference Share Issuance

Series 9

On March 13, 2014, the Company issued 11 million Preference Shares, Series 9 for gross proceeds of $275 million. The 4.4% Cumulative Redeemable Preference Shares, Series 9 are entitled to receive a fixed, cumulative, quarterly preferential dividend aggregating to $1.10 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for $25.00 per share plus all accrued and unpaid dividends on December 1, 2019 and on December 1 of every fifth year thereafter. The holders of Preference Shares, Series 9 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 10, subject to certain conditions, on December 1, 2019 and on December 1 of every fifth year thereafter. The holders of Preference Shares, Series 10 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.7%.

Series 11

On May 22, 2014, the Company issued 20 million Preference Shares, Series 11 for gross proceeds of $500 million. The 4.4% Cumulative Redeemable Preference Shares, Series 11 are entitled to receive a fixed, cumulative, quarterly preferential dividend aggregating to $1.10 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for $25.00 per share plus all accrued and unpaid dividends on March 1, 2020 and on March 1 of every fifth year thereafter.

The holders of Preference Shares, Series 11 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 12, subject to certain conditions, on March 1, 2020 and on March 1 of every fifth year thereafter. The holders of Preference Shares, Series 12 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.6%.

Series 13

On July 17, 2014, the Company issued 14 million Preference Shares, Series 13 for gross proceeds of $350 million. The 4.4% Cumulative Redeemable Preference Shares, Series 13 are entitled to receive a fixed, cumulative, quarterly preferential dividend aggregating to $1.10 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for $25.00 per share plus all accrued and unpaid dividends on June 1, 2020 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series 13 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 14, subject to certain conditions, on June 1, 2020 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series 14 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.7%.

Series 15

On September 23, 2014, the Company issued 11 million Preference Shares, Series 15 for gross proceeds of $275 million. The 4.4% Cumulative Redeemable Preference Shares, Series 15 are entitled to receive a fixed, cumulative, quarterly preferential dividend aggregating to $1.10 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for $25.00 per share plus all accrued and unpaid dividends on September 1, 2020 and on September 1 of every fifth year thereafter. The holders of Preference Shares, Series 15 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 16, subject to certain conditions, on September 1, 2020 and on September 1 of every fifth year thereafter. The holders of Preference Shares, Series 16 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.7%.

Common Share Issuance

On June 24, 2014, the Company completed the issuance of 7.9 million Common Shares for gross proceeds of approximately $400 million and, on July 8, 2014, issued a further 1.2 million Common Shares pursuant to the underwriters over-allotment option for gross proceeds of approximately $60 million. The proceeds will be used to partially fund the Company s capital projects, including the Line 3 Replacement Program (L3R Program), to reduce short term indebtedness and for other general corporate purposes. For further discussion on the L3R Program refer to *Growth Projects Commercially Secured Projects Liquids Pipelines Canadian Line 3 Replacement Program* and *Growth Projects Commercially Secured Projects Sponsored Investments Enbridge Energy Partners, L.P. United States Line 3 Replacement Program*.

GROWTH PROJECTS COMMERCIALLY SECURED PROJECTS

The table below summarizes the current status of the Company s commercially secured projects, organized by business segment.

		Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)					
LIQUIDS PIPELINES					
1.	Seaway Crude Pipeline System Twinning/Extension	US$1.2 billion	US$1.1 billion	2014	Substantially complete
2.	Eastern Access Line 9 Reversal and Expansion	$0.7 billion	$0.6 billion		

2013-TBD3 (in phases)	Under construction

10

		Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
3.	Eddystone Rail Project	US$0.1 billion	US$0.1 billion	2014	Complete
4.	Norealis Pipeline	$0.5 billion	$0.5 billion	2014	Complete
5.	Flanagan South Pipeline Project	US$2.8 billion	US$2.7 billion	2014	Substantially complete
6.	Canadian Mainline Expansion	$0.7 billion	$0.3 billion	2015	Under construction
7.	Surmont Phase 2 Expansion	$0.3 billion	$0.2 billion	2014-2015 (in phases)	Under construction
8.	Sunday Creek Terminal Expansion	$0.2 billion	$0.1 billion	2015	Under construction
9.	Woodland Pipeline Extension	$0.6 billion	$0.4 billion	2015	Under construction
10.	Edmonton to Hardisty Expansion	$1.8 billion	$0.7 billion	2015	Under construction
11.	Southern Access Extension	US$0.6 billion	US$0.2 billion	2015	Pre-construction
12.	AOC Hangingstone Lateral	$0.2 billion	No significant expenditures to date	2015	Pre-construction
13.	Canadian Mainline System Terminal Flexibility and Connectivity	$0.7 billion	$0.3 billion	2013-2015 (in phases)	Under construction
14.	JACOS Hangingstone Project	$0.1 billion	No significant expenditures to date	2016	Pre-construction
15.	Athabasca Pipeline Twinning	$1.2 billion	$1.0 billion	2017	Under construction
16.	Wood Buffalo Extension	$1.6 billion	$0.1 billion	2017	Pre-construction
17.	Norlite Pipeline System[4]	$1.4 billion	No significant expenditures to date	2017	Pre-construction
18.	Canadian Line 3 Replacement Program	$4.9 billion	$0.1 billion	2017	Pre-construction
GAS DISTRIBUTION					
19.	Greater Toronto Area Project	$0.7 billion	$0.1 billion	2015	Pre-construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES					
20.	Pipestone and Sexsmith Project	$0.3 billion	$0.3 billion	2012-2014 (in phases)	Complete
21.	Blackspring Ridge Wind Project	$0.3 billion	$0.3 billion	2014	Complete
22.	Walker Ridge Gas Gathering System	US$0.4 billion	US$0.3 billion	2015 (in phases)	Under construction
23.	Big Foot Oil Pipeline	US$0.2 billion	US$0.1 billion	2015	Under construction
24.	Keechi Wind Project	US$0.2 billion	US$0.1 billion	2015	Under construction
25.	Aux Sable Extraction Plant Expansion	US$0.1 billion	No significant expenditures to date	2016	Pre-construction
26.	Heidelberg Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2016	Under construction
SPONSORED INVESTMENTS					
27.	EEP - Line 6B 75-Mile Replacement Program	US$0.4 billion	US$0.4 billion	2013-2014 (in phases)	Complete

11

		Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status
28.	EEP - Eastern Access5	US$2.7 billion	US$2.0 billion	2013-2016 (in phases)	Under construction
29.	EEP - Lakehead System Mainline Expansion5	US$2.3 billion	US$0.8 billion	2014-2016 (in phases)	Under construction
30.	EEP - Beckville Cryogenic Processing Facility	US$0.1 billion	US$0.1 billion	2015	Under construction
31.	EEP - Sandpiper Project6	US$2.6 billion	US$0.2 billion	2017	Pre-construction
32.	EEP - U.S. Line 3 Replacement Program	US$2.6 billion	US$0.2 billion	2017	Pre-construction

1 *These amounts are estimates and subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect Enbridge s share of joint venture projects.*
2 *Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to September 30, 2014.*
3 *Enbridge is currently working with the National Energy Board to provide the information needed to satisfy a National Energy Board condition in relation to the Line 9 Reversal and Expansion project. As a result, the Company is unable to estimate the length of the delay to the expected in-service date.*
4 *Enbridge will construct and operate the Norlite Pipeline System. Keyera Corp. will fund 30% of the project.*
5 *The Eastern Access and Lakehead System Mainline Expansion projects are funded 75% by Enbridge and 25% by EEP.*
6 *Enbridge will construct and operate the Sandpiper Project. Marathon Petroleum Corporation will fund 37.5% of the project.*

LIQUIDS PIPELINES

Seaway Pipeline

Enbridge holds a 50% interest in the Seaway Pipeline which includes an 805-kilometre (500-mile) 30-inch diameter long-haul system between Cushing, Oklahoma and Freeport, Texas.

Reversal and Expansion

The flow direction of the Seaway Pipeline was reversed in 2012, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the Gulf Coast. Further pump station additions and modifications were completed in 2013, increasing capacity available to shippers to up to approximately 400,000 bpd, depending on crude oil slate.

Twinning and Extension

A second line was constructed in order to more than double the existing capacity of the Seaway Pipeline to approximately 850,000 bpd and was mechanically completed in July 2014. Line fill on the Seaway Pipeline twinning is expected to follow the completion of line fill on the Flanagan South Pipeline (Flanagan South). See *Growth Projects Commercially Secured Projects Liquids Pipelines Flanagan South Pipeline Project.* This 30-inch diameter pipeline follows the same route as the existing Seaway Pipeline and was constructed to meet additional capacity commitments from shippers. Included in the project scope is the 105-kilometre (65-mile), 36-inch diameter pipeline lateral from the Seaway Jones Creek facility southwest of Houston, Texas to Enterprise Product Partners L.P. s ECHO crude oil terminal (ECHO Terminal) in Houston, Texas. The lateral was placed into service in January 2014.

In addition, a 161-kilometre (100-mile) pipeline was constructed from the ECHO Terminal to the Port Arthur/Beaumont, Texas refining centre to provide shippers access to the region s heavy oil refining capabilities. This extension was mechanically completed in August 2014 and provides capacity of 750,000 bpd.

Including the acquisition of the initial 50% interest, Enbridge s total expected cost for the Seaway Pipeline is now approximately US$2.5 billion. The acquisition, reversal and expansion were completed at an approximate cost of US$1.3 billion, with the twinning, extension and lateral components of the project expected to cost approximately US$1.2 billion. Total expenditures incurred to date are approximately US$2.4 billion.

Eastern Access

The Eastern Access initiative includes a series of Enbridge and EEP crude oil pipeline projects to provide increased access to refineries in the upper midwest United States and eastern Canada. Projects being undertaken by Enbridge include a partial reversal of Line 9A, a full reversal and expansion of Line 9B and expansion of the Toledo Pipeline. For discussion on EEP s portion of Eastern Access refer to *Growth Projects Commercially Secured Projects Sponsored Investments Enbridge Energy Partners, L.P. Eastern Access*.

In 2013, Enbridge completed the 80,000 bpd expansion of its Toledo Pipeline (Line 17), which connects with the EEP mainline at Stockbridge, Michigan and serves refineries at Toledo, Ohio and Detroit, Michigan. The project was completed at an approximate cost of US$0.2 billion.

In 2013, Enbridge also completed the reversal of a portion of its Line 9A in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario. Enbridge is also undertaking a full reversal of its 240,000 bpd Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in that province. The Line 9B reversal was expected to be completed at an estimated cost of approximately $0.3 billion. Following an open season held on the Line 9B reversal project, further commitments were received that required additional delivery capacity within Ontario and Quebec, resulting in the Line 9B capacity expansion project. The Line 9B capacity expansion will increase the annual capacity of Line 9B from 240,000 bpd to 300,000 bpd at an estimated cost of approximately $0.1 billion.

Both the Line 9B reversal and Line 9B capacity expansion projects were approved by the National Energy Board (NEB) in March 2014 subject to 30 conditions. In October 2014, the NEB requested additional information regarding one of the conditions imposed on the Line 9B reversal and Line 9B capacity expansion projects. On October 23, 2014, Enbridge responded to the NEB describing the Company s rigorous approach to risk management and isolation valve placement. Enbridge is currently awaiting response from the NEB to determine whether additional information is needed to satisfy the condition prior to applying for a Leave to Open allowing the operation of the project. As a result of the current discussions, the Company is unable to estimate the length of delay to the in-service date for the Line 9B reversal and Line 9B capacity expansion projects. The conditions previously imposed by the NEB, including costs associated with additional NEB mandated integrity testing increased the total expected cost of the projects to $0.7 billion, inclusive of costs related to the previously discussed Line 9A reversal. Enbridge is currently in discussions with shippers to recover the incremental costs of Line 9B through tolls. Total expenditures to date on the Line 9A and Line 9B projects are approximately $0.6 billion.

Eddystone Rail Project

In April 2014, under a joint venture agreement with Canopy Prospecting Inc., the Company completed the development of a unit-train unloading facility and related local pipeline infrastructure near Philadelphia, Pennsylvania to deliver Bakken and other light sweet crude oil to Philadelphia area refineries. The Eddystone Rail Project (Eddystone) included leasing portions of a power generation facility and involved replacing and twinning the existing track to accommodate 120-car unit-trains, installing crude oil offloading equipment, refurbishing an existing 200,000 barrel tank and upgrading an existing barge loading facility. Eddystone is capable of receiving and delivering an initial capacity of 80,000 bpd, and could be expanded to 160,000 bpd. Based on its 75% joint venture interest, Enbridge s investment in the project was approximately US$0.1 billion.

Norealis Pipeline

In order to provide pipeline and terminalling services to the Husky Energy Inc. operated Sunrise Energy Project that is currently under development, Enbridge constructed a new originating terminal (Norealis Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline from the Norealis Terminal to the Cheecham Terminal and additional tankage at Cheecham. The Norealis Pipeline project was completed in April 2014 at a total cost of approximately $0.5 billion. Enbridge expects to receive first oil in the fourth quarter of 2014, commensurate with the start-up of the Sunrise Energy project.

Flanagan South Pipeline Project

The 950-kilometre (590-mile) pipeline has an initial design capacity of approximately 600,000 bpd; however, in the initial years it is not expected to operate at its full design capacity. Flanagan South will transport crude oil from the Company s terminal at Flanagan, Illinois to Cushing, Oklahoma. The 36-inch diameter pipeline is installed adjacent to the Company s Spearhead Pipeline for the majority of the route. The pipeline is now mechanically completed and line fill arrangements have begun and will continue throughout November 2014. The estimated cost of the project is approximately US$2.8 billion, with expenditures to date of approximately US$2.7 billion.

The Sierra Club and National Wildlife Federation (the Plaintiff) filed a complaint for Declaratory and Injunctive Relief (the Complaint) with the United States District Court for the District of Columbia (the Court) in August 2013. The Complaint was filed against multiple federal agencies (the Defendants) and included a request that the Court issue a preliminary injunction suspending previously granted federal permits and ordering Enbridge to discontinue construction of the project on the basis that the Defendants failed to comply with environmental review standards of the National Environmental Protection Act. Enbridge obtained intervenor status and joined the Defendants in filing a response in opposition to the motion for preliminary injunction in September 2013. The Plaintiff s request for preliminary injunction was denied by the Court in November 2013. A court hearing was held on February 21, 2014 concerning the merits of the Complaint against the Defendants, and on August 18, 2014, the Court ruled to dismiss all claims in favour of Enbridge and the Defendants. The Plaintiffs filed an appeal to the United States Court of Appeals for the District of Columbia Circuit.

Canadian Mainline Expansion

Enbridge is undertaking an expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The scope of the project consists of two phases which involve the addition of pumping horsepower to raise the capacity of the Alberta Clipper line from 450,000 bpd to 800,000 bpd. The initial phase to increase capacity from 450,000 bpd to 570,000 bpd was mechanically completed in the third quarter of 2014 at an estimated capital cost of approximately $0.2 billion. Delays in receipt of the applicable regulatory approvals on EEP s portion of the mainline system expansion are expected to delay the full operation of the first phase of the Canadian Mainline Expansion. However, a number of temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput associated with the initial 120,000 bpd capacity increase. See *Growth Projects Commercially Secured Projects Sponsored Investments Enbridge Energy Partners, L.P. Lakehead System Mainline Expansion*.

The second phase to increase capacity from 570,000 bpd to 800,000 bpd is expected to be placed into service in 2015. The second phase is expected to cost approximately $0.5 billion following the completion of a detailed engineering review conducted in the first quarter of 2014. The revised estimate reflected enhanced tanking, terminalling and connectivity to optimize pipeline operation at the full 800,000 bpd design capacity. The estimated cost of the entire expansion is approximately $0.7 billion, with expenditures to date of approximately $0.3 billion.

Surmont Phase 2 Expansion

In 2013, the Company entered into a terminal services agreement with ConocoPhillips Canada Resources Corp. (ConocoPhillips) and Total E&P Canada Ltd. (together, the ConocoPhillips Partnership) to expand the Cheecham Terminal to accommodate incremental bitumen production from Surmont s Phase 2 expansion. The Company is constructing two new 450,000 barrel blend tanks and converting an existing tank from blend to diluent service. The expansion is expected to come into service in two phases, with the blended product system expected in the fourth quarter of 2014 and the diluent system expected in the first quarter of 2015. The estimated cost of the project is approximately $0.3 billion with expenditures to date of approximately $0.2 billion.

Sunday Creek Terminal Expansion

In January 2014, the Company announced it will construct additional facilities at its existing Sunday Creek Terminal, located in the Christina Lake area of northern Alberta, to support production growth from the Christina Lake oil sands project operated by Cenovus Energy Inc. and jointly owned with ConocoPhillips. The expansion includes development of a new site adjacent to the existing terminal, construction of a new 350,000 barrel tank with associated piping, pumps and measurement equipment, as well as civil construction work for a future tank. The estimated cost for the expansion is approximately $0.2 billion, with expenditures to date of approximately $0.1 billion and a targeted in-service date of the third quarter of 2015.

Woodland Pipeline Extension

The joint venture Woodland Pipeline Extension Project will extend the Woodland Pipeline south from Enbridge s Cheecham Terminal to its Edmonton Terminal. The extension is a proposed 388-kilometre (241-mile) 36-inch diameter pipeline with an initial capacity of 400,000 bpd, expandable to 800,000 bpd. Enbridge s share of the estimated capital cost of the project is approximately $0.6 billion, with expenditures incurred to date of approximately $0.4 billion. Subject to finalization of scope and a definitive cost estimate, the project has a target in-service date of the third quarter of 2015.

Edmonton to Hardisty Expansion

The Company is undertaking an expansion of the Canadian Mainline system between Edmonton, Alberta and Hardisty, Alberta. The expansion project will include 181 kilometres (112 miles) of new 36-inch diameter pipeline and will provide an initial capacity of approximately 570,000 bpd, expandable to 800,000 bpd. The new line is expected to generally follow the same route as Enbridge s existing Line 4 pipeline. Also included in the project scope are connections into existing infrastructure at the Hardisty Terminal and new terminal facilities in Edmonton which include five new 500,000 barrel tanks. The new pipeline is expected to be placed into service in the first quarter of 2015, with additional tankage requirements expected to be completed in the fourth quarter of 2015, all at an expected total cost of approximately $1.8 billion. Expenditures incurred to date are approximately $0.7 billion.

Southern Access Extension

The Southern Access Extension project (Southern Access Extension) will involve the construction of a new 265-kilometre (165-mile) 24-inch diameter crude oil pipeline from Flanagan, Illinois to Patoka, Illinois, for an initial capacity of approximately 300,000 bpd, as well as additional tankage and two new pump stations. Effective July 1, 2014, the Company entered into an agreement with Lincoln Pipeline LLC (Lincoln), an affiliate of Marathon Petroleum Corporation (MPC), to, among other things, admit Lincoln as a partner and participate in Southern Access Extension. Lincoln has purchased a 35% equity interest in the project and will make additional cash contributions in accordance with the Southern Access Extension spend profile in proportion to its 35% interest. Subject to regulatory and other approvals, the project is now expected to be placed into service in late 2015. Southern Access Extension is expected to cost approximately US$0.9 billion, with Enbridge s share of the estimated capital cost expected to be approximately US$0.6 billion. Enbridge s expenditures to date on the project are approximately US$0.2 billion.

AOC Hangingstone Lateral

In 2013, the Company entered into an agreement with Athabasca Oil Corporation (AOC) to provide pipeline and terminalling services to the proposed AOC Hangingstone Oil Sands Project (AOC Hangingstone) in Alberta. Phase I of the project will involve the construction of a new 49-kilometre (31-mile) 16-inch diameter pipeline from the AOC Hangingstone project site to Enbridge s existing Cheecham Terminal, and related facility modifications at Cheecham. Phase I of the project will provide an initial capacity of 16,000 bpd and is now expected to be placed into service in the fourth quarter of 2015, to align with shipper volume availability, now at an estimated cost of approximately $0.2 billion. Phase 2 of the project, which is subject to commercial approval, would provide up to an additional 60,000 bpd for a total capacity of 76,000 bpd.

Canadian Mainline System Terminal Flexibility and Connectivity

As part of the Light Oil Market Access Program initiative, the Company is undertaking the Canadian Mainline System Terminal Flexibility and Connectivity project in order to accommodate additional light oil volumes and enhance the operational flexibility of the Canadian mainline terminals. The modifications are comprised of upgrading existing booster pumps, additional booster pumps and new tank line connections. These projects have varying completion dates from 2013 through 2015. The cost of the project is expected to be approximately $0.7 billion following the completion of a detailed engineering review. The revised estimate reflects enhanced tankage, terminalling and connectivity in conjunction with the Company s Canadian Mainline Expansion project. Refer to *Growth Projects Commercially Secured Projects Liquids Pipelines Canadian Mainline Expansion*. Expenditures to date total approximately $0.3 billion.

JACOS Hangingstone Project

Enbridge will undertake the construction of facilities and provide transportation services to the Japan Canada Oil Sands Limited (JACOS) Hangingstone Oil Sands Project (JACOS Hangingstone). JACOS and Nexen Energy ULC, a wholly-owned subsidiary of China National Offshore Oil Corporation Limited, are partners in the project which is operated by JACOS. Subject to regulatory approvals, Enbridge plans to construct a new 53-kilometre (33-mile) 12-inch lateral pipeline to connect the JACOS Hangingstone project site to Enbridge s existing Cheecham Terminal. The project will provide capacity of 40,000 bpd at an estimated cost of approximately $0.1 billion and is expected to enter service in 2016.

Athabasca Pipeline Twinning

This project involves twinning the southern section of the Athabasca Pipeline from Kirby Lake, Alberta to the Hardisty, Alberta crude oil hub to provide additional capacity to serve expected oil sands growth in the Kirby Lake producing region. The expansion project, with an estimated cost of approximately $1.2 billion, and expenditures to date of approximately $1.0 billion, will include 346 kilometres (215 miles) of 36-inch diameter pipeline adjacent to the existing Athabasca Pipeline right-of-way. The line is expected to be delayed beyond its original in-service date and is now expected to be completed in 2017 due to a change in the construction schedule to align with shipper volume availability.

Wood Buffalo Extension

In 2013, Enbridge was selected by Suncor Energy Inc., Total E&P Canada Ltd. and Teck Resources Limited (the Fort Hills Partners), as well as the Suncor Energy Oil Sands Limited Partnership (Suncor Partnership), to develop a new pipeline to transport crude oil production to Enbridge s mainline hub at Hardisty, Alberta. The proposed Wood Buffalo Extension will extend Enbridge s existing Wood Buffalo Pipeline and includes construction of a new 450-kilometre (281-mile) 30-inch pipeline from Enbridge s Cheecham Terminal to its Battle River Terminal at Hardisty, as well as associated terminal upgrades. The completed project will provide capacity of 490,000 bpd of diluted bitumen to be transported for the proposed Fort Hills Partners oil sands project (Fort Hills Project) in northeastern Alberta and Suncor Partnership s oil sands production in the Athabasca region. Subject to regulatory approvals, the project is expected to be completed in 2017 at an estimated cost of approximately $1.6 billion, with expenditures incurred to date of approximately $0.1 billion.

Norlite Pipeline System

Enbridge is undertaking the development of Norlite Pipeline System (Norlite), a new industry diluent pipeline originating from Edmonton to meet the needs of multiple producers in the Athabasca oil sands region. The scope of the project was increased to a 24-inch diameter pipeline, which will provide an initial capacity of approximately 224,000 bpd of diluent, with the potential to be further expanded to approximately 400,000 bpd of capacity with the addition of pump stations. Norlite will be anchored by throughput commitments from both the Fort Hills Partners for production from the proposed Fort Hills Project and from Suncor Partnership s proprietary oil sands production. Norlite will involve the construction of a new 449-kilometre (278-mile) pipeline from Enbridge s Stonefell Terminal to its Cheecham Terminal with an extension to Suncor Partnership s East Tank Farm, which is adjacent to Enbridge s existing Athabasca Terminal.

Under an agreement with Keyera Corp. (Keyera), Norlite has the right to access certain existing capacity on Keyera s pipelines between Edmonton and Stonefell and, in exchange, Keyera has elected to participate in the new pipeline infrastructure project as a 30% non-operating owner. Subject to regulatory and other approvals as well as finalization of scope, Norlite is expected to be completed in 2017 at an estimated cost of approximately $1.4 billion.

Canadian Line 3 Replacement Program

In March 2014, Enbridge and EEP jointly announced that shipper support was received for investment in the L3R Program. The Canadian portion of the Line 3 Replacement Program (Canadian L3R Program) will complement existing integrity programs by replacing approximately 1,084-kilometres (673-miles) of the remaining line segments of the existing Line 3 pipeline between Hardisty, Alberta and Gretna, Manitoba. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the system, enhance flexibility and allow the Company to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd, which will enhance the flexibility and reliability of the Enbridge mainline system s overall Western Canada export capacity.

Subject to regulatory and other approvals, the Canadian L3R Program is targeted to be completed in late 2017. Following the completion of a definitive cost estimate in the second quarter of 2014, the estimated capital cost of the Canadian L3R Program is approximately $4.9 billion, with expenditures to date of approximately $0.1 billion. Costs of the Canadian L3R Program will be recovered through a 15-year toll surcharge mechanism under the Competitive Toll Settlement (CTS). For discussion on EEP s portion of the L3R Program refer to *Growth Projects Commercially Secured Projects Sponsored Investments Enbridge Energy Partners, L.P. United States Line 3 Replacement Program*.

GAS DISTRIBUTION

Greater Toronto Area Project

EGD will undertake the expansion of its natural gas distribution system in the Greater Toronto Area (GTA) to meet the demands of growth and to continue the safe and reliable delivery of natural gas to current and future customers. The GTA project will involve the construction of two new segments of pipeline, a 27-kilometre (17-mile) 42-inch diameter pipeline and a 23-kilometre (14-mile) 36-inch diameter pipeline in Toronto, Ontario, as well as related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in Ontario. With the OEB approval received in January 2014, construction is targeted to start in late 2014. The project is expected to be completed by the end of 2015 at an estimated cost of approximately $0.7 billion, with expenditures to date of approximately $0.1 billion.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Pipestone and Sexsmith Project

In 2012, the Company acquired from Encana Corporation (Encana) certain sour gas gathering and compression facilities located in the Peace River Arch (PRA) region of northwest Alberta (collectively, Pipestone and Sexsmith). These facilities were either in service (Sexsmith) or under construction (Pipestone) at the time of acquisition. Construction of new gathering lines and NGL handling facilities was completed in June 2014. Enbridge s investment in Pipestone and Sexsmith is approximately $0.3 billion. Enbridge also retains an exclusive right to work with Encana on facility scoping for development of additional major midstream facilities in the liquids-rich PRA region.

Blackspring Ridge Wind Project

In 2013, Enbridge secured a 50% interest in the development of the 300-MW Blackspring Ridge Wind Project (Blackspring Ridge), located 50 kilometres (31 miles) north of Lethbridge, Alberta in Vulcan County. The project was constructed under a fixed price engineering, procurement and construction contract and commercial operations commenced in May 2014. Renewable Energy Credits generated from Blackspring Ridge are contracted to Pacific Gas and Electric Company under a 20-year purchase agreement. The electricity is being sold into the Alberta power pool with pricing fixed on 75% of production through long-term price swap arrangements. The Company s total investment in the project is approximately $0.3 billion.

Walker Ridge Gas Gathering System

The Company has agreements with Chevron USA Inc. (Chevron) and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge is constructing and will own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the Jack St. Malo and Big Foot ultra-deep water developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter pipeline at depths of up to approximately 2,150 meters (7,000 feet) with capacity of 100 million cubic feet per day (mmcf/d). The Jack St. Malo portion of the WRGGS is now expected to be placed into service in the first quarter of 2015 and the Big Foot Oil Pipeline (Big Foot Pipeline) portion is now expected to be placed into service in the fourth quarter of 2015. The total WRGGS project is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion.

Big Foot Oil Pipeline

Under agreements with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc., Enbridge is constructing a 64-kilometre (40-mile) 20-inch oil pipeline with capacity of 100,000 bpd from the Big Foot ultra-deep water development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge s undertaking of the WRGGS construction, discussed above. Upon completion of the project, Enbridge will operate the Big Foot Pipeline, located approximately 274 kilometres (170 miles) south of the coast of Louisiana. The estimated capital cost of the project is approximately US$0.2 billion, with expenditures to date of approximately US$0.1 billion. As noted above, the Big Foot Pipeline is now expected to enter service in the fourth quarter of 2015.

Keechi Wind Project

In January 2014, Enbridge announced it had entered into an agreement with Renewable Energy Systems Americas Inc. (RES Americas) to own and operate the 110-MW Keechi Wind Project (Keechi), located in Jack County, Texas, at an investment of approximately US$0.2 billion, with expenditures incurred to date of approximately US$0.1 billion. RES Americas is constructing the wind project under a fixed price, engineering, procurement and construction agreement, with expected completion in the first quarter of 2015. Keechi will deliver 100% of the electricity generated into the Electric Reliability Council of Texas, Inc. market under a 20-year power purchase agreement with Microsoft Corporation.

Aux Sable Extraction Plant Expansion

In October 2014, the Company approved the expansion of fractionation capacity and related facilities at its Aux Sable Extraction Plant located in Channahon, Illinois. The expansion will facilitate the growing NGL-rich gas stream on the Alliance Pipeline System (Alliance System), allow for the effective management of Alliance System s downstream natural gas heat content and for additional production and sale of NGL products. The expansion is expected to be placed into service in 2016 with Enbridge s share of the project cost being approximately US$0.1 billion.

Heidelberg Lateral Pipeline

The Company will construct, own and operate a crude oil pipeline in the Gulf of Mexico to connect the proposed Heidelberg development, operated by Anadarko Petroleum Corporation, to an existing third-party system. The Heidelberg Lateral Pipeline (Heidelberg), a 58-kilometre (36-mile), 20-inch diameter pipeline with capacity of 100,000 bpd, will originate in Green Canyon Block 860, approximately 320 kilometres (200 miles) southwest of New Orleans, Louisiana, and in an estimated 1,600 metres (5,300 feet) of water. Heidelberg is expected to be operational by 2016 at an approximate cost of US$0.1 billion.

SPONSORED INVESTMENTS   ENBRIDGE ENERGY PARTNERS, L.P.

Line 6B 75-Mile Replacement Program

The Line 6B 75-Mile Replacement Program included the replacement of 120 kilometres (75 miles) of non-contiguous sections of Line 6B of EEP s Lakehead System. The Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. The new segments were completed in components, with approximately 104 kilometres (65 miles) of segments placed in service in 2013. The two remaining 8-kilometre (5-mile) segments in Indiana were placed in service in March 2014. The total cost of the replacement program was approximately US$0.4 billion and EEP is recovering these costs through a tariff surcharge that is part of the system-wide rates for the Lakehead System.

Eastern Access

The Eastern Access initiative includes a series of Enbridge and EEP crude oil pipeline projects to provide increased access to refineries in the upper midwest United States and eastern Canada. Projects being undertaken by EEP include an expansion of its Line 5 and expansions of the United States mainline involving the Spearhead North Pipeline (Line 62) and further segments of Line 6B. For discussion on Enbridge s portion of Eastern Access refer to *Growth Projects Commercially Secured Projects Liquids Pipelines Eastern Access*.

In 2013, EEP completed and placed into service the expansion of its Line 5 light crude oil line between Superior, Wisconsin and the international border at the St. Clair River. The Line 5 expansion increased capacity by 50,000 bpd at an approximate cost of US$0.1 billion. Also in 2013, EEP completed and placed into service the expansion of Line 62 between Flanagan, Illinois and Griffith, Indiana, which increased capacity by 105,000 bpd.

EEP also replaced additional sections of Line 6B in Indiana and Michigan, which included the addition of new pumps and terminal upgrades at Hartsdale, Griffith and Stockbridge, as well as tanks at Flanagan, Stockbridge and Hartsdale, to increase capacity from 240,000 bpd to 500,000 bpd. Portions of the existing 30-inch diameter pipeline were also replaced with 36-inch diameter pipe. The Line 6B project is split into two phases. The segment between Griffith and Stockbridge was completed in May 2014 and the segment from Ortonville, Michigan to the international border at the St. Clair River was completed in September 2014. The replacement of the Line 6B sections is in addition to the Line 6B 75-mile Replacement Program discussed previously. Following detailed engineering estimates completed in the first quarter of 2014 which reflect issues with local ground terrain conditions including tie-ins, the expected cost of the United States mainline expansions is approximately US$2.4 billion, and includes the US$0.1 billion cost of the previously discussed Line 5 expansion.

The Eastern Access initiative also includes a further upsizing of EEP s Line 6B. The Line 6B capacity expansion from Griffith, Indiana to Stockbridge, Michigan will increase capacity from 500,000 bpd to 570,000 bpd and will include pump station modifications at Griffith, Niles and Mendon stations, additional modifications at the Griffith and Stockbridge terminals and breakout tankage at Stockbridge. Following the completion, in the first quarter of 2014, of a detailed engineering estimate and a scope revision that removed a proposed tank, the total cost of the project is approximately US$0.3 billion. The project is expected to be placed into service in early 2016.

The total estimated cost of the projects being undertaken by EEP as part of the Eastern Access initiative, including the United States mainline expansions, the Line 5 expansion and the Line 6B capacity expansion project, is approximately US$2.7 billion, with expenditures to date of approximately US$2.0 billion. The Eastern Access projects undertaken by EEP are being funded 75% by Enbridge and 25% by EEP. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%.

Lakehead System Mainline Expansion

The Lakehead System Mainline Expansion includes several projects to expand capacity of the Lakehead System mainline between its origin at the Canada/United States border, near Neche, North Dakota, to Flanagan, Illinois. These projects are in addition to expansions of the Lakehead System mainline being undertaken as part of the Eastern Access initiative and includes the expansion of Alberta Clipper (Line 67) and Southern Access (Line 61).

The current scope of the Alberta Clipper expansion between the border and Superior, Wisconsin consists of two phases. The initial phase included increasing capacity from 450,000 bpd to 570,000 bpd at an estimated capital cost of approximately US$0.2 billion. The second phase of the expansion will increase capacity from 570,000 bpd to 800,000 bpd, at an estimated capital cost of approximately US$0.2 billion. Both phases of the Alberta Clipper expansion require only the addition of pumping horsepower and no pipeline construction. Subject to regulatory and other approvals, including an amendment to the current Presidential border crossing permit to allow for operation of Line 67 at its currently planned operating capacity of 800,000 bpd, the initial phase was mechanically completed in the third quarter of 2014 and the second phase is expected to be in-service in 2015. It is now anticipated that obtaining regulatory approval will take longer than originally planned though approval is expected in mid-2015. A number of temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput associated with the initial 120,000 bpd capacity increase.

The current scope of the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois also consists of two phases. The initial phase to increase the capacity from 400,000 bpd to 560,000 bpd was completed in August 2014 at an estimated capital cost of approximately US$0.2 billion. EEP also plans to undertake a further expansion of the Southern Access line between Superior and Flanagan to increase capacity from 560,000 bpd to 1,200,000 bpd. Following completion of a more detailed engineering estimate in the first quarter of 2014, the second phase of the Southern Access expansion is expected to cost approximately US$1.2 billion. Both phases of the expansion require only the addition of pumping horsepower and crude oil tanks at existing sites, with no pipeline construction. For the second phase of the expansion, which remains subject to regulatory and other approvals, the pump stations are expected to be available for service in the third quarter of 2015, with additional tankage requirements expected to be completed in early 2016.

As part of the Light Oil Market Access Program, EEP also plans to expand the capacity of the Lakehead System between Flanagan, Illinois and Griffith, Indiana. This section of the Lakehead System will be expanded by constructing a 127-kilometre (79-mile), 36-inch diameter twin of the existing Spearhead North Pipeline (Line 62). The project is expected to be completed at an estimated cost of approximately US$0.5 billion. Subject to regulatory and other approvals, the new line will have an initial capacity of 570,000 bpd and is expected to be placed into service in the third quarter of 2015.

The projects collectively referred to as the Lakehead System Mainline Expansion are expected to cost approximately US$2.3 billion, with expenditures incurred to date of approximately US$0.8 billion. EEP will operate the project on a cost-of-service basis. The Lakehead System Mainline Expansion is funded 75% by Enbridge and 25% by EEP. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%.

Beckville Cryogenic Processing Facility

EEP and its partially-owned subsidiary MEP are constructing a cryogenic natural gas processing plant near Beckville (the Beckville Plant) in Panola County, Texas. The Beckville Plant will offer incremental processing capacity for existing and future customers in the 10-county Cotton Valley shale region, where the East Texas system is located. The Beckville Plant has a planned natural gas processing capability of 150 mmcf/d and is also expected to produce 8,500 bpd of NGL. The Beckville Plant is expected to be placed into service in the first quarter of 2015 at an estimated cost of approximately US$0.1 billion. Expenditures incurred to date are approximately US$0.1 billion.

Sandpiper Project

As part of the Light Oil Market Access Program initiative, EEP plans to undertake the Sandpiper project (Sandpiper) which will expand and extend EEP s North Dakota feeder system. The Bakken takeaway capacity of the North Dakota System will be expanded by 225,000 bpd to a total of 580,000 bpd. The proposed expansion will involve construction of a 965-kilometre (600-mile) line from Beaver Lodge Station near Tioga, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the existing 210,000 bpd North Dakota System mainline, which now terminates at Clearbrook Terminal in Minnesota, by adding 250,000 bpd of capacity between Tioga and Berthold, North Dakota and 225,000 bpd of capacity between Berthold and Clearbrook, both with new 24-inch diameter pipelines, as well as adding 375,000 bpd of capacity between Clearbrook and Superior with a new 30-inch diameter pipeline. Sandpiper is expected to cost approximately US$2.6 billion, with expenditures incurred to date of approximately US$0.2 billion.

MPC has been secured as an anchor shipper for Sandpiper. As part of the arrangement, EEP, through its subsidiary, North Dakota Pipeline Company LLC (NDPC) (formerly known as Enbridge Pipelines (North Dakota) LLC), and Williston Basin Pipeline LLC (Williston), an affiliate of MPC, entered into an agreement to, among other things, admit Williston as a member of NDPC. Williston will fund 37.5% of Sandpiper construction and will have the option to participate in other growth projects within NDPC, unless specifically excluded by the agreement; this investment is not to exceed US$1.2 billion in aggregate. In return for funding part of Sandpiper s construction, Williston will obtain an approximate 27% equity interest in NDPC at the in-service date of Sandpiper, now targeted for 2017 due to a longer than expected permitting process in the State of Minnesota.

A petition was filed with the FERC to approve recovery of Sandpiper s costs through a surcharge to the NDPC rates between Beaver Lodge and Clearbrook and a cost of service structure for rates between Clearbrook and Superior. In March 2013, the FERC denied the petition on procedural grounds. In late 2013, EEP held an open season to solicit commitments from shippers for capacity created by Sandpiper. The open season closed in late January 2014 with the receipt of a further capacity commitment which can be accommodated within the planned incremental capacity identified above. EEP re-filed its petition with the FERC on February 12, 2014 and received a FERC declaratory order in May 2014 approving the tariffs structure for the project. The pipeline is now expected to begin service in 2017, subject to obtaining regulatory and other approvals.

United States Line 3 Replacement Program

In March 2014, Enbridge and EEP jointly announced that shipper support was received for investment in the L3R Program. EEP will undertake the United States portion of the Line 3 Replacement Program (U.S. L3R Program) which will complement existing integrity programs by replacing approximately 576-kilometres (358-miles) of the remaining line segments of the existing Line 3 pipeline between Neche, North Dakota and Superior, Wisconsin. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the system, enhance flexibility and allow the Company to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd, which will enhance the flexibility and reliability of the Enbridge mainline system s overall Western Canada export capacity.

Subject to regulatory and other approvals, the U.S. L3R Program is targeted to be completed in late 2017 at an estimated capital cost of approximately US$2.6 billion, with expenditures to date of approximately US$0.2 billion. The U.S. L3R Program will be jointly funded by Enbridge and EEP at participation levels that are subject to finalization. EEP will recover the costs based on its existing Facilities Surcharge Mechanism with the initial term of the agreement being 15 years. For the purpose of the toll surcharge, the agreement specifies a 30-year recovery of the capital based on a cost of service methodology.

GROWTH PROJECTS OTHER PROJECTS UNDER DEVELOPMENT

The following projects have been announced by the Company, but have not yet met Enbridge s criteria to be classified as commercially secured. The Company also has significant additional attractive projects under development which have not yet progressed to the point of public announcement. In its long-term funding plans, the Company makes full provision for all commercially secured projects and makes provision for projects under development based on an assessment of the aggregate securement success anticipated. Actual securement success achieved could exceed or fall short of the anticipated level.

LIQUIDS PIPELINES

Northern Gateway Project

Northern Gateway Project (Northern Gateway) involves constructing a twin 1,177-kilometre (731-mile) pipeline system from near Edmonton, Alberta to a new marine terminal in Kitimat, British Columbia. One pipeline would transport crude oil for export from the Edmonton area to Kitimat and is proposed to be a 36-inch diameter line with an initial capacity of 525,000 bpd. The other pipeline would be used to transport imported condensate from Kitimat to the Edmonton area and is proposed to be a 20-inch diameter line with an initial capacity of 193,000 bpd.

On December 19, 2013, the Joint Review Panel (JRP) issued its report on Northern Gateway. The report found that the petroleum industry is a significant driver of the Canadian economy and an important contributor to the Canadian standard of living and noted that the benefits of Northern Gateway outweigh its burdens and that Canadians would be better off with the Enbridge Northern Gateway Project than without it. The JRP recommended to the Governor in Council that Certificates of Public Convenience and Necessity (Certificates) for the oil and condensate pipelines, incorporating the terms and conditions in their report, be issued to Northern Gateway pursuant to Part III of the NEB Act. The Government of Canada has consulted with Aboriginal groups on the JRP report and its recommendations prior to making its decision on whether to direct the NEB to issue the certificates for the pipelines.

On June 17, 2014, the Governor in Council issued an Order in Council approving the JRP recommendation, including all 209 recommended conditions. The NEB issued the Certificates for the oil and condensate pipelines on June 18, 2014.

Nine applications for leave for judicial review of the Order in Council have been filed pursuant to section 55 of the NEB Act. The applicants make two basic arguments in seeking leave. First, they argue that the report and the Order in Council contain evidentiary gaps or gaps in reasoning. Second, they allege that the Crown has failed to discharge its constitutional duty to consult and, if appropriate, accommodate the Aboriginal applicants.

On September 26, 2014, the Federal Court of Appeal (Federal Court) granted leave to all nine applications. Based on discussions between counsel for the various parties involved, the Company expects that the applications will be consolidated into a single proceeding, and for these judicial proceedings to be completed in the first half of 2015 with a decision from the Federal Court expected by late 2015.

In October 2014, the Company reviewed an updated cost estimate of Northern Gateway based on full engineering analysis of the pipeline route and terminal location. Based on this comprehensive review, the Company expects that the final cost of the project will be substantially higher than the preliminary cost figures included in the Northern Gateway filing with the JRP, which reflected a preliminary estimate prepared in 2004 and escalated to 2010. The drivers behind this substantial increase include the significant costs associated with escalation of labour and construction costs, satisfying the 209 conditions imposed in the Governor in Council approval, a larger portion of high cost pipeline terrain, more extensive terminal site rock excavations and a delayed anticipated in-service date. The updated cost estimate is currently being refined by Northern Gateway and the potential shippers.

Subject to continued commercial support, regulatory and other approvals and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company now estimates that Northern Gateway could be in service in 2019 at the earliest. The timing and outcome of judicial reviews could also impact the start of construction or other project activities, which may lead to a delay in the start of operations beyond the current forecast. Of the 45 Aboriginal groups eligible to participate as equity owners, 26 have signed up to do so.

Expenditures to date, which relate primarily to the regulatory process, are approximately $0.5 billion, of which approximately half is being funded by potential shippers on Northern Gateway. Given the many uncertainties surrounding Northern Gateway, including final ownership structure, the potential financial impact of the project cannot be determined at this time.

The JRP posts public filings related to Northern Gateway on its website at http://gatewaypanel.review-examen.gc.ca/clf-nsi/hm-eng.html and Northern Gateway also maintains a website at www.northerngateway.ca where the full regulatory application submitted to the NEB, the 2010 Enbridge Northern Gateway Community Social Responsibility Report and the December 19, 2013 Report of the JRP on the Northern Gateway Application are available. ***None of the information contained on, or connected to, the JRP website or the Northern Gateway website is incorporated in or otherwise part of this MD&A.***

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

NEXUS Gas Transmission Project

In 2012, Enbridge, DTE Energy Company (DTE) and Spectra Energy Corp. (Spectra) announced the execution of a Memorandum of Understanding (MOU) to jointly develop the NEXUS Gas Transmission System, a project that would move growing supplies of Ohio Utica shale gas to markets in the United States midwest, including Ohio and Michigan, and Ontario, Canada. The MOU has expired and Enbridge is in discussions with Spectra and DTE regarding the terms of its continued participation in the project.

FINANCIAL RESULTS

LIQUIDS PIPELINES

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Canadian Mainline	**128**	112	**400**	341
Regional Oil Sands System	**44**	38	**134**	115
Southern Lights Pipeline	**13**	15	**37**	36
Seaway Pipeline	**16**	9	**39**	38
Spearhead Pipeline	**9**	8	**27**	25
Feeder Pipelines and Other	**11**	5	**22**	10
Adjusted earnings	**221**	187	**659**	565
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**(231)**	133	**(192)**	(125)
Canadian Mainline - Line 9B costs incurred during reversal	**(2)**	-	**(6)**	-
Regional Oil Sands System - make-up rights adjustment	**5**	-	**5**	-
Regional Oil Sands System - make-up rights out-of-period adjustment	**-**	(37)	**-**	(37)
Regional Oil Sands System - leak insurance recoveries	**-**	-	**4**	-
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**(4)**	(13)	**(4)**	(53)
Regional Oil Sands System - long-term contractual recovery out-of-period adjustment, net	**-**	31	**-**	31
Southern Lights Pipeline - changes in unrealized derivative fair value loss	**(9)**	-	**(9)**	-
Seaway Pipeline - make-up rights adjustment	**(11)**	-	**(11)**	-
Spearhead Pipeline - make-up rights adjustment	**-**	-	**(1)**	-
Feeder Pipelines and Other - make-up rights adjustment	**1**	-	**3**	-
Feeder Pipelines and Other - project development costs	**(1)**	-	**(4)**	-
Earnings/(loss) attributable to common shareholders	**(31)**	301	**444**	381

Canadian Mainline

Canadian Mainline adjusted earnings increased for the three and nine months ended September 30, 2014 compared with the respective 2013 comparative periods. Trends experienced in the first half of 2014 continued into the third quarter of 2014. Adjusted earnings growth was primarily driven by higher throughput with several factors contributing to the increase including: increased oil sands production; strong refinery demand in the midwest market partly due to a start-up of a midwest refinery s conversion to heavy oil processing in the second quarter of 2014; and successful efforts by the Company to optimize capacity and throughput and to enhance scheduling efficiency with shippers. Higher terminalling revenues and lower operating and administrative costs during the first half of 2014 were also positive contributors to adjusted earnings growth.

Partially offsetting these positive impacts was a lower average Canadian Mainline IJT Residual Benchmark Toll for the three and nine months ended September 30, 2014 compared with the corresponding 2013 periods. Changes in the Canadian Mainline IJT Residual Benchmark Toll are inversely related to the Lakehead System Toll, which on average was higher throughout 2014 due to the recovery of incremental costs associated with EEP s growth projects. Higher power costs associated with incremental throughput as well as higher depreciation from an increased asset base also impacted adjusted earnings in 2014. Finally, Canadian Mainline adjusted earnings for 2014 continued to be impacted by the absence of revenues from Line 9B, which was idled in late 2013 and is being reversed and expanded as part of the Company s Eastern Access initiative. For further information on Line 9B refer to *Growth Projects Commercially Secured Projects Liquids Pipelines Eastern Access.*

Supplemental information on Canadian Mainline adjusted earnings for the three and nine months ended September 30, 2014 and 2013 is provided below.

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Revenues	**366**	353	**1,121**	1,064
Expenses				
Operating and administrative	**99**	90	**282**	303
Power	**41**	31	**117**	86
Depreciation and amortization	**67**	62	**198**	180
	207	183	**597**	569
	159	170	**524**	495
Other income/(expense)	**6**	(3)	**4**	1
Interest expense	**(40)**	(42)	**(118)**	(122)
	125	125	**410**	374
Income taxes recovery/(expense)	**3**	(13)	**(10)**	(33)
Adjusted earnings	**128**	112	**400**	341
Effective United States to Canadian dollar exchange rate1	**1.016**	1.000	**1.019**	0.999

As at September 30,	**2014**	2013
(United States dollars per barrel)		
IJT Benchmark Toll2	**$4.02**	$3.98
Lakehead System Local Toll3	**$2.49**	$2.18
Canadian Mainline IJT Residual Benchmark Toll4	**$1.53**	$1.80

1 Inclusive of realized gains and losses on foreign exchange derivative financial instruments.

2 The IJT Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Chicago, Illinois. A separate distance adjusted toll applies to shipments originating at receipt points other than Hardisty and lighter hydrocarbon liquids pay a lower toll than heavy crude oil. Effective July 1, 2014, the IJT Benchmark Toll increased from US$3.98 to US$4.02.

3 The Lakehead System Local Toll is per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois. Effective January 1, 2014, the Lakehead System Local Toll decreased from US$2.18 to US$2.17. EEP delayed its annual April 1 tariff filing for its Lakehead System as it was in negotiations with the Canadian Association of Petroleum Producers concerning certain components of the tariff rate structure. The toll application was filed with the FERC on June 27, 2014, and effective August 1, 2014, the Lakehead System Local Toll increased from US$2.17 to US$2.49 per barrel.

4 The Canadian Mainline IJT Residual Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Gretna, Manitoba. For any shipment, this toll is the difference between the IJT Benchmark Toll and the Lakehead System Local Toll. Effective January 1, 2014, this toll increased from US$1.80 to US$1.81. This toll increased to US$1.85 effective July 1, 2014 and subsequently decreased to US$1.53 *effective August 1, 2014, coinciding with the revised Lakehead System Local Toll.*

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
Throughput1 *(thousand barrels per day (kbpd))*	**2,039**	1,736	**1,970**	1,707

1 Throughput volume, presented in kbpd, represents mainline deliveries ex-Gretna, Manitoba which is made up of United States and eastern Canada deliveries originating from western Canada.

Regional Oil Sands System

Regional Oil Sands System adjusted earnings increased for the three and nine months ended September 30, 2014 compared with the corresponding 2013 periods. Adjusted earnings growth was primarily driven by contributions from the Norealis Pipeline which was completed in April 2014, as well as higher throughput on the Athabasca mainline. Partially offsetting the increase in adjusted earnings were higher depreciation expense from a larger asset base and higher operating and administrative, interest and tax expenses from increased operational activities.

Seaway Pipeline

Seaway Pipeline adjusted earnings for the nine months ended September 30, 2014 were comparable with the equivalent 2013 period, however, due to offsetting factors. Adjusted earnings increased due to higher average tolls, offset by higher operating and financing costs. Seaway Pipeline adjusted earnings for the third quarter of 2014 reflected a make-up rights adjustment related to the first half of 2014. Excluding the impact of the make-up rights adjustment, quarter-over-quarter adjusted earnings were comparable and reflected the same trends noted in the nine-month period comparison.

Feeder Pipelines and Other

Feeder Pipelines and Other adjusted earnings for the three and nine month period ended September 30, 2014 were higher compared with the same periods of 2013 due to lower business development costs not eligible for capitalization, a combination of higher tolls and throughput on the Toledo Pipeline and the incremental earnings from Eddystone completed in April 2014. Partially offsetting the increase in earnings were lower average tolls on Olympic Pipeline.

Liquids Pipelines earnings/(loss) were impacted by the following adjusting items:

- Canadian Mainline earnings/(loss) for each period reflected changes in unrealized fair value gains and losses on derivative financial instruments used to risk manage exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.

- Canadian Mainline earnings/(loss) for 2014 included depreciation and interest expenses charged to Line 9B while it was idled and undergoing a reversal as part of the Company s Eastern Access initiative.

- Regional Oil Sands System earnings for the third quarter of 2014 included a make-up rights adjustment.

- Regional Oil Sands System earnings for 2013 included an out-of-period, non-cash adjustment to defer revenues associated with make-up rights earned under certain long-term take-or-pay contracts.

- Regional Oil Sands System earnings for 2014 included insurance recoveries associated with the Line 37 crude oil release which occurred in June 2013.

- Regional Oil Sands System earnings for 2014 and 2013 included charges related to the Line 37 crude oil release which occurred in June 2013.

- Regional Oil Sands System earnings for 2013 included an out-of-period, non-cash adjustment to correct deferred income tax expense and to correct the rate at which deemed taxes are recovered under a long-term contract.

- Southern Lights Pipeline earnings for 2014 included an unrealized fair value loss on derivative financial instruments.

- Seaway Pipeline earnings for 2014 included a make-up rights adjustment.

- Spearhead Pipeline earnings for 2014 included a make-up rights adjustment.

- Feeder Pipelines and Other earnings for 2014 included a make-up rights adjustment.

- Feeder Pipelines and Other earnings for 2014 included certain business development costs related to Northern Gateway that are anticipated to be recovered over the life of the project.

GAS DISTRIBUTION

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc. (EGD)	**(3)**	(26)	**100**	97
Other Gas Distribution and Storage	**(6)**	(3)	**9**	12
Adjusted earnings/(loss)	**(9)**	(29)	**109**	109
EGD - (warmer)/colder than normal weather	**(2)**	-	**35**	(4)
EGD - gas transportation costs out-of-period adjustment	**-**	(56)	**-**	(56)
Earnings/(loss) attributable to common shareholders	**(11)**	(85)	**144**	49

EGD adjusted earnings reflected the impact of the OEB decision on EGD s IR mechanism which was approved with modifications by the OEB on July 17, 2014. EGD operated the first half of 2014 under OEB approved interim distribution rates. On August 22, 2014, an OEB Rate Order under the IR mechanism approved the final rates with an effective date of January 1, 2014.

EGD adjusted earnings increased slightly for the nine months ended September 30, 2014 compared with the equivalent 2013 period and reflected customer growth, as well as the impacts of the Rate Order. The Rate Order approved a new approach for determining depreciation and future removal and site restoration reserves which resulted in a lower depreciation expense for the nine months ended September 30, 2014. This positive effect was partially offset by reduced rates under the Rate Order, with an effective date of January 1, 2014, requiring a refund of a portion of the previously collected interim rates to customers which was also reflected in the third quarter of 2014. Also partially offsetting the adjusted earnings increase was higher interest expense due to an increase in external debt issued in 2014.

EGD adjusted loss for the third quarter of 2014 decreased compared with the corresponding 2013 three-month period. EGD 2013 third quarter adjusted loss included a gas transportation adjustment related to the first half of 2013. Excluding the impact of the gas transportation adjustment, EGD 2014 third quarter adjusted loss was lower compared with the adjusted loss for the comparative period and reflected similar trends as the year-to-date results noted above.

Adjusted earnings from Other Gas Distribution and Storage for the nine months ended September 30, 2014 included a loss from EGNB related to a contract to sell natural gas to the province of New Brunswick. Due to an abnormally cold winter in the first quarter of 2014, costs associated with the fulfilment of the contract were higher than the revenues received. This contract expired in October 2014 and will not have an impact to adjusted earnings for the remainder of the year.

Gas Distribution earnings/(loss) were impacted by the following adjusting items:

- EGD earnings/(loss) were adjusted to reflect the impact of weather. Included in EGD adjusted earnings for the third quarter of 2014 was an adjustment to reflect weather normalization under lower distribution rates from the OEB approved Rate Order under the IR mechanism. Refer to *Recent Developments Gas Distribution Enbridge Gas Distribution Incentive Regulation.*

- EGD earnings/(loss) for 2013 reflected an out-of-period correction to gas transportation costs which had previously been deferred.

26

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Aux Sable	**9**	16	**20**	32
Energy Services	**(3)**	19	**27**	94
Alliance Pipeline US	**12**	10	**36**	31
Vector Pipeline	**3**	5	**12**	18
Enbridge Offshore Pipelines (Offshore)	**(3)**	(4)	**(3)**	(4)
Other	**2**	8	**14**	15
Adjusted earnings	**20**	54	**106**	186
Energy Services - changes in unrealized derivative fair value gains	**71**	18	**288**	131
Offshore - changes in unrealized derivative fair value loss	**(2)**	-	**(2)**	-
Offshore - gain on sale of non-core assets	**-**	-	**43**	-
Other - changes in unrealized derivative fair value loss	**(1)**	(4)	**(3)**	(60)
Earnings attributable to common shareholders	**88**	68	**432**	257

Aux Sable earnings decreased for the three and nine months ended September 30, 2014 compared with the 2013 comparative periods and reflected lower fractionation margins partially offset by an increase in propane volumes produced at the Channahon Plant, lower volumes at upstream processing plants and higher administrative expense.

Energy Services operates a physical commodity marketing business which captures value from quality, time and location differentials when opportunities arise. To execute these strategies Energy Services may lease storage or rail cars, as well as hold nomination or contractual rights on both third party and Enbridge-owned pipelines. Adjusted earnings for the third quarter of 2014 decreased compared with the third quarter of 2013 due to narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, combined with associated unrecovered demand charges. The trends noted above which also negatively impacted the first half of 2014 are expected to continue into the fourth quarter of 2014.

Energy Services adjusted earnings for the nine months ended September 30, 2014 were lower compared with the very strong comparative 2013 period. In addition to the factors noted above, losses were realized in the first quarter of 2014 on certain financial contracts intended to hedge the value of committed transportation capacity, but which were not effective in doing so. During the second quarter of 2014, the Company closed out a forward component of these derivative contracts which had been determined to be no longer effective. Partially offsetting the decrease in the adjusted earnings were favourable natural gas location differentials caused by abnormal winter weather conditions during the first quarter of 2014. Adjusted earnings from Energy Services are dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

Alliance Pipeline US earnings increased in both the three and nine months ended September 30, 2014 compared with the equivalent 2013 periods due to an increase in depreciation expense recovered in tolls as well as earnings from the Tioga Lateral which was placed into service in September 2013.

Vector Pipeline earnings in the three and nine months ended September 30, 2014 decreased compared with the comparative periods of 2013 and reflected lower depreciation expense recognized in tolls. For the nine months ended September 30, 2014, the decrease in earnings was partially offset by higher uncommitted transportation volumes and prices. Higher volumes were primarily driven by increased demand for natural gas in eastern North America in response to abnormal winter weather conditions experienced in the first quarter of 2014.

Offshore adjusted loss for the three and nine months ended September 30, 2014 reflected persistent weak volumes within Offshore s corridor due to decreased production in the Gulf of Mexico. Offshore adjusted earnings are expected to remain weak, until such time as the WRGGS and the Big Foot Pipeline are placed into service, which are expected in the first and fourth quarters of 2015, respectively. Offshore adjusted earnings also reflected the absence of earnings from the disposal of non-core assets which was finalized in March 2014, partially offset by cost savings achieved from the Company s decision not to renew windstorm insurance coverage effective May 2013.

Adjusted earnings from Other for the nine months ended September 30, 2014 decreased slightly compared with the comparative 2013 period and reflected higher depreciation expense and financing costs from the Montana-Alberta Tie-Line, as well as higher business development costs not eligible for capitalization within Other. Partially offsetting the decrease in earnings were an increase in fees earned from the Company s Canadian midstream assets, being the Cabin Gas Plant and Pipestone and Sexsmith, and the positive impact of new wind farms placed into service over the past two years.

Adjusted earnings from Other for the third quarter of 2014 decreased compared with the corresponding 2013 period and largely reflected the same year-to-date trends; however, the Company had lower adjusted earnings from its wind farms in the third quarter of 2014.

Gas Pipelines, Processing and Energy Services earnings were impacted by the following adjusting items:

- Energy Services earnings for each period reflected changes in unrealized fair value gains related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and the revaluation of inventory.

- Energy Services adjusted earnings for 2014 excluded a realized loss of $71 million incurred during the second quarter of 2014 to close out certain forward derivative financial contracts intended to hedge the value of committed physical transportation capacity in certain markets accessed by Energy Services, but determined to be no longer effective in doing so.

- Energy Services adjusted earnings for 2013 excluded a realized loss of $58 million incurred to close out certain forward derivative contracts intended to hedge forecasted Energy Services transactions which did not occur.

- Offshore earnings/(loss) for 2014 included an unrealized fair value loss on derivative financial instruments.

- Offshore earnings for 2014 included a gain from the disposal of non-core assets.

- Other earnings/(loss) for each period reflected changes in unrealized fair value losses on the long-term power price derivative contracts acquired to hedge expected revenues and cash flows from Blackspring Ridge.

SPONSORED INVESTMENTS

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Enbridge Energy Partners, L.P. (EEP)	**62**	46	**157**	119
Enbridge Energy, Limited Partnership (EELP)	**38**	8	**58**	24

Enbridge Income Fund (the Fund)	**26**	32	**91**	81
Adjusted earnings	**126**	86	**306**	224
EEP - changes in unrealized derivative fair value loss	**(6)**	(6)	**(9)**	(3)
EEP - make-up rights adjustment	**-**	-	**(1)**	-
EEP - leak remediation costs	**(12)**	(5)	**(17)**	(35)
EEP - leak insurance recoveries	**-**	-	**-**	6
EEP - tax rate differences/changes	**-**	-	**-**	(3)
The Fund - changes in unrealized derivative fair value gains	**3**	-	**3**	-
The Fund - make-up rights adjustment	**(1)**	-	**(1)**	-
The Fund - drop down transaction costs	**(2)**	-	**(2)**	-
Earnings attributable to common shareholders	**108**	75	**279**	189

EEP adjusted earnings increased for the three and nine months ended September 30, 2014 compared with the corresponding 2013 periods. Adjusted earnings increased in EEP s liquids business primarily as a result of new assets placed into service during 2013 and 2014, combined with higher throughput and tolls on EEP s major liquids pipelines. New assets placed into service include the replacement and expansion of Line 6B as part of Enbridge and EEP s Eastern Access initiative, as well as the Line 6B 75-mile replacement program. Within EEP s North Dakota system, the Bakken Expansion and Access programs, which enhance crude oil gathering capabilities in the Bakken region, have also been a significant contributor to adjusted earnings growth. Positive factors experienced by Canadian Mainline as noted earlier also resulted in higher throughput on EEP s Lakehead System. Partially offsetting the increase in adjusted earnings in EEP s liquids business were incremental power costs associated with higher throughput, higher depreciation expense from an increased asset base and higher operating and administrative costs primarily associated with workforce and property taxes, although for the three months ended September 30, 2014 these increases in operating and administrative costs were more than offset by lower pipeline integrity costs.

EEP delayed its annual April 1 tariff filing for its Lakehead System as it was in negotiations with the Canadian Association of Petroleum Producers concerning certain components of the tariff rate structure. The toll application was filed with the FERC on June 27, 2014, and effective August 1, 2014, the Lakehead System Toll increased from US$2.17 per barrel to US$2.49 per barrel.

Within EEP s natural gas and NGL businesses, which it holds directly and indirectly through its partially-owned subsidiary MEP, lower volumes had a negative impact on adjusted earnings. Finally, EEP s contribution to Enbridge s adjusted earnings for the first nine months of 2014 continued to reflect higher earnings from Enbridge s May 2013 investment in preferred units of EEP.

EELP earnings reflect Enbridge s interest in the United States segment of Alberta Clipper, as well as interests in both the Eastern Access and Lakehead System Mainline expansion projects. Earnings from EELP increased for the three and nine months ended September 30, 2014 compared with the corresponding 2013 periods and reflected the positive contributions from assets recently placed into service, in particular the expansion of Line 6B from 240,000 bpd to 500,000 bpd completed in phases during 2014.

Adjusted earnings for the Fund for the nine months ended September 30, 2014 were higher compared with the comparative 2013 period. Higher adjusted earnings reflected strong performance from the Fund s liquids business. Also contributing to period-over-period growth in adjusted earnings was the absence of an after-tax charge of $12 million ($4 million after-tax attributable to Enbridge) related to the write-off of a regulatory deferral balance which occurred in the first quarter of 2013. Partially offsetting the adjusted earnings increase was higher income taxes.

Earnings from the Fund decreased in the third quarter of 2014 compared with the comparative 2013 period. Lower earnings were primarily attributable to higher income taxes as noted above, as well as lower earnings from the Fund s Sarnia Solar Project. Partially offsetting the decrease were positive earnings from the Fund s liquids business.

Sponsored Investments earnings were impacted by the following adjusting items:

- Earnings from EEP for each period included changes in unrealized fair value gains and losses on derivative financial instruments.
- Earnings from EEP for 2014 included a make-up rights adjustment.

- Earnings from EEP for 2014 and 2013 included charges related to estimated costs, before insurance recoveries, associated with the Line 6B crude oil release. See *Recent Developments Sponsored Investments Enbridge Energy Partners, L.P. Line 6B Crude Oil Release.*

- Earnings from EEP for 2013 included insurance recoveries associated with the Line 6B crude oil release. See *Recent Developments Sponsored Investments Enbridge Energy Partners, L.P. Line 6B Crude Oil Release.*

• Earnings from EEP for 2013 included an out-of-period, non-cash deferred income tax adjustment related to a tax law change.

• Earnings from the Fund for 2014 included an unrealized fair value gain on derivative financial instruments.

• Earnings from the Fund for 2014 included a make-up rights adjustment.

• Earnings from the Fund for 2014 included costs incurred in relation to a proposed transaction to transfer natural gas and diluent pipeline interests to the Fund. See *Recent Developments Sponsored Investments Enbridge Income Fund Proposed Natural Gas and Diluent Interests Transfer.*

CORPORATE

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Noverco	**(3)**	(2)	**22**	34
Other Corporate	**(10)**	(18)	**(37)**	(46)
Adjusted loss	**(13)**	(20)	**(15)**	(12)
Noverco - changes in unrealized derivative fair value gains/(loss)	**-**	5	**(5)**	4
Other Corporate - changes in unrealized derivative fair value gains/(loss)	**(221)**	77	**(227)**	(177)
Other Corporate - gain on sale of investment	**-**	-	**14**	-
Other Corporate - foreign tax recovery	**-**	-	**-**	4
Other Corporate - impact of tax rate changes	**-**	-	**-**	18
Earnings/(loss) attributable to common shareholders	**(234)**	62	**(233)**	(163)

Noverco adjusted earnings decreased for the nine months ended September 30, 2014 compared with the corresponding 2013 period. Noverco adjusted earnings included returns on the Company s preferred share investment as well as its equity earnings from Noverco s underlying gas and power distribution investments. Excluding the impact of a small one-time gain on sale of an investment in the first quarter of 2013 and an equity earnings true-up adjustment recognized in the first quarter of 2013, Noverco adjusted earnings were comparable between periods.

Other Corporate adjusted loss decreased for the three and nine months ended September 30, 2014 compared with the corresponding 2013 periods. The decreased loss reflected lower net corporate segment finance costs and lower income taxes partially offset by higher preference share dividends due to an increase in the number of preference shares outstanding

Corporate earnings/(loss) were impacted by the following adjusting items:

• Noverco earnings/(loss) for each period included changes in unrealized fair value gains and losses on derivative financial instruments.

- Other Corporate earnings/(loss) for each period included changes in the unrealized fair value gains and losses on derivative financial instruments primarily related to forward foreign exchange risk management positions.
- Other Corporate loss for 2014 included a gain on sale of an investment.
- Other Corporate loss for 2013 was reduced by recovery of taxes related to a historical foreign investment.
- Other Corporate loss for 2013 was impacted by tax rate differences.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to Enbridge s growth strategy, particularly in light of the record level of capital projects secured or under development. The Company actively manages financial plans and strategies to ensure it maintains sufficient liquidity to meet routine operating and future capital requirements. In the near term, the Company generally expects to utilize cash from operations and the issuance of debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends.

The Company s longer-term financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives, including utilization of its sponsored vehicles through which it can monetize assets, with the objective of diversifying funding sources and maintaining access to low cost capital. In September 2014, Enbridge entered into a proposed transaction with the Fund to transfer natural gas and diluent pipeline interests to the Fund. Subject to receipt of customary regulatory approvals, the transaction is expected to provide approximately $1.2 billion of net funding to Enbridge. See *Recent Developments Sponsored Investments Enbridge Income Fund Proposed Natural Gas and Diluent Interests Transfer.*

In June 2014, the Company took a significant action to re-establish EEP as a cost-effective sponsored vehicle by restructuring EEP s equity. The Equity Restructuring is expected to benefit Enbridge in the longer term by improving EEP s cost of capital and growth outlook, thus increasing the incentive distributions to Enbridge. See *Recent Developments Sponsored Investments Enbridge Energy Partners, L.P. Sponsored Vehicle Transactions Equity Restructuring*. Following the Equity Restructuring, Enbridge and EEP announced in September 2014 a proposed drop down of Enbridge s current 66.7% interest in the United States segment of the Alberta Clipper pipeline to EEP for proceeds of approximately US$900 million. See *Recent Developments Sponsored Investments Enbridge Energy Partners, L.P. Sponsored Vehicle Transactions Proposed Alberta Clipper Drop Down.*

In accordance with its funding plan, the Company has completed the following issuances to date in 2014:

- Corporate - $460 million of common shares; $1,400 million of preference shares; $1,530 million of medium-term notes; $1,641 million of senior notes;
- Liquids Pipelines - Southern Lights Pipeline - $352 million and US$1,061 million of private placement notes;
- Gas Distribution - EGD - $730 million of medium-term notes; and
- Sponsored Investments - MEP - US$400 million of private senior notes.

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, Enbridge also bolstered its committed bank credit facilities in 2014. The following table provides details of the Company s committed credit facilities at September 30, 2014 and December 31, 2013.

		September 30, 2014			December 31, 2013
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2016	**300**	**261**	**39**	300
Gas Distribution	2016-2019	**1,008**	**981**	**27**	713
Sponsored Investments	2016-2018	**4,395**	**1,861**	**2,534**	4,781
Corporate	2015-2019	**12,557**	**4,403**	**8,154**	11,805
		18,260	**7,506**	**10,754**	17,599
Southern Lights project financing[2]	2016	**27**	**-**	**27**	1,570
Total committed credit facilities		**18,287**	**7,506**	**10,781**	19,169

1 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*

2 On August 18, 2014, long-term private debt was issued for $352 million and US$1,061 million with the proceeds utilized to repay the construction credit facilities on a dollar-for-dollar basis.

In addition to the committed credit facilities noted above, the Company also has $352 million of uncommitted demand credit facilities, of which $332 million was unutilized, as at September 30, 2014.

Subsequent to September 30, 2014, the Company has extended the maturity dates of a number of credit facilities representing total commitments of approximately of $4.4 billion for another year.

Excluding project financing, the Company s net available liquidity of $11,472 million at September 30, 2014 was inclusive of $1,088 million of unrestricted cash and cash equivalents and net of bank indebtedness of $370 million.

There are no material restrictions on the Company s cash with the exception of restricted cash of $5 million related to Southern Lights project financing and cash in trust of $34 million for specific shipper commitments. Cash and cash equivalents held by EEP and the Fund are generally not readily accessible by Enbridge until distributions are declared and paid by these entities, which occurs quarterly for EEP and monthly for the Fund. Further, cash and cash equivalents held by certain foreign subsidiaries may not be readily accessible for alternative uses by Enbridge.

OPERATING ACTIVITIES

Cash provided by operating activities for the three and nine months ended September 30, 2014 was $746 million and $1,891 million, respectively, compared with $830 million and $2,560 million for the three and nine months ended September 30, 2013. As discussed in *Financial Results*, the Company experienced higher earnings mainly from higher throughput and new assets placed into service within Liquids Pipelines and stronger contributions from EEP and EELP, partially offset by less favourable arbitrage opportunities in Energy Services. Also partially offsetting the increases were payments for environmental liabilities in respect to Line 6B leak, as well as lower distributions from the Company s equity investments. The Company received a one-time dividend of $248 million from its equity investment in Noverco during the second quarter of 2013.

Despite the positive earnings effects noted above, the comparability of period-over-period cash flows from operating activities was impacted by changes in operating assets and liabilities as they absorbed cash of $295 million and $1,271 million for the three and nine months ended September 30, 2014, respectively compared with a cash generation of $50 million and cash absorption of $362 million in the corresponding 2013 periods. Operating assets and liabilities fluctuate from time to time due to inventory levels, which in turn are impacted by weather and commodity prices, as well as activity levels within the Company s businesses.

At September 30, 2014, the Company had a negative working capital position. Despite this negative working capital, the Company continues to have significant liquidity available through committed credit facilities, which allow the funding of liabilities as they become due. As at September 30, 2014, the Company s net available liquidity totalled $11,472 million (December 31, 2013 - $12,909 million). In addition, it is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

INVESTING ACTIVITIES

Cash used in investing activities for the three and nine months ended September 30, 2014 was $2,525 million and $8,154 million, respectively, compared with $2,562 million and $6,154 million for the three and nine months ended September 30, 2013. Cash used in investing activities on a period-over-period basis has primarily been impacted by additions to property, plant and equipment associated with the Company s growth projects which are further described in *Growth Projects Commercially Secured Projects*. Additional funding of various investments and joint ventures, primarily the Seaway Pipeline Twinning/Extension project, also contributed to the increased cash usage for the nine month period ended September 30, 2014, although such funding was lower in the third quarter of 2014 compared with the third quarter of 2013.

32

FINANCING ACTIVITIES

For the three and nine months ended September 30, 2014, cash generated from financing activities was $1,594 million and $6,549 million, respectively, compared with $1,175 million and $2,326 million for the three and nine months ended September 30, 2013. The Company continues to execute its funding and liquidity strategy in support of its long-term growth plan. During the first nine months of 2014, the Company increased its overall debt by $5,740 million compared with an increase of $944 million during the same period in 2013. The most significant contributor of this increase during the first nine months of 2014 was the issuance of $4,334 million (2013 - $1,232 million) in medium-term and senior notes. The Company also issued preference and common shares during the same period of 2014 for net proceeds of $1,365 million and $470 million, respectively, compared with $1,186 million and $616 million for the comparative periods in 2013. Furthermore, the Company bolstered its liquidity during the first nine months of 2014 through the securement of additional credit facilities.

Additional preference and common shares outstanding gave rise to an increase in the dividends paid during the first nine months of 2014 compared with the same period of 2013, partially offsetting the cash inflows from financing activities. Also partially offsetting the cash flows from financing activities were the transactions between the Company s sponsored vehicles and their public unitholders. During the first nine months of 2014, EEP, MEP and the Fund made distributions, net of contributions, of $287 million to their public unitholders. For the comparative period in 2013, sponsored vehicles received contributions, net of distributions, of $212 million primarily as a result of their equity issuances to the public.

Participants in the Company s Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended September 30, 2014, dividends declared were $296 million (2013 - $261 million), of which $193 million (2013 - $167 million) were paid in cash and reflected in financing activities. The remaining $103 million (2013 - $94 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the nine months ended September 30, 2014, dividends declared were $880 million (2013 - $774 million), of which $565 million (2013 - $504 million) were paid in cash and reflected in financing activities. The remaining $315 million (2013 - $270 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the three and nine months ended September 30, 2014, 34.8% (2013 - 36.0%) and 35.8% (2013 - 34.9%) of total dividends declared were reinvested.

On October 22, 2014, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on December 1, 2014 to shareholders of record on November 14, 2014.

Common Shares	$0.35000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
Preference Shares, Series L	US$0.25000
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R	$0.25000
Preference Shares, Series 1	US$0.25000
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5	US$0.27500
Preference Shares, Series 7	$0.27500
Preference Shares, Series 9	$0.27500

Preference Shares, Series 1[1]	$0.27500
Preference Shares, Series 13[1]	$0.41290
Preference Shares, Series 15[2]	$0.20790

1 This first dividend declared for the Preference Shares, Series 13 includes accrued dividends from July 17, 2014, the date the shares were issued. The regular quarterly dividend of $0.275 per share will take effect on March 1, 2015. See Recent Developments Corporate Preference Share Issuance Series 13.

2 The first dividend declared for the Preference Shares, Series 15 includes accrued dividends from September 23, 2014, the date the shares were issued. The regular quarterly dividend of $0.275 per share will take effect on March 1, 2015. See Recent Developments Corporate Preference Share Issuance Series 15.

CAPITAL EXPENDITURE COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totalling $3,399 million which are expected to be paid over the next five years.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company s earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company s share price (collectively, market risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

The Company generates certain revenues, incurs expenses and holds a number of investments and subsidiaries denominated in currencies other than Canadian dollars. As a result, the Company s earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

The Company has implemented a policy whereby, at a minimum, it hedges a level of foreign currency denominated earnings exposures over a five year forecast horizon. A combination of qualifying and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses, and to manage variability in cash flows. The Company hedges certain net investments in United States dollar denominated investments and subsidiaries using foreign currency derivatives and United States dollar denominated debt.

Interest Rate Risk

The Company s earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2019 through execution of floating to fixed interest rate swaps with an average swap rate of 2.1%.

The Company s earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2018 through execution of floating to fixed interest rate swaps with an average swap rate of 4%.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt which stays within its Board of Directors approved policy limit of a maximum of 25% floating rate debt as a percentage of total debt outstanding. The Company uses primarily qualifying derivative instruments to manage interest rate risk.

Commodity Price Risk

The Company s earnings and cash flows are exposed to changes in commodity prices as a result of its ownership interests in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. The Company employs financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. The Company uses primarily non-qualifying derivative instruments to manage commodity price risk.

Equity Price Risk

Equity price risk is the risk of earnings fluctuations due to changes in the Company s share price. The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted stock units. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income

The following table presents the effect of derivative instruments on the Company s consolidated earnings and consolidated comprehensive income.

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Amount of unrealized gains/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**22**	(18)	**(9)**	29
Interest rate contracts	**(173)**	(86)	**(694)**	703
Commodity contracts	**9**	(23)	**(8)**	(6)
Other contracts	**7**	(3)	**15**	(4)
Net investment hedges				
Foreign exchange contracts	**(63)**	25	**(66)**	(42)
	(198)	(105)	**(762)**	680
Amount of gains/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*				
Foreign exchange contracts[1]	**(5)**	(2)	**10**	(5)
Interest rate contracts[2]	**30**	43	**74**	89
Commodity contracts[3]	**2**	5	**14**	1
Other contracts[4]	**(5)**	-	**(12)**	-
	22	46	**86**	85
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts[2]	**130**	1	**158**	24
Commodity contracts[3]	**-**	-	**3**	(2)
	130	1	**161**	22
Amount of gains/(loss) from non-qualifying derivatives included in earnings				
Foreign exchange contracts[1]	**(568)**	319	**(510)**	(382)
Interest rate contracts[2]	**1**	(2)	**3**	(7)

Commodity contracts[3]	**146**	20	**447**	124
Other contracts[4]	**5**	(1)	**12**	3
	(416)	336	**(48)**	(262)

1 Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.

2 Reported as an (increase)/decrease to Interest expense in the Consolidated Statements of Earnings.

3 Reported within Transportation and other services revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company s primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities as at September 30, 2014. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

Entering into derivative financial instruments may result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

The Company generally has a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company s credit risk exposure on derivative asset positions outstanding with the counterparties in these particular circumstances.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Within Gas Distribution, credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, commodity and share) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread, as well as the credit default swap spreads associated with its counterparties, in its estimation of fair value.

36

CRITICAL ACCOUNTING ESTIMATES

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (ARO) associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset s useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company s estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

In May 2009, the NEB released a report on the financial issues associated with pipeline abandonment and established a goal for pipelines regulated under the NEB Act to begin collecting and setting aside funds to cover future abandonment costs no later than January 1, 2015. Subsequently, the NEB issued revised base case assumptions based on feedback from member companies. Companies were given the option to follow the base case assumptions or to submit pipeline specific applications. On November 29, 2011, as required by the NEB, the Company filed its estimated abandonment costs for its regulated pipeline systems within Enbridge Pipelines Inc. and Enbridge Pipelines (NW) Inc. (Group 1 companies) and Enbridge Southern Lights GP Inc., Enbridge Bakken Pipeline Company Inc., Enbridge Pipelines (Westspur) Inc., Vector Pipelines Limited Partnership, Niagara Gas Transmission Limited and 2103914 Canada Limited (Group 2 companies).

In the fourth quarter of 2012, the NEB held a hearing on the abandonment costs estimates for Group 1 companies and issued its decision on February 14, 2013. The outcome does not materially impact tolls. On February 28, 2013, Group 1 companies filed a proposed process and mechanism to set aside the funds for future abandonment costs and chose the qualified environmental trust as the appropriate set-aside mechanism to hold pipeline abandonment funds. On May 31, 2013, the Group 1 companies filed collection mechanism applications and the Group 2 companies filed both their set-aside and collection mechanism applications. Once the set-aside and collection mechanism is approved by the NEB, both Group 1 and Group 2 companies can start to recover these costs from shippers through tolls in accordance with the NEB s determination that abandonment costs are a legitimate cost of providing service and are recoverable upon NEB approval from users of the system. The collections are expected to begin in 2015.

All applications by the Company will require NEB approval. The NEB hearings commenced January 14, 2014, covering both the set-aside mechanism applications and the collection mechanism applications for both Group 1 and Group 2 companies. The NEB released its decision on May 29, 2014 approving both the set aside mechanism and collection mechanisms for all of the Enbridge Group 1 companies and Group 2 companies.

Currently, for the majority of the Company s assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

In 2014, the Company recognized ARO in the amount of $167 million. Of this amount, $64 million related to the decommissioning of certain portions of Line 6B of EEP s Lakehead System in connection with the replacement work expected to occur into 2015 and $103 million related to the Canadian and United States portions of the L3R Program announced in March 2014.

37

CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Obligations Resulting from Joint and Several Liability Arrangements

Effective January 1, 2014, the Company retrospectively adopted Accounting Standards Update (ASU) 2013-04 which provides measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

Parent s Accounting for the Cumulative Translation Adjustment

Effective January 1, 2014, the Company prospectively adopted ASU 2013-05 which provides guidance on the timing of release of the cumulative translation adjustment into net income when a disposition or ownership change occurs related to an investment in a foreign entity or a business within a foreign entity. There was no material impact to the interim consolidated financial statements as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Revenue from Contracts with Customers

ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The new standard is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

ASU 2014-08 was issued in April 2014 and changes the criteria and disclosures for reporting discontinued operations. It is anticipated that in general, the revised criteria will result in fewer transactions being categorized as discontinued operations. The adoption of the pronouncement is not anticipated to have a material impact on the Company s consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively.

QUARTERLY FINANCIAL INFORMATION

		2014			2013			2012
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
(millions of Canadian dollars, except per share amounts)								

Revenues	**8,297**	10,026	10,521	8,293	8,998	7,730	7,897	7,007
Earnings attributable to common shareholders	**(80)**	756	390	(267)	421	42	250	146
Earnings per common share	**(0.10)**	0.92	0.48	(0.33)	0.52	0.05	0.32	0.19
Diluted earnings per common share	**(0.10)**	0.91	0.47	(0.32)	0.51	0.05	0.31	0.18
Dividends per common share	**0.3500**	0.3500	0.3500	0.3150	0.3150	0.3150	0.3150	0.2825
EGD - warmer/(colder) than normal weather	**2**	(4)	(33)	(13)	-	(2)	6	(1)
Changes in unrealized derivative fair value and intercompany foreign exchange (gains)/loss	**396**	(430)	190	613	(223)	246	207	81

Several factors impact comparability of the Company s financial results on a quarterly basis, including, but not limited to, seasonality in the Company s gas distribution businesses, fluctuations in market prices such as foreign exchange rates and commodity prices, disposals of investments or assets and the timing of in-service dates of new projects.

EGD and the Company s other gas distribution businesses are subject to seasonal demand. A significant portion of gas distribution customers use natural gas for space heating; therefore, volumes delivered and resulting revenues and earnings typically increase during the winter months of the first and fourth quarters of any given year. Revenues generated by EGD and other gas distribution businesses also vary from quarter-to-quarter with fluctuations in the price of natural gas, although earnings remain neutral due to the pass through nature of these costs.

The Company actively manages its exposure to market risks including, but not limited to, commodity prices and foreign exchange rates. To the extent derivative instruments used to manage these risks are non-qualifying for the purposes of applying hedge accounting, changes in unrealized fair value gains and losses on these instruments will impact earnings.

In addition to the impacts of weather in EGD s franchise area and changes in unrealized gains and losses outlined above, significant items that impacted the quarterly earnings included:

- First quarter earnings for 2014 included a $43 million after-tax gain on the disposal of non-core Offshore assets and a $14 million after-tax gain on the sale of an Alternative and Emerging Technologies investment within the Corporate segment.

- Included in earnings are after-tax costs of $4 million in the third quarter of 2014 as well as $40 million, $13 million and $3 million incurred respectively in the second, third and fourth quarters of 2013, in connection with the Line 37 crude oil release which occurred in June 2013. Earnings also reflected insurance recoveries associated with the Line 37 crude oil release of $4 million recognized in the second quarter of 2014.

- Reflected in earnings is the Company s share of leak remediation costs associated with the Line 6B crude oil release. Remediation costs of $5 million and $12 million were recognized in the second and third quarters of 2014; and $24 million, $6 million, $5 million and $9 million were recognized in the first, second, third and fourth quarters of 2013. Earnings also reflected insurance recoveries associated with the Line 6B crude oil release of $6 million in the second quarter of 2013.

- Fourth quarter earnings for 2012 included a $63 million, after-tax gain on recognition of a regulatory asset related to other postretirement benefits within EGD.

- Fourth quarter earnings for 2012 included an impairment charge of $166 million ($105 million after-tax) related to certain of its Offshore assets, predominantly located within the Stingray and Garden Banks corridors.

- Fourth quarter earnings for 2012 also included the impact of asset transfers between entities under common control of Enbridge, resulting in income taxes of $56 million incurred on the related capital gain.

Finally, the Company is in the midst of a substantial capital program and the timing of construction and completion of growth projects may impact the comparability of quarterly results. The Company s capital expansion initiatives, including construction commencement and in-service dates, are described in *Growth Projects Commercially Secured Projects* and *Growth Projects Other Projects Under Development.*

NON-GAAP RECONCILIATIONS

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Earnings/(loss) attributable to common shareholders	**(80)**	421	**1,066**	713
Adjusting items:				
Liquids Pipelines				
Canadian Mainline - changes in unrealized derivative fair value (gains)/loss[1]	**231**	(133)	**192**	125
Canadian Mainline - Line 9B costs incurred during reversal	**2**	-	**6**	-
Regional Oil Sands System - make-up rights adjustment	**(5)**	-	**(5)**	-
Regional Oil Sands System - make-up rights out-of-period adjustment	**-**	37	**-**	37
Regional Oil Sands System - leak insurance recoveries	**-**	-	**(4)**	-
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**4**	13	**4**	53
Regional Oil Sands System - long-term contractual recovery out-of-period adjustment, net	**-**	(31)	**-**	(31)
Southern Lights Pipeline - changes in unrealized derivative fair value loss[1]	**9**	-	**9**	-
Seaway Pipeline - make-up rights adjustment	**11**	-	**11**	-
Spearhead Pipeline - make-up rights adjustment	**-**	-	**1**	-
Feeder Pipelines and Other - make-up rights adjustment	**(1)**	-	**(3)**	-
Feeder Pipelines and Other - project development costs	**1**	-	**4**	-
Gas Distribution				
EGD - warmer/(colder) than normal weather	**2**	-	**(35)**	4
EGD - gas transportation cost cut-off-period adjustment	**-**	56	**-**	56
Gas Pipelines, Processing and Energy Services				
Energy Services - changes in unrealized derivative fair value gains[1]	**(71)**	(18)	**(288)**	(131)
Offshore - changes in unrealized derivative fair value loss[1]	**2**	-	**2**	-
Offshore - gain on sale of non-core assets	**-**	-	**(43)**	-
Other - changes in unrealized derivative fair value loss[1]	**1**	4	**3**	60
Sponsored Investments				
EEP - changes in unrealized derivative fair value loss[1]	**6**	6	**9**	3
EEP - make-up rights adjustment	**-**	-	**1**	-
EEP - leak remediation costs	**12**	5	**17**	35
EEP - leak insurance recoveries	**-**	-	**-**	(6)
EEP - tax rate differences/changes	**-**	-	**-**	3
The Fund - changes in unrealized derivative fair value gains[1]	**(3)**	-	**(3)**	-
The Fund - make-up rights adjustment	**1**	-	**1**	-
The Fund - drop down transaction costs	**2**	-	**2**	-
Corporate				
Noverco - changes in unrealized derivative fair value (gains)/loss[1]	**-**	(5)	**5**	(4)
Other Corporate - changes in unrealized derivative fair value (gains)/loss[1]	**221**	(77)	**227**	177
Other Corporate - gain on sale of investment	**-**	-	**(14)**	-
Other Corporate - foreign tax recovery	**-**	-	**-**	(4)
Other Corporate - impact of tax rate changes	**-**	-	**-**	(18)
Adjusted earnings	**345**	278	**1,165**	1,072

1 *Changes in unrealized derivative fair value gains and losses are presented net of amounts realized on the settlement of derivative contracts during the applicable period.*

OUTSTANDING SHARE DATA[1]

PREFERENCE SHARES

	Number	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3]
Preference Shares, Series A	5,000,000	-	-
Preference Shares, Series B	20,000,000	June 1, 2017	

Energy revenue	$	489	$	1,064	(54)%
Capacity revenue		407		415	(2)
Risk management activities		277		85	N/A
Other revenues		28		66	(58)
Total operating revenues		1,201		1,630	(26)
Operating Costs and Expenses					
Cost of energy		341		695	(51)
Depreciation and amortization		118		109	8
Other operating expenses		399		392	2
Operating Income	$	343	$	434	(21)
MWh sold (in thousands)		9,220		13,349	(31)
MWh generated (in thousands)		9,220		13,349	(31)
Business Metrics					
Average on-peak market power prices ($/MWh)	$	46.14	$	91.68	(50)
Cooling Degree Days, or CDDs[(a)]		475		611	(22)
CDD s 30-year rolling average		537		537	
Heating Degree Days, or HDDs[(a)]		6,286		6,057	4
HDD s 30-year rolling average		6,262		6,294	(1)%

(a) National Oceanic and Atmospheric Administration-Climate Prediction Center A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

Operating Income

Operating income decreased by $91 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Operating revenues decreased by $429 million due to unfavorable energy revenues, other revenues and capacity revenues partially offset by a favorable impact from risk management activities.

Cost of energy decreased by $354 million due to lower generation and fuel prices.

Operating Revenues

Operating revenues decreased by $429 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Energy revenue decreased by $575 million due to:

Energy prices decreased by $295 million reflecting an average 40% decline in merchant energy prices.

Generation decreased by $334 million due to a 31% decrease in generation in 2009 compared to 2008, driven by a 31% decrease in coal generation and a 31% decrease in oil and gas generation. Coal generation declined 24%, or 1,471,726 MWhs, in western New York; 39%, or 1,503,975 MWhs, at Indian River; and 80%, or 476,537 MWh, at Somerset. The decline in generation at these plants is due to a combination of weakened demand for power, low gas prices and higher cost of production from the introduction of RGGI resulting in increased hours where the units were uneconomic to dispatch. The decline in oil and gas generation is attributable to fewer reliability run hours at the Norwalk plant and higher maintenance work at the Arthur Kill plant in 2009.

Margin on MWh sold from market purchases increased by $54 million driven by lower net costs incurred in meeting obligations under load serving contracts in the PJM market.

Other revenues decreased by $38 million due to $20 million from decreased activity in the trading of emission allowances and $17 million lower allocations of net physical gas sales.

Capacity revenue decreased by $8 million due to lower capacity cash flow revenue in New York in 2009.

These decreases were offset by:

Risk management activities gains of $277 million were recorded for the year ended December 31, 2009, compared to gains of $85 million during the same period in 2008. The $277 million gain included $107 million of unrealized mark-to-market losses and $384 million in gains on settled transactions, or financial income, compared to $82 million in unrealized mark-to-market gains and $3 million in financial gains during the same period in 2008. For further discussion of the Company s risk management activities, see Consolidated Results of Operations.

Cost of Energy

Cost of energy decreased by $354 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Natural gas and oil costs decreased by $187 million, or 60%, due to 31% lower generation and 56% lower average natural gas prices.

Coal costs decreased by $129 million, or 35%, due to lower coal generation of 31% accounting for $111 million and lower prices accounting for $18 million. The lower prices are due to lower fuel transportation surcharges.

Fuel risk management activities gains of $60 million were recorded for the year ended December 31, 2009. In the first quarter 2009, all NPNS coal contracts were discontinued and reclassified to mark-to-market accounting. The $60 million gain included $67 million of unrealized mark-to-market gains, largely associated with forward coal positions and $7 million in losses on settled transactions, or financial cost of energy. For further discussion of the Company s risk management activities, see Consolidated Results of Operations.

These decreases were offset by:

Carbon emission expense increased by $22 million due to the January 1, 2009, implementation of RGGI and the recognition of carbon compliance cost under this program.

Depreciation and Amortization

Depreciation and amortization increased by $9 million primarily due to depreciation from the 2009 baghouse projects at NRG s Western New York coal plants.

Other Operating Expenses

Other operating expenses increased by $7 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Property taxes increased by $14 million due to lower Empire Zone tax benefits recognized in 2009 at the Oswego plant due to the plant receiving notice of decertification from the Empire Zone program in 2009 from the State of New York which decision is under appeal by the Company.

Write-down of assets increased by $12 million for the year ended December 31, 2009, compared to the same period in 2008. The write-down was due to the cancellation and subsequent write off of construction costs incurred through year end 2009 on the Indian River Unit 3 air pollution control equipment project. NRG and DNREC announced a proposed plan, subject to definitive documentation, that would shut down Unit 3 by December 31, 2013, and relieve NRG of the requirement to install this back-end control equipment. Unit 4 is not affected by this plan and construction on similar equipment continues with an expected in-service date of year-end 2011.

General and administrative expense increased by $2 million due to higher labor and employee benefit costs.

Development costs increased by $2 million due to increased repowering efforts at the Astoria plant and a biomass project at the Montville plant.

These increases was offset by:

Operations and maintenance expenses decreased by $22 million due to lower chemical spending and routine maintenance work as a result of lower generation and lower planned major maintenance work at the Huntley and Indian River plants.

2008 compared to 2007

The following table provides selected financial information for the Northeast region for the years ended December 31, 2008, and 2007:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 1,064	$ 1,104	(4)%
Capacity revenue	415	402	3
Risk management activities	85	27	215
Other revenues	66	72	(8)
Total operating revenues	1,630	1,605	2
Operating Costs and Expenses			
Cost of energy	695	641	8
Depreciation and amortization	109	102	7
Other operating expenses	392	404	(3)
Operating Income	$ 434	$ 458	(5)
MWh sold (in thousands)	13,349	14,163	(6)
MWh generated (in thousands)	13,349	14,163	(6)
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 91.68	$ 76.37	20
Cooling Degree Days, or CDDs[(a)]	611	702	(13)
CDD s 30-year rolling average	537	537	
Heating Degree Days, or HDDs[(a)]	6,057	6,074	
HDD s 30-year rolling average	6,294	6,261	1%

(a) National Oceanic and Atmospheric Administration-Climate Prediction Center A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

Operating Income

Operating income decreased by $24 million for the year ended December 31, 2008, compared to 2007, due to:

Cost of energy increased by $54 million due to higher coal costs, increased coal transportation surcharges and higher natural gas prices. The increase was offset by lower oil costs from lower oil-fired generation.

This unfavorable variance was offset by:

Operating revenues increased by $25 million due to higher capacity revenue and risk management revenues partially offset by lower energy revenue.

Other operating expenses decreased by $12 million due to lower major maintenance expenses and property taxes offset by higher utilities expense.

Operating Revenues

Operating revenues increased by $25 million for the year ended December 31, 2008, compared to 2007, due to:

Risk management activities gains of $85 million were recorded for the year ended December 31, 2008, compared to gains of $27 million during the same period in 2007. The $85 million gain includes $82 million of unrealized mark-to-market gains and $3 million of gains in settled transactions, or financial revenue. The $82 million unrealized gains is the net effect of a $96 million gain from economic hedge positions, the $13 million loss due to the reversal of previously recognized mark-to-market gains on economic hedges, the $14 million loss due to the reversal of mark-to-market gains on trading activity and $13 million in unrealized mark-to-market gains on trading activity. Gains are driven by increases in power and gas prices.

Capacity revenue increased by $13 million due to:

PJM capacity revenue increased by $20 million reflecting recognition of a year of revenue from the RPM capacity market (effective on June 1, 2007) in 2008 compared to seven months in 2007.

NEPOOL capacity revenue increased $11 million due to increased revenue recognized on the Norwalk RMR contract (effective on June 19, 2007) in 2008 compared to seven months in 2007.

NYISO capacity revenue decreased by $18 million due to unfavorable market prices. The lower capacity market prices are a result of NYISO s reductions in Installed Reserve Margins and installed capacity in-city mitigation rules effective March 2008. These decreases were offset by higher capacity contract revenue.

These gains were offset by:

Energy revenues decreased by $40 million due to:

Energy prices increased by $64 million due to an average 6% rise in merchant energy prices.

Generation decreased by $66 million due to a net 6% decrease in generation. The decrease in generation represented a 55% decrease in oil-fired generation as these oil-fired plants were not dispatched due to 41% higher average oil prices. In addition, there was a 12% decrease in gas-fired generation related to a cooler summer in 2008 as compared to 2007. Coal generation was flat in 2008 compared to 2007.

Margin on MWh sold from market purchases decreased by $38 million driven by higher net costs incurred to service PJM contracts as a result of the increase in market energy prices.

Other revenues decreased by $6 million due to lower allocations of net physical sales in 2008 of $17 million offset by higher allocations for trading of emission allowances and carbon financial instruments of $10 million.

Cost of Energy

Cost of energy increased by $54 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

Coal costs increased by $61 million due to higher coal costs and fuel transportation surcharges.

Natural gas costs increased by $22 million, despite 12% lower generation, due to a 32% higher average natural gas prices.

These increases were offset by:

Oil costs decreased by $27 million due to lower oil-fired generation of 55% as these plants were not dispatched in 2008 due to 41% higher average oil prices.

Other Operating Expenses

Other operating expenses decreased by $12 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

Major maintenance decreased $18 million as a result of less outage work at the Norwalk and Indian River plants.

Property taxes decreased $10 million due to $4 million in property tax credits received in 2008 at the region s New York City plants and higher property credits received in 2008 at the region s Western New York plants.

These decreases were offset by:

Utilities expense increased by $16 million as a result of a $19 million benefit included in the 2007 utilities cost due to a lower than planned settlement of the station service agreement with CL&P.

South Central Region

2009 compared to 2008

The following table provides selected financial information for the South Central region for the years ended December 31, 2009 and 2008:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 360	$ 478	(25)%
Capacity revenue	269	233	15
Risk management activities	(71)	10	N/A
Contract amortization	22	23	(4)
Other revenues	1	2	(50)
Total operating revenues	581	746	(22)
Operating Costs and Expenses			
Cost of energy	399	468	(15)
Depreciation and amortization	67	67	
Other operating expenses	109	111	(2)
Operating Income	$ 6	$ 100	(94)
MWh sold (in thousands)	12,144	12,447	(2)
MWh generated (in thousands)	10,398	11,148	(7)
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 33.58	$ 71.25	(53)
Cooling Degree Days, or CDDs[a]	1,549	1,618	(4)
CDD s 30-year rolling average	1,548	1,547	
Heating Degree Days, or HDDs[a]	3,521	3,672	(4)
HDD s 30-year rolling average	3,604	3,623	(1)%

(a) National Oceanic and Atmospheric Administration-Climate Prediction Center A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

Operating Income

Operating income decreased by $94 million for the year ended December 31, 2009, compared to the same period in 2008 due to:

Operating revenues declined by $165 million as a result of decreases in energy revenue, risk management activities and other revenue. These decreases were offset by an increase in capacity revenue.

*Cost of energ*y declined by $69 million due to lower purchased energy, fuel and transmission costs, offset by higher fuel risk management activities.

Operating Revenues

Operating revenues decreased by $165 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Energy revenue decreased by $118 million due to a $80 million decline in contract revenue, a $2 million decrease in merchant energy revenue and a $36 million decrease in margin on MWh sold from market purchases. The contract revenue decrease was attributed to a 10% decrease in sales volumes and a $5.15 per MWh lower average realized price. The decline in contract energy price was driven by a $16 million decrease in fuel cost pass-through to the cooperatives reflecting an overall decline in natural gas prices. Also contributing to the decline in contract revenue was a $60 million decrease due to the expiration of a contract with a regional utility. The expiration of the contract allowed more energy to be sold into the merchant market, but at lower prices resulting in a $2 million decline in revenue.

Risk management activities losses of $71 million were recorded for the year ended December 31, 2009, compared to gains of $10 million during the same period in 2008. The $71 million loss included $78 million of unrealized mark-to-market losses offset by $7 million in gains on settled transactions, or financial income, compared to $26 million in unrealized mark-to-market gains offset by $16 million in financial losses during the same period in 2008. For further discussion of the Company s risk management activities, see Consolidated Results of Operations.

These decreases were offset by:

Capacity revenue grew by $36 million driven by a $40 million increase from new capacity agreements with regional utilities and a $5 million increase in capacity revenue contributed by the region s Rockford plants which dispatch into the PJM market, offset by reduced contract capacity revenue of $9 million.

Cost of Energy

Cost of energy is down by $69 million for the year ended December 31, 2009, compared to the same period in 2008, reflecting:

Purchased energy declined by $58 million while purchased capacity rose by $3 million. The lower purchased energy was driven by lower fuel costs associated with the region s tolled facility and lower market energy prices. The energy declines were offset by increased capacity payments of $3 million on tolled facilities.

Natural gas expense decreased by $15 million reflecting a 30% drop in owned gas generation and a 54% decline in gas prices. The region s gas facilities ran extensively to support transmission system stability following hurricane Gustav in September 2008.

Coal expense decreased $11 million as coal generation was down 6%, offset by a 1% increase in cost per ton.

Transmission expense declined by $8 million due to certain transmission line outages between electrical power regions which limited merchant energy volumes that would incur transmission costs as well as lower network interchange transmission costs associated with reduced contract customer energy volumes.

These decreases were offset by:

Fuel risk management activities losses of $21 million were recorded for the year ended December 31, 2009. In the first quarter 2009, all NPNS coal contracts were discontinued and reclassified into mark-to-market accounting. The $21 million loss included $12 million of unrealized mark-to-market losses largely associated with forward coal positions and $9 million in losses on settled transactions, or financial cost of energy. For further discussion of the Company s risk management activities, see Consolidated Results of Operations.

Other Operating Expenses

Other operating expenses decreased by $2 million for the year ended December 31, 2009, compared to 2008, associated with:

General and administrative expense Corporate allocations declined by $8 million in 2009 versus the same period in 2008. Franchise tax expense grew by $2 million due to credits recorded in 2008 related to prior years.

Operating and maintenance expense Labor costs increased by $2 million because of higher benefit costs. Major maintenance rose by $2 million due to more extensive outage work performed at the Big Cajun II plant in 2009 compared to the same period in 2008.

2008 compared to 2007

The following table provides selected financial information for the South Central region for the years ended December 31, 2008, and 2007:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 478	$ 404	18%
Capacity revenue	233	221	5
Risk management activities	10	10	
Contract amortization	23	23	
Other revenues	2		N/A
Total operating revenues	746	658	13
Operating Costs and Expenses			
Cost of energy	468	412	14
Depreciation and amortization	67	68	(1)
Other operating expenses	111	121	(8)
Operating Income	$ 100	$ 57	75
MWh sold (in thousands)	12,447	12,452	
MWh generated (in thousands)	11,148	10,930	2
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 71.25	$ 59.63	19
Cooling Degree Days, or CDDs[(a)]	1,618	1,963	(18)
CDD s 30-year rolling average	1,547	1,547	
Heating Degree Days, or HDDs[(a)]	3,672	3,236	13
HDD s 30-year rolling average	3,623	3,604	1%

(a) National Oceanic and Atmospheric Administration-Climate Prediction Center A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

Operating Income

Operating income increased by $43 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

Operating revenues increased by $88 million due to increases in energy revenue and capacity revenue.

Cost of energy increased by $56 million due to higher purchased energy, coal transportation costs, natural gas and transmission costs.

Operating Revenues

Operating revenues increased by $88 million for the year ended December 31, 2008, compared to 2007, due to:

Energy revenue increased by $74 million due to a $41 million increase in merchant energy revenues and a $33 million increase in margin on MWh sold from market purchases. A decline in contract sales of 577 thousand MWh allowed for increased sales into the merchant market at higher prices. Revenue from contract load was flat as higher fuel cost pass-through adjustments for the region s cooperative customers were offset by reductions in contract volume to other contract customers.

Capacity revenue increased by $12 million. Capacity payments from the region s cooperative customers increased by $10 million due to new peak loads set by the region s cooperative customers and increased transmission and environmental pass-through costs. Increased RPM capacity payments from the region s Rockford facilities in the PJM market contributed an additional

$8 million. These increases were offset by a reduction in contract volumes to other customers of $6 million.

Risk management activities gains of $10 million were recognized during 2008 compared to $10 million in gains recognized during the same period in 2007. Unrealized gains in 2008 of $26 million were offset by realized losses of $16 million. The $26 million unrealized gain was the net effect of a $45 million unrealized mark-to-market gain from trading activities in the region offset by the reversal of $19 million loss of previously recognized mark-to-market gains on trading activity. Unrealized gains were primarily driven by decreases in power and gas prices relative to the Company s forward positions.

Cost of Energy

Cost of energy increased by $56 million for the year ended December 31, 2008, compared to 2007, due to:

Purchased energy increased by $16 million reflecting a 21% increase in the average cost per MWh of purchased energy which reflects higher gas costs associated with the region s tolling agreements. This increase was offset by an 8% decrease in purchased MWh as increased plant availability and lower contract load requirements reduced the need to purchase power.

Coal costs increased by $16 million due to a $2 per ton increase in fuel transportation surcharges combined with a 1% increase in coal generation. These increases were offset by a $3 million decrease in allocated rail car lease fees.

Natural gas costs increased $14 million. The region s Bayou Cove and Big Cajun I peaker plants ran extensively to support transmission system stability after hurricane Gustav in September 2008.

Transmission costs increased by $9 million due to additional point-to-point transmission costs driven by an increase in merchant energy sales.

Other Operating Expenses

Other operating expenses decreased by $10 million for the year ended December 31, 2008, compared to 2007, due to:

General and administrative expense Franchise tax decreased by $5 million due to retroactive charges recorded in 2007. The Louisiana state franchise tax is assessed on the Company s total debt and equity that significantly increased following the acquisition of Texas Genco. This decrease was offset by $6 million in higher corporate allocations in 2008 compared to the same period in 2007.

Operating and maintenance expense Major maintenance decreased by $9 million due to more extensive spring outage work performed at the Big Cajun II plant in 2007 compared to the same period in 2008. Normal maintenance rose $2 million as a result of increased forced outages and higher contractor costs. Asset retirements decreased by $4 million reflecting disposals associated with the 2007 outage work at Big Cajun II.

West Region

2009 compared to 2008

The following table provides selected financial information for the West region for the years ended December 31, 2009, and 2008:

	Year Ended December 31,		
	2009	2008	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 34	$ 39	(13)%
Capacity revenue	122	125	(2)
Risk management activities	(8)		
Other revenues	2	7	(71)
Total operating revenues	150	171	(12)
Operating Costs and Expenses			
Cost of energy	29	35	(17)
Depreciation and amortization	8	8	
Other operating expenses	81	70	16
Operating Income	$ 32	$ 58	(45)
MWh sold (in thousands)	1,279	1,532	(17)
MWh generated (in thousands)	1,279	1,532	(17)
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 40.10	$ 82.20	(51)
Cooling Degree Days, or CDDs[(a)]	908	953	(5)
CDD s 30-year rolling average	704	704	
Heating Degree Days, or HDDs[(a)]	3,105	3,190	(3)%
HDD s 30-year rolling average	3,228	3,243	

(a) National Oceanic and Atmospheric Administration-Climate Prediction Center A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

Operating Income

Operating income decreased by $26 million for the year ended December 31, 2009, compared to the same period in 2008, due to decreases in capacity revenue, energy revenue, risk management activities and other revenues.

Operating Revenues

Operating revenues decreased by $21 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Capacity revenue decreased by $3 million due to the expiration of a two-year tolling agreement at the El Segundo facility in April 2008, which was replaced by resource adequacy and capacity contracts at lower prices.

Energy revenue decreased by $5 million primarily due to a 16% decrease in merchant prices in 2009 compared to 2008. This decrease was offset by a 5% increase in merchant generation in 2009 compared to 2008.

Other revenues decreased by $5 million due to lower emission allowance sales partially offset by an increase in ancillary services revenue.

Risk management activities realized losses of $8 million on settled transactions were recognized during the period. There was no risk management activity in 2008. For further discussion of the Company s risk management activities, see Consolidated Results of Operations.

Cost of Energy and Other Operating Expenses

Cost of energy and other operating expenses increased by $5 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Cost of energy decreased by $6 million due to a 29% decline in average natural gas prices per MMBtu. This decrease was partially offset by an 8% increase in natural gas consumption and a $3 million increase in fuel oil expense resulting from a write-down to market of fuel oil inventory no longer used in the production of energy.

Other operating expenses increased by $11 million due to higher maintenance expense associated with a major overhaul at El Segundo and higher maintenance at Long Beach.

2008 compared to 2007

The following table provides selected financial information for the West region for the years ended December 31, 2008, and 2007:

	Year Ended December 31, 2008	2007	Change%
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 39	$ 4	N/A
Capacity revenue	125	122	2%
Risk management activities			N/A
Other revenues	7	1	N/A
Total operating revenues	171	127	35
Operating Costs and Expenses			
Cost of energy	35	5	N/A
Depreciation and amortization	8	3	167
Other operating expenses	70	80	(13)
Operating Income	$ 58	$ 39	49
MWh sold (in thousands)	1,532	1,246	23
MWh generated (in thousands)	1,532	1,246	23
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 82.20	$ 66.46	24
Cooling Degree Days, or CDDs[(a)]	953	785	21
CDD s 30-year rolling average	704	704	
Heating Degree Days, or HDDs[(a)]	3,190	3,048	5%
HDD s 30-year rolling average	3,243	3,228	

(a) National Oceanic and Atmospheric Administration-Climate Prediction Center A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

Operating Income

Operating income increased by $19 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

Operating Revenues

Operating revenues increased by $44 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

Energy revenue increased by $35 million due to the 2008 dispatch of the El Segundo plant outside of the tolling agreement in 2008. In 2007, no such dispatch occurred.

Other revenues increased by $6 million due to higher allocations for trading of emission allowances in 2008.

Capacity revenue increased by $3 million primarily due to the tolling agreement at the Long Beach plant partially offset by the expiration of a two year tolling agreement at the El Segundo facility:

- *Long Beach* On August 1, 2007, NRG successfully completed the repowering of a 260 MW natural gas-fueled generating plant at its Long Beach generating facility. The plant contributed $15 million in incremental capacity revenues for the year ended December 31, 2008.

- *El Segundo* The expiration of the two year tolling agreement at the end of April resulted in a decrease of $11 million in capacity revenues for the year ended December 31, 2008.

Cost of Energy and Other Operating Expenses

Cost of energy and other operating expenses increased by $25 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

Cost of energy increased by $30 million due to the dispatch of the El Segundo plant outside of the tolling agreement in 2008. In 2007, no such dispatch occurred.

Depreciation and amortization increased by $5 million, reflecting depreciation associated with the repowered plant at the Long Beach generating facility.

Other operating expenses decreased by $10 million as a result of a $5 million reduction in *Repowering*NRG expenses due to the capitalization of cost for the El Segundo Energy Center project in 2008. In addition there was a $3 million reduction in lease expenses in 2008 and the recognition of a $2 million environmental liability for the El Segundo plant in 2007.

Liquidity and Capital Resources

Liquidity Position

As of December 31, 2009, and 2008, NRG s liquidity, excluding collateral received, was approximately $3.8 billion and $3.4 billion, respectively, comprised of the following:

	As of December 31, 2009	2008
	(In millions)	
Cash and cash equivalents	$ 2,304	$ 1,494
Funds deposited by counterparties	177	754
Restricted cash	2	16
Total cash	2,483	2,264
Synthetic Letter of Credit Facility availability	583	860
Revolving Credit Facility availability	905	1,000
Total liquidity	3,971	4,124
Less: Funds deposited as collateral by hedge counterparties	(177)	(760)
Total liquidity, excluding collateral received	$ 3,794	$ 3,364

For the year ended December 31, 2009, total liquidity, excluding collateral received, increased by $430 million due to a higher cash balance of $810 million, partially offset by decreased availability of the Synthetic Letter of Credit Facility and the Revolving Credit Facility of $277 million and $95 million, respectively. Changes in cash balances are further discussed hereinafter under *Cash Flow Discussion*. Cash and cash equivalents and funds deposited by counterparties at December 31, 2009, are predominantly held in money market funds invested in treasury securities, treasury repurchase agreements or government agency debt.

The line item Funds deposited by counterparties represents the amounts that are held by NRG as a result of collateral posting obligations from the Company s counterparties due to positions in the Company s hedging program. These amounts are segregated into separate accounts that are not contractually restricted but, based on the Company s intention, are not available for the payment of NRG s general corporate obligations. Depending on market fluctuation and the settlement of the underlying contracts, the Company will refund this collateral to the counterparties pursuant to the terms and conditions of the underlying trades. Since collateral requirements fluctuate daily and the Company cannot predict if any collateral will be held for more than twelve months, the funds deposited by counterparties are classified as a current asset on the Company s balance sheet, with an offsetting liability for this cash collateral received within current liabilities. The decrease in these amounts from December 31, 2008, was due to cash collateral moved from NRG to Merrill Lynch in connection with novations under the CSRA (see Item 14 Note 3, *Business Acquisitions*, to the Consolidated Financial Statements), offset by a increase of in-the-money positions as a result of decreasing forward prices.

Management believes that the Company s liquidity position and cash flows from operations will be adequate to finance operating and maintenance capital expenditures, to fund dividends to NRG s preferred shareholders, and other liquidity commitments. Management continues to regularly monitor the Company s ability to finance the needs of its operating, financing and investing activity in a manner consistent with its intention to maintain a net debt to capital ratio in the range of 45-60%.

Credit Ratings

Credit rating agencies rate a firm s public debt securities. These ratings are utilized by the debt markets in evaluating a firm s credit risk. Ratings influence the price paid to issue new debt securities by indicating to the market the Company s ability to pay principal, interest and preferred dividends. Rating agencies evaluate a firm s industry, cash flow, leverage, liquidity, and hedge profile, among other factors, in their credit analysis of a firm s credit risk.

The following table summarizes the credit ratings for NRG Energy, Inc., its Term Loan Facility and its Senior Notes as of December 31, 2009:

	S&P	**Moody s**	**Fitch**
NRG Energy, Inc.	BB−	Ba3	B
8.5% Senior Notes due 2019	BB−	B1	B+
7.375% Senior Notes, due 2016, 2017	BB−	B1	B+
7.25% Senior Notes due 2014	BB−	B1	B+
Term Loan Facility	BB+	Baa3	BB

SOURCES OF FUNDS

The principal sources of liquidity for NRG s future operating and capital expenditures are expected to be derived from new and existing financing arrangements, asset sales, existing cash on hand and cash flows from operations.

Financing Arrangements

Senior Credit Facility

As of December 31, 2009, NRG has a Senior Credit Facility which is comprised of a senior first priority secured term loan, or the Term Loan Facility, a $1.0 billion senior first priority secured revolving credit facility, or the Revolving Credit Facility, and a $1.3 billion senior first priority secured synthetic letter of credit facility, or the

Synthetic Letter of Credit Facility. The Senior Credit Facility was last amended on June 8, 2007. As of December 31, 2009, NRG had issued $717 million of letters of credit under the Synthetic Letter of Credit Facility, leaving $583 million available for future issuances. Under the Revolving Credit Facility as of December 31, 2009, NRG had issued letters of credit of $95 million, of which $59 million supports the tax exempt bonds issued by Dunkirk Power LLC as described in Item 14 Note 12, *Debt and Capital Leases,* to the Consolidated Financial Statements.

2019 Senior Notes

On June 5, 2009, NRG completed the issuance of $700 million aggregate principal amount of 8.5% Senior Notes due 2019, or 2019 Senior Notes, as described in Item 14 Note 12, *Debt and Capital Leases,* to the Consolidated Financial Statements. The Company used a portion of the net proceeds of $678 million to facilitate the early termination on October 5, 2009 of NRG s obligations pursuant to the CSRA Amendment. Net proceeds in excess of this amount are available for general corporate purposes. See further discussion of the CSRA Amendment in Item 14 Note 3, *Business Acquisitions,* to the Consolidated Financial Statements.

Merrill Lynch Credit Sleeve Facility

See discussion in Item 14 Note 3, *Business Acquisitions,* to the Consolidated Financial Statements, regarding the CSRA entered into to support the retail business as a result of the acquisition of Reliant Energy on May 1, 2009. Effective October 5, 2009, the Company executed the CSRA Amendment. In connection with this amendment, the Company posted $366 million of cash collateral to Merrill Lynch and other counterparties, returned $53 million of counterparty collateral, issued $206 million of letters of credit, and received $45 million of counterparty collateral. In addition, Merrill Lynch returned $250 million of previously posted cash collateral, and released liens on $322 million of unrestricted cash held by Reliant Energy. Upon execution of the CSRA Amendment, the Company was required to post collateral for any net liability derivatives, and other static margin associated with supply for Reliant Energy.

TANE Facility

On February 24, 2009, NINA executed an EPC agreement with TANE, which specifies the terms under which STP Units 3 and 4 will be constructed. Concurrent with the execution of the EPC agreement, NINA and TANE entered into the TANE Facility wherein TANE has committed up to $500 million to finance purchases of long-lead materials and equipment for the construction of STP Units 3 and 4. The TANE Facility matures on February 24, 2012, subject to two renewal periods, and provides for customary events of default, which include, among others: nonpayment of principal or interest; default under other indebtedness; the rendering of judgments; and certain events of bankruptcy or insolvency. Outstanding borrowings will accrue interest at LIBOR plus 3%, subject to a ratings grid, and are secured by substantially all of the assets of and membership interests in NINA and its subsidiaries. As of December 31, 2009, no amounts had been borrowed under the TANE Facility.

Dunkirk Power LLC Tax-Exempt Bonds

On April 15, 2009, NRG executed a $59 million tax-exempt bond financing through its wholly-owned subsidiary, Dunkirk Power LLC. The bonds were issued by the County of Chautauqua Industrial Development Agency and will be used for construction of emission control equipment on the Dunkirk Generating Station in Dunkirk, NY. The bonds initially bear weekly interest based on the Securities Industry and Financial Markets Association, or SIFMA, rate, have a maturity date of April 1, 2042, and are enhanced by a letter of credit under the Company s Revolving Credit Facility covering amounts drawn on the facility. The proceeds received through December 31, 2009, were $52 million with the remaining balance being released over time as construction costs are paid. On February 1, 2010, the Company fixed the rate on the bonds at 5.875%. Interest will be payable semiannually. In addition, the $59 million letter of credit issued by NRG in support of the bonds was cancelled and replaced with a parent guarantee. These bonds are part of the Company s first lien debt.

GenConn Energy LLC related financings

In April 2009, NRG Connecticut Peaking LLC., a wholly-owned subsidiary of NRG, executed an equity bridge loan facility, or EBL, in the amount of $121.5 million from a syndicate of banks. The purpose of the EBL is to fund the Company s proportionate share of the project construction costs required to be contributed into GenConn Energy LLC, or GenConn, a 50% equity method investment of the Company. The EBL, which is fully collateralized with a letter of credit issued under the Company s Synthetic Letter of Credit Facility covering amounts drawn on the facility, will bear interest at a rate of LIBOR plus 2% on drawn amounts. The EBL will mature on the earlier of the commercial operations date of the Middletown project or July 26, 2011. The EBL also requires mandatory prepayment of the portion of the loan utilized to pay costs of the Devon project, of approximately $54 million, on the earlier of Devon s commercial operations date or January 27, 2011. The proceeds of the EBL received through December 31, 2009, were $108 million and the remaining amounts will be drawn as necessary to fund construction costs.

In April 2009, GenConn secured financing for 50% of the Devon and Middletown project construction costs through a 7-year term loan facility, and also entered into a 5-year revolving working capital loan and letter of credit facility, which collectively with the term loan is referred to as the GenConn Facility. The aggregate credit amount secured under the GenConn Facility, which is non-recourse to NRG, is $291 million, including $48 million for the revolving facility. In August 2009, GenConn began to draw under the GenConn Facility to cover costs related to the Devon project and as of December 31, 2009, has drawn $48 million.

First and Second Lien Structure

NRG has granted first and second liens to certain counterparties on substantially all of the Company s assets. NRG uses the first or second lien structure to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under out-of-the-money hedge agreements for forward sales of power or MWh equivalents. To the extent that the underlying hedge positions for a counterparty are in-the-money to NRG, the counterparty would have no claim under the lien program. The lien program limits the volume that can be hedged, not the value of underlying out-of-the-money positions. The first lien program does not require NRG to post collateral above any threshold amount of exposure. Within the first and second lien structure, the Company can hedge up to 80% of its baseload capacity and 10% of its non-baseload assets with these counterparties for the first 60 months and then declining thereafter. Net exposure to a counterparty on all trades must be positively correlated to the price of the relevant commodity for the first lien to be available to that counterparty. The first and second lien structure is not subject to unwind or termination upon a ratings downgrade of a counterparty and has no stated maturity date.

NRG s lien counterparties may have a claim on the Company s assets to the extent market prices exceed the hedged price. As of December 31, 2009 and February 9, 2010, all hedges under the first and second lien were in-the-money on a counterparty aggregate basis.

The following table summarizes the amount of MWs hedged against the Company s baseload assets and as a percentage relative to the Company s forecasted baseload capacity under the first and second lien structure as of February 9, 2010:

Equivalent Net Sales Secured by First and Second Lien Structure[(a)]	**2010**	**2011**	**2012**	**2013**
In MW[(b)]	3,358	2,931	1,520	732
As a percentage of total forecasted baseload capacity[(c)]	49%	43%	22%	11%

(a) Equivalent Net Sales include natural gas swaps converted using a weighted average heat rate by region.
(b) 2010 MW value consists of March through December positions only.
(c) Forecasted baseload capacity under the first and second lien structure represents 80% of the total Company s baseload assets.

Asset Sales

MIBRAG On June 10, 2009, NRG completed the sale of its 50% ownership interest in Mibrag B.V. to a consortium of Severoćeské doly Chomutov, a member of the CEZ Group, and J&T Group. Mibrag B.V. s principal

115

holding was MIBRAG, which was jointly owned by NRG and URS Corporation. As part of the transaction, URS Corporation also entered into an agreement to sell its 50% stake in MIBRAG.

For its share, NRG received EUR 203 million ($284 million at an exchange rate of 1.40 U.S.$/EUR), net of transaction costs. During the year ended December 31, 2009, NRG recognized a pre-tax gain of $128 million. Prior to completion of the sale, NRG continued to record its share of MIBRAG s operations to Equity in earnings of unconsolidated affiliates.

In connection with the transaction, NRG entered into a foreign currency forward contract to hedge the impact of exchange rate fluctuations on the sale proceeds. The foreign currency forward contract had a fixed exchange rate of 1.277 and required NRG to deliver EUR 200 million in exchange for $255 million on June 15, 2009. For the year ended December 31, 2009, NRG recorded an exchange loss of $24 million on the contract within Other income/(loss), net.

ITISA On April 28, 2008, NRG completed the sale of its 100% interest in Tosli Acquisition B.V., or Tosli, which held all NRG s interest in ITISA, to Brookfield Renewable Power Inc. (previously Brookfield Power Inc.), a wholly-owned subsidiary of Brookfield Asset Management Inc. In addition, the purchase price adjustment contingency under the sale agreement was resolved on August 7, 2008. In connection with the sale, NRG received $300 million of cash proceeds from Brookfield, and removed $163 million of assets, including $59 million of cash, $122 million of liabilities, including $63 million of debt, and $15 million in foreign currency translation adjustment from its 2008 consolidated balance sheet. As discussed in Item 14 Note 4, *Discontinued Operations and Dispositions*, to the Consolidated Financial Statements, the activities of Tosli and ITISA have been classified as discontinued operations.

USES OF FUNDS

The Company s requirements for liquidity and capital resources, other than for operating its facilities, can generally be categorized by the following: (i) commercial operations activities; (ii) debt service obligations; (iii) capital expenditures including *Repowering*NRG and environmental; and (iv) corporate financial transactions including return of capital to shareholders.

Commercial Operations

NRG s commercial operations activities require a significant amount of liquidity and capital resources. These liquidity requirements are primarily driven by: (i) margin and collateral posted with counterparties; (ii) initial collateral required to establish trading relationships; (iii) timing of disbursements and receipts (i.e., buying fuel before receiving energy revenues); and (iv) initial collateral for large structured transactions. As of December 31, 2009, commercial operations had total cash collateral outstanding of $359 million, and $508 million outstanding in letters of credit to third parties primarily to support its economic hedging activities for both wholesale and retail transactions. As of December 31, 2009, total collateral held from counterparties was $177 million, and $24 million of letters of credit.

Upon execution of the CSRA Amendment, effective October 5, 2009, the Company was required to post collateral for any net liability derivatives, and other static margin associated with supply for Reliant Energy that was transferred to NRG. As of January 29, 2010, all wholesale energy supply contracts relating to retail supply hedging were transferred to the Company, so that Merrill Lynch was no longer providing any credit support for wholesale energy supply contracts relating to retail supply hedging.

Future liquidity requirements may change based on the Company s hedging activities and structures, fuel purchases, and future market conditions, including forward prices for energy and fuel and market volatility. In addition, liquidity requirements are dependent on NRG s credit ratings and general perception of its creditworthiness.

Debt Service Obligations

NRG must annually offer a portion of its excess cash flow (as defined in the Senior Credit Facility) to its first lien lenders under the Term Loan Facility. The percentage of excess cash flow offered to these lenders is dependent upon the Company s consolidated leverage ratio (as defined in the Senior Credit Facility) at the end of the preceding year. The 2010 mandatory offer related to 2009 is expected to be $430 million, against which the Company made a prepayment of $200 million in December 2009. Based on current credit market conditions, the Company expects that its lenders will accept in full the 2010 mandatory offer related to 2009, and, as such, the Company has reclassified approximately $230 million of Term Loan Facility maturity from a non-current to a current liability as of December 31, 2009.

On October 9, 2009, NRG commenced the process of unwinding the CSF II Debt, making a $181 million capital contribution to a CSF II cash account, effectively restricting the cash for the benefit of Credit Suisse Group, or CS. On October 13, 2009, CS began the process of unwinding their hedges in connection with the CSF II structure, which they completed by November 24, 2009. Once complete, CS returned 5,400,000 shares of NRG common stock borrowed under the Share Lending Agreements, and released 9,528,930 common shares held as collateral for the CSF II Debt, and the Company remitted payment to CS of the $181 million for outstanding principal and interest. The CSF II Debt contained an embedded derivative feature, or CFS II CAGR, which required NRG to pay CS at maturity, either in cash or stock at NRG s option, the excess of NRG s then current stock price over a Threshold Price of $40.80 per share. On November 24, 2009, the CSF II CAGR expired with no payment due.

Principal payments on debt and capital leases as of December 31, 2009, are due in the following periods:

Subsidiary/Description	2010	2011	2012	2013	2014	Thereafter	Total
				(In millions)			
Debt:							
8.5% Notes due 2019	$	$	$	$	$	$ 700	$ 700
7.375% Notes due 2017						1,100	1,100
7.375% Notes due 2016						2,400	2,400
7.25% Notes due 2014					1,200		1,200
Term Loan Facility, due 2013	261	32	32	1,888			2,213
CSF I notes and preferred interests, due June 2010	190						190
NRG Energy Center Minneapolis LLC, due 2013 and 2017	11	12	13	10	6	21	73
Dunkirk Power LLC tax-exempt bonds, due April 2042						52	52
NRG Connecticut Peaking LLC, equity bridge loan facility	54	54					108
Nuclear Innovation North America LLC, due 2010	20						20
NRG Repowering Holdings LLC, due 2011		19					19
NRG Peaker Finance Co. LLC, due June 2019	20	21	22	23	29	136	251
Subtotal Debt, Bonds and Notes	556	138	67	1,921	1,235	4,409	8,326
Capital Lease:							
Saale Energie GmbH, Schkopau	22	10	8	8	7	68	123
Total Payments and Capital Leases	$ 578	$ 148	$ 75	$ 1,929	$ 1,242	$ 4,477	$ 8,449

In addition to the debt and capital leases shown in the preceding table, NRG had issued $717 million of letters of credit under the Company s $1.3 billion Synthetic Letter of Credit Facility and $95 million of letters of credit under the Company s Revolving Credit Facility as of December 31, 2009. The Company s Revolving Credit Facility matures on February 2, 2011, and the Synthetic Letter of Credit Facility matures on February 1, 2013.

Capital Expenditures

For the year ended December 31, 2009, the Company s capital expenditures, including accruals, were approximately $783 million. The following table summarizes the Company s capital expenditures for the year ended December 31, 2009 and the estimated capital expenditure and repowering investments forecast for 2010.

	Maintenance	Environmental	Repowering	Total
		(In millions)		
Northeast	$ 30	$ 172	$ 5	$ 207
Texas	160		29	189
South Central	9			9
West	4		4	8
Reliant Energy	7			7
Wind			120	120
Nuclear Development			197	197
Other	46			46
Total	$ 256	$ 172	$ 355	$ 783
Estimated capital expenditures for 2010	$ 241	$ 233	$ 707	$ 1,181

*Repowering*NRG *capital expenditures and investments* *Repowering*NRG project capital expenditures consisted of approximately $197 million related to the development of STP Units 3 and 4 in Texas, $120 million related to the Company s Langford wind farm project which became commercially operational in December 2009 and $29 million for the construction of Cedar Bayou Unit 4 in Texas.

The Company s repowering capital expenditures for 2010 are expected to be approximately $707 million. Of this amount, $684 million is estimated for STP Units 3 and 4 without giving effect to any partner contributions or potential equity sell down.

Major maintenance and environmental capital expenditures The Company s maintenance capital expenditures were $256 million, of which $160 million was related to the Texas region s assets including approximately $61 million in nuclear fuel expenditures related to STP Units 1 and 2. The Company s environmental capital expenditures were $172 million consisting of $130 million at the Huntley and Dunkirk plants due to the baghouse projects and $31 million at the Indian River plant due to a project to install selective catalytic reduction systems, scrubbers and fabric filters on Units 3 and 4. On February 3, 2010, NRG and DNREC announced a proposed plan, subject to definitive documentation, that would shut down Unit 3 by December 31, 2013 and relieve NRG of the requirement to install this back end control equipment on this unit. Unit 4 is not affected by this plan and construction on similar equipment continues with an expected in service date of year end 2011.

NRG anticipates funding these maintenance capital projects primarily with funds generated from operating activities. In addition, on April 15, 2009, the Company executed a $59 million tax-exempt bond financing through its wholly-owned subsidiary, Dunkirk Power LLC, with the bonds issued by the County of Chautauqua Industrial Development Agency. These funds are expected to fund environmental capital expenditures at the Dunkirk facility.

Loans to affiliates The Company had funded approximately $48 million in interest bearing loans to GenConn Energy LLC, a 50/50 joint venture vehicle of NRG and the United Illuminating Company as part of the Devon and Middletown plant repowering projects prior to the closing of the EBL and GenConn Facility. During 2009, these loans were repaid with proceeds from the EBL financing. Subsequent to the financing, the equity portion of construction costs for GenConn is funded through the EBLs of NRG Connecticut Peaking and United Illuminating. These funds are made available to GenConn through convertible interest bearing promissory notes that convert to equity upon repayment of the EBL loans by NRG Connecticut Peaking and United Illuminating. As of December 31, 2009, there was $108 million outstanding under the loan from NRG Connecticut Peaking.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures to be incurred from 2010 through 2014 to meet NRG s environmental commitments will be approximately $0.9 billion. These capital expenditures, in general, are related to installation of particulate, SO_2, NO_x, and mercury controls to comply with federal and state air quality rules and consent orders, as well as installation of Best Technology Available under the Phase II 316(b) rule. NRG continues to explore cost effective alternatives that can achieve desired results. While this estimate reflects schedules and controls to meet anticipated reduction requirements, the full impact on the scope and timing of environmental retrofits cannot be determined until issuance of final rules by the U.S. EPA.

The following table summarizes the estimated environmental capital expenditures for the referenced periods by region:

	Texas	Northeast	South Central	Total
		(In millions)		
2010	$	$ 230	$ 3	$ 233
2011		179	52	231
2012	6	45	108	159
2013	39	9	109	157
2014	50	4	$ 68	122
Total	$ 95	$ 467	$ 340	$ 902

This estimate reflects the recent announcement to retrofit only Unit 4 at the Indian River Generating Station and shifts in the timing of other projects to reflect anticipated issuance dates for revised regulations.

NRG s current contracts with the Company s rural electrical customers in the South Central region allow for recovery of a significant portion of the regions capital costs, along with a capital return incurred by complying with new laws, including interest over the asset life of the required expenditures. Actual recoveries will depend, among other things, on the duration of the contracts.

Capital Allocation

2009 Capital Allocation Plan In addition to the aforementioned planned investments in maintenance and environmental capital expenditures and *Repowering*NRG in 2009, and the 2009 repayment of Term Loan Facility debt to the first lien lenders, the Company s Capital Allocation Plan included the completion of the 2008 Capital Allocation Plan with the purchase of $30 million of common stock as well as the purchase of an additional $300 million in common stock under the previously announced 2009 Capital Allocation Plan. In July 2009, as part of the Company s 2009 Capital Allocation Program, the Board of Directors approved an increase to the Company s previously authorized common share repurchases under its capital allocation plan from the existing $330 million to $500 million. The Company s repurchases during the year ended December 31, 2009, were $500 million.

2010 Capital Allocation Plan On February 23, 2010, the Company announced its 2010 Capital Allocation Plan to purchase $180 million in common stock. The Company s share repurchases are subject to market prices, financial restrictions under the Company s debt facilities, and as permitted by securities laws. As part of the 2010 plan, the

Company will invest approximately $474 million in maintenance and environmental capital expenditures in existing assets and $707 million in projects under *Repowering*NRG that are currently under construction or for which there exists current obligations. Finally, in addition to scheduled debt amortization payment, in the first quarter 2010 the Company will offer its first lien lenders $430 million of its 2009 excess cash flow (as defined in the Senior Credit Facility) of which the Company made a prepayment of $200 million in December 2009.

Preferred Stock Dividend Payments

For the year ended December 31, 2009, NRG paid $6 million, $17 million and $10 million in dividend payments to holders of the Company s 5.75%, 4% and 3.625% Preferred Stock. On March 16, 2009, the outstanding shares of the 5.75% Preferred Stock converted into common stock and, as a result, there will be no further dividends paid with respect to this series of preferred stock. During 2009, a total of 265,870 shares of the 4% Preferred Stock were converted into common stock and 73 shares were redeemed for cash.

Benefit Plans Obligations

As of December 31, 2009, NRG contributed $27 million towards its three defined benefit pension plans to meet the Company s 2009 benefit obligation. Based on the Company s December 31, 2009 measurement of its benefit obligation for its three defined benefit pension plans, the Company is expected to contribute another $18 million to these plans during 2010, $5 million of which also relates to the Company s 2009 benefit obligation.

Reliant Energy Customer Deposits

Revisions in the PUCT rules will require that NRG keep a segregated account, or that the Company post a fully collateralized letter of credit on or before May 21, 2010 to cover outstanding customer deposits and residential advance payments. The Company s current plan is to file for an amendment to its Retail Energy Provider recertification applications during the first quarter 2010 and post a letter of credit to satisfy the rule changes. The amount of deposits subject to segregation or collateralization at December 31, 2009, was $54 million.

Cash Flow Discussion

The following table reflects the changes in cash flows for the comparative years; all cash flow categories include the cash flows from both continuing operations and discontinued operations:

	Year ended December 31,		
	2009	**2008**	**Change**
		(In millions)	
Net cash provided by operating activities	$ 2,106	$ 1,479	$ 627
Net cash used by investing activities	(954)	(672)	(282)
Net cash used by financing activities	(343)	(487)	144

Net Cash Provided By Operating Activities

For the year ended December 31, 2009, net cash provided by operating activities increased by $627 million compared to the same period in 2008, due to:

> *Cash generated by Reliant Energy* Reliant Energy contributed approximately $855 million to the Company s consolidated cash flow from operations in 2009, primarily reflecting $966 million in pre-tax income since the May 1, 2009, acquisition date, adjusted for the non-cash effects of depreciation and amortization and changes in derivatives.
>
> *Lower cash flows from Wholesale Power Generation* The Company s cash flow from operation excluding Reliant Energy was lower by approximately $228 million in 2009 compared to 2008, as decreases in generation and power prices impacted results from operations. In addition, $16 million more cash was used for working capital in 2009 compared to 2008, as higher coal inventory balances were partially offset by $72 million in lower pension contributions.

Net Cash Used By Investing Activities

For the year ended December 31, 2009, net cash used in investing activities increased by $282 million compared to the same period in 2008, due to:

Acquisition of businesses During 2009, the Company paid $427 million, net of cash acquired of $6 million, to acquire three businesses.

Proceeds from sale of equity method investment and discontinued operations Net proceeds from investing activities increased by $43 million in 2009 as compared to 2008 due to the sale of MIBRAG in June 2009 for net proceeds of $284 million compared to the sale of ITISA for proceeds, net of divested cash, of $241 million in April 2008.

Capital expenditures and loans to affiliates NRG s capital expenditures decreased by $165 million due to decreased spending on *Repowering*NRG.

Trading of emission allowances Net purchases and sales of emission allowances resulted in a decrease in cash of $105 million for 2009 as compared to 2008.

Net Cash Used By Financing Activities

For the year ended December 31, 2009, net cash used by financing activities decreased by $144 million compared to the same period in 2008, due to:

Issuance of debt During 2009, the Company received $688 million in gross proceeds from the 2019 Senior Notes, $108 million in NRG Connecticut Peaking financing, $52 million from the Dunkirk bonds and $19 million from other borrowings. During 2008, the Company received $20 million in proceeds from borrowings which resulted in a net cash increase of $872 million.

Term Loan Facility debt payment In 2009, the Company paid down $429 million of its Term Loan Facility, including the payment of excess cash flow, as discussed above under *Debt Service Obligations*. The Company paid down $174 million of its Term Loan Facility during 2008 which resulted in a net cash decrease of $255 million.

Other debt payments In November 2009, the Company paid $181 million to CS for the benefit of CSF II to unwind the Company s CSF II notes and preferred interests.

Share repurchase During 2009, the Company repurchased common stock of $500 million as compared to $185 million in 2008, which resulted in a net cash decrease of $315 million.

NOLs, Deferred Tax Assets and Uncertain Tax Position Implications, under ASC-740, Income Taxes, or ASC 740

As of December 31, 2009, the Company had generated total domestic pre-tax book income of $1.5 billion and foreign continuing pre-tax book income of $161 million. The Company has net operating losses for tax return purposes available to offset taxable income in the current period. The tax return net operating losses have been classified as capital loss carryforwards for financial statement purposes and a full valuation allowance has been established. As of December 31, 2009, these capital losses have expired for financial statement purposes. In addition, NRG has cumulative foreign NOL carryforwards of $280 million, of which $82 million will expire starting in 2011 through 2017 and of which $198 million do not have an expiration date.

In addition to these amounts, the Company has $643 million of tax effected unrecognized tax benefits which relate primarily to net operating losses for tax return purposes but have been classified as capital loss carryforwards for financial statements purposes and for which a full valuation allowance has been established. As a result of the Company s tax position, and based on current forecasts, we anticipate income tax payments of up to $75 million in 2010.

However, as the position remains uncertain for the $643 million of tax effected unrecognized tax benefits, the Company has recorded a non-current tax liability of $347 million and may accrue the remaining balance as an increase to non-current liabilities until final resolution with the related taxing authority. The $347 million non-current tax liability for unrecognized tax benefits is primarily due to taxable earnings for the period for which there are no NOLs available to offset for financial statement purposes.

The Company is under examination by the Internal Revenue Service for years 2004 through 2006. It is possible that the IRS examination may conclude during 2010 but because of a possible extension, an estimate of the range of reasonably possible changes in unrecognized tax benefits cannot be made.

Off-Balance Sheet Arrangements

Obligations under Certain Guarantee Contracts

NRG and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See also Item 14 Note 26, *Guarantees,* to the Consolidated Financial Statements for additional discussion.

Retained or Contingent Interests

NRG does not have any material retained or contingent interests in assets transferred to an unconsolidated entity.

Derivative Instrument Obligations

The Company s 3.625% Preferred Stock includes a feature which is considered an embedded derivative per ASC 815. Although it is considered an embedded derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to ASC 815. As of December 31, 2009, based on the Company s stock price, the embedded derivative was out-of-the-money and had no redemption value. See also Item 14 Note 15, *Capital Structure,* to the Consolidated Financial Statements for additional discussion.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable interest in Equity investments As of December 31, 2009, NRG has several investments with an ownership interest percentage of 50% or less in energy and energy-related entities that are accounted for under the equity method of accounting. One of these investments, GenConn Energy LLC, is a variable interest entity for which NRG is not the primary beneficiary.

NRG s pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $93 million as of December 31, 2009. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG. See also Item 14 Note 16, *Investments Accounted for by the Equity Method,* to the Consolidated Financial Statements for additional discussion.

Letter of Credit Facilities The Company s $1.3 billion Synthetic Letter of Credit Facility is unfunded by NRG and is secured by a $1.3 billion cash deposit at Deutsche Bank AG, New York Branch that was funded using proceeds from the Term Loan Facility investors who participated in the facility syndication. Under the Synthetic Letter of Credit Facility, NRG is allowed to issue letters of credit for general corporate purposes including posting collateral to support the Company s commercial operations activities.

Contractual Obligations and Commercial Commitments

NRG has a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to the Company s capital expenditure programs. The following tables summarize NRG s contractual obligations and contingent obligations for guarantee. See also Item 14 Note 12, *Debt and Capital Leases*, Note 22, *Commitments and Contingencies*, and Note 26, *Guarantees* , to the Consolidated Financial Statements for additional discussion.

	By Remaining Maturity at December 31, 2009					
Contractual Cash Obligations	**Under 1 Year**	**1-3 Years**	**3-5 Years**	**Over 5 Years**	**Total[b]**	**2008 Total**
	(In millions)					
Long-term debt (including estimated interest)	$ 1,074	$ 1,195	$ 3,950	$ 5,171	$ 11,390	$ 11,142
Capital lease obligations (including estimated interest)	28	30	27	107	192	321
Operating leases	100	120	98	264	582	421
Fuel purchase and transportation obligations[a]	1,011	405	140	600	2,156	2,378
Purchased power commitments[c]	55	56	10		121	
Pension minimum funding requirement[d]	21	55	56	31	163	194
Other postretirement benefits minimum funding requirement[e]	4	6	8	5	23	19
Other liabilities[f]	53	75	38	230	396	98
Total	$ 2,346	$ 1,942	$ 4,327	$ 6,408	$ 15,023	$ 14,573

(a) Includes only those coal transportation and lignite commitments for 2010 as no other nominations were made as of December 31, 2009. Natural gas nomination is through February 2011.
(b) Excludes $347 million non-current payable relating to NRG s uncertain tax benefits under ASC-740 as the period of payment cannot be reasonably estimated. Also excludes $415 million of asset retirement obligations which are discussed in Item 14 Note 13, *Asset Retirement Obligations,* to the Consolidated Financial Statements.
(c) Includes commitments with both fixed and variable components.
(d) These amounts represent the Company s estimated minimum pension contributions required under the Pension Protection Act of 2006. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contribution for years after 2015 is currently not available.
(e) These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contribution for years after 2015 are currently not available.
(f) Includes water right agreements, service and maintenance agreements, stadium naming rights and other contractual obligations.

	By Remaining Maturity at December 31, 2009				
	Under			**Over**	**2008**

uarantees, Indemnifications and Other Contingent Obligations	1 Year	1-3 Years	3-5 Years	5 Years	Total	Total
				(In millions)		
ynthetic letters of credit	$ 531	$ 186	$	$	$ 717	$ 440
nfunded standby letters of credit and surety bonds	61	36			97	5
sset sales guarantee obligations		118		8	126	129
ommercial sales arrangements	104	44	103	965	1,216	1,005
ther guarantees				117	117	80
otal	$ 696	$ 384	$ 103	$ 1,090	$ 2,273	$ 1,659

Fair Value of Derivative Instruments

NRG may enter into long-term power sales contracts, fuel purchase contracts and other energy-related financial instruments to mitigate variability in earnings due to fluctuations in spot market prices and to hedge fuel requirements at generation facilities. In addition, in order to mitigate interest rate risk associated with the issuance of the Company s variable rate and fixed rate debt, NRG enters into interest rate swap agreements.

NRG s trading activities are subject to limits in accordance with the Company s Risk Management Policy. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings.

The tables below disclose the activities that include both exchange and non-exchange traded contracts accounted for at fair value in accordance with ASC 820, *Fair Value Measurements and Disclosures*, or ASC 820. Specifically, these tables disaggregate realized and unrealized changes in fair value; disaggregate estimated fair values at December 31, 2009, based on their level within the fair value hierarchy defined in ASC 820; and indicate the maturities of contracts at December 31, 2009. Also, in connection with the Company s acquisition of Reliant Energy, NRG acquired retail load and supply contracts. The tables below also includes the fair value of these contracts receiving mark-to-market accounting treatment as of May 1, 2009.

Derivative Activity Gains/(Losses)	**(In millions)**
Fair value of contracts as of December 31, 2008	$ 996
Contracts realized or otherwise settled during the period	(432)
Contracts acquired in conjunction with Reliant Energy	(1,054)
Changes in fair value	949
Fair value of contracts as of December 31, 2009	$ 459

	Fair Value of Contracts as of December 31, 2009				
Fair value hierarchy Gains/(Losses)	**Maturity Less Than 1 Year**	**Maturity 1-3 Years**	**Maturity 4-5 Years**	**Maturity in Excess 4-5 Years**	**Total Fair Value**
			(In millions)		
Level 1	$ 25	$ (13)	$ (24)	$	$ (12)
Level 2	159	234	118	(27)	484
Level 3	(21)	7	1		(13)
Total	$ 163	$ 228	$ 95	$ (27)	$ 459

A small portion of NRG s contracts are exchange-traded contracts with readily available quoted market prices. The majority of NRG s contracts are non-exchange-traded contracts valued using prices provided by external sources, primarily price quotations available through brokers or over-the-counter and on-line exchanges. For the majority of NRG markets, the Company receives quotes from multiple sources. To the extent that NRG receives multiple quotes, the Company s prices reflect the average of the bid-ask mid-point prices obtained from all sources that NRG believes provide the most liquid market for the commodity. If the Company receives one quote then the mid point of the bid-ask spread for that quote is used. The terms for which such price information is available vary by commodity, region and product. A significant portion of the fair value of the Company s derivative portfolio is based on price quotes from brokers in active markets who regularly facilitate the Company s transactions and the Company believes such price quotes are executable. The Company does not use third party sources that derive price based on proprietary models or market surveys. The remainder of the assets and liabilities represent contracts for which external sources or observable market quotes are not available. These contracts are valued based on various valuation techniques including but not limited to internal models based on a fundamental analysis of the market and extrapolation of observable market data with similar characteristics. Contracts valued with prices provided by models and other valuation techniques make up 3% of the total fair value of all derivative contracts. The fair value of each contract is discounted using a risk free interest rate. In addition, the Company applies a credit reserve to reflect credit risk which is calculated based on published default probabilities. To the extent that NRG s net exposure after cash collateral paid/received under a specific master agreement is an asset, the Company calculates credit reserve applying the counterparty s default swap rate. If the net exposure after cash collateral paid/received under a specific master agreement is a liability, the Company calculates credit reserve applying NRG s default swap rate. The credit reserve is added to the discounted fair value to reflect the exit price that a market participant would be willing to receive to assume NRG s liabilities or that a market participant would be willing to pay for NRG s assets. As of December 31, 2009, the credit reserve resulted in a $1 million increase in fair value which is composed of a $1 million loss in OCI and a $2 million gain in derivative revenue and cost of operations.

The fair values in each category reflect the level of forward prices and volatility factors as of December 31, 2009 and may change as a result of changes in these factors. Management uses its best estimates to determine the fair value of commodity and derivative contracts NRG holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors and credit exposure. It is possible however, that future market prices could vary from those used in recording assets and liabilities from energy marketing and trading activities and such variations could be material.

The Company has elected to disclose derivative assets and liabilities on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. Also, collateral received or paid on the Company s derivative assets or liabilities are recorded on a separate line item on the balance sheet. Consequently, the magnitude of the changes in individual current and non-current derivative assets or liabilities is higher than the underlying credit and market risk of the Company s portfolio. As discussed in Item 6A *Commodity Price Risk*, NRG measures the sensitivity of the Company s portfolio to potential changes in market prices using Value at Risk, or VaR, a statistical model which attempts to predict risk of loss based on market price and volatility. NRG s risk management policy places a limit on one-day holding period VaR, which limits the Company s net open position. As the Company s trade-by-trade derivative accounting results in a gross-up of the Company s derivative assets and liabilities, the net derivative assets and liability position is a better indicator of NRG s hedging activity. As of December 31, 2009, NRG s net derivative asset was $459 million, a decrease to total fair value of $537 million as compared to December 31, 2008. This decrease was primarily driven by the acquisition of Reliant Energy s retail portfolio offset by increase in fair value due to the decreases in gas and power prices as well as the roll-off of trades that settled during the period.

Based on a sensitivity analysis using simplified assumptions, the impact of a $1 per MMBtu increase or decrease in natural gas prices across the term of the derivative contracts would cause a change of approximately $489 million in the net value of derivatives as of December 31, 2009.

Critical Accounting Policies and Estimates

NRG s discussion and analysis of the financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the U.S. The preparation of these financial statements and related disclosures in compliance with generally accepted accounting principles, or GAAP, requires the application of appropriate technical accounting rules and guidance as well as the use of estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges. These judgments, in and of themselves, could materially affect the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment may also have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies have not changed.

On an ongoing basis, NRG evaluates these estimates, utilizing historic experience, consultation with experts and other methods the Company considers reasonable. In any event, actual results may differ substantially from the Company s estimates. Any effects on the Company s business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

NRG s significant accounting policies are summarized in Item 14 Note 2, *Summary of Significant Accounting Policies*, to the Consolidated Financial Statements. The Company identifies its most critical accounting policies as those that are the most pervasive and important to the portrayal of the Company s

financial position and results of operations, and that require the most difficult, subjective and/or complex judgments by management regarding estimates about matters that are inherently uncertain.

Accounting Policy	**Judgments/Uncertainties Affecting Application**
Derivative Instruments	Assumptions used in valuation techniques Assumptions used in forecasting generation Market maturity and economic conditions Contract interpretation Market conditions in the energy industry, especially the effects of price volatility on contractual commitments
Income Taxes and Valuation Allowance for Deferred Tax Assets	Ability to withstand legal challenges of tax authority decisions or appeals Anticipated future decisions of tax authorities Application of tax statutes and regulations to transactions Ability to utilize tax benefits through carry backs to prior periods and carry forwards to future periods
Impairment of Long Lived Assets	Recoverability of investment through future operations Regulatory and political environments and requirements Estimated useful lives of assets Environmental obligations and operational limitations Estimates of future cash flows Estimates of fair value Judgment about triggering events
Goodwill and Other Intangible Assets	Estimated useful lives for finite-lived intangible assets Judgment about impairment triggering events Estimates of reporting unit s fair value Fair value estimate of intangible assets acquired in business combinations
Contingencies	Estimated financial impact of event(s) Judgment about likelihood of event(s) occurring Regulatory and political environments and requirements
Accrued Unbilled Revenues of Reliant Energy	Estimates of unbilled volumes

Derivative Instruments

The Company follows the guidance of ASC 815, to account for derivative instruments. ASC 815 requires the Company to mark-to-market all derivative instruments on the balance sheet, and recognize changes in the fair value of non-hedge derivative instruments immediately in earnings. In certain cases, NRG may apply hedge accounting to the Company s derivative instruments. The criteria used to determine if hedge accounting treatment is appropriate are: (i) the designation of the hedge to an underlying exposure; (ii) whether the overall risk is being reduced; and (iii) if there is a correlation between the fair value of the derivative instrument and the underlying hedged item. Changes in the fair value of derivatives instruments accounted for as hedges are either recognized in earnings as an offset to the changes in the fair value of the related hedged item, or deferred and recorded as a component of OCI, and subsequently recognized in earnings when the hedged transactions occur.

For purposes of measuring the fair value of derivative instruments, NRG uses quoted exchange prices and broker quotes. When external prices are not available, NRG uses internal models to determine the fair value. These internal models include assumptions of the future prices of energy commodities based on the specific market in which the energy commodity is being purchased or sold, using externally available forward market pricing curves for all periods possible under the pricing model. In order to qualify derivative instruments for hedged transactions, NRG estimates the forecasted generation occurring within a specified time period. Judgments related to the probability of forecasted generation occurring are based on available baseload capacity, internal forecasts of sales and generation, and historical physical delivery on similar contracts. The probability that hedged forecasted generation will occur by the end of a specified time period could change the results of operations by requiring amounts currently classified in OCI to be reclassified into earnings, creating increased variability in the Company s earnings. These estimations are considered to be critical accounting estimates.

Certain derivative instruments that meet the criteria for derivative accounting treatment also qualify for a scope exception to derivative accounting, as they are considered NPNS. The availability of this exception is based upon the assumption that NRG has the ability and it is probable to deliver or take delivery of the underlying item. These assumptions are based on available baseload capacity, internal forecasts of sales and generation and historical physical delivery on contracts. Derivatives that are considered to be NPNS are exempt from derivative accounting treatment, and are accounted for under accrual accounting. If it is determined that a transaction designated as NPNS no longer meets the scope exception due to changes in estimates, the related contract would be recorded on the balance sheet at fair value combined with the immediate recognition through earnings.

Income Taxes and Valuation Allowance for Deferred Tax Assets

As of December 31, 2009, NRG had a valuation allowance of $233 million. This amount is comprised of U.S. domestic capital loss carryforwards and non-depreciable property of $154 million, foreign net operating loss carryforwards of $78 million and foreign capital loss carryforwards of approximately $1 million. In assessing the recoverability of NRG s deferred tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected capital gains and available tax planning strategies.

NRG continues to be under audit for multiple years by taxing authorities in other jurisdictions. Considerable judgment is required to determine the tax treatment of a particular item that involves interpretations of complex tax laws. NRG is subject to examination by taxing authorities for income tax returns filed in the U.S. federal jurisdiction and various state and foreign jurisdictions including major operations located in Germany and Australia. The Company is no longer subject to U.S. federal income tax examinations for years prior to 2002. With few exceptions, state and local income tax examinations are no longer open for years before 2003. The Company s significant foreign operations are also no longer subject to examination by local jurisdictions for years prior to 2000.

Evaluation of Assets for Impairment and Other Than Temporary Decline in Value

In accordance with ASC-360, *Property, Plant, and Equipment*, or ASC 360, NRG evaluates property, plant and equipment and certain intangible assets for impairment whenever indicators of impairment exist. Examples of such indicators or events are:

- Significant decrease in the market price of a long-lived asset;
- Significant adverse change in the manner an asset is being used or its physical condition;
- Adverse business climate;
- Accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset;

- Current-period loss combined with a history of losses or the projection of future losses; and
- Change in the Company s intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life.

Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the assets to the future net cash flows expected to be generated by the asset, through considering project specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operations. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets by factoring in the probability weighting of different courses of action available to the Company. Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. NRG uses its best estimates in making these evaluations and considers various factors, including forward price curves for energy, fuel costs and operating costs. However, actual future market prices and project costs could vary from the assumptions used in the Company s estimates, and the impact of such variations could be material.

For assets to be held and used, if the Company determines that the undiscounted cash flows from the asset are less than the carrying amount of the asset, NRG must estimate fair value to determine the amount of any impairment loss. Assets held-for-sale are reported at the lower of the carrying amount or fair value less the cost to sell. The estimation of fair value under ASC 360, whether in conjunction with an asset to be held and used or with an asset held-for-sale, and the evaluation of asset impairment are, by their nature subjective. NRG considers quoted market prices in active markets to the extent they are available. In the absence of such information, the Company may consider prices of similar assets, consult with brokers, or employ other valuation techniques. NRG will also discount the estimated future cash flows associated with the asset using a single interest rate representative of the risk involved with such an investment or employ an expected present value method that probability-weights a range of possible outcomes. The use of these methods involves the same inherent uncertainty of future cash flows as previously discussed with respect to undiscounted cash flows. Actual future market prices and project costs could vary from those used in the Company s estimates, and the impact of such variations could be material.

For the years ended December 31, 2008, and 2007, there were reductions of $23 million and $11 million, respectively, in income from continuing operation due to impairment of an investment in commercial paper. The Company recorded these impairments as a reduction to interest income. There were no impairment charges on this investment in 2009.

NRG is also required to evaluate its equity-method and cost-method investments to determine whether or not they are impaired. ASC-323, *Investments-Equity Method and Joint Ventures*, or ASC 323, provides the accounting requirements for these investments. The standard for determining whether an impairment must be recorded under ASC 323 is whether the value is considered an other than a temporary decline in value. The evaluation and measurement of impairments under ASC 323 involves the same uncertainties as described for long-lived assets that the Company owns directly and accounts for in accordance with ASC 360. Similarly, the estimates that NRG makes with respect to its equity and cost-method investments are subjective, and the impact of variations in these estimates could be material. Additionally, if the projects in which the Company holds these investments recognize an impairment under the provisions of ASC 360, NRG would record its proportionate share of that impairment loss and would evaluate its investment for an other than temporary decline in value under ASC 323.

Goodwill and Other Intangible Assets

As part of the acquisition of Texas Genco in 2006, NRG recorded goodwill and intangible assets at its Texas segment reporting unit. The Company also recorded intangible assets in connection with the Reliant Energy acquisition in 2009, measured primarily based on significant inputs that are not observable in the market and thus represent a Level 3 measurement as defined in ASC 820. See Item 14 Note 3, *Business Acquisitions*, to the Consolidated Financial Statements for a discussion of the Reliant Energy acquisition fair value measurements. The Company applied ASC 805, *Business Combinations,* or ASC 805, and ASC 350, *Intangibles Goodwill and Other*, or ASC 350, to account for its goodwill and intangible assets. Under these standards, the Company amortizes all finite-lived intangible assets over their respective estimated weighted-average useful lives, while goodwill has an indefinite life and is not amortized. However, goodwill and all intangible assets not subject to amortization are tested for impairments at least annually, or more frequently whenever an event or change in circumstances occurs that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The Company tests goodwill for impairment at the reporting unit level, which is identified by assessing whether the components of the Company s operating segments constitute businesses for which discrete financial information is available and whether segment management regularly reviews the operating results of those components. If it is determined that the fair value of a reporting unit is below its carrying amount, where necessary the Company s goodwill and/or intangible asset with indefinite lives will be impaired at that time.

The Company performed its annual goodwill impairment assessment as of December 31, 2009, for its Texas reporting unit, or NRG Texas, which is at the operating segment level. The Company determined the fair value of this reporting unit using primarily an income approach and then applied an overall market approach reasonableness test to reconcile that fair value with NRG s overall market capitalization. Significant inputs to the determination of fair value were as follows:

For the three solid-fuel baseload plants that drive a majority of the value in the reporting unit, and for the region s Elbow Creek, Langford and Cedar Bayou facilities that recently commenced operations, the Company applied a discounted cash flow methodology to their long-term budgets in accordance with the guidance in paragraphs B152 and B155 of SFAS 142. This approach is consistent with that used to determine fair value at December 31, 2008 and 2007. These budgets are based on the Company s views of power and fuel prices, which consider market prices in the near term and the Company s fundamental view for the longer term as some relevant market prices are illiquid beyond 24 months. Hedging is included to the extent of contracts already in place. Projected generation in the long-term budgets is based on management s estimate of supply and demand within the sub-markets for each plant and the physical and economic characteristics of each plant;

For the reporting unit s remaining gas plants, the Company applied a market-derived earnings multiple to the gas plants aggregate estimated 2009 earnings before interest, taxes, depreciation and amortization, in accordance with the guidance in ASC-350-20-35-24. This approach is consistent with that used to determine fair values at December 31, 2008 and 2007;

The potential impact of carbon legislation was estimated using a discounted cash flow methodology applied to the Company s view of the impact of potential legislation that is based on recent proposals to Congress.

If fair value of a reporting unit exceeds its carrying value, goodwill of the reporting unit is not considered impaired. Under the income approach described above, the Company estimated the fair value of NRG Texas invested capital to exceed its carrying value by approximately 25% at December 31, 2009. This estimate of fair value is affected by assumptions about projected power prices, generation, fuel costs, capital expenditure requirements and environmental regulations, and the Company believes that the most significant impact arises from future power prices. Assuming all other factors are held constant, a hypothetical $1 drop in the Company s long-term natural gas price view would not have caused the fair value of NRG Texas to fall below its carrying value at December 31, 2009.

To reconcile the fair value determined under the income approach with NRG s market capitalization, the Company considered historical and future budgeted earnings measures to estimate the average percentage of total company value represented by NRG Texas, and applied this percentage to an adjusted business enterprise value of NRG. To derive this adjusted business enterprise value, the Company applied a range of control premiums based on recent market transactions to the business enterprise value of NRG on a non-controlling, marketable basis, and also made adjustments for some non-operating assets and for some of the significant factors that impact NRG differently from NRG Texas, such as environmental capital expenditures outside of the Texas region, or limitations on the Company s Capital Allocation Plans under NRG s debt. The Company was able to reconcile the proportional value of NRG Texas to NRG s market capitalization at a value that would not indicate an impairment.

Contingencies

NRG records a loss contingency when management determines it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. Gain contingencies are not recorded until management determines it is certain that the future event will become or does become a reality. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events, and estimates of the financial impacts of such events.

NRG describes in detail its contingencies in Item 14   Note 22, *Commitments and Contingencies,* to the Consolidated Financial Statements.

Accrued Unbilled Revenues

Accrued unbilled revenues related to the Reliant Energy segment are critical accounting estimates as volumes are not precisely known at the end of each reporting period and the revenue amounts are material. Accrued unbilled revenues were $308 million as of December 31, 2009, which represents 3% of the Company s consolidated revenues for the year ended December 31, 2009, and 7% of Reliant Energy s revenues for the eight-month period ended December 31, 2009. Accrued unbilled revenues are based on Reliant Energy s estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Volume estimates are based on daily forecasted volumes and estimated customer usage by class. Unbilled revenues are calculated by multiplying these volume estimates by the applicable rate by customer class. Estimated amounts are adjusted when actual usage is known and billed.

Recent Accounting Developments

See Item 14 Note 2, *Summary of Significant Accounting Policies,* to the Consolidated Financial Statements for a discussion of recent accounting developments.

Item 6A ***Quantitative and Qualitative Disclosures about Market Risk***

NRG is exposed to several market risks in the Company s normal business activities. Market risk is the potential loss that may result from market changes associated with the Company s merchant power generation or with an existing or forecasted financial or commodity transaction. The types of market risks the Company is exposed to are commodity price risk, interest rate risk and currency exchange risk. In order to manage these risks the Company uses various fixed-price forward purchase and sales contracts, futures and option contracts traded on the New York Mercantile Exchange, and swaps and options traded in the over-the-counter financial markets to:

- Manage and hedge fixed-price purchase and sales commitments;
- Manage and hedge exposure to variable rate debt obligations;
- Reduce exposure to the volatility of cash market prices, and
- Hedge fuel requirements for the Company s generating facilities.

Commodity Price Risk

Commodity price risks result from exposures to changes in spot prices, forward prices, volatility in commodities, and correlations between various commodities, such as natural gas, electricity, coal, oil, and emissions credits. A number of factors influence the level and volatility of prices for energy commodities and related derivative products. These factors include:

- Seasonal, daily and hourly changes in demand;
- Extreme peak demands due to weather conditions;
- Available supply resources;
- Transportation availability and reliability within and between regions; and
- Changes in the nature and extent of federal and state regulations.

NRG s portfolio consists of generation assets and full requirement load serving obligations. NRG manages the commodity price risk of the Company s merchant generation operations and load serving obligations by entering into various derivative or non-derivative instruments to hedge the variability in future cash flows from forecasted sales of electricity and purchases and fuel. These instruments include forwards, futures, swaps, and option contracts traded on various exchanges, such as New York Mercantile Exchange, or NYMEX, Intercontinental Exchange, or ICE, and

Chicago Climate Exchange, or CCX, as well as over-the-counter markets. The portion of forecasted transactions hedged may vary based upon management s assessment of market, weather, operation and other factors.

While some of the contracts the Company uses to manage risk represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. NRG uses the Company s best estimates to determine the fair value of those derivative contracts.

However, it is likely that future market prices could vary from those used in recording mark-to-market derivative instrument valuation, and such variations could be material.

NRG measures the risk of the Company s portfolio using several analytical methods, including sensitivity tests, scenario tests, stress tests, position reports, and VaR. VaR is a statistical model that attempts to predict risk of loss based on market price and volatility. Currently, the company estimates VaR using a Monte Carlo simulation based methodology.

NRG uses a diversified VaR model to calculate an estimate of the potential loss in the fair value of the Company s energy assets and liabilities, which includes generation assets, load obligations, and bilateral physical and financial transactions. The key assumptions for the Company s diversified model include: (i) a lognormal distribution of prices; (ii) one-day holding period; (iii) a 95% confidence interval; (iv) a rolling 36-month forward looking period; and (v) market implied volatilities and historical price correlations.

As of December 31, 2009, the VaR for NRG s commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions calculated using the diversified VaR model was $38 million.

The following table summarizes average, maximum and minimum VaR for NRG for the year ended December 31, 2009, and 2008:

VaR	**In millions**
As of December 31, 2009	$ 38
Average	41
Maximum	55
Minimum	28
As of December 31, 2008	$ 43
Average	50
Maximum	65
Minimum	35

Due to the inherent limitations of statistical measures such as VaR, the evolving nature of the competitive markets for electricity and related derivatives, and the seasonality of changes in market prices, the VaR calculation may not capture the full extent of commodity price exposure. As a result, actual changes in the fair value of mark-to-market energy assets and liabilities could differ from the calculated VaR, and such changes could have a material impact on the Company s financial results.

In order to provide additional information for comparative purposes to NRG s peers, the Company also uses VaR to estimate the potential loss of derivative financial instruments that are subject to mark-to-market accounting. These derivative instruments include transactions that were entered into for both asset management and trading purposes. The VaR for the derivative financial instruments calculated using the diversified VaR model as of December 31, 2009, for the entire term of these instruments entered into for both asset management and trading, was $24 million primarily driven by asset-backed transactions.

Interest Rate Risk

NRG is exposed to fluctuations in interest rates through the Company s issuance of fixed rate and variable rate debt. Exposures to interest rate fluctuations may be mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to interest rate volatility and result in primarily fixed rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. NRG s risk management policies allow the Company to reduce interest rate exposure from variable rate debt obligations.

In May 2009, NRG entered into a series of forward-starting interest rate swaps. These interest rate swaps become effective on April 1, 2011, and are intended to hedge the risks associated with floating interest rates. For each of the interest rate swaps, the Company will pay its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG receives the monthly equivalent of a floating interest payment based on a 1-month LIBOR calculated on the same notional value. All interest rate swap payments by NRG and its counterparties are made monthly and the LIBOR is determined in advance of each interest period. The total notional amount of these swaps, which mature on February 1, 2013, is $900 million.

In 2006, the Company entered into a series of interest rate swaps which are intended to hedge the risk associated with floating interest rates. For each of the interest rate swaps, NRG pays its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG receives the equivalent of a floating interest payment based on a 3-month LIBOR rate calculated on the same notional value. All interest rate swap payments by NRG and its counterparties are made quarterly, and the LIBOR is determined in advance of each interest period. While the notional value of each of the swaps does not vary over time, the swaps are designed to mature sequentially. The total notional amount of these swaps as of December 31, 2009, was $1.7 billion. The maturities and notional amounts of each tranche of these swaps in connection with the Senior Credit Facility are as follows:

Maturity	**Notional Value**
March 31, 2010	$ 190 million
March 31, 2011	$ 1.55 billion

In addition to those discussed above, the Company had the following additional interest rate swaps outstanding as of December 31, 2009:

	Notional Value	**Maturity**
Floating to fixed interest rate swap for NRG Peaker Financing LLC	$ 251 million	June 10, 2019
Fixed to floating interest rate swap for Senior Notes, due 2014	$ 400 million	December 15, 2013

If all of the above swaps had been discontinued on December 31, 2009, the Company would have owed the counterparties $104 million. Based on the investment grade rating of the counterparties, NRG believes its exposure to credit risk due to nonperformance by counterparties to its hedge contracts to be insignificant.

NRG has both long and short-term debt instruments that subject the Company to the risk of loss associated with movements in market interest rates. As of December 31, 2009, a 1% change in interest rates would result in a $10 million change in interest expense on a rolling twelve month basis.

As of December 31, 2009, the Company s long-term debt fair value was $8.2 billion and the carrying amount was $8.3 billion. NRG estimates that a 1% decrease in market interest rates would have increased the fair value of the Company s long-term debt by $415 million.

Liquidity Risk

Liquidity risk arises from the general funding needs of NRG s activities and in the management of the Company s assets and liabilities. NRG s liquidity management framework is intended to maximize liquidity access and minimize funding costs. Through active liquidity management, the Company seeks to preserve stable, reliable and cost-effective sources of funding. This enables the Company to replace maturing obligations when due and fund assets at appropriate maturities and rates. To accomplish this task, management uses a variety of liquidity risk measures that take into consideration market conditions, prevailing interest rates, liquidity needs, and the desired maturity profile of liabilities.

Based on a sensitivity analysis for power and gas positions under marginable contracts, a $1 per MMBtu change in natural gas prices across the term of the marginable contracts would cause a change in margin collateral posted of approximately $128 million as of December 31, 2009, and a 0.25 MMBtu/MWh change in heat rates for heat rate positions would result in a change in margin collateral posted of approximately $51 million as of December 31, 2009. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of December 31, 2009. Currently, NRG is exposed to additional margin if natural gas prices decrease.

Under the second lien, NRG is required to post certain letter of credits as credit support for changes in commodity prices. As of December 31, 2009, no letters of credit are outstanding to second lien counterparties. With changes in commodity prices, the letters of credit could grow to $64 million, the cap under the agreements.

Credit Risk

Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. The Company monitors and manages credit risk through credit policies that include: (i) an established credit approval process; (ii) a daily monitoring of counterparties credit limits; (iii) the use of credit mitigation measures such as margin, collateral, credit derivatives, prepayment arrangements, or volumetric limits; (iv) the use of payment netting agreements; and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. The Company seeks to mitigate counterparty risk with a diversified portfolio of counterparties, including nine participants under its first and second lien structure. The Company also has credit protection within various agreements to call on additional collateral support if and when necessary. Cash margin is collected and held at NRG to cover the credit risk of the counterparty until positions settle.

As of December 31, 2009, total credit exposure to substantially all wholesale counterparties was $1.3 billion and NRG held collateral (cash and letters of credit) against those positions of $186 million resulting in a net exposure of $1.1 billion. Total credit exposure is discounted at the risk free rate.

The following table highlights the credit quality and the net counterparty credit exposure by industry sector. Net counterparty credit risk is defined as the aggregate net asset position for NRG with counterparties where netting is permitted under the enabling agreement and includes all cash flow, mark-to-market and NPNS, and non-derivative transactions. The exposure is shown net of collateral held, and includes amounts net of receivables or payables.

Category	**Net Exposure[(a)] (% of Total)**
Financial institutions	69%
Utilities, energy merchants, marketers and other	25
Coal suppliers	3
ISOs	3
Total as of December 31, 2009	100%

Category	**Net Exposure[(a)] (% of Total)**
Investment grade	90%
Non-rated	8
Non- Investment grade	2
Total as of December 31, 2009	100%

(a) Credit exposure excludes California tolling, uranium, coal transportation/railcar leases, New England RMR, certain cooperative load contracts and Texas Westmoreland coal contracts. The aforementioned exposures were excluded for various reasons including regulatory support liens held against the contracts which serve to reduce the risk of loss, or credit risks for certain contracts are not readily measurable due to a lack of market reference prices.

NRG has credit risk exposure to certain wholesale counterparties representing more than 10% of total net exposure and the aggregate of such counterparties was $351 million. Approximately 82% of NRG s positions relating to credit risk roll-off by the end of 2012. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. Given the credit quality, diversification and term of the exposure in the portfolio, NRG does not anticipate a material impact on the Company s financial position or results of operations from nonperformance by any of NRG s counterparties.

NRG is exposed to retail credit risk through its competitive electricity supply business, which serves C&I customers and the Mass market in Texas. Retail credit risk results when a customer fails to pay for services rendered. The losses could be incurred from nonpayment of customer accounts receivable and any in-the-money forward value. NRG manages retail credit risk through the use of established credit policies that include monitoring of the portfolio, and the use of credit mitigation measures such as deposits or prepayment arrangements.

As of December 31, 2009, the Company s credit exposure to C&I customers was diversified across many customers and various industries. No one customer represented more than 2% of total exposure and the majority of the customers have investment grade credit quality, as determined by NRG.

NRG is also exposed to credit risk relating to its 1.5 million Mass customers, which may result in a write-off of a bad debt. The current economic conditions may affect the Company s customers ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in bad debt expense.

Certain of the Company s hedging agreements contain provisions that require the Company to post additional collateral if the counterparty determines that there has been deterioration in credit quality, generally termed adequate assurance under the agreements. Other agreements contain provisions that require the Company to post additional collateral if there was a one notch downgrade in the Company s credit rating. The collateral required for out-of-the-money positions and net accounts payable for contracts that have adequate assurance clauses that are in a net liability position as of December 31, 2009, was $80 million. The collateral required for out-of-the-money positions and net accounts payable for contracts with credit rating contingent features that are in a net liability position as of December 31, 2009, was $49 million. The Company is also a party to certain marginable agreements where NRG has a net liability position but the counterparty has not called for the collateral due, which is approximately $3 million as of December 31, 2009.

Currency Exchange Risk

NRG may be subject to foreign currency risk as a result of the Company entering into purchase commitments with foreign vendors for the purchase of major equipment associated with *Repowering*NRG initiatives. To reduce the risks to such foreign currency exposure, the Company may enter into transactions to hedge its foreign currency exposure using currency options and forward contracts. At December 31, 2009, no foreign currency options and forward contracts were outstanding.

In connection with the MIBRAG sale transaction, NRG entered into a foreign currency forward contract to hedge the impact of exchange rate fluctuations on the sale proceeds. The foreign currency forward contract had a fixed exchange rate of 1.277 and required NRG to deliver EUR 200 million in exchange for $255 million on June 15, 2009. For the year ended December 31, 2009, NRG recorded an exchange loss of $24 million on the contract within Other income/(loss), net.

As a result of the Company s limited foreign currency exposure to date, the effect of foreign currency fluctuations has not been material to the Company s results of operations, financial position and cash flows.

The effects of a hypothetical simultaneous 10% appreciation in the U.S. dollar from year-end 2008 levels against all other currencies of countries in which the Company has continuing operations would result in an immaterial impact to NRG s consolidated statements of operations and approximately $79 million in pre-tax unrealized income reflected in the currency translation adjustment component of OCI.

Item 7 ***Financial Statements and Supplementary Data***

The financial statements and schedules are listed in Part IV, Item 14 of this Form 10-K.

Item 8 ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosures***

None.

Item 8A ***Controls and Procedures***

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of NRG s management, including its principal executive officer, principal financial officer and principal accounting officer, NRG conducted an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures, as such term is defined in Rules 13a-15(e) or 15d-15(e) of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Based on this evaluation, the Company s principal executive officer, principal financial officer and principal accounting officer concluded that the disclosure controls and procedures were effective as of the end of the period covered by this annual report on Form 10-K. Management s report on the Company s internal control over financial reporting and the report of the Company s independent registered public accounting firm are incorporated under the caption Management s Report on Internal Control over Financial Reporting and under the caption Report of Independent Registered Public Accounting Firm, of the Company s 2009 Annual Report to Shareholders.

Changes in Internal Control over Financial Reporting

There were no changes in the Company s internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act) that occurred in the fourth quarter of 2009 that materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Inherent Limitations over Internal Controls

NRG s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. The Company s internal control over financial reporting includes those policies and procedures that:

1. Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

2. Provide reasonable assurance that transactions are recorded as necessary to permit preparation of consolidated financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

3. Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the consolidated financial statements.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations, including the possibility of human error and circumvention by collusion or overriding of controls. Accordingly, even an effective internal control system may not prevent or detect material misstatements on a timely basis. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Item 8B ***Other Information***

None.

PART III

Item 9 *Directors, Executive Officers and Corporate Governance*

NRG Energy, Inc. has adopted a code of ethics entitled NRG Code of Conduct that applies to directors, officers and employees, including the chief executive officer and senior financial officers of NRG Energy, Inc. It may be accessed through the Corporate Governance section of NRG Energy Inc. s website at *http://www.nrgenergy.com/investor/corpgov.htm.* NRG Energy, Inc. also elects to disclose the information required by Form 8-K, Item 5.05, Amendments to the registrant s code of ethics, or waiver of a provision of the code of ethics, through the Company s website, and such information will remain available on this website for at least a 12-month period. A copy of the NRG Energy, Inc. Code of Conduct is available in print to any shareholder who requests it.

Other information required by this Item will be incorporated by reference to the similarly named section of NRG s definitive Proxy Statement for its 2010 Annual Meeting of Stockholders.

Item 10 *Executive Compensation*

Other information required by this Item will be incorporated by reference to the similarly named section of NRG s Definitive Proxy Statement for its 2010 Annual Meeting of Stockholders.

Item 11 *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Other information required by this Item will be incorporated by reference to the similarly named section of NRG s Definitive Proxy Statement for its 2010 Annual Meeting of Stockholders.

Item 12 *Certain Relationships and Related Transactions, and Director Independence*

Other information required by this Item will be incorporated by reference to the similarly named section of NRG s Definitive Proxy Statement for its 2010 Annual Meeting of Stockholders.

Item 13 *Principal Accounting Fees and Services*

Other information required by this Item will be incorporated by reference to the similarly named section of NRG s Definitive Proxy Statement for its 2010 Annual Meeting of Stockholders.

PART IV

Item 14 ***Exhibits and Financial Statement Schedules***

(a)(1) Financial Statements

The following consolidated financial statements of NRG Energy, Inc. and related notes thereto, together with the reports thereon of KPMG LLP are included herein:

Consolidated Statements of Operations Years ended December 31, 2009, 2008 and 2007

Consolidated Balance Sheets December 31, 2009 and 2008

Consolidated Statements of Cash Flows Years ended December 31, 2009, 2008 and 2007

Consolidated Statement of Stockholders Equity and Comprehensive Income/(Loss) Years ended December 31, 2009, 2008 and 2007

Notes to Consolidated Financial Statements

(a)(2) Financial Statement Schedule

The following Consolidated Financial Statement Schedule of NRG Energy, Inc. is filed as part of Item 14(d) of this report and should be read in conjunction with the Consolidated Financial Statements.

Schedule II Valuation and Qualifying Accounts

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions or are inapplicable, and therefore, have been omitted.

(a)(3) *Exhibits:* See Exhibit Index submitted as a separate section of this report.

(b) Exhibits

See Exhibit Index submitted as a separate section of this report.

(c) Not applicable

MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

NRG Energy Inc. s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company s management, including its principal executive officer, principal financial officer and principal accounting officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Company s evaluation under the framework in Internal Control Integrated Framework, the Company s management concluded that its internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of the Company s internal control over financial reporting as of December 31, 2009 has been audited by KPMG LLP, the Company s independent registered public accounting firm, as stated in its report which is included in this Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
NRG Energy, Inc.:

We have audited NRG Energy, Inc. s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control   Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). NRG Energy, Inc. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

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

In our opinion, NRG Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control   Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of NRG Energy, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders   equity and comprehensive income / (loss), and cash flows for each of the years in the three-year period ended December 31, 2009, and our report dated February 23, 2010 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

KPMG LLP

Philadelphia, Pennsylvania
February 23, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
NRG Energy, Inc.:

We have audited the accompanying consolidated balance sheets of NRG Energy, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders equity and comprehensive income / (loss), and cash flows for each of the years in the three-year period ended December 31, 2009. In connection with our audits of the consolidated financial statements, we also have audited financial statement schedule Schedule II. Valuation and Qualifying Accounts. These consolidated financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of NRG Energy, Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards (SFAS) 141R, *Business Combinations* (incorporated into Accounting Standards Codification (ASC) Topic 805, *Business Combinations*), SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51, Consolidated Financial Statements* (incorporated into ASC Topic 810, *Consolidation*), Financial Accounting Standards Board Staff Position (FSP FAS) 141R-1, *Accounting for Assets and Liabilities Assumed in a Business Combination That Arise from Contingencies* (incorporated into ASC Topic 805, *Business Combinations*), and FSP Accounting Principles Board (APB) No. 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlements)* (incorporated into ASC Topic 825, *Financial Instruments*), effective January 1, 2009; SFAS No. 157, *Fair Value Measurements* (incorporated into ASC Topic 820, *Fair Value Measurements and Disclosures*), effective January 1, 2008; and FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of SFAS No. 109 (incorporated into ASC Topic 740, *Income Taxes*), effective January 1, 2007.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of NRG Energy, Inc. and subsidiaries internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 23, 2010 expressed an unqualified opinion on the effective operation of internal control over financial reporting.

/s/ KPMG LLP

KPMG LLP

Philadelphia, Pennsylvania
February 23, 2010

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
(In millions, except per share amounts)	**2009**	**2008**	**2007**
Operating Revenues			
Total operating revenues	$ 8,952	$ 6,885	$ 5,989
Operating Costs and Expenses			
Cost of operations	5,323	3,598	3,378
Depreciation and amortization	818	649	658
Selling, general and administrative	550	319	309
Acquisition-related transaction and integration costs	54		
Development costs	48	46	101
Total operating costs and expenses	6,793	4,612	4,446
Gain on sale of assets			17
Operating Income	2,159	2,273	1,560
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	41	59	54
Gains on sales of equity method investments	128		1
Other income/(loss), net	(5)	17	55
Refinancing expenses	(20)		(35)
Interest expense	(634)	(583)	(702)
Total other expenses	(490)	(507)	(627)
Income From Continuing Operations Before Income Taxes	1,669	1,766	933
Income tax expense	728	713	377
Income From Continuing Operations	941	1,053	556
Income from discontinued operations, net of income taxes		172	17
Net Income	941	1,225	573
Less: Net loss attributable to noncontrolling interest	(1)		
Net Income attributable to NRG Energy, Inc.	942	1,225	573
Dividends for preferred shares	33	55	55
Income Available for Common Stockholders	$ 909	$ 1,170	$ 518
Earnings per share attributable to NRG Energy, Inc. Common Stockholders			
Weighted average number of common shares outstanding basic	246	235	240

Income from continuing operations per weighted average common share basic	$ 3.70	$ 4.25	$ 2.09
Income from discontinued operations per weighted average common share basic		0.73	0.07
Net Income per Weighted Average Common Share Basic	$ 3.70	$ 4.98	$ 2.16
Weighted average number of common shares outstanding diluted	271	275	288
Income from continuing operations per weighted average common share diluted	$ 3.44	$ 3.80	$ 1.90
Income from discontinued operations per weighted average common share diluted		0.63	0.06
Net Income per Weighted Average Common Share Diluted	$ 3.44	$ 4.43	$ 1.96
Amounts Attributable to NRG Energy, Inc.:			
Income from continuing operations, net of income taxes	942	1,053	556
Income from discontinued operations, net of income taxes		172	17
Net Income	$ 942	$ 1,225	$ 573

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2009	As of December 31, 2008
	(In millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 2,304	$ 1,494
Funds deposited by counterparties	177	754
Restricted cash	2	16
Accounts receivable trade, less allowance for doubtful accounts of $29 and $3	876	464
Current portion of note receivable affiliate and capital leases	32	68
Inventory	541	455
Derivative instruments valuation	1,636	4,600
Cash collateral paid in support of energy risk management activities	361	494
Prepayments and other current assets	279	147
Total current assets	6,208	8,492
Property, Plant and Equipment		
In service	14,083	13,084
Under construction	533	804
Total property, plant and equipment	14,616	13,888
Less accumulated depreciation	(3,052)	(2,343)
Net property, plant and equipment	11,564	11,545
Other Assets		
Equity investments in affiliates	409	490
Note receivable affiliate and capital leases, less current portion	504	435
Goodwill	1,718	1,718
Intangible assets, net of accumulated amortization of $648 and $335	1,777	815
Nuclear decommissioning trust fund	367	303
Derivative instruments valuation	683	885
Other non-current assets	148	125
Total other assets	5,606	4,771
Total Assets	$ 23,378	$ 24,808

See notes to Consolidated Financial Statements.

LIABILITIES AND STOCKHOLDERS EQUITY

	As of December 31, 2009		2008	
	(In millions, except share data)			
LIABILITIES AND STOCKHOLDERS EQUITY				
Current Liabilities				
Current portion of long-term debt and capital leases	$	571	$	464
Accounts payable trade		693		447
Accounts payable affiliates		4		4
Derivative instruments valuation		1,473		3,981
Deferred income taxes		197		201
Cash collateral received in support of energy risk management activities		177		760
Accrued interest expense		207		178
Other accrued expenses		298		215
Other current liabilities		142		331
Total current liabilities		3,762		6,581
Other Liabilities				
Long-term debt and capital leases		7,847		7,697
Nuclear decommissioning reserve		300		284
Nuclear decommissioning trust liability		255		218
Postretirement and other benefit obligations		287		277
Deferred income taxes		1,783		1,190
Derivative instruments valuation		387		508
Out-of-market contracts		294		291
Other non-current liabilities		519		392
Total non-current liabilities		11,672		10,857
Total Liabilities		15,434		17,438
3.625% convertible perpetual preferred stock; $0.01 par value; 250,000 shares issued and outstanding (at liquidation value of $250, net of issuance costs)		247		247
Commitments and Contingencies				
Stockholders Equity				
4% convertible perpetual preferred stock; $0.01 par value; 154,057 shares issued and outstanding at December 31, 2009 (at liquidation value of $154, net of issuance costs) and 420,000 shares issued and outstanding at December 31, 2008 (at liquidation value of $420, net of issuance costs)		149		406
5.75% convertible perpetual preferred stock; $0.01 par value, 1,841,680 shares issued and outstanding at December 31, 2008 (at liquidation value of $460, net of issuance costs)				447
Common stock; $0.01 par value; 500,000,000 shares authorized; 295,861,759 and 263,599,200 shares issued and 253,995,308 and 234,356,717 shares outstanding at December 31, 2009 and 2008		3		3

Additional paid-in capital	4,948	4,350
Retained earnings	3,332	2,423
Less treasury stock, at cost - 41,866,451 and 29,242,483 shares at December 31, 2009 and 2008	(1,163)	(823)
Accumulated other comprehensive income	416	310
Noncontrolling interest	12	7
Total Stockholders Equity	7,697	7,123
Total Liabilities and Stockholders Equity	$ 23,378	$ 24,808

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME

	Serial Preferred Stock	Shares	Common Stock	Shares	Additional Paid-In Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Noncontrolling Interest	Total Stockholders Equity
					(In millions)					
Balances at December 31, 2006	$ 892	2.4	$ 3	245	$ 4,506	$ 735	$ (732)	$ 282	$	$ 5,686
Net income						573				573
Foreign currency translation adjustments								73		73
Unrealized loss on derivatives, net of $310 tax benefit								(474)		(474)
Available-for-sale securities, net of $1 tax								2		2
Defined benefit plan prior service cost of $4 and net loss of $2, net of $2 tax								2		2
Comprehensive income for 2007										176
Equity-based compensation				1	9					9
Reduction to tax valuation allowance					56					56
Preferred stock dividends						(55)				(55)
Purchase of treasury stock				(9)			(353)			(353)
Retirement of treasury stock					(447)		447			
Balances at December 31, 2007	892	2.4	3	237	4,124	1,253	(638)	(115)		5,519
Net income						1,225				1,225
Foreign currency translation adjustments, net of $22 tax								(112)		(112)
Reclassification adjustment for translation loss realized upon sale of ITISA								15		15
Unrealized gain on derivatives, net of $369 tax								580		580
Available-for-sale securities, net of $2 tax benefit								(4)		(4)
								(54)		(54)

Defined benefit plan prior service credit of $1 and net loss of $55, net of $35 tax benefit										
Comprehensive income for 2008										1,650
Equity-based compensation				1	25					25
Payment to settle CSF I CAGR					(45)					(45)
Purchase of treasury stock				(5)			(185)			(185)
Reduction to tax valuation allowance					162					162
Preferred stock dividends						(55)				(55)
NINA contribution, net of $17 tax					26				7	33
5.75% preferred stock conversion to common stock	(39)	(0.1)		1	39					
Other					19					19
Balances at December 31, 2008	$ 853	2.3	$ 3	234	$ 4,350	$ 2,423	$ (823)	$ 310	$ 7	$ 7,123
Net income/(loss)						942			(1)	941
Foreign currency translation adjustments, net of $21 tax								35		35
Reclassification adjustment for translation loss realized upon sale of MIBRAG, net of tax benefit $13								(22)		(22)
Unrealized gain on derivatives, net of $53 tax								91		91
Available-for-sale securities, net of $2 tax								4		4
Defined benefit plan prior service credit of $1 and net loss of $8, net of $1 tax benefit								(2)		(2)
Comprehensive income for 2009										1,047
Equity-based compensation					26					26
Purchase of treasury stock				(19)			(500)			(500)
Preferred stock dividends						(33)				(33)
ESPP share purchases					2					2
NINA contribution, net of $16 tax					28				6	34
5.75% preferred stock conversion to common stock	(447)	(1.9)		19	447					
	(257)	(0.3)		13	257					

4.00% preferred stock conversion to common stock										
Shares loaned to affiliate of CS				12	(291)		291			
Shares returned from affiliate of CS				(5)	131		(131)			
Other					(2)					(2)
Balances at December 31, 2009	$ 149	0.1	$ 3	254	$ 4,948	$ 3,332	$ (1,163)	$ 416	$ 12	$ 7,697

See notes to Consolidated Financial Statements

144

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
	(In millions)		
Cash Flows from Operating Activities			
Net income	$ 941	$ 1,225	$ 573
Adjustments to reconcile net income to net cash provided by operating activities:			
Distributions and equity in earnings of unconsolidated affiliates	(41)	(44)	(33)
Depreciation and amortization	818	649	661
Provision for bad debts	61		
Amortization of nuclear fuel	36	39	58
Amortization of financing costs and debt discount/premiums	44	37	79
Amortization of intangibles and out-of-market contracts	153	(270)	(156)
Amortization of unearned equity compensation	26	26	19
Loss/(gain) on disposals and sales of assets	17	25	(17)
Impairment charges and asset write downs		23	20
Changes in derivatives	(225)	(484)	77
Changes in deferred income taxes and liability for unrecognized tax benefits	689	762	359
Gain on sales of equity method investments	(128)		(1)
Gain on sale of discontinued operations		(273)	
Gain on sale of emission allowances	(4)	(51)	(31)
Gain recognized on settlement of pre-existing relationship	(31)		
Changes in nuclear decommissioning trust liability	26	34	32
Changes in collateral deposits supporting energy risk management activities	127	(417)	(125)
Cash provided/(used) by changes in other working capital, net of acquisition and disposition effects: Accounts receivable, net	88	1	(102)
Inventory	(83)	(5)	(38)
Prepayments and other current assets	26	(7)	22
Accounts payable	(176)	(31)	49
Option premiums collected	(282)	268	8
Accrued expenses and other current liabilities	48	(6)	98
Other assets and liabilities	(24)	(22)	(35)
Net Cash Provided by Operating Activities	2,106	1,479	1,517
Cash Flows from Investing Activities			
Acquisition of businesses, net of cash acquired	(427)		
Capital expenditures	(734)	(899)	(481)
Increase in restricted cash, net	14	13	12
(Increase)/decrease in notes receivable	(22)	10	34
Decrease in trust fund balances			19
Purchases of emission allowances	(78)	(8)	(161)
Proceeds from sale of emission allowances	40	75	272

Investments in nuclear decommissioning trust fund securities	(305)	(616)	(265)
Proceeds from sales of nuclear decommissioning trust fund securities	279	582	233
Proceeds from sale of assets, net	6	14	2
Proceeds from sale of equity method investment	284		
Equity investment in unconsolidated affiliate	(6)	(84)	
Purchases of securities			(49)
Proceeds from sale of discontinued operations and assets, net of cash divested		241	57
Other	(5)		
Net Cash Used by Investing Activities	(954)	(672)	(327)
Cash Flows from Financing Activities			
Payment of dividends to preferred stockholders	(33)	(55)	(55)
Net payments to settle acquired derivatives that include financing elements	(79)	(43)	
Payment for treasury stock	(500)	(185)	(353)
Installment proceeds from sale of noncontrolling interest in subsidiary	50	50	
Payment to settle CSF I CAGR		(45)	
Proceeds from issuance of common stock, net of issuance costs	2	9	7
Proceeds from issuance of long-term debt	892	20	1,411
Payment of deferred debt issuance costs	(31)	(4)	(5)
Payments for short and long-term debt	(644)	(234)	(1,819)
Net Cash Used by Financing Activities	(343)	(487)	(814)
Change in cash from discontinued operations		43	(25)
Effect of exchange rate changes on cash and cash equivalents	1	(1)	4
Net Increase in Cash and Cash Equivalents	810	362	355
Cash and Cash Equivalents at Beginning of Period	1,494	1,132	777
Cash and Cash Equivalents at End of Period	$ 2,304	$ 1,494	$ 1,132

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Nature of Business

General

NRG Energy, Inc., or NRG or the Company, is primarily a wholesale power generation company with a significant presence in major competitive power markets in the U.S., as well a major retail electricity franchise in the ERCOT (Texas) market. NRG is engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, the trading of energy, capacity and related products in the U.S. and select international markets, and supply of electricity and energy services to retail electricity customers in the Texas market.

As of December 31, 2009, NRG had a total global generation portfolio of 187 active operating fossil fuel and nuclear generation units, at 44 power generation plants, with an aggregate generation capacity of approximately 24,115 MW, and approximately 400 MW under construction which includes partner interests of 200 MW. In addition to its fossil fuel plant ownership, NRG has ownership interests in operating renewable facilities with an aggregate generation capacity of 365 MW, consisting of three wind farms representing an aggregate generation capacity of 345 MW (which includes partner interest of 75 MW) and a solar facility with an aggregate generation capacity of 20 MW. Within the U.S., NRG has large and diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 23,110 MW of fossil fuel and nuclear generation capacity in 179 active generating units at 42 plants. The Company s power generation facilities are most heavily concentrated in Texas (approximately 11,340 MW, including 345 MW from three wind farms), the Northeast (approximately 7,015 MW), South Central (approximately 2,855 MW), and West (approximately 2,150 MW, including 20 MW from a solar farm) regions of the U.S., with approximately 115 MW of additional generation capacity from the Company s thermal assets. In addition, through certain foreign subsidiaries, NRG has investments in power generation projects located in Australia and Germany with approximately 1,005 MW of generation capacity.

On May 1, 2009, NRG acquired Reliant Energy, which is the second largest electricity provider to Mass customers in Texas. Reliant Energy is also the largest electricity and energy services provider, based on load, to C&I customers in Texas. Based on metered locations, as of December 31, 2009, Reliant Energy had approximately 1.5 million Mass customers and approximately 0.1 million C&I customers. Reliant Energy arranges for the transmission and delivery of electricity to customers, bills customers, collects payments for electricity sold and maintains call centers to provide customer service.

NRG was incorporated as a Delaware corporation on May 29, 1992. NRG s common stock is listed on the New York Stock Exchange under the symbol NRG . The Company s headquarters and principal executive offices are located at 211 Carnegie Center, Princeton, New Jersey 08540. NRG s telephone number is (609) 524-4500. The address of the Company s website is *www.nrgenergy.com*. NRG s recent annual reports, quarterly reports, current reports, and other periodic filings are available free of charge through the Company s website.

Note 2 Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include NRG s accounts and operations and those of its subsidiaries in which the Company has a controlling interest. All significant intercompany transactions and balances have been eliminated in consolidation. The usual condition for a controlling financial interest is ownership of a majority of the voting interests of an entity. However, a controlling financial interest may also exist in entities, such as a variable interest entity, through arrangements that do not involve controlling voting interests.

As such, NRG applies the guidance of ASC 810, *Consolidations,* or ASC 810, to consolidate variable interest entities, or VIEs, for which the Company is the primary beneficiary. ASC 810 requires a variable interest holder to consolidate a VIE if that party will absorb a majority of the expected losses of the VIE, receive the majority of the expected residual returns of the VIE, or both. This party is considered the primary beneficiary. Conversely, NRG will not consolidate a VIE in which it has a majority ownership interest when the Company is not considered the primary beneficiary. In determining the primary beneficiary, NRG thoroughly evaluates the VIE s design, capital structure, and relationships among variable interest holders.

As discussed in Note 16, *Investments Accounted for by the Equity Method*, NRG has investments in partnerships, joint ventures and projects, one of which is a VIE for which the Company is not the primary beneficiary.

Accounting policies for all of NRG s operations are in accordance with accounting principles generally accepted in the U.S. Upon its emergence from bankruptcy on December 5, 2003, the Company qualified for and adopted fresh start reporting, or Fresh Start, under ASC 852, *Reorganizations*, or ASC 852.

These financial statements and notes reflect the Company s evaluation of events occurring subsequent to the balance sheet date through February 23, 2010, the date the financial statements were issued.

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments with an original maturity of three months or less at the time of purchase.

Funds Deposited by Counterparties

Funds deposited by counterparties consist of cash held by NRG as a result of collateral posting obligations from the Company s counterparties due to positions in NRG s hedging program. These amounts are segregated into separate accounts that are not contractually restricted but, based on the Company s intention, are not available for the payment of NRG s general corporate obligations. Depending on market fluctuations and the settlement of the underlying contracts, the Company will refund this collateral to the hedge counterparties pursuant to the terms and conditions of the underlying trades. Since collateral requirements fluctuate daily and the Company cannot predict if any collateral will be held for more than twelve months, the funds deposited by counterparties are classified as a current asset on the Company s balance sheet, with an offsetting liability for this cash collateral received within current liabilities. Changes in funds deposited by counterparties are closely associated with the Company s operating activities, and are classified as an operating activity in the Company s consolidated statements of cash flows.

Restricted Cash

Restricted cash consists primarily of funds held to satisfy the requirements of certain debt agreements and funds held within the Company s projects that are restricted in their use. These funds are used to pay for current operating expenses and current debt service payments, per the restrictions of the debt agreements.

Trade Receivables and Allowance for Doubtful Accounts

Trade receivables are reported in the balance sheet at outstanding principal adjusted for any write-offs and the allowance for doubtful accounts. For its Reliant Energy business, the Company accrues an allowance for doubtful accounts based on estimates of uncollectible revenues by analyzing counterparty credit ratings (for commercial and industrial customers), historical collections, accounts receivable aging and other factors. Reliant Energy writes-off accounts receivable balances against the allowance for doubtful accounts when it determines a receivable is uncollectible.

Inventory

Inventory is valued at the lower of weighted average cost or market, unless evidence indicates that the weighted average cost will be recovered with a normal profit in the ordinary course of business, and consists principally of fuel oil, coal and raw materials used to generate electricity or steam. The Company removes these inventories as they are used in the production of electricity or steam. Spare parts inventory is valued at a weighted average cost, since the Company expects to recover these costs in the ordinary course of business. The Company removes these inventories when they are used for repairs, maintenance or capital projects. Sales of inventory are classified as an operating activity in the consolidated statements of cash flows.

Property, Plant and Equipment

Property, plant and equipment are stated at cost; however impairment adjustments are recorded whenever events or changes in circumstances indicate that their carrying values may not be recoverable. NRG also classifies nuclear fuel related to the Company s 44% ownership interest in STP as part of the Company s property, plant, and equipment. Significant additions or improvements extending asset lives are capitalized as incurred, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred. Depreciation other than nuclear fuel is computed using the straight-line method, while nuclear fuel is amortized based on units of production over the estimated useful lives. Certain assets and their related accumulated depreciation amounts are adjusted for asset retirements and disposals with the resulting gain or loss included in cost of operations in the consolidated statements of operations.

Asset Impairments

Long-lived assets that are held and used are reviewed for impairment whenever events or changes in circumstances indicate carrying values may not be recoverable. Such reviews are performed in accordance with ASC 360. An impairment loss is recognized if the total future estimated undiscounted cash flows expected from an asset are less than its carrying value. An impairment charge is measured by the difference between an asset s carrying amount and fair value with the difference recorded in operating costs and expenses in the statements of operations. Fair values are determined by a variety of valuation methods, including appraisals, sales prices of similar assets and present value techniques.

Investments accounted for by the equity method are reviewed for impairment in accordance with ASC 323, which requires that a loss in value of an investment that is other than a temporary decline should be recognized. The Company identifies and measures losses in the value of equity method investments based upon a comparison of fair value to carrying value.

Discontinued Operations

Long-lived assets or disposal groups are classified as discontinued operations when all of the required criteria specified in ASC 360 are met. These criteria include, among others, existence of a qualified plan to dispose of an asset or disposal group, an assessment that completion of a sale within one year is probable and approval of the appropriate level of management. In addition, upon completion of the transaction, the operations and cash flows of the disposal group must be eliminated from ongoing operations of the Company, and the disposal group must not have any significant continuing involvement with the Company. Discontinued operations are reported at the lower of the asset s carrying amount or fair value less cost to sell.

Project Development Costs and Capitalized Interest

Project development costs are expensed in the preliminary stages of a project and capitalized when the project is deemed to be commercially viable. Commercial viability is determined by one or a series of actions including among others, Board of Director approval pursuant to a formal project plan that subjects the Company to significant future obligations that can only be discharged by the use of a Company asset.

Interest incurred on funds borrowed to finance capital projects is capitalized, until the project under construction is ready for its intended use. The amount of interest capitalized for the years ended December 31, 2009, 2008, and 2007, was $37 million, $45 million, and $11 million, respectively.

When a project is available for operations, capitalized interest and project development costs are reclassified to property, plant and equipment and amortized on a straight-line basis over the estimated useful life of the project s related assets. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

Debt Issuance Costs

Debt issuance costs are capitalized and amortized as interest expense on a basis which approximates the effective interest method over the term of the related debt.

Intangible Assets

Intangible assets represent contractual rights held by NRG. The Company recognizes specifically identifiable intangible assets including customer contracts, customer relationships, energy supply contracts, trade names, emission allowances, and fuel contracts when specific rights and contracts are acquired. In addition, NRG also established values for emission allowances and power contracts upon adoption of Fresh Start reporting. These intangible assets are amortized based on expected volumes, expected delivery, expected discounted future net cash flows, straight line or units of production basis.

Intangible assets determined to have indefinite lives are not amortized, but rather are tested for impairment at least annually or more frequently if events or changes in circumstances indicate that such acquired intangible assets have been determined to have finite lives and should now be amortized over their useful lives. NRG had no intangible assets with indefinite lives recorded as of December 31, 2009.

Emission allowances held-for-sale, which are included in other non-current assets on the Company s consolidated balance sheet, are not amortized; they are carried at the lower of cost or fair value and reviewed for impairment in accordance with ASC 360.

Goodwill

In accordance with ASC 350, the Company recognizes goodwill for the excess cost of an acquired entity over the net value assigned to assets acquired and liabilities assumed.

NRG performs goodwill impairment tests annually, typically during the fourth quarter, and when events or changes in circumstances indicate that the carrying value may not be recoverable. Goodwill impairment is determined using a two step process:

Step one Identify potential impairment by comparing the fair value of a reporting unit to the book value, including goodwill. If the fair value exceeds book value, goodwill of the reporting unit is not considered impaired. If the book value exceeds fair value, proceed to step two.

Step two Compare the implied fair value of the reporting unit s goodwill to the book value of the reporting unit goodwill. If the book value of goodwill exceeds fair value, an impairment charge is recognized for the sum of such excess.

Income Taxes

NRG accounts for income taxes using the liability method in accordance with ASC 740, *Income Taxes*, or ASC 740, which requires that the Company use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences.

NRG has two categories of income tax expense or benefit current and deferred, as follows:

Current income tax expense or benefit consists solely of regular tax less applicable tax credits, and

Deferred income tax expense or benefit is the change in the net deferred income tax asset or liability, excluding amounts charged or credited to accumulated other comprehensive income.

NRG reports some of the Company s revenues and expenses differently for financial statement purposes than for income tax return purposes resulting in temporary and permanent differences between the Company s financial statements and income tax returns. The tax effects of such temporary differences are recorded as either deferred income tax assets or deferred income tax liabilities in the Company s consolidated balance sheets. NRG measures the Company s deferred income tax assets and deferred income tax liabilities using income tax rates that are currently in effect. A valuation allowance is recorded to reduce the Company s net deferred tax assets to an amount that is more-likely-than-not to be realized.

The Company accounts for uncertain tax positions in accordance with ASC 740, which applies to all tax positions related to income taxes. Under ASC 740, tax benefits are recognized when it is more-likely-than-not that a tax position will be sustained upon examination by the authorities. The benefit from a position that has surpassed the more-likely-than-not threshold is the largest amount of benefit that is more than 50% likely to be realized upon settlement. The Company recognizes interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense.

Revenue Recognition

Energy Both physical and financial transactions are entered into to optimize the financial performance of NRG s generating facilities. Electric energy revenue is recognized upon transmission to the customer. Physical transactions, or the sale of generated electricity to meet supply and demand, are recorded on a gross basis in the Company s consolidated statements of operations. Financial transactions, or the buying and selling of energy for trading purposes, are recorded net within operating revenues in the consolidated statements of operations in accordance with ASC 815, *Derivatives and Hedging*, or ASC 815.

Capacity Capacity revenues are recognized when contractually earned, and consist of revenues billed to a third party at either the market or a negotiated contract price for making installed generation capacity available in order to satisfy system integrity and reliability requirements.

Sale of Emission Allowances NRG records the Company s bank of emission allowances as part of the Company s intangible assets. From time to time, management may authorize the transfer of emission allowances in excess of usage from the Company s emission bank to intangible assets held-for-sale for trading purposes. NRG records the sale of emission allowances on a net basis within other revenue in the Company s consolidated statements of operations.

Contract Amortization Assets and liabilities recognized from power sales agreements assumed at Fresh Start and through acquisitions related to the sale of electric capacity and energy in future periods for which the fair value has been determined to be significantly less (more) than market is amortized to revenue over the term of each underlying contract based on actual generation and/or contracted volumes.

Retail revenues Gross revenues for energy sales and services to Mass customers and to C&I customers are recognized upon delivery under the accrual method. Energy sales and services that have been delivered but not billed by period end are estimated. Gross revenues also includes energy revenues from resales of purchased power, which were $251 million for the eight-month period ended December 31, 2009. These revenues represent a sale of excess supply to third parties in the market.

As of December 31, 2009, Reliant Energy recorded unbilled revenues of $308 million for energy sales and services. Accrued unbilled revenues are based on Reliant Energy s estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Volume estimates are based on daily forecasted volumes and estimated customer usage by class. Unbilled revenues are calculated by multiplying these volume estimates by the applicable rate by customer class. Estimated amounts are adjusted when actual usage is known and billed.

Cost of Energy for Reliant Energy

Reliant Energy records cost of energy for electricity sales and services to retail customers based on estimated supply volumes for the applicable reporting period. A portion of its cost of energy ($69 million as of December 31, 2009) consisted of estimated transmission and distribution charges not yet billed by the transmission and distribution utilities. In estimating supply volumes, Reliant Energy considers the effects of historical customer volumes, weather factors and usage by customer class. Reliant Energy estimates its transmission and distribution delivery fees using the same method that it uses for electricity sales and services to retail customers. In addition, Reliant Energy estimates ERCOT ISO fees based on historical trends, estimates supply volumes and initial ERCOT

ISO settlements. Volume estimates are then multiplied by the supply rate and recorded as cost of operations in the applicable reporting period.

Derivative Financial Instruments

NRG accounts for derivative financial instruments under ASC 815, which requires the Company to record all derivatives on the balance sheet at fair value unless they qualify for a NPNS exception. Changes in the fair value of non-hedge derivatives are immediately recognized in earnings. Changes in the fair value of derivatives accounted for as hedges are either:

- Recognized in earnings as an offset to the changes in the fair value of the related hedged assets, liabilities and firm commitments; or

- Deferred and recorded as a component of accumulated OCI until the hedged transactions occur and are recognized in earnings.

NRG s primary derivative instruments are power sales contracts, fuels purchase contracts, other energy related commodities, and interest rate instruments used to mitigate variability in earnings due to fluctuations in market prices and interest rates. On an ongoing basis, NRG assesses the effectiveness of all derivatives that are designated as hedges for accounting purposes in order to determine that each derivative continues to be highly effective in offsetting changes in fair values or cash flows of hedged items. Internal analyses that measure the statistical correlation between the derivative and the associated hedged item determine the effectiveness of such an energy contract designated as a hedge. If it is determined that the derivative instrument is not highly effective as a hedge, hedge accounting will be discontinued prospectively. Hedge accounting will also be discontinued on contracts related to commodity price risk previously accounted for as cash flow hedges when it is probable that delivery will not be made against these contracts. In this case, the gain or loss previously deferred in OCI would be immediately reclassified into earnings. If the derivative instrument is terminated, the effective portion of this derivative in OCI will be frozen until the underlying hedged item is delivered.

Revenues and expenses on contracts that qualify for the NPNS exception are recognized when the underlying physical transaction is delivered. While these contracts are considered derivative financial instruments under ASC 815, they are not recorded at fair value, but on an accrual basis of accounting. If it is determined that a transaction designated as NPNS no longer meets the scope exception, the fair value of the related contract is recorded on the balance sheet and immediately recognized through earnings.

NRG s trading activities are subject to limits in accordance with the Company s Risk Management Policy. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings.

Foreign Currency Translation and Transaction Gains and Losses

The local currencies are generally the functional currency of NRG s foreign operations. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses, and cash flows are translated at the weighted-average rates of exchange for the period. The resulting currency translation adjustments are not included in the determination of the Company s statements of operations for the period, but are accumulated and reported as a separate component of stockholders equity until sale or complete or substantially complete liquidation of the net investment in the foreign entity takes place. Foreign currency transaction gains or losses are reported within other income/(expense) in the Company s statements of operations. For the years ended December 31, 2009, 2008, and

2007, amounts recognized as foreign currency transaction gains (losses) were immaterial. The Company s cumulative translation adjustment balances as of December 31, 2009, 2008, and 2007 were $21 million, $58 million and $59 million, respectively.

Concentrations of Credit Risk

Financial instruments which potentially subject NRG to concentrations of credit risk consist primarily of cash, trust funds, accounts receivable, notes receivable, derivatives, and investments in debt securities. Cash and cash equivalents and funds deposited by counterparties are predominantly held in money market funds invested in treasury securities, treasury repurchase agreements or government agency debt. Trust funds are held in accounts managed by experienced investment advisors. Certain accounts receivable, notes receivable, and derivative instruments are concentrated within entities engaged in the energy industry. These industry concentrations may impact the Company s overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. Receivables and other contractual arrangements are subject to collateral requirements under the terms of enabling agreements. However, NRG believes that the credit risk posed by industry concentration is offset by the diversification and creditworthiness of the Company s customer base. See Note 5, *Fair Value of Financial Instruments,* for a further discussion of derivative concentrations.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, funds deposited by counterparties, trust funds, receivables, accounts payables, and accrued liabilities approximate fair value because of the short-term maturity of these instruments. The carrying amounts of long-term receivables usually approximate fair value, as the effective rates for these instruments are comparable to market rates at year-end, including current portions. Any differences are disclosed in Note 5, *Fair Value of Financial Instruments.* The fair value of long-term debt is based on quoted market prices for those instruments that are publicly traded, or estimated based on the income approach valuation technique for non-publicly traded debt. For the years ended December 31, 2009, 2008, and 2007, the Company recorded an unrealized gain of $3 million, and impairment charges of $23 million and $11 million respectively, related to an investment in commercial paper. As of December 31, 2009 the net carrying value of the investment was $9 million.

Asset Retirement Obligations

NRG accounts for its asset retirement obligations, or AROs, in accordance with ASC 410-20, Asset *Retirement Obligations,* or ASC 410-20. Retirement obligations associated with long-lived assets included within the scope of ASC 410-20 are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel, and for which the timing and/or method of settlement may be conditional on a future event. ASC 410-20 requires an entity to recognize the fair value of a liability for an ARO in the period in which it is incurred and a reasonable estimate of fair value can be made.

Upon initial recognition of a liability for an ARO, NRG capitalizes the asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount. Over time, the liability is accreted to its future value, while the capitalized cost is depreciated over the useful life of the related asset. See Note 13, *Asset Retirement Obligations,* for a further discussion of AROs.

Pensions

NRG offers pension benefits through either a defined benefit pension plan or a cash balance plan. In addition, the Company provides postretirement health and welfare benefits for certain groups of employees. NRG accounts for pension and other postretirement benefits in accordance with ASC 715. NRG recognizes the funded status of the Company s defined benefit plans in the statement of financial position and records an offset to other comprehensive income. In addition, NRG also recognizes on an after-tax basis, as a component of other comprehensive income, gains and losses as well as all prior service costs that have not been included as part of the Company s net periodic benefit cost. The determination of NRG s obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets and the rate of future compensation increases. NRG s actuarial consultants use assumptions for such items as retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of pension obligation or expense recorded by the Company.

NRG measures the fair value of its pension assets in accordance with ASC 820, *Fair Value Measurements and Disclosures*, or ASC 820.

Stock-Based Compensation

NRG accounts for its stock-based compensation in accordance with ASC 718. The fair value of the Company s non-qualified stock options and performance units are estimated on the date of grant using the Black-Scholes option-pricing model and the Monte Carlo valuation model, respectively. NRG uses the Company s common stock price on the date of grant as the fair value of the Company s restricted stock units and deferred stock units. Forfeiture rates are estimated based on an analysis of NRG s historical forfeitures, employment turnover, and expected future behavior. The Company recognizes compensation expense for both graded and cliff vesting awards on a straight-line basis over the requisite service period for the entire award.

Investments Accounted for by the Equity Method

NRG has investments in various international and domestic energy projects. The equity method of accounting is applied to such investments in affiliates, which include joint ventures and partnerships, because the ownership structure prevents NRG from exercising a controlling influence over the operating and financial policies of the projects. Under this method, equity in pre-tax income or losses of domestic partnerships and, generally, in the net income or losses of international projects, are reflected as equity in earnings of unconsolidated affiliates.

Issuance of Subsidiary s Stock

The Company accounts for issuance of its subsidiaries stock in accordance with ASC 810, which requires an entity to account for a decrease in its ownership interest of a subsidiary that does not result in a change of control of the subsidiary as an equity transaction. In March 2008, NRG formed NINA, an NRG development stage subsidiary focused on developing, financing, and investing in nuclear projects in North America. TANE has partnered with NRG on the NINA venture, receiving a 12% equity ownership in NINA in exchange for $300 million to be invested in NINA in six annual installments of $50 million, the last three of which are subject to certain restrictions. NRG continues to control NINA through its voting interest. Any change in NRG s proportionate share of NINA s equity resulting from cash invested by TANE directly into NINA is accounted for by the Company as an equity transaction in consolidation, and not a gain on sale, as long as there is no change in control of NINA. Accordingly, receipt of TANE s installment contributions results in increases in additional paid in capital and noncontrolling interest on the Company s consolidated balance sheet.

Gross Receipts and Sales Taxes

In connection with its Reliant Energy business, the Company records gross receipts taxes on a gross basis in revenues and cost of operations in its consolidated statements of operations. During the eight-month period ended December 31, 2009, Reliant Energy s revenues and cost of operations included gross receipts taxes of $55 million. Additionally, Reliant Energy records sales taxes collected from its taxable customers and remitted to the various governmental entities on a net basis, thus, there is no impact on the Company s consolidated statement of operations.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the U.S. requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

In recording transactions and balances resulting from business operations, NRG uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts, actuarially determined benefit costs, and the valuation of energy commodity contracts, environmental liabilities, and legal costs incurred in connection with recorded loss contingencies, among others. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Reclassifications

Certain prior-year amounts have been reclassified for comparative purposes.

Recent Accounting Developments

SFAS 168 In June 2009, the Financial Accounting Standards Board, or FASB, issued SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*, or SFAS 168. Effective July 1, 2009, this guidance establishes the FASB Accounting Standards Codification, or ASC, as the source of authoritative U.S. GAAP recognized by the FASB to be applied by nongovernmental entities. In addition, SFAS 168 also specifies that rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants. All guidance contained in the ASC carries an equal level of authority. The Company adopted SFAS 168 for the quarterly reporting period ending September 30, 2009. SFAS 168 has been incorporated into the ASC as ASC-105, *Generally Accepted Accounting Principles,* or ASC 105.

Certain U.S. GAAP standards and interpretations were adopted by the Company in 2009 prior to the July 1, 2009, effective date of the ASC, and were subsequently incorporated into one or more ASC topics. Further, certain U.S. GAAP standards were ratified by the FASB in 2009 prior to July 1, 2009, but are not yet effective and have therefore not yet been incorporated into the ASC. This report retains the original title of these standards and interpretations, and references the ASC topic or topics in which they have been, or are expected to be, incorporated.

SFAS 141R The Company adopted SFAS No. 141 (revised 2007), *Business Combinations*, or SFAS 141R, on January 1, 2009. The provisions of SFAS 141R are applied prospectively to business combinations for which the acquisition date occurs after January 1, 2009. The statement requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. It also recognizes and measures the goodwill acquired or a gain from a bargain purchase in the business combination and determines what information to disclose to enable users of an entity s financial statements to evaluate the nature and financial effects of the business combination. In addition, transaction costs are required to be expensed as incurred. On May 1, 2009, NRG acquired all of the Texas electric retail business operations, or Reliant Energy, of Reliant Energy, Inc., now known as RRI. As discussed in Note 3, *Business Acquisitions*, to the Consolidated Financial Statements, the Company has applied the provisions of SFAS 141R to the Reliant Energy acquisition, as well as all other business acquisitions completed in 2009. As discussed further in Note 19, *Income Taxes*, any reductions after January 1, 2009, to existing net deferred tax assets or valuation allowances or changes to uncertain tax benefits, as they relate to Fresh Start or previously completed acquisitions, will be recorded to income tax expense rather than additional paid-in capital or goodwill. SFAS 141R has been incorporated into ASC-805, *Business Combinations*, or ASC 805.

FSP FAS 141R-1 In April 2009, the FASB issued FSP No. FAS 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies*, or FSP FAS 141R-1, which the Company adopted effective January 1, 2009. This FSP amends and clarifies SFAS 141R, to address application issues on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. The provisions of FSP FAS 141R-1 are applied prospectively to assets or liabilities arising from contingencies in business combinations for which the acquisition date occurs after January 1, 2009. Accordingly, the Company has applied the provisions of FSP FAS 141R-1 to the Reliant Energy acquisition as well as all other business acquisitions completed in 2009. The provisions of FSP FAS 141R-1 have been incorporated into ASC 805.

SFAS 160 The Company adopted SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements-an amendment of ARB No. 51, Consolidated Financial Statements*, or SFAS 160, on January 1, 2009. SFAS 160 establishes accounting and reporting standards for the minority interest in a subsidiary and for the deconsolidation of a subsidiary. It also amends certain of ARB No. 51 s consolidation procedures for consistency with the requirements of SFAS 141R. This statement is applied prospectively from the date of adoption, except for the presentation and disclosure requirements, which shall be applied retrospectively. Accordingly, the Company has conformed its financial statement presentation and disclosures to the requirements of SFAS 160. SFAS 160 has been incorporated into ASC-810, *Consolidation*, or ASC 810.

ASU No. 2010-02 - In January 2010 the FASB issued ASU No. 2010-02, *Consolidation (Topic 810): Accounting and Reporting for Decreases in Ownership of a Subsidiary a Scope Clarification,* or ASU 2010-02. ASU 2010-02 amends ASC 810, *Consolidation* to resolve a conflict between the consolidation guidance in the Accounting Standards Codification and other sections of U.S. GAAP when there is a decrease in ownership of a subsidiary. Entities are required to apply the amendments in ASU 2010-02 retrospectively for the first reporting period in which they applied SFAS 160. Although ASU 2010-02 is effective for the Company beginning in the fourth quarter of 2009, no decrease in ownership transactions resulting in a change in control within the scope of ASU 2010-02 and related guidance had occurred as of December 31, 2009, therefore there was no impact on the Company s results of operations, financial position, or cash flows.

FSP APB 14-1 The Company adopted FSP No. APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement),* or FSP APB 14-1, on January 1, 2009, applying it retrospectively to all periods presented. FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) should separately account for the liability component and the equity component represented by the embedded conversion option in a manner that will reflect the entity s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. Upon settlement, the entity shall allocate consideration transferred and transaction costs incurred to the extinguishment of the liability component and the reacquisition of the equity component. The provisions of FSP APB 14-1 have been incorporated into ASC-470, *Debt*, or ASC 470, and ASC-825, *Financial Instruments*, or ASC 825.

During the third quarter 2006, NRG s unrestricted wholly-owned subsidiaries CSF I and CSF II issued notes and preferred interests, or CSF Debt, which included embedded derivatives, or CSF CAGRs, requiring NRG to pay to CS at maturity, either in cash or stock at NRG s option, the excess of NRG s then current stock price over a threshold price. The CSF Debt and CSF CAGRs are accounted for under the guidance in ASC 470. Upon adoption of FSP APB 14-1, the fair value of the CSF CAGRs at the date of issuance was determined to be $32 million and has been recorded as a debt discount to the CSF Debt, with a corresponding credit to Additional Paid-in Capital. This debt discount will be amortized over the terms of the underlying CSF Debt. The cumulative effect of the change in accounting principle for periods prior to December 31, 2006, was recorded as a $28 million decrease to Long-Term Debt, a $32 million increase to Additional Paid-In Capital, and a $4 million decrease to Retained Earnings on the Condensed Consolidated Balance Sheet as of December 31, 2006. In addition, in August 2008 the Company paid $45 million to CS for the benefit of CSF I to early settle the CSF CAGR in the Company s CSF I notes and preferred interests, which was reclassified from interest expense to Additional Paid-In Capital upon the adoption of FSP APB 14-1.

The following table summarizes the effect of the adoption of FSP APB 14-1 on income and per-share amounts for all periods presented:

	For the Year Ended December 31,		
	2009	**2008**	**2007**
	(In millions, except per share amounts)		
Increase/(decrease):			
Interest Expense	$ 6	$ (37)	$ 13
Income From Continuing Operations	(6)	37	(13)
Net Income attributable to NRG Energy, Inc.	(6)	37	(13)
Basic Earnings Per Share	$ (0.03)	$ 0.16	$ (0.05)
Diluted Earnings Per Share	$ (0.02)	$ 0.14	$ (0.05)

FSP FAS 157-4 In April 2009, the FASB issued FSP No. FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,* or FSP FAS 157-4. FSP FAS 157-4 provides additional guidance for estimating fair value in accordance with ASC-820, *Fair Value Measurements and Disclosure*, or ASC 820, when the volume and level of activity for the asset or liability have significantly decreased, includes guidance on identifying circumstances that indicate a transaction is not orderly, and requires disclosures about inputs and valuation techniques used to measure fair value. This FSP applies to all assets and liabilities within the scope of accounting pronouncements that require or permit fair value measurements. FSP FAS 157-4 is effective for interim and annual reporting periods ending after

June 15, 2009, and is applied prospectively. The Company s adoption of FSP FAS 157-4 beginning with the interim reporting period ended June 30, 2009, did not have a material impact on the Company s results of operations, financial position, or cash flows. The provisions of FSP FAS 157-4 have been incorporated into ASC 820.

FSP FAS 107-1 and APB 28-1 In April 2009, the FASB issued FSP No. FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments,* or FSP 107-1 and APB 28-1. This FSP requires disclosures about fair value of financial instruments for interim and annual reporting periods of publicly traded companies ending after the FSP s effective date of June 15, 2009. The Company s adoption of FSP FAS 107-1 and APB 28-1 beginning with the interim period ended June 30, 2009, did not have an impact on the Company s results of operations, financial position, or cash flows. The provisions of FSP FAS 107-1 and APB 28-1 have been incorporated in ASC-270, *Interim Reporting*, or ASC 270, and ASC-825, *Financial Instruments,* or ASC 825.

FSP FAS 115-2 and FAS 124-2 In April 2009, the FASB issued FSP No. FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments,* or FSP FAS 115-2 and FAS 124-2. This FSP amends the other-than-temporary impairment guidance in U.S. GAAP for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. This FSP does not amend existing recognition and measurement guidance related to other-than-temporary impairments of equity securities. FSP FAS 115-2 and FAS 124-2 are effective for interim and annual reporting periods ending after June 15, 2009, and disclosure requirements apply only to periods ending after the FSP s effective date. The Company s adoption of FSP FAS 115-2 and FAS 124-2 beginning with the interim period ended June 30, 2009, did not have an impact on the Company s results of operations, financial position, or cash flows. The provisions of FSP FAS 115-2 and FAS 124-2 have been incorporated in ASC-320, *Investments Debt and Equity Securities*, or ASC 320.

SFAS 165 In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*, or SFAS 165. SFAS 165 incorporates the accounting and disclosure requirements related to subsequent events found in auditing standards into U.S. GAAP, effectively making management directly responsible for subsequent events accounting and disclosures. SFAS 165 also requires disclosure of the date through which subsequent events have been evaluated. SFAS 165 is effective for interim and annual reporting periods ending after June 15, 2009, and shall be applied prospectively. The Company s adoption of SFAS 165 beginning with the interim period ended June 30, 2009, did not have an impact on the Company s results of operations, financial position, or cash flows. SFAS 165 has been incorporated in ASC-855, *Subsequent Events*, or ASC 855.

SFAS 167/ASU No. 2009-17 In June 2009, the FASB issued SFAS No. 167, *Amendments to FASB Interpretation No. 46(R)*, or SFAS 167. This guidance amends ASC 810 by altering how a company determines when an entity that is insufficiently capitalized or not controlled through its voting interests should be consolidated. The previous ASC 810 guidance required a quantitative analysis of the economic risk/rewards of a VIE to determine the primary beneficiary. FAS 167 now specifies that a qualitative analysis be performed, requiring the primary beneficiary to have both the power to direct the activities of a VIE that most significantly impact the entities economic performance, as well as either the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE. In December 2009 the FASB issued ASU No. 2009-17*, Consolidations: Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*, or ASU 2009-17. ASU 2009-17 formally incorporates the provisions of SFAS 167 into ASC 810 and is effective for NRG as of January 1, 2010. The Company s adoption of ASU 2009-17 on January 1, 2010 did not have an impact on its results of operations, financial position, or cash flows.

ASU 2009-15/EITF 09-1 In July 2009, the FASB ratified EITF Issue No. 09-1, *Accounting for Own-Share Lending Arrangements in Contemplation of Convertible Debt Issuance or Other Financing,* or EITF 09-1. This Issue applies to equity-classified share lending arrangements on an entity s own shares, when executed in contemplation of a convertible debt offering or other financing. EITF 09-1 addresses how to account for the share-lending arrangement and the effect, if any, that the loaned shares have on earnings-per-share calculations. The share lending arrangement is required to be measured at fair value and recognized as an issuance cost associated with the convertible debt offering or other financing. Earnings-per-share calculations would not be affected by the loaned shares unless the share borrower defaults on the arrangement and does not return the shares. If counterparty default is probable, the share lender is required to recognize an expense equal to the then fair value of the unreturned shares, net of the fair value of probable recoveries. The Company will apply EITF 09-1 for share lending agreements entered into after June 15, 2009, and will apply EITF 09-1 on a retrospective basis for arrangements outstanding as of January 1, 2010. This statement did not have a material impact on the Company s results of operations, financial position and cash flows. In October 2009, the FASB issued Accounting Standards Update, or ASU No. 2009-15, *Accounting for Own-Share Lending Arrangements in Contemplation of Convertible Debt Issuance or Other Financing*, or ASU 2009-15, which formally incorporated the provisions of EITF 09-1 into ASC 470.

ASU 2009-05 In August 2009, the FASB issued ASU No. 2009-05, *Fair Value Measurement and Disclosures: Measuring Liabilities at Fair Value*, or ASU 2009-5. This ASU, which amends ASC 820 and ASC 825, provides clarification on measuring liabilities at fair value when a quoted price in an active market is not available. The Company s adoption of ASU 2009-5 beginning with the interim period ended September 30, 2009, did not have an impact on the Company s results of operations, financial position or cash flows.

ASU 2010-06 In January 2010, the FASB issued ASU No. 2010-06, *Fair Value Measurement and Disclosures: Improving Disclosures about Fair Value Measurements*, or ASU 2010-6, intending to improve disclosures about fair value measurements. The guidance requires entities to disclose significant transfers in and out of fair value hierarchy levels and the reasons for the transfers and to present information about purchases, sales, issuances and settlements separately in the reconciliation of fair value measurements using significant unobservable inputs (Level 3). Additionally, the guidance clarifies that a reporting entity should provide fair value measurements for each class of assets and liabilities and disclose the inputs and valuation techniques used for fair value measurements using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3). This guidance is effective for interim and annual periods beginning after December 15, 2009 except for the disclosures about purchases, sales, issuances and settlements in the Level 3 reconciliation, which will be effective for interim and annual periods beginning after December 15, 2010. As this guidance provides only disclosure requirements, the adoption of this standard will not impact the Company s results of operations, cash flows or financial position.

Other The following accounting standards were adopted on January 1, 2009, with no impact on the Company s results of operations, financial position, or cash flows:

FSP No. FAS 142-3, *Determination of the Useful Life of Intangible Assets,* which has been incorporated in ASC-275, *Risks and Uncertainties,* or ASC 275, and ASC-350, *Intangibles Goodwill and Other*, or ASC 350.

FSP No. FAS 157-2, *Effective Date of FASB Statement No. 157*, which has been incorporated in ASC 820.

SFAS No. 161, *Disclosures About Derivative Instruments and Hedging Activities,* which has been incorporated in ASC-815, *Derivatives and Hedging,* or ASC 815.

FSP No. FAS 132(R)-1, *Employers Disclosures about Postretirement Benefit Plan Assets,* which has been incorporated in ASC-715, *Compensation-Retirement Benefits,* or ASC 715.

EITF No. 07-5, *Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own Stock,* which has been incorporated in ASC 718, *Compensation-Equity Compensation,* or ASC 718, and ASC 815.

EITF No. 08-5, *Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement,* which has been incorporated in ASC 820.

EITF No. 08-6, *Equity Method Investment Accounting Considerations*, which has been incorporated in ASC-323, *Investments-Equity Method and Joint Ventures,* or ASC 323.

Note 3 Business Acquisitions

Acquisition of Reliant Energy

General

On May 1, 2009, NRG, through its wholly-owned subsidiary NRG Retail LLC, acquired Reliant Energy, which consisted of the entire Texas electric retail business operations of RRI, including the exclusive use of the trade name Reliant and related branding rights. Reliant Energy arranges for the transmission and delivery of electricity to customers, bills customers, collects payments for electricity sold and maintains call centers to provide customer service. Reliant Energy is the second largest electricity provider to Mass customers in Texas, with approximately 1.5 million Mass customers as of December 31, 2009. Reliant Energy is also the largest electricity and energy services provider, based on load, to C&I customers in Texas with approximately 0.1 million C&I customers, based on metered locations as of December 31, 2009. These customers include refineries, chemical plants, manufacturing facilities, hospitals, universities, government agencies, restaurants, and other facilities.

With its complementary generation portfolio, the Texas region is a supplier of power to Reliant Energy, thereby creating the potential for a more stable, reliable and competitive business that benefits Texas consumers. By backing Reliant Energy s load-serving requirements with NRG s generation and risk management practices, the need to sell and buy power from other financial institutions and intermediaries that trade in the ERCOT market may be reduced, resulting in reduced transaction costs and credit exposures. This combination of generation and retail allows for a reduction in actual and contingent collateral, initially through offsetting transactions and over time by reducing the need to hedge the retail power supply through third parties. In addition, with Reliant Energy s base of retail customers, NRG now has a customer interface with the scale that is important to the successful deployment of consumer facing energy technologies and services.

Credit Support

On May 1, 2009, NRG arranged with Merrill Lynch Commodities, Inc. and certain of its affiliates, or Merrill Lynch, the former credit provider of RRI, to provide continuing credit support to Reliant Energy after closing the acquisition. In connection with entering into a transitional credit sleeve facility, or CSRA, NRG contributed $200 million of cash to Reliant Energy. In conjunction with the CSRA, NRG Power Marketing LLC, or PML, and Reliant Energy Power Supply LLC, or REPS, wholly-owned subsidiaries of NRG, modified or novated certain transactions with counterparties to transfer PML s in-the-money transactions to REPS and moved $522 million of cash collateral held by NRG to Merrill Lynch, thereby reducing Merrill Lynch s actual and contingent collateral supporting Reliant Energy out-of-money positions. Through October 5, 2009, these trades with counterparties were still open, thus there was no impact on NRG s consolidated financial statements, and NRG continued to record unrealized and realized gains/losses for these novated trades in its Texas and Northeast segments. The monthly fee for the CSRA was 5.875% on an annualized basis of the predetermined exposure.

Additionally, on May 1, 2009, NRG entered into a $50 million working capital facility with Merrill Lynch in connection with the acquisition of Reliant Energy. The facility required that the Company comply with all terms of the CSRA. NRG initially drew $25 million under the facility, which accrued interest at the prime rate. The $25 million outstanding under this facility was repaid, and the facility was terminated on October 5, 2009. See further discussion below.

Reliant Energy conducts its business through RERH Holdings, LLC and subsidiaries, or RERH, Reliant Energy Texas Retail, LLC, and Reliant Energy Services Texas, LLC. Through October 5, 2009, the obligations of Reliant Energy under the CSRA were secured by first liens on substantially all of the assets of RERH, and the obligations of RERH under the CSRA were non-recourse to NRG and its other non-pledgor subsidiaries.

The Company executed an amendment of the existing CSRA with Merrill Lynch, or CSRA Amendment, which became effective October 5, 2009. In connection with the CSRA Amendment, the Company recorded refinancing expense of $20 million in its results of operations for the year ended December 31, 2009, primarily related to the write-off of previously deferred financing costs. The CSRA Amendment removed the first liens associated with the CSRA, and RERH subsequently became a guarantor of the Company s obligations under its Senior Notes. See Note 29, *Condensed Consolidating Financial Information*, for further discussion of NRG s guarantees under its Senior Notes.

In connection with the CSRA Amendment, NRG net settled certain REPS transactions with counterparties and received $165 million in net cash consideration. Merrill Lynch returned $250 million of previously posted cash collateral and released liens on $322 million of unrestricted cash held at Reliant Energy. See Note 6, *Accounting for Derivative Instruments and Hedging Activities*, for the accounting impact of these settlements.

Pursuant to the CSRA Amendment, the Company was required to post collateral for any net liability derivatives and other static margin associated with supply for Reliant Energy. In connection with this amendment, NRG posted $366 million of cash collateral to Merrill Lynch and other counterparties, returned $53 million of counterparty collateral, issued letters of credit of $206 million, and received $45 million in counterparty collateral. The funds posted by the Company were sourced from a portion of the proceeds from the June 5, 2009 issuance of the 2019 Senior Notes. See Note 12, *Debt and Capital Leases*, for further discussion of the 2019 Senior Notes.

Under the amended CSRA, the parties had agreed to settle any outstanding wholesale obligations under the CSRA Amendment by January 29, 2010. As of that date, there was one remaining wholesale counterparty, for which NRG provided Merrill Lynch with a $10 million letter of credit to protect them from any potential liability. The parties continue to work to settle all outstanding obligations, including C&I counterparties, by April 30, 2010.

Acquisition method of accounting

The acquisition of Reliant Energy is accounted for under the acquisition method of accounting in accordance with ASC 805. Accordingly, NRG has conducted an assessment of net assets acquired and has recognized provisional amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition are expensed as incurred. The initial accounting for the business combination is not complete because the evaluations necessary to assess the fair values of certain net assets acquired and the amount of goodwill (if any) to be recognized are still in process. The provisional amounts recognized are subject to revision until the evaluations are completed and to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date. Any changes to the fair value assessments will affect the final balance of goodwill.

NRG paid RRI $287.5 million in cash at closing, funded from NRG s cash on hand. NRG also made payments to RRI of $78 million as remittances of acquired net working capital. In addition, the Company expects to remit approximately $4 million of acquired net working capital to RRI by the second quarter 2010, bringing the total cash consideration to approximately $370 million. NRG also recognized a $31 million non-cash gain on the settlement of a pre-existing relationship, representing the in-the-money value to NRG of an agreement that permits Reliant Energy to call on certain NRG gas plants when necessary for Reliant Energy to meet its load obligations. NRG has recorded this gain within Operating Revenues in its consolidated statement of operations. This non-cash gain is considered a component of consideration in accordance with ASC 805, and together with cash consideration, brings total consideration to approximately $401 million.

The following table summarizes the provisional values assigned to the net assets acquired, including cash acquired of $6 million, as of the acquisition date:

	(In millions)
Assets	
Current and non-current assets	$ 635
Property, plant and equipment	72

Intangible assets subject to amortization:		
In-market customer contracts		790
Customer relationships		399
Trade names		178
In-market energy supply contracts		54
Other		6
Derivative assets		1,942
Deferred tax asset, net		14
Goodwill		
Total assets acquired	$	4,090

	(In millions)
Liabilities	
Current and non-current liabilities	$ 550
Derivative liabilities	2,996
Out-of-market energy supply and customer contracts	143
Total liabilities assumed	$ 3,689
Net assets acquired	$ 401

Current assets include accounts receivable with a preliminary fair value of $569 million and gross contractual amounts of $589 million at the time of acquisition. The Company has collected substantially all of the fair value of the contractual cash flows; any difference between fair value and the amount collected will be an adjustment to the acquired working capital payment due to RRI.

The Company, through its acquisition of Reliant Energy, is subject to material contingencies relating to Excess Mitigation Credits (see Note 22, *Commitments and Contingencies*) and Retail Replacement Reserve (see Note 23, *Regulatory Matters*). Due to the number of variables and assumptions involved in assessing the possible outcome of these matters, sufficient information does not exist to reasonably estimate the fair value of these contingent liabilities. These material contingencies have been evaluated in accordance with ASC-450, *Contingencies,* or ASC 450, and related guidance, and no provisional amounts for these matters have been recorded at the acquisition date. In addition, NRG provided certain indemnities in connection with the acquisition. See Note 26, *Guarantees,* for further discussion.

Measurement period adjustments

The following measurement period adjustments to the provisional amounts, attributable to refinement of the underlying appraisal assumptions, were recognized during 2009 subsequent to the acquisition date:

	Increase/(Decrease) (In millions)
Assets	
Intangible assets subject to amortization:	
In-market customer contracts	$ 57
Customer relationships	(82)
In-market energy supply contracts	17
Deferred tax asset, net	3
Total assets acquired	(5)
Liabilities	
Out-of-market energy supply and customer contracts	(5)
Total liabilities assumed	(5)

Net assets acquired	$

Fair value measurements

The provisional fair values of the intangible assets/liabilities and property, plant and equipment at the acquisition date were measured primarily based on significant inputs that are not observable in the market and thus represent a Level 3 measurement as defined in ASC 820. Significant inputs were as follows:

Customer contracts The fair values of the customer contracts, representing those with Reliant Energy s C&I customers, were estimated based on the present value of the above/below market cash flows attributable to the contracts based on contract type, discounted utilizing a current market interest rate consistent with the overall credit quality of the portfolio. The fair values also accounted for Reliant Energy s historical costs to acquire customers. The above/below market cash flows were estimated by comparing the expected cash flows to be generated based on existing contracted prices and expected volumes with the cash flows from estimated current market contract prices for the same expected volumes. The estimated current market contract prices were derived considering current market costs, such as price of energy, transmission and distribution costs, and miscellaneous fees, plus a normal profit margin. The customer contracts are amortized to revenues, over a weighted average amortization period of five years, based on expected volumes to be delivered for the portfolio.

Customer relationships The customer relationships, reflective of Reliant Energy s Mass customer base, were valued using a variation of the income approach. Under this approach, the Company estimated the present value of expected future cash flows resulting from the existing customer relationships, considering attrition and charges for contributory assets (such as net working capital, fixed assets, software, workforce and trade names) utilized in the business, discounted at an independent power producer peer group s weighted average cost of capital. The customer relationships are amortized to depreciation and amortization expense, over a weighted-average amortization period of eight years, based on the expected discounted future net cash flows by year.

Trade names The trade names were valued using a relief from royalty method, an approach under which fair value is estimated to be the present value of royalties saved because NRG owns the intangible asset and therefore does not have to pay a royalty for its use. The trade names were valued in two parts based on Reliant Energy s two primary customer segments Mass customers and C&I customers. The avoided royalty revenues were discounted at an independent power producer peer group s weighted average cost of capital. The remaining useful life of the trade names were determined by considering various factors, such as turnover and name changes in the independent power producer and utility industries, the current age of the Reliant brand, management s intent to continue using the name at the current time, and feedback from external consultants regarding their experience with similar trade names. The trade names are amortized to depreciation and amortization expense, on a straight-line basis, over 15 years.

Energy supply contracts The fair values of the in-market and out-of-market energy supply contracts were determined in accordance with ASC 820. These contracts are amortized over periods ranging through 2016, based on the expected delivery under the respective contracts.

Property, plant and equipment The fair value of property, plant and equipment was valued using a cost approach, which estimates value by determining the current cost of replacing an asset with another of equivalent economic utility. The cost to replace a given asset reflects the estimated reproduction or replacement cost for the property, less an allowance for loss in value due to depreciation.

The fair values of derivative assets and liabilities as of the acquisition date were determined in accordance with ASC 820. The breakdown of Level 1, 2 and 3 is as follows:

	Fair Value			
	Level 1	Level 2	Level 3	Total
	(In millions)			
Derivative assets	$ 534	$ 1,375	$ 33	$ 1,942
Derivative liabilities	$ 534	$ 2,357	$ 105	$ 2,996

Amortization of acquired intangible assets and out-of-market contracts

See Note 11, *Goodwill and Other Intangibles*, for the estimated remaining amortization related to acquired intangible assets and out-of-market contracts, including Customer contracts, Customer relationships, Trade names and Energy supply contracts, for 2010 2014.

Supplemental Pro-Forma Information

Since the acquisition date, Reliant Energy contributed $4.2 billion of operating revenues and $1.0 billion in net income attributable to NRG. See Note 18, *Segment Reporting*, for more information on the Company s segment results.

The following supplemental pro-forma information represents the results of operations as if NRG and Reliant Energy had combined at the beginning of the respective reporting periods:

	For the Year Ended December 31, 2009	For the Year Ended December 31, 2008
	(In millions, except per share amounts)	
Operating revenues	$ 10,799	$ 15,124
Net income attributable to NRG Energy, Inc.	945	419
Earnings per share attributable to NRG common stockholders:		
Basic	$ 3.71	$ 1.55
Diluted	$ 3.45	$ 1.48

The supplemental pro-forma information has been adjusted to include the pro-forma impact of amortization of intangible assets and out-of-market contracts, and depreciation of property, plant and equipment, based on the preliminary purchase price allocations. The pro-forma data has also been adjusted to eliminate the non-recurring transaction costs incurred by NRG. Transactions between NRG and Reliant Energy have not been eliminated. The pro-forma results are presented for illustrative purposes only and do not reflect the realization of potential cost savings, or any related integration costs. Certain cost savings may result from the acquisition; however, there can be no assurance that these cost savings will be achieved.

Other Acquisitions

The Company also completed the following acquisitions during the fourth quarter of 2009, for combined consideration totaling $68 million:

Bluewater Wind LLC On November 9, 2009, NRG, through its wholly-owned subsidiary NRG Bluewater Holdings LLC, acquired all the subsidiaries of Bluewater Wind LLC (such subsidiaries, together with NRG Bluewater Holdings LLC, NRG Bluewater). NRG Bluewater, a developer of off-shore wind energy, has a number of projects that are in various stages of development along the eastern seaboard and the Great Lakes region of the U.S.

FSE Blythe 1, LLC On November 20, 2009, NRG, through its wholly owned subsidiary NRG Solar LLC, acquired FSE Blythe 1, LLC, or Blythe Solar, from First Solar, Inc. On December 18, 2009, construction was completed and commercial operations began for Blythe Solar s 20 MW utility-scale photovoltaic, or PV, solar facility located in Riverside County in southeastern California. The Blythe Solar PV field provides electricity to Southern California Edison under a 20-year PPA.

Note 4 Discontinued Operations and Dispositions

Discontinued Operations

NRG classifies material business operations and gains/(losses) recognized on sales as discontinued operations for businesses that were sold or have met the required criteria for such classification. ASC 360 requires that discontinued operations be valued on an asset-by-asset basis at the lower of carrying amount or fair value, less costs to sell. In applying the provisions of ASC 360, the Company s management considers cash flow analyses, bids, and offers related to those assets and businesses. In accordance with the provisions of ASC 360, assets held by discontinued operations are not depreciated commencing with their classification as such.

NRG s discontinued operations reflect the disposal of ITISA, reported in the Company s international segment. On April 28, 2008, NRG completed the sale of its 100% interest in Tosli Acquisition B.V, which held all NRG s interest in ITISA, to Brookfield Renewable Power Inc. (previously Brookfield Power Inc.), a wholly-owned subsidiary of Brookfield Asset Management Inc. In addition, the purchase price adjustment contingency under the sale agreement was resolved on August 7, 2008. In connection with the sale, NRG received $300 million of cash proceeds from Brookfield, and removed $163 million of assets, including $59 million of cash, $122 million of liabilities, including $63 million of debt, and $15 million in foreign currency translation adjustment from its 2008 consolidated balance sheet. The Company recorded a pre-tax gain on the disposal of ITISA of $273 million in the year ended December 31, 2008. Summarized results of ITISA, reflected within discontinued operations for the years ended December 31, 2008, and 2007, were as follows:

	Year Ended December 31, 2008	Year Ended December 31, 2007
	(In millions)	
Operating revenues	$ 20	$ 50
Operating costs and other expenses	9	27
Pre-tax income from operations of discontinued components	11	23
Income tax expense	3	6
Income from operations of discontinued components	8	17
Disposal of discontinued components pre-tax gain	273	
Income tax expense	109	
Gain on disposal of discontinued components, net of income taxes	164	
Income from discontinued operations, net of income taxes	$ 172	$ 17

Other Dispositions

MIBRAG On June 10, 2009, NRG completed the sale of its 50% ownership interest in Mibrag B.V. to a consortium of Severoćeské doly Chomutov, a member of the CEZ Group, and J&T Group. Mibrag B.V. s principal holding was MIBRAG, which was jointly owned by NRG and URS Corporation. As part of the transaction, URS Corporation also entered into an agreement to sell its 50% stake in MIBRAG.

For its share, NRG received EUR 203 million ($284 million at an exchange rate of 1.40 U.S.$/EUR), net of transaction costs. During the year ended December 31, 2009, NRG recognized an after-tax gain of $128 million. Prior to completion of the sale, NRG continued to record its share of MIBRAG s operations to Equity in earnings of unconsolidated affiliates.

In connection with the transaction, NRG entered into a foreign currency forward contract to hedge the impact of exchange rate fluctuations on the sale proceeds. The foreign currency forward contract had a fixed exchange rate of 1.277 and required NRG to deliver EUR 200 million in exchange for $255 million on June 15, 2009. For the year ended December 31, 2009, NRG recorded an exchange loss of $24 million on the contract within Other (loss)/income, net. NRG provided certain indemnities in connection with its share of the transaction. See Note 26, *Guarantees*, for further discussion.

Red Bluff and Chowchilla On January 3, 2007, NRG completed the sale of the Company s Red Bluff and Chowchilla II power plants to an entity controlled by Wayzata Investment Partners LLC. These power plants, located in California, are fueled by natural gas, with generating capacity of 45 MW and 49 MW, respectively.

Note 5 Fair Value of Financial Instruments

The estimated carrying values and fair values of NRG s recorded financial instruments related to continuing operations are as follows:

	Year Ended December 31,			
	Carrying Amount		Fair Value	
	2009	2008	2009	2008
	(In millions)			
Cash and cash equivalents	$ 2,304	$ 1,494	$ 2,304	$ 1,494
Funds deposited by counterparties	177	754	177	754
Restricted cash	2	16	2	16
Cash collateral paid in support of energy risk management activities	361	494	361	494
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	9	7	9	7
Marketable equity securities	5	2	5	2

163

	Year Ended December 31,			
	Carrying Amount		Fair Value	
	2009	2008	2009	2008
	(In millions)			
Trust fund investments	369	305	369	305
Notes receivable	231	156	238	166
Derivative assets	2,319	5,485	2,319	5,485
Long-term debt, including current portion	8,295	8,019	8,211	7,475
Cash collateral received in support of energy risk management activities	177	760	177	760
Derivative liabilities	$ 1,860	$ 4,489	$ 1,860	$ 4,489

For cash and cash equivalents, funds deposited by counterparties, restricted cash, and cash collateral paid and received in support of energy risk management activities, the carrying amount approximates fair value because of the short-term maturity of those instruments. The fair value of marketable securities is based on quoted market prices for those instruments. Trust fund investments are comprised of various U.S. debt and equity securities carried at fair market value.

The fair value of notes receivable, debt securities and certain long-term debt are based on expected future cash flows discounted at market interest rates. The fair value of long-term debt is based on quoted market prices for these instruments that are publicly traded, or estimated based on the income approach valuation technique for non-publicly traded debt using current interest rates for similar instruments with equivalent credit quality.

Fair Value Accounting under ASC 820

ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

Level 1 quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access as of the measurement date. NRG s financial assets and liabilities utilizing Level 1 inputs include active exchange-traded securities, energy derivatives, and trust fund investments.

Level 2 inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. NRG s financial assets and liabilities utilizing Level 2 inputs include fixed income securities, exchange-based derivatives, and over the counter derivatives such as swaps, options and forwards.

Level 3 unobservable inputs for the asset or liability only used when there is little, if any, market activity for the asset or liability at the measurement date. NRG s financial assets and liabilities utilizing Level 3 inputs include infrequently-traded, non-exchange-based derivatives and commingled investment funds, and are measured using present value pricing models.

In accordance with ASC 820, the Company determines the level in the fair value hierarchy within which each fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety.

Recurring Fair Value Measurements

The following table presents assets and liabilities measured and recorded at fair value on the Company s consolidated balance sheet on a recurring basis and their level within the fair value hierarchy as of December 31, 2009:

	Fair Value			
	Level 1	Level 2	Level 3	Total
	(In millions)			
Cash and cash equivalents	$ 2,304	$	$	$ 2,304
Funds deposited by counterparties	177			177
Restricted cash	2			2
Cash collateral paid in support of energy risk management activities	361			361
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities			9	9
Marketable equity securities	5			5
Trust fund investments	214	118	37	369
Derivative assets	489	1,767	63	2,319
Total assets	$ 3,552	$ 1,885	$ 109	$ 5,546
Cash collateral received in support of energy risk management activities	$ 177	$	$	$ 177
Derivative liabilities	501	1,283	76	1,860
Total liabilities	$ 678	$ 1,283	$ 76	$ 2,037

The following table reconciles, for the year ended December 31, 2009, the beginning and ending balances for financial instruments that are recognized at fair value in the consolidated financial statements at least annually using significant unobservable inputs:

	Fair Value Measurement Using Significant Unobservable Inputs (Level 3)			
	Debt Securities	Trust Fund Investments	Derivatives[(a)]	Total
	(In millions)			
Beginning balance as of January 1, 2009	$ 7	$ 31	$ 49	$ 87
Total gains and losses (realized/unrealized):				
Included in OCI	2			2

Included in earnings			(97)	(97)
Included in nuclear decommissioning obligations		9		9
Purchases/(sales), net		(3)	1	(2)
Transfers, out of Level 3			34	34
Ending balance as of December 31, 2009	$ 9	$ 37	$ (13)	$ 33
The amount of the total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held as of December 31, 2009	$	$	$ 25	$ 25

(a) Consists of derivatives assets and liabilities, net.

Realized and unrealized gains and losses included in earnings that are related to the energy derivatives are recorded in operating revenues and cost of operations.

Non-derivative fair value measurements

NRG s investment in debt securities are classified as Level 3 and consist of non-traded debt instruments that are valued based on third-party market value assessments.

The trust fund investments are held primarily to satisfy NRG s nuclear decommissioning obligations. These trust fund investments hold debt and equity securities directly and equity securities indirectly through commingled funds. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. In addition, U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized in Level 2. Commingled funds, which are analogous to mutual funds, are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair value of commingled funds are based on net asset values per fund share (the unit of account), derived from the quoted prices in active markets of the underlying equity securities. However, because the shares in the commingled funds are not publicly quoted, not traded in an active market and are subject to certain restrictions regarding their purchase and sale, the commingled funds are categorized in Level 3. See also Note 7, *Nuclear Decommissioning Trust Fund.*

Derivative fair value measurements

A small portion of NRG s contracts are exchange-traded contracts with readily available quoted market prices. The majority of NRG s contracts are non-exchange-traded contracts valued using prices provided by external sources, primarily price quotations available through brokers or over-the-counter and on-line exchanges. For the majority of NRG markets, the Company receives quotes from multiple sources. To the extent that NRG receives multiple quotes, the Company s prices reflect the average of the bid-ask mid-point prices obtained from all sources that NRG believes provide the most liquid market for the commodity. If the Company receives one quote, then the mid-point of the bid-ask spread for that quote is used. The terms for which such price information is available vary by commodity, region and product. A significant portion of the fair value of the Company s derivative portfolio is based on price quotes from brokers in active markets who regularly facilitate those transactions and the Company believes such price quotes are executable. The Company does not use third party sources that derive price based on proprietary models or market surveys. The remainder of the assets and liabilities represents contracts for which external sources or observable market quotes are not available. These contracts are valued based on various valuation techniques including but not limited to internal models based on a fundamental analysis of the market and extrapolation of observable market data with similar characteristics. Contracts valued with prices provided by models and other valuation techniques make up 3% of the total fair value of all derivative contracts. The fair value of each contract is discounted using a risk free interest rate. In addition, the Company applies a credit reserve to reflect credit risk which is calculated based on published default probabilities. To the extent that NRG s net exposure under a specific master agreement is an asset, the Company uses the counterparty s default swap rate. If the exposure under a specific master agreement is a liability, the Company uses NRG s default swap rate. The credit reserve is added to the discounted fair value to reflect the exit price that a market participant would be willing to receive to assume NRG s liabilities or that a market participant would be willing to pay for NRG s assets. As of December 31, 2009, the credit reserve resulted in a $1 million increase in fair value which is composed of a $1 million loss in OCI and a $2 million gain in derivative revenue and cost of operations.

The fair values in each category reflect the level of forward prices and volatility factors as of December 31, 2009, and may change as a result of changes in these factors. Management uses its best estimates to determine the fair value of commodity and derivative contracts NRG holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors and credit exposure. It is possible, however, that future market prices could vary from those used in recording assets and liabilities from energy marketing and trading activities and such variations could be material.

Under the guidance of ASC 815, entities may choose to offset cash collateral paid or received against the fair value of derivative positions executed with the same counterparties under the same master netting agreements. The Company has chosen not to offset positions as defined in ASC 815. As of December 31, 2009, the Company recorded $361 million of cash collateral paid and $177 million of cash collateral received on its balance sheet.

Concentration of Credit Risk

In addition to the credit risk discussion as disclosed in Note 2, *Summary of Significant Accounting Policies*, the following item is a discussion of the concentration of credit risk for the Company s financial instruments. Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. The Company monitors and manages credit risk through credit policies that include: (i) an established credit approval process; (ii) a daily monitoring of counterparties credit limits; (iii) the use of credit mitigation measures such as margin, collateral, credit derivatives, prepayment arrangements, or volumetric limits (iv) the use of payment netting agreements; and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. The Company seeks to mitigate counterparty risk with a diversified portfolio of counterparties, including nine participants under its first and second lien structure. The Company also has credit protection within various agreements to call on additional collateral support if and when necessary. Cash margin is collected and held at NRG to cover the credit risk of the counterparty until positions settle.

Since the credit crisis began in late 2008, NRG has taken several additional steps to mitigate credit risk including the use of netting arrangements, entering contracts with collateral thresholds, setting volumetric limits with certain counterparties and restricting trading relationships with counterparties where exposure was high or where credit quality of the counterparty had deteriorated. NRG avoids concentration of counterparties whenever possible and applies credit policies that include an evaluation of counterparties financial condition, collateral requirements and the use of standard agreements that allow for netting and other security.

As of December 31, 2009, total credit exposure to substantially all counterparties was $1.3 billion and NRG held collateral (cash and letters of credit) against those positions of $186 million resulting in a net exposure of $1.1 billion. Total credit exposure is discounted at the risk free rate.

The following table highlights the credit quality and the net counterparty credit exposure by industry sector. Net counterparty credit exposure is defined as the aggregate net asset position for NRG with counterparties where netting is permitted under the enabling agreement and includes all cash flow, mark-to-market and NPNS, and non-derivative transactions. The exposure is shown net of collateral held, includes amounts net of receivables or payables.

Category	Net Exposure (a) as of December 31, 2009 (% of Total)
Financial institutions	69%
Utilities, energy merchants, marketers and other	25
Coal suppliers	3
ISOs	3
Total as of December 31, 2009	100%

	Net Exposure (a) as of December 31, 2009

Category	**(% of Total)**
Investment grade	90%
Non-rated	8
Non-Investment grade	2
Total as of December 31, 2009	100%

(a) Credit exposure excludes California tolling, uranium, coal transportation, New England RMR, certain cooperative load contracts, and Texas Westmoreland coal contracts. The aforementioned exposures were excluded for various reasons including regulatory support or liens held against the contracts which serve to reduce the risk of loss, or credit risks for certain contracts are not readily measurable due to a lack of market reference prices.

NRG has credit risk exposure to certain counterparties representing more than 10% of total net exposure and the aggregate of such counterparties was $351 million. Approximately 82% of NRG s positions relating to credit risk roll-off by the end of 2012. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. Given the credit quality, diversification and term of the exposure in the portfolio, NRG does not anticipate a material impact on the Company s financial position or results of operations from nonperformance by any of NRG s counterparties.

NRG is exposed to retail credit risk through its competitive electricity supply business, which serves C&I customers and the Mass market in Texas. Retail credit risk results when a customer fails to pay for services rendered. The losses could be incurred from nonpayment of customer accounts receivable and any in-the-money forward value. NRG manages retail credit risk through the use of established credit policies that include monitoring of the portfolio, and the use of credit mitigation measures such as deposits or prepayment arrangements.

As of December 31, 2009, the Company s credit exposure to C&I customers was diversified across many customers and various industries. No one customer represented more than 2% of total exposure and the majority of the customers have investment grade credit quality, as determined by NRG.

NRG is also exposed to credit risk relating to its 1.5 million Mass customers, which may result in a write-off of a bad debt. The current economic conditions may affect the Company s customers ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in bad debt expense.

Note 6 Accounting for Derivative Instruments and Hedging Activities

ASC 815 requires NRG to recognize all derivative instruments on the balance sheet as either assets or liabilities and to measure them at fair value each reporting period unless they qualify for a Normal Purchase Normal Sale, or NPNS, exception. If certain conditions are met, NRG may be able to designate certain derivatives as cash flow hedges and defer the effective portion of the change in fair value of the derivatives to OCI until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge is immediately recognized in earnings.

For derivatives designated as hedges of the fair value of assets or liabilities, the changes in fair value of both the derivative and the hedged transaction are recorded in current earnings. The ineffective portion of a hedging derivative instrument s change in fair value is immediately recognized into earnings.

For derivatives that are not designated as cash flow hedges or do not qualify for hedge accounting treatment, the changes in the fair value will be immediately recognized in earnings. Under the guidelines established per ASC 815, certain derivative instruments may qualify for the NPNS exception and are therefore exempt from fair value accounting treatment. ASC 815 applies to NRG s energy related commodity contracts, interest rate swaps, and foreign exchange contracts.

As the Company engages principally in the trading and marketing of its generation assets and retail business, some of NRG s commercial activities qualify for hedge accounting under the requirements of ASC 815. In order for the generation assets to qualify, the physical generation and sale of electricity should be highly probable at inception of the trade and throughout the period it is held, as is the case with the Company s baseload plants. For this reason, many trades in support of NRG s baseload units normally qualify for NPNS or cash flow hedge accounting treatment, and trades in support of NRG s peaking units asset optimization will generally not qualify for hedge accounting treatment, with any changes in fair value likely to be reflected on a mark-to-market basis in the statement of operations. Most of the retail load contracts either qualify for the NPNS exception or fail to meet the criteria for a derivative and the majority of the supply contracts are recorded under mark-to-market accounting. All of NRG s hedging and trading activities are in accordance with the Company s Risk Management Policy.

Energy-Related Commodities

To manage the commodity price risk associated with the Company s competitive supply activities and the price risk associated with wholesale and retail power sales from the Company s electric generation facilities, NRG may enter into a variety of derivative and non-derivative hedging instruments, utilizing the following:

Forward contracts, which commit NRG to sell or purchase energy commodities or purchase fuels in the future.

Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument.

Swap agreements, which require payments to or from counter-parties based upon the differential between two prices for a predetermined contractual, or notional, quantity.

Option contracts, which convey the right or obligation to purchase or sell a commodity.

Weather and hurricane derivative products used to mitigate a portion of Reliant Energy s lost revenue due to weather.

The objectives for entering into derivative contracts designated as hedges include:

Fixing the price for a portion of anticipated future electricity sales through the use of various derivative instruments including gas collars and swaps at a level that provides an acceptable return on the Company s electric generation operations.

Fixing the price of a portion of anticipated fuel purchases for the operation of NRG s power plants.

Fixing the price of a portion of anticipated energy purchases to supply Reliant Energy s customers.

NRG s trading activities are subject to limits in accordance with the Company s Risk Management Policy. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings.

As of December 31, 2009, NRG had hedge and non-hedge energy-related derivative financial instruments, and other energy-related contracts that did not qualify as derivative financial instruments extending through December 2026. As of December 31, 2009, NRG s derivative assets and liabilities consisted primarily of the following:

Forward and financial contracts for the purchase/sale of electricity and related products economically hedging NRG s generation assets forecasted output or NRG s retail load obligations through 2015.

Forward and financial contracts for the purchase of fuel commodities relating to the forecasted usage of NRG s generation assets into 2017.

Also, as of December 31, 2009, NRG had other energy-related contracts that qualified for the NPNS exception and were therefore exempt from fair value accounting treatment under the guidelines established by ASC 815 as follows:

Power sales and capacity contracts extending to 2025.

Also, as of December 31, 2009, NRG had other energy-related contracts that did not qualify as derivatives under the guidelines established by ASC 815 as follows:

Load-following forward electric sale contracts extending through 2026;

Power Tolling contracts through 2029;

Lignite purchase contract through 2018;

Power transmission contracts through 2015;

Natural gas transportation contracts and storage agreements through 2018; and

Coal transportation contracts through 2016.

Interest Rate Swaps

NRG is exposed to changes in interest rates through the Company s issuance of variable and fixed rate debt. In order to manage the Company s interest rate risk, NRG enters into interest-rate swap agreements. As of December 31, 2009, NRG had interest rate derivative instruments extending through June 2019, all of which had been designated as either cash flow or fair value hedges.

Volumetric Underlying Derivative Transactions

The following table summarizes the net notional volume buy/(sell) of NRG s derivative transactions broken out by commodity, excluding those derivatives that qualified for the NPNS exception as of December 31, 2009. Option contracts are reflected using delta volume. Delta volume equals the notional volume of an option adjusted for the probability that the option will be in-the-money at its expiration date.

Commodity	**Units**	**Total Volume as of December 31, 2009 (In millions)**
Emissions	Short Ton	(2)
Coal	Short Ton	55
Natural Gas	MMBtu	(484)
Oil	Barrel	1
Power[(a)]	MWH	(41)
Interest	Dollar	$ 3,291

(a) *Power volumes include capacity sales.*

Fair Value of Derivative Instruments

The Company has elected to disclose derivative assets and liabilities on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. Also, collateral received or paid on the Company s derivative assets or liabilities are recorded on a separate line item on the balance sheet. The Company has chosen not to offset positions as defined in ASC 815. As of December 31, 2009, the Company recorded $361 million of cash collateral paid and $177 million of cash collateral received on its balance sheet. The following table summarizes the fair value within the derivative instrument valuation on the balance sheet as of December 31, 2009:

	Fair Value	
	Derivatives Asset	**Derivatives Liability**
	(In millions)	
Derivatives Designated as Cash Flow or Fair Value Hedges:		
Interest rate contracts current	$	$ 2
Interest rate contracts long-term	8	106
Commodity contracts current	300	12
Commodity contracts long-term	508	6
Total Derivatives Designated as Cash Flow or Fair Value Hedges	816	126
Derivatives Not Designated as Cash Flow or Fair Value Hedges:		
Commodity contracts current	1,336	1,459
Commodity contracts long-term	167	275
Total Derivatives Not Designated as Cash Flow or Fair Value Hedges	1,503	1,734

Total Derivatives	$	2,319	$	1,860

Impact of Derivative Instruments on the Statement of Operations

The following table summarizes the amount of gain/(loss) resulting from fair value hedges reflected in interest income/(expense) for interest rate contracts:

Amount of gain/(loss) recognized	**Years Ended December 31, 2009 (In millions)**
Derivative	$ (6)
Senior Notes (hedged item)	$ 6

The following table summarizes the location and amount of gain/(loss) resulting from cash flow hedges:

Year ended December 31, 2009	Amount of gain recognized in OCI (effective portion) after tax	Location of gain/(loss) reclassified from Accumulated OCI into Income	Amount of gain/(loss) reclassified from Accumulated OCI into Income (In millions)	Location of gain/(loss) recognized in income (ineffective portion)	Amount of gain recognized in income (ineffective portion)
Interest rate contracts	$ 36	Interest expense	$ 1	Interest expense	$ 4
Commodity contracts	55	Operating revenue	(472)	Operating revenue	45
Total	$ 91		$ (471)		$ 49

The following table summarizes the amount of gain/(loss) recognized in income for derivatives not designated as cash flow or fair value hedges on commodity contracts:

Amount of gain/(loss) recognized in income or cost of operations for derivatives	Year ended December 31, 2009 (In millions)
Location of gain/(loss) recognized in income for derivatives:	
Operating revenues	$ (335)
Cost of operations	$ 842

Credit Risk Related Contingent Features

Certain of the Company s hedging agreements contain provisions that require the Company to post additional collateral if the counterparty determines that there has been deterioration in credit quality, generally termed adequate assurance under the agreements. Other agreements contain provisions that require the Company to post additional collateral if there was a one notch downgrade in the Company s credit rating. The collateral required for out-of-the-money positions and net accounts payable for contracts that have adequate assurance clauses that are in a net liability position as of December 31, 2009, was $80 million. The collateral required for out-of-the-money positions and net accounts payable for contracts with credit rating contingent features that are in a net liability position as of December 31, 2009, was $49 million. The Company is also a party to certain marginable agreements where NRG has a net liability position but the counterparty has not called for the collateral due, which is approximately $3 million as of December 31, 2009.

As of January 29, 2010, Merrill Lynch was no longer providing credit support for any wholesale energy supply contracts relating to the retail business. Merrill Lynch continues to provide guaranties to certain C&I customers as part of the credit sleeve arrangement. If Merrill Lynch were to default, NRG would be required to post guaranties to replace Merrill.

See Note 5, *Fair Value of Financial Instruments*, for discussion regarding concentration of credit risk.

Accumulated Other Comprehensive Income

The following table summarizes the effects of ASC 815 on NRG s accumulated OCI balance attributable to hedged derivatives, net of tax:

Year ended December 31, 2009	**Energy Commodities**	**Interest Rate**	**Total**
		(In millions)	
Accumulated OCI balance at December 31, 2008	$ 406	$ (91)	$ 315
Realized from OCI during the period:			
- Due to realization of previously deferred amounts	(335)	1	(334)
- Due to discontinuance of cash flow hedge accounting	(137)		(137)
Mark-to-market of cash flow hedge accounting contracts	527	35	562
Accumulated OCI balance at December 31, 2009	$ 461	$ (55)	$ 406
Gains/(losses) expected to be realized from OCI during the next 12 months, net of $123 tax	$ 213	$ (3)	$ 210

Year ended December 31, 2008	**Energy Commodities**	**Interest Rate**	**Total**
		(In millions)	
Accumulated OCI balance at December 31, 2007	$ (234)	$ (31)	$ (265)
Realized from OCI during the period:			
- Due to realization of previously deferred amounts		(1)	(1)
Mark-to-market of cash flow hedge accounting contracts	640	(59)	581
Accumulated OCI balance at December 31, 2008	$ 406	$ (91)	$ 315

Year ended December 31, 2007	**Energy Commodities**	**Interest Rate**	**Total**
		(In millions)	
Accumulated OCI balance at December 31, 2006	$ 193	$ 16	$ 209
Realized from OCI during the period:			
- Due to realization of previously deferred amounts	(50)	(2)	(52)
Mark-to-market of cash flow hedge accounting contracts	(377)	(45)	(422)
Accumulated OCI balance at December 31, 2007	$ (234)	$ (31)	$ (265)

As of December 31, 2009, the net balance in OCI relating to ASC 815 was an unrecognized gain of approximately $406 million, which is net of $247 million in income taxes. As of December 31, 2008, the net balance in OCI relating to ASC 815 was an unrecognized gain of approximately $315 million, which was net of $194 million in income taxes.

Accounting guidelines require a high degree of correlation between the derivative and the hedged item throughout the period in order to qualify as a cash flow hedge. As of July 31, 2008, the Company s regression analysis for natural gas prices to ERCOT power prices, while positively correlated, did not meet the required threshold for cash flow hedge accounting for calendar years 2012 and 2013. As a result, the Company de-designated its 2012 and 2013 ERCOT cash flow hedges as of July 31, 2008 and prospectively marked these derivatives to market. On April 1, 2009, the required correlation threshold for cash flow hedge accounting was achieved for these transactions, and accordingly, these hedges were re-designated as cash flow hedges.

As discussed in Note 3, *Business Acquisitions*, in conjunction with the CSRA, PML and REPS modified or novated certain transactions with counterparties. The novated transactions are financial sales of natural gas to the counterparties covering the period from 2009 through 2012 to hedge NRG s Texas baseload generation. A portion of these transactions were accounted for as cash flow hedges. The effective portion of the fair value of these transactions recorded in OCI was approximately $247 million. On the date of novation, NRG elected to de-designate these cash flow hedges and to recognize future changes in value in earnings prospectively. As the underlying baseload power generation is still probable, the gains through the date of novation related to the cash flow hedges remain frozen in OCI and will be amortized into income when the underlying power is generated. Approximately $240 million of the fair values of these transactions at the novation date were accounted for as mark-to-market transactions through the income statement both before and after the novations.

As also discussed in Note 3, *Business Acquisitions*, on October 5, 2009, the Company amended the CSRA with Merrill Lynch. In connection with the CSRA amendment, NRG net settled certain REPS out-of-money supply transactions with Merrill Lynch and paid $104 million in consideration. In addition, NRG net settled certain in-the-money REPS transactions with Morgan and received $269 million in consideration. As noted above, the in-the-money transaction was previously novated by NRG s wholly owned subsidiary PML to REPS. As these transactions were net settled, the $245 million in OCI will continue to be frozen and will be amortized into income when the underlying power from the baseload plants are generated and the balance of $24 million of previously recorded unrealized revenue was recorded as a loss of $24 million in unrealized derivative revenue and a $24 million gain in realized or financial revenue. The net settlement on the Merrill Lynch transactions resulted in a realized loss of $104 million and an unrealized gain of $104 million due to the reversal of an unrealized loss.

Statement of Operations

In accordance with ASC 815, unrealized gains and losses associated with changes in the fair value of derivative instruments not accounted for as cash flow hedge derivatives and ineffectiveness of hedge derivatives are reflected in current period earnings.

The following table summarizes the pre-tax effects of economic hedges that did not qualify for cash flow hedge accounting, ineffectiveness on cash flow hedges, and trading activity on NRG s statement of operations. These amounts are included within operating revenues and cost of operations.

	Year ended December 31, 2009	2008
	(In millions)	
Unrealized mark-to-market results		
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	$ (68)	$ (38)
Reversal of loss positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	656	
Reversal of previously recognized unrealized gains on settled positions related to trading activity	(157)	(32)
Reversal of previously recognized unrealized losses due to the termination of positions related to the CSRA unwind	80	
Net unrealized gains on open positions related to economic hedges	22	524
Gains/(losses) on ineffectiveness associated with open positions treated as cash flow hedges	45	(24)
Net unrealized (losses)/gains on open positions related to trading activity	(26)	95
Total unrealized gains	$ 552	$ 525

	Year Ended December 31, 2009	2008
	(In millions)	
Revenue/(expense) from operations - energy commodities	$ (290)	$ 525
Cost of operations	842	
Total impact to statement of operations	$ 552	$ 525

The $22 million gain from economic hedge positions includes a gain of $217 million recognized in earnings from previously deferred amounts in OCI as the Company discontinued cash flow hedge accounting for certain 2009 transactions in Texas and New York due to lower expected generation, offset by a loss of $29 million resulting from discontinued NPNS designated coal purchases due to expected lower coal consumption and accordingly could not assert taking physical delivery and a $166 million decrease in value of forward purchases and sales of natural gas, electricity and fuel due to decrease in forward power and gas prices.

The Reliant Energy s loss positions were acquired as of May 1, 2009, and valued using forward prices on that date. The $656 million roll-off amounts were offset by realized losses at the settled prices and are reflected in revenue and cost of operations during the same period.

For the year ended December 31, 2008, the unrealized gain associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $525 million was comprised of $524 million of fair value increases in forward sales of electricity and fuel, a $24 million loss due to the ineffectiveness associated with financial forward contracted electric and gas sales, $70 million from the reversal of mark-to-market gains which ultimately settled as financial and physical revenues of which $38 million was related to economic hedges and $32 million was related to trading activity. These decreases were partially offset by $95 million of gains associated with open positions related to trading activity.

Discontinued Hedge Accounting - During the first half of 2009, a relatively sharp decline in commodity prices resulted in falling power prices and lower power generation for the remainder of 2009. As such, NRG discontinued cash flow hedge accounting for certain 2009 contracts previously accounted for as cash flow hedges. These contracts were originally entered into as hedges of forecasted sales by baseload plants in Texas and Northeast. As a result, $217 million of gain previously deferred in OCI was recognized in earnings for the year ended December 31, 2009.

Discontinued Normal Purchase and Sale for Coal Purchases - Due to lower coal-fired generation during the first quarter 2009, the Company s coal consumption was lower than forecasted. The Company net settled some of its coal purchases under NPNS designation and thus was no longer able to assert physical delivery under these coal contracts. The forward positions previously treated as accrual accounting have been reclassified into mark-to-market accounting during the first quarter and prospectively. The impact of discontinuance of coal NPNS designated transactions resulted in a derivative loss of $29 million that is reflected in the cost of operations for the year ended December 31, 2009.

Note 7 Nuclear Decommissioning Trust Fund

NRG s nuclear decommissioning trust fund assets, which are for the decommissioning of STP, are comprised of securities classified as available-for-sale and recorded at fair value based on actively quoted market prices. Although NRG is responsible for managing the decommissioning of its 44% interest in STP, the predecessor utilities that owned STP are authorized by the PUCT to collect decommissioning funds from their ratepayers to cover decommissioning costs on behalf of NRG. NRC requirements determine the decommissioning cost estimate which is the minimum required level of funding. In the event that funds from the ratepayers that accumulate in the nuclear decommissioning trust are ultimately determined to be inadequate to decommission the STP facilities, the utilities will be required to collect through rate base all additional amounts, with no obligation from NRG, provided that NRG has complied with PUCT rules and regulations regarding decommissioning trusts. Following completion of the decommissioning, if surplus funds remain in the decommissioning trusts, any excess will be refunded to the respective ratepayers of the utilities.

NRG accounts for the nuclear decommissioning trust fund in accordance with ASC 980 *Regulated Operations*, or ASC 980 because the Company s nuclear decommissioning activities are subject to approval by the PUCT, with regulated rates that are designed to recover all decommissioning costs and that can be charged to and collected from the ratepayers per PUCT mandate. Since the Company is in compliance with PUCT rules and regulations regarding decommissioning trusts and the cost of decommissioning is the responsibility of the Texas ratepayers, not NRG, all realized and unrealized gains or losses (including other-than-temporary impairments) related to the Nuclear Decommissioning Trust Fund are recorded to the Nuclear Decommissioning Trust Liability to the ratepayers and are not included in net income or accumulated other comprehensive income, consistent with regulatory treatment.

The following table summarizes the aggregate fair values and unrealized gains and losses (including other-than-temporary impairments) for the securities held in the trust funds as of December 31, 2009 and 2008, as well as information about the contractual maturities of those securities. The cost of securities sold is determined on the specific identification method.

	As of December 31, 2009				As of December 31, 2008		
	Fair Value	Unrealized gains	Unrealized losses	Weighted-average maturities (years)	Fair Value	Unrealized gains	Unrealized losses
	(In millions, except otherwise noted)						
Cash and cash equivalents	$ 4	$	$		$ 2	$	$

U.S. government and federal agency obligations	23	1		19	21	2	
Federal agency mortgage-backed securities	60	2		23	49	2	
Commercial mortgage-backed securities	10		1	29	16		4
Corporate debt securities	48	3	1	10	37	1	2
Marketable equity securities	220	89	2		178	41	6
Foreign government fixed income securities	2			6			
Total	$ 367	$ 95	$ 4		$ 303	$ 46	$ 12

174

The following tables summarize proceeds from sales of available-for-sale securities and the related realized gains and losses from these sales. The cost of securities sold is determined on the specific identification method.

	Year ended December 31,		
	2009	2008	2007
	(In millions)		
Realized gains	$ 2	$ 11	$ 6
Realized losses	(1)	(33)	(1)
Proceeds from sale of securities	279	582	233

Note 8 Inventory

Inventory consists of:

	As of December 31,	
	2009	2008
	(In millions)	
Fuel oil	$ 104	$ 128
Coal/Lignite	288	189
Natural gas	9	11
Spare parts	137	127
Other	3	
Total Inventory	$ 541	$ 455

Note 9 Capital Leases and Notes Receivable

Notes receivable primarily consists of fixed and variable rate notes secured by equity interests in partnerships and joint ventures. NRG s notes receivable and capital leases as of December 31, 2009, and 2008 were as follows:

	As of December 31,	
	2009	2008
	(In millions)	
Capital Leases Receivable non-affiliates		
VEAG Vereinigte Energiewerke AG, due August 31, 2021, 11.00%[(a)]	$ 301	$ 338
Other	5	9
Capital Leases non-affiliates	306	347
Notes Receivable affiliates		
GenConn Energy LLC, due April 30, 2009, LIBOR + 3.75%[(b)] current		36

Kraftwerke Schkopau GBR, indefinite maturity date, 6.91%-7.00%[c] non-current	122	120
GCE Holding LLC which wholly-owns GenConn Energy LLC, indefinite maturity date, LIBOR +3%[d]	108	
Notes receivable affiliates	230	156
Subtotal Capital leases and notes receivable	536	503
Less current maturities:		
Capital leases	32	32
Notes receivable GenConn		36
Subtotal current maturities	32	68
Total Capital leases and notes receivable noncurrent	$ 504	$ 435

(a) Saale Energie GmbH, or SEG, has sold 100% of its share of capacity from the Schkopau power plant to VEAG Vereinigte Energiewerke AG under a 25-year contract, which is more than 83% of the useful life of the plant. This direct financing lease receivable amount was calculated based on the present value of the income to be received over the life of the contract.

(b) In 2008, NRG entered into a short-term $45 million note receivable facility with GenConn Energy LLC to fund project liquidity needs.

(c) SEG entered into a note receivable with Kraftwerke Schkopau GBR, a partnership between Saale and E.On Kraftwerke GmbH. The note was used to fund SEG s initial capital contribution to the partnership and to cover project liquidity shortfalls during construction of the Schkopau power plant. The note is subject to repayment upon the disposition of the Schkopau plant.

(d) NRG entered into a long-term $121.6 million note receivable facility with GCE Holding LLC to fund project liquidity needs.

Note 10 Property, Plant, and Equipment

NRG s major classes of property, plant, and equipment as of December 31, 2009 and 2008 were as follows:

	As of December 31, 2009	2008	Depreciable Lives
	(In millions)		
Facilities and equipment	$ 13,023	$ 12,193	1-40 Years
Land and improvements	621	593	
Nuclear fuel	286	225	5 Years
Office furnishings and equipment	153	73	2-10 Years
Construction in progress	533	804	
Total property, plant and equipment	14,616	13,888	
Accumulated depreciation	(3,052)	(2,343)	
Net property, plant and equipment	$ 11,564	$ 11,545	

Note 11 Goodwill and Other Intangibles

Goodwill NRG s goodwill arose in connection with the acquisitions of Texas Genco and Padoma Wind Power LLC. As of December 31, 2009 and 2008, goodwill was approximately $1.7 billion. In accordance with ASC 805, goodwill associated with the Texas Genco acquisition decreased by $68 million during 2008 due to an adjustment to deferred tax liabilities originally established under the 2006 purchase price allocation. Goodwill is not amortized but instead tested for impairment in accordance with ASC 350 at the reporting-unit level. Goodwill is tested annually, typically during the fourth quarter, or more often if events or circumstances, such as adverse changes in the business climate, indicate there may be impairment. As of December 31, 2009, there was no impairment to goodwill. As of December 31, 2009 and 2008, NRG had approximately $721 million and $786 million, respectively, of goodwill that is deductible for U.S. income tax purposes in future periods.

Intangible Assets The Company s intangible assets as of December 31, 2009 reflect intangible assets acquired from the acquisition of Bluewater Wind and Blythe Solar in November 2009, the acquisition of Reliant Energy in May 2009, the acquisition of Texas Genco in February 2006 and the adoption of Fresh Start accounting.

For the Reliant Energy acquisition, the intangible assets include energy supply contracts, customer contracts, customer relationships, trade names, and other. The energy supply contracts consist of in-market and out-of-market contracts that are amortized based on the expected delivery under the respective contracts. The amortization expense associated with the energy supply contracts is recorded as part of cost of operations. The customer contracts are amortized to revenues, based on expected volumes to be delivered for the portfolio. The customer relationships are amortized to depreciation and amortization expense, based on the expected discounted future cash flow by year. The trade names are amortized to depreciation and amortization expense on a straight line basis over the estimated useful life.

The intangible assets established with the Texas Genco acquisition and upon the adoption of Fresh Start reporting include SO_2 and NO_x emission allowances and certain in-market power, fuel (coal, gas, and nuclear) and water contracts. The emission allowances are amortized and recorded as a part of the cost of operations, with NO_x emission allowances amortized on a straight line basis and SO_2 emission allowances amortized based on units of production. The power contracts are amortized based on contracted volumes over the life of each contract and the fuel contracts are amortized over expected volumes over the life of each contract. The power contracts are amortized and recorded as part of revenues, while fuel and water contracts are amortized and recorded as part of the cost of operations.

In 2009, NRG began purchasing RGGI emission allowance credits, which are amortized based on units of production and recorded as a part of the costs of operations.

The following tables summarize the components of NRG s intangible assets subject to amortization for the years ended December 31, 2009 and 2008:

		Contracts							
December 31, 2009	**Emission Allowances**	**Power**	**Energy Supply**	**Fuel**	**Customer**	**Customer Relationships**	**Trade Names**	**Other**	**Total**
					(In millions)				
January 1, 2009	$ 916	$ 58	$	$ 171	$	$	$	$ 5	$ 1,150
Write-off of fully amortized intangible assets	(19)	(58)		(88)					(165)
Acquisition of businesses			54		790	399	178	11	1,432
Reclassification of NPNS contract to derivative				(12)					(12)
Other	22							(2)	20
Adjusted gross amount	919		54	71	790	399	178	14	2,425
Less accumulated amortization[(a)]	(199)		(18)	(48)	(258)	(117)	(8)		(648)
Net carrying amount	$ 720	$	$ 36	$ 23	$ 532	$ 282	$ 170	$ 14	$ 1,777

(a) Includes annual amortization expense as described in the table below; netting of fully amortized intangible assets of $19 million and $58 million for emission allowances and power contracts, respectively; and decrease of accumulated amortization expense of $88 million as a result of the reclassification of NPNS contract to derivatives in fuel contracts.

		Contracts				
December 31, 2008	**Emission Allowances**	**Power**	**Fuel**	**Water**	**Other**	**Total**
			(In millions)			
January 1, 2008	$ 916	$ 92	$ 171	$ 64	$ 2	$ 1,245
Additions	6				3	9
Transfer to held for sale	(6)					(6)
Fully amortized intangible assets		(34)		(64)		(98)
Adjusted gross amount	916	58	171		5	1,150
Less accumulated amortization	(155)	(58)	(122)			(335)
Net carrying amount	$ 761	$	$ 49	$	$ 5	$ 815

The following table presents NRG s amortization of intangible assets for the years ended December 31, 2009, 2008 and 2007:

Amortization	**2009**	**2008**	**2007**
		(In millions)	
Emission allowances	$ 63	$ 41	$ 40
Energy supply contracts	18		
Fuel contracts	15	20	37
Customer contracts	258		
Customer relationships	117		
Trade names	8		
Water contracts			36
Total amortization	$ 479	$ 61	$ 113

The following table presents estimated amortization related to NRG s emission allowances, in-market energy supply and fuel contracts, customer contracts, customer relationships and trade names:

		Contracts					
Year Ended December 31,	**Emission Allowances**	**Energy Supply**	**Fuel**	**Customer**	**Customer Relationships**	**Trade Names**	**Total**
				(In millions)			
2010	$ 89	$ 3	$ 6	$ 225	$ 81	$ 12	$ 416
2011	82	4	2	152	57	12	309
2012	76	5	2	105	44	12	244
2013	77	6	2	50	31	12	178
2014	80	6	2		24	12	124

177

The following table presents the weighted average remaining amortization period related to NRG s intangible assets purchased in 2009 through the Reliant Energy acquisition:

In years	Contracts Energy Supply	Contracts Customer	Customer Relationships	Trade Names	Total
Weighted average remaining amortization period	4.4	2.0	3.1	7.7	3.3

Intangible assets held for sale NRG records the Company s bank of emission allowances held-for-use as part of the Company s intangible assets. From time to time, management may authorize the transfer from the Company s emission bank to intangible assets held-for-sale. Emission allowances held-for-sale are included in other non current assets on the Company s consolidated balance sheet and are not amortized, but rather expensed as sold. As of December 31, 2009, the value of emission allowances held-for-sale is $7 million and is managed within the Corporate segment. Once transferred to held-for-sale, these emission allowances are prohibited from moving back to held-for-use.

Out-of-market contracts Due to Fresh Start accounting, as well as the acquisition of Blythe Solar, Reliant Energy and Texas Genco, NRG acquired certain out-of-market contracts. These are primarily customer contracts, energy supply, power, gas swaps, and certain coal contracts and are classified as non-current liabilities on NRG s consolidated balance sheet. The gas swap, power and customer contracts are amortized to revenues, while the energy supply and coal contracts are amortized to cost of operations.

The following table summarizes the estimated amortization related to NRG s out-of-market contracts:

Year Ended December 31,	Contracts Customer	Contracts Energy Supply	Contracts Coal	Contracts Gas Swap	Contracts Power	Contracts Total
	(In millions)					
2010	$ 8	$ 39	$ 6	$ 51	$ 27	$ 131
2011	7	11			20	38
2012	1	6			21	28
2013		3			19	22
2014					16	16

Note 12 Debt and Capital Leases

Long-term debt and capital leases consist of the following:

	As of December 31, 2009	2008	Interest Rate
	(In millions except rates)		
NRG Recourse Debt:			
Senior notes, due 2019[(a)]	$ 689	$	8.50
Senior notes, due 2017	1,100	1,100	7.375
Senior notes, due 2016	2,400	2,400	7.375
Senior notes, due 2014[(b)]	1,211	1,217	7.25
Term Loan Facility, due 2013	2,213	2,642	L+1.75/L+1.5[(f)]
NRG Non-Recourse Debt:			
CSF, notes and preferred interests, due 2010[(c)]	188	325	5.45-12.65 for 2009/5.45-13.23 for 2008
NRG Peaker Finance Co. LLC, bonds, due 2019[(d)]	220	229	L+1.07[(f)]
NRG Energy Center Minneapolis LLC, senior secured notes, due 2013 and 2017[(e)]	75	86	7.12-7.31
Dunkirk Power LLC tax-exempt bonds, due 2042	52		Weekly rate based on SIFMA rate[(g)]
NRG Connecticut Peaking LLC, equity bridge loan facility, due 2010 and 2011	108		L + 2[(f)]
Other	39	20	L + 0.45[(f)]
Subtotal long-term debt	8,295	8,019	
Capital leases:			
Saale Energie GmbH, Schkopau capital lease, due 2021	123	142	
Subtotal	8,418	8,161	
Less current maturities[(h)]	571	464	
Total	$ 7,847	$ 7,697	

(a) Includes discount of $(11) million as of December 31, 2009. On June 5, 2009, NRG issued these $700 million aggregate principal amount bonds resulting in a yield of 8.75%.
(b) Includes fair value adjustment as of December 31, 2009 and 2008 of $11 million and $17 million, respectively, reflecting an adjustment for an interest rate swap.
(c) Includes discount of $(2) million and $(8) million as of December 31, 2009 and 2008, respectively.
(d) Includes discount of $(31) million and $(37) million as of December 31, 2009 and 2008, respectively.
(e) Includes premium of $2 million as of December 31, 2009 and 2008.
(f) L+ equals LIBOR plus x%.
(g) Securities Industry and Financial Markets Association, or SIFMA.
(h)

Includes discount of $(6) million on the NRG Peaker Finance debt as of December 31, 2009 and 2008; discount of $(1) million on the CSF notes and preferred interests as of December 31, 2009 and a premium of $1 million on NRG Energy Center Minneapolis debt as of December 31, 2009 and 2008.

Senior Notes

NRG has four outstanding issuances of senior notes, or Senior Notes, under an Indenture, dated February 2, 2006, or the Indenture, between NRG and Law Debenture Trust Company of New York, as trustee:

(i) 7.25% senior notes, issued February 2, 2006 and due February 1, 2014, or the 2014 Senior Notes;
(ii) 7.375% senior notes, issued February 2, 2006 and due February 1, 2016, or the 2016 Senior Notes;
(iii) 7.375% senior notes, issued November 21, 2006 and due January 15, 2017, or the 2017 Senior Notes; and
(iv) 8.5% senior notes, issued June 5, 2009 and due June 15, 2019, or the 2019 Senior Notes.

Supplemental indentures to the series of notes have been issued to add newly formed or acquired subsidiaries as guarantors.

The Indentures and the form of notes provide, among other things, that the Senior Notes will be senior unsecured obligations of NRG. The Indentures also provide for customary events of default, which include, among others: nonpayment of principal or interest; breach of other agreements in the Indentures; defaults in failure to pay certain other indebtedness; the rendering of judgments to pay certain amounts of money against NRG and its subsidiaries; the failure of certain guarantees to be enforceable; and certain events of bankruptcy or insolvency. Generally, if an event of default occurs, the Trustee or the Holders of at least 25% in principal amount of the then outstanding series of Senior Notes may declare all of the Senior Notes of such series to be due and payable immediately.

The terms of the Indentures, among other things, limit NRG s ability and certain of its subsidiaries ability to:

return capital to shareholders;

grant liens on assets to lenders; and

incur additional debt.

Interest is payable semi-annually on the Senior Notes until their maturity dates. In addition, the Company entered into a fixed to floating interest rate swap in 2004 with a notional amount as of December 31, 2009 of $400 million and a maturity date of December 15, 2013.

Prior to February 1, 2010, NRG may redeem all or a portion of the 2014 Senior Notes at a price equal to 100% of the principal amount plus a premium and accrued interest. The premium is the greater of: (i) 1% of the principal amount of the note, or (ii) the excess of the principal amount of the note over the following: the present value of 103.625% of the note, plus interest payments due on the note from the date of redemption through February 1, 2010, discounted at a Treasury rate plus 0.50%. On or after February 1, 2010, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth below, plus accrued and unpaid interest on the notes redeemed to the applicable redemption date:

Redemption Period	**Redemption Percentage**
February 1, 2010 to February 1, 2011	103.625%
February 1, 2011 to February 1, 2012	101.813%
February 1, 2012 and thereafter	100.000%

Prior to February 1, 2011, NRG may redeem all or a portion of the 2016 Senior Notes at a price equal to 100% of the principal amount plus a premium and accrued interest. The premium is the greater of: (i) 1% of the principal amount of the note, or (ii) the excess of the principal amount of the note over the following: the present value of 103.688% of the note, plus interest payments due on the note from the date of redemption through February 1, 2011, discounted at a Treasury rate plus 0.50%. On or after February 1, 2011, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth below, plus accrued and unpaid interest on the notes redeemed to the applicable redemption date:

Redemption Period	Redemption Percentage
February 1, 2011 to February 1, 2012	103.688%
February 1, 2012 to February 1, 2013	102.458%
February 1, 2013 to February 1, 2014	101.229%
February 1, 2014 and thereafter	100.000%

Prior to January 15, 2012, NRG may redeem up to 35% of the 2017 Senior Notes with net cash proceeds of certain equity offerings at a price of 107.375%, provided at least 65% of the aggregate principal amount of the notes issued remain outstanding after the redemption. Prior to January 15, 2012, NRG may redeem all or a portion of the Senior Notes at a price equal to 100% of the principal amount of the notes redeemed, plus a premium and any accrued and unpaid interest. The premium is the greater of: (i) 1% of the principal amount of the note, or (ii) the excess of the principal amount of the note over the following: the present value of 103.688% of the note, plus interest payments due on the note from the date of redemption through January 15, 2012, discounted at a Treasury rate plus 0.50%. In addition, on or after January 15, 2012, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth below, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	Redemption Percentage
February 1, 2012 to February 1, 2013	103.688%
February 1, 2013 to February 1, 2014	102.458%
February 1, 2014 to February 1, 2015	101.229%
February 1, 2015 and thereafter	100.000%

Prior to June 15, 2012, NRG may redeem up to 35% of the aggregate principal amount of the 2019 Senior Notes with the net proceeds of certain equity offerings, at a redemption price of 108.5% of the principal amount. Prior to June 15, 2014, NRG may redeem all or a portion of the 2019 Senior Notes at a price equal to 100% of the principal amount plus a premium and accrued and unpaid interest. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the principal amount of the note over the following: the present value of 104.25% of the note, plus interest payments due on the note from the date of redemption through June 15, 2014, discounted at a Treasury rate plus 0.50%. In addition, on or after June 15, 2014, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	Redemption Percentage
June 15, 2014 to June 14, 2015	104.25%
June 15, 2015 to June 14, 2016	102.83%
June 15, 2016 to June 14, 2017	101.42%
June 15, 2017 and thereafter	100.00%

Senior Credit Facility

As of December 31, 2009, NRG has a Senior Credit Facility which is comprised of a senior first priority secured term loan, or the Term Loan Facility, a $1.0 billion senior first priority secured revolving credit facility, or the Revolving Credit Facility, and a $1.3 billion senior first priority secured synthetic letter of credit facility, or the Synthetic Letter of Credit Facility. The Senior Credit Facility was last amended on June 8, 2007 which resulted in a charge of $35 million which was recorded to the Company s results of operations for the year ended December 31, 2007, primarily related to the write-off of previously deferred financing costs. The pricing on the Company s Term Loan Facility and Synthetic Letter of Credit Facility is also subject to further reductions upon the achievement of certain financial ratios.

As of December 31, 2009, NRG had issued $717 million of letters of credit under the Synthetic Letter of Credit Facility, leaving $583 million available for future issuances. Under the Company s Revolving Credit Facility as of

December 31, 2009, NRG had issued letters of credit totaling $95 million, leaving $905 million available for borrowings, of which approximately $805 million could be used to issue additional letters of credit.

The Term Loan Facility matures on February 1, 2013, and amortizes in twenty-seven consecutive equal quarterly installments of 0.25% term loan commitments, beginning June 30, 2006, with the balance payable on the seventh anniversary thereof. The full amount of the Revolving Credit Facility will mature on February 2, 2011. The Synthetic Letter of Credit Facility will mature on February 1, 2013, and no amortization will be required in respect thereof. NRG has the option to prepay the Senior Credit Facility in whole or in part at any time.

NRG must annually offer a portion of its excess cash flow (as defined in the Senior Credit Facility) to its first lien lenders under the Term Loan Facility. The percentage of the excess cash flow offered to these lenders is dependent upon the Company s consolidated leverage ratio (as defined in the Senior Credit Facility) at the end of the preceding year. Of the amount offered, the first lien lenders must accept 50%, while the remaining 50% may either be accepted or rejected at the lenders option. The 2010 mandatory offer related to 2009 is expected to be $430 million, against which the Company made a prepayment of $200 million in December 2009. Based on current credit market conditions, the Company expects that its lenders will accept in full the 2010 mandatory offer related to 2009, and, as such, the Company has reclassified approximately $230 million of Term Loan Facility maturity from a non-current to a current liability as of December 31, 2009. The 2009 mandatory offer and prepayment related to 2008 paid in March 2009 was $197 million.

The Senior Credit Facility is guaranteed by substantially all of NRG s existing and future direct and indirect subsidiaries, with certain customary or agreed-upon exceptions for unrestricted foreign subsidiaries, project subsidiaries, and certain other subsidiaries. The capital stock of substantially all of NRG s subsidiaries, with certain exceptions for unrestricted subsidiaries, foreign subsidiaries, and project subsidiaries, has been pledged for the benefit of the Senior Credit Facility s lenders.

The Senior Credit Facility is also secured by first-priority perfected security interests in substantially all of the property and assets owned or acquired by NRG and its subsidiaries, other than certain limited exceptions. These exceptions include assets of certain unrestricted subsidiaries, equity interests in certain of NRG s project affiliates that have non-recourse debt financing, and voting equity interests in excess of 66% of the total outstanding voting equity interest of certain of NRG s foreign subsidiaries.

The Senior Credit Facility contains customary covenants, which, among other things, require NRG to meet certain financial tests, including minimum interest coverage ratio and a maximum leverage ratio on a consolidated basis, and limit NRG s ability to:

- incur indebtedness and liens and enter into sale and lease-back transactions;
- make investments, loans and advances; and
- return capital to shareholders.

Interest Rate Swaps In May 2009, NRG entered into a series of forward-starting interest rate swaps. These interest rate swaps become effective on April 1, 2011, and are intended to hedge the risks associated with floating interest rates. For each of the interest rate swaps, the Company will pay its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG receives the monthly equivalent of a floating interest payment based on a 1-month LIBOR calculated on the same notional value. All interest rate swap payments by NRG and its counterparties are made monthly and the LIBOR is determined in advance of each interest period. The total notional amount of these swaps, which mature on February 1, 2013, is $900 million.

In 2006 in connection with the Senior Credit Facility, NRG entered into another series of forward-setting interest rate swaps which are intended to hedge the risks associated with floating interest rates. For each of the interest rate swaps, the Company pays its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG receives quarterly the equivalent of a floating interest payment based on a 3-month LIBOR calculated on the same notional value. All interest rate swap payments by NRG and its counterparties are made quarterly, and the LIBOR is determined in advance of each interest period. While the notional value of each of the swaps does not vary over time, the swaps are designed to mature sequentially. The notional amounts and maturities of each tranche of these swaps as of December 31, 2009, are as follows:

Maturity	**Notional Value**
March 31, 2010	$ 190 million
March 31, 2011	$ 1.55 billion

Dunkirk Power LLC Tax-Exempt Bonds

On April 15, 2009, NRG executed a $59 million tax-exempt bond financing, or the Dunkirk bonds, through its wholly-owned subsidiary, Dunkirk Power LLC. The bonds were issued by the County of Chautauqua Industrial Development Agency and will be used for construction of emission control equipment on the Dunkirk Generating Station in Dunkirk, NY. The bonds initially bear weekly interest based on the Securities Industry and Financial Markets Association, or SIFMA, rate, have a maturity date of April 1, 2042, and are enhanced by a letter of credit under the Company s Revolving Credit Facility covering amounts drawn on the facility. The proceeds received through December 31, 2009 were $52 million, with the remaining balance being released over time as construction costs are paid. On February 1, 2010, the Company fixed the rate on the Dunkirk bonds at 5.875%. Interest will be payable semiannually. In addition, the $59 million letter of credit issued by NRG in support of the bonds was cancelled and replaced with a parent guarantee.

NRG Non-Recourse Debt

Debt Related to Capital Allocation Program

In 2006, the Company formed CSF I and II, two wholly-owned unrestricted subsidiaries that are both consolidated by NRG. Their purpose was to repurchase an aggregate of $500 million in shares of NRG s common stock in the public markets or in privately negotiated transactions in connection with the Company s Capital Allocation Program. These subsidiaries were funded with a combination of cash from NRG, and a mix of notes and preferred interests issued to CS, or the CSF Debt. Both the notes and the preferred interests are non-recourse debt to NRG or any of its restricted subsidiaries, with the debt collateralized by the NRG common stock held by CSF I and II. In addition, the assets of CSF I and II are not available to the creditors of NRG or the Company s other subsidiaries.

From inception through July 2008, the notes and preferred interests of CSF I contained a feature considered an embedded derivative, which required NRG to pay to CS at maturity, either in cash or stock at NRG s option, the excess of NRG s then current stock price over a Threshold Price. From inception through November 24, 2009, the notes and preferred interests of CSF II also contained a feature considered an embedded derivative with terms similar to the CSF I embedded derivative. The Threshold Price is the price of NRG s stock in excess of a compound annual growth rate, or CAGR, of 20% beyond the volume-weighted average share price of the stock at the time of repurchase. Although this feature was considered a derivative, it was exempt from derivative accounting under the guidance of ASC 815, and was only recognized upon settlement. As a result of the early settlement in August 2008 by the CSF I extension and the unwinding of the CSF II debt in November 2009, both described below, there were no notes or preferred interests containing an embedded derivative feature as of December 31, 2009.

CSF I Extension In March 2008, the Company executed an arrangement with CS to extend the notes and preferred interest maturities of the CSF I Debt from October 2008 to June 2010. In addition, the settlement date of the embedded derivative, or CSF I CAGR, was extended 30 days to early December 2008. As part of this extension arrangement, the Company contributed 795,503 treasury shares to CSF I as additional collateral to maintain a blended interest rate in the CSF I facility of approximately 7.5%. The amount due at maturity in June 2010, including accrued interest, for the CSF I Debt will be $249 million. In August 2008, the Company amended the CSF I Debt to early settle the CSF I CAGR. Accordingly, NRG made a cash payment of $45 million to CS for the benefit of CSF I, which was recorded to additional paid in capital on the Company s consolidated balance sheet as of December 31, 2008. See further discussion below regarding the adoption of FSP APB 14-1.

Share Lending Agreements On February 20, 2009, CSF I and II entered into Share Lending Agreements, or SLAs, with affiliates of CS relating to the shares of NRG common stock currently held by CSF I and II in connection with the CSF Debt. The Company entered into the SLAs due to a lack of liquidity in the stock borrow market for NRG shares that existed at that time and in order to maintain the intended economic benefits of the CSF Debt agreements. The SLAs permitted affiliates of CS to borrow up to the total number of shares of NRG common stock held by CSF I and II. CSF I and II loaned affiliates of CS 6,600,000 and 5,400,000 shares, respectively, of NRG common stock under the SLAs.

Shares borrowed by affiliates of CS under the SLAs were used to replace shares borrowed by affiliates of CS from third parties in connection with CS hedging activities related to the financing agreements. The shares are expected to be returned upon the termination of the financing agreements. Until the shares are returned, the shares will be treated as outstanding for corporate law purposes, and accordingly, the holders of the borrowed shares will have all of the rights of a holder of the Company s outstanding shares, including the right to vote the shares on all matters submitted to a vote of the Company s stockholders. However, because the CS affiliates must return all borrowed shares (or identical shares), the borrowed shares are not considered outstanding for the purpose of computing and reporting the Company s basic or diluted earnings per share.

CSF II Debt Maturity On November 24, 2009, the Company completed the unwinding of the CSF II Debt, remitting a cash payment to CS of the $181 million outstanding principal and interest, while CS returned 5,400,000 shares of NRG common stock borrowed under the SLAs, and then released all 9,528,930 common shares held as collateral for the CSF II Debt. The CSF II Debt contained an embedded derivative feature, or CFS II CAGR, which could have required NRG to pay CS at maturity, either in cash or stock at NRG s option, the excess of NRG s then current stock price over a Threshold Price of $40.80 per share. On November 24, 2009, it was determined that no payment was required on the CSF II CAGR at which point the CSF II CAGR expired.

At December 31, 2009, CSF I held 12,441,973 shares of NRG common stock of which 6,600,000 shares lent to affiliates of CS under the SLAs, with a fair value of $156 million, are considered outstanding and 5,841,973 shares are reflected within treasury stock on the Company s consolidated balance sheet.

Notes As of December 31, 2009, CSF I had a total of $137 million in notes in connection with Phase I of the Capital Allocation Program which mature in June 2010, plus accrued interest at an annual rate of 5.45%. As of December 31, 2008, CSF I and II had a total of $249 million in notes outstanding in connection with Phase I.

Preferred Interests As of December 31, 2009, CSF I had a total of $53 million in preferred interests issued and outstanding which mature in June 2010, plus accrued interest at an annual rate of 12.65%. As of December 31, 2008, CSF I and II had a total of $84 million in preferred interests issued and outstanding. The preferred interests are classified as a liability per ASC 480, *Distinguishing Liabilities from Equity,* or ASC 480, because they embody a fixed unconditional obligation that the unrestricted subsidiaries must settle.

Adoption of FSP APB 14-1 As discussed in Note 2, *Summary of Significant Accounting Policies*, the Company adopted FSP APB 14-1 on January 1, 2009, which has been incorporated in ASC 470 and ASC 825. The following table summarizes certain information related to the CSF Debt in accordance with ASC 470:

	December 31, 2009	December 31, 2008
	(In millions)	
Equity Component		
Additional Paid-in Capital	$	$ 14

Liability Component				
Principal amount	$	190	$	333
Unamortized discount		(2)		(8)
Net carrying amount	$	188	$	325

The unamortized discount will be amortized through the maturity of the CSF Debt. The CSF II debt matured in November 2009 and the CSF I debt has a maturity date of June 2010. Interest expense for the CSF Debt, including the debt discount amortization for the years ended December 31, 2009, 2008, and 2007 was $33 million, $37 million, and $40 million, respectively. The effective interest rate as of December 31, 2009, was 11.4% for the CSF I debt. The effective interest rate as of December 31, 2008, was 11.4% for the CSF I debt and 12.1% for the CSF II debt.

Project Financings

The following are descriptions of certain indebtedness of NRG s project subsidiaries that remain outstanding as of December 31, 2009. The indebtedness described below is non-recourse to NRG, unless otherwise noted.

TANE Facility

On February 24, 2009, Nuclear Innovation North America LLC, or NINA, executed an EPC agreement with Toshiba American Nuclear Energy Corporation, or TANE, which specifies the terms under which STP Units 3 and 4 will be constructed. Concurrent with the execution of the EPC agreement, NINA and TANE entered into a credit facility, or the TANE Facility, wherein TANE has committed up to $500 million to finance purchases of long-lead materials and equipment for the construction of STP Units 3 and 4. The TANE Facility matures on February 24, 2012, subject to two renewal periods, and provides for customary events of default, which include, among others: nonpayment of principal or interest; default under other indebtedness; the rendering of judgments; and certain events of bankruptcy or insolvency. Outstanding borrowings will accrue interest at LIBOR plus 3%, subject to a ratings grid, and are secured by substantially all of the assets of and membership interests in NINA and its subsidiaries. As of December 31, 2009, no amounts have been borrowed under the TANE Facility.

GenConn Energy LLC related financings

On April 27, 2009, NRG Connecticut Peaking LLC, a wholly-owned subsidiary of NRG, closed on an equity bridge loan facility, or EBL, in the amount of $121.5 million from a syndicate of banks. The purpose of the EBL is to fund the Company s proportionate share of the project construction costs required to be contributed into GenConn Energy LLC, or GenConn, a 50% equity method investment of the Company. The EBL, which is fully collateralized with a letter of credit issued under the Company s Synthetic Letter of Credit Facility covering amounts drawn on the facility, will bear interest at a rate of LIBOR plus 2% on drawn amounts. The EBL will mature on the earlier of Middletown s commercial operations date or July 26, 2011. The EBL also requires mandatory prepayment of the portion of the loan utilized to pay costs of the Devon project, of approximately $54 million, on the earlier of Devon s commercial operations date, currently anticipated to be June 2010, or January 27, 2011. The proceeds of the EBL received through December 31, 2009, were $108 million and the remaining amounts will be drawn as necessary.

Borrowings of an equity method investment In April 2009, GenConn, a variable interest entity, secured financing for 50% of the Devon and Middletown project construction costs through a 7-year term loan facility, and also entered into a 5-year revolving working capital loan and letter of credit facility, which collectively with the term loan is referred to as the GenConn Facility. The aggregate credit amount secured under the GenConn Facility, which is non-recourse to NRG, is $291 million, including $48 million for the revolving facility. In August 2009, GenConn began to draw under the GenConn Facility to cover costs related to the Devon project and as of December 31, 2009, has drawn $48 million.

Other

In 2008, NINA and NRG Repowering Holdings LLC, or NRG Repowering, each obtained a $20 million revolving credit facility to provide working capital which permits NINA and NRG Repowering to make cash draws or issue letters of credit. The facilities mature on April 30, 2010, for NINA and August 12, 2011, for NRG Repowering. The facilities provide for customary events of default, which include, among others: nonpayment of principal or interest; breach of other agreements in the facility; the rendering of judgments to pay certain amounts of money against NINA or NRG Repowering and their subsidiaries; and certain events of bankruptcy or insolvency. Borrowings under the facilities accrue interest at LIBOR or a base rate, plus a spread and are supported by a letter of credit issued by NRG. As of December 31, 2009, and 2008, NINA had borrowed approximately $20 million and $10 million, respectively.

As of December 31, 2009, and 2008, NRG Repowering had borrowed approximately $19 million and $10 million, respectively. As of December 31, 2009, NRG Repowering also had outstanding approximately $1 million in letters of credit.

Peakers

In June 2002, NRG Peaker Finance Company LLC, or Peakers, an indirect wholly-owned subsidiary, issued $325 million in floating rate bonds due June 2019. Peakers subsequently swapped such floating rate debt for fixed rate debt at an all-in cost of 6.67% per annum. Principal, interest, and swap payments were originally guaranteed by Syncora Guarantee Inc., successor in interest to XL Capital Assurance, through a financial guaranty insurance policy. In 2009, Assured Guaranty Mutual Corp assumed the responsibility as the bond insurer and controlling party. Syncora Guarantee Inc. continues to be the swap insurer. These notes are also secured by, among other things, substantially all of the assets of and membership interests in Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Sterlington Power LLC, NRG Rockford LLC, NRG Rockford II LLC, and NRG Rockford Equipment LLC. As of December 31, 2009, approximately $251 million in principal remained outstanding on these bonds. Upon emergence from bankruptcy, NRG issued a $36 million letter of credit to the Peakers collateral agent. The letter of credit may be drawn if the project is unable to meet principal or interest payments. There are no provisions requiring NRG to replenish the letter of credit if it is drawn. On December 10, 2009, the collateral agent drew approximately $0.6 million on the letter of credit to meet the debt service requirements.

NRG Thermal

NRG owns and operates its thermal business through a wholly-owned subsidiary holding company, NRG Thermal LLC, or NRG Thermal. In 1993, the predecessor entity to NRG Thermal s largest subsidiary, NRG Energy Center Minneapolis LLC, or NRG Thermal Minneapolis, issued $84 million of 7.31% senior secured notes due June 2013, of which approximately $25 million remained outstanding as of December 31, 2009. In 2002, NRG Thermal Minneapolis issued an additional $55 million of 7.25% Series A notes due August 2017, of which approximately $37 million remained outstanding as of December 31, 2009, and $20 million of 7.12% Series B notes due August 2017, of which approximately $13 million remained outstanding as of December 31, 2009. This indebtedness is secured by substantially all of the assets of NRG Thermal Minneapolis. NRG Thermal has guaranteed the indebtedness, and its guarantee is secured by a pledge of the equity interests in all of NRG Thermal s subsidiaries.

Capital Leases

Saale Energie GmbH

Saale Energie GmbH, or SEG, an NRG wholly-owned subsidiary, has a 41.9% participation in Schkopau through NRG s interest in the Kraftwerke Schkopau GbR, or KSGbR, partnership. Under the terms of a Use and Benefit Fee Agreement, SEG and the other partner to the project, E.ON Kraftwerke GmbH, are required to fund debt service and certain other costs resulting from the construction and financing of Schkopau. The Use and Benefit Fee Agreement is treated as a capital lease under U.S. GAAP. Calls for funds are made to the partners based on their participation interest as cash is needed. As of December 31, 2009, the capital lease obligation at SEG was approximately $123 million.

The KSGbR issued debt to fund Schkopau pursuant to multiple facilities totaling approximately 785 million. As of December 31, 2009, approximately 141 million (approximately $202 million) remained outstanding at Schkopau. Interests on the individual loans accrue at fixed rates averaging 4.26% per annum, with maturities occurring between 2010 and 2015. SEG remains liable to the lenders as a partner in KSGbR, but there is no recourse to NRG.

Consolidated Annual Maturities and Future Minimum Lease Payments

Annual payments based on the maturities of NRG s long-term debt and capital leases for the years ending after December 31, 2009 are as follows:

		(In millions)
2010	$	571
2011		143
2012		70
2013		1,926
2014		1,250
Thereafter		4,458
Total	$	8,418

NRG s future minimum lease payments for capital leases included above as of December 31, 2009, are as follows:

		(In millions)
2010	$	28
2011		16
2012		14
2013		13
2014		14
Thereafter		107
Total minimum obligations		192
Interest		69
Present value of minimum obligations		123
Current portion		22
Long-term obligations	$	101

Note 13 Asset Retirement Obligations

NRG s AROs are primarily related to the future dismantlement of equipment on leased property and environmental obligations related to nuclear decommissioning, ash disposal, site closures, and fuel storage facilities. In addition, NRG has also identified conditional AROs for asbestos removal and disposal, which are specific to certain power generation operations.

See Note 7, *Nuclear Decommissioning Trust Fund,* for a further discussion of NRG s nuclear decommissioning obligations. Consequently, accretion for the nuclear decommissioning ARO and amortization of the related ARO asset are recorded to the Nuclear Decommissioning Trust Liability to the ratepayers and are not included in net income, consistent with regulatory treatment.

The following table represents the balance of ARO obligations as of December 31, 2009, and 2008, along with the additions, reductions and accretion related to the Company s ARO obligations for the year ended December 31, 2009:

	Total (In millions)
Balance as of December 31, 2008	$ 393
Additions	3
Revisions in estimated cashflows	(5)
Accretion Expense	8
Accretion Nuclear decommissioning	16
Balance as of December 31, 2009	$ 415

Note 14 Benefit Plans and Other Postretirement Benefits

NRG sponsors and operates three defined benefit pension and other postretirement plans. The NRG Plan for Bargained Employees and the NRG Plan for Non-bargained Employees are maintained solely for eligible legacy NRG participants. A third plan, the Texas Genco Retirement Plan, is maintained for participation by eligible Texas based employees. NRG expects to contribute approximately $18 million to the Company s three pension plans in 2010.

NRG Plans for Bargained and Non-bargained Employees Substantially all employees hired prior to December 5, 2003, were eligible to participate in NRG s legacy defined benefit pension plans. The Company initiated a noncontributory, defined benefit pension plan effective January 1, 2004, with credit for service from December 5, 2003. In addition, the Company provides postretirement health and welfare benefits for certain groups of employees. Generally, these are groups that were acquired prior to 2004 and for whom prior benefits are being continued (at least for a certain period of time or as required by union contracts). Cost sharing provisions vary by acquisition group and terms of any applicable collective bargaining agreements.

Texas Genco Retirement Plan The Texas region s pension plan is a noncontributory defined benefit pension plan that provides a final average pay benefit or cash balance benefit, where the participant receives the more favorable of the two formulas, based on all years of service. In addition, employees who were hired prior to 1999 are also eligible for grandfathered benefits under a final average pay formula. In most cases, the benefits under the grandfathered formula were frozen on December 31, 2008. NRG s Texas region employees are also covered under an unfunded postretirement health and welfare plan. Each year, employees receive a fixed credit of $750 to their account plus interest. Certain grandfathered employees will receive additional credits through 2008. At retirement, the employees may use their accounts to purchase retiree medical and dental benefits from NRG. NRG s costs are limited to the amounts earned in the employee s account; all other costs are paid by the participant.

NRG Defined Benefit Plans

The net annual periodic pension cost related to NRG domestic pension and other postretirement benefit plans include the following components:

	Year Ended December 31, Pension Benefits		
	2009	2008	2007
		(In millions)	
Service cost benefits earned	$ 12	$ 14	$ 15
Interest cost on benefit obligation	20	18	17
Expected return on plan assets	(16)	(14)	(11)
Amortization of unrecognized net gain	1	(1)	
Net periodic benefit cost	$ 17	$ 17	$ 21

Year Ended December 31,

	Other Postretirement Benefits		
	2009	2008	2007
		(In millions)	
Service cost benefits earned	$ 2	$ 2	$ 2
Interest cost on benefit obligation	6	6	5
Amortization of unrecognized prior service cost	1	1	
Net periodic benefit cost	$ 9	$ 9	$ 7

A comparison of the pension benefit obligation, other post retirement benefit obligations, and related plan assets as of December 31, 2009 and 2008 for NRG s plans on a combined basis is as follows:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(In millions)			
Benefit obligation at January 1	$ 291	$ 290	$ 91	$ 83
Service cost	12	14	2	2
Interest cost	20	18	6	6
Plan amendments	1			5
Actuarial gain	45	(19)	6	(4)
Employee and retiree contributions			1	
Benefit payments	(12)	(12)	(2)	(1)
Benefit obligation at December 31	357	291	104	91
Fair value of plan assets at January 1	195	168		
Actual return on plan assets	53	(60)		
Employee contributions			1	
Employer contributions	27	99	1	1
Benefit payments	(12)	(12)	(2)	(1)
Fair value of plan assets at December 31	263	195		
Funded status at December 31 excess of obligation over assets	$ (94)	$ (96)	$ (104)	$ (91)

Amounts recognized in NRG s balance sheets were as follows:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(In millions)			
Current liabilities	$	$	$ 2	$ 2
Non-current liabilities	94	96	102	89

Amounts recognized in NRG s accumulated other comprehensive income that have not yet been recognized as components of net periodic benefit cost were as follows:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(In millions)			
Unrecognized loss/(gain)	$ 29	$ 21	$ 1	$ (6)
Prior service (credit)/cost	(3)	(3)	4	5

Other changes in plan assets and benefit obligations recognized in other comprehensive income were as follows:

	Year Ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(In millions)			
Net loss/(gain)	$ 7	$ 55	$ 7	$ (4)
Amortization of net actuarial loss		1		
Prior service cost	1			5
Amortization for prior service cost			(1)	(1)
Total recognized in other comprehensive loss	$ 8	$ 56	$ 6	$
Total recognized in net periodic pension cost and other comprehensive income	$ 25	$ 73	$ 15	$ 9

The Company s estimated net gain for NRG s domestic pension plan that will be amortized from the accumulated other comprehensive income to net periodic cost over the next fiscal year is minimal.

The following table presents the balances of significant components of NRG s domestic pension plan:

	As of December 31, Pension Benefits	
	2009	2008
	(In millions)	
Projected benefit obligation	$ 357	$ 291
Accumulated benefit obligation	309	251
Fair value of plan assets	263	195

NRG s market-related value of its plan assets is the fair value of the assets. The fair values of the Company s pension plan assets at December 31, 2009 by asset category are as follows:

	Fair Value Measurements at December 31, 2009			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable	Significant Unobservable Inputs (Level 3)	Total

		Inputs (Level 2)		
		(In millions)		
U.S. equity investment	$ 44	$	$	$ 44
International equity investment	12			12
Corporate bond investment-fixed income	23			23
Common/collective trust investment U.S. equity		107		107
Common/collective trust investment international equity		29		29
Common/collective trust investment fixed income		48		48
Total	$ 79	$ 184	$	$ 263

The fair value of the U.S. and international equity investments and the corporate bond investment are based on quoted prices in active markets and are categorized in Level 1. All equity investments are valued at the net asset value of shares held at year end. The fair value of the corporate bond investment is based on the closing price reported on the active market on which the individual securities are traded. The fair value of the common /collective trusts are valued at fair value which is equal to the sum of the market value of all of the fund s underlying investments and is categorized as Level 2.

The following table presents the significant assumptions used to calculate NRG s benefit obligations:

	As of December 31,			
Weighted-Average	**Pension Benefits**		**Other Postretirement Benefits**	
Assumptions	**2009**	**2008**	**2009**	**2008**
Discount rate	5.93%	6.88%	6.14%	6.88%
Rate of compensation increase	4.00-4.50%	4.00-4.50%	N/A	N/A
Health care trend rate			9.5% grading to 5.5% in 2016	9.5% grading to 5.5% in 2016

The following table presents the significant assumptions used to calculate NRG s benefit expense:

	As of December 31,					
Weighted-Average	**Pension Benefits**			**Other Postretirement Benefits**		
Assumptions	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
Discount rate	6.88%	6.56%	5.92%	6.88%	6.56%	5.92%
Expected return on plan assets	7.50%	7.50%	8.00%			
Rate of compensation increase	4.00-4.50%	4.00-4.50%	4.00-4.50%			
Health care trend rate				9.5% grading to 5.5% in 2016	9.5% grading to 5.5% in 2016	10.5% grading to 5.5% in 2012

NRG uses December 31 of each respective year as the measurement date for the Company s pension and other postretirement benefit plans. The Company sets the discount rate assumptions on an annual basis for each of NRG s retirement related benefit plans at their respective measurement date. This rate is determined by NRG s Investment Committee based on information provided by the Company s actuary. The discount rate assumptions reflect the current rate at which the associated liabilities could be effectively settled at the end of the year. The discount rate assumptions used to determine future pension obligations as of December 31, 2009, and 2008 were based on the Hewitt Yield Curve, or HYC, which was designed by Hewitt Associates to provide a means for plan sponsors to value the liabilities of their postretirement benefit plans. The HYC is a hypothetical yield curve represented by a series of annualized individual discount rates. Each bond issue underlying the HYC is required to have a rating of Aa or better by Moody s Investor Service, Inc. or a rating of AA or better by Standard & Poor s.

NRG employs a total return investment approach, whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The target allocation of plan assets is 63% to 77% invested in equity securities of which 50% to 60% invested in U.S. equity securities, with the remainder invested in fixed income securities. The Investment Committee reviews the asset mix periodically and as the plan assets increase in future years, the Investment Committee may examine other asset classes such as real estate or private equity. NRG employs a building block approach to determining the long-term rate of return for plan assets, with proper consideration given to diversification and rebalancing. Historical markets are studied and long-term historical relationships between equities and fixed income are preserved, consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. Peer data and historical returns are reviewed to check for reasonability and appropriateness.

Plan assets are currently invested in a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. equities, as well as among growth, value, small and large capitalization stocks.

NRG s pension plan assets weighted average allocation as of December 31, 2009, and 2008 were as follows:

	As of December 31,	
	2009	2008
U.S. Equity	50-60%	50-55%
International Equity	13-17%	15%
U.S. Fixed Income	25-35%	30-35%

NRG s expected future benefit payments for each of the next five years, and in the aggregate for the five years thereafter, are as follows:

	Pension Benefit Payments	Other Postretirement Benefit: Benefit Payments	Other Postretirement Benefit: Medicare Prescription Drug Reimbursements
	(In millions)		
2010	$ 16	$ 2	$
2011	17	3	
2012	19	3	
2013	21	4	
2014	23	4	
2015-2019	149	30	1

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effect:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total service and interest cost components	$ 1	$ (1)
Effect on postretirement benefit obligation	9	(7)

STP Defined Benefit Plans

NRG has a 44% undivided ownership interest in STP, as discussed further in Note 27, *Jointly Owned Plants*. STPNOC, who operates and maintains STP, provides its employees a defined benefit pension plan as well as postretirement health and welfare benefits. Although NRG does not sponsor the STP plan, it reimburses STPNOC for 44% of the contributions made towards its retirement plan obligations. For the years ending December 31, 2009, and 2008, NRG reimbursed STPNOC approximately $5 million and $6 million, respectively, towards its defined benefit plans. In 2010, NRG expects to reimburse STPNOC approximately $4 million for its contributions towards the plans.

The Company has recognized the following in its statement of financial position and accumulated other comprehensive income related to its 44% interest in STP:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(In millions)			

Funded status STPNOC benefit plans	$	(43)	$	(48)	$	(30)	$	(27)
Net periodic benefit costs		10		5		4		3
Other changes in plan assets and benefit obligations recognized in other comprehensive income		(10)		27		5		6

Defined Contribution Plans

NRG s employees have also been eligible to participate in defined contribution 401(K) plans. The Company s contributions to these plans were approximately $22 million, $17 million, and $16 million for the years ended December 31, 2009, 2008, and 2007, respectively.

Note 15 Capital Structure

The following table reflects the changes in NRG s common stock issued and outstanding for the year ended December 31, 2009, 2008, and 2007:

	Authorized	Issued	Treasury	Outstanding
Balance as of December 31, 2006	500,000,000	274,248,264	(29,601,162)	244,647,102
Retirement of shares		(14,094,962)	14,094,962	
Additional Share Repurchase			(2,037,700)	(2,037,700)
Capital Allocation Plans			(7,006,700)	(7,006,700)
Shares issued from LTIP		1,132,227		1,132,227
Balance as of December 31, 2007	500,000,000	261,285,529	(24,550,600)	236,734,929
Capital Allocation Plans			(4,691,883)	(4,691,883)
Shares issued from LTIP		1,004,176		1,004,176
5.75% Preferred Stock conversion		1,309,495		1,309,495
Balance as of December 31, 2008	500,000,000	263,599,200	(29,242,483)	234,356,717
Shares issued under NRG Employee Stock Purchase Plan, or ESPP			81,532	81,532
Shares loaned to affiliates of CS			12,000,000	12,000,000
Shares returned by affiliate of CS			(5,400,000)	(5,400,000)
Capital Allocation Plans			(19,305,500)	(19,305,500)
Shares issued from LTIP		367,858		367,858
4.00% Preferred Stock conversion		13,293,500		13,293,500
5.75% Preferred Stock conversion		18,601,201		18,601,201
Balance as of December 31, 2009	500,000,000	295,861,759	(41,866,451)	253,995,308

The following table summarizes NRG s common stock reserved for the maximum number of shares potentially issuable based on the conversion and redemption features of outstanding equity instruments and the long-term incentive plan as of December 31, 2009:

Equity Instrument	**Common Stock Reserve Balance**
4% Convertible perpetual preferred	12,858,472
3.625% Convertible perpetual preferred	16,000,000
Long term incentive plan	13,193,707
Total	42,052,179

Capital Allocation Plan In December 2007, the Company initiated its 2008 Capital Allocation Plan, with the repurchase of 2,037,700 shares of NRG common stock during that month for approximately $85 million. In February 2008, the Company s Board of Directors authorized an additional $200 million in common share repurchases that raised the total 2008 Capital Allocation Plan to approximately $300 million. During 2008, the Company repurchased a total of 4,691,883 shares for approximately $185 million. As of December 31, 2008, NRG had repurchased a total of 6,729,583 shares of NRG common stock at a cost of approximately $270 million as part of its 2008 Capital Allocation Plan.

In the third quarter 2009, to complete its remaining $30 million planned share re-purchase under the 2008 Capital Allocation plan and to initiate its 2009 Capital Allocation Plan, the Company repurchased 8,919,100 shares of NRG common stock for approximately $250 million. In the fourth quarter 2009, the Company repurchased an additional 10,386,400 shares of NRG common stock for approximately $250 million. For 2009, NRG repurchased a total of 19,305,500 shares of NRG common stock at a cost of approximately $500 million under its share repurchase program.

Retirement of Treasury Stock On May 22, 2007, NRG retired 14,094,962 shares of treasury stock. These retired shares are now included in the Company s pool of authorized but unissued shares. The retired stock had a carrying value of approximately $447 million. The Company s accounting policy upon the formal retirement of treasury stock is to deduct its par value from Common Stock and to reflect any excess of cost over par value as a deduction from Additional Paid-in Capital.

Employee Stock Purchase Plan In May 2008, NRG shareholders approved the adoption of the NRG Energy, Inc. Employee Stock Purchase Plan, or ESPP, pursuant to which eligible employees may elect to withhold up to 10% of their eligible compensation to purchase shares of NRG common stock at 85% of its fair market value on the exercise date. An exercise date occurs each June 30 and December 31. The initial six month employee withholding period began July 1, 2008 and the first issuance of common stock under the ESPP occurred in 2009. As of December 31, 2009, there remained 418,468 shares of treasury stock reserved for issuance under the ESPP, and in January 2010, 54,845 shares of common stock were issued to employee accounts from treasury stock.

Share Lending Agreements As discussed in Note 12, *Debt and Capital Leases*, under *Debt Related to Capital Allocation Program,* CSF I and CSF II loaned 12,000,000 shares of NRG common stock to affiliates of CS in the first quarter 2009, and in the fourth quarter 2009, CS returned 5,400,000 of these shares in connection with the maturity of the CSF II Debt.

Preferred Stock

As of December 31, 2009, and 2008, the Company had 10,000,000 shares of preferred stock authorized. As of December 31, 2009, the Company s preferred stock consisted of two series: the 4% Convertible Perpetual Preferred Stock, or 4% Preferred Stock; and the 3.625% Convertible Perpetual Preferred Stock, which is treated as Redeemable Preferred Stock, or 3.625% Preferred Stock.

5.75% Preferred Stock

On February 2, 2006, NRG completed the issuance of 2,000,000 shares of 5.75% Preferred Stock, for net proceeds of $486 million, reflecting an offering price of $250 per share and the deduction of offering expenses and discounts of approximately $14 million. Dividends on the 5.75% Preferred Stock were $14.375 per share per year, and were due and payable on a quarterly basis beginning on March 15, 2006.

Certain holders of the Company s 5.75% Preferred Stock elected to convert their preferred shares into NRG common shares prior to the mandatory conversion date of March 16, 2009 at the minimum conversion rate of 8.2712. As of March 16, 2009, each remaining outstanding share of the 5.75% Preferred Stock automatically converted into shares of common stock at a rate of 10.2564, based upon the applicable market value of NRG s common stock. These conversions resulted in a decrease in preferred stock of $447 million, and a corresponding increase in Additional Paid-in Capital. The following table summarizes the conversion of the 5.75% Preferred Stock into NRG Common Stock:

	Preferred Stock Shares	Conversion Rate (per share)	Common Stock Shares
Balance as of December 31, 2008	1,841,680		
Preferred shares converted by the holders prior to March 16, 2009	144,975	8.2712	1,199,116
Preferred shares automatically converted as of March 16, 2009	1,696,705	10.2564	17,402,085

Balance at December 31, 2009	18,601,201

4% Preferred Stock

As of December 31, 2009, and 2008, 154,057 and 420,000 shares of the Company s 4% Preferred Stock were issued and outstanding at a liquidation value, net of issuance costs, of $149 million and $406 million, respectively. The 4% Preferred Stock has a liquidation preference of $1,000 per share. Holders of the 4% Preferred Stock are entitled to receive, when declared by NRG s Board of Directors, cash dividends at the rate of 4% per annum, or $40.00 per share per year, payable quarterly in arrears commencing on March 15, 2005. The 4% Preferred Stock is convertible, at the option of the holder, at any time into shares of NRG s common stock at an initial conversion price of $20.00 per share. In addition, NRG had the ability to redeem, on or after December 20, 2009, and subject to certain limitations, some or all of the 4% Preferred Stock with cash at a redemption price equal to 100% of the liquidation preference, plus accumulated but unpaid dividends, including liquidated damages, if any, to the redemption date.

During the first half of 2009, 413 shares of 4% Preferred Stock were converted, at the option of the holder, into 20,650 shares of common stock. In addition, in November 2009, NRG notified the holders of the Company s intention to redeem approximately 50% of the outstanding 4% Preferred Stock and 265,457 shares of the 4% Preferred Stock were converted, at the option of the holder, into 13,272,850 shares of common stock in December 2009 in response to this notification. These conversions resulted in a decrease in preferred stock of $257 million, and a corresponding increase in Additional Paid-in Capital. The following table summarizes all 4% Preferred Stock conversions and redemptions for the year ended December 31, 2009:

	Preferred Stock Shares	**Conversion Rate (per share)**	**Common Stock Shares**
Balance as of December 31, 2008	420,000		
Preferred shares converted by the holders prior to November 20, 2009	413	50	20,650
First redemption:			
Preferred shares converted by the holders prior to December 22, 2009	256,486	50	12,824,300
Preferred shares redeemed for cash by the Company prior to December 22, 2009	73		
Second redemption:			
Preferred shares converted by the holders prior to December 31 , 2009	8,971	50	448,550
Balance at December 31, 2009	154,057		13,293,500

On December 22, 2009, NRG notified the holders of the 4% Preferred Stock of the Company s intention to call for redemption the remaining outstanding shares of 4% Preferred Stock on January 21, 2010. As of January 21, 2010, the Company completed the redemption of the remaining shares of 4% Preferred Stock, with holders converting 154,029 shares to 7,701,450 shares of common stock and the Company redeeming 28 shares for $28,000 cash.

Redeemable Preferred Stock

3.625% Preferred Stock

On August 11, 2005, NRG issued 250,000 shares of 3.625% Preferred Stock, which is treated as Redeemable Preferred Stock, to CS in a private placement. As of December 31, 2009 and 2008, 250,000 shares of the 3.625% Preferred Stock were issued and outstanding at a liquidation value, net of issuance costs, of $247 million. The 3.625% Preferred Stock amount is located after the liabilities but before the stockholders equity section on the balance sheet, due to the fact that the preferred shares can be redeemed in cash by the shareholder. The 3.625% Preferred Stock has a liquidation preference of $1,000 per share. Holders of the 3.625% Preferred Stock are entitled to receive, out of legally available funds, cash dividends at the rate of 3.625% per annum, or $36.25 per share per year, payable in cash quarterly in arrears commencing on December 15, 2005.

Each share of the 3.625% Preferred Stock is convertible during the 90-day period beginning August 11, 2015 at the option of NRG or the holder. Holders tendering the 3.625% Preferred Stock for conversion shall be entitled to receive, for each share of 3.625% Preferred Stock converted, $1,000 in cash and a number of shares of NRG common stock equal to the product of (a) the greater of (i) the difference between the average closing share price of NRG common stock on each of the 20 consecutive scheduled trading days starting on the date 30 exchange business days immediately prior to the conversion date, or the Market Price, and $29.54 and (ii) zero, times (b) 50.77. The number of NRG common stock to be delivered under the conversion feature is limited to 16,000,000 shares. If upon conversion, the Market Price is less than $19.69, then the Holder will deliver to NRG cash or a number of shares of NRG common stock equal in value to the product of (i) $19.69 minus the Market Price, times (ii) 50.77. NRG may elect to make a cash payment in lieu of delivering shares of NRG common stock in connection with such conversion, and NRG may elect to receive cash in lieu of shares of common stock, if any, from the Holder in connection with such conversion. The conversion feature is considered an embedded derivative per ASC 815 that is exempt from derivative accounting as it is excluded from the scope pursuant to ASC 815.

If a fundamental change occurs, the holders will have the right to require NRG to repurchase all or a portion of the 3.625% Preferred Stock for a period of time after the fundamental change at a purchase price equal to 100% of the liquidation preference, plus accumulated and unpaid dividends. The 3.625% Preferred Stock is senior to all classes of common stock, on parity with the Company s 4% Preferred Stock, and junior to all of the Company s existing and future debt obligations and all of NRG subsidiaries existing and future liabilities and capital stock held by persons other than NRG or its subsidiaries.

Note 16 Investments Accounted for by the Equity Method

NRG accounts for the Company s significant investments using the equity method of accounting. NRG s carrying value of equity investments can be impacted by impairments, unrealized gains and losses on derivatives and movements in foreign currency exchange rates, as well as other adjustments.

The following table summarizes NRG s equity method investments, as of December 31, 2009:

Name	Geographic Area	Economic Interest
Sherbino I Wind Farm LLC	USA	50.0%
Saguaro Power Company	USA	50.0%
GenConn Energy LLC	USA	50.0%
Gladstone Power Station	Australia	37.5%

MIBRAG On June 10, 2009, NRG completed the sale of its 50% ownership in Mibrag B.V. See further discussion in Note 4, *Discontinued Operations and Dispositions*.

Sherbino I Wind Farm LLC NRG owns a 50% interest in Sherbino, a joint venture with BP Wind Energy North America Inc. Sherbino is a 150MW wind farm consisting of 50 Vestas 3MW wind turbine generators, which commenced commercial operations in October 2008. NRG contributed approximately $84 million to its equity investment in Sherbino in 2008. NRG s equity loss from Sherbino was insignificant for the year ended December 31, 2009, and for the year ended December 31, 2008, NRG posted equity earnings from Sherbino of $8 million.

Saguaro Power Company NRG owns a 50% interest in the Saguaro plant, a cogeneration plant with dual-fuel capability, natural gas and oil. For the year ended December 31, 2009, NRG s equity income from Saguaro was $10 million. NRG posted equity losses in 2008 and 2007 of $2 million and $3 million, respectively.

GenConn Energy LLC NRG owns a 50% interest in GenConn, a limited liability company formed in February 2008 by NRG and The United Illuminating Company, or UI, for the construction and operation of two 200 MW peaking facilities in Connecticut through GenConn s wholly-owned subsidiaries, GenConn Devon, LLC, or Devon, and GenConn Middletown LLC, or Middletown. Devon and Middletown have each entered into 30-year cost of service type contracts with CL&P as mandated by the DPUC, commencing when the facilities reach commercial operations, currently expected to be 2010 and 2011, respectively.

The project is expected to be funded through equity contributions from the owners and non-recourse, project level debt. As of December 31, 2009, NRG has made a nominal equity investment in GenConn. In addition, as discussed in Note 9, *Capital Leases and Notes Receivable*, in 2008 NRG entered into a short-term $45 million note receivable facility with GenConn to fund NRG s proportionate share of project liquidity needs which was repaid in 2009. NRG s maximum exposure to loss is limited to its equity investments and note receivable.

On April 27, 2009, a wholly-owned subsidiary of NRG, NRG Connecticut Peaking LLC, closed on an equity bridge loan facility, or EBL, in the amount of $121.5 million from a syndicate of banks. For a detailed discussion on the facility, see Note 12 *Debt and Capital Leases*. GenConn had borrowed $108 million under this facility as of December 31, 2009.

As discussed in Note 21, *Related Party Transactions*, NRG has entered into construction management agreements with Devon and Middletown, and recognized approximately $7 million and $1 million of revenue for the years ended December 31, 2009 and 2008, respectively. In addition, NRG earned interest income of $2 million in 2009 from GenConn on an outstanding note receivable as discussed in Note 9, *Capital Leases and Notes Receivable*.

GenConn is considered a VIE under ASC 810, but NRG is not the primary beneficiary of GenConn and accounts for its 50% interest under the equity method. GenConn is a development stage entity, and is not expected to begin generating revenues until 2010; therefore NRG recognized no equity earnings from the joint venture for the years ended December 31, 2008 or 2009.

Gladstone Through a joint venture, NRG owns a 37.5% interest in Gladstone, a 1,613 megawatt coal-fueled power generation facility in Queensland, Australia. The power generation facility is managed by the joint venture participants and the facility is operated by NRG. Operating expenses incurred in connection with the operation of the facility are funded by each of the participants in proportion to their ownership interests. Coal is sourced from local mines in Queensland. NRG and the joint venture participants receive their respective share of revenues directly from the off takers in proportion to the ownership interests in the joint venture. Power generated by the facility is primarily sold to an adjacent aluminum smelter, with excess power sold to the Queensland Government owned utility under long term supply contracts. For the years ended December 31, 2009, 2008 and 2007, NRG s equity earnings from Gladstone were approximately $17 million, $21 million and $21 million, respectively.

The undistributed earnings from equity investments as of December 31, 2009 and 2008, were $132 million and $116 million, respectively.

Note 17 Earnings Per Share

Basic earnings per common share is computed by dividing net income less accumulated preferred stock dividends by the weighted average number of common shares outstanding. Shares issued and treasury shares repurchased during the year are weighted for the portion of the year that they were outstanding. Diluted earnings per share is computed in a manner consistent with that of basic earnings per share while giving effect to all potentially dilutive common shares that were outstanding during the period.

Dilutive effect for equity compensation The outstanding non-qualified stock options, non-vested restricted stock units, deferred stock units and performance units are not considered outstanding for purposes of computing basic earnings per share. However, these instruments are included in the denominator for purposes of computing diluted earnings per share under the treasury stock method.

Dilutive effect for other equity instruments NRG s outstanding 4% Preferred Stock and 5.75% Preferred Stock are not considered outstanding for purposes of computing basic earnings per share. However, these instruments are considered for inclusion in the denominator for purposes of computing diluted earnings per share under the if-converted method. The if-converted method is also used to determine the dilutive effect of embedded derivatives in the Company s 3.625% Preferred Stock, and CSF preferred interests and notes.

The reconciliation of NRG s basic earnings per common share to diluted earnings per share for the years ended December 31, 2009, 2008 and 2007 is shown in the following table:

	Year Ended December 31, 2009	2008	2007
	(In millions)		
Basic earnings per share attributable to NRG common stockholders			
Numerator:			
Income from continuing operations, net of income taxes	$ 942	$ 1,053	$ 556
Preferred stock dividends	(33)	(55)	(55)
Net income available to common stockholders from continuing operations	909	998	501
Income from discontinued operations, net of tax		172	17
Net income attributable to NRG Energy, Inc. available to common stockholders	$ 909	$ 1,170	$ 518
Denominator:			
Weighted average number of common shares outstanding	245.5	235.0	240.2
Basic earnings per share:			
Income from continuing operations	$ 3.70	$ 4.25	$ 2.09
Income from discontinued operations, net of tax		0.73	0.07
Net income attributable to NRG Energy, Inc.	$ 3.70	$ 4.98	$ 2.16
Diluted earnings per share attributable to NRG common stockholders			
Numerator:			
Net income available to common stockholders from continuing operations	$ 909	$ 998	$ 501
Add preferred stock dividends for dilutive preferred stock	23	46	46
Adjusted income from continuing operations available to common stockholders	932	1,044	547
Income from discontinued operations, net of tax		172	17
Net income attributable to NRG Energy, Inc. available to common stockholders	$ 932	$ 1,216	$ 564
Denominator:			
Weighted average number of common shares outstanding	245.5	235.0	240.2
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	1.2	2.3	3.8
Incremental shares attributable to embedded derivatives of certain financial instruments (if-converted method)			6.0
Incremental shares attributable to the assumed conversion features of outstanding preferred stock (if-converted method)	24.5	37.5	37.5

Total dilutive shares	271.2	274.8	287.5
Diluted earnings per share:			
Income from continuing operations available to common stockholders	$ 3.44	$ 3.80	$ 1.90
Income from discontinued operations, net of tax		0.63	0.06
Net income attributable to NRG Energy, Inc.	$ 3.44	$ 4.43	$ 1.96

The following table summarizes NRG s outstanding equity instruments that are anti-dilutive and were not included in the computation of the Company s diluted earnings per share:

	Year Ended December 31,		
	2009	2008	2007
	(In millions of shares)		
Equity compensation NQSO s and PU s	5.7	1.9	0.1
Embedded derivative of 3.625% redeemable perpetual preferred stock	16.0	16.0	12.2
Embedded derivatives of CSF preferred interests and notes		7.6	16.1
Total	21.7	25.5	28.4

Note 18 Segment Reporting

NRG s segment structure reflects core areas of operation which are primarily segregated based on the Company s wholesale power generation, retail, thermal and chilled water business, and corporate activities. In May 2009, NRG s segment structure changed to reflect the Company s acquisition of Reliant Energy and has been incorporated as a separate reporting segment as per ASC 280, *Segment Reporting*. Within NRG s wholesale power generation operations, there are distinct components with separate operating results and management structures for the following geographical regions: Texas, Northeast, South Central, West and International. The Company s corporate activities include wind, solar and nuclear development.

In the second quarter 2009, management changed its method for allocating corporate general and administrative expenses to the segments. Corporate general and administrative expenses had been allocated based on budgeted segment revenues. Beginning in the second quarter 2009, corporate general and administrative expenses have been allocated based on forecasted earnings/(losses) before interest expense, income taxes, depreciation and amortization expense.

As of December 31, 2009, there were no customers from whom the Company derived more than 10% of the Company s consolidated revenues. The following table summarizes customers from whom NRG derived more than 10% of the Company s consolidated revenues for the years ended December 31, 2008 and 2007:

	Year Ended December 31, 2008	Year Ended December 31, 2007
Customer A Texas region	11%	%
Customer B Texas region	11	27
Total	22%	27%

	Year Ended December 31, 2009									
		Wholesale Power Generation								
	Reliant Energy	Texas[a]	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
	(In millions)									
erating revenues	$ 4,182	$ 2,946	$ 1,201	$ 581	$ 150	$ 144	$ 135	$ 28	$ (415)	$ 8,95
erating expenses	3,044	1,634	740	508	110	116	112	129	(418)	5,97
preciation and ortization	137	472	118	67	8		10	6		81
erating income/(loss)	1,001	840	343	6	32	28	13	(107)	3	2,15
uity in earnings of consolidated affiliates					10	31				4
ins on sales of equity thod investments						128				12
her income/(loss), net		7	2	1		(20)		27	(22)	(
financing expenses	(1)							(19)		(2
erest expense	(34)	(4)	(54)	(48)	(2)	(8)	(5)	(497)	18	(63
come/(loss) from ntinuing operations fore income taxes	966	843	291	(41)	40	159	8	(596)	(1)	1,66
come tax expense		171				9		548		72
come/(loss) from ntinuing operations	966	672	291	(41)	40	150	8	(1,144)	(1)	94
t income/(loss)	966	672	291	(41)	40	150	8	(1,144)	(1)	94
ss: Net loss ributable to ncontrolling interest		(1)								(
t income/(loss) ributable to NRG ergy, Inc.	$ 966	$ 673	$ 291	$ (41)	$ 40	$ 150	$ 8	$ (1,144)	$ (1)	$ 94
lance sheet										
uity investments in iliates	$ 2	$ 92	$ 6	$	$ 35	$ 273	$	$ 1	$	$ 40
pital expenditures	7	189	207	9	8		10	353		78
odwill		1,713						5		1,71
tal assets	$ 2,007	$ 13,092	$ 1,866	$ 909	$ 329	$ 785	$ 206	$ 22,442	$ (18,258)	$ 23,37

Includes inter-segment sales of $411 million to Reliant Energy.

he Company continued using the 2008 allocation method for corporate general and administrative expenses, the effect to net ome/(loss) of each segment for the year ended December 31, 2009, would have been as follows:

	$ 966	$ 673	$ 291	$ (41)	$ 40	$ 150	$ 8	$ (1,144)	$ (1)	$ 94

t income/(loss) ributable to NRG ergy, Inc. as reported										
crease/(decrease) in t income/(loss) ributable to NRG ergy, Inc.	(46)	33	13	(3)	2	1				
ljusted net come/(loss) ributable to NRG ergy, Inc.	$ 920	$ 706	$ 304	$ (44)	$ 42	$ 151	$ 8	$ (1,144)	$ (1)	$ 94

	Year Ended December 31, 2008								
	Wholesale Power Generation								
	Texas	**Northeast**	**South Central**	**West**	**International**	**Thermal**	**Corporate**	**Elimination**	**Total**
	(In millions)								
Operating revenues	$ 4,026	$ 1,630	$ 746	$ 171	$ 158	$ 154	$ 3	$ (3)	$ 6,885
Operating expenses	1,890	1,087	579	105	133	122	52	(5)	3,963
Depreciation and amortization	451	109	67	8		10	4		649
Operating income/(loss)	1,685	434	100	58	25	22	(53)	2	2,273
Equity in earnings/(loss) of unconsolidated affiliates	9			(2)	52				59
Other income, net	9	12	1	1	5		20	(31)	17
Interest expense	(100)	(56)	(51)	(6)		(6)	(383)	19	(583)
Income/(loss) from continuing operations before income taxes	1,603	390	50	51	82	16	(416)	(10)	1,766
Income tax expense	692				19		2		713
Income/(loss) from continuing operations	911	390	50	51	63	16	(418)	(10)	1,053
Income from discontinued operations, net of income taxes					172				172
Net income/(loss)	911	390	50	51	235	16	(418)	(10)	1,225
Net income/(loss) attributable to NRG Energy, Inc.	$ 911	$ 390	$ 50	$ 51	$ 235	$ 16	$ (418)	$ (10)	$ 1,225
Balance sheet									
Equity investments in affiliates	$ 92	$ 1	$	$ 25	$ 372	$	$	$	$ 490
Capital expenditures	238	208	14	35		11	509		1,015
Goodwill	1,713						5		1,718
Total assets	$ 12,899	$ 1,667	$ 933	$ 264	$ 973	$ 208	$ 20,215	$ (12,351)	$ 24,808

	Year Ended December 31, 2007								
	Wholesale Power Generation								
	Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
	(In millions)								
Operating revenues	$ 3,287	$ 1,605	$ 658	$ 127	$ 140	$ 159	$ 30	$ (17)	$ 5,989
Operating expenses	1,849	1,045	533	85	112	125	47	(8)	3,788
Depreciation and amortization	469	102	68	3		11	5		658
Gain/(loss) on disposal/sale of assets						18	(1)		17
Operating income/(loss)	969	458	57	39	28	41	(23)	(9)	1,560
Equity in earnings/(loss) of unconsolidated affiliates				(3)	57				54
Gains on sales of equity method investments							1		1
Other income, net	7				8	1	58	(19)	55
Refinancing expenses							(35)		(35)
Interest expense	(164)	(57)	(53)		(5)	(6)	(436)	19	(702)
Income/(loss) from continuing operations before income taxes	812	401	4	36	88	36	(435)	(9)	933
Income tax expense/(benefit)	327				(12)		62		377
Income/(loss) from continuing operations	485	401	4	36	100	36	(497)	(9)	556
Income from discontinued operations, net of income taxes					17				17
Net income/(loss)	485	401	4	36	117	36	(497)	(9)	573
Net Income/(loss) attributable to NRG Energy, Inc.	$ 485	$ 401	$ 4	$ 36	$ 117	$ 36	$ (497)	$ (9)	$ 573

Note 19 Income Taxes

The income tax provision from continuing operations for the years ended December 31, 2009, 2008 and 2007 consisted of the following amounts:

	Year Ended December 31,		
	2009	2008	2007
	(In millions)		
Current			
U.S. Federal	$ 99	$ 89	$ (6)
State	20	31	(1)
Foreign	18	17	20
	137	137	13
Deferred			
U.S. Federal	599	539	347
State	1	35	47
Foreign	(9)	2	(30)
	591	576	364
Total income tax	$ 728	$ 713	$ 377
Effective tax rate	43.6%	40.4%	40.4%

The following represents the domestic and foreign components of income from continuing operations before income tax expense for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
	(In millions)		
U.S.	$ 1,508	$ 1,681	$ 847
Foreign	161	85	86
Total	$ 1,669	$ 1,766	$ 933

A reconciliation of the U.S. federal statutory rate of 35% to NRG s effective rate from continuing operations for the years ended December 31, 2009, 2008 and 2007 were as follows:

Year Ended December 31,

	2009	2008	2007
	(In millions, except percentages)		
Income from continuing operations before income taxes	$ 1,669	$ 1,766	$ 933
Tax at 35%	584	618	327
State taxes, net of federal benefit	23	74	46
Foreign operations	(53)	(10)	(13)
Subpart F taxable income		2	
Valuation allowance	119	(12)	6
Expiration of capital losses	249		
Reversal of valuation allowance on expired capital losses	(249)		
Change in state effective tax rate	(5)	(11)	
Change in local German effective tax rates			(29)
Foreign dividends and foreign earnings	33	32	26
Non-deductible interest	10	12	10
FIN 48 interest	9	8	
Production tax credit	(10)		
Other	18		4
Income tax expense	$ 728	$ 713	$ 377
Effective income tax rate	43.6%	40.4%	40.4%

The effective income tax rate for the year ended December 31, 2009, 2008 and 2007 differs from the U.S. statutory rate of 35% due to changes in the valuation allowance as a result of capital gain or losses generated during the period. In addition, the current earnings in foreign jurisdictions are taxed at rates lower than the U.S. statutory rate, including the sale of the MIBRAG in 2009 which resulted in minimal tax due to the local jurisdiction.

For the year ended December 31, 2009, NRG s state effective income tax rate has been reduced to 3%, which is lower than its 2008 rate of 6%, due to increased operational activities within the state of Texas in the current year. This decrease was primarily due to the acquisition of Reliant Energy which operates in the state of Texas.

The temporary differences, which gave rise to the Company s deferred tax assets and liabilities as of December 31, 2009 and 2008, consisted of the following:

	As of December 31,	
	2009	**2008**
	(In millions)	
Deferred tax liabilities:		
Discount/premium on notes	$ 12	$ 13
Emissions allowances	119	112
Difference between book and tax basis of property	1,604	1,477
Derivatives, net	434	440
Goodwill	93	73
Anticipated repatriation of foreign earnings	6	26
Cumulative translation adjustments	29	22
Development costs	16	
Intangibles amortization (excluding goodwill)	242	
Investment in projects	32	
Total deferred tax liabilities	2,587	2,163
Deferred tax assets:		
Deferred compensation, pension, accrued vacation and other reserves	195	126
Differences between book and tax basis of contracts	270	377
Non-depreciable property	19	19
Intangibles amortization (excluding goodwill)		164
Equity compensation	26	22
Claimants reserve		10
U.S. capital loss carryforwards	135	274
Foreign net operating loss carryforwards	78	66
State net operating loss carryforwards	28	28
Foreign capital loss carryforwards	1	1
Investments in projects		10
Deferred financing costs	7	10
Alternative minimum tax	40	20
Federal benefit on state FIN 48 liabilities	30	
Other	11	4
Total deferred tax assets	840	1,131

Valuation allowance		(233)		(359)
Net deferred tax assets		607		772
Net deferred tax liability	$	1,980	$	1,391

The following table summarizes NRG s net deferred tax position as of December 31, 2009 and 2008:

	As of December 31,			
	2009		2008	
	(In millions)			
Current deferred tax liability	$	197	$	201
Non-current deferred tax liability		1,783		1,190
Net deferred tax liability	$	1,980	$	1,391

Tax Receivable and Payable

As of December 31, 2009, NRG recorded a current tax payable of approximately $32 million that represents a tax liability due for domestic state taxes of approximately $20 million, as well as foreign taxes payable of approximately $12 million. In addition, NRG has a domestic tax receivable of $153 million, of which $102 million is federal cash grant receivable on Blythe Solar and Langford plants.

Deferred tax assets and valuation allowance

Net deferred tax balance As of December 31, 2009, and 2008, NRG recorded a net deferred tax liability of $1,747 million and $1,032 million, respectively. However, due to an assessment of positive and negative evidence, including projected capital gains and available tax planning strategies, NRG believes that it is more likely than not that a benefit will not be realized on $233 million and $359 million of tax assets, thus a valuation allowance has remained, resulting in a net deferred tax liability of $1,980 million and $1,391 million as of December 31, 2009 and 2008, respectively. NRG believes it is more likely than not that future earnings will be sufficient to utilize the Company s deferred tax assets, net of the existing valuation allowances at December 31, 2009.

NOL carryforwards At December 31, 2009, and 2008, the Company had cumulative state net operating losses, or NOLs, of $28 million. These NOLs will expire starting 2010. In addition, as of December 31, 2009, NRG has cumulative foreign NOL carryforwards of $280 million of which $82 million will expire starting 2011 through 2017 and of which $198 million do not have an expiration date.

Valuation allowance As of December 31, 2009, the Company s valuation allowance was reduced by $249 million as result of the expiration of unused capital loss carryforwards. The valuation allowance was increased by $123 million primarily for certain derivative contracts that are eligible for capital loss treatment for tax purposes resulting in a net reduction of $126 million.

Uncertain tax benefits

NRG has identified unrecognized tax benefits whose after-tax value was $643 million that if recognized, would impact the Company s income tax expense.

As of December 31, 2009, and 2008, NRG has recorded a non-current tax liability of $347 and $208 million, respectively, for unrecognized tax benefits resulting from taxable earnings for the period for which there are no NOLs available to offset for financial statement purposes. The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. During the years ended December 31, 2009, and 2008, the Company recognized approximately $9 million, and $8 million, respectively, in interest and penalties. For the year ended December 31, 2007, the Company incurred an immaterial amount of interest and penalties related to its unrecognized tax benefit. As of December 31, 2009, and 2008, NRG had accrued interest and penalties related to these unrecognized tax benefits of approximately $17 and $8 million, respectively.

Tax jurisdictions NRG is subject to examination by taxing authorities for income tax returns filed in the U.S. federal jurisdiction and various state and foreign jurisdictions including major operations located in Germany and Australia. The Company is no longer subject to U.S. federal income tax examinations for years prior to 2002. With few exceptions, state and local income tax examinations are no longer open for years before 2003. The Company s significant foreign operations are also no longer subject to examination by local jurisdictions for years prior to 2000.

The Company continues to be under examination by the Internal Revenue Service, or IRS, for years 2004 through 2006. It is possible that the IRS examination may conclude during 2010 but because of a possible extension, an estimate of the range of reasonably possible changes in unrecognized tax benefits cannot be made.

Sale of ITISA On April 28, 2008, NRG completed the sale of its 100% interest in Tosli Acquisition B.V., or Tosli, which held all NRG s interest in ITISA, to Brookfield Renewable Power Inc. (previously Brookfield Power Inc.), a wholly-owned subsidiary of Brookfield Asset Management Inc. In addition, the purchase price adjustment contingency under the sale agreement was resolved on August 7, 2008. In connection with the sale, NRG recorded a capital gain of $218 million which further reduced the Company s uncertain tax benefits.

205

The following table reconciles the total amounts of unrecognized tax benefits at the beginning and end of the respective periods:

	As of December 31, 2009	As of December 31, 2008
	(In millions)	
Balance as of January 1	$ 527	$ 683
Increase due to current year positions	80	18
Decrease due to current year positions		(183)
Increase due to prior year positions	40	9
Decrease due to prior year positions	(4)	
Decrease due to settlements and payments		
Decrease due to statute expirations		
Unrecognized tax benefits as of December 31	$ 643	$ 527

Included in the balance at December 31, 2009, are $43 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash or use of net operating loss carryforwards to an earlier period.

German Tax Reform Act 2008

On July 6, 2007, the German government passed the Tax Reform Act of 2008, which reduces the German statutory and resulting effective tax rates on earnings from approximately 36% to approximately 27% effective January 1, 2008. Due to this reduction in the statutory and resulting effective tax rate in 2007, NRG recognized a $29 million tax benefit and as of December 31, 2007, NRG had a German net deferred tax liability of approximately $84 million which includes the impact of this tax rate change.

Note 20 Stock-Based Compensation

Long-Term Incentive Plan, or LTIP

As of December 31, 2009, and 2008, a total of 16,000,000 shares of NRG common stock were authorized for issuance under the LTIP, subject to adjustments in the event of reorganization, recapitalization, stock split, reverse stock split, stock dividend, and a combination of shares, merger or similar change in NRG s structure or outstanding shares of common stock. There were 5,129,593 and 6,798,074 shares of common stock remaining available for grants under NRG s LTIP as of December 31, 2009, and 2008, respectively.

Non-Qualified Stock Options, or NQSO s

NQSO s granted under the LTIP typically have a three-year graded vesting schedule beginning on the grant date and become exercisable at the end of the requisite service period. NRG recognizes compensation costs for NQSO s on a straight-line basis over the requisite service period for the entire award. The maximum contractual term is ten years for approximately 1.1 million of NRG s outstanding NQSO s, and six years for the remaining 3.7 million NQSO s.

The following table summarizes the Company s NQSO activity as of December 31, 2009, and changes during the year then ended:

	Shares (In whole)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In millions)
Outstanding at December 31, 2008	4,008,188	$ 25.84	4	$ 14
Granted	1,406,500	23.62		
Forfeited	(506,103)	29.86		
Exercised	(115,000)	13.21		
Outstanding at December 31, 2009	4,793,585	25.07	4	13
Exercisable at December 31, 2009	2,766,165	22.21	3	13

The weighted average grant date fair value of options granted during the years ended December 31, 2009, 2008 and 2007 was $8.64, $10.33, and $8.28, respectively. The total intrinsic value of options exercised during the years ended December 31, 2009, 2008 and 2007 was $1.4 million, $14 million and $11 million, respectively and cash received from the exercise of these options was $2 million, $9 million and $7 million, respectively.

The fair value of the Company s NQSO s is estimated on the date of grant using the Black-Scholes option-pricing model. Significant assumptions used in the fair value model for the years ended December 31, 2009, 2008, and 2007 with respect to the Company s NQSO s are summarized below:

	2009	2008	2007
Expected volatility	44.36%-48.29%	26.75%-44.00%	25.88%-27.28%
Expected term (in years)	4	4	4
Risk free rate	1.43%-1.93%	1.33%-3.09%	4.58%-4.68%

For 2009, 2008, and 2007, expected volatility is calculated based on NRG s historical stock price volatility data over the period commensurate with the expected term of the stock option. Typically, the expected term for the Company s NQSO s is based on the simple average of the contractual term and vesting term. The Company uses this simplified method as it does not have sufficient historical exercise data to provide a reasonable basis upon which to estimate the expected term.

Restricted Stock Units, or RSU s

Typically, RSU s granted under the Company s LTIP fully vest three years from the date of issuance. Fair value of the RSU s is based on the closing price of NRG common stock on the date of grant. The following table summarizes the Company s non-vested RSU awards as of December 31, 2009, and changes during the year then ended:

	Units	Weighted Average Grant-Date Fair Value per Unit
	(In whole)	
Non-vested at December 31, 2008	1,061,996	$ 32.97
Granted	1,021,800	26.13
Forfeited	(119,955)	31.79
Vested	(349,072)	23.50
Non-vested at December 31, 2009	1,614,769	30.78

The total fair value of RSU s vested during the years ended December 31, 2009, 2008, and 2007, was $8 million, $22 million and $40 million, respectively. The weighted average grant date fair value of RSU s granted during the years ended December 31, 2009, 2008 and 2007 was $26.13, $39.84 and $38.61, respectively.

Deferred Stock Units, or DSU s

DSU s represent the right of a participant to be paid one share of NRG common stock at the end of a deferral period established under the terms of the award. DSU s granted under the Company s LTIP are fully vested at the date of issuance. Fair value of the DSU s, which is based on the closing price of NRG common stock on the date of grant, is recorded as compensation expense in the period of grant.

The following table summarizes the Company s outstanding DSU awards as of December 31, 2009, and changes during the year then ended:

	Units	**Weighted Average Grant-Date Fair Value per Unit**
	(In whole)	
Outstanding at December 31, 2008	260,768	$ 18.50
Granted	65,437	22.77
Conversions	(22,156)	23.69
Outstanding at December 31, 2009	304,049	19.34

The aggregate intrinsic values for DSU s outstanding as of December 31, 2009, 2008, and 2007 were approximately $7 million, $6 million, and $12 million respectively. The aggregate intrinsic values for DSU s converted to common stock for the years ended December 31, 2009, 2008 and 2007 were $0.5 million, $1.5 million and $1.2 million, respectively. The weighted average grant date fair value of DSU s granted during the years ended December 31, 2009, 2008 and 2007 was $22.77, $35.12 and $44.43, respectively.

Performance Units, or PU s

PU s granted under the Company s LTIP fully vest three years from the date of issuance. PU s granted prior to January 1, 2009, are paid out upon vesting if the closing price of NRG s common stock on the vesting date, or the Measurement Price, is equal to or greater than the Target Price. PU s granted after January 1, 2009, are paid out upon vesting if the Measurement Price is equal to or greater than Threshold Price. The Threshold Price, Target Price and Maximum Price are determined on the date of issuance. The payout for each PU will be equal to: (i) a pro-rata amount between 0.5 and 1 share of common stock, if the Measurement Price is equal to or greater than the target Threshold Price but less than the Target Price, for grants made after January 1, 2009; (ii) one share of common stock, if the Measurement Price equals the Target Price; (iii) a pro-rata amount between one and two shares of common stock, if the Measurement Price is greater than the Target Price but less than the Maximum Price; and (iv) two shares of common stock, if the Measurement Price is equal to, or greater than, the Maximum Price.

The following table summarizes the Company s non-vested PU awards as of December 31, 2009, and changes during the year then ended:

	Weighted Average

	Outstanding Units	Grant-Date Fair Value per Unit
	(In whole except weighted average data)	
Non-vested at December 31, 2008	659,564	$ 22.81
Granted	339,300	22.91
Forfeited	(381,564)	20.86
Non-vested at December 31, 2009	617,300	24.27

The weighted average grant date fair value of PU s granted during the years ended December 31, 2009, 2008 and 2007 was $22.91, $26.99 and $22.43, respectively.

The fair value of PU s is estimated on the date of grant using a Monte Carlo simulation model and expensed over the service period, which equals the vesting period. Significant assumptions used in the fair value model for the years ended December 31, 2009, 2008 and 2007 with respect to the Company s PU s are summarized below:

	2009	2008	2007
Expected volatility	48.48%-53.00%	27.81%-48.06%	25.91%-27.28%
Expected term (in years)	3	3	3
Risk free rate	1.14%-1.48%	1.13%-2.89%	4.54%-4.69%

For 2009, 2008, and 2007, expected volatility is calculated based on NRG s historical stock price volatility data over the period commensurate with the expected term of the PU, which equals the vesting period.

Supplemental Information

The following table summarizes NRG s total compensation expense recognized in accordance with ASC 718 for the years ended December 31, 2009, 2008, and 2007 for each of the four types of awards issued under the Company s LTIP, as well as total non-vested compensation costs not yet recognized and the period over which this expense is expected to be recognized as of December 31, 2009. Minimum tax withholdings of $3 million, $10 million, and $17 million paid by the Company during 2009, 2008, and 2007, respectively, are reflected as a reduction to Additional Paid-in Capital on the Company s statement of financial position, and are reflected as operating activities on the Company s statement of cash flows.

	Compensation Expense Year Ended December 31			Non-vested Compensation Cost Unrecognized Total Cost As of December 31	Non-vested Compensation Cost Weighted Average Recognition Period Remaining (In years) As of December 31
Award	**2009**	**2008**	**2007**	**2009**	**2009**
	(In millions, except weighted average data)				
NQSO s	$ 9	$ 8	$ 5	$ 10	2.2
RSU s	11	12	10	31	1.8
DSU s	1	1	1		
PU s	5	5	3	6	1.5
Total	$ 26	$ 26	$ 19	$ 47	
Tax benefit recognized	$ 10	$ 10	$ 8		

Other Compensation Arrangements

Beginning in 2008, NRG also sponsored certain cash-settled equity award programs, under which employees are eligible to receive future cash compensation upon fulfillment of the vesting criteria for the particular program. The aggregate compensation expense for these arrangements was approximately $2 million and $1 million for the years ended December 31, 2009, and 2008, respectively.

Note 21 Related Party Transactions

The following table summarizes NRG s material related party transactions with affiliates that are included in the Company s operating revenues, operating costs and other income and expense:

	Year Ended December 31, 2009	2008	2007
	(In millions)		
Revenues from Related Parties Included in Operating Revenues			
MIBRAG[(a)]	$ 2	$ 4	$ 4
Gladstone	2	2	1
GenConn	7	1	
Sherbino		1	
Total	$ 11	$ 8	$ 5
Expenses from Related Parties Included in Cost of Operations			
MIBRAG[(a)]			
Cost of purchased coal	$ 43	$ 57	$ 43
Interest income from Related Parties Included in Other Income and Expense			
GenConn[(b)]	2		
Kraftwerke Schkopau GBR	4	4	4
Total	$ 6	$ 4	$ 4

(a) The period in 2009 is from January 1, 2009 to June 10, 2009.

(b) For the period Apri1 1, 2009 to June 10, 2009.

Gladstone - NRG provides services to Gladstone, an equity method investment, under an operation and maintenance, or O&M, agreement Fees for services under this contract primarily include recovery of NRG s costs of operating the plant as approved in the annual budget, as well as a base monthly fee.

GenConn and Sherbino - Under construction management, or CMA, agreements with GenConn and Sherbino, NRG has received fees for management, design and construction services. The construction at Sherbino was completed during 2008. In addition, NRG entered into a loan agreement with GenConn during 2009, pursuant to which it receives interest income. See further discussion in Note 16, *Investments Accounted for by the Equity Method.*

MIBRAG - Prior to NRG s sale of its 50% ownership in MIBRAG on June 10, 2009, NRG rendered technical consulting services to MIBRAG under a consulting agreement and had entered into long-term coal purchase agreements with MIBRAG to supply coal to Schkopau. See further discussion in Note 4, *Discontinued Operations and Dispositions*.

Kraftwerke Schkopau GBR - A subsidiary of NRG, Saale Energie GmbH has entered into a loan agreement with Kraftwerke Schkopau GBR, a partnership between Saale and E.ON Kraftwerke GmbH, pursuant to which NRG receives interest income. See further discussion in Note 9, *Capital Leases and Notes Receivable*.

Note 22 Commitments and Contingencies

Operating Lease Commitments

NRG leases certain Company facilities and equipment under operating leases, some of which include escalation clauses, expiring on various dates through 2040. NRG also has certain tolling arrangements to purchase power which qualifies as operating leases. Certain operating lease agreements over their lease term include provisions such as scheduled rent increases, leasehold incentives, and rent concessions. The Company recognizes the effects of these scheduled rent increases, leasehold incentives, and rent concessions on a straight-line basis over the lease term unless another systematic and rational allocation basis is more representative of the time pattern in which the leased property is physically employed. Lease expense under operating leases was approximately $102 million, $54 million, and $40 million for the years ended December 31, 2009, 2008, and 2007, respectively.

Future minimum lease commitments under operating leases for the years ending after December 31, 2009 are as follows:

Period	**(In millions)**
2010	$ 100
2011	66
2012	54
2013	50
2014	48
Thereafter	264
Total	$ 582

Coal, Gas and Transportation Commitments

NRG has entered into long-term contractual arrangements to procure fuel and transportation services for the Company s generation assets and for the years ended December 31, 2009, 2008, and 2007, the Company purchased approximately $1.4 billion, $2.0 billion, and $1.7 billion, respectively, under such arrangements.

As of December 31, 2009, the Company s commitments under such outstanding agreements are estimated as follows:

Period	**(In millions)**
2010	$ 1,011
2011	225
2012	180
2013	65
2014	75
Thereafter	600
Total[(a)]	$ 2,156

(a) Includes those coal transportation and lignite commitments for 2010 as no other nominations were made as of December 31, 2009. Natural gas nomination is through February 2011.

Purchased Power Commitment

NRG has purchased power contracts of various quantities and durations that are not classified as derivative assets and liabilities and do not qualify as operating leases. These contracts are not included in the consolidated balance sheet as of December 31, 2009. Minimum purchase commitment obligations under these agreements are as follows as of December 31, 2009:

Period	Fixed Pricing [a]		Variable Pricing [b]	
	(In millions)			
2010	$	53	$	2
2011		30		4
2012		21		1
2013		10		
Total[a]	$	114	$	7

(a) As of December 31, 2010, the maximum remaining term under any individual purchased power contract is four years.
(b) For contracts with variable pricing components, estimated prices are based on forward commodity curves as of December 31, 2009.

Other

As a result of the acquisition of Reliant Energy, the Company acquired the naming rights, including advertising and other benefits, for a football stadium and other convention and entertainment facilities included in the stadium complex in Houston, Texas. Pursuant to this agreement, the Company is required to pay $10 million per year through 2031.

Lignite Contract with Texas Westmoreland Coal Co.

The lignite used to fuel the Texas region s Limestone facility is obtained from a surface mine, or the Jewett mine, adjacent to the Limestone facility under a long-term contract with Texas Westmoreland Coal Co., or TWCC. The contract is based on a cost-plus arrangement with incentives and penalties to ensure proper management of the mine. NRG has the flexibility to increase or decrease lignite purchases from the mine within certain ranges, including the ability to suspend or terminate lignite purchases with adequate notice. The mining period was extended through 2018 with an option to extend the mining period by two five-year intervals.

TWCC is responsible for performing ongoing reclamation activities at the mine until all lignite reserves have been produced. When production is completed at the mine, NRG will be responsible for final mine reclamation obligations. The Railroad Commission of Texas has imposed a bond obligation of approximately $83 million on TWCC for the reclamation of this lignite mine. Pursuant to the contract with TWCC, an affiliate of CenterPoint Energy, Inc. has guaranteed $107 million of this obligation and approximately $32 million of such amount is supported by letters of credit posted by NRG. Under the terms of the cost plus agreement with TWCC, NRG is required to maintain a corporate guarantee of TWCC s bond obligation in the amount of $50 million when CenterPoint Energy, Inc. s obligation lapses in April 2010, or pay the costs of obtaining replacement performance assurance. Additionally, NRG is required to provide additional performance assurance over TWCC s current bond obligations if required by the Commission. On January 14, 2010, NRG made a filing with the Railroad Commission of Texas to provide a corporate guaranty and indemnity in the amount of $50 million in support of TWCC s bond obligation. NRG s corporate guaranty and indemnity will become effective on April 14, 2010, upon acceptance by the Texas Railroad Commission.

First and Second Lien Structure

NRG has granted first and second liens to certain counterparties on substantially all of the Company s assets. NRG uses the first or second lien structure to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under out-of-the-money hedge agreements for forward sales of power or MWh equivalents. To the extent that the underlying hedge positions for a counterparty are in-the-money to NRG, the counterparty would have no claim under the lien program. The lien program limits the volumes that can be hedged, not the value of underlying out-of-the money positions. The first lien program does not require NRG to post collateral above any threshold amount of exposure. Within the first and second lien structure, the Company can hedge up to 80% of its baseload capacity and 10% of its non-baseload assets with these counterparties for the first 60 months and then declining thereafter. Net exposure to a counterparty on all trades must be positively correlated to the price of the relevant commodity for the first lien to be available to that counterparty. The first and second lien structure is not subject to unwind or termination upon a ratings downgrade of a counterparty and has no stated maturity date.

NRG s lien counterparties may have a claim on the Company s assets to the extent market prices exceed the hedged price. As of December 31, 2009, and February 9, 2010, all hedges under the first and second liens were in-the-money on a counterparty aggregate basis.

RepoweringNRG Initiatives

NRG has capitalized $33 million through December 31, 2009, for the repowering of its El Segundo generating facility in California. Air permitting litigation unrelated to the El Segundo project has delayed receipt of certain required permits and prevented, the El Segundo project from meeting its original completion date of June 1, 2011. The Company is working with the counterparty to consider certain PPA modifications including the commercial operations date currently expected to be the summer of 2013.

Contingencies

Set forth below is a description of the Company s material legal proceedings. The Company believes that it has valid defenses to these legal proceedings and intends to defend them vigorously. Pursuant to the requirements of ASC 450 and related guidance, NRG records reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. In addition legal costs are expensed as incurred. Management has assessed each of the following matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought, and the probability of success. Unless specified below, the Company is unable to predict the outcome of these legal proceedings or reasonably estimate the scope or amount of any associated costs and potential liabilities. As additional information becomes available, management adjusts its assessment and estimates of such contingencies accordingly. Because litigation is subject to inherent uncertainties and unfavorable rulings or developments, it is possible that the ultimate resolution of the Company s liabilities and contingencies could be at amounts that are different from its currently recorded reserves and that such difference could be material.

In addition to the legal proceedings noted below, NRG and its subsidiaries are party to other litigation or legal proceedings arising in the ordinary course of business. In management s opinion, the disposition of these ordinary course matters will not materially adversely affect NRG s consolidated financial position, results of operations, or cash flows.

California Department of Water Resources

This matter concerns, among other contracts and other defendants, the CDWR and its wholesale power contract with subsidiaries of WCP (Generation) Holdings, Inc., or WCP. The case originated with a February 2002 complaint filed by the State of California alleging that many parties, including WCP subsidiaries, overcharged the State of California. For WCP, the alleged overcharges totaled approximately $940 million for 2001 and 2002. The complaint demanded that the or FERC abrogate the CDWR contract and sought refunds associated with revenues collected under the contract. In 2003, the FERC rejected this complaint, denied rehearing, and the case was appealed to the U.S. Court of Appeals for the Ninth Circuit where oral argument was held on December 8, 2004. On December 19, 2006, the Ninth Circuit decided that in the FERC s review of the contracts at issue, the FERC could not rely on the *Mobile-Sierra* standard presumption of just and reasonable rates, where such contracts were not reviewed by the FERC with full knowledge of the then existing market conditions. WCP and others sought review by the U.S. Supreme Court. WCP s appeal was not selected, but instead held by the Supreme Court. In the appeal that was selected by the Supreme Court, on June 26, 2008 the Supreme Court ruled: (i) that the *Mobile-Sierra* public interest standard of review applied to contracts made under a seller s market-based rate authority; (ii) that the public interest bar required to set aside a contract remains a very high one to overcome; and (iii) that the *Mobile-Sierra* presumption of contract reasonableness applies when a contract is formed during a period of market dysfunction unless (a) such market conditions were caused by the illegal actions of one of the parties or (b) the contract negotiations were tainted by fraud or duress. In this related case, the U.S. Supreme Court affirmed the Ninth Circuit s decision agreeing that the case should be remanded to the FERC to clarify the FERC s 2003 reasoning regarding its rejection of the original complaint relating to the financial burdens under the contracts at issue and to alleged market manipulation at the time these contracts were formed. As a result, the U.S. Supreme Court then reversed and remanded the WCP CDWR case to the Ninth Circuit for treatment consistent with its June 26, 2008 decision in the related case. On October 20, 2008, the Ninth Circuit asked the parties in the remanded CDWR case, including WCP and the FERC, whether that Court should answer a question the U.S. Supreme Court did not address in its June 26, 2008, decision; whether the *Mobile-Sierra* doctrine applies to a third-party that was not a signatory to any of the wholesale power contracts, including the CDWR contract, at issue in that case. Without answering that reserved question, on December 4, 2008, the Ninth Circuit vacated its prior opinion and remanded the WCP CDWR case back to the FERC for proceedings consistent with the U.S. Supreme Court s June 26, 2008 decision. On December 15, 2008, WCP and the other seller-defendants filed with the FERC a Motion for Order Governing Proceedings on Remand. On January 14, 2009, the Public Utilities Commission of the State of California filed an Answer and Cross Motion for an Order Governing Procedures on Remand, and on January 28, 2009, WCP and the other seller-defendants filed their reply.

At this time, while NRG cannot predict with certainty whether WCP will be required to make refunds for rates collected under the CDWR contract or estimate the range of any such possible refunds, a reconsideration of the CDWR contract by the FERC with a resulting order mandating significant refunds could have a material adverse impact on NRG s financial position, statement of operations, and statement of cash flows. As part of the 2006 acquisition of Dynegy s 50% ownership interest in WCP, WCP and NRG assumed responsibility for any risk of loss arising from this case, unless any such loss was deemed to have resulted from certain acts of gross negligence or willful misconduct on the part of Dynegy, in which case any such loss would be shared equally between WCP and Dynegy.

On January 14, 2010, the U.S. Supreme Court issued its decision in an unrelated proceeding involving the *Mobile-Sierra* doctrine that will affect the standard of review applied to the CDWR contract on remand before the FERC. In *NRG Power Marketing v. Maine Public Utilities Commission*, the Supreme Court held that the *Mobile-Sierra* presumption regarding the reasonableness of contract rates does not depend on the identity of the complainant who seeks a FERC investigation/refund. The Supreme Court proceeding arose following an appeal by the Attorneys General of the State of Connecticut and of the Commonwealth of Massachusetts regarding the settlement establishing the New England Forward Capacity Market. The settlement, filed with the FERC on March 7, 2006, provides for interim capacity transition payments for all generators in New England for the period from December 1, 2006 through May 31, 2010 and for the Forward Capacity Market auction rates thereafter. The Court of Appeals for the DC Circuit, or DC Circuit, had rejected all substantive challenges to the settlement, but had sustained one procedural argument relating to the applicability of the *Mobile-Sierra* doctrine to third parties. The Supreme Court reversed the DC Circuit on this point, and remanded the case for further consideration of whether the transition payments and auction rates qualify as contract rates.

Louisiana Generating, LLC

On February 11, 2009, the U.S. Department of Justice acting at the request of the U.S. Environmental Protection Agency, or U.S. EPA, commenced a lawsuit against Louisiana Generating, LLC in federal district court in the Middle District of Louisiana alleging violations of the Clean Air Act, or CAA, at the Big Cajun II power plant. This is the same matter for which Notices of Violation, or NOVs, were issued to Louisiana Generating, LLC on February 15, 2005, and on December 8, 2006. Specifically, it is alleged that in the late 1990 s, several years prior to NRG s acquisition of the Big Cajun II power plant from the Cajun Electric bankruptcy and several years prior to the NRG bankruptcy, modifications were made to Big Cajun II Units 1 and 2 by the prior owners without appropriate or adequate permits and without installing and employing the best available control technology, or BACT, to control emissions of nitrogen oxides and/or sulfur dioxides. The relief sought in the complaint includes a request for an injunction to: (i) preclude the operation of Units 1 and 2 except in accordance with the CAA; (ii) order the installation of BACT on Units 1 and 2 for each pollutant subject to regulation under the CAA; (iii) obtain all necessary permits for Units 1 and 2; (iv) order the surrender of emission allowances or credits; (v) conduct audits to determine if any additional modifications have been made which would require compliance with the CAA s Prevention of Significant Deterioration program; (vi) award to the Department of Justice its costs in prosecuting this litigation; and (vii) assess civil penalties of up to $27,500 per day for each CAA violation found to have occurred between January 31, 1997, and March 15, 2004, up to $32,500 for each CAA violation found to have occurred between March 15, 2004, and January 12, 2009, and up to $37,500 for each CAA violation found to have occurred after January 12, 2009.

On April 27, 2009, Louisiana Generating, LLC made several filings. It filed an objection in the Cajun Electric Cooperative Power, Inc. s bankruptcy proceeding in the U.S. Bankruptcy Court for the Middle District of Louisiana to seek to prevent the bankruptcy from closing. It also filed a complaint in the same bankruptcy proceeding in the same court seeking a judgment that: (i) it did not assume liability from Cajun Electric for any claims or other liabilities under environmental laws with respect to Big Cajun II that arose, or are based on activities that were undertaken, prior to the closing date of the acquisition; (ii) it is not otherwise the successor to Cajun Electric; and (iii) Cajun Electric and/or the Bankruptcy Trustee are exclusively liable for the violations alleged in the February 11, 2009, lawsuit to the extent that such claims are determined to have merit. On June 8, 2009, the parties filed a joint status report setting forth their views of the case and proposing a trial schedule. On June 18, 2009, Louisiana Generating, LLC filed a motion to bifurcate the Department of Justice lawsuit into separate liability and remedy phases, and on June 30, 2009, the Department of Justice filed its opposition. On August 24, 2009, Louisiana Generating, LLC filed a motion to dismiss this lawsuit, and on September 25, 2009, the Department of Justice filed its opposition to the motion to dismiss. A new federal bankruptcy judge was appointed on October 9, 2009.

On February 18, 2010, the LDEQ filed a motion to intervene in the above lawsuit and a complaint against Louisiana Generating LLC for alleged violations of Louisiana s PSD regulations and Louisiana s Title V operating permit program. LDEQ seeks similar relief to that requested by the Department of Justice. Specifically, LDEQ seeks injunctive relief to: (1) preclude the operation of Units 1 and 2 except in accordance with the CAA; (2) order the installation of BACT on Units 1 and 2 for each pollutant subject to regulation under the CAA; (3) obtain all necessary permits for Units 1 and 2 pursuant to the requirements of PSD and the Louisiana Title V operating permits program; (4) conduct audits to determine if any additional modifications have occurred which would require it to meet the requirements of PSD and report the results of the audit to the LDEQ and EPA; (5) order the surrender of emission allowances or credits; (6) take other appropriate actions to remedy, mitigate and offset the harm to public health and the environment caused by violations of the CAA; (7) assess civil penalties; and (8) award to the LDEQ its costs in prosecuting the litigation. On February 19, 2010, the district court granted LDEQ s motion to intervene.

Nuclear Innovation North America, LLC

On December 6, 2009, CPS commenced a lawsuit against two NINA entities asking the court to declare the rights, obligations, and remedies of the parties pursuant to the 1997 and 2007 agreements between the parties should CPS unilaterally withdraw from the proposed STP Units 3 and 4 Project. On December 23, 2009, CPS amended its original December 6 complaint adding NRG, Toshiba Corporation, and NINA LLC as defendants and not only continued to request that the Court declare the rights, obligations, and remedies of the parties under the two operative governing agreements, but also sought $32 billion in damages. CPS amended its complaint again on December 28, 2009.

On January 6, 2010, CPS amended its complaint for the third time. In addition to requesting immediate injunctive relief, the amended complaint alleges that NRG, Toshiba, and NINA have been involved in a conspiracy to defraud CPS, that they purposefully misled CPS in inducing it to be a partner in the STP Units 3 and 4 Project, that they maliciously interfered with CPS contracts and business relationships, and that they willfully disparaged CPS. It sought declarations that: (i) owner consensus is required for all development decisions; (ii) there is a right to voluntary withdrawal, after which no further obligations accrue but undiluted ownership continues; (iii) both the partition waiver and forfeiture provisions are unenforceable against CPS under Texas law if they did apply; and (iv) CPS is not currently in breach. In addition, CPS sought relief among the following alternatives: partition by sale; an order forcing NRG and NINA to buy CPS undiluted share at an independent valuation; an order requiring NRG to compensate CPS $350 million investment and fair value for the site; an order granting CPS twelve months following withdrawal to sell its stake in the project; or an order that no further development take place without consensus of all project owners. This case was removed and remanded to and from federal court on three separate occasions. On January 19, 2010, CPS dismissed Toshiba from the lawsuit.

The parties agreed to a January 25, 2010, phased trial wherein all other claims would be reserved for an undetermined future phase II date and a trial would go forward in phase I only on CPS request for declaratory relief to determine the respective rights, obligations, and remedies of the parties under the two operative governing agreements should CPS withdraw from the STP Units 3 and 4 Project. On January 25, 2010, the parties argued the NINA entities and NRG s Motion for Summary Judgment which was denied on January 26, 2010. After a two-day trial, the court issued its ruling on January 29, 2010, making a number of findings. It ruled that as of January 29, 2010, CPS and NINA were each 50% equity owners as tenants in common under Texas law in the STP Units 3 and 4 Project. The court found that while a withdrawing party does not forfeit its 50% interest upon a withdrawal, the governing agreements are silent as to whether that withdrawing party can recoup its sunk costs upon withdrawal. Finally, the court noted that for CPS to remain a 50% equity owner, it must pay all appropriate costs. Failure to do so, the court determined, would result in a complete loss of CPS equity share. On February 17, 2010, an agreement in principle was reached with CPS for NINA to acquire a controlling interest in the STP Units 3 and 4 Project through a settlement of all pending litigation between the parties. As part of that agreement, all litigation would be dismissed with prejudice, including all phase II claims, thereby ending this matter. The parties continue to negotiate terms regarding final documentation of the agreement in principle.

Dunkirk Construction Litigation

In 2005, NRG entered into a Consent Decree with the New York State Department of Environmental Conservation whereby it agreed to reduce certain emissions generated by its Huntley and Dunkirk power plants. Pursuant to the Consent Decree, on November 21, 2007, Clyde Bergemann EEC, or CBEEC, and NRG entered into a firm fixed price contract for the supply of equipment, material and services for six fabric filters for NRG s Dunkirk Electric Power Generating Station. Subsequent to contracting with NRG, CBEEC subcontracted with Hohl Industrial Services, Inc., or Hohl, to perform steel erection and equipment installation at Dunkirk.

On August 28, 2009, Hohl filed its original complaint against NRG, its subsidiary Dunkirk Power LLC, or Dunkirk Power, and CBEEC among others for claims of breach of contract, quantum meruit, unjust enrichment and foreclosure of mechanics liens. As part of CBEEC s contractual obligation to NRG, CBEEC agreed to defend, under a reservation of rights, NRG s interest in this lawsuit. CBEEC filed an answer to the above complaint on behalf of itself, NRG and Dunkirk Power on October 5, 2009. On December 16, 2009, CBEEC filed a Motion for Summary Judgment on behalf of itself, NRG, and Dunkirk Power, which has yet to be decided.

On February 1, 2010, NRG and Dunkirk Power filed a Motion for Leave to file an Amended Answer with Cross-Claims against CBEEC. NRG asserted breach of contract claims seeking liquidated damages for the delays caused by CBEEC. NRG also retained its own counsel to represent its interest in the cross-claims and reserved its rights to seek reimbursement from CBEEC. On February 17, 2010, CBEEC filed an Amended Answer with Affirmative Defenses, Counterclaims and Cross-Claims against NRG. CBEEC is seeking approximately $30 million alleging breach of contract, quantum meruit, unjust enrichment, and foreclosure of two mechanic s liens, as a result of alleged delays caused by NRG and Dunkirk Power. A court ordered hearing and settlement conference is scheduled for February 23, 2010.

Excess Mitigation Credits

From January 2002 to April 2005, CenterPoint Energy applied excess mitigation credits, or EMCs, to its monthly charges to retail electric providers as ordered by the PUCT. The PUCT imposed these credits to facilitate the transition to competition in Texas, which had the effect of lowering the retail electric providers monthly charges payable to CenterPoint Energy. As indicated in its Petition for Review filed with the Supreme Court of Texas on June 2, 2008, CenterPoint Energy has claimed that the portion of those EMCs credited to Reliant Energy Retail Services, LLC, or RERS, a retail electric provider and NRG subsidiary acquired from RRI, totaled $385 million for RERS s Price to Beat Customers. It is unclear what the actual number may be. Price to Beat was the rate RERS was required by state law to charge residential and small commercial customers that were transitioned to RERS from the incumbent integrated utility company commencing in 2002. In its original stranded cost case brought before the PUCT on March 31, 2004, CenterPoint Energy sought recovery of all EMCs that were credited to all retail electric providers, including RERS, and the PUCT ordered that relief in its Order on Rehearing in Docket No. 29526, on December 17, 2004. After an appeal to state district court, the court entered a final judgment on August 26, 2005, affirming the PUCT s order with regard to EMCs credited to RERS. Various parties filed appeals of that judgment with the Court of Appeals for the Third District of Texas with the first such appeal filed on the same date as the state district court judgment and the last such appeal filed on October 10, 2005. On April 17, 2008, the Court of Appeals for the Third District reversed the lower court s decision ruling that CenterPoint Energy s stranded cost recovery should exclude only EMCs credited to RERS for its Price to Beat customers. On June 2, 2008, CenterPoint Energy filed a Petition for Review with the Supreme Court of Texas and on June 19, 2009, the Court agreed to consider the CenterPoint Energy appeal as well as two related petitions for review filed by other entities. Oral argument occurred on October 6, 2009.

In November 2008, CenterPoint Energy and RRI, on behalf of itself and affiliates including RERS, agreed to suspend unexpired deadlines, if any, related to limitations periods that might exist for possible claims against REI and its affiliates if CenterPoint Energy is ultimately not allowed to include in its stranded cost calculation those EMCs previously credited to RERS. Regardless of the outcome of the Texas Supreme Court proceeding, NRG believes that any possible future CenterPoint Energy claim against RERS for EMCs credited to RERS would lack legal merit. No such claim has been filed.

Note 23 Regulatory Matters

NRG operates in a highly regulated industry and is subject to regulation by various federal and state agencies. As such, NRG is affected by regulatory developments at both the federal and state levels and in the regions in which NRG operates. In addition, NRG is subject to the market rules, procedures and protocols of the various ISO markets in which NRG participates. These power markets are subject to ongoing legislative and regulatory changes that may impact NRG s wholesale and retail businesses.

In addition to the regulatory proceedings noted below, NRG and its subsidiaries are a party to other regulatory proceedings arising in the ordinary course of business or have other regulatory exposure. In management s opinion, the disposition of these ordinary course matters will not materially adversely affect NRG s consolidated financial position, results of operations, or cash flows.

PJM On June 18, 2009, FERC denied rehearing of its order dated September 19, 2008, dismissing a complaint filed by the Maryland Public Service Commission, or MDPSC, together with other load interests, against PJM challenging the results of the RPM transition Base Residual Auctions for installed capacity, held between April 2007 and January 2008. The complaint had sought to replace the auction-determined results for installed capacity for the 2008/2009, 2009/2010, and 2010/2011 delivery years with administratively-determined prices. On August 14, 2009, the MDPSC and the New Jersey Board of Public Utilities filed an appeal of FERC s orders to the U.S. Court of Appeals for the Fourth Circuit, and a successful appeal could disrupt the auction-determined results and create a refund obligation for market participants. The case has been transferred to the U.S. Court of Appeals for the DC Circuit.

Retail (Replacement Reserve) On November 14, 2006, Constellation Energy Commodities Group, or Constellation, filed a complaint with the PUCT alleging that ERCOT misapplied the Replacement Reserve Settlement, or RPRS, Formula contained in the ERCOT protocols from April 10, 2006, through September 27, 2006. Specifically, Constellation disputed approximately $4 million in under-scheduling charges for capacity insufficiency asserting that ERCOT applied the wrong protocol. Reliant Energy Power Supply, or REPS, other market participants, ERCOT, and PUCT staff opposed Constellation s complaint. On January 25, 2008, the PUCT entered an order finding that ERCOT correctly settled the capacity insufficiency charges for the disputed dates in accordance with ERCOT protocols and denied Constellation s complaint. On April 9, 2008, Constellation appealed the PUCT order to the Civil District Court of Travis County, Texas and on June 19, 2009, the court issued a judgment reversing the PUCT order, finding that the ERCOT protocols were in irreconcilable conflict with each other. On July 20, 2009, REPS filed an appeal to the Third Court of Appeals in Travis County, Texas, thereby staying the effect of the trial court s decision. If all appeals are unsuccessful, on remand to the PUCT, it would determine the appropriate methodology for giving effect to the trial court s decision. It is not known at this time whether only Constellation s under-scheduling charges, the under-scheduling charges of all other QSEs that disputed REPS charges for the same time frame, the entire market, or some other approach would be used for any resettlement.

Under the PUCT ordered formula, Qualified Scheduling Entities, or QSEs, who under-scheduled capacity within any of ERCOT s four congestion zones were assessed under-scheduling charges which defrayed the costs incurred by ERCOT for RPRS that would otherwise be spread among all load-serving QSEs. Under the Court s decision, all RPRS costs would be assigned to all load-serving QSEs based upon their load ratio share without assessing any separate charge to those QSEs who under-scheduled capacity. If under-scheduling charges for capacity insufficient QSEs were not used to defray RPRS costs, REPS s share of the total RPRS costs allocated to QSEs would increase.

Note 24 Environmental Matters

The construction and operation of power projects are subject to stringent environmental and safety protection and land use laws and regulation in the U.S. If such laws and regulations become more stringent, or new laws, interpretations or compliance policies apply and NRG s facilities are not exempt from coverage, the Company could be required to make modifications to further reduce potential environmental impacts. New legislation and regulations to mitigate the effects of GHG including CO_2 from power plants, are under consideration at the federal and state levels. In general, the effect of such future laws or regulations is expected to require the addition of pollution control equipment or the imposition of restrictions or additional costs on the Company s operations.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures from 2010 through 2014 to meet NRG s environmental commitments will be approximately $0.9 billion and are primarily associated with controls on the Company s Big Cajun and Indian River facilities. These capital expenditures, in general, are related to installation of particulate, SO_2, NOx, and mercury controls to comply with federal and state air quality rules and consent orders, as well as installation of Best Technology Available under the Phase II 316(b) Rule. NRG continues to explore cost effective alternatives that can achieve desired results. This estimate reflects anticipated schedules and controls related to the CAIR, MACT for mercury, and the Phase II 316(b) Rule which are under remand to the U.S. EPA, and, as such, the full impact on the scope and timing of environmental retrofits from any new or revised regulations cannot be determined at this time.

Northeast Region

In January 2006, NRG s Indian River Operations, Inc. received a letter of informal notification from the DNREC stating that it may be a potentially responsible party with respect to Burton Island Old Ash Landfill, a historic captive landfill located at the Indian River facility. On October 1, 2007, NRG signed an agreement with the DNREC to investigate the site through the Voluntary Clean-up Program. On February 4, 2008, the DNREC issued findings that no further action is required in relation to surface water and that a previously planned shoreline stabilization project would adequately address shore line erosion. The landfill itself will require a further Remedial Investigation and Feasibility Study to determine the type and scope of any additional work required. Until the Remedial Investigation and Feasibility Study are completed, the Company is unable to predict the impact of any required remediation.

On May 29, 2008, the DNREC requested that NRG s Indian River Operations, Inc. participate in the development and performance of a Natural Resource Damage Assessment, or NRDA, at the Burton Island Old Ash Landfill. NRG is currently working with the DNREC and other trustees to close out the assessment phase.

South Central Region

On February 11, 2009, the U.S. Department of Justice acting at the request of the U.S. EPA commenced a lawsuit against Louisiana Generating, LLC in federal district court in the Middle District of Louisiana alleging violations of the CAA at the Big Cajun II power plant. This is the same matter for which NOVs were issued to Louisiana Generating, LLC on February 15, 2005, and on December 8, 2006. Further discussion on this matter can be found in Item 3 Legal Proceedings*, United States of America v. Louisiana Generating, LLC*.

Note 25 Cash Flow Information

Detail of supplemental disclosures of cash flow and non-cash investing and financing information was:

	Year Ended December 31, 2009	2008	2007
	(In millions)		
Interest paid, net of amount capitalized[a]	$ 587	$ 563	$ 598
Income taxes paid[b]	47	46	22
Non-cash investing and financing activities:			
(Reduction)/addition to fixed assets due to asset retirement obligations	(1)	(39)	7

Additions to fixed assets for accrued capital expenditures	44	116
Decrease to fixed assets for accrued grants and related tax impact	(132)	
Decrease to 4.0% preferred stock from conversion to common stock	257	
Decrease to 5.75% preferred stock from conversion to common stock	447	39
Decrease to treasury stock from the net impact of shares loaned to and returned by affiliates of CS	160	

(a) 2008 interest paid includes $45 million payment to settle the CSF I CAGR.

(b) 2009, 2008 and 2007 income taxes paid is net of $3, $2 and $6 million, respectively, of income tax refunds received.

Note 26 Guarantees

NRG and its subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of the Company s business activities. Examples of these contracts include asset purchases and sale agreements, commodity sale and purchase agreements, retail contracts, joint venture agreements, EPC agreements, operation and maintenance agreements, service agreements, settlement agreements, and other types of contractual agreements with vendors and other third parties, as well as affiliates. These contracts generally indemnify the counterparty for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements. The Company is also obligated with respect to customer deposits associated with Reliant Energy. In some cases, NRG s maximum potential liability cannot be estimated, since the underlying agreements contain no limits on potential liability. In accordance with ASC 460, NRG has estimated that the current fair value for issuing these guarantees was approximately $8.0 million as of December 31, 2009, and the liability in this amount is included in the Company s non-current liabilities.

The following table summarizes NRG s estimated guarantees, indemnity, and other contingent liability obligations by maturity:

	By Remaining Maturity at December 31, 2009					
Guarantees	**Under 1 Year**	**1-3 Years**	**3-5 Years**	**Over 5 Years**	**Total**	**2008 Total**
	(In millions)					
Synthetic letters of credit	$ 531	$ 186	$	$	$ 717	$ 440
Unfunded letters of credit and surety bonds	61	36			97	5
Asset sales guarantee obligations		118		8	126	129
Commercial sales arrangements	104	44	103	965	1,216	1,005
Other guarantees				117	117	80
Total guarantees	$ 696	$ 384	$ 103	$ 1,090	$ 2,273	$ 1,659

Letters of credit and surety bonds As of December 31, 2009, NRG and its consolidated subsidiaries were contingently obligated for a total of approximately $814 million under letters of credit and surety bonds. Most of these letters of credit and surety bonds are issued in support of the Company s obligations to perform under commodity agreements, financing or other arrangements. A majority of these letters of credit and surety bonds expire within one year of issuance, and it is typical for the Company to renew them on similar terms.

Asset sale guarantees NRG is typically requested to provide certain assurances to the counter-parties of the Company s asset sale agreements. Such assurances may take the form of a guarantee issued by the Company on behalf of a directly or indirectly held majority-owned subsidiary which include certain indemnifications to a third party, usually the buyer, as described below. Due to the inter-company nature of such arrangements, NRG is essentially guaranteeing its own performance, and the nature of the guarantee being provided. It is not the Company s policy to recognize the value of such an obligation in its consolidated financial statements. Most of these guarantees provide an explicit cap on the Company s maximum liability, as well as an expiration period, exclusive of breach of representations and warranties.

In connection with the agreement to sell its 50% ownership interest in Mibrag B.V., NRG executed an agreement guaranteeing the performance of its subsidiary Lambique Beheer under the purchase and sale agreement. This agreement indemnifies the buyer for tax, environmental liability and other matters, as well as breaches of representations and warranties and is limited to EUR 206 million.

Commercial sales arrangements In connection with the purchase and sale of fuel, emission allowances and power generation products to and from third parties with respect to the operation of some of NRG s generation facilities in the U.S., the Company may be required to guarantee a portion of the obligations of certain of its subsidiaries. These obligations may include liquidated damages payments or other unscheduled payments.

Other guarantees NRG has issued guarantees of obligations that its subsidiaries may incur as a provision for environmental site remediation, payment of debt obligations, rail car leases, performance under purchase, EPC and operating and maintenance agreements. NRG has executed guarantees with related parties for one of its subsidiary s obligations as construction manager under EPC contracts for the construction of the two peaking power plants at GenConn s Devon and Middletown sites. See Note 16, *Investments Accounted for by the Equity Method,* for more information on this equity investment. The Company does not believe that it will be required to perform under these guarantees.

NRG signed a guarantee agreement on behalf of its subsidiary NRG Retail, LLC guaranteeing the payment and performance of its obligations under the LLC Membership Interest Purchase Agreement and related agreements with RRI in connection with the purchase of its retail business, including purchase price and acquired net working capital. In accordance with the LLC Membership Interest Purchase Agreement, on May 1, 2009, NRG signed an agreement guaranteeing payments up to $85 million related to the Restated Power Purchase Agreement with FPL Energy Upton Wind II, LLC. NRG has no reason to believe that the Company currently has any material liability relating to such routine indemnification obligations.

In connection with the October 5, 2009, amendment of the CSRA, NRG signed guarantee agreements on behalf of its subsidiary NRG Retail, LLC guaranteeing performance under power purchase and sales contracts. See Note 3, Business Acquisitions, for more information on the amendment of the CSRA.

The material indemnities, within the scope of ASC 460, are as follows:

Asset purchases and divestitures The purchase and sale agreements which govern NRG s asset or share investments and divestitures customarily contain indemnifications of the transaction to third parties. The contracts indemnify the parties for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party, or as a result of a change in tax laws. These obligations generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or estimate at the time of the transaction. In several cases, the contract limits the liability of the indemnifier. For those indemnities in which liability is capped, the maximum exposures range from $1 million to $300 million. NRG has no reason to believe that the Company currently has any material liability relating to such routine indemnification obligations.

Other indemnities Other indemnifications NRG has provided cover operational, tax, litigation and breaches of representations, warranties and covenants. NRG has also indemnified, on a routine basis in the ordinary course of business, consultants or other vendors who have provided services to the Company. NRG s maximum potential exposure under these indemnifications can range from a specified dollar amount to an indeterminate amount, depending on the nature of the transaction. Total maximum potential exposure under these indemnifications is not estimable due to uncertainty as to whether claims will be made or how they will be resolved. NRG does not have any reason to believe that the Company will be required to make any material payments under these indemnity provisions.

Because many of the guarantees and indemnities NRG issues to third parties and affiliates do not limit the amount or duration of its obligations to perform under them, there exists a risk that the Company may have obligations in excess of the amounts described above. For those guarantees and indemnities that do not limit the Company s liability exposure, it may not be able to estimate what the Company s liability would be, until a claim is made for payment or performance, due to the contingent nature of these contracts.

Note 27 Jointly Owned Plants

Certain NRG subsidiaries own undivided interests in jointly-owned plants, described below. These plants are maintained and operated pursuant to their joint ownership participation and operating agreements. NRG is responsible for its subsidiaries share of operating costs and direct expense and includes its proportionate share of the facilities and related revenues and direct expenses in these jointly-owned plants in the corresponding balance sheet and income statement captions of the Company s consolidated financial statements.

The following table summarizes NRG s proportionate ownership interest in the Company s jointly-owned facilities:

As of December 31, 2009	Ownership Interest	Property, Plant & Equipment	Accumulated Depreciation	Construction in Progress
		(In millions unless otherwise stated)		
South Texas Project Units 1 and 2, Bay City, TX	44.00%	$ 3,003	$ (663)	$ 32
Big Cajun II Unit 3, New Roads, LA	58.00	175	(58)	13
Cedar Bayou Unit 4, Baytown, TX	50.00	215	(5)	
Keystone, Shelocta, PA	3.70	88	(19)	4
Conemaugh, New Florence, PA	3.72	74	(22)	2

Note 28 Unaudited Quarterly Financial Data

Summarized unaudited quarterly financial data is as follows:

	Quarter Ended 2009			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$ 2,141	$ 2,916	$ 2,237	$ 1,658
Operating income	314	611	619	615
Income from continuing operations, net of income taxes	33	278	433	198
Income from discontinued operations, net of income taxes				
Net income attributable to NRG Energy, Inc.	$ 33	$ 278	$ 433	$ 198
Weighted average number of common shares outstanding basic	242	249	253	237
Income from continuing operations per weighted average common share basic	$ 0.11	$ 1.09	$ 1.68	$ 0.78
Net income per weighted average common share basic	$ 0.11	$ 1.09	$ 1.68	$ 0.78
Weighted average number of common shares outstanding diluted	244	272	275	275
Income from continuing operations per weighted average common share diluted	$ 0.11	$ 1.02	$ 1.56	$ 0.70
Net income per weighted average common share diluted	$ 0.11	$ 1.02	$ 1.56	$ 0.70

	Quarter Ended 2008			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$ 1,655	$ 2,612	$ 1,316	$ 1,302
Operating income	595	1,371	57	250
Income/(loss) from continuing operations, net of income taxes	271	778	(41)	45
Income from discontinued operations, net of income taxes			168	4
Net income attributable to NRG Energy, Inc.	$ 271	$ 778	$ 127	$ 49
Weighted average number of common shares outstanding basic	233	235	236	236
Income from continuing operations per weighted average common share basic	$ 1.10	$ 3.26	$ (0.23)	$ 0.13
Income/(loss) from discontinued operations per weighted average common share basic			0.71	0.02
Net income per weighted average common share basic	$ 1.10	$ 3.26	$ 0.48	$ 0.15
Weighted average number of common shares outstanding diluted	276	277	236	245
Income/(loss) from continuing operations per weighted average common share diluted	$ 0.97	$ 2.81	$ (0.23)	$ 0.12
Income from discontinued operations per weighted average common share diluted			0.71	0.02
Net income per weighted average common share diluted	$ 0.97	$ 2.81	$ 0.48	$ 0.14

222

Note 29 Condensed Consolidating Financial Information

As of December 31, 2009, the Company had $1.2 billion of 7.25% Senior Notes due 2014, $2.4 billion of 7.375% Senior Notes due 2016 and $1.1 billion of 7.375%. Senior Notes due 2017 and $700 million of 8.50% Senior Notes due 2019. These notes are guaranteed by certain of NRG s current and future wholly-owned domestic subsidiaries, or guarantor subsidiaries.

On October 5, 2009, RERH became a guarantor subsidiary as a result of the CSRA Amendment. The consolidating financial statements hereinafter have been recast to reflect RERH as a guarantor subsidiary for the period ended December 31, 2009. RERH s cash balance on the date it became a guarantor subsidiary was $734 million.

Unless otherwise noted below, each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of December 31, 2009:

Arthur Kill Power LLC
Astoria Gas Turbine Power LLC
Berrians I Gas Turbine Power LLC
Big Cajun II Unit 4 LLC
Cabrillo Power I LLC
Cabrillo Power II LLC
Chickahominy River Energy Corp.
Commonwealth Atlantic Power LLC
Conemaugh Power LLC
Connecticut Jet Power LLC
Devon Power LLC
Dunkirk Power LLC
Eastern Sierra Energy Company
El Segundo Power, LLC
El Segundo Power II LLC
GCP Funding Company LLC
Hanover Energy Company
Hoffman Summit Wind Project LLC
Huntley IGCC LLC
Huntley Power LLC
Indian River IGCC LLC
Indian River Operations Inc.
Indian River Power LLC
James River Power LLC
Kaufman Cogen LP
Keystone Power LLC
Lake Erie Properties Inc.
Langford Wind Power, LLC
Louisiana Generating LLC
Middletown Power LLC
Montville IGCC LLC
Montville Power LLC
NRG Generation Holdings, Inc.
NRG Huntley Operations Inc.
NRG International LLC
NRG Kaufman LLC
NRG Mesquite LLC
NRG MidAtlantic Affiliate Services Inc.
NRG Middletown Operations Inc.
NRG Montville Operations Inc.
NRG New Jersey Energy Sales LLC
NRG New Roads Holdings LLC
NRG North Central Operations, Inc.
NRG Northeast Affiliate Services Inc.
NRG Norwalk Harbor Operations Inc.
NRG Operating Services Inc.
NRG Oswego Harbor Power Operations Inc.
NRG Power Marketing LLC
NRG Retail LLC
NRG Rocky Road LLC
NRG Saguaro Operations Inc.
NRG South Central Affiliate Services Inc.
NRG South Central Generating LLC
NRG South Central Operations Inc.
NRG South Texas LP
NRG Texas LLC
NRG Texas C & I Supply LLC
NRG Texas Holding Inc.
NRG Texas Power LLC
NRG West Coast LLC
NRG Western Affiliate Services Inc.
Oswego Harbor Power LLC
Padoma Wind Power, LLC
Reliant Energy Power Supply, LLC

NEO Chester-Gen LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Power Services Inc.
New Genco GP LLC
Norwalk Power LLC
NRG Affiliate Services Inc.
NRG Arthur Kill Operations Inc.
NRG Asia-Pacific Ltd.
NRG Astoria Gas Turbine Operations Inc.
NRG Bayou Cove LLC
NRG Cabrillo Power Operations Inc.
Reliant Energy Retail Holding, LLC
Reliant Energy Retail Services, LLC
RE Retail Receivables, LLC
RERH Holdings, LLC
Reliant Energy Services Texas LLC
Reliant Energy Texas Retail LLC
Saguaro Power LLC
San Juan Mesa Wind Project II, LLC
Somerset Operations Inc.
Somerset Power LLC
Texas Genco Financing Corp.
Texas Genco GP, LLC

NRG Cadillac Operations Inc.	Texas Genco Holdings, Inc.
NRG California Peaker Operations LLC	Texas Genco LP, LLC
NRG Cedar Bayou Development Company LLC	Texas Genco Operating Services, LLC
NRG Connecticut Affiliate Services Inc.	Texas Genco Services, LP
NRG Construction LLC	Vienna Operations, Inc.
NRG Devon Operations Inc.	Vienna Power LLC
NRG Dunkirk Operations, Inc.	WCP (Generation) Holdings LLC
NRG El Segundo Operations Inc.	West Coast Power LLC

The non-guarantor subsidiaries include all of NRG s foreign subsidiaries and certain domestic subsidiaries. NRG conducts much of its business through and derives much of its income from its subsidiaries. Therefore, the Company s ability to make required payments with respect to its indebtedness and other obligations depends on the financial results and condition of its subsidiaries and NRG s ability to receive funds from its subsidiaries. Except for NRG Bayou Cove, LLC, which is subject to certain restrictions under the Company s Peaker financing agreements, there are no restrictions on the ability of any of the guarantor subsidiaries to transfer funds to NRG. In addition, there may be restrictions for certain non-guarantor subsidiaries.

The following condensed consolidating financial information presents the financial information of NRG Energy, Inc., the guarantor subsidiaries and the non-guarantor subsidiaries in accordance with Rule 3-10 under the Securities and Exchange Commission s Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiaries or non-guarantor subsidiaries operated as independent entities.

In this presentation, NRG Energy, Inc. consists of parent company operations. Guarantor subsidiaries and non-guarantor subsidiaries of NRG are reported on an equity basis. For companies acquired, the fair values of the assets and liabilities acquired have been presented on a push-down accounting basis.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2009

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer) (In millions)	Eliminations (a)	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 8,584	$ 357	$ 31	$ (20)	$ 8,952
Operating Costs and Expenses					
Cost of operations	5,110	236	1	(24)	5,323
Depreciation and amortization	772	40	6		818
Selling, general and administrative	266	11	273		550
Acquisition-related transaction and integration costs			54		54
Development costs	6	8	34		48
Total operating costs and expenses	6,154	295	368	(24)	6,793
Operating Income/(Loss)	2,430	62	(337)	4	2,159
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	166		1,503	(1,669)	
Equity in earnings of unconsolidated affiliates	10	31			41
Gains on sales of equity method investments		128			128
Other income/(loss), net	9	(16)	6	(4)	(5)
Refinancing expense	(1)		(19)		(20)
Interest expense	(106)	(86)	(442)		(634)
Total other income/(expense)	78	57	1,048	(1,673)	(490)
Income/(Losses) Before Income Taxes	2,508	119	711	(1,669)	1,669
Income tax expense/(benefit)	964	(5)	(231)		728
Net Income/(Loss)	1,544	124	942	(1,669)	941
	(1)				(1)

Less: Net loss attributable to noncontrolling interest										
Net Income/(Loss) attributable to NRG Energy, Inc.	$	1,545	$	124	$	942	$	(1,669)	$	942

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEETS
December 31, 2009

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (In millions)	Eliminations[(a)]	Consolidated Balance
ASSETS					
Current Assets					
Cash and cash equivalents	$ 20	$ 120	$ 2,164	$	$ 2,304
Funds deposited by counterparties	177				177
Restricted cash	1	1			2
Accounts receivable-trade, net	837	39			876
Inventory	529	12			541
Derivative instruments valuation	1,636				1,636
Cash collateral paid in support of energy risk management activities	359	2			361
Prepayments and other current assets	194	61	157	(101)	311
Total current assets	3,753	235	2,321	(101)	6,208
Net Property, Plant and Equipment	10,494	1,009	61		11,564
Other Assets					
Investment in subsidiaries	613	222	16,862	(17,697)	
Equity investments in affiliates	42	367			409
Capital leases and note receivable, less current portion	4,982	504	3,027	(8,009)	504
Goodwill	1,718				1,718
Intangible assets, net	1,755	20	33	(31)	1,777
Nuclear decommissioning trust fund	367				367
Derivative instruments valuation	718		8	(43)	683
Other non-current assets	29	8	111		148
Total other assets	10,224	1,121	20,041	(25,780)	5,606
Total Assets	$ 24,471	$ 2,365	$ 22,423	$ (25,881)	$ 23,378
LIABILITIES AND STOCKHOLDERS EQUITY					
Current Liabilities					
	$ 58	$ 310	$ 261	$ (58)	$ 571

Current portion of long-term debt and capital leases					
Accounts payable	(852)	393	1,156		697
Derivative instruments valuation	1,469	2	2		1,473
Deferred income taxes	456	11	(270)		197
Cash collateral received in support of energy risk management activities	177				177
Accrued expenses and other current liabilities	261	82	347	(43)	647
Total current liabilities	1,569	798	1,496	(101)	3,762
Other Liabilities					
Long-term debt and capital leases	2,533	1,003	12,320	(8,009)	7,847
Nuclear decommissioning reserve	300				300
Nuclear decommissioning trust liability	255				255
Deferred income taxes	1,711	(165)	237		1,783
Derivative instruments valuation	323	28	79	(43)	387
Out-of-market contracts	318	7		(31)	294
Other non-current liabilities	431	16	359		806
Total non-current liabilities	5,871	889	12,995	(8,083)	11,672
Total liabilities	7,440	1,687	14,491	(8,184)	15,434
3.625% Preferred Stock			247		247
Stockholders Equity	17,031	678	7,685	(17,697)	7,697
Total Liabilities and Stockholders Equity	$ 24,471	$ 2,365	$ 22,423	$ (25,881)	$ 23,378

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
Year Ended December 31, 2009

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (In millions)	Eliminations[(a)]	Consolidated Balance
Cash Flows from Operating Activities					
Net income	$ 1,544	$ 124	$ 942	$ (1,669)	$ 941
Adjustments to reconcile net income to net cash provided by operating activities:					
Distributions and equity (earnings)/losses of unconsolidated affiliates	154	(31)	(1,173)	1,009	(41)
Depreciation and amortization	772	40	6		818
Provision for bad debts	61				61
Amortization of nuclear fuel	36				36
Amortization of financing costs and debt discounts/premiums		13	31		44
Amortization of intangibles and out-of-market contracts	153				153
Changes in deferred income taxes and liability for unrecognized tax benefits	934	(16)	(229)		689
Changes in nuclear decommissioning liability	26				26
Changes in derivatives	(228)	3			(225)
Changes in collateral deposits supporting energy risk management activities	129	(2)			127
Loss on disposals and sales of assets	17				17
Gain on sales of equity method investments		(128)			(128)
Gain on sale of emission allowances	(4)				(4)
Gain recognized on settlement of pre-existing relationship			(31)		(31)
Amortization of unearned equity compensation			26		26
	(282)				(282)

Changes in option premiums collected					
Cash provided/(used) by changes in other working capital, net of acquisition/disposition affects	(487)	31	335		(121)
Net Cash Provided/(Used) by Operating Activities	2,825	34	(93)	(660)	2,106
Cash Flows from Investing Activities					
Intercompany (loans to)/receipts from subsidiaries	(1,755)		159	1,596	
Investment in subsidiaries	200	60	(260)		
Capital expenditures	(507)	(197)	(30)		(734)
Acquisition of businesses, net of cash acquired	(72)	(67)	(288)		(427)
Increase in restricted cash, net	6	8			14
(Increase)/decrease in notes receivable		(58)	36		(22)
Purchases of emission allowances	(78)				(78)
Proceeds from sale of emission allowances	40				40
Investments in nuclear decommissioning trust fund securities	(305)				(305)
Proceeds from sales of nuclear decommissioning trust fund securities	279				279
Proceeds from sale of assets, net	6				6
Proceeds from sale of equity method investment		284			284
Equity investment in unconsolidated affiliate			(6)		(6)
Other			(5)		(5)
Net Cash Provided/(Used) by Investing Activities	(2,186)	30	(394)	1,596	(954)
Cash Flows from Financing Activities					
(Payments)/proceeds from intercompany loans	(258)	99	1,755	(1,596)	
Payment of intercompany dividends	(330)	(330)		660	
Payment of dividends to preferred stockholders			(33)		(33)
Net payments to settle acquired derivatives that include financing elements	(79)				(79)
Payment for treasury stock			(500)		(500)

Installment proceeds from sale of noncontrolling interest in subsidiary		50			50
Proceeds from issuance of common stock, net of issuance costs			2		2
Proceeds from issuance of long-term debt	77	127	688		892
Payment of deferred debt issuance costs	(2)	(3)	(26)		(31)
Payments of short and long-term debt	(25)	(47)	(572)		(644)
Net Cash Provided/(Used) by Financing Activities	(617)	(104)	1,314	(936)	(343)
Effect of exchange rate changes on cash and cash equivalents		1			1
Net Increase/(Decrease) in Cash and Cash Equivalents	22	(39)	827		810
Cash and Cash Equivalents at Beginning of Period	(2)	159	1,337		1,494
Cash and Cash Equivalents at End of Period	$ 20	$ 120	$ 2,164	$	$ 2,304

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2008

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (In millions)	Eliminations[(a)]	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 6,504	$ 405	$	$ (24)	$ 6,885
Operating Costs and Expenses					
Cost of operations	3,321	303		(26)	3,598
Depreciation and amortization	618	27	4		649
General and administrative	64	14	241		319
Development costs	(1)	7	40		46
Total operating costs and expenses	4,002	351	285	(26)	4,612
Operating Income/(Loss)	2,502	54	(285)	2	2,273
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	276		1,638	(1,914)	
Equity in earnings of unconsolidated affiliates	(2)	61			59
Other income/(expense), net	23	11	(15)	(2)	17
Interest expense	(183)	(77)	(323)		(583)
Total other income/(expense)	114	(5)	1,300	(1,916)	(507)
Income From Continuing Operations Before Income Taxes	2,616	49	1,015	(1,914)	1,766
Income tax expense/(benefit)	1,001	19	(307)		713
Income From Continuing Operations	1,615	30	1,322	(1,914)	1,053
Income from discontinued operations, net of income taxes		269	(97)		172
Net Income/(Loss) attributable to NRG Energy, Inc.	$ 1,615	$ 299	$ 1,225	$ (1,914)	$ 1,225

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2008

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (a)	Consolidated Balance
			(In millions)		
		ASSETS			
Current Assets					
Cash and cash equivalents	$ (2)	$ 159	$ 1,337	$	$ 1,494
Funds deposited by counterparties			754		754
Restricted cash	7	9			16
Accounts receivable-trade, net	422	42			464
Inventory	443	12			455
Derivative instruments valuation	4,600				4,600
Cash collateral paid in support of energy risk management activities	494				494
Prepayments and other current assets	130	37	278	(230)	215
Total current assets	6,094	259	2,369	(230)	8,492
Net Property, Plant and Equipment	10,725	791	29		11,545
Other Assets					
Investment in subsidiaries	651		11,949	(12,600)	
Equity investments in affiliates	26	464			490
Capital leases and note receivable, less current portion	598	435	3,177	(3,775)	435
Goodwill	1,718				1,718
Intangible assets, net	797	16	2		815
Nuclear decommissioning trust fund	303				303
Derivative instruments valuation	870		15		885
Other non-current assets	9	4	112		125
Total other assets	4,972	919	15,255	(16,375)	4,771
Total Assets	$ 21,791	$ 1,969	$ 17,653	$ (16,605)	$ 24,808

LIABILITIES AND STOCKHOLDERS EQUITY

Current Liabilities					
Current portion of long-term debt and capital leases	$ 67	$ 235	$ 229	$ (67)	$ 464
Accounts payable	(1,302)	429	1,324		451
Derivative instruments valuation	3,976	3	2		3,981
Deferred income taxes	503	31	(333)		201
Cash collateral received in support of energy risk management activities	760				760
Accrued expenses and other current liabilities	507	48	333	(164)	724
Total current liabilities	4,511	746	1,555	(231)	6,581
Other Liabilities					
Long-term debt and capital leases	2,730	1,014	7,729	(3,776)	7,697
Nuclear decommissioning reserve	284				284
Nuclear decommissioning trust liability	218				218
Deferred income taxes	705	(187)	672		1,190
Derivative instruments valuation	348	46	114		508
Out-of-market contracts	291				291
Other non-current liabilities	405	44	220		669
Total non-current liabilities	4,981	917	8,735	(3,776)	10,857
Total liabilities	9,492	1,663	10,290	(4,007)	17,438
3.625% Preferred Stock			247		247
Stockholders Equity	12,299	306	7,116	(12,598)	7,123
Total Liabilities and Stockholders Equity	$ 21,791	$ 1,969	$ 17,653	$ (16,605)	$ 24,808

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND
NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
Year Ended December 31, 2008

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (a)	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 1,615	$ 299	$ 1,225	$ (1,914)	$ 1,225
Adjustments to reconcile net income to net cash provided/(used) by operating activities:					
Distributions and equity (earnings)/losses of unconsolidated affiliates	(274)	(46)	(1,638)	1,914	(44)
Depreciation and amortization	618	27	4		649
Amortization of nuclear fuel	39				39
Amortization of financing costs and debt discount/premiums		15	22		37
Amortization of intangibles and out-of-market contracts	(270)				(270)
Amortization of unearned equity compensation			26		26
Loss on disposals and sales of assets	25				25
Impairment charges and asset write downs			23		23
Changes in derivatives	(482)	(2)			(484)
Changes in deferred income taxes and liability for unrecognized tax benefits	312	(16)	466		762
Gain on sale of discontinued operations		(273)			(273)
Gain on sale of emission allowances	(51)				(51)
Change in nuclear decommissioning trust liability	34				34
Changes in collateral deposits supporting energy risk management activities	(417)				(417)
Cash provided/(used) by changes in other working capital, net of disposition affects	745	88	(635)		198

Net Cash Provided/(Used) by Operating Activities	1,894	92	(507)		1,479
Cash Flows from Investing Activities					
Intercompany (loans to)/receipts from subsidiaries	(238)		696	(458)	
Capital expenditures	(597)	(294)	(8)		(899)
(Increase)/decrease in restricted cash	(6)	19			13
Decrease/(increase) in notes receivable		45	(35)		10
Purchases of emission allowances	(8)				(8)
Proceeds from sale of emission allowances	75				75
Investments in nuclear decommissioning trust fund securities	(616)				(616)
Proceeds from sales of nuclear decommissioning trust fund securities	582				582
Proceeds from sale of assets, net	14				14
Equity investment in unconsolidated affiliate		(84)			(84)
Proceeds from sale of discontinued operations, net of cash divested		(59)	300		241
Net Cash Provided/(Used) by Investing Activities	(794)	(373)	953	(458)	(672)
Cash Flows from Financing Activities					
(Payments)/proceeds from intercompany loans	(1,059)	315	286	458	
Payment for dividends to preferred stockholders			(55)		(55)
Net payments to settle acquired derivatives that include financing elements	(43)				(43)
Payment for treasury stock			(185)		(185)
Installment proceeds from sale of noncontrolling interest of subsidiary		50			50
Payment to settle CSF I CAGR		(45)			(45)
Proceeds from issuance of common stock, net of issuance costs			9		9
Proceeds from issuance of long-term debt		20			20
Payment of deferred debt issuance costs		(2)	(2)		(4)
Payments of short and long-term debt		(60)	(174)		(234)

Net Cash Provided/(Used) by Financing Activities	(1,102)	278	(121)	458	(487)
Change in cash from discontinued operations		43			43
Effect of exchange rate changes on cash and cash equivalents		(1)			(1)
Net Increase/(Decrease) in Cash and Cash Equivalents	(2)	39	325		362
Cash and Cash Equivalents at Beginning of Period		120	1,012		1,132
Cash and Cash Equivalents at End of Period	$ (2)	$ 159	$ 1,337	$	$ 1,494

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2007

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (In millions)	Eliminations (a)	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 5,614	$ 375	$	$	$ 5,989
Operating Costs and Expenses					
Cost of operations	3,130	248			3,378
Depreciation and amortization	630	24	4		658
General and administrative	102	18	189		309
Development costs	66	2	33		101
Total operating costs and expenses	3,928	292	226		4,446
Gain/(loss) on sale of assets	18		(1)		17
Operating Income/(Loss)	1,704	83	(227)		1,560
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	204		973	(1,177)	
Equity in earnings of unconsolidated affiliates	(3)	57			54
Gains on sales of equity method investments		1			1
Other income, net	9	13	33		55
Refinancing expenses			(35)		(35)
Interest expense	(250)	(77)	(375)		(702)
Total other income/(expense)	(40)	(6)	596	(1,177)	(627)
Income/(Loss) From Continuing Operations Before Income Taxes	1,664	77	369	(1,177)	933
Income tax expense/(benefit)	576	5	(204)		377
Income/(Loss) From Continuing Operations	1,088	72	573	(1,177)	556
Income from discontinued operations, net of income taxes		17			17

Net Income/(Loss)	$	1,088	$	89	$	573	$	(1,177)	$	573

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATING STATEMENTS OF CASH FLOWS
Year Ended December 31, 2007

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations[(a)]	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 1,088	$ 89	$ 573	$ (1,177)	$ 573
Adjustments to reconcile net income to net cash provided/(used) by operating activities:					
Distributions and equity (earnings)/losses of unconsolidated affiliates	101	(36)	(684)	586	(33)
Depreciation and amortization	630	27	4		661
Amortization of nuclear fuel	58				58
Amortization of financing costs and debt discount/premiums		19	60		79
Amortization of intangibles and out-of-market contracts	(160)	4			(156)
Amortization of unearned equity compensation			19		19
(Gain)/loss on sale of assets	(18)		1		(17)
Impairment charges and asset write downs	9		11		20
Changes in derivatives	77				77
Changes in deferred income taxes and liability for unearned tax benefits	112	(31)	278		359
Gains on sale of equity method investments		(1)			(1)
Gain on sale of emission allowances	(30)	(1)			(31)
Change in nuclear decommissioning trust liability	32				32
Changes in collateral deposits supporting energy risk management activities	(125)				(125)
Cash provided/(used) by changes in other working capital, net of disposition affects	218	96	(299)	(13)	2
Net Cash Provided/(Used) by Operating Activities	1,992	166	(37)	(604)	1,517
Cash Flows from Investing Activities					
Intercompany (loans to)/receipts from subsidiaries	655		2,109	(2,764)	
Capital expenditures	(389)	(84)	(8)		(481)

Decrease in restricted cash, net		12			12
Decrease in notes receivable		34			34
Decrease in trust fund balances	19				19
Purchases of emission allowances	(161)				(161)
Proceeds from sale of emission allowances	271	1			272
Investments in nuclear decommissioning trust fund securities	(265)				(265)
Proceeds from sales of nuclear decommissioning trust fund securities	233				233
Proceeds from sale of assets		2			2
Purchase of securities			(49)		(49)
Proceeds from sale of discontinued operations and assets, net of cash divested	29		28		57
Net Cash Provided/(Used) by Investing Activities	392	(35)	2,080	(2,764)	(327)
Cash Flows from Financing Activities					
(Payments)/proceeds from intercompany loans	(2,101)	(38)	(625)	2,764	
Payment from intercompany dividends	(302)	(302)		604	
Payment for dividends to preferred stockholders			(55)		(55)
Payment for treasury stock			(353)		(353)
Proceeds from issuance of common stock, net of issuance costs			7		7
Proceeds from issuance of long-term debt			1,411		1,411
Payment of deferred debt issuance costs			(5)		(5)
Payments of short and long-term debt	(1)	(64)	(1,754)		(1,819)
Net Cash (Used)/Provided by Financing Activities	(2,404)	(404)	(1,374)	3,368	(814)
Change in cash from discontinued operations		(25)			(25)
Effect of exchange rate changes on cash and cash equivalents		4			4
Net Increase/(Decrease) in Cash and Cash Equivalents	(20)	(294)	669		355
Cash and Cash Equivalents at Beginning of Period	20	414	343		777
Cash and Cash Equivalents at End of Period	$	$ 120	$ 1,012	$	$ 1,132

(a) All significant intercompany transactions have been eliminated in consolidation.

Schedule of valuation and qualifying accounts disclosure

NRG ENERGY, INC.

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2009, 2008, and 2007

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(In millions)		
Allowance for doubtful accounts, deducted from accounts receivable					
Year ended December 31, 2009	$ 3	$ 61(a)	$	$ (35)(b)	$ 29
Year ended December 31, 2008	$ 1	$ 2	$	$	$ 3
Year ended December 31, 2007	$ 1	$	$	$	$ 1
Income tax valuation allowance, deducted from deferred tax assets					
Year ended December 31, 2009	$ 359	$ (130)	$ 4	$	$ 233
Year ended December 31, 2008	$ 539	$ (12)	$ (6)	$ (162)	$ 359
Year ended December 31, 2007	$ 581	$ 6	$ 8	$ (56)	$ 539

(a) Significant increase reflects acquisition of Reliant Energy in May 2009.
(b) Represents principally net amounts charged as uncollectable.

233

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.

NRG Energy, Inc.
(Registrant)

By: /s/ David W. Crane

David W. Crane
Chief Executive Officer

Date: February 23, 2010

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints David W. Crane, Michael R. Bramnick, Tanuja M. Dehne and Brian Curci, each or any of them, such person s true and lawful attorney-in-fact and agent with full power of substitution and resubstitution for such person and in such person s name, place and stead, in any and all capacities, to sign any and all amendments to this report on Form 10-K, and to file the same with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing necessary or desirable to be done in and about the premises, as fully to all intents and purposes as such person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or his or their substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

In accordance with the Exchange Act, this report has been signed by the following persons on behalf of the registrant in the capacities indicated on February 23, 2010.

Signature	Title	Date
/s/ David W. Crane David W. Crane	President, Chief Executive Officer and Director (Principle Executive Officer)	February 23, 2010
/s/ Gerald Luterman Gerald Luterman	Chief Financial Officer and Director (Principle Financial Officer)	February 23, 2010
/s/ James J. Ingoldsby James J. Ingoldsby	Chief Accounting Officer (Principle Accounting Officer)	February 23, 2010
/s/ Howard E. Cosgrove Howard E. Cosgrove	Chairman of the Board	February 23, 2010
Kirbyjon H. Caldwell	Director	February 23, 2010
/s/ John F. Chlebowski John F. Chlebowski	Director	February 23, 2010
/s/ Lawrence S. Coben Lawrence S. Coben	Director	February 23, 2010
/s/ Stephen L. Cropper Stephen L. Cropper	Director	February 23, 2010
/s/ William E. Hantke William E. Hantke	Director	February 23, 2010

/s/ Paul W. Hobby Paul W. Hobby	Director	February 23, 2010
/s/ Kathleen A. McGinty Kathleen A. McGinty	Director	February 23, 2010
/s/ Anne C. Schaumburg Anne C. Schaumburg	Director	February 23, 2010

Signature	Title	Date
/s/ Herbert H. Tate Herbert H. Tate	Director	February 23, 2010
/s/ Thomas H. Weidemeyer Thomas H. Weidemeyer	Director	February 23, 2010
Walter R. Young	Director	February 23, 2010

EXHIBIT INDEX

2.1	Third Amended Joint Plan of Reorganization of NRG Energy, Inc., NRG Power Marketing, Inc., NRG Capital LLC, NRG Finance Company I LLC, and NRGenerating Holdings (No. 23) B.V.(5)
2.2	First Amended Joint Plan of Reorganization of NRG Northeast Generating LLC (and certain of its subsidiaries), NRG South Central Generating (and certain of its subsidiaries) and Berrians I Gas Turbine Power LLC.(5)
2.3	Acquisition Agreement, dated as of September 30, 2005, by and among NRG Energy, Inc., Texas Genco LLC and the Direct and Indirect Owners of Texas Genco LLC.(11)
3.1	Amended and Restated Certificate of Incorporation.(45)
3.2	Amended and Restated By-Laws.(47)
3.3	Certificate of Designations of 3.625% Convertible Perpetual Preferred Stock, as filed with the Secretary of State of the State of Delaware on August 11, 2005.(17)
3.4	Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance I LLC, as filed with the Secretary of State of Delaware on August 14, 2006.(27)
3.5	Certificate of Amendment to Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance I LLC, as filed with the Secretary of State of Delaware on February 27, 2008.(36)
3.6	Second Certificate of Amendment to Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance I LLC, as filed with the Secretary of State of Delaware on August 8, 2008.(37)
4.1	Supplemental Indenture dated as of December 30, 2005, among NRG Energy, Inc., the subsidiary guarantors named on Schedule A thereto and Law Debenture Trust Company of New York, as trustee.(13)
4.2	Amended and Restated Common Agreement among XL Capital Assurance Inc., Goldman Sachs Mitsui Marine Derivative Products, L.P., Law Debenture Trust Company of New York, as Trustee, The Bank of New York, as Collateral Agent, NRG Peaker Finance Company LLC and each Project Company Party thereto dated as of January 6, 2004, together with Annex A to the Common Agreement.(2)
4.3	Amended and Restated Security Deposit Agreement among NRG Peaker Finance Company, LLC and each Project Company party thereto, and the Bank of New York, as Collateral Agent and Depositary Agent, dated as of January 6, 2004.(2)
4.4	NRG Parent Agreement by NRG Energy, Inc. in favor of the Bank of New York, as Collateral Agent, dated as of January 6, 2004.(2)

4.5 Indenture dated June 18, 2002, between NRG Peaker Finance Company LLC, as Issuer, Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Rockford LLC, NRG Rockford II LLC and Sterlington Power LLC, as Guarantors, XL Capital Assurance Inc., as Insurer, and Law Debenture Trust Company, as Successor Trustee to the Bank of New York.(3)

4.6 Specimen of Certificate representing common stock of NRG Energy, Inc.(26)

4.7 Indenture, dated February 2, 2006, among NRG Energy, Inc. and Law Debenture Trust Company of New York.(19)

4.8 First Supplemental Indenture, dated February 2, 2006, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.250% Senior Notes due 2014.(20)

4.9 Second Supplemental Indenture, dated February 2, 2006, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2016.(20)

4.10 Form of 7.250% Senior Note due 2014.(20)

4.11 Form of 7.375% Senior Note due 2016.(20)

4.12 Form of 7.375% Senior Note due 2017.(29)

4.13 Form of 8.5% Senior Note due 2019.(42)

4.14 Third Supplemental Indenture, dated March 14, 2006, among NRG, the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.250% Senior Notes due 2014.(22)

4.15 Fourth Supplemental Indenture, dated March 14, 2006, among NRG, the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2016.(22)

4.16 Fifth Supplemental Indenture, dated April 28, 2006, among NRG, the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.250% Senior Notes due 2014.(23)

4.17 Sixth Supplemental Indenture, dated April 28, 2006, among NRG, the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2016.(23)

4.18 Seventh Supplemental Indenture, dated November 13, 2006, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.250% Senior Notes due 2014.(28)

4.19 Eighth Supplemental Indenture, dated November 13, 2006, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2016.(28)

4.20 Ninth Supplemental Indenture, dated November 13, 2006, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2017.(29)

4.21 Tenth Supplemental Indenture, dated July 19, 2007, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.250% Senior Notes due 2014.(33)

4.22 Eleventh Supplemental Indenture, dated July 19, 2007, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2016.(33)

4.23 Twelfth Supplemental Indenture, dated July 19, 2007, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s

7.375% Senior Notes due 2017.(33)

4.24 Thirteenth Supplemental Indenture, dated August 28, 2007, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.250% Senior Notes due 2014.(34)

4.25 Fourteenth Supplemental Indenture, dated August 28, 2007, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2016.(34)

4.26 Fifteenth Supplemental Indenture, dated August 28, 2007, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2017.(34)

4.27 Sixteenth Supplemental Indenture, dated April 28, 2009, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiary named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.250% Senior Notes due 2014.(40)

4.28	Seventeenth Supplemental Indenture, dated April 28, 2009, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiary named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2016.(40)
4.29	Eighteenth Supplemental Indenture, dated April 28, 2009, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiary named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2017.(40)
4.30	Nineteenth Supplemental Indenture, dated May 8, 2009, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.250% Senior Notes due 2014.(41)
4.31	Twentieth Supplemental Indenture, dated May 8, 2009, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2016.(41)
4.32	Twenty-First Supplemental Indenture, dated May 8, 2009, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2017.(41)
4.33	Twenty-Second Supplemental Indenture, dated June 5, 2009, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 8.5% Senior Notes due 2019.(42)
4.34	Twenty-Third Supplemental Indenture, dated July 14, 2009, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 8.5% Senior Notes due 2019. (44).
4.35	Twenty-Fourth Supplemental Indenture, dated October 5, 2009, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.250% Senior Notes due 2014.(46)
4.36	Twenty-Fifth Supplemental Indenture, dated October 5, 2009, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2016.(46).
4.37	Twenty-Sixth Supplemental Indenture, dated October 5, 2009, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 7.375% Senior Notes due 2017.(46).
4.38	Twenty-Seventh Supplemental Indenture, dated October 5, 2009, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc. s 8.5% Senior Notes due 2019. (46).
10.1	Note Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc. and each of the purchasers named therein.(4)

10.2	Master Shelf and Revolving Credit Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc., The Prudential Insurance Registrants of America and each Prudential Affiliate, which becomes party thereto.(4)
10.3*	Form of NRG Energy Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Officers and Key Management.(15)
10.4*	Form of NRG Energy, Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Directors.(15)
10.5*	Form of NRG Energy, Inc. Long-Term Incentive Plan Non-Qualified Stock Option Agreement.(8)
10.6*	Form of NRG Energy, Inc. Long-Term Incentive Plan Restricted Stock Unit Agreement.(8)
10.7*	Form of NRG Energy, Inc. Long Term Incentive Plan Performance Unit Agreement.(1)
10.8*	Annual Incentive Plan for Designated Corporate Officers.(43)

10.9	Railroad Car Full Service Master Leasing Agreement, dated as of February 18, 2005, between General Electric Railcar Services Corporation and NRG Power Marketing Inc.(15)
10.10	Purchase Agreement (West Coast Power) dated as of December 27, 2005, by and among NRG Energy, Inc., NRG West Coast LLC (Buyer), DPC II Inc. (Seller) and Dynegy, Inc.(14)
10.11	Purchase Agreement (Rocky Road Power), dated as of December 27, 2005, by and among Termo Santander Holding, L.L.C.(Buyer), Dynegy, Inc., NRG Rocky Road LLC (Seller) and NRG Energy, Inc.(14)
10.12	Stock Purchase Agreement, dated as of August 10, 2005, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.(17)
10.13	Agreement with respect to the Stock Purchase Agreement, dated December 19, 2008, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.(37)
10.14	Investor Rights Agreement, dated as of February 2, 2006, by and among NRG Energy, Inc. and Certain Stockholders of NRG Energy, Inc. set forth therein.(21)
10.15	Terms and Conditions of Sale, dated as of October 5, 2005, between Texas Genco II LP and Freight Car America, Inc., (including the Proposal Letter and Amendment thereto).(25)
10.16*	Amended and Restated Employment Agreement, dated December 4, 2008, between NRG Energy, Inc. and David Crane.(37)
10.17*	CEO Compensation Table.(48)
10.18	Limited Liability Company Agreement of NRG Common Stock Finance I LLC.(27)
10.19	Note Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance I LLC, Credit Suisse International and Credit Suisse Securities (USA) LLC.(27)
10.20	Amendment Agreement, dated February 27, 2008, to the Note Purchase Agreement by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.(36)
10.21	Amendment Agreement, dated August 8, 2008, to the Note Purchase Agreement by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.(37)
10.22	Amendment Agreement, dated December 19, 2008, to the Note Purchase Agreement by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.(37)
10.23	Agreement with respect to Note Purchase Agreement, dated December 19, 2008, by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA)

LLC.(37)

10.24 Preferred Interest Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance I LLC, Credit Suisse Capital LLC and Credit Suisse Securities (USA) LLC, as agent.(27)

10.25 Preferred Interest Amendment Agreement, dated February 27, 2008, by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.(36)

10.26 Preferred Interest Amendment Agreement, dated August 8, 2008, by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.(37)

10.27 Preferred Interest Amendment Agreement, dated December 19, 2008, by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.(37)

10.28 Agreement with respect to Preferred Interest Purchase Agreement, dated December 19, 2008, by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.(37)

10.29	Second Amended and Restated Credit Agreement, dated June 8, 2007, by and among NRG Energy, Inc., the lenders party thereto, Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Citicorp North America Inc. and Credit Suisse.(32)
10.30*	Amended and Restated Long-Term Incentive Plan(43)
10.31*	NRG Energy, Inc. Executive Change-in-Control and General Severance Agreement, dated December 9, 2008.(37)
10.32	Amended and Restated Contribution Agreement (NRG), dated March 25, 2008, by and among Texas Genco Holdings, Inc., NRG South Texas LP and NRG Nuclear Development Company LLC and Certain Subsidiaries Thereof.(36)
10.33	Contribution Agreement (Toshiba), dated February 29, 2008, by and between Toshiba Corporation and NRG Nuclear Development Company LLC.(36)
10.34	Multi-Unit Agreement, dated February 29, 2008, by and among Toshiba Corporation, NRG Nuclear Development Company LLC and NRG Energy, Inc.(36)
10.35	Amended and Restated Operating Agreement of Nuclear Innovation North America LLC, dated May 1, 2008(36)
10.36	Credit Agreement by and among Nuclear Innovation North America LLC, Nuclear Innovation North America Investments LLC, NINA Texas 3 LLC and NINA Texas 4 LLC, as Borrowers and Toshiba America Nuclear Energy Corporation, as Administrative Agent and as Collateral Agent.(38)
10.37	LLC Membership Purchase Agreement between Reliant Energy, Inc. and NRG Retail LLC, dated as of February 28, 2009.(39)
12.1	NRG Energy, Inc. Computation of Ratio of Earnings to Fixed Charges.(1)
12.2	NRG Energy, Inc. Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividend Requirements.(1)
21.1	Subsidiaries of NRG Energy. Inc.(1)
23.1	Consent of KPMG LLP.(1)
31.1	Rule 13a-14(a)/15d-14(a) certification of David W. Crane.(1)
31.2	Rule 13a-14(a)/15d-14(a) certification of Gerald Luterman.(1)
31.3	Rule 13a-14(a)/15d-14(a) certification of James J. Ingoldsby.(1)
32	Section 1350 Certification.(1)

101.INS	XBRL Instance Document(1)
101.SCH	XBRL Taxonomy Extension Schema(1)
101.CAL	XBRL Taxonomy Extension Calculation Linkbase(1)
101.DEF	XBRL Taxonomy Extension Definition Linkbase(1)
101.LAB	XBRL Taxonomy Extension Label Linkbase(1)
101.PRE	XBRL Taxonomy Extension Presentation Linkbase(1)

* Exhibit relates to compensation arrangements.
Portions of this exhibit have been redacted and are subject to a confidential treatment request filed with the Secretary of the Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended.

(1) Filed herewith.

(2) Incorporated herein by reference to NRG Energy, Inc. s annual report on Form 10-K filed on March 16, 2004.

(3) Incorporated herein by reference to NRG Energy, Inc. s annual report on Form 10-K filed on March 31, 2003.

(4) Incorporated herein by reference to NRG Energy Inc. s Registration Statement on Form S-1, as amended, Registration No. 333-33397.
(5) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on November 19, 2003.
(6) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q for the quarter ended September 30, 2004.
(7) Incorporated herein by reference to NRG Energy, Inc. s 2004 proxy statement on Scheduleb14A filed on July 12, 2004.
(8) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q for the quarter ended March 31, 2004.
(9) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on October 3, 2005.
(10) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q for the quarter ended June 30, 2005.
(11) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on January 4, 2006.
(12) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on December 28, 2005.
(13) Incorporated herein by reference to NRG Energy, Inc. s annual report on Form 10-K filed on March 30, 2005.
(14) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on May 24, 2005.
(15) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on August 11, 2005.
(16) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on August 3, 2005.
(17) Incorporated herein by reference to NRG Energy, Inc. s Form 8-A filed on January 27, 2006.
(18) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on February 6, 2006.
(19) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on February 8, 2006.
(20) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on March 16, 2006.
(21) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on May 3, 2006.
(22) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on May 4, 2006.
(23) Incorporated herein by reference to NRG Energy, Inc. s annual report on Form 10-K filed on March 7, 2006.
(24) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q filed on August 4, 2006.
(25) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on August 10, 2006.
(26) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on November 14, 2006.
(27) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on November 27, 2006.
(28) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on December 26, 2007.
(29) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q filed on May 2, 2007.
(30) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on June 13, 2007.

(31) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on July 20, 2007.
(32) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on September 4, 2007.
(33) Incorporated herein by reference to NRG Energy, Inc. s annual report on Form 10-K filed on February 28, 2008.
(34) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q filed on May 1, 2008.
(35) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q filed on October 30, 2008.
(36) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on December 9, 2008.
(37) Incorporated herein by reference to NRG Energy, Inc. s annual report on Form 10-K filed on February 12, 2009.
(38) Incorporated herein by reference to NRG Energy Inc s current report on Form 8-K filed on February 27, 2009.
(39) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q filed on April 30, 2009.
(40) Incorporated herein by reference to NRG Energy, Inc s current report on Form 8-K filed on May 4, 2009.
(41) Incorporated herein by reference to NRG Energy, Inc s current report on Form 8-K filed on May 14, 2009.
(42) Incorporated herein by reference to NRG Energy, Inc s current report on Form 8-K filed on June 5, 2009.
(43) Incorporated herein by reference to NRG Energy, Inc. s 2009 proxy statement on Schedule 14A filed on June 16, 2009.
(44) Incorporated herein by reference to NRG Energy, Inc s current report on Form 8-K filed on July 15, 2009.
(45) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on August 4, 2009.
(46) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on October 6, 2009.
(47) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on October 21, 2009.
(48) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on December 9, 2009.