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

FORM 8-K

CURRENT REPORT

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

Date of Report (Date of earliest event reported): **July 23, 2012**

NRG Energy, Inc.
(Exact name of Registrant as specified in its charter)

Delaware	**001-15891**	**41-1724239**
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

211 Carnegie Center, Princeton, New Jersey 08540
(Address of principal executive offices, including zip code)

(609) 524-4500
(Registrant's telephone number, including area code)

N/A
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events.

As previously disclosed in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, filed with the Securities and Exchange Commission on May 3, 2012, effective January 1, 2012, NRG Energy, Inc. (or NRG or the Company):

- updated its segment structure and allocation of corporate expenses to reflect how management currently makes financial decisions and allocates resources;
- adopted Accounting Standards Update, or ASU, No. 2011-05, *Comprehensive Income (Topic 220) Presentation of Comprehensive Income*, or ASU No. 2011-05, which was further amended by ASU No. 2011-12, *Comprehensive Income (Topic 220) Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05,* or ASU No. 2011-12.

In accordance with accounting principles generally accepted in the United States, or US GAAP, these changes in our reporting must be applied retrospectively. We are issuing this Current Report on Form 8-K, or Form 8-K, to update our historical financial information on a basis that is consistent with the new reporting structure and the adoption of ASU No. 2011-05 and ASU No. 2011-12. The change in reportable segments and the adoption of ASU No. 2011-05 and ASU No. 2011-12 did not change our consolidated results of operations, financial condition or cash flows for any period.

In this Form 8-K, we have updated the following information that appeared in NRG's Annual Report on Form 10-K for the year ended December 31, 2011, or the 2011 Form 10-K:

- Part I, Item 1: Business, attached as Exhibit 99.1 to this report and incorporated herein by reference;
- Part I, Item 2: Properties, attached as Exhibit 99.2 to this report and incorporated herein by reference;
- Part II, Item 6: Selected Financial Data, attached as Exhibit 99.3 to this report and incorporated herein by reference;
- Part II, Items 7 and 7A: Management's Discussion and Analysis of Financial Condition and Results of Operations, and Quantitative and Qualitative Disclosures About Market Risk, attached as Exhibit 99.4 to this report and incorporated herein by reference;
- Part II, Item 8 and Part IV, Item 15: Financial Statements and Supplementary Data - Consolidated Financial Statements of NRG Energy, Inc. and Subsidiaries and the Notes to Consolidated Financial Statements, and Financial Statement Schedule, attached as Exhibit 99.5 to this report and incorporated herein by reference; and
- Consent of Independent Registered Public Accounting Firm, attached as Exhibit 23.1 and incorporated herein by reference.

The information included in and with this Form 8-K is presented for information purposes only in connection with the reporting changes described above for NRG. This Form 8-K does not reflect events occurring after February 28, 2012, the date we filed our 2011 Form 10-K, and does not modify or update the disclosures therein in any way, other than as required to reflect the change in reportable segments and the adoption of a new accounting standard, as described above and set forth in Exhibits 99.1 through 99.5 attached hereto. You should therefore read this document and exhibits in conjunction with the 2011 Form 10-K and any subsequent amendments on Form 10-K/A and with our reports filed with the Securities and Exchange Commission after February 28, 2012.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits:

23.1	Consent of Independent Registered Public Accounting Firm
99.1	Part I, Item 1: Business
99.2	Part I, Item 2: Properties
99.3	Part II, Item 6: Selected Financial Data
99.4	Part II, Items 7 and 7A: Management's Discussion and Analysis of Financial Condition and Results of Operations, and Quantitative and Qualitative Disclosures About Market Risk
99.5	Part II, Item 8 and Part IV, Item 15: Financial Statements and Supplementary Data - Consolidated Financial Statements of NRG Energy, Inc. and Subsidiaries and the Notes to Consolidated Financial Statements, and Financial Statement Schedule
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)

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(1) Filed herewith.

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.

NRG ENERGY, INC.
(Registrant)

By: /s/ KIRKLAND B. ANDREWS

Kirkland B. Andrews
Executive Vice President and
Chief Financial Officer

Date: July 23, 2012

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
NRG Energy, Inc.:

We consent to the incorporation by reference in the registration statement No. 333-182379, No. 333-171318, No. 333-151992, No. 333-135973, and No. 333-114007 on Form S-8, No. 333-123677 on Form S-3, and No. 333-178024, No. 333-175470, and No. 333-171323 on Form S-4 of NRG Energy, Inc. of our reports dated February 28, 2012, except as to the effects of the update in segment structure and the method of presenting comprehensive income as described in Note 2 to the consolidated financial statements, which is as of July 6, 2012, with respect to the consolidated balance sheets of NRG Energy, Inc. as of December 31, 2011 and 2010, and the related consolidated statements of operations, statements of comprehensive (loss)/income, cash flows, and statement of stockholders' equity for each of the years in the three-year period ended December 31, 2011, and the related financial statement schedule, and the effectiveness of internal control over financial reporting as of December 31, 2011, which reports appear in Exhibit 99.5 to this Current Report on Form 8-K of NRG Energy, Inc.

(signed) KPMG LLP

Philadelphia, Pennsylvania
July 23, 2012

EXHIBIT 99.1

The information provided in this Exhibit is presented only in connection with the reporting changes described in the accompanying Form 8-K. This information does not reflect events occurring after February 28, 2012, the date we filed our 2011 Form 10-K, and does not modify or update the disclosures therein in any way, other than as required to reflect the change in reportable segments and the adoption of a new accounting standard, as described in the Form 8-K and set forth in Exhibits 99.1 through 99.5 attached thereto. You should therefore read this information in conjunction with the 2011 Form 10-K and any subsequent amendments on Form 10-K/A and with our reports filed with the Securities and Exchange Commission after February 28, 2012.

Part I, Item 1 — Business

General

NRG Energy, Inc., or NRG or the Company, is an integrated wholesale power generation and retail electricity company that aspires to be a leader in the way the industry and consumers think about, use, produce and deliver energy and energy services in major competitive power markets in the United States. First, NRG is a wholesale power generator engaged in the ownership and operation of power generation facilities; the trading of energy, capacity and related products; and the transacting in and trading of fuel and transportation services. Second, NRG is a retail electricity company engaged in the supply of electricity, energy services, and cleaner energy products to retail electricity customers in deregulated markets through Reliant Energy, Green Mountain Energy, and Energy Plus (collectively, the Retail Businesses). Finally, NRG is focused on the deployment and commercialization of potential disruptive technologies, like electric vehicles, Distributed Solar and smart meter technology, which have the potential to change the nature of the power supply industry.

Wholesale Power Generation

NRG's generation facilities consist of intermittent, baseload, intermediate and peaking power generation facilities in the United States and two international locations. The sale of capacity and power from baseload generation facilities accounts for a majority of the Company's generation revenues. In addition, NRG's generation portfolio provides the Company with opportunities to capture additional revenues by selling power during periods of peak demand, offering capacity or similar products, and providing ancillary services to support system reliability.

Retail

NRG's Retail Businesses arrange for the transmission and delivery of energy-related products to customers, bill customers, collect payments for products sold, and maintain call centers to provide customer service. The Retail Businesses sell products that range from system power to bundled products, which combine system power with protection products, energy efficiency and renewable energy solutions, or other value added products and services, including customer rewards offered through exclusive loyalty and affinity program partnerships. Based on metered locations, as of December 31, 2011, NRG's Retail Businesses combined to serve approximately 2.1 million residential, small business, commercial and industrial customers.

Alternative Energy

NRG's investment in and development of new technologies is focused where the Company believes the benefits of such investments represent significant commercial opportunities and create a comparative advantage for the Company. The development and investment initiatives are primarily focused in the areas of Distributed Solar, solar thermal and solar photovoltaic, and also include other low or no Greenhouse Gases, or GHG, emitting energy generating sources, such as the fueling infrastructure for electric vehicle, or EV, ecosystems.

NRG's Business Strategy

The Company believes that the American energy industry is going to be increasingly impacted by the long-term societal trend towards sustainability which is both generational and irreversible. Moreover, the information technology-driven revolution which has enabled greater and easier personal choice in other sectors of the consumer economy will do the same in the American energy sector over the years to come. As a result, energy consumers will have increasing personal control over whom they buy their energy from, how that energy is generated and used and what environmental impact these individual choices will have. The Company's initiatives in this area of future growth are focused on: (i) renewables, with a concentration in solar development; (ii) electric vehicle ecosystems; (iii) customer-facing energy products and services including smart grid services, nationwide retail green electricity, unique retail sales channels involving loyalty and affinity programs and custom design; and (iv) construction of other forms of on-site clean power generation. The Company's advances in each of these areas are driven by select acquisitions, joint ventures, and investments that are more fully described in Item 1, *Business - New and On-going Company Initiatives and Development Projects.*

The Company's core business is focused on: (i) excellence in safety and operating performance of its existing assets; (ii) serving the energy needs of end-use residential, commercial and industrial customers in the Company's core markets with a retail energy product that is differentiated either by premium service (Reliant), sustainability (Green Mountain Energy) or loyalty/affinity programs (Energy Plus); (iii) optimal hedging of baseload generation and retail load operations, while retaining optionality on the Company's peaking facilities; (iv) repowering of power generation assets at premium sites; (v) investment in, and deployment of, alternative energy technologies both in its wholesale and, particularly, in and around its retail businesses and their customers; (vi) pursuing selective acquisitions, joint ventures, divestitures and investments; and (vii) engaging in a proactive capital allocation plan focused on achieving the regular return of and on stockholder capital within the dictates of prudent balance sheet management.

In summary, NRG's business strategy is intended to maximize stockholder value through the production and sale of safe, reliable and affordable power to its customers in the markets served by the Company, while aggressively positioning the Company to meet the market's increasing demand for sustainable and low carbon energy solutions. This strategy is designed to enhance the Company's core business of competitive power generation and mitigate the risk of declining power prices. The Company expects to become a leading provider of sustainable energy solutions that promotes national energy security, while utilizing the Company's retail business to complement and advance both initiatives.

Competition

NRG competes in wholesale power generation, deregulated retail energy services and in the development of renewable and conventional energy resources.

Wholesale Power Generation

Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. NRG competes on the basis of the location of its plants and ownership of portfolios of plants in various regions, which increases the stability and reliability of its energy supply. Wholesale power generation is a regional business that is currently highly fragmented and diverse in terms of industry structure. As such, there is a wide variation in terms of the capabilities, resources, nature and identity of the companies NRG competes with depending on the market. Competitors include regulated utilities, other independent power producers, and power marketers or trading companies, including those owned by financial institutions, municipalities and cooperatives.

Retail

The restructured electricity markets across the nation provide an intensely competitive landscape for energy providers to sell products and services to all customer segments (residential, small and mid-market businesses, governments and other public institutions). The markets in which we compete include, but are not limited to: Connecticut, Delaware, the District of Columbia, Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, Ohio and Texas. The Electric Reliability Council of Texas, or ERCOT, is our primary market and constitutes both the highest number of customers and a substantial concentration of NRG's gross profits.

Retail customers make purchase decisions based on a variety of factors, including price, customer service, brand image, product choices, bundles or value-added features. Customers purchase products through a variety of sales channels including direct sales force, call centers, websites, brokers and brick-and-mortar stores. The Retail Businesses compete with national and international companies that operate in multiple geographic areas, as well as numerous companies that are regional or local in nature. Significant competitors in the markets in which we compete include Constellation, Direct Energy, GDF Suez and Energy Future Holdings (d/b/a TXU Energy), and other competitors, typically incumbent retail electric providers, which have the advantage of long-standing relationships with customers.

Development

NRG may submit bids to develop generation resources, predominantly in response to requests for proposals, or RFPs, for new conventional or renewable generation and/or generating capacity. Bids are solicited by regulated utilities or electric system operators, often to comply with mandated renewable portfolio standards or to achieve an improved reserve margin, which is a measure of a utility's available electric power capacity over and above the electric power capacity needed to meet normal peak demand levels. NRG competes against other power plant developers and manufacturers of solar panel assemblies. The number and type of competitors vary based on the location, generation type, project size and counterparty specified in the RFP. Bids are awarded based on price, location of existing generation, prior experience developing generation resources similar to that specified in the RFP, and creditworthiness.

Competitive Strengths

Conventional Wholesale Power Generation

NRG has one of the largest and most diversified power generation portfolios in the United States, with approximately 23,585 MW of fossil fuel and nuclear generation capacity in 189 active generating units at 45 plants as of December 31, 2011. In addition, the Company has a 550 MW combined cycle gas plant under construction. The Company's power generation assets are diversified by fuel-type, dispatch level and region, which helps mitigate the risks associated with fuel price volatility and market demand cycles.

NRG's U.S. baseload and intermediate facilities provide the Company with a significant source of cash flow, while its peaking facilities provide NRG with opportunities to capture upside potential that can arise from time to time during periods of high demand.

Many of NRG's generation assets are located within densely populated areas that tend to have more robust wholesale pricing as a result of relatively favorable local supply-demand balance. NRG has generation assets located within Houston, New York City, southwestern Connecticut, and the Los Angeles and San Diego load basins. These facilities are often ideally situated for repowering or the addition of new capacity, because their location and existing infrastructure give them significant advantages over undeveloped sites.

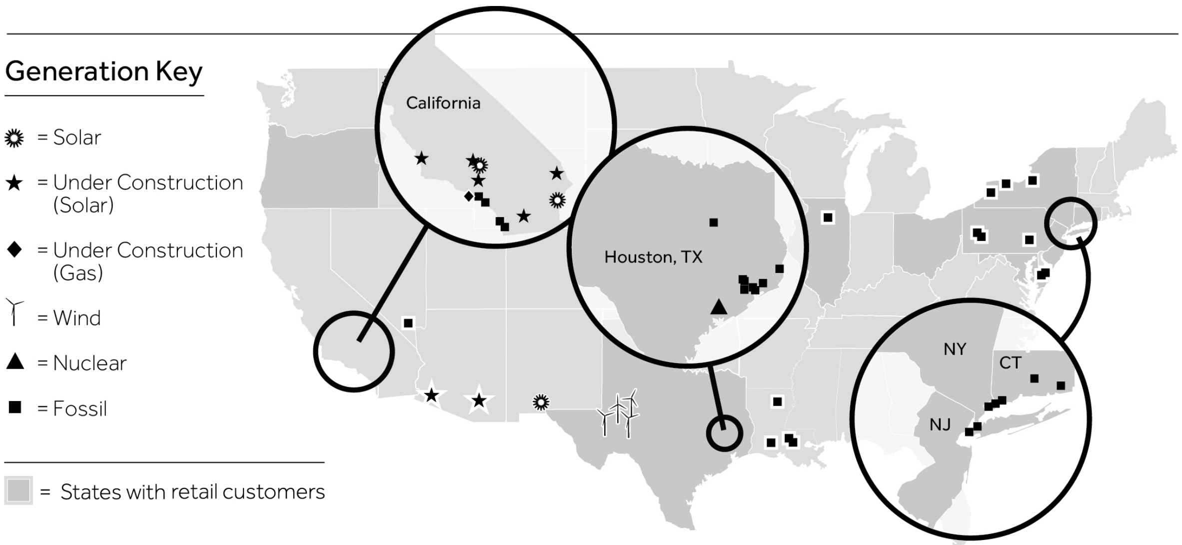
Retail

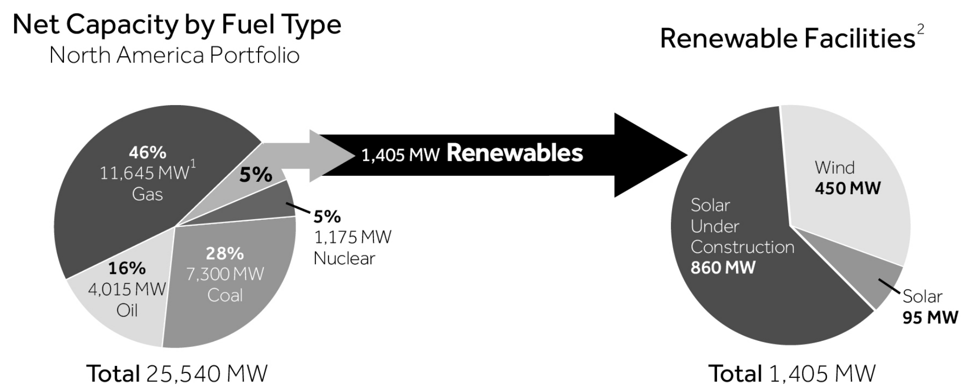
Through its Retail Businesses, NRG served 2.1 million customers in 2011, delivering over 57 TWhs, making it one of the largest retail energy providers in the United States. NRG's Retail Businesses offer a broad range of services and value propositions that enable it to attract, retain, and increase the value of our residential, small business and commercial customer relationships. With the largest market share in ERCOT based on volume sales, Reliant Energy is recognized by its exemplary customer service (ranked the highest in customer satisfaction by the Public Utility Commission of Texas, or PUCT, in 2011) as well as its innovative technology product offerings and home energy services. As one of the nation's leading retail providers of clean energy, Green Mountain Energy is widely recognized as a pioneer in the competitive retail energy market and provides customers an environmentally friendly alternative to their energy supply requirements. Acquired in 2011, Energy Plus primarily enrolls and retains electricity and natural gas customers through exclusive marketing arrangements with leading loyalty program providers and affinity group associations. Through these Retail Businesses, NRG is able to provide its customers a broad range of energy services and products, including system power, distributed generation, solar and wind products, carbon management and specialty services, and smart grid services. The breadth and scope of these Retail Businesses also create opportunities for delivering value enhancing energy solutions to customers on a national level.

Solar and Other Alternative Energy Technologies

NRG is one of the largest solar power developers in the U.S., having demonstrated the ability to develop, construct and finance a full range of solar energy solutions for utilities, schools, municipalities, commercial and residential market segments. The Company has 545 MW of renewable generation capacity which consists of ownership interests in four wind farms, three Utility Scale Solar facilities, and approximately 30 MW of Distributed Solar as of December 31, 2011. In addition, the Company has 860 MW of solar capacity under construction: 855 MW at six Utility Scale Solar facilities and 5 MW of Distributed Solar. Through its relationships with solar equipment providers, NRG is able to deploy diverse solar technologies in both the utility and distributed generating scale projects that creates value for the Company while meeting the clean renewable energy requirements of its customers   NRG is responding to the growing consumer demand for cleaner transportation solutions by building the first privately funded EV charging infrastructure network in select major metropolitan areas.

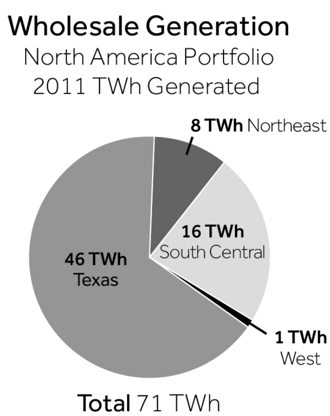
The map below shows the locations of NRG's U.S. power generation facilities as of December 31, 2011, (excluding Distributed Solar), both operating and under construction, as well as the states where NRG operates its Retail Businesses:

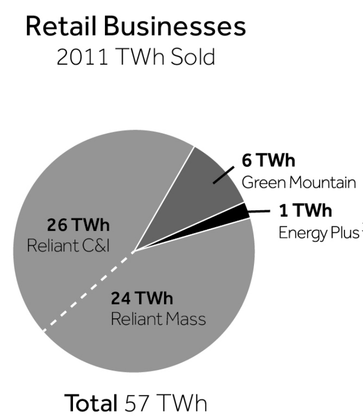




[1] *Includes 550 MW under construction*

[2] *Includes 35 MW Distributed Solar, including 5 MW under construction*





[3] *Included since September 30, 2011, date of acquisition*

The following table summarizes NRG's global generation portfolio as of December 31, 2011, by operating segment, which includes 47 fossil fuel plants, three Utility Scale Solar facilities and four wind farms, as well as Distributed Solar facilities. Also included are one natural gas plant, six Utility Scale Solar facilities and additional Distributed Solar facilities currently under construction. All Utility Scale Solar and Distributed Solar facilities are described in megawatts on an alternating current, or AC, basis:

	Fossil Fuel, Nuclear, and Renewable (In MW)								
Generation Type	**Texas**	**Northeast**	**South Central**	**West**	**Other (Thermal)**	**Alter-native Energy**	**Total Domestic**	**Other (Inter-national)**	**Total Global**
Natural gas	4,930	1,300	2,630	2,130	105	—	11,095	—	11,095
Coal	4,190	1,600	1,495	—	15	—	7,300	1,005	8,305
Oil	—	4,015	—	—	—	—	4,015		4,015
Nuclear	1,175	—	—	—	—	—	1,175	—	1,175
Wind	—	—	—	—	—	450	450	—	450
Utility Scale Solar	—	—	—	—	—	65	65	—	65
Distributed Solar	—	—	—	—	—	30	30	—	30
Total generation capacity	10,295	6,915	4,125	2,130	120	545	24,130	1,005	25,135
Under Construction									
Natural gas	—	—	—	550	—	—	550	—	550
Utility Scale Solar (a)	—	—	—	—	—	855	855	—	855
Distributed Solar	—	—	—	—	—	5	5	—	5
Total under construction	—	—	—	550	—	860	1,410	—	1,410

(a) Includes 142 MWs, representing 49% of Agua Caliente's capacity, which was sold to a partner on January 18, 2012

In addition, the Company's thermal assets provide steam and chilled water capacity of approximately 1,170 megawatts thermal equivalent, or MWt, through its district energy business.

Reliability of future cash flows and portfolio diversification

NRG has hedged a portion of its expected baseload generation capacity with decreasing hedge levels through 2016. NRG also has cooperative load contract obligations in the South Central region expiring over various dates through 2025, which largely hedge the Company's generation in this region. In addition, as of December 31, 2011, the Company had purchased fuel forward under fixed price contracts, with contractually-specified price escalators, for approximately 42% of its expected baseload coal requirement from 2012 to 2016, excluding inventory. The Company has the capacity and intent to enter into additional hedges when market conditions are favorable.

The Company also has the advantage of being able to supply its Retail Businesses with its own generation, which can reduce the need to sell and buy power from other financial institutions and intermediaries, resulting in lower transaction costs and credit exposures. This combination of generation and retail allows for a reduction in actual and contingent collateral, through offsetting transactions and by reducing the need to hedge the retail power supply through third parties.

The generation and retail combination also provides stability in cash flows, as changes in commodity prices generally have offsetting impacts between the two businesses. The offsetting nature of generation and retail in relation to changes in market prices, is an integral part of NRG's goal of providing a reliable source of future cash flow for the Company.

When developing renewable and new, conventional power generation facilities, NRG typically secures long-term Power Purchase Agreements, or PPAs, which insulate the Company from commodity market volatility and provide future cash flow stability. These PPAs are typically contracted with high credit quality local utilities and have durations up to 25 years. Such projects include all of the Company's major Utility Scale Solar projects, in operation and under construction, as well as the 550 MW El Segundo Energy Center, or ESEC, project that is under construction.

Commercial Operations Overview

NRG seeks to maximize profitability and manage cash flow volatility through the marketing, trading and sale of energy, capacity and ancillary services into spot, intermediate and long-term markets and through the active management and trading of emissions allowances, fuel supplies and transportation-related services. The Company's principal objectives are the realization of the full market value of its asset base, including the capture of its extrinsic value, the management and mitigation of commodity market risk and the reduction of cash flow volatility over time.

NRG enters into power sales and hedging arrangements via a wide range of products and contracts, including power purchase agreements, or PPAs, fuel supply contracts, capacity auctions, natural gas derivative instruments and other financial instruments. The PPAs that NRG enters into require the Company to deliver MWh of power to its counterparties. In addition, because changes in power prices in the markets where NRG operates are generally correlated to changes in natural gas prices, NRG uses hedging strategies which may include power and natural gas forward sales contracts to manage the commodity price risk primarily associated with the Company's baseload generation assets. The objective of these hedging strategies is to stabilize the cash flow generated by NRG's portfolio of assets.

Baseload Operations

The following table summarizes NRG's U.S. Baseload capacity and the corresponding revenues and average natural gas prices and positions resulting from Baseload hedge agreements extending beyond February 14, 2012, and through 2016:

	2012 [a]	2013	2014	2015	2016	Annual Average for 2012-2016
	(Dollars in millions unless otherwise stated)					
Net Baseload Capacity (MW) [b]	8,466	8,466	8,311	8,311	8,311	8,373
Forecasted Baseload Capacity (MW) [c]	5,823	5,797	5,453	5,818	6,013	5,781
Total Baseload Sales (MW) [d]	5,761	4,756	3,098	1,407	1,399	3,284
Percentage Baseload Capacity Sold Forward [e]	99%	82%	57%	24%	23%	57%
Total Forward Hedged Revenues [f][g]	$ 2,236	$ 1,909	$ 1,103	NM [h]	NM [h]	
Weighted Average Hedged Price ($ per MWh) [f]	$ 52.86	$ 45.83	$ 40.64	NM [h]	NM [h]	
Average Equivalent Natural Gas Price ($ per MMBtu)	$ 5.38	$ 5.29	$ 4.80	NM [h]	NM [h]	
Baseload Gas $1/MMBtu Up Sensitivity	$ 50	$ 145	$ 259	$ 368	$ 387	
Baseload Gas $1/MMBtu Down Sensitivity	$ —	$ (46)	$ (180)	$ (329)	$ (350)	
Baseload Heat Rate 1 MMBtu/MWh Up Sensitivity	$ 16	$ 70	$ 146	$ 171	$ 209	
Baseload Heat Rate 1 MMBtu/MWh Down Sensitivity	$ (1)	$ (47)	$ (119)	$ (157)	$ (191)	

(a) 2012 represents the period March through December.

(b) Nameplate capacity net of station services reflecting unit retirement schedule.

(c) Forecasted generation dispatch output (MWh) based on forward price curve as of February 14, 2012, which is then divided by number of hours in a given year to arrive at MW capacity. The dispatch takes into account planned and unplanned outage assumptions.

(d) Includes amounts under power sales contracts and natural gas hedges. The forward natural gas quantities are reflected in equivalent MWh based on forward market implied heat rate as of February 14, 2012, and then combined with power sales to arrive at equivalent MWh hedged which is then divided by number of hours in given year to arrive at MW hedged. The Baseload Sales include swaps and delta of options sold which is subject to change. For detailed information on the Company's hedging methodology through use of derivative instruments, see discussion in Item 15 - Note 6, *Accounting for Derivative Instruments and Hedging Activities* , to the Consolidated Financial Statements. Includes inter-segment sales from the Company's Texas wholesale power generation business to the Retail Businesses.

(e) Percentage hedged is based on total baseload sales as described in (d) above divided by the forecasted baseload capacity.

(f) Represents all North American baseload sales, including energy revenue and demand charges.

(g) The South Central region's weighted average hedged prices ranges from $40/MWh-$50/MWh. These prices include demand charges and an estimated energy charge.

(h) NM — Not meaningful, as South Central hedges, which are subject to renegotiation of the transportation component of coal costs, represent a substantial portion of total hedges.

Retail Operations

NRG's retail operations sell electricity on fixed price or indexed products, and these contracts have terms typically ranging from one month to five years. In 2011, the Company's Retail Businesses sold approximately 57 TWh of load. In any given year, TWh sold can be affected by weather, economic conditions and competition. The wholesale supply is typically purchased as the load is contracted in order to secure profit margin. The wholesale supply is purchased from a combination of NRG's wholesale portfolio and other third parties, depending on the existing hedge position for the NRG wholesale portfolio at the time.

Capacity and Other Contracted Revenue Sources

NRG revenues and cash flows benefit from capacity/demand payments and other contracted revenue sources, originating from either market clearing capacity prices, Resource Adequacy, or RA, contracts, tolling arrangements, PPAs and other long-term contractual arrangements:

- Northeast — The Company's largest sources for capacity revenues are derived from market capacity auctions in ISO New England Inc., or ISO-NE, New York Independent System Operator, or NYISO, and PJM Interconnection LLC, or PJM. The region's share of the GenConn plants in Connecticut earns fixed payments for their output under long-term financial contracts with a utility counterparty.
- South Central — NRG earns demand payments from its long-term full-requirements load contracts with ten Louisiana distribution cooperatives. Of the ten contracts, seven expire in 2025 and account for 57% of the cooperative customer contract load, with the remaining three contracts currently set to expire in 2014. The Company has executed agreements to extend the contracts of two of these three cooperatives representing 19% of the cooperative load through 2025, subject to regulatory approval. The remaining counterparty, with a 550 MW load service contract, accounting for 24% of the cooperative total, has elected not to extend their contract when it expires in 2014. Demand payments from the current long term contracts are tied to summer peak demand and provide a mechanism for recovering a portion of costs associated with new or changed environmental laws or regulations.
- West — Many of the region's sites, including gas projects currently under construction, are under tolling agreements. The remaining sites have short-term RA contracts.
- Thermal — Output from the Company's thermal assets is generally sold under long-term contracts or through regulated public utility tariffs. The contracts or tariffs contain capacity or demand elements, mechanisms for fuel recovery and/or the recovery of operating expenses. Thermal output from the Thermal region's Northwind business is sold under long-term agreements with customers in Phoenix, while the PJM assets participate in the PJM capacity markets.
- Texas — The region's sources of capacity and contracted revenues are through capacity option premium agreements and black start agreements with ERCOT.
- International — Generation output from the Company's share of the Schkopau facility in Germany and the Gladstone facility in Australia is sold under long-term contracts, which include capacity payments as well as the reimbursement of certain fixed and variable costs.
- Alternative Energy — Output from alternative energy assets is generally sold through long-term PPAs and renewable incentive agreements.

Fuel Supply and Transportation

NRG's fuel requirements consist of nuclear fuel and various forms of fossil fuel including coal, natural gas and oil. The prices of fossil fuels are highly volatile. The Company obtains its fossil fuels from multiple suppliers and transportation sources. Although availability is generally not an issue, localized shortages, transportation availability and supplier financial stability issues can and do occur. The preceding factors related to the sources and availability of raw materials are fairly uniform across the Company's business segments.

Coal — The Company is completely hedged for its domestic coal consumption for 2012; less so for subsequent years. Coal hedging is dynamic and is based on forecasted generation and market volatility. As of December 31, 2011, NRG had purchased forward contracts to provide fuel for approximately 42% of the Company's expected requirements from 2012 through 2016, excluding inventory. NRG arranges for the purchase, transportation and delivery of coal for the Company's baseload coal plants via a variety of coal purchase agreements, rail/barge transportation agreements, and rail car lease arrangements. The Company purchased approximately 27 million tons of coal in 2011, of which 98% was Powder River Basin coal and lignite.

The following table shows the percentage of the Company's coal requirements from 2012 through 2016 that have been purchased forward as of December 31, 2011:

	Percentage of Company's Requirement [(a)(b)]
2012	100%
2013	52%
2014	21%
2015	20%
2016	17%

(a) The hedge percentages reflect the current plan for the Jewett mine, which supplies lignite for NRG's Limestone facility. NRG has the contractual ability to change volumes and may do so in the future.

(b) Does not include coal inventory.

As of December 31, 2011, NRG had approximately 5,900 privately leased or owned rail cars in the Company's transportation fleet. NRG has entered into rail transportation agreements with varying tenures that provide for substantially all of the Company's rail transportation requirements for the next three years.

Natural Gas — NRG operates a fleet of natural gas plants across all its U.S. wholesale regions, which are primarily comprised of peaking assets that run in times of high power demand. Due to the uncertainty of their dispatch, the fuel needs are managed on a spot basis as the Company does not believe it is prudent to forward purchase natural gas for units, the dispatch of which is highly unpredictable. The Company contracts for natural gas storage services as well as natural gas transportation services to ensure delivery of natural gas when needed.

Nuclear Fuel — South Texas Project's, or STP's, owners satisfy STP's fuel supply requirements by: (i) acquiring uranium concentrates and contracting for conversion of the uranium concentrates into uranium hexafluoride; (ii) contracting for enrichment of uranium hexafluoride; and (iii) contracting for fabrication of nuclear fuel assemblies. Through its proportionate participation in South Texas Project Nuclear Operating Company, or STPNOC, which is the U.S. Nuclear Regulatory Commission, or NRC, -licensed operator of STP and responsible for all aspects of fuel procurement, NRG is party to a number of long-term forward purchase contracts with many of the world's largest suppliers covering STP requirements for uranium and conversion services for the next five years, and with substantial portions of STP's requirements procured thereafter. Similarly, NRG is party to long-term contracts to procure STP's requirements for enrichment services and fuel fabrication for the life of the operating license.

Seasonality and Price Volatility

Annual and quarterly operating results of the Company's wholesale power generation segments can be significantly affected by weather and energy commodity price volatility. Significant other events, such as the demand for natural gas, interruptions in fuel supply infrastructure and relative levels of hydroelectric capacity can increase seasonal fuel and power price volatility. NRG derives a majority of its annual revenues in the months of May through October, when demand for electricity is generally at its highest in the Company's core domestic markets. Further, power price volatility is generally higher in the summer months, traditionally NRG's most important season. The Company's second most important season is the winter months of December through March when volatility and price spikes in underlying delivered fuel prices have tended to drive seasonal electricity prices. The preceding factors related to seasonality and price volatility are fairly uniform across the Company's wholesale generation business segments.

The sale of electric power to retail customers is also a seasonal business with the demand for power generally peaking during the summer months. As a result, net working capital requirements for the Company's retail operations generally increase during summer months along with the higher revenues, and then decline during off-peak months. Weather may impact operating results and extreme weather conditions could materially affect results of operations. The rates charged to retail customers may be impacted by fluctuations in the price of natural gas, transmission constraints, competition, and changes in market heat rates.

Regional Segment Review

Revenues

The following table contains a summary of NRG's operating revenues by segment for the years ended December 31, 2011, 2010, and 2009, as discussed in Item 15 — Note 18, *Segment Reporting,* to the Consolidated Financial Statements. Refer to that footnote for additional financial information about NRG's business segments and geographic areas, including a profit measure and total assets. In addition, refer to Item 2 — *Properties*, for information about facilities in each of NRG's business segments.

	Year Ended December 31, 2011						
	Energy Revenues	Capacity Revenues	Retail Revenues[a]	Mark-to-Market Activities	Contract Amor-tization	Other Revenues[b]	Total Operating Revenues
	(In millions)						
Retail	$ —	$ —	$ 5,812	$ 8	$ (178)	$ —	$ 5,642
Texas	2,545	28	—	173	—	86	2,832
Northeast	579	291	—	28	—	26	924
South Central	548	243	—	(12)	20	18	817
West	31	118	—	(4)	—	4	149
Other Conventional Generation	58	70	—	—	(1)	196	323
Alternative Energy	43	—	—	—	—	1	44
Corporate and Eliminations [c]	(1,735)	(14)	(5)	132	—	(30)	(1,652)
Total	$ 2,069	$ 736	$ 5,807	$ 325	$ (159)	$ 301	$ 9,079

(a) Retail revenues include Energy Plus revenues of $63 million for the period October 1, 2011, to December 31, 2011.
(b) Primarily consists of revenues generated by the Thermal business, O&M revenues and unrealized trading activities.
(c) Energy revenues include inter-segment sales primarily between Texas and Northeast, and the Retail Businesses.

	Year Ended December 31, 2010						
	Energy Revenues	Capacity Revenues	Retail Revenues[d]	Mark-to-Market Activities	Contract Amor-tization	Other Revenues[e]	Total Operating Revenues
	(In millions)						
Retail	$ —	$ —	$ 5,279	$ (1)	$ (223)	$ —	$ 5,055
Texas	2,840	25	—	57	7	111	3,040
Northeast	726	396	—	(144)	—	47	1,025
South Central	387	235	—	(45)	21	10	608
West	25	113	—	(4)	—	4	138
Other Conventional Generation	46	71	—	(2)	—	186	301
Alternative Energy	39	—	—	—	—	2	41
Corporate and Eliminations [f]	(1,209)	(16)	(2)	(60)	—	(72)	(1,359)
Total	$ 2,854	$ 824	$ 5,277	$ (199)	$ (195)	$ 288	$ 8,849

(d) Retail revenues include Green Mountain Energy revenues of $69 million for the period November 5, 2010, to December 31, 2010.
(e) Primarily consists of revenues generated by the Thermal business, O&M revenues and unrealized trading activities.
(f) Energy revenues include inter-segment sales primarily between Texas and both Reliant Energy and Green Mountain Energy.

	Year Ended December 31, 2009						
	Energy Revenues	Capacity Revenues	Retail Revenues[g]	Mark-to-Market Activities	Contract Amor-tization	Other Revenues[h]	Total Operating Revenues
	(In millions)						
Retail	$ —	$ —	$ 4,440	$ —	$ (258)	$ —	$ 4,182
Texas	2,762	193	—	(17)	57	(57)	2,938
Northeast	873	407	—	(70)	—	(9)	1,201
South Central	367	269	—	(17)	22	(60)	581
West	26	122	—	—	—	2	150
Other Conventional Generation	52	79	—	(2)	—	157	286
Alternative Energy	8	—	—	—	—	—	8
Corporate and Eliminations [i]	(362)	(47)	—	(1)	—	16	(394)
Total	$ 3,726	$ 1,023	$ 4,440	$ (107)	$ (179)	$ 49	$ 8,952

(g) Retail revenues reflect Reliant Energy revenues for the period May 1, 2009, to December 31, 2009.
(h) Primarily consists of revenues generated by the Thermal business, O&M revenues and unrealized trading activities.
(i) Energy revenues include inter-segment sales between Texas and Reliant Energy.

Operational Statistics

The following are industry statistics for the Company's fossil and nuclear plants, as defined by the North American Electric Reliability Council, or NERC, and are more fully described below:

Annual Equivalent Availability Factor, or EAF — Measures the percentage of maximum generation available over time as the fraction of net maximum generation that could be provided over a defined period of time after all types of outages and deratings, including seasonal deratings, are taken into account.

Net heat rate — The net heat rate represents the total amount of fuel in British Thermal Unit, or BTU, required to generate one net kWh provided.

Net Capacity Factor — The net amount of electricity that a generating unit produces over a period of time divided by the net amount of electricity it could have produced if it had run at full power over that time period. The net amount of electricity produced is the total amount of electricity generated minus the amount of electricity used during generation.

The tables below present these performance metrics for the Company's U.S. power generation portfolio, including those accounted for through equity method investments, for the years ended December 31, 2011, and 2010:

	Year Ended December 31, 2011				
			Fossil and Nuclear Plants		
	Net Owned Capacity (MW)	Net Generation (MWh)	Annual Equivalent Availability Factor	Average Net Heat Rate BTU/kWh	Net Capacity Factor
		(In thousands of MWh)			
Texas	10,295	45,165	88.2%	10,300	46.7%
Northeast [(a)]	6,915	7,376	87.2	11,100	11.1
South Central	4,125	16,000	89.9	9,700	43.9
West	2,130	1,052	88.5	12,400	5.6
Alternative Energy	545	1,262			

	Year Ended December 31, 2010				
			Fossil and Nuclear Plants		
	Net Owned Capacity (MW)	Net Generation (MWh)	Annual Equivalent Availability Factor	Average Net Heat Rate BTU/kWh	Net Capacity Factor
		(In thousands of MWh)			
Texas	10,295	43,722	89.6%	10,300	48.1%
Northeast [(a)]	6,900	9,366	88.3	11,000	14.1
South Central [(b)]	4,125	11,168	91.3	10,500	41.9
West	2,130	869	89.7	11,800	4.8
Alternative Energy	470	1,030			

(a) Factor data and heat rate do not include the Keystone and Conemaugh facilities.
(b) Includes Cottonwood for the period November 15, 2010 (acquisition date), to December 31, 2010.

The generation performance by region for the three years ended December 31, 2011, 2010, and 2009, is shown below:

	Net Generation		
	2011	2010	2009
	(In thousands of MWh)		
Texas			
Coal	30,256	29,633	30,023
Gas [(a)]	5,949	4,794	5,224
Nuclear [(b)]	8,960	9,295	9,396
Total Texas	45,165	43,722	44,643
Northeast			
Coal	5,551	7,905	7,945
Oil	83	114	134
Gas	1,742	1,347	1,141
Total Northeast	7,376	9,366	9,220
South Central			
Coal	10,865	10,778	10,235
Gas [(c)]	5,135	390	163
Total South Central	16,000	11,168	10,398
West			
Gas	1,052	869	639
Total West	1,052	869	639
Alternative Energy			
Solar	79	52	1
Wind	1,183	978	350
Total Alternative Energy	1,262	1,030	351

(a) MWh information reflects the undivided interest in total MWh generated by Cedar Bayou 4 beginning June 2009.
(b) MWh information reflects the Company's undivided interest in total MWh generated by STP.
(c) Includes Cottonwood since November 15, 2010 (acquisition date).

Market Framework

Texas

NRG's largest wholesale power generation business segment is located in Texas in the physical control areas of the ERCOT market. In addition, Reliant Energy, Green Mountain Energy and Energy Plus activities in Texas are subject to standards and regulations adopted by the PUCT and ERCOT. In the ERCOT market, NRG's Retail Businesses are certified by the PUCT as Retail Electric Providers, or REPs, to contract with end-users to sell electricity and provide other value-enhancing services. In addition, NRG's Retail Businesses contract with transmission and distribution service providers, or TDSPs, to arrange for transportation to the customer.

The ERCOT market is one of the nation's largest and historically fastest growing power markets. For 2011, hourly demand ranged from a low of approximately 22,000 MW to a high of over 68,000 MW with installed generation capacity of approximately 81,000 MW (24,000 MW from coal, lignite and nuclear plants, 48,000 MW from gas, and 9,000 MW from wind). The ERCOT market has limited interconnections compared to other markets in the United States.

In November 2010, the ERCOT board of directors approved a new target equilibrium reserve margin level of 13.75%. The summer reserve margin for 2011 was forecast to be 18.4% in ERCOT's May 2011 Capacity, Demand and Reserve Report, or CDR. The latest CDR, initially published in December 2011, but updated in January 2012, forecasts a reserve margin level of 13.86% for Summer 2012. There are currently plans being implemented by the PUCT to build a significant amount of transmission from west Texas, the Texas panhandle, and continuing across the state to enable wind generation to reach load. The ultimate impact on wholesale dynamics from these plans are unknown. Currently, due to its intermittency and Texas' typically lower wind speeds during the summer months, ERCOT utilizes a capacity factor of 8.7% for the installed wind units when calculating the summer reserve margins.

On December 1, 2010, in compliance with a rule adopted by the PUCT, ERCOT replaced the zonal wholesale market design with a nodal market design that is based on Location Marginal Prices, or LMPs. The new nodal market, operational for all of 2011, includes, among other design changes, a financially binding day-ahead energy and ancillary services market administered by ERCOT. The nodal market design has resulted in improved dispatch of generation resources, more efficient management of transmission congestion, and an improved ability to integrate increased quantities of intermittent resources, such as wind and solar generating resources. Transmission congestion costs in the nodal market are directly assigned to the parties causing the congestion.

In response to projected shortfalls in planning reserves, and real time supply constraints in August 2011, at the direction of the PUCT, the ERCOT Independent System Operator, or ISO, is developing and implementing a number of market rule changes designed to achieve real-time energy pricing more reflective of higher energy value when ISO operating reserves are scarce or constrained - and thus improve forward market pricing signals and provide incentives for resource investment. Energy offer floors for certain ancillary service deployments have been implemented; other proposals under review include administrative pricing adjustments during operational shortages, higher energy pricing for ISO unit commitments for capacity, mitigation of price dampening from minimum energy from on-line resources, and formalizing emergency supply procurement by the ISO in a manner that would not suppress competitive pricing.

Northeast

NRG's second largest asset base is located in the Northeast region of the United States with generation assets within the control areas of the NYISO, ISO-NE, and PJM. Although each of the three NYISOs, also referred to as Regional Transmission Organizations, or RTOs, and their respective energy markets are functionally, administratively and operationally independent, they all follow, to a certain extent, similar market designs. Each ISO optimizes the scheduling and dispatch of power plant capabilities and price offers to meet system energy and reliability needs, and settles financial and physical energy deliveries at LMPs. LMPs reflect the value of energy at the specific location and time it is delivered. The LMP is determined by dispatching generators with the least cost energy supply offers to create the most reliable and economic solution where the energy is needed, subject to reliability and operational constraints on the system or individual generators. The ISO-sponsored LMP energy markets consist of two separate and characteristically distinct settlement time-frames. The first time-frame is a financially firm, day-ahead unit commitment market. The second time-frame is a financially settled, real-time dispatch and balancing market that fluctuates over a 24 hour period. All of these LMP energy markets are subject to stringent market mitigation measures, which can result in lower prices associated with certain generating units that are mitigated because they are deemed to have locational market power. In addition to the energy markets, each of the Northeast ISOs operates a capacity market that provides an additional opportunity for generating and demand response resources to earn revenues to offset their fixed costs that are not recovered in the energy markets, and reserve markets.

NRG's Retail Businesses are active in a number of areas in the Northeast region that have introduced retail competition, which allows our businesses to competitively provide retail power, natural gas and other value-enhancing services to customers. Each retail choice state is responsible for its own retail competition laws and regulations, and the specific operational, licensing, and compliance requirements vary on a state-by-state basis. In general, our Retail Businesses purchase energy from the wholesale market and utilize the existing transmission and distribution system to provide that power to end-use customers. Primary factors in the success of retail competition include how the state provides and prices default service. Incumbent utilities currently provide default service and as a result typically serve a majority of residential customers. However, as customers become more informed about the many benefits of retail choice and states continue to implement retail policies to further improve market dynamics, retail choice is expected to grow. The Company's Retail Businesses are currently licensed in many of the states allowing for retail choice in either the Commercial, industrial and governmental/institutional, or C&I, or Residential markets. Our Retail Businesses are expanding into a number of competitive choice states and offering a plethora of value propositions to customers to meet individual consumer preferences.

South Central

NRG's South Central region operates primarily in the Southeastern Electric Reliability Council/Entergy, or SERC-Entergy, region, which is a bilateral market without an RTO. In the South Central region, all power sales and purchases are consummated bilaterally between individual counterparties. Transacting counterparties are required to procure transmission service from the relevant transmission owners at their Federal Energy Regulatory Commission, or FERC, -approved tariff rates. In this market structure, NRG is able to provide balancing authority services in addition to wholesale power that allows NRG to provide full requirement services to load-serving entities, thus making NRG a competitive alternative to the integrated utilities operating in the region. NRG operates four Balancing Authorities, including the LAGEN Balancing Authority, which encompasses the generating facilities, the Company's cooperative load, and certain municipal entities purchasing long-term firm power from NRG.

West & Solar

The Company operates a fast-growing fleet of Utility Scale Solar and Distributed Solar generating assets within the balancing authority of the California Independent System Operator, or CAISO, as well as neighboring systems, and operates a fleet of natural gas fired facilities located entirely within the CAISO footprint. The CAISO operates day-ahead and real-time locational markets for energy and ancillary services, while managing congestion through nodal price fluctuations. The CAISO system facilitates NRG's sale of power and capacity products at market-based rates, or bilaterally pursuant to tolling arrangements with California's load serving entities, or LSEs. The CAISO, in conjunction with the California Public Utilities Commission, or CPUC, also determines specific capacity requirements for specified local areas. Both CAISO and CPUC rules require LSEs to contract with sufficient generation resources in order to maintain minimum levels of generation within defined local reliability areas.

California's resource mix is being significantly shaped by California's renewable portfolio standard and its greenhouse gas reduction rules. In particular, the state's renewable portfolio standard is 33% by 2020. In part driven by the renewable portfolio standard, several LSEs have entered into long-term PPAs with the Company's California and Arizona-based Utility Scale Solar generating facilities. The Company currently has PPAs for over 890 MW of solar generation assets both within the CAISO balancing authority, and selected markets outside of California, including Arizona. These contracts were approved by the CPUC.

The renewable portfolio standard is also expected to drive the need for generation resources with increased operating flexibility. The need is expected to be particularly acute in constrained areas of the transmission system, such as the San Diego and Los Angeles local reliability areas in which the Company currently operates natural gas-fired generation. The projected retirement of older flexible gas-fired coastal generating units that utilize once-through cooling is also a significant driver of long-term prices in California. Implementing market mechanisms to procure the needed flexibility, and allocating the costs associated with this flexibility, are key CAISO 2012 initiatives. NRG's CAISO natural gas-fired assets are in the Los Angeles or San Diego local reliability areas, and may benefit from local capacity requirements. The Company's El Segundo Energy Center development, which is currently under construction and the subject of a long-term tolling agreement, is an example of the type of flexible natural gas-fired generation resource that the CAISO has suggested will be necessary to maintain system reliability. Longer term, NRG's California portfolio's locational advantage may be impacted by new transmission, which may affect load pocket procurement requirements, and by the state's goal for additional distributed generation, which may also be located within these constrained local areas.

New and On-going Company Initiatives and Development Projects

NRG has a comprehensive set of initiatives and development projects that supports its strategy focused on: (i) excellence in safety and enhanced operating performance; (ii) earning a margin by selling electricity to end-use customers; (iii) development of new renewable and conventional power generation projects and repowering of power generation assets at existing sites; (iv) empowering retail customers with distinctive products and services; (v) engaging in a proactive capital allocation plan; and (vi) pursuing selective acquisitions, joint ventures, divestitures and investment in new energy-related businesses and new technologies in order to enhance the Company's asset mix and combat climate change.

Renewable Development and Acquisitions

As part of its core strategy, NRG has started and intends to continue to invest significantly in the development and acquisition of renewable energy projects, primarily solar. NRG's renewable strategy is intended to capitalize on first mover advantage in a high growth segment of NRG's business, the Company's existing presence in regions with attractive renewable resources and the prevalence, in the Company's core markets, of state-mandated renewable portfolio standards. A brief description of the Company's development efforts with respect to each renewable technology follows.

Solar

NRG has acquired and is developing a number of solar projects utilizing photovoltaic, or PV, as well as solar thermal technologies. The following table is a brief summary of the Company's major Utility Scale Solar projects as of December 31, 2011, that are under construction.

NRG Owned Projects	Location	PPA	MW (a)	Expected COD	Status
Ivanpah	Ivanpah, CA	20 - 25 year	392	2013	Under Construction
Agua Caliente (b)	Yuma County, AZ	25 year	290	2012 - 2014	Under Construction
CVSR	San Luis Obispo, CA	25 year	250	2012 - 2013	Under Construction
Alpine	Lancaster, CA	20 year	66	2012	Under Construction
Borrego	Borrego Springs, CA	25 year	26	2012	Under Construction
Avra Valley	Pima County, AZ	25 year	25	2012	Under Construction

(a) Represents total project size.
(b) Includes a 30 MW block, which reached commercial operations on January 18, 2012.

Below is a summary of recent developments related to solar projects:

Ivanpah — On April 5, 2011, NRG acquired a 50.1% stake in the 392 MW Ivanpah Solar Electric Generation System, or Ivanpah, from BrightSource Energy, Inc., or BSE. BSE maintained a 21.8% interest in Ivanpah and the remaining 28.1% was acquired by a wholly-owned subsidiary of Google. Ivanpah is composed of three separate facilities - Ivanpah 1 (126 MW), Ivanpah 2 (133 MW), and Ivanpah 3 (133 MW). Operations for the first phase are scheduled to commence in the first quarter of 2013, with the second and third phases expected to reach commercial operations in the second and third quarters of 2013, respectively. Power generated from Ivanpah will be sold to Southern California Edison and Pacific Gas and Electric, under multiple 20 to 25 year PPAs. Ivanpah has entered into the Ivanpah Credit Agreement with the Federal Financing Bank, or FFB, which is guaranteed by the United States Department of Energy, or U.S. DOE, to borrow up to $1.6 billion to fund the construction of this solar facility. On June 10, 2011, the U.S. Fish and Wildlife Service, or FWS, issued a revised biological opinion allowing the Bureau of Land Management to lift its temporary suspension of activities order with respect to the Ivanpah Project, thus allowing those aspects of the project which were delayed to proceed.

Western Watershed Project filed a motion seeking a temporary restraining order against the Ivanpah Project on June 27, 2011, to shut the project down in order to protect the desert tortoise as well as other animals. It was denied as was plaintiff's request for a preliminary injunction. The plaintiffs appealed this decision on August 20, 2011 to the U.S. Court of Appeals for the Ninth Circuit. On January 27, 2012, the district court heard arguments on the parties' cross motions for summary judgment. The Company awaits the court's rulings.

Agua Caliente — On August 5, 2011, NRG acquired 100% of the 290 MW Agua Caliente solar project, or Agua Caliente, in Yuma, AZ. Operations are scheduled to commence in phases, with the first 30 MW block achieving commercial operations on January 19, 2012, and the final block scheduled to come on line in the first quarter of 2014. Power generated from Agua Caliente will be sold to Pacific Gas and Electric under a 25 year PPA. In connection with the acquisition, Agua Caliente Solar, LLC, a wholly-owned subsidiary of NRG, entered into the Agua Caliente Financing Agreement with the FFB, which is guaranteed by the U.S. DOE, to borrow up to $967 million to fund the construction of this solar facility.

On January 18, 2012, the Company completed the sale of a 49% interest in NRG Solar AC Holdings LLC, the indirect owner of the Agua Caliente project entity, to MidAmerican Energy Holdings Company, or MidAmerican. A portion of the cash consideration received at closing represented 49% of construction costs funded by NRG's equity contributions. MidAmerican will fund its proportionate share of future equity contributions and other credit support for the project.

CVSR — On September 30, 2011, NRG acquired 100% of the 250 MW California Valley Solar Ranch project, or CVSR, in eastern San Luis Obispo County, California. Power generated from CVSR will be sold to Pacific Gas and Electric under a 25 year PPA. In connection with the acquisition, High Plains Ranch II, LLC, a wholly-owned subsidiary of NRG, entered into the CVSR Financing Agreement with the FFB, which is guaranteed by the U.S. DOE, to borrow up to $1.2 billion to fund the construction of this solar facility. The Company continues to work with its partners and the U.S. DOE to satisfy all of the U.S. DOE loan disbursement requirements and funding is anticipated by the end of the first quarter of 2012. Operations are expected to commence in phases beginning in the third quarter of 2012 through the fourth quarter of 2013.

Utility Scale Solar Development Pipeline

NRG has a pipeline of solar development projects that currently total approximately 967 MW in generation capacity as of December 31, 2011. The projects in the pipeline, which were either acquired or internally developed, range in size from 20 MW to 238 MW, and have the potential to become operational between 2012 and 2018.

Distributed Solar

On September 28, 2011, the Company entered into an agreement with Prologis, Inc. to invest in a distributed generation project of up to 733 MW led by Prologis, which includes a U.S. DOE loan guarantee commitment of up to $1.4 billion.

On November 8, 2011, the Company acquired Solar Power Partners, or SPP, a leading developer of commercial and industrial Distributed Solar projects with 21 MW of Distributed Solar projects in operation or under construction. The acquisition combines the financial resources of NRG with the development and deal structuring capability of SPP to facilitate the build out of SPP's development pipeline of more than 300 MW of projects in early to late stage development in California, Hawaii, Arizona, Connecticut, New Mexico, Massachusetts, New Jersey, Ontario and Puerto Rico.

In furtherance of its Distributed Solar strategy, in December 2011, NRG announced that it will install solar power generating systems at MetLife Stadium, home of the New York Football Giants and New York Jets, as well as Gillette Stadium, home of the New England Patriots. In addition, it will install a solar power generating system at Patriot Place, a shopping, dining, and entertainment venue in Foxborough, Massachusetts. All of the Company's Distributed Solar projects are supported by long-term PPAs.

In support of the Company's solar generation strategy, in the fourth quarter of 2011, NRG Solar purchased solar panels in the aggregate amount of approximately $130 million from various equipment vendors, including SunPower Systems SARL, GCL Solar Energy, Inc., Solar Frontier Americas Inc. and Hanwha SolarOne (Qidong) Co., Ltd.. These transactions will provide economic benefits for designated Utility Scale Solar and Distributed Solar projects in the development pipeline as they are constructed and achieve commercial operation.

Retail Acquisition

On September 30, 2011, NRG acquired Energy Plus, a Philadelphia-based retail electricity and natural gas provider with a customer base principally in New York, Connecticut, Pennsylvania, New Jersey, Maryland, and Illinois. Energy Plus also sells electricity to retail customers in Texas and natural gas in Ohio, New York and New Jersey. As of December 31, 2011, Energy Plus had 188,000 customers from its retail and natural gas businesses combined. Through its rewards program offered through the company's exclusive marketing partnerships with leading loyalty program providers, Energy Plus provides NRG with an additional retail platform to expand its customer services and products in multiple retail markets.

Retail Growth Initiatives

Reliant Energy continues to expand its Reliant eSense ™ product offerings. eSense is a suite of technology solutions that use the advanced meter system network (smart meters) that is being rolled out to customers in ERCOT. Through December 31, 2011, Reliant has 525,000 customers using one of these products that provide customers insights, choices and convenience solutions. Reliant's eSense development was accelerated by the U.S. DOE grant received during 2010.

Reliant also continues to expand its Home Solutions ℠ business with almost 220,000 customers utilizing home services products including protection products such as surge protection, in home power line protection, HVAC maintenance and energy efficiency products like air filter delivery and solar panel leasing.

Reliant Energy now offers commercial service in Delaware, Illinois, Maryland, New Jersey, Pennsylvania, and Washington, DC.

Electric Vehicle Infrastructure Development

NRG, through its subsidiary eVgo, continues its build out of the Houston and Dallas/Fort Worth Metroplex EV ecosystems, and the Company is on track to be the first company to equip an entire major market with the privately funded infrastructure needed for successful EV adoption and integration. As of December 2011, Houston had the largest single metropolitan-area network of DC fast chargers in the nation. eVgo offers consumers a subscription-based plan that locks in all charging requirements for EVs at a competitive monthly fee. Based upon the successful launch of its subscription-based business model in Texas, eVgo is evaluating a number of other geographical areas for expansion.

In September 2011, NRG, through its subsidiary, eV2g LLC, agreed to partner with the University of Delaware to develop vehicle-to-grid, or V2G, aggregation technology, a new EV infrastructure technology that manages the interaction of plugged-in electric vehicles with the electric grid to provide electricity supply and ancillary services including frequency regulation, demand response and other grid functions.

Post-combustion Carbon Capture Project

On March 9, 2010, NRG was selected by the U.S. DOE to receive up to $167 million, including funding from the American Recovery and Reinvestment Act, to build a 60 MW-equivalent post-combustion carbon capture demonstration unit at NRG's WA Parish plant southwest of Houston, with the intent of using the captured CO_2 in enhanced oil recovery operations in oil fields on the Texas Gulf Coast. In the first half of 2011, an application was submitted to and approved by the U.S. DOE to conduct a front-end engineering and design, or FEED, study for an up-to 250 MW sized project, which would allow for larger volumes of CO_2 production, leading to increased oil production through enhanced recovery efforts. The FEED study has been completed, and 50% of the costs of this phase were reimbursed by the U.S. DOE. To further the project's enhanced oil recovery operations, on October 3, 2011, Petra Nova LLC, a wholly-owned subsidiary of NRG, acquired a 50% interest in Texas Coastal Ventures, LLC, which owns a 100% working interest in the West Ranch oil field in Jackson County, Texas.

Energy Technology Ventures

On January 27, 2011, NRG entered into a joint venture with GE and ConocoPhillips to invest in venture-stage and growth-stage next generation energy technology companies. The joint venture, Energy Technology Ventures, will invest in and offer commercial collaboration opportunities to emerging energy technology companies in various sectors, including renewable power generation, smart grid, energy efficiency, emission controls, oil, natural gas, coal and biofuels. As of December 31, 2011, NRG has invested $14 million in several growth companies through Energy Technology Ventures as part of its plan to invest up to $100 million in this joint venture over four years.

Conventional Power Development

Projects Under Construction

The Company's El Segundo Energy Center LLC, or ESEC, commenced construction at its El Segundo Power Generating Station in El Segundo, California. Full notice to proceed with construction of the 550 MW fast start, gas turbine combined cycle generating facility was provided to the construction vendor on June 6, 2011. On August 23, 2011, the Company through its wholly owned subsidiary, NRG West Holdings LLC, entered into a credit agreement that established a loan facility with respect to ESEC consisting of a $540 million construction loan, $138 million in letter of credit facilities, and a revolving loan facility which permits working capital loans or letters of credit of up to $10 million. At the end of construction, the loan will convert to a term facility with semi annual amortization of principal and interest and a maturity date of August 31, 2023. The Company expects a commercial operation date of August 1, 2013.

Regulatory Matters

As operators of power plants and participants in wholesale and retail energy markets, certain NRG entities are subject to regulation by various federal and state government agencies. These include the Commodities Futures Trading Commission, or CFTC, FERC, NRC, and PUCT, as well as other public utility commissions in certain states where NRG's generating, thermal, or distributed generation assets are located. In addition, NRG is subject to the market rules, procedures and protocols of the various ISO markets in which it participates. Likewise, certain NRG entities participating in the retail markets are subject to rules and regulations established by the states in which NRG entities are licensed to sell at retail. NRG must also comply with the mandatory reliability requirements imposed by NERC and the regional reliability entities in the regions where the Company operates.

NRG's operations within the ERCOT footprint are not subject to rate regulation by the FERC, as they are deemed to operate solely within the ERCOT market and not in interstate commerce. As discussed below, these operations are subject to regulation by PUCT, as well as to regulation by the NRC with respect to the Company's ownership interest in STP.

CFTC

The CFTC, among other things, has regulatory oversight authority over the trading of electricity and gas commodities, including financial products and derivatives, under the Commodity Exchange Act, or CEA. On July 21, 2010, President Obama signed the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which, among other things, aims to improve transparency and accountability in derivative markets. The Dodd-Frank Act increases the CFTC's regulatory authority on matters related to over-the-counter derivatives, market clearing, position reporting, and capital requirements. The Company expects that in 2012 the CFTC will clarify the scope of the Dodd-Frank Act and issue final rules concerning a central clearing and execution exemption for derivative end-users, margin requirements for transactions, the definition of a “swap” and other issues that will affect the Company's over-the-counter derivatives trading. Because there are many details that remain to be addressed in CFTC rulemaking proceedings, at this time we cannot measure the impact to the Company on its current operations or collateral requirements.

FERC

The FERC, among other things, regulates the transmission and the wholesale sale of electricity in interstate commerce under the authority of the Federal Power Act, or FPA. The transmission of electric energy occurring wholly within ERCOT is not subject to the FERC's jurisdiction under Sections 203 or 205 of the Federal Power Act. Under existing regulations, the FERC determines whether an entity owning a generation facility is an Exempt Wholesale Generator, or EWG, as defined in the Public Utility Holding Company Act of 2005, or PUHCA of 2005. The FERC also determines whether a generation facility meets the ownership and technical criteria of a Qualifying Facility, or QF, under Public Utility Regulatory Policies Act of 1978, or PURPA. Each of NRG's non-ERCOT U.S. generating facilities qualifies as a QF, or the subsidiary owning the facility qualifies as an EWG.

Federal Power Act — The FPA gives the FERC exclusive rate-making jurisdiction over the wholesale sale of electricity and transmission of electricity in interstate commerce. Under the FPA, the FERC, with certain exceptions, regulates the owners of facilities used for the wholesale sale of electricity or transmission in interstate commerce as public utilities, and establishes market rules that are just and reasonable.

Public utilities are required to obtain the FERC's acceptance, pursuant to Section 205 of the FPA, of their rate schedules for the wholesale sale of electricity. All of NRG's non-QF generating and power marketing entities located outside of ERCOT make sales of electricity pursuant to market-based rates, as opposed to traditional cost-of-service regulated rates. Every three years FERC conducts a review of the Company's market based rates and potential market power on a regional basis. In 2011, FERC approved NRG's market power update filing for its Northeast assets.

The FPA also gives the FERC jurisdiction to review certain transactions and numerous other activities of public utilities. Section 203 of the FPA requires the FERC's prior approval for the transfer of control of assets subject to the FERC's jurisdiction. Section 204 of the FPA gives the FERC jurisdiction over a public utility's issuance of securities or assumption of liabilities. However, the FERC typically grants blanket approval for future securities issuances and the assumption of liabilities to entities with market-based rate authority.

In accordance with the Energy Policy Act of 2005, or EPAct of 2005, the FERC has approved the NERC as the national Energy Reliability Organization, or ERO. As the ERO, NERC is responsible for the development and enforcement of mandatory reliability standards for the wholesale electric power system. In addition to complying with NERC requirements, each NRG entity must comply with the requirements of the regional reliability entity for the region in which it is located.

Public Utility Holding Company Act of 2005 — PUHCA of 2005 provides the FERC with certain authority over and access to books and records of public utility holding companies not otherwise exempt by virtue of their ownership of EWGs, QFs, and Foreign Utility Companies, or FUCOs. NRG is a public utility holding company, but because all of the Company's generating facilities have QF status or are owned through EWGs, it is exempt from the accounting, record retention, and reporting requirements of the PUHCA of 2005.

Public Utility Regulatory Policies Act — PURPA was passed in 1978 in large part to promote increased energy efficiency and development of independent power producers. PURPA created QFs to further both goals, and the FERC is primarily charged with administering PURPA as it applies to QFs. Certain QFs are exempt from regulation, either in whole or in part, under the FPA as public utilities.

NRC

The NRC is authorized under the Atomic Energy Act of 1954, as amended, or the AEA, among other things, to grant licenses for, and regulate the operation of, commercial nuclear power reactors. As a holder of an ownership interest in STP, NRG is an NRC licensee and is subject to NRC regulation. The NRC license gives the Company the right to only possess an interest in STP but not to operate it. Operating authority under the NRC operating license for STP is held by STPNOC. NRC regulation involves licensing, inspection, enforcement, testing, evaluation, and modification of all aspects of plant design and operation including the right to order a plant shutdown, technical and financial qualifications, and decommissioning funding assurance in light of NRC safety and environmental requirements. In addition, NRC's written approval is required prior to a licensee transferring an interest in its license, either directly or indirectly. As a possession-only licensee, i.e., non-operating co-owner, the NRC's regulation of NRG is primarily focused on the Company's ability to meet its financial and decommissioning funding assurance obligations. In connection with the NRC license, the Company and its subsidiaries have a support agreement to provide up to $120 million to support operations at STP.

Decommissioning Trusts — Upon expiration of the operation licenses for the two generating units at STP, currently scheduled for 2027 and 2028, the co-owners of STP are required under federal law to decontaminate and decommission the STP facility. Under NRC regulations, a power reactor licensee generally must pre-fund the full amount of its estimated NRC decommissioning obligations unless it is a rate-regulated utility, or a state or municipal entity that sets its own rates, or has the benefit of a state-mandated non-bypassable charge available to periodically fund the decommissioning trust such that the trust, plus allowable earnings, will equal the estimated decommissioning obligations by the time the decommissioning is expected to begin.

NRG, through its 44% ownership interest, is the beneficiary of decommissioning trusts that have been established to provide funding for decontamination and decommissioning of STP. CenterPoint Energy Houston Electric, LLC, or CenterPoint, and American Electric Power, or AEP, collect, through rates or other authorized charges to their electric utility customers, amounts designated for funding NRG's portion of the decommissioning of the facility. See also Item 15 — Note 7, *Nuclear Decommissioning Trust Fund,* to the Consolidated Financial Statements for additional discussion.

In the event that the funds from the trusts are ultimately determined to be inadequate to decommission the STP facilities, the original owners of the Company's STP interests, CenterPoint and AEP, each will be required to collect, through their PUCT-authorized non-bypassable rates or other charges to customers, additional amounts required to fund NRG's obligations relating to the decommissioning of the facility. Following the completion of the decommissioning, if surplus funds remain in the decommissioning trusts, those excesses will be refunded to the respective rate payers of CenterPoint or AEP, or their successors.

PUCT

The Company's Texas generation subsidiaries are registered as power generation companies with the PUCT. The PUCT also has jurisdiction over power generation companies with regard to their sales in the wholesale markets, the implementation of measures to address undue market power or price volatility, and the administration of nuclear decommissioning trusts. The PUCT exercises its jurisdiction both directly, and indirectly, through its oversight of the ERCOT, the regional transmission organization. Certain of the Company's subsidiaries within the Texas region are also subject to regulatory oversight as a power marketer or as a Qualified Scheduling Entity. NRG Power Marketing, LLC, or PML, is registered as a power marketer with the PUCT and thus is also subject to the jurisdiction of the PUCT with respect to its sales in the ERCOT. Certain of the Company's retail entities are competitive REPs, and as such are subject to the rules and regulations of the PUCT governing REPs.

New York State Public Service Commission, or NYSPSC

The Company's NYSPSC generation subsidiaries are electric corporations subject to "lightened" regulation by the NYSPSC. As such, the NYSPSC exercises its jurisdictional authority over certain non-rate aspects of the facilities, including safety, retirements, and the issuance of debt secured by recourse to the Company's generation assets located in New York. The Company currently has blanket authorization from the NYSPSC for the issuance of $15 billion of debt.

Regional Regulatory Developments

In New England, New York, the Mid-Atlantic region, the Midwest and California, the FERC has approved regional transmission organizations, also commonly referred to as ISOs. Most of these ISOs administer a wholesale centralized bid-based spot market in their regions pursuant to tariffs approved by the FERC and associated ISO market rules. These tariffs/market rules dictate how the capacity and energy markets operate, how market participants may make bilateral sales with one another, and how entities with market-based rates are compensated within those markets. The ISOs in these regions also control access to and the operation of the transmission grid within their regions. In Texas, pursuant to a 1999 restructuring statute, the PUCT granted similar responsibilities to the ERCOT. NRG is affected by rule/tariff changes that occur in the ISO regions.

For further discussion on regulatory developments see Item 15 — Note 23, *Regulatory Matters,* to the Consolidated Financial Statements.

Texas Region

Nuclear Regulatory Commission, or NRC, Task Force Report — On July 12, 2011, the NRC Near-Term Task Force, or the Task Force, issued its report, which reviewed nuclear processes and regulations in light of the accident at the Fukushima Daiichi Nuclear Power Station in Japan. The Task Force concluded that U.S. nuclear plants are operating safely and did not identify changes to the existing nuclear licensing process nor recommend fundamental changes to spent nuclear fuel storage. The Task Force report made recommendations in three key areas: the NRC's regulatory framework, specific plant design requirements, and emergency preparedness and actions. STPNOC expects the report to be the first step in a longer-term review that the NRC will conduct, along with seeking broad stakeholder input. STPNOC continues to apply lessons learned and work with regulators and industry organizations on appropriate assessments and actions.

On January 13, 2012, the NRC issued six draft "information request letters," seeking industry comment on additional recommendations made by the Near-Term Task Force. Topics for comment include how to improve the robustness of existing emergency preparedness plans, whether to mandate on-site availability of emergency response materials, and guidance on how to identify sites vulnerable to flooding, seismic events, or other natural external hazards (such as hurricanes and tornadoes). The NRC has requested feedback from nuclear utilities on its proposed measures. Until further actions are taken by the NRC, the Company cannot predict the impact of the recommendations in the NRC Task Force report, and could be required to make additional investments at STP Units 1 & 2.

Northeast Region

New England — On April 13, 2011, FERC issued an order addressing proposed amendments submitted by ISO-NE to its Forward Capacity Market, or FCM, design, as well as two pending complaints. Among other market revisions, FERC's order extends the price floor for "at least" the fifth (2014/2015) and sixth (2015/2016) Forward Capacity Auctions in order to address the effect of historical out-of-market capacity. On January 19, 2012, FERC issued an order largely denying rehearing of its prior decision. The January 19 order also approved ISO-NE's request to eliminate the price floor as of the seventh (2016/2017) Forward Capacity Auction.

New York — On November 30, 2010, the NYISO filed at FERC its proposed installed capacity demand curves for 2011/2012, 2012/2013, and 2013/2014. The demand curves are a critical determinant of capacity market prices. The Company and other market participants protested the NYISO's filing, and on January 28, 2011, FERC found in favor of generators on a number of issues principally related to determining the cost of new entry and the resulting adjustments to the demand curves should positively affect capacity clearing prices. On May 19, 2011, FERC granted rehearing to remove property taxes from the cost of new entry of new in-city generation, denied other requests for rehearing, and directed the NYISO to make a series of compliance filings to implement the new rate. On September 15, 2011, FERC issued an order accepting the NYISO's compliance filing, and directing the NYISO to implement the new rate, to take effect November 1, 2011. On December 15, 2011, FERC issued an order denying rehearing of its May 19, 2011, order. The Company and other independent generators with interests in the New York City capacity market have requested judicial review of FERC's December 15, 2011, order.

In addition, on June 3, 2011, as amended on June 15, 2011, several New York in-city generators filed a complaint with FERC seeking additional transparency into: whether (i) the NYISO was correctly evaluating if new entrants into the capacity markets should be subject to mitigation and, if so, (ii) the NYISO was appropriately setting the level of any mitigation. On June 29, 2011, the NYISO released its July spot capacity auction clearing prices for New York City, which significantly decreased over June clearing prices. Clearing prices for the third quarter 2011 were comparable to the July clearing prices. The apparent cause of this decrease was a decision by the NYISO to allow a new entrant to bid into the July spot capacity auction, either without mitigation or without proper mitigation. Additionally, another new entrant has since indicated that it also received a mitigation exemption from NYISO and that it intends to begin participating in the NYISO capacity market starting with the May 2012 capability period. The addition of this second new entrant may further affect capacity clearing prices in New York. On July 10, 2011, in response to the July spot auction capacity clearing prices, two independent generators filed a second complaint alleging that the NYISO had improperly exempted both new entrants from mitigation, and requested that FERC immediately direct the NYISO to apply its offer-floor market mitigation rules to both new entrants, to resettle the July capacity spot auction, and other relief. The Company filed at FERC in support of applying offer-floor mitigation to the new entrants. On August 31, 2011, FERC issued an interim order on the second complaint directing the NYISO to provide additional information, on a confidential basis, regarding its mitigation decisions, which were filed on September 23, 2011. Several market participants, including the Company, filed comments in response. Both complaints are pending before FERC.

PJM — On April 12, 2011, FERC issued an order addressing a complaint filed by PJM Power Providers Group seeking to require PJM to address the potential adverse impacts of out-of-market generation on the PJM capacity market, as well as PJM's subsequent submission seeking revisions to the capacity market design, in particular the Minimum Offer Price Rule, or MOPR. In its order, FERC generally strengthened the MOPR and the protections against market price distortion from out-of-market generation. On November 17, 2011, FERC largely denied rehearing of its April 12, 2011, order. Several parties have appealed FERC's decision to federal court, and those appeals have been consolidated in the Third Circuit Court of Appeals. The outcome of this proceeding could affect the Company's ability to meet its obligations under New Jersey's Long-Term Capacity Agreement Pilot Program.

South Central Region

On April 25, 2011, Entergy Corporation, or Entergy, announced that it will pursue joining the Midwest Independent System Operator regional transmission organization, or MISO, with a current target date for joining of December 2013. Entergy's proposal is subject to approval from the regulatory commissions of the states of Arkansas, Louisiana, Mississippi, and Texas, as well as the City of New Orleans. The Company's South Central region is dependent upon Entergy's transmission system to conduct its business, and thus would necessarily move with Entergy into MISO. This development is not expected to materially impact the Company's ability to serve its customers in the region, and the Company is continuing to analyze the impact of the possible changes in transmission access and market design.

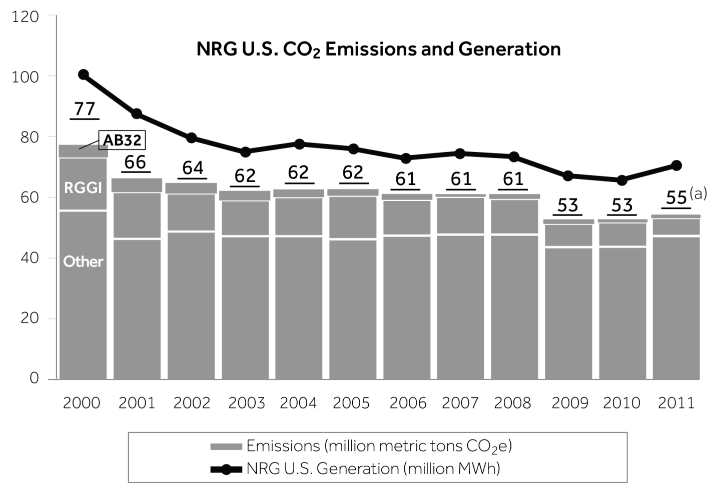
West Region

California — On March 17, 2011, FERC issued an order on CAISO's proposal to replace its interim backstop Capacity Procurement Mechanism, or CPM, with a permanent version. On December 23, 2011, the parties to the proceeding submitted a proposed settlement that increases the price, quantity and term of contracts given to generating units not otherwise contracted to fulfill California's Resource Adequacy requirements, but nevertheless needed for reliability. The settlement is subject to FERC approval and may increase payments to any non-contracted units called upon to provide reliability service.

Environmental Matters

NRG is subject to a wide range of environmental regulations across a broad number of jurisdictions in the development, ownership, construction and operation of domestic and international projects. These laws and regulations generally require that governmental permits and approvals be obtained before construction and during operation of power plants. Environmental laws have become increasingly stringent and NRG expects this trend to continue. The electric generation industry will face new requirements to address air emissions, climate change, combustion byproducts and water use. In general, future laws and regulations are expected to require the addition of emission controls or other environmental quality equipment or the imposition of certain restrictions on the operations of the Company's facilities. NRG expects that future liability under, or compliance with, environmental requirements could have a material effect on the Company's operations or competitive position.

Climate Change — NRG emits GHGs in the process of generating electricity. The following table shows the reduction in CO_2, which makes up greater than 99% of the Company's GHG emissions, from 2000 to the present. NRG anticipates reductions in its future emissions profile as the Company implements its strategy to add more renewable sources like wind and solar, modernize the fleet through Repowering, improve generation efficiencies, explore methods to capture CO_2, and seeks ways to offset GHGs.



(a) 2011 is the first year NRG reported Cottonwood's full-year CO_2 emissions.

2011 NRG CO_2e Emissions

	MWh Generation	CO_2e metric ton
	(in millions)	
NRG Total	76	60
NRG U.S.Total	72	55
RGGI	7	6
CA	1	0.6
NRG Germany	2	2
NRG Australia	2	3

The impact from legislation or federal, regional or state regulation of GHGs on the Company's financial performance will depend on a number of factors, including the level of GHG standards under any such regulations, the applicability of offsets, and the extent to which NRG would be entitled to receive CO_2 emissions credits without having to purchase them in an auction or on the open market. Thereafter, under any such legislation or regulation, the impact on NRG would depend on the Company's level of success in developing and deploying low and no carbon technologies.

Federal Environmental Initiatives

Environmental Regulatory Landscape — In 2011, a number of U.S. Environmental Protection Agency, or U.S. EPA, air regulations were finalized providing more clarity on the impact to electric generating units. A number of regulations with the potential for impact are still in development or under review by the U.S. EPA: New Source Performance Standards, or NSPS, for GHGs, National Ambient Air Quality Standards, or NAAQS, revisions, coal combustion byproducts, and once-through cooling. While most of these regulations have been considered for some time, the outcomes and any resulting impact on NRG cannot be fully predicted until the rules are finalized. The timing and stringency of these regulations will contribute to a framework for the retrofit of existing fossil plants and deployment of new, cleaner technologies in the next decade. See discussion below for more detail.

Air — The U.S. EPA released the Cross-State Air Pollution Rule, or CSAPR, on July 7, 2011, with additional proposed updates on October 6, 2011. CSAPR was scheduled to replace the Clean Air Interstate Rule, or CAIR, on January 1, 2012. It was designed to bring states into attainment with PM 2.5 and ozone NAAQS, reducing SO_2 and NO_x emissions from power plants. The proposed implementation employed cap and trade allowance programs starting in 2012 for Group 1 SO_2, Group 2 SO_2, Annual NO_x, and Ozone Season NO_x. In 2014, the SO_2 cap would be further reduced in Group 1 states. Under CSAPR, use of Acid Rain SO_2 and NO_x allowances for CAIR would be discontinued and replaced with these completely distinct allowance programs. Acid Rain allowances would still be required on a 1:1 basis under the Acid Rain Program. NRG owns or has minority interests in plants in six states that would be covered by the rule. No plant impairments nor material capital investment were expected for NRG facilities to comply with CSAPR.

State	Group 1 SO_2	Group 2 SO_2	Annual NO_x	Ozone NO_x
IL	X		X	X
LA				X
MD	X		X	X
NY	X		X	X
PA	X		X	X
TX		X	X	X

In the third quarter 2011, the Company recorded an impairment charge of $160 million on the Company's Acid Rain Program SO_2 emission allowances, which were recorded as an intangible asset on the Company's balance sheet. The impairment charge reflects the write-off under CSAPR of the value of emission allowances in excess of those required for compliance with the Acid Rain Program.

CSAPR was challenged by numerous petitioners. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the rule pending resolution of the numerous petitions for judicial review. CAIR will remain in effect during the stay. The court has implemented briefing schedules that would allow the CSAPR appeal to be heard as early as April 2012. The Company is unable to predict the final outcome of the court proceeding. There is no material impact to NRG related to the stay.

On March 16, 2011, the U.S. EPA released the proposed Mercury and Air Toxics Standards, or MATS, to control emissions of hazardous air pollutants from coal and oil fired electric generating units. The rule was signed in final form on December 16, 2011, but has not yet been published in the Federal Register (the timing of which will set compliance dates). Requirements include meeting the standards for mercury, acid gases, and certain metals (such as particulate matter) in 2015 on a plantwide basis with the potential for a one year extension. NRG does not anticipate any plant impairments or capital expenditures beyond the current environmental capital expenditures schedule.

On September 22, 2011, the U.S. EPA released draft guidance on the development and submission of state implementation plans, or SIPs, for the 1-hour SO_2 standard that was finalized in 2010. States will have to identify areas of non-attainment and submit SIPs by June 2013 and demonstrate attainment by August 2017. If any areas in which NRG owns coal-fired power plants were ultimately designated as non-attainment, it could require further SO_2 controls. The Company cannot determine the impact, if any, of the NAAQS until the rules are final.

On December 20, 2011, the U.S. EPA published their intended designations for the 2008 ozone standard. Designations for counties/parishes in which NRG has power plants remained largely unchanged. The U.S. EPA intends to release final designations in the spring of 2012 and a final rule by July 2014. NRG cannot determine the impact, if any, of these NAAQS until the rules are final.

Waste — On May 4, 2010, the U.S. EPA proposed two options for the regulation of coal combustion residue, commonly known as coal ash. Under the Proposal's first regulatory option, the U.S. EPA would reverse its August 1993 and May 2000 Bevill Regulatory Determinations and list coal ash as a special waste subject to regulation under hazardous waste regulations. The second regulatory option would leave the Bevill Determination in place and regulate disposal of coal ash as non-hazardous. Under both options, an exemption for the beneficial use of coal ash would remain in place. Additionally, under both options, the U.S. EPA would establish dam safety requirements to address the structural integrity of surface impoundments. While it is not possible to predict the impact of this rule until it is final, as proposed it is not expected to have a material impact on NRG's operations, as all NRG flyash disposal sites are dry landfills. However, should the U.S. EPA implement the hazardous waste option, NRG may incur significant costs due to loss of markets for beneficial reuse. Given the recent release of this proposed rule, NRG will continue to monitor developments and their respective impact on the Company's operations

Water — In July 2004, the U.S. EPA published rules governing cooling water intake structures at existing power facilities commonly referred to as the 316(b) Rule. As a result of a decision by the U.S. Court of Appeals for the Second Circuit, the U.S. EPA suspended the rule in July 2007 while preparing a revised version. On March 28, 2011, the U.S. EPA released the proposed 316(b) Rule. States such as California and New York moved ahead with their own more stringent requirements for once-through cooled units, which are expected to satisfy the requirements of the proposed 316(b) Rule. NRG expects to comply with these requirements with a mix of intake and operational modifications.

Regional U.S. Environmental Initiatives

Northeast

On July 20, 2011, the New York State Department of Environmental Conservation, or NYDEC, announced the State's final policy on cooling water intake structures, confirming the Company's planned capital expenditure for cooling water intakes in that state. NRG expects to comply with these requirements with a mix of intake and operational modifications.

West

The California Air Resources Board adopted the state's GHG cap-and-trade program under Assembly Bill 32, or AB32, on October 20, 2011. Participation by the electric generation sector will begin in 2013. NRG does not expect implementation of the GHG cap-and-trade program in California to have a significant adverse financial impact on the Company for a variety of reasons, including the fact that the portion of NRG's California portfolio that is merchant consists mainly of natural gas-fired facilities and the market price of power when dispatched is expected to have embedded in it the market price of allowances. The contracted portion of NRG's portfolio included pass-through language with respect to the obligation to purchase allowances. New NRG renewable projects in California markets will support AB32 requirements for the increased use of renewable energy.

The California statewide 316(b) policy to mitigate once-through cooling was effective as of October 1, 2010. NRG's affected plants submitted alternative plans to meet equivalent mitigation criteria which are reflected in our current schedule of environmental capital expenditures. Specified compliance dates for NRG's El Segundo and Encina power plants are December 31, 2015, and December 31, 2017, respectively.

South Central Region

On February 11, 2009, the U.S. Department of Justice, or U.S. DOJ, acting at the request of the U.S. EPA commenced a lawsuit against Louisiana Generating, LLC in the United States 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 Notice of Violations, or 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*.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures from 2012 through 2016 to meet NRG's environmental commitments will be approximately $553 million. These costs are primarily associated with mercury controls to satisfy MATS on the Company's Big Cajun II, W.A. Parish and Limestone facilities and a number of intake modification projects across the fleet under state or proposed federal 316(b) rules. NRG continues to explore cost effective compliance alternatives to reduce costs. A more detailed discussion of environmental capital expenditures can be found in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources, Capital Expenditures* and *Environmental Capital Expenditures.*

Domestic Site Remediation Matters

Under certain federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility, including an electric generating facility, may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products at the facility. NRG may also be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by a party in connection with hazardous material releases or threatened releases. These laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended by the Superfund Amendments and Reauthorization Act of 1986, or SARA, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and the courts have interpreted liability under such laws to be strict (without fault) and joint and several. Cleanup obligations can often be triggered during the closure or decommissioning of a facility, in addition to spills or other occurrences during its operations. Further discussions of affected NRG sites can be found in Item 15 — Note 24, *Environmental Matters*, to the Consolidated Financial Statements.

Nuclear Waste — The federal government's program to construct a nuclear waste repository at Yucca Mountain, Nevada was discontinued in 2010. In order to meet the federal government's obligations to safely manage used nuclear fuel and radioactive waste under the U.S. Nuclear Waste Policy Act of 1982, the U.S. DOE established a blue ribbon commission to explore alternatives. Also consistent with the Act, owners of nuclear plants, including the owners of STP, entered into contracts setting out the obligations of the owners and the U.S. DOE, including the fees to be paid by the owners for the U.S. DOE's services. Since 1998, the U.S. DOE has been in default on its obligations to begin removing spent nuclear fuel and high-level radioactive waste from reactors, necessitating each site to take steps to construct interim spent fuel storage installations. STP has sufficient capacity in its spent fuel pool through 2016 at which time its dry cask storage facility will be ready for operation.

Under the federal Low-Level Radioactive Waste Policy Act of 1980, as amended, the state of Texas is required to provide, either on its own or jointly with other states in a compact, for the disposal of all low-level radioactive waste generated within the state. STP's warehouse capacity is adequate for on-site storage until a site in Andrews County, Texas becomes fully operational.

Employees

As of December 31, 2011, NRG had 5,193 employees, approximately 28% of whom were covered by U.S. bargaining agreements. During 2011, the Company did not experience any labor stoppages or labor disputes at any of its facilities.

Available Information

NRG's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, or Exchange Act, are available free of charge through the Company's website, www.nrgenergy.com, as soon as reasonably practicable after they are electronically filed with, or furnished to the United States Securities and Exchange Commission, or SEC. The Company also routinely posts press releases, presentations, webcasts, and other information regarding the Company on the Company's website.

The information provided in this Exhibit is presented only in connection with the reporting changes described in the accompanying Form 8-K. This information does not reflect events occurring after February 28, 2012, the date we filed our 2011 Form 10-K, and does not modify or update the disclosures therein in any way, other than as required to reflect the change in reportable segments and the adoption of a new accounting standard, as described in the Form 8-K and set forth in Exhibits 99.1 through 99.5 attached thereto. You should therefore read this information in conjunction with the 2011 Form 10-K and any subsequent amendments on Form 10-K/A and with our reports filed with the Securities and Exchange Commission after February 28, 2012.

Part I, Item 2 — Properties

Listed below are descriptions of NRG's interests in facilities, operations and/or projects owned as of December 31, 2011. The MW figures provided represent nominal summer net megawatt capacity of power generated as adjusted for the Company's ownership position excluding capacity from inactive/mothballed units as of December 31, 2011. The following table summarizes NRG's power production and cogeneration facilities by region:

Name and Location of Facility	Power Market	% Owned	Net Generation Capacity (MW) [(a)]	Primary Fuel-type
Texas Region:				
Cedar Bayou, Baytown, TX	ERCOT	100.0	1,495	Natural Gas
Cedar Bayou 4, Baytown, TX	ERCOT	50.0	260	Natural Gas
Greens Bayou, Houston, TX	ERCOT	100.0	355	Natural Gas
Limestone, Jewett, TX	ERCOT	100.0	1,690	Coal
San Jacinto, LaPorte, TX	ERCOT	100.0	160	Natural Gas
South Texas Project, Bay City, TX [(b)]	ERCOT	44.0	1,175	Nuclear
S. R. Bertron, Deer Park, TX	ERCOT	100.0	470	Natural Gas
T. H. Wharton, Houston, TX	ERCOT	100.0	1,025	Natural Gas
W. A. Parish, Thompsons, TX [(c)]	ERCOT	100.0	2,490	Coal
W. A. Parish, Thompsons, TX [(c)]	ERCOT	100.0	1,175	Natural Gas
Northeast Region:				
Arthur Kill, Staten Island, NY	NYISO	100.0	865	Natural Gas
Astoria Gas Turbines, Queens, NY	NYISO	100.0	550	Natural Gas
Conemaugh, New Florence, PA	PJM	3.7	65	Coal
Connecticut Jet Power, CT (four sites)	ISO-NE	100.0	140	Oil
Devon, Milford, CT	ISO-NE	100.0	135	Oil
GenConn Devon, Milford, CT	ISO-NE	50.0	95	Oil
Dunkirk, NY	NYISO	100.0	530	Coal
Huntley, Tonawanda, NY	NYISO	100.0	380	Coal
Indian River, Millsboro, DE [(d)]	PJM	100.0	580	Coal
Keystone, Shelocta, PA	PJM	3.7	65	Coal
Middletown, CT	ISO-NE	100.0	770	Oil
GenConn Middletown, CT	ISO-NE	50.0	95	Oil
Montville, Uncasville, CT	ISO-NE	100.0	500	Oil
Norwalk Harbor, So. Norwalk, CT	ISO-NE	100.0	340	Oil
Oswego, NY	NYISO	100.0	1,635	Oil
Vienna, MD	PJM	100.0	170	Oil
South Central Region:				
Bayou Cove, Jennings, LA	SERC-Entergy	100.0	300	Natural Gas

Big Cajun I, Jarreau, LA	SERC-Entergy	100.0	430	Natural Gas
Big Cajun II, New Roads, LA (e)	SERC-Entergy	86.0	1,495	Coal
Cottonwood, Deweyville, TX	SERC-Entergy	100.0	1,265	Natural Gas
Rockford I, IL	PJM	100.0	305	Natural Gas
Rockford II, IL	PJM	100.0	155	Natural Gas
Sterlington, LA	SERC-Entergy	100.0	175	Natural Gas
West Region:				
El Segundo Power, CA	CAISO	100.0	670	Natural Gas
Encina, Carlsbad, CA	CAISO	100.0	965	Natural Gas
Long Beach, CA	CAISO	100.0	260	Natural Gas
Saguaro Power Co., Henderson, NV	WECC	50.0	45	Natural Gas
San Diego Combustion Turbines, CA (four sites)	CAISO	100.0	190	Natural Gas
Alternative Energy:				
Avenal, CA	CAISO	50.0	25	Solar
Blythe, CA	CAISO	100.0	20	Solar
Roadrunner, Santa Teresa, NM	EPE	100.0	20	Solar
Elbow Creek Wind Farm, Howard County, TX	ERCOT	100.0	125	Wind
Langford Wind Farm, Christoval, TX	ERCOT	100.0	150	Wind
Sherbino Wind Farm, Pecos County, TX	ERCOT	50.0	75	Wind
South Trent Wind Farm, Sweetwater, TX	ERCOT	100.0	100	Wind
International Region:				
Gladstone Power Station, Queensland, Australia	Enertrade/Boyne Smelter	37.5	605	Coal
Schkopau Power Station, Germany	Vattenfall Europe	41.9	400	Coal

(a) Actual capacity can vary depending on factors including weather conditions, operational conditions, and other factors. Additionally, ERCOT requires periodic demonstration of capability, and the capacity may vary individually and in the aggregate from time to time.

(b) Generation capacity figure consists of the Company's 44% individual interest in the two units at STP.

(c) W.A. Parish has nine units, four of which are baseload coal-fired units and five of which are natural gas-fired units.

(d) Indian River Unit 1 was retired May 31, 2011, and Indian River Unit 3 will be retired by December 31, 2013.

(e) Units 1 and 2 owned 100.0%, Unit 3 owned 58.0%.

Thermal Facilities

The Company's thermal businesses in Pittsburgh, Harrisburg and San Francisco are regulated by their respective state's Public Utility Commission. The other thermal businesses are subject to contract terms with their customers.

The following table summarizes NRG's thermal steam and chilled water facilities as of December 31, 2011:

Name and Location of Facility	% Owned	Thermal Energy Purchaser	Megawatt Thermal Equivalent Capacity (MWt)	Generating Capacity
NRG Energy Center Minneapolis, MN	100.0	Approx. 100 steam and 50 chilled water customers	334 141	Steam: 1,140 MMBtu/hr. Chilled Water: 40,200 tons
NRG Energy Center San Francisco, CA	100.0	Approx 170 steam customers	133	Steam: 454 MMBtu/Hr.
NRG Energy Center Harrisburg, PA	100.0	Approx 210 steam and 3 chilled water customers	129 8	Steam: 440 MMBtu/hr. Chilled water: 2,400 tons
NRG Energy Center Phoenix, AZ	100.0	Approx 30 chilled water customers	90	Chilled water: 25,600 tons
NRG Energy Center Pittsburgh, PA	100.0	Approx 25 steam and 25 chilled water customers	87 45	Steam: 296 MMBtu/hr. Chilled water: 12,920 tons
NRG Energy Center San Diego, CA	100.0	Approx 20 chilled water customers	26	Chilled water: 7,425 tons
Camas Power Boiler Camas, WA	100.0	Georgia Pacific Group	59	Steam: 200 MMBtu/hr.
NRG Energy Center Dover, DE	100.0	Kraft Foods Inc. and Proctor & Gamble Company	56	Steam: 190 MMBtu/hr.

The following table summarizes NRG's thermal power generation facilities, as of December 31, 2011:

Name and Location of Facility	Power Market/ Zone	% Owned	Generation Capacity (MW)	Primary Fuel Type
Paxton Creek Cogeneration Harrisburg, PA	PJM / East	100.0	12	Natural Gas
Dover Cogeneration, DE	PJM / West	100.0	104	Coal
Princeton Hospital, NJ	PJM/East	100.0	5	Natural Gas

Other Properties

NRG owns 30 MW of Distributed Solar facilities at various locations throughout the United States, concentrated primarily in the West Region.

In addition, NRG owns several real properties and facilities relating to its generation assets, other vacant real property unrelated to the Company's generation assets, interests in construction projects, and properties not used for operational purposes. NRG believes it has satisfactory title to its plants and facilities in accordance with standards generally accepted in the electric power industry, subject to exceptions that, in the Company's opinion, would not have a material adverse effect on the use or value of its portfolio.

NRG leases its corporate offices at 211 Carnegie Center, Princeton, New Jersey, its Reliant Energy, Green Mountain Energy, and Energy Plus offices and call centers, and various other office space.

EXHIBIT 99.3

The information provided in this Exhibit is presented only in connection with the reporting changes described in the accompanying Form 8-K. This information does not reflect events occurring after February 28, 2012, the date we filed our 2011 Form 10-K, and does not modify or update the disclosures therein in any way, other than as required to reflect the change in reportable segments and the adoption of a new accounting standard, as described in the Form 8-K and set forth in Exhibits 99.1 through 99.5 attached thereto. You should therefore read this information in conjunction with the 2011 Form 10-K and any subsequent amendments on Form 10-K/A and with our reports filed with the Securities and Exchange Commission after February 28, 2012.

Part II, Item 6 — Selected Financial Data

The following table presents NRG's historical selected financial data. The data included in the following table has been recast to reflect the assets, liabilities and results of operations of certain projects that have met the criteria for treatment as discontinued operations in 2007 and 2008.

This historical data should be read in conjunction with the Consolidated Financial Statements and the related notes thereto in Item 15 and Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(In millions except ratios and per share data)				
Statement of income data:					
Total operating revenues	$ 9,079	$ 8,849	$ 8,952	$ 6,885	$ 5,989
Total operating costs and expenses, and other expenses	9,725	8,119	7,283	5,119	5,073
Income from continuing operations, net	197	476	941	1,053	556
Income from discontinued operations, net	—	—	—	172	17
Net income attributable to NRG Energy, Inc.	$ 197	$ 477	$ 942	$ 1,225	$ 573
Common share data:					
Basic shares outstanding — average	240	252	246	235	240
Diluted shares outstanding — average	241	254	271	275	288
Shares outstanding — end of year	228	247	254	234	237
Per share data:					
Income attributable to NRG from continuing operations — basic	$ 0.78	$ 1.86	$ 3.70	$ 4.25	$ 2.09
Income attributable to NRG from continuing operations — diluted	0.78	1.84	3.44	3.80	1.90
Net income attributable to NRG — basic	0.78	1.86	3.70	4.98	2.16
Net income attributable to NRG — diluted	0.78	1.84	3.44	4.43	1.96
Book value	$ 33.71	$ 32.65	$ 29.72	$ 26.75	$ 19.55
Business metrics:					
Cash flow from operations	$ 1,166	$ 1,623	$ 2,106	$ 1,479	$ 1,517
Liquidity position [(a)]	$ 2,328	$ 4,660	$ 3,971	$ 4,124	$ 2,715
Ratio of earnings to fixed charges	0.77	2.03	3.27	3.65	2.24
Ratio of earnings to fixed charges and preferred dividends	0.76	1.99	3.04	3.19	1.99
Return on equity	2.57%	5.91%	12.24%	17.20%	10.38%
Ratio of debt to total capitalization	52.43%	42.94%	43.49%	47.50%	55.58%
Balance sheet data:					
Current assets	$ 7,597	$ 7,137	$ 6,208	$ 8,492	$ 3,562
Current liabilities	5,671	4,220	3,762	6,581	2,277
Property, plant and equipment, net	13,621	12,517	11,564	11,545	11,320
Total assets	26,715	26,896	23,378	24,808	19,274
Long-term debt, including current maturities, capital leases, and funded letter of credit	9,832	10,511	8,418	8,161	8,346
Total stockholders' equity	$ 7,669	$ 8,072	$ 7,697	$ 7,123	$ 5,519

(a) Liquidity position is determined as disclosed in Item 7, *Liquidity and Capital Resources, Liquidity Position*. It includes funds deposited by counterparties of $258 million, $408 million, and $177 million as of December 31, 2011, 2010, and 2009, respectively, which represents cash held as collateral from hedge counterparties in support of energy risk management activities. It is the Company's intention to limit the use of these funds for repayment of the related current liability for collateral received in support of energy risk management activities.

The following table provides the details of NRG's operating revenues:

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(In millions)				
Energy revenue	$ 3,804	$ 4,063	$ 4,087	$ 4,408	$ 4,349
Capacity revenue	750	840	1,070	1,343	1,175
Retail revenue	5,807	5,277	4,440	—	—
Mark-to-market for economic hedging activities	325	(199)	(107)	462	(94)
Contract amortization	(159)	(195)	(179)	278	242
Other revenues	342	361	62	417	358
Eliminations	(1,790)	(1,298)	(421)	(23)	(41)
Total operating revenues	$ 9,079	$ 8,849	$ 8,952	$ 6,885	$ 5,989

Energy revenue consists of revenues received from third parties for sales of electricity in the day-ahead and real-time markets, as well as bilateral sales. It also includes energy sold through long-term PPAs for renewable facilities. In addition, energy revenue includes revenues from the settlement of financial instruments and net realized trading revenues.

Capacity revenue consists of revenues received from a third party at either the market or negotiated contract rates for making installed generation capacity available in order to satisfy system integrity and reliability requirements. Capacity revenue also includes revenues from the settlement of financial instruments. In addition, capacity revenue includes revenues received under tolling arrangements, which entitle third parties to dispatch NRG's facilities and assume title to the electrical generation produced from that facility.

Retail revenue, representing operating revenues of NRG's Retail Businesses, consists of revenues from retail electric sales to residential, small business, commercial, industrial and governmental/institutional customers, as well as revenues from the sale of excess supply into various markets, primarily in Texas.

Mark-to-market for economic hedging activities includes fair value changes of economic hedges that did not qualify for cash flow hedge accounting and ineffectiveness on cash flow hedges.

Contract amortization revenue consists of the amortization of the intangible assets for net in-market C&I contracts established in connection with the acquisitions of Reliant Energy and Green Mountain Energy, as well as acquired power contracts, gas derivative instruments, and certain power sales agreements assumed at Fresh Start and Texas Genco purchase accounting dates related to the sale of electric capacity and energy in future periods. These amounts are amortized into revenue over the term of the underlying contracts based on actual generation or contracted volumes.

Other revenues include revenues generated by the Thermal business consisting of revenues received from the sale of steam, hot and chilled water generally produced at a central district energy plant and sold to commercial, governmental and residential buildings for space heating, domestic hot water heating and air conditioning. It also includes the sale of high-pressure steam produced and delivered to industrial customers that is used as part of an industrial process. Other revenues also consists of operations and maintenance fees, or O&M fees, construction management services, or CMA fees, sale of natural gas and emission allowances, and revenues from ancillary services. O&M fees consist of revenues received from providing certain unconsolidated affiliates with services under long-term operating agreements. CMA fees are earned where NRG provides certain management and oversight of construction projects pursuant to negotiated agreements such as for the GenConn, Cedar Bayou 4 and certain solar construction projects. Ancillary services are comprised of the sale of energy-related products associated with the generation of electrical energy such as spinning reserves, reactive power and other similar products. Other revenues also includes unrealized trading activities.

EXHIBIT 99.4

The information provided in this Exhibit is presented only in connection with the reporting changes described in the accompanying Form 8-K. This information does not reflect events occurring after February 28, 2012, the date we filed our 2011 Form 10-K, and does not modify or update the disclosures therein in any way, other than as required to reflect the change in reportable segments and the adoption of a new accounting standard, as described in the Form 8-K and set forth in Exhibits 99.1 through 99.5 attached thereto. You should therefore read this information in conjunction with the 2011 Form 10-K and any subsequent amendments on Form 10-K/A and with our reports filed with the Securities and Exchange Commission after February 28, 2012.

Part II

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

The discussion and analysis below has been organized as follows:

- Executive Summary, including business strategy, the business environment in which NRG operates, how regulation, weather, competition and other factors affect the business, and significant events that are important to understanding the results of operations and financial condition for the 2011 period;

- Results of operations, including an explanation of significant differences between the periods in the specific line items of NRG's Consolidated Statements of Operations;

- Financial condition addressing credit ratings, liquidity position, sources and uses of cash, capital resources and requirements, commitments, and off-balance sheet arrangements; and

- Critical accounting policies which are most important to both the portrayal of the Company's financial condition and results of operations, and which require management's most difficult, subjective or complex judgment.

As you read this discussion and analysis, refer to NRG's Consolidated Statements of Operations to this Form 8-K, which presents the results of the Company's operations for the years ended December 31, 2011, 2010, and 2009, and also refer to Exhibit 99.1 to this Form 8-K for more detailed discussion about the Company's business.

Executive Summary

Business Strategy

NRG Energy, Inc., or NRG or the Company, is an integrated wholesale power generation and retail electricity company that aspires to be a leader in the way the industry and consumers think about, use, produce and deliver energy and energy services in major competitive power markets in the United States. First, NRG is a wholesale power generator engaged in the ownership and operation of power generation facilities; the trading of energy, capacity and related products; and the transacting in and trading of fuel and transportation services. Second, NRG is a retail electricity company engaged in the supply of electricity, energy services, and cleaner energy products to retail electricity customers in deregulated markets through the Retail Businesses. Finally, NRG is focused on the deployment and commercialization of potential disruptive technologies, like electric vehicles, Distributed Solar and smart meter technology, which have the potential to change the nature of the power supply industry.

The Company's core business is focused on: (i) excellence in safety and operating performance of its existing assets; (ii) serving the energy needs of end-use residential, commercial and industrial customers in the Company's core markets with a retail energy product that is differentiated either by premium service (Reliant), sustainability (Green Mountain Energy) or loyalty/affinity programs (Energy Plus); (iii) optimal hedging of baseload generation and retail load operations, while retaining optionality on the Company's peaking facilities; (iv) repowering of power generation assets at premium sites; (v) investment in, and deployment of, alternative energy technologies both in its wholesale and, particularly, in and around its retail businesses and their customers; (vi) pursuing selective acquisitions, joint ventures, divestitures and investments; and (vii) engaging in a proactive capital allocation plan focused on achieving the regular return of and on stockholder capital within the dictates of prudent balance sheet management.

The Company believes that the American energy industry is going to be increasingly impacted by the long-term societal trend towards sustainability which is both generational and irreversible. Moreover, the information technology-driven revolution which has enabled greater and easier personal choice in other sectors on the consumer economy will do the same in the American energy sector over the years to come. As a result, energy consumers will have increasing personal control over whom they buy their energy from, how that energy is generated and used and what environmental impact these individual choices will have. The Company's initiatives in this area of future growth are focused on: (i) renewables, with a concentration in solar development; (ii) electric vehicle ecosystems; (iii) customer-facing energy products and services including smart grid services, nationwide retail green electricity, unique retail sales channels involving loyalty and affinity programs and custom design; and (iv) construction of other forms of on-site clean power generation. The Company's advances in each of these areas are driven by select acquisitions, joint ventures, and investments that are more fully described in Item 1, *Business — New and On-going Company Initiatives and Development Projects.*

Business Environment

The industry dynamics and external influences affecting the Company and the power generation industry in 2011 and for the future medium term include:

Consolidation — There were several mergers and acquisitions in the U.S. power sector in 2011. Over the long term, industry consolidation is expected to continue.

Environmental Regulatory Landscape — In 2011, a number of U.S. EPA air regulations were finalized providing more clarity on the impact to electric generating units. A number of regulations with the potential for impact are still in development or under review by the U.S. EPA: NSPS for GHGs, NAAQS revisions, coal combustion byproducts, and once-through cooling. While most of these regulations have been considered for some time, the outcomes and any resulting impact on NRG cannot be fully predicted until the rules are finalized. The timing and stringency of these regulations will contribute to a framework for the retrofit of existing fossil plants and deployment of new, cleaner technologies in the next decade. See Item 1, *Business — Environmental Matters*, for further discussion.

Public Policy Support and Government Financial Incentives for Clean Infrastructure Development — Policy mechanisms including production and investment tax credits, cash grants, loan guarantees, accelerated depreciation tax benefits, RPS, and carbon trading plans have been implemented at the state and federal levels to support the development of renewable generation, demand-side and smart grid, and other clean infrastructure technologies. The availability and continuation of public policy support mechanisms will drive a significant part of the economics of the Company's development program and expansion into clean energy investments.

Natural Gas Market — The price of natural gas plays an important role in setting the price of electricity in many of the regions where NRG operates power plants. Natural gas prices are driven by variables including demand from the industrial, residential, and electric sectors, productivity across natural gas supply basins, costs of natural gas production, changes in pipeline infrastructure, and the financial and hedging profile of natural gas consumers and producers. In 2011, average natural gas prices were 8% lower than 2010 and comparable to prices seen in 2009. Supply continues to reflect increased production from low extraction cost resources such as the shale basins. In 2012, a mild winter and increased production have led to spot prices dipping into the $2.50/MMBtu range. At these current depressed levels, significant coal-to-gas switching is expected, making wholesale changes to Merit Order in many electric markets. While some gas producers have publicly spoken of scaling back production, it is too early to assess whether there is action behind their words. At current rates of production, storage levels may challenge storage limits later in the year. While the near-term gas price outlook is depressed, a return to normal weather, coal-fired plant retirements due to proposed environmental regulations and Liquid Natural Gas export possibilities may drive higher gas prices in the medium term.

If long-term gas prices remain depressed, the Company is likely to encounter further reductions in realized energy prices, leading to lower energy revenues as higher priced hedge contracts mature and are replaced by contracts with lower gas and power prices. The Retail Businesses' gross margins have historically improved as natural gas prices decline and are likely to partially offset the impact of declining gas prices on conventional wholesale power generation. To further mitigate this impact, NRG may increase its percentage of baseload capacity sold forward using a variety of hedging instruments, as described under the heading Energy Related Commodities in Item 15 — Note 6, *Accounting for Derivative Instruments and Hedging Activities,* to the Consolidated Financial Statements. The Company's increased investment in renewable power generation supported by PPAs also mitigates declines in long term gas prices.

Electricity Price — The price of electricity is a key determinant of the profitability of the Company's generation portfolio. Many variables such as the price of different fuels, weather, load growth and unit availability all coalesce to impact the final price for electricity. In 2011, electricity prices in Texas were higher than 2010 due primarily to the extreme weather and record-setting load experienced in August 2011. In NRG's other regions, prices were lower than in 2010, mainly due to lower gas prices and negligible demand growth. The following table summarizes average on-peak power prices for each of the major markets in which NRG operates for the years ended December 31, 2011, 2010, and 2009:

	Average on Peak Power Price ($/MWh)		
Region	**2011**	**2010**	**2009**
Texas	$ 57.42	$ 40.40	$ 35.43
Northeast	53.09	56.69	46.14
South Central	36.30	40.25	33.58
West	36.39	40.05	39.70

Weather

Weather conditions in the regions of the United States in which NRG does business influence the Company's financial results. Weather conditions can affect the supply and demand for electricity and fuels. Changes in energy supply and demand may impact the price of these energy commodities in both the spot and forward markets, which may affect the Company's results in any given period. Typically, demand for and the price of electricity is higher in the summer and the winter seasons, when temperatures are more extreme. The demand for and price of natural gas are higher in the winter. However, all regions of the United States typically do not experience extreme weather conditions at the same time, thus NRG is typically not exposed to the effects of extreme weather in all parts of its business at once.

Other Factors

A number of other factors significantly influence the level and volatility of prices for energy commodities and related derivative products for NRG's business. These factors include:

- seasonal, daily and hourly changes in demand;
- extreme peak demands;
- available supply resources;
- transportation and transmission availability and reliability within and between regions;
- location of NRG's generating facilities relative to the location of its load-serving opportunities;
- procedures used to maintain the integrity of the physical electricity system during extreme conditions; and
- changes in the nature and extent of federal and state regulations.

These factors can affect energy commodity and derivative prices in different ways and to different degrees. These effects may vary throughout the country as a result of regional differences in:

- weather conditions;
- market liquidity;
- capability and reliability of the physical electricity and gas systems;
- local transportation systems; and
- the nature and extent of electricity deregulation.

Environmental Matters, Regulatory Matters and Legal Proceedings

NRG discusses details of its other environmental matters in Item 15 — Note 24, *Environmental Matters*, to the Consolidated Financial Statements and Item 1, *Business — Environmental Matters,* section. NRG discusses details of its regulatory matters in Item 15 — Note 23, *Regulatory Matters*, to the Consolidated Financial Statements and Item 1, *Business — Regulatory Matters,* section. NRG discusses details of its legal proceedings in Item 15 — Note 22, *Commitments and Contingencies*, to the Consolidated Financial Statements. Some of this information relates to costs that may be material to the Company's financial results.

Impact of inflation on NRG's results

Unless discussed specifically in the relevant segment, for the years ended December 31, 2011, 2010 and 2009, the impact of inflation and changing prices (due to changes in exchange rates) on NRG's revenues and net income was immaterial.

Significant events during the year ended December 31, 2011

Results of Operations and Financial Condition

- *Lower net income* — Net income decreased by 59% from $477 million to $197 million, which reflects a decrease in gross margin for wholesale generation driven by lower realized prices and a decrease in gross margin from the unprecedented heat wave in August 2011 in Texas, which negatively impacted both retail and generation gross margins. In addition, the decrease reflects a $160 million impairment charge on emissions allowances, the $495 million impairment of NRG's investment in Nuclear Innovation North America LLC, or NINA, and a loss on debt extinguishment of $175 million. These amounts were offset in part by a tax benefit of $843 million in 2011, which primarily reflects the impact of the resolution of the federal tax audit in June 2011, compared to tax expense of $277 million in 2010.

- *Liquidity position* — The Company's total liquidity, excluding collateral received, decreased by $2.2 billion in 2011. Cash balances decreased by $1.8 billion since the end of 2010, primarily due to capital expenditures for solar and other repowering projects, as well as additional share repurchases. In addition, availability under the revolving credit arrangements decreased due to additional letters of credit required for solar and other repowering projects.

- *Long-term debt* — During 2011, the Company increased its non-recourse debt by approximately $1.0 billion primarily in connection with the financing of the construction of three Utility Scale Solar facilities.

Consolidated Results of Operations

2011 compared to 2010

The following table provides selected financial information for the Company:

(In millions except otherwise noted)	Year Ended December 31, 2011	Year Ended December 31, 2010	Change %
Operating Revenues			
Energy revenue [(a)]	$ 2,069	$ 2,854	(28)%
Capacity revenue [(a)]	736	824	(11)
Retail revenue	5,807	5,277	10
Mark-to-market for economic hedging activities	325	(199)	263
Contract amortization	(159)	(195)	18
Other revenues [(b)]	301	288	5
Total operating revenues	9,079	8,849	3
Operating Costs and Expenses			
Generation cost of sales [(a)]	2,488	2,170	15
Retail cost of sales [(a)]	2,815	2,822	—
Mark-to-market for economic hedging activities	169	(111)	252
Contract and emissions credit amortization [(c)]	47	15	213
Other cost of operations	1,156	1,177	(2)
Total cost of operations	6,675	6,073	10
Depreciation and amortization	896	838	7
Impairment charge on emission allowances	160	—	N/A
Selling, general and administrative	668	598	12
Development costs	45	55	(18)
Total operating costs and expenses	8,444	7,564	12
Gain on sale of assets	—	23	(100)
Operating Income	635	1,308	(51)
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	35	44	(20)
Impairment charge on investment	(495)	—	N/A
Other income, net	19	33	(42)
Loss on debt extinguishment	(175)	(2)	N/A
Interest expense	(665)	(630)	6
Total other expense	(1,281)	(555)	131
(Loss)/Income before income tax expense	(646)	753	(186)
Income tax (benefit)/ expense	(843)	277	(404)
Net Income	197	476	(59)
Less: Net loss attributable to noncontrolling interest	—	(1)	100
Net income attributable to NRG Energy, Inc.	$ 197	$ 477	(59)
Business Metrics			
Average natural gas price — Henry Hub ($/MMBtu)	4.04	4.39	(8)%

(a) Includes realized gains and losses from financially settled transactions.
(b) Includes unrealized trading gains and losses.
(c) Includes amortization of SO_2 and NO_x credits and excludes amortization of Regional Greenhouse Gas Initiative, or RGGI, credits.
N/A - Not Applicable

Management's discussion of the results of operations for the years ended December 31, 2011 and 2010

Conventional Generation gross margin

The following is a discussion of gross margin for NRG's Conventional Generation businesses, adjusted to eliminate intersegment activity primarily with the Retail businesses.

	Year Ended December 31, 2011								
	Conventional Generation								
(In millions except otherwise noted)	Texas	Northeast	South Central	West	Other	Subtotal	Alternative Energy	Eliminations/Corporate	Consolidated Total
Energy revenue	$ 2,545	$ 579	$ 548	$ 31	$ 58	$ 3,761	$ 43	$ (1,735)	$ 2,069
Capacity revenue	28	291	243	118	70	750		(14)	736
Other revenue	86	26	18	4	196	330	1	(30)	301
Generation revenue	2,659	896	809	153	324	4,841	$ 44	$ (1,779)	$ 3,106
Generation cost of sales	(1,228)	(527)	(547)	(16)	(186)	(2,504)		$ 16	$ (2,488)
Generation gross margin	$ 1,431	$ 369	$ 262	$ 137	$ 138	$ 2,337	$ 44		
Business Metrics									
MWh sold (in thousands)	48,078	9,317	17,131	215			1,263		
MWh generated (in thousands)	45,165	7,361	16,000	215			1,263		

	Year Ended December 31, 2010								
	Conventional Generation								
(In millions except otherwise noted)	Texas	Northeast	South Central	West	Other	Subtotal	Alternative Energy	Eliminations/Corporate	Consolidated Total
Energy revenue	$ 2,840	$ 726	$ 387	$ 25	$ 46	$ 4,024	$ 39	$ (1,209)	$ 2,854
Capacity revenue	25	396	235	113	71	840		(16)	824
Other revenue	111	47	10	4	186	358	2	(72)	288
Generation revenue	2,976	1,169	632	142	303	5,222	$ 41	$ (1,297)	$ 3,966
Generation cost of sales	(1,111)	(493)	(403)	(15)	(166)	(2,188)		$ 18	$ (2,170)
Generation gross margin	$ 1,865	$ 676	$ 229	$ 127	$ 137	$ 3,034	$ 41		
Business Metrics									
MWh sold (in thousands)	45,948	10,581	13,046	217			1,030		
MWh generated (in thousands)	43,722	9,355	11,168	217			1,030		

	Year Ended December 31,			
	Texas	Northeast	South Central	West
Weather Metrics				
2011				
CDDs [(a)]	3,440	750	1,817	717
HDDs [(a)]	1,911	5,770	3,387	3,364
2010				
CDDs	2,884	850	2,006	678
HDDs	2,161	5,720	3,929	2,753
30 year average				
CDDs	2,647	537	1,548	704
HDDs	1,997	6,257	3,601	3,218

(a) National Oceanic and Atmospheric Administration-Climate Prediction Center — A Cooling Degree Day, or CDD, represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. A Heating Degree Day, or 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.

Conventional Generation gross margin — decreased by $697 million, including intercompany sales, during the year ended December 31, 2011, compared to the same period in 2010, due to:

Decrease in Texas region	$ (434)
Decrease in Northeast region	(307)
Increase in South Central region	33
Increase in West region	10
Other	1
	$ (697)

The decrease in gross margin in the Texas region was driven by:

Lower energy revenue due to a 14% decrease in average realized energy prices, which reflects lower hedged prices in 2011	$ (315)
Losses incurred primarily due to hedging and trading optimization activities, and the impact of unplanned outages at gas plants as ERCOT power prices spiked in August 2011	(80)
Higher coal costs due to a 9% increase in realized coal prices offset by favorable financial fuel hedges	(40)
Favorable gross margin impact from a 2% increase in coal generation driven by higher economic dispatch and fewer planned outages, partially offset by greater unplanned outages	24
Unfavorable gross margin impact due to a 4% decrease in nuclear generation driven by an increase in unplanned outages	(18)
Other	(5)
	$ (434)

The decrease in gross margin in the Northeast region was driven by:

Lower gross margin from coal plants due to a 34% decrease in realized energy prices	$	(129)
Lower gross margin from coal plants resulting from a 30% decrease in generation, due to the region's power generation switching from coal to gas plants as gas prices decreased and due to the retirement of one unit at Indian River		(81)
Lower capacity revenue due to 10% lower volumes from higher forced outage rates and a 12% decrease in realized prices		(71)
Lower capacity revenue due to significantly lower LFRM prices and volumes in New England		(27)
Other		1
	$	(307)

The increase in gross margin in the South Central region was driven by:

Higher gross margin from merchant energy due to a 155% increase in MWh sold, primarily related to the addition of the Cottonwood facility	$	29
Lower merchant revenue related to a 7% decrease in average realized prices		(18)
Higher contract revenue from new contracts with three regional municipalities		29
Higher capacity revenue due primarily to higher cooperative billing peaks		8
Higher coal costs due to a 1% increase in generation at the region's coal plant which reflects fewer outage hours in 2011 and a 4% increase in price due to higher transportation costs		(16)
Other		1
	$	33

The increase in gross margin in the West region was driven by:

Higher capacity revenue due to additional sales at El Segundo and a price increase on the Cabrillo I tolling agreement	$	5
Increase in other revenue due to fuel oil sales at Encina and financial revenues		6
Other		(1)
	$	10

Retail gross margin

The Company's Retail business segment is comprised of Reliant Energy, Green Mountain Energy and Energy Plus. The following is a detailed discussion of retail gross margin for NRG's Retail business segment. Green Mountain Energy and Energy Plus were acquired on November 5, 2010 and September 30, 2011, respectively.

(In millions except otherwise noted)	Year ended December 31 2011	2010
Operating Revenues		
Mass revenues	$ 3,545	$ 3,127
Commercial and Industrial revenues	2,079	1,994
Supply management revenues	188	158
Retail operating revenues (a)(b)	5,812	5,279
Retail cost of sales (c)	4,558	4,066
Retail gross margin	$ 1,254	$ 1,213
Business Metrics		
Electricity sales volume — GWh		
Mass	28,035	22,924
Commercial and Industrial (a)	28,567	26,372
Electricity sales volume — GWh		
Texas	55,085	49,261
All other regions	1,517	35
Average retail customers count (in thousands, metered locations)		
Mass	2,031	1,815
Commercial and Industrial (a)	85	74
Retail customers count (in thousands, metered locations)		
Mass	2,063	1,788
Commercial and Industrial (a)	91	74
Weather Metrics		
CDDs (d)	3,845	3,305
HDDs (d)	1,570	1,812

(a) Includes customers of the Texas General Land Office, for whom the Company provides services.
(b) Includes intercompany sales of $5 million and $2 million, representing sales from Retail to the Texas region for the years ended December 31, 2011 and 2010, respectively.
(c) Includes intercompany purchases of $1,743 million and $1,244 million, respectively.
(d) The CDDs/HDDs amounts are representative of the Coast and North Central Zones within the ERCOT market in which Retail serves its customer base.

- *Retail gross margin* — Retail gross margin increased $41 million for the year ended December 31, 2011, compared to the same period in 2010, driven by:

Reliant Energy:	
Unfavorable gross margin impact of an unprecedented heat wave which resulted in high supply costs for incremental weather volume in August 2011, offset in part by the favorable impact of weather in the first six months of 2011	$ (50)
Favorable volume impact on gross margin of higher average customer usage, offset in part by fewer customers and a change in customer mix	25
Decrease in retail margins of 8% due to lower pricing on acquisitions and renewals consistent with competitive offers	(42)
Estimated favorable impact in 2010 as compared to 2011 from the termination of out-of-market supply contracts in conjunction with 2009 CSRA unwind	(68)
Acquisition of Green Mountain Energy on November 5, 2010	151
Acquisition of Energy Plus on September 30, 2011	25
	$ 41

- *Trends* — Customer counts increased by approximately 104,000 since December 31, 2010, excluding the approximately 188,000 customers acquired in the Energy Plus acquisition, indicating a stabilization of customer attrition at Reliant Energy and customer acquisition efforts at Green Mountain Energy. Higher than normal cooling and heating degree days in both periods resulted in higher customer usage for Reliant Energy of 13% in 2011 and 7% in 2010 when compared to ten-year normal weather.

Alternative Energy gross margin

NRG's Alternative Energy business segment, which is comprised mainly of the solar and wind businesses, had gross margin of $44 million for the year ended December 31, 2011, compared to gross margin of $41 million for the year ended December 31, 2010. The increase in gross margin primarily resulted from the addition of the Roadrunner facility, which began commercial operations in late 2011.

Mark-to-market for Economic Hedging Activities

Mark-to-market for economic hedging activities includes asset-backed hedges that have not been designated as cash flow hedges and ineffectiveness on cash flow hedges. Total net mark-to-market results increased by $244 million in the year ended December 31, 2011, compared to the same period in 2010.

The breakdown of gains and losses included in operating revenues and operating costs and expenses by region are as follows:

	Year Ended December 31, 2011						
	Retail	Texas	Northeast	South Central	West	Elimination [(a)]	Total
	(In millions)						
Mark-to-market results in operating revenues							
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (1)	$ (72)	$ 19	$ 26	$ (2)	$ (48)	$ (78)
Net unrealized gains/(losses) on open positions related to economic hedges	9	245	9	(38)	(2)	180	403
Total mark-to-market gains/(losses) in operating revenues	$ 8	$ 173	$ 28	$ (12)	$ (4)	$ 132	$ 325
Mark-to-market results in operating costs and expenses							
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$ 94	$ —	$ (6)	$ (4)	$ —	$ 48	$ 132
Reversal of loss positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	72	—	—	—	—	—	72
Reversal of loss positions acquired as part of the Green Mountain Energy acquisition as of November 5, 2010	35	—	—	—	—	—	35
Net unrealized losses on open positions related to economic hedges	(175)	(23)	(17)	(13)	—	(180)	(408)
Total mark-to-market gains/(losses) in operating costs and expenses	$ 26	$ (23)	$ (23)	$ (17)	$ —	$ (132)	$ (169)

(a) Represents the elimination of the intercompany activity between the Retail businesses and the Conventional Generation regions and Alternative Energy.

Mark-to-market results consist of unrealized gains and losses. The settlement of these transactions is reflected in the same caption as the items being hedged.

For the year ended December 31, 2011, the $403 million gain in operating revenue from economic hedge positions was primarily driven by an increase in value of forward purchases and sales of natural gas and electricity due to a decrease in forward power and gas prices. The $408 million loss in operating costs and expenses from economic hedge positions was primarily driven by a decrease in value of forward purchases of natural gas, electricity and fuel due to a decrease in forward power and gas prices. Reliant Energy's $72 million gain from the roll-off of acquired derivatives consists of loss positions that were acquired as of May 1, 2009, and valued using forward prices on that date. These roll-off amounts were offset by realized losses at the settled prices and higher costs of physical power which are reflected in operating costs and expenses during the same period. Green Mountain Energy's $35 million gain from the roll-off of acquired derivatives consists of loss positions that were acquired as of November 5, 2010, and valued using forward prices on that date. These roll-off amounts were offset by realized losses at the settled prices and higher costs of physical power which are reflected in operating costs and expenses during the same period.

In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the years ended December 31, 2011, and 2010. The realized and unrealized financial and physical trading results are included in operating revenues. The Company's trading activities are subject to limits within the Company's Risk Management Policy.

	Year Ended December 31, 2011	Year Ended December 31, 2010
	(In millions)	
Trading gains/(losses)		
Realized	$ (31)	$ (25)
Unrealized	63	64
Total trading gains	$ 32	$ 39

Contract Amortization Revenue

Contract amortization represents the roll-off of in-market customer contracts valued under purchase accounting and the favorable change of $36 million as compared to the prior period in 2010 related primarily to lower contract amortization of $74 million for Reliant Energy, offset by higher contract amortization of $29 million for Green Mountain Energy.

Contract and Emissions Credit Amortization

Contract and emissions credit amortization increased primarily due to lower amortization, which is an offset to expense, of out-of-the-money energy supply contracts that were valued as part of the purchase accounting for Reliant Energy.

Other Operating Costs

	Retail	Texas	Northeast	South Central	West	Other	Alternative Energy	Corporate/Eliminations	Total
					(In millions)				
Year ended December 31, 2011	$ 216	$ 477	$ 241	$ 104	$ 56	$ 71	$ 17	$ (26)	$ 1,156
Year ended December 31, 2010	$ 195	$ 484	$ 287	$ 93	$ 64	$ 68	$ 15	$ (29)	$ 1,177

Other operating costs decreased by $21 million for the year ended December 31, 2011, compared to the same period in 2010, due to:

	(In millions)
Decrease in Northeast region operations and maintenance expense	$ (50)
Increase in Retail operations and maintenance expense	22
Increase in South Central region operations and maintenance expense	6
Other	1
	$ (21)

- *Northeast operations and maintenance* — decreased due to a $19 million reduction in normal and major maintenance, primarily in Western New York, an $18 million decrease in operational labor from headcount reductions at plants in New England and New York, and prior year write-offs of $21 million of construction-in-progress, including those in connection with the early retirement of Indian River Unit 3, and additional write-offs at Arthur Kill, Keystone and Conemaugh. These were offset in part by the current year write-off of $12 million of Bluewater Wind assets.

- *Retail operations and maintenance* — increased as a result of the acquisition of Green Mountain Energy in November 2010, resulting in a full year of expense compared to two months in the prior year, as well as the acquisition of Energy Plus on September 30, 2011.

- *South Central operations and maintenance* — increased by $18 million due to increased operations and maintenance related to the addition of the Cottonwood Facility, offset in part by $12 million related to the scope and timing of outage work at Big Cajun II in 2010.

Depreciation and Amortization

NRG's depreciation and amortization expense increased by $58 million during the year ended December 31, 2011, compared to the same period in 2010. This was primarily due to additional depreciation related to a full year of depreciation for Cottonwood, Green Mountain Energy, and Northwind Phoenix which were acquired in 2010, as compared to a partial year of depreciation in 2010.

Impairment Charge on Emission Allowances

As described in Item 15 — Note 24, *Environmental Matters,* to the Consolidated Financial Statements, the Company recorded an impairment charge of $160 million in the year ended December 31, 2011, on the Company's Acid Rain Program SO_2 emission allowances, which were recorded as an intangible asset on the Company's balance sheet. The impairment charge reflects the write-off of the value of emission allowances in excess of those required for compliance with the Acid Rain Program.

Selling, General and Administrative Expenses

Selling, general and administrative expenses increased by $70 million during the year ended December 31, 2011, compared to the same period in 2010, which was primarily due to:

- The acquisition of Green Mountain Energy in November 2010, and the acquisition of Energy Plus in September 2011, which resulted in additional expense in 2011 of $74 million and $16 million, respectively.

- Increased marketing costs of $8 million associated with additional advertising campaigns and sponsorship arrangements.

These increases were offset by:

- A decrease in bad debt expense of $13 million at Reliant Energy due to improved customer payment behavior and decreased revenues.

- A decrease in employee benefits costs of $24 million.

- A reduction in charitable contributions, due to $8 million of funding for the Reliant Energy Charitable Foundation which was created and funded in 2010.

Development Costs

Development costs decreased $10 million during the year ended December 31, 2011, compared to the same period in 2010, as many of the NRG Solar projects are in construction phase in 2011.

Gain on Sale of Assets

On January 11, 2010, NRG sold Padoma to Enel, recognizing a gain on the sale of $23 million.

Equity in Earnings of Unconsolidated Affiliates

NRG's equity earnings from unconsolidated affiliates decreased by $9 million during the year ended December 31, 2011, compared to the same period in 2010. The decrease is due primarily to the changes in fair value of Sherbino's forward gas contract of $10 million and a decrease in equity earnings from Gladstone of $15 million, offset by an increase in equity earnings of $10 million from GenConn, as the Devon and Middletown peaking facilities commenced commercial operations in June 2010 and June 2011, respectively, and an increase of $2 million from Saguaro.

Impairment Charge on Investment

As discussed in more detail in Item 15— Note 4, *Nuclear Innovation North America LLC Developments, Including Impairment Charge* , to the Consolidated Financial Statements, the devastating March 2011 earthquake and tsunami in Japan, which in turn, triggered a nuclear incident at the Fukushima Daiichi Nuclear Power Station, caused NRG to evaluate its investment in NINA for impairment. Consequently, NRG deconsolidated its investment in NINA and recorded an impairment charge in the first quarter equal to the balance of its investment in NINA. In concurrence with a substantial reduction in NINA's project workforce, and to support NINA's reduced scope of work, NRG contributed an additional $14 million into NINA in the year ended December 31, 2011. As a result, NRG recorded an impairment charge of $495 million in the year ended December 31, 2011.

Other Income/(Expense), Net

NRG's other income, net decreased $14 million during the year ended December 31, 2011, compared to the same period in 2010, which relates primarily to foreign exchange gains of $14 million recognized in the prior period.

Loss on Debt Extinguishment

A loss on debt extinguishment of $175 million was recorded in the year ended December 31, 2011, which primarily consisted of the premiums paid on redemption and the write-off of previously deferred financing costs related to the redemptions of the 2014 Senior Notes and the 2016 Senior Notes, and the write-off of previously deferred financing costs related to the replacement of NRG's Senior Credit Facility with the 2011 Senior Credit Facility.

Interest Expense

NRG's interest expense increased by $35 million during the year ended December 31, 2011, compared to the same period in 2010 due to the following:

	(In millions)
Increase/(decrease) in interest expense	
Increase for 2020 Senior Notes issued in August 2010	$ 58
Increase for 2018 Senior Notes issued in January 2011	85
Increase for 2019 and 2021 Senior Notes issued in May 2011	94
Decrease for 2014 Senior Notes redeemed in January and February 2011	(65)
Decrease for 2016 Senior Notes redeemed in May and June 2011	(102)
Increase for project financings	15
Increase for tax-exempt bonds	12
Decrease for refinancing of term loan and revolving credit facility	(18)
Decrease for capitalized interest	(44)
Total	$ 35

Income Tax Expense

There was an income tax benefit of $843 million for the year ended December 31, 2011, compared to income tax expense of $277 million for the year ended December 31, 2010. The effective tax rate was 130.5% and 36.8% for the year ended December 31, 2011, and 2010, respectively.

	Year Ended December 31,	
	2011	**2010**
	(In millions except as otherwise stated)	
(Loss)/Income Before Income Taxes	$ (646)	$ 753
Tax at 35%	(226)	264
State taxes, net of federal benefit	15	18
Foreign operations	(3)	(3)
Federal and state tax credits	(1)	(7)
Valuation allowance	(63)	(34)
Expiration/utilization of capital losses	45	—
Reversal of valuation allowance on expired/utilized capital losses	(45)	—
Foreign earnings	4	17
Non-deductible interest	—	4
Interest accrued on uncertain tax positions	2	25
Production tax credits	(14)	(11)
Reversal of uncertain tax position reserves	(561)	—
Other	4	4
Income tax (benefit)/expense	$ (843)	$ 277
Effective income tax rate	130.5%	36.8%

The effective tax rate for the year ended December 31, 2011 differs from the statutory rate of 35% primarily due to a benefit of $633 million resulting from the resolution of the federal tax audit. The benefit is predominantly due to the recognition of previously uncertain tax benefits that were settled upon audit in 2011 and that were mainly composed of net operating losses of $536 million which had been classified as capital loss carryforwards for financial statement purposes.

The effective income tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and changes in valuation allowances in accordance with ASC 740, *Income Taxes,* or ASC 740. These factors and others, including the Company's history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Consolidated Results of Operations

2010 compared to 2009

The following table provides selected financial information for the Company:

(In millions except otherwise noted)	Year Ended December 31, 2010	Year Ended December 31, 2009	Change %
Operating Revenues			
Energy revenue [(a)]	$ 2,854	$ 3,726	(23)%
Capacity revenue [(a)]	824	1,023	(19)
Retail revenue	5,277	4,440	19
Mark-to-market for economic hedging activities	(199)	(107)	(86)
Contract amortization	(195)	(179)	(9)
Other revenues [(b)]	288	49	488
Total operating revenues	8,849	8,952	(1)
Operating Costs and Expenses			
Generation cost of sales [(a)]	2,170	1,911	14
Retail cost of sales [(a)]	2,822	3,121	(10)
Mark-to-market activities	(111)	(842)	(87)
Contract and emissions credit amortization [(c)]	15	(4)	475
Other cost of operations	1,177	1,137	4
Total cost of operations	6,073	5,323	14
Depreciation and amortization	838	818	2
Selling, general and administrative	598	550	9
Acquisition-related transaction and integration costs	—	54	(100)
Development costs	55	48	15
Total operating costs and expenses	7,564	6,793	11
Gain on sale of assets	23	—	N/A
Operating income	1,308	2,159	(39)
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	44	41	7
Gain on sale of equity method investments	—	128	(100)
Other income/(expense), net	33	(5)	N/A
Loss on debt extinguishment and refinancing expenses	(2)	(20)	(90)
Interest expense	(630)	(634)	(1)
Total other expense	(555)	(490)	13
Income before income tax expense	753	1,669	(55)
Income tax expense	277	728	(62)
Net Income	476	941	(49)
Less: Net loss attributable to noncontrolling interest	(1)	(1)	—
Net income attributable to NRG Energy, Inc.	$ 477	$ 942	(49)
Business Metrics			
Average natural gas price — Henry Hub ($/MMBtu)	4.39	3.92	12 %

(a) Includes realized gains and losses from financially settled transactions.

(b) Includes unrealized trading gains and losses.

(c) Includes amortization of SO_2 and NO_x credits and excludes amortization of Regional Greenhouse Gas Initiative, or RGGI, credits.

N/A - Not Applicable

Management's discussion of the results of operations for the years ended December 31, 2010 and 2009

Conventional Generation gross margin

The following is a discussion of gross margin for NRG's Conventional Generation businesses, adjusted to eliminate intersegment activity primarily with the Retail businesses.

	Year Ended December 31, 2010								
(In millions except otherwise noted)	Texas	Northeast	South Central	West	Other	Subtotal	Alternative Energy	Eliminations/Corporate	Consolidated Total
Energy revenue	$ 2,840	$ 726	$ 387	$ 25	$ 46	$ 4,024	$ 39	$ (1,209)	$ 2,854
Capacity revenue	25	396	235	113	71	840	—	(16)	824
Other revenue	111	47	10	4	186	358	2	(72)	288
Generation revenue	2,976	1,169	632	142	303	5,222	$ 41	$ (1,297)	$ 3,966
Generation cost of sales	(1,111)	(493)	(403)	(15)	(166)	(2,188)	—	$ 18	$ (2,170)
Generation gross margin	$ 1,865	$ 676	$ 229	$ 127	$ 137	$ 3,034	$ 41		
Business Metrics									
MWh sold (in thousands)	45,948	10,581	13,046	217			1,030		
MWh generated (in thousands)	43,722	9,355	11,168	217			1,030		

	Year Ended December 31, 2009								
(In millions except otherwise noted)	Texas	Northeast	South Central	West	Other	Subtotal	Alternative Energy	Eliminations/Corporate	Consolidated Total
Energy revenue	$ 2,762	$ 873	$ 367	$ 26	$ 52	$ 4,080	$ 8	$ (362)	$ 3,726
Capacity revenue	193	407	269	122	79	1,070	—	(47)	1,023
Other revenue	(57)	(9)	(60)	2	157	33	—	16	49
Generation revenue	2,898	1,271	576	150	288	5,183	$ 8	$ (393)	$ 4,798
Generation cost of sales	(909)	(408)	(387)	(29)	(177)	(1,910)	—	$ (1)	$ (1,911)
Generation gross margin	$ 1,989	$ 863	$ 189	$ 121	$ 111	$ 3,273	$ 8		
Business Metrics									
MWh sold (in thousands)	46,909	9,220	12,144	1,278			351		
MWh generated (in thousands)	44,643	9,220	10,398	1,278			351		

	Year Ended December 31,			
	Texas	Northeast	South Central	West
Weather Metrics				
2010				
CDDs	2,884	850	2,006	678
HDDs	2,161	5,720	3,929	2,753
2009				
CDDs	2,881	475	1,549	908
HDDs	1,890	6,286	3,521	3,105
30 year average				
CDDs	2,647	537	1,548	704
HDDs	1,997	6,262	3,604	3,228

Conventional Generation gross margin — decreased by $239 million, including intercompany sales, during the year ended December 31, 2010, compared to the same period in 2009, due to:

Decrease in Texas region	$ (124)
Decrease in Northeast region	(187)
Increase in South Central region	40
Increase in West region	6
Other [(a)]	26
	$ (239)

(a) The increase in other gross margin primarily represents revenues from the maintenance services business, which are eliminated in consolidation.

The decrease in gross margin in the Texas region was driven by:

Lower capacity revenue due to a lower proportion of baseload contracts which contain a capacity component	$ (168)
Increase in unrealized trading activities	119
Higher energy margin driven by 2% higher average realized energy prices which reflect higher hedged prices in 2010	56
Increased coal costs due primarily to increased transportation costs	(61)
Increase in costs of purchased energy for increased obligations when baseload plants are unavailable and additional purchases for bilateral and toll energy agreements	(61)
Unfavorable gross margin impact from a 1% reduction in coal generation driven by lower economic dispatch and more unplanned outages, partially offset by fewer planned outages	(16)
Other	7
	$ (124)

The decrease in gross margin in the Northeast region was driven by:

Lower gross margin from coal plants due to a 30% decrease in realized energy prices	$	(236)
Lower capacity revenue from the expiration of RMR contracts for Montville, Middletown, and Norwalk		(26)
Lower capacity revenue due to significantly lower LFRM prices and volumes in New England		(10)
Higher capacity revenue due to 17% higher prices in the NYISO and PJM markets driven in part by the retirement of the New York Power Authority's Poletti facility in January 2010, offset in part by slightly lower volumes and unfavorable hedges.		26
Lower margin on contract revenue due to a decrease in prices		(27)
Higher gross margin from oil and gas plants due to a 31% increase in realized energy prices		21
Increase in unrealized trading activities		58
Other		7
	$	(187)

The increase in gross margin in the South Central region was driven by:

Lower gross margin related to merchant energy due primarily to a decrease in average realized prices and lower volumes	$	(50)
Higher contract revenue due primarily to the region's cooperative customers from fuel cost pass-through and a new contract with a regional municipality		70
Lower capacity revenue due the expiration of a capacity agreement with a regional utility		(34)
Increase in unrealized trading activities		68
Higher natural gas costs due primarily to the addition of the Cottonwood facility to the region in 2010		(9)
Other		(5)
	$	40

The increase in gross margin in the West region was driven by:

Higher merchant gross margin from an increase in realized energy prices, offset in part by a decrease in generation	$	13
Lower capacity revenue due to reduced resource adequacy and call option contract sales at El Segundo in 2010 as compared to 2009		(9)
Other		2
	$	6

Retail Gross Margin

The following is a detailed discussion of retail gross margin for NRG's Retail business segment.

Selected Income Statement Data

(In millions except otherwise noted)	Year ended December 31, 2010 [c]	Four months ended April 30, 2010	Eight months ended December 31, 2010 [c]	Eight months ended December 31, 2009
Operating Revenues				
Mass revenues	$ 3,127	$ 903	$ 2,224	$ 2,597
Commercial and Industrial revenues	1,994	640	1,354	1,592
Supply management revenues	158	56	102	251
Retail operating revenues [(a)]	5,279	1,599	3,680	4,440
Retail cost of sales [(b)]	4,066	1,232	2,834	3,531
Retail gross margin	$ 1,213	$ 367	$ 846	$ 909

(c) The year ended December 31, 2010 and eight months ended December 31, 2010 include $69 million of revenue and $46 million of cost of sales for Green Mountain Energy, which was acquired on November 5, 2010.

Business Metrics				
Electricity sales volume — GWh				
Mass	22,924	6,089	16,835	17,152
Commercial and Industrial [(a)]	26,372	8,268	18,104	20,915
Average retail customers count (in thousands, metered locations)				
Mass	1,815	1,519	1,800	1,566
Commercial and Industrial [(a)]	74	64	73	68
Retail customers count (in thousands, metered locations)				
Mass	1,788	1,513	1,788	1,531
Commercial and Industrial [(a)]	74	64	74	66
Weather Metrics				
CDDs [(c)]	3,305	166	3,139	2,972
HDDs [(c)]	1,812	1,267	545	699

(a) Includes customers of the Texas General Land Office, for whom the Company provides services.

(b) Includes intercompany purchases from the Texas region of $1,244 million, $293 million, $951 million and $409 million, respectively.

(c) The CDDs/HDDs amounts are representative of the Coast and North Central Zones within the ERCOT market in which Retail serves its customer base.

- *Retail gross margin* — excluding gross margin of $367 million for the first four months of 2010, Retail gross margin decreased $63 million for the year ended December 31, 2010, compared to the same period in 2009, driven by:

Reliant Energy:	
Decrease in retail margins of 12% due to lower lower pricing on acquisitions and renewals and price reductions for certain customer segments.	$ (138)
Estimated favorable impact in 2010 as compared to 2009 from the termination of out-of-market supply contracts in conjunction with the termination of the Reliant credit sleeve	129
Unfavorable volume impact on gross margin from fewer customers in 2010 as well as a change in customer mix	(60)
Unfavorable gross margin impact due to a 36% decrease in the margin rate on the incremental weather volumes partially offset by higher volumes in 2010 primarily due to warmer weather in the second and third quarters	(17)
Acquisition of Green Mountain Energy in November 2010	23
	$ (63)

Alternative Energy gross margin

NRG's Alternative Energy business segment, which is comprised mainly of the solar and wind businesses, had gross margin of $41 million for the year ended December 31, 2010, compared to gross margin of $8 million for the year ended December 31, 2009. The increase in gross margin primarily resulted from an increase in owned wind farm generation as the Langford wind facilities began commercial operations in December 2009 and South Trent was acquired in June 2010. In addition, the Blythe solar facility reached commercial operations in late 2009.

Mark-to-market for Economic Hedging Activities

Mark-to-market for economic hedging activities includes asset-backed hedges that have not been designated as cash flow hedges and ineffectiveness on cash flow hedges. Total net mark-to-market results decreased by $823 million in years ended December 31, 2010, compared to the same period in 2009.

The breakdown of gains and losses included in operating revenues and operating costs and expenses by region are as follows:

	Year Ended December 31, 2010							
	Retail	Texas	Northeast	South Central	West	Other	Elimination[(a)]	Total
	(In millions)							
Mark-to-market results in operating revenues								
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (1)	$ (68)	$ (108)	$ 2	$ —	$ (2)	$ 11	$ (166)
Net unrealized gains/(losses) on open positions related to economic hedges	—	125	(36)	(47)	(4)	—	(71)	$ (33)
Total mark-to-market (losses)/gains in operating revenues	$ (1)	$ 57	$ (144)	$ (45)	$ (4)	$ (2)	$ (60)	$ (199)
Mark-to-market results in operating costs and expenses								
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (60)	$ 36	$ 13	$ 17	$ —	$ —	$ (11)	$ (5)
Reversal of loss positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	223	—	—	—	—	—	—	$ 223
Reversal of loss positions acquired as part of the Green Mountain Energy acquisition as of November 5, 2010	13	—	—	—	—	—	—	$ 13
Net unrealized (losses)/gains on open positions related to economic hedges	(198)	(2)	5	4	—	—	71	(120)
Total mark-to-market (losses)/gains in operating costs and expenses	$ (22)	$ 34	$ 18	$ 21	$ —	$ —	$ 60	$ 111

(a) Represents the elimination of the intercompany activity between the Retail businesses and the Conventional Generation regions.

Mark-to-market results consist of unrealized gains and losses. The settlement of these transactions is reflected in the same caption as the items being hedged.

For the year ended December 31, 2010, the $33 million loss in operating revenue from economic hedge positions is primarily driven by a decrease in value of forward purchases and sales of natural gas and electricity due to a decrease in forward power and gas prices. The $120 million loss in operating costs and expenses from economic hedge positions is primarily driven by a decrease in value of forward purchases of natural gas, electricity and fuel due to a decrease in forward power and gas prices. Reliant Energy's $223 million gain from the roll-off of acquired derivatives consists of loss positions that were acquired as of May 1, 2009, and valued using forward prices on that date. These roll-off amounts were offset by realized losses at the settled prices and higher costs of physical power which are reflected in operating costs and expenses during the same period. Green Mountain Energy's $13 million gain from the roll-off of acquired derivatives consists of loss positions that were acquired as of November 5, 2010, and valued using forward prices on that date. These roll-off amounts were offset by realized losses at the settled prices and higher costs of physical power which are reflected in operating costs and expenses during the same period.

In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the years ended December 31, 2010, and 2009. The realized and unrealized financial and physical trading results are included in operating revenues. The Company's trading activities are subject to limits within the Company's Risk Management Policy.

	Year Ended December 31,	
	2010	2009
	(In millions)	
Trading gains/(losses)		
Realized	$ (25)	$ 216
Unrealized	64	(183)
Total trading gains	$ 39	$ 33

Contract Amortization Revenue

Contract amortization represents the roll-off of in-market customer contracts valued under purchase accounting and the increase of $16 million as compared to the prior period in 2010 related primarily to lower contract amortization of $50 million for Texas offset in part by higher contract amortization for Reliant Energy.

Contract and Emissions Credit Amortization

Contract and emissions credit amortization increased primarily due to lower amortization, which is an offset to expense, in the current year for energy supply contracts that were valued as part of the purchase accounting for Reliant Energy.

Other Operating Costs

	Retail	Texas	Northeast	South Central	West	Other	Alternative Energy	Corporate/Eliminations	Total
	(In millions)								
Year ended December 31, 2010	$ 195	$ 484	$ 287	$ 93	$ 64	$ 68	$ 15	$ (29)	$ 1,177
Year ended December 31, 2009	$ 153	$ 509	$ 306	$ 80	$ 63	$ 30	$ 6	$ (10)	$ 1,137

Other operating costs increased $40 million during the year ended December 31, 2010, compared to the same period in 2009, due to:

	(In millions)
Increase due to Reliant Energy for an additional four months of costs in 2010 as compared to 2009	$ 49
Decrease in property and other tax expense	(22)
Increase in South Central operations and maintenance expense	12
Increase in Thermal operations and maintenance expense	6
Decrease in Retail operations and maintenance expense	(9)
Other	4
	$ 40

- *Property and other taxes* — decreased by $8 million due to a charge in June 2009 to reflect changes in Empire Zone regulations that eliminated the Oswego plant's ability to continue participation in the Empire Zone program and decreased $10 million due to a decrease in gross receipts tax as a result of the decrease in retail revenues.

- *South Central operations and maintenance expense* — increased by $12 million as the scope and duration of planned maintenance work at the region's coal facility was greater in 2010 than in the same period in 2009.

- *Thermal operations and maintenance expense* — increase by $6 million relating to the acquisition of Northwind Phoenix in 2010.

- *Retail operations and maintenance expense* — decreased at Reliant Energy by $11 million due to lower spending for external costs associated with customer activities including the call center, billing, remittance processing, and credit and collections as well as information technology costs associated with those activities, offset in part by an additional $2 million related to the acquisition of Green Mountain Energy.

Depreciation and Amortization

NRG's depreciation and amortization expense increased by $20 million during the year ended December 31, 2010, compared to the same period in 2009. An increase of $26 million was due to depreciation on the baghouse projects in Western New York and additional depreciation at the Cedar Bayou plant, the Langford wind facilities and the Blythe solar facility. Cedar Bayou began commercial operation in June 2009 and the Langford wind facilities began commercial operation in December 2009. An additional increase of $9 million was due to amortization expense at Green Mountain Energy after the date of acquisition.

This increase was offset by a $20 million decrease in depreciation and amortization for Reliant Energy compared to the same period in 2009. Reliant Energy's depreciation and amortization expense decreased $59 million during the eight months ended December 31, 2010 as compared to the same period in 2009, which relates primarily to the amortization expense related to Mass customer relationships valued under purchase accounting which is recognized as the underlying contracts roll off. This decrease at Reliant Energy was offset by $39 million of additional depreciation and amortization expense for the first four months of 2010.

Selling, General and Administrative Expenses

Selling, general and administrative expenses increased by $48 million during the year ended December 31, 2010, compared to the same period in 2009. Excluding $68 million of additional expense for Reliant Energy in the first four months of 2010, selling, general and administrative expenses decreased by $20 million, due to:

- A decrease in bad debt expense of $20 million due to decreased revenues and improved customer payment behavior.
- Prior year non-recurring costs related to Exelon's exchange offer and proxy contest efforts of $31 million.

These decreases were offset by:

- Green Mountain Energy's costs of $10 million incurred since the acquisition date.
- The contribution of $8 million in funding for the Reliant Energy Charitable Foundation which was created in 2010.
- An increase in $8 million in professional services for various on-going projects in 2010.

Reliant Energy Acquisition-Related Transaction and Integration Costs

NRG incurred Reliant Energy acquisition-related transaction and integration costs of $54 million for 2009. These integration efforts were completed by the end of 2009.

Development Costs

Development costs increased $7 million during the year ended December 31, 2010, compared to the same period in 2009 due to increased costs incurred primarily on NRG Solar development projects.

Gain on Sale of Assets

On January 11, 2010, NRG sold Padoma to Enel, recognizing a gain on sale of $23 million.

Equity in Earnings of Unconsolidated Affiliates

NRG's equity earnings from unconsolidated affiliates increased by $3 million during the year ended December 31, 2010, compared to the same period in 2009. The 2010 results included increased equity earnings of $15 million from Sherbino, which related to the fair value of a hedge, and $7 million from Gladstone. In 2009, NRG recognized equity earnings of $15 million from MIBRAG, which was sold in June 2009.

Gain on Sale of Equity Method Investments and Other Income/(Loss), Net

NRG's gain on sale of equity method investments in 2009 represents a $128 million gain on the sale of NRG's 50% ownership interest in MIBRAG.

Other Income/(Expense), Net

NRG's other income, net increased $38 million during the year ended December 31, 2010, compared to the same period in 2009 principally due to foreign exchange transactions. The 2010 amount included $5 million and $9 million of unrealized and realized foreign exchange gains, respectively. The 2009 amount included a $24 million loss on a forward contract for foreign currency executed to hedge the sale proceeds from the MIBRAG sale in 2009.

Refinancing Expenses

In 2009, NRG incurred a $20 million expense associated with the CSRA unwind with Merrill Lynch.

Interest Expense

NRG's interest expense decreased by $4 million during the year ended December 31, 2010, compared to the same period in 2009 due to the following:

	(In millions)
(Decrease)/increase in interest expense	
Increase for 2020 Senior Notes issued in August 2010	$ 33
Increase for 2019 Senior Notes issued in June 2009	25
Decrease due to settlement of the CSF Debt in 2009 and early 2010	(26)
Decrease in fees incurred on the CSRA facility	(27)
Decrease in capitalized interest	2
Decrease due to Term Loan balance reduction in 2010	(9)
Other	(2)
Total	$ (4)

Income Tax Expense

Income tax expense decreased by $451 million for the year ended December 31, 2010, compared to 2009. The effective tax rate was 36.8% and 43.6% for the year ended December 31, 2010, and 2009, respectively.

	Year Ended December 31, 2010	Year Ended December 31, 2009
	(In millions except as otherwise stated)	
Income before income taxes	$ 753	$ 1,669
Tax at 35%	264	584
State taxes, net of federal benefit	18	23
Foreign operations	(3)	(53)
State investment tax credits	(7)	—
Valuation allowance	(34)	119
Expiration of capital losses	—	249
Reversal of valuation allowance on expired capital losses	—	(249)
Change in state effective tax rate	—	(5)
Foreign earnings	17	33
Non-deductible interest	4	10
Interest on uncertain tax positions	25	9
Production tax credits	(11)	(10)
Other	4	18
Income tax expense	$ 277	$ 728
Effective income tax rate	36.8%	43.6%

The Company's effective tax rate differs from the U.S. statutory rate of 35% due to:

- *Valuation Allowance* — The Company generated capital gains in 2010 primarily due to the derivative contracts that are treated as capital items for tax purposes. The valuation allowance is recorded primarily against capital loss carryforwards, this resulted in an decrease of $34 million in income tax expense in 2010.

- *Tax Expense Reduction* — The Company recorded a lower federal and state tax expense of $325 million primarily due to lower pre-tax earnings.

- *Foreign Operations* — In 2010, the Company repatriated foreign dividends to the U.S. resulting in an increase in tax expense of $17 million.

The effective income tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and changes in valuation allowances in accordance with ASC 740, *Income Taxes,* or ASC 740. These factors and others, including the Company's history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Liquidity and Capital Resources

Liquidity Position

As of December 31, 2011, and 2010, NRG's liquidity, excluding collateral received, was approximately $2.1 billion and $4.3 billion, respectively, comprised of the following:

	As of December 31,			
	2011		2010	
	(In millions)			
Cash and cash equivalents	$	1,105	$	2,951
Funds deposited by counterparties		258		408
Restricted cash		292		8
Total		1,655		3,367
2011 Revolving Credit Facility availability		673		—
Funded Letter of Credit Facility availability		—		440
Revolving Credit Facility availability		—		853
Total liquidity		2,328		4,660
Less: Funds deposited as collateral by hedge counterparties		(258)		(408)
Total liquidity, excluding collateral received	$	2,070	$	4,252

For the year ended December 31, 2011, total liquidity, excluding collateral received, decreased by $2.2 billion due primarily to $1.8 billion lower cash and cash equivalent balances. Changes in cash and cash equivalent balances are further discussed hereinafter under the heading *Cash Flow Discussion*. Cash and cash equivalents and funds deposited by counterparties at December 31, 2011, were predominantly held in money market funds invested in treasury securities, treasury repurchase agreements or government agency debt.

Included in restricted cash is $216 million of cash and cash equivalents held in controlled accounts as collateral to support the Company's equity funding obligations for the Ivanpah, Agua Caliente, and CVSR projects. As discussed more fully in Item 15 — Note 3, *Business Acquisitions and Disposition*, to the Consolidated Financial Statements, this is a requirement of the U.S. DOE, which guarantees the Agua Caliente, Ivanpah, and CVSR debt. This collateral can be replaced, at the Company's discretion, with a letter of credit in order to utilize such amounts for other purposes. The Company's total liquidity excluding such amounts is $1.9 billion.

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.

As discussed more fully in Item 15— Note 12, *Debt and Capital Leases,* to the Consolidated Financial Statements, to this Form 10-K, on July 1, 2011, NRG replaced its Senior Credit Facility, consisting of its Term Loan Facility, Revolving Credit Facility and Funded Letter of Credit Facility, with the 2011 Senior Credit Facility, which includes the 2011 Revolving Credit Facility.

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 stockholders, and other liquidity commitments. Management continues to regularly monitor the Company's ability to finance the needs of its operating, financing and investing activity within the dictates of prudent balance sheet management.

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 2011 Term Loan Facility and its Senior Notes as of December 31, 2011:

	S&P	Moody's	Fitch
NRG Energy, Inc.	BB-	Ba3	B+
7.875% Senior Notes, due 2021	BB-	B1	BB
8.25% Senior Notes, due 2020	BB-	B1	BB
7.625% Senior Notes, due 2019	BB-	B1	BB
8.5% Senior Notes, due 2019	BB-	B1	BB
7.625% Senior Notes, due 2018	BB-	B1	BB
7.375% Senior Notes, due 2017	BB-	B1	BB
Term Loan Facility, due 2018	BB+	Baa3	BB+

Sources of Liquidity

The principal sources of liquidity for NRG's future operating and capital expenditures are expected to be derived from new and existing financing arrangements, existing cash on hand and cash flows from operations. As described in Item 15 — Note 12, *Debt and Capital Leases,* to the Consolidated Financial Statements, the Company's financing arrangements consist mainly of the 2011 Senior Credit Facility, the Senior Notes, and project-related financings.

In addition, NRG has granted first liens to certain counterparties on substantially all of the Company's assets. NRG uses the first 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 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 lien structure is not subject to unwind or termination upon a ratings downgrade of a counterparty and has no stated maturity date.

The Company's lien counterparties may have a claim on its assets to the extent market prices exceed the hedged prices. As of December 31, 2011, all hedges under the first liens 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 baseload capacity under the first lien structure as of December 31, 2011:

Equivalent Net Sales Secured by First Lien Structure (a)	2012	2013	2014	2015
In MW (b)	1,268	464	127	—
As a percentage of total net baseload capacity (c)	19%	7%	2%	—%

(a) Equivalent Net Sales include natural gas swaps converted using a weighted average heat rate by region.
(b) 2012 MW value consists of February through December positions only.
(c) Net baseload capacity under the first lien structure represents 80% of the Company's total baseload assets.

Uses of Liquidity

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, as described more fully in Item 15 — Note 12, *Debt and Capital Leases*, to the Consolidated Financial Statements; (iii) capital expenditures, including repowering and renewable development, and environmental; and (iv) corporate financial transactions including return of capital to stockholders, as described in Item 15 — Note 15, *Capital Structure*, to the Consolidated Financial Statements.

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) margin and collateral required to participate in physical markets and commodity exchanges; (iii) timing of disbursements and receipts (i.e. buying fuel before receiving energy revenues); (iv) initial collateral for large structured transactions; and (v) collateral for project development. As of December 31, 2011, commercial operations had total cash collateral outstanding of $311 million, and $715 million outstanding in letters of credit to third parties primarily to support its commercial activities for both wholesale and retail transactions (includes a $51 million letter of credit relating to deposits at the PUCT that cover outstanding customer deposits and residential advance payments). As of December 31, 2011, total collateral held from counterparties was $258 million in cash, and $12 million of letters of credit.

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

Principal payments on debt and capital leases as of December 31, 2011, are due in the following periods:

Description	2012	2013	2014	2015	2016	Thereafter	Total
				(In millions)			
NRG Recourse Debt:							
7.875% Notes due 2021	$ —	$ —	$ —	$ —	$ —	$ 1,200	$ 1,200
8.25% Notes due 2020	—	—	—	—	—	1,100	1,100
7.625% Notes due 2019	—	—	—	—	—	800	800
8.5% Notes due 2019	—	—	—	—	—	700	700
7.625% Notes due 2018	—	—	—	—	—	1,200	1,200
7.375% Notes due 2017	—	—	—	—	—	1,090	1,090
Term Loan Facility, due 2018	16	16	16	16	16	1,512	1,592
Indian River Power LLC, tax-exempt bonds, due 2040 and 2045	—	—	—	—	—	205	205
Dunkirk Power LLC, tax-exempt bonds, due 2042	—	—	—	—	—	59	59
Subtotal NRG Recourse Debt	16	16	16	16	16	7,866	7,946
NRG Non-Recourse Debt:							
Ivanpah Financing:							
Solar Partners I, due 2014 and 2033	—	—	154	5	6	125	290
Solar Partners II, due 2014 and 2038	—	—	128	5	6	175	314
Solar Partners VIII, due 2014 and 2038	—	—	111	4	4	151	270
NRG Peaker Finance Co. LLC, bonds, due 2019	22	23	29	31	33	72	210
Agua Caliente Solar, LLC	—	—	5	5	6	165	181
NRG West Holdings LLC, term loan, due 2023	—	—	32	37	41	49	159
NRG Energy Center Minneapolis LLC, senior secured notes, due 2013, 2017 and 2025	13	10	7	12	12	96	150
South Trent Wind LLC, due 2020	3	3	4	4	4	57	75
Solar Power Partners Financing	10	9	5	4	3	38	69
NRG Roadrunner LLC, due 2031	14	2	2	2	3	38	61
NRG Solar Blythe LLC, due 2028	2	2	1	2	1	19	27
Other	5	4	—	—	—	—	9
Subtotal NRG Non-Recourse Debt	69	53	478	111	119	985	1,815
Capital Lease:							
Saale Energie GmbH, Schkopau	8	7	6	6	4	72	103
Total Debt and Capital Leases	$ 93	$ 76	$ 500	$ 133	$ 139	$ 8,923	$ 9,864

In addition to the debt and capital leases shown in the preceding table, NRG had issued $1.627 billion of letters of credit under the Company's $2.3 billion 2011 Revolving Credit Facility as of December 31, 2011.

Capital Expenditures

The following tables and descriptions summarize the Company's capital expenditures, including accruals, for maintenance, environmental, and repowering and renewable development, other than cash paid for nuclear development, for the year ended December 31, 2011, and the estimated capital expenditure and repowering and renewable investments forecast for 2012.

	Maintenance	Environmental	Repowering and Renewables	Total
		(In millions)		
Northeast	$ 21	$ 167	$ —	$ 188
Texas	99	—	—	99
South Central	23	2	—	25
West	18	—	252	270
Other Conventional	8	—	32	40
Alternative Energy	—	—	1,820	1,820
Retail	23	—	—	23
Corporate	17	—	24	41
Total capital expenditures for the year ended December 31, 2011	209	169	2,128	2,506
Accrual impact	(9)	20	(227)	(216)
Total cash capital expenditures for the year ended December 31, 2011	200	189	1,901	2,290
Other investments [(a)]	—	—	621	621
Funding from debt financing, net of fees	—	(138)	(1,215)	(1,353)
Funding from third party equity partners	—	—	(29)	(29)
Total capital expenditures and investments, net	$ 200	$ 51	$ 1,278	$ 1,529
Estimated capital expenditures for 2012	$ 259	$ 54	$ 3,200	$ 3,513
Other investments [(b)]	—	—	(172)	(172)
Funding from debt financing, net of fees	—	(61)	(2,452)	(2,513)
Funding from third party equity partners	—	—	(192)	(192)
NRG estimated capital expenditures for 2012, net of financings	$ 259	$ (7)	$ 384	$ 636

(a) 2011 Other investments includes initial investments in the Agua Caliente, Ivanpah and Distributed Solar projects; solar project reserves that are placed in restricted cash on the balance sheet; and other project costs.

(b) 2012 Other investments represents the use of project reserves previously placed in restricted cash on the balance sheet and other project costs.

- *Repowering and Renewable capital expenditures* — For the year ended December 31, 2011, the Company's repowering and renewable capital expenditures included $1.8 billion for solar projects and $252 million for the Company's El Segundo project. In 2012, NRG will be continuing its efforts on the solar and El Segundo projects.

- *Maintenance and Environmental capital expenditures* — For the year ended December 31, 2011, the Company's maintenance capital expenditures includes $51 million in nuclear fuel expenditures related to STP Units 1 and 2. The environmental capital expenditures includes $155 million related to a project to install selective catalytic reduction systems, scrubbers and fabric filters on Indian River Unit 4. The system was operational at year-end 2011 and is undergoing performance testing.

Environmental Capital Expenditures Estimate

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures from 2012 through 2016 to meet NRG's environmental commitments will be approximately $553 million. These costs are primarily associated with mercury controls to satisfy MATS on the Company's Big Cajun II, W.A. Parish and Limestone facilities and a number of intake modification projects across the fleet under state or proposed federal 316(b) rules. NRG continues to explore cost effective compliance alternatives to reduce costs. While this estimate reflects anticipated schedules and controls related to the proposed 316(b) Rule, the full impact on the scope and timing of environmental retrofits from any new or revised regulations cannot be determined until these rules are final and any legal challenges are reviewed. However, NRG believes it is positioned to meet more stringent requirements through its planned capital expenditures, existing controls, and increasing generation from renewable resources.

The table below summarizes installed and planned air quality controls for the NRG coal fleet. Planned investments are either in construction or budgeted in the existing capital expenditures budget. Changes to regulations could result in changes to planned installation dates. NRG uses an integrated approach to fuels, controls and emissions markets to meet environmental standards.

	SO_2		NO_x		Mercury		Particulate	
Units	Control Equipment	Install Date	Control Equipment	Install Date	Control Equipment	Install Date	Control Equipment	Install Date
Huntley 67	DSI/FF	2009	SNCR	2009	ACI	2009	FF	2009
Huntley 68	DSI/FF	2009	SNCR	2009	ACI	2009	FF	2009
Dunkirk 1	DSI/FF	2010	SNCR	2010	ACI	2010	FF	2010
Dunkirk 2	DSI/FF	2010	SNCR	2010	ACI	2010	FF	2010
Dunkirk 3	DSI/FF	2009	SNCR	2009	ACI	2009	FF	2009
Dunkirk 4	DSI/FF	2009	SNCR	2009	ACI	2009	FF	2009
Indian River 3			SNCR	2000	ACI	2008	ESP	1980
Indian River 4	Circulating Dry Scrubber	2011	SCR	2011	ACI	2008	ESP/FF	1980 / 2011
Big Cajun II 1	FF co-benefit	2015	LNBOFA	2005	ACI	2015	ESP/FF	1981 / 2015
Big Cajun II 2			LNBOFA	2004	ACI	2015	ESP	1981
Big Cajun II 3	FF co-benefit	2015	LNBOFA	2002	ACI	2015	ESP/FF	1983 / 2015
Limestone 1 & 2	Wet Scrubbers	1985-86	LNBOFA/ SNCR	2002 / 2014	ACI	2014	ESP	1985-86
WA Parish 5, 6, 7	FF co-benefit	1988	SCR	2004	ACI	2014	FF	1988
WA Parish 8	Wet Scrubber	1982	SCR	2004	ACI	2014	FF	1988

ACI — Activated Carbon Injection
DSI — Dry Sorbent Injection with Trona
ESP — Electrostatic Precipitator
FF— Fabric Filter
LNBOFA — Low NO_x Burner with Overfire Air
SCR — Selective Catalytic Reduction
SNCR — Selective Non-Catalytic Reduction

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

	Texas	Northeast	South Central	Total
	(in millions)			
2012	$ 4	$ 45	$ 8	$ 57
2013	35	16	93	144
2014	48	20	172	240
2015	9	3	92	104
2016	7	1	—	8
Total	$ 103	$ 85	$ 365	$ 553

NRG's current contracts with the Company's rural electrical customers in the South Central region allow for recovery of a portion of the regions' capital costs once in operation, along with a capital return incurred by complying with any change in law, including interest over the asset life of the required expenditures. The actual recoveries will depend, among other things, on the timing of the completion of the capital projects and the remaining duration of the contracts.

2011 Capital Allocation Program

On February 22, 2011, the Company announced its 2011 Capital Allocation Plan to purchase $180 million in common stock. On August 4, 2011, the Company announced additional share repurchases of $250 million under the Capital Allocation Plan, bringing the total targeted share repurchases for 2011 to $430 million. During 2011, the Company repurchased 14,875,798 shares of NRG common stock for $320 million under two separate Accelerated Share Repurchase, or ASR, Agreements, and purchased an additional 5,099,856 shares for $110 million in open market purchases. The Company's share repurchases are subject to market prices, financial restrictions under the Company's debt facilities and securities laws.

As part of the 2011 program, the Company invested approximately $389 million in maintenance and environmental capital expenditures in existing assets, and approximately $2.5 billion in solar and other projects under development. In 2011, the Company obtained U.S. DOE loan guarantees for its Ivanpah, Agua Caliente, and CVSR solar projects in the amounts of $1.6 billion, $967 million, and $1.2 billion, respectively.

Finally, in addition to scheduled debt amortization payments, in the first quarter 2011 the Company paid its first lien lenders $149 million of its 2010 excess cash flow, as defined in the Senior Credit Facility.

2012 Capital Allocation Program

On February 28, 2012, the Company announced its intention to initiate an annual common stock dividend of $0.36 per share, with the first quarterly payment expected to be paid in the third quarter of 2012. Furthermore, the Company still intends to refinance its remaining $1.1 billion of 2017 Senior Notes to simplify its capital structure and better align covenant packages, but any refinancing will depend on market conditions and is therefore subject to change. Upon completion of this undertaking, a more flexible covenant package across credit facilities and debt securities will enable NRG to invest more opportunistically in growth initiatives and enhance its ability to efficiently return capital to all stockholders.

Preferred Stock Dividend Payments

For the year ended December 31, 2011, NRG paid $9 million in dividend payments to holders of the Company's 3.625% Preferred Stock.

Cash Flow Discussion

The following table reflects the changes in cash flows for the comparative years:

(In millions)

Year ended December 31,	**2011**	**2010**	**Change**
Net cash provided by operating activities	$ 1,166	$ 1,623	$ (457)
Net cash used by investing activities	(3,047)	(1,623)	(1,424)
Net cash provided by financing activities	33	651	(618)

Net Cash Provided By Operating Activities

Changes to net cash provided by operating activities were driven by:

Decrease in operating income adjusted for non-cash charges	$ (454)
Other changes in working capital	(3)
	$ (457)

Net Cash Used By Investing Activities

Changes to net cash used by investing activities were driven by:

Increase in capital expenditures due to increased spending on maintenance, repowering and renewable development，primarily for solar projects in construction	$	(1,604)
Increase in restricted cash, which was mainly to support equity requirements for U.S. DOE funded projects		(246)
Lower cash spent for acquisitions, which primarily reflects three Solar acquisitions and Energy Plus in 2011, compared to Green Mountain, South Trent, Northwind Phoenix and Cottonwood in 2010		629
Decrease in purchases and sales of emissions allowances		15
Decrease in cash for sale of assets, which primarily reflects sale of land in 2011, compared to the sale of Padoma in 2010		(36)
Receipt of cash grants in 2010		(102)
Investments in unconsolidated affiliates, primarily related to investments in a clean technology joint venture and Petra Nova		(43)
Other		(37)
	$	(1,424)

Net Cash Provided By Financing Activities

Changes in net cash provided by financing activities were driven by:

Increase in cash paid to repurchase shares of NRG common stock	$	(250)
Increase in net cash paid/received for the settlement of acquired derivatives with financing elements		(220)
Increase in cash paid for debt issuance and hedging costs		(132)
Net increase in cash received for proceeds for issuance of long-term debt		4,740
Net increase in the payments of debt, primarily related to payment of secured Senior Notes		(4,735)
Decrease in cash contributions from noncontrolling interest		(21)
	$	(618)

NOLs, Deferred Tax Assets and Uncertain Tax Position Implications, under ASC 740

As of December 31, 2011, the Company had a total domestic pre-tax book loss of $680 million and foreign pre-tax book income of $34 million. For the year ended December 31, 2011, the Company generated a net operating loss, or NOL, of $30 million which is available to offset taxable income in future periods. As of December 31, 2011, the Company has cumulative domestic NOL carryforwards of $233 million for financial statement purposes. In addition, NRG has cumulative foreign NOL carryforwards of $255 million, of which $77 million will expire starting 2012 through 2019 and of which $178 million do not have an expiration date.

In addition to these amounts, the Company has $178 million of tax effected uncertain tax benefits. As a result of the Company's tax position, and based on current forecasts, NRG anticipates income tax payments, primarily due to foreign, state and local jurisdictions, of up to $50 million in 2012.

However, as the position remains uncertain for the $178 million of tax effected uncertain tax benefits, the Company has recorded a non-current tax liability of $58 million and may accrue the remaining balance as an increase to non-current liabilities until final resolution with the related taxing authority. The $58 million non-current tax liability for uncertain tax benefits is primarily from positions taken on various state returns, including accrued interest.

During 2011, the Company settled the Internal Revenue Service's audit examination for the years 2004 through 2006 and recognized a benefit of $633 million. The benefit is predominantly due to the recognition of previously uncertain tax benefits mainly composed of net operating losses of $536 million which had been classified as capital loss carryforwards for financial statement purposes.

The Company continues to be under examination for various state jurisdictions for multiple years.

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 15 — 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, 2011, based on the Company's stock price, the embedded derivative was out-of-the-money and had no redemption value. See also Item 15 — 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, 2011, 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. Several of these investments are variable interest entities for which NRG is not the primary beneficiary.

NRG's pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $244 million as of December 31, 2011. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG. See also Item 15 — Note 16, *Investments Accounted for by the Equity Method and Variable Interest Entities,* to the Consolidated Financial Statements for additional discussion.

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 15 — 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,					
	2011					
Contractual Cash Obligations	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total (a)	2010 Total
	(In millions)					
Long-term debt and funded letter of credit (including estimated interest)	$ 708	$ 1,793	$ 1,513	$ 10,639	$ 14,653	$ 14,340
Capital lease obligations (including estimated interest)	11	18	12	82	123	133
Operating leases	67	125	106	280	578	508
Fuel purchase and transportation obligations (b)	891	266	204	484	1,845	1,761
Fixed purchased power commitments	37	32	18	9	96	370
Pension minimum funding requirement (c)	37	90	98	89	314	191
Other postretirement benefits minimum funding requirement (d)	4	7	9	18	38	22
Other liabilities (e)	54	85	66	280	485	697
Total	$ 1,809	$ 2,416	$ 2,026	$ 11,881	$ 18,132	$ 18,022

(a) Excludes $57 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 $443 million of asset retirement obligations which are discussed in Item 15 — Note 13, *Asset Retirement Obligations*, to the Consolidated Financial Statements.

(b) Includes only those coal transportation and lignite commitments for 2012 as no other nominations were made as of December 31, 2011. Natural gas nomination is through February 2016.

(c) 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.

(d) These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contribution for years after 2019 are currently not available.

(e) Includes water right agreements, service and maintenance agreements, stadium naming rights and other contractual obligations.

	By Remaining Maturity at December 31,					
	2011					
Guarantees	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2010 Total
	(In millions)					
Letters of credit and surety bonds	$ 1,562	$ 108	$ —	$ —	$ 1,670	$ 887
Asset sales guarantee obligations	60	—	567	8	635	1,022
Commercial sales arrangements	91	100	91	1,123	1,405	1,285
Other guarantees	1	—	—	460	461	171
Total guarantees	$ 1,714	$ 208	$ 658	$ 1,591	$ 4,171	$ 3,365

Fair Value of Derivative Instruments

NRG may enter into long-term power purchase and 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 or retail load obligations. 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, 2011, based on their level within the fair value hierarchy defined in ASC 820; and indicate the maturities of contracts at December 31, 2011. For a full discussion of the Company's valuation methodology of its contracts, see *Derivative Fair Value Measurements* in Item 15 — Note 5, *Fair Value of Financial Instruments*, to the Consolidated Financial Statements.

Derivative Activity Gains/(Losses)	(In millions)
Fair value of contracts as of December 31, 2010	$ 672
Contracts realized or otherwise settled during the period	(395)
Changes in fair value	174
Fair value of contracts as of December 31, 2011	$ 451

Fair value hierarchy Gains/(Losses)	Fair Value of Contracts as of December 31, 2011 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	$ (36)	$ (52)	$ (8)	$ —	$ (96)
Level 2	493	80	(20)	(14)	539
Level 3	8	—	—	—	8
Total	$ 465	$ 28	$ (28)	$ (14)	$ 451

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 7A — *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, 2011, NRG's net derivative asset was $451 million, a decrease to total fair value of $221 million as compared to December 31, 2010. This decrease was primarily driven by the roll off of contracts that settled during the period offset by an increase in fair value due to the decreases in gas and power prices.

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 $35 million in the net value of derivatives as of December 31, 2011.

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, or U.S. GAAP. The preparation of these financial statements and related disclosures in compliance with U.S. 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, and the fair value of certain assets and liabilities. 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 information that gives rise to the revision becomes known.

NRG's significant accounting policies are summarized in Item 15 — 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

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 changes in 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 Other Comprehensive Income, or 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 to be Normal Purchase Normal Sale, or 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, 2011, NRG had a valuation allowance of $83 million. This amount is comprised of foreign net operating loss carryforwards of $71 million, foreign capital loss carryforwards of approximately $1 million and U.S. domestic state NOLs of $11 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 primarily dependent upon earnings in foreign jurisdictions.

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 operations located in Germany and Australia. The Company is no longer subject to U.S. federal income tax examinations for years prior to 2007. 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 2004.

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.

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

At December 31, 2011, NRG reported goodwill of $1.9 billion, consisting of $1.7 billion in its Texas operating segment, or NRG Texas, that is associated with the acquisition of Texas Genco in 2006, and $144 million and $29 million in its corporate operating segment that is associated with the acquisition of Green Mountain Energy in November 2010 and Energy Plus in September 2011, respectively. The Company has also recorded intangible assets in connection with its business acquisitions, 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 15 — Note 3, *Business Acquisitions and Dispositions*, and Note 11, *Goodwill and Other Intangibles*, to the Consolidated Financial Statements for further discussion.

The Company applies ASC 805, *Business Combinations*, or ASC 805, and 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. The Company performs the annual goodwill impairment assessment as of December 31 or when events or changes in circumstances indicate that the carrying value may not be recoverable. In 2011, NRG adopted the provisions of ASU 2011-08, *Intangibles - Goodwill and Other (Topic 350) Testing Goodwill for Impairment*, or ASU 2011-08, which allows the consideration of qualitative factors to determine if it is more likely than not that impairment has occurred. In the absence of sufficient qualitative factors, goodwill impairment is determined utilizing a two-step process. 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, 2011, based on its qualitative assessment of macroeconomic, industry, and market events and circumstances as well as the overall financial performance subsequent to the November 2010 and September 2011 acquisition dates of the Green Mountain Energy and Energy Plus reporting units, respectively, the Company determined it was not more likely than not that the fair value of goodwill attributed to these reporting units was less than its carrying amount; as such, the annual two-step impairment test was deemed not necessary to be performed for these reporting units for the year ended December 31, 2011.

The Company performed step one of the two-step impairment test for its Texas reporting unit, 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. The Company believes the methodology and assumptions used in the valuation are consistent with the views of market participants. 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, Cedar Bayou and South Trent facilities, the Company applied a discounted cash flow methodology to their long-term budgets. This approach is consistent with that used to determine fair value in prior years. 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 2011 earnings before interest, taxes, depreciation and amortization. This approach is consistent with that used to determine fair values in prior years; and
- The intangible value to NRG Texas for synergies it provides to the Retail Businesses was determined by capitalizing estimated annual collateral charge and supply cost savings.

Under step one, if the 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 12% at December 31, 2011. The Company also evaluated various market-derived data including market research forecasts, recent merger and acquisition activity and earnings multiples, and together with its estimate of fair value, concluded that NRG Texas's goodwill is not impaired at December 31, 2011.

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 on NRG's stock price. The Company also qualitatively considered the impact on its stock price of shorter-term market views about forward natural gas prices. 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.

The Company's estimate of fair value under the income approach described above 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. The price of natural gas plays an important role in setting the price of electricity in many of the regions where NRG operates power plants. Due to recent downward trends in market natural gas prices, the Company performed a sensitivity scenario by using the quoted natural gas prices on the New York Mercantile Exchange, or NYMEX, as of December 31, 2011, and changes to the implied heat rate that would support new build of combined cycle gas plant in the Texas markets, coal and transportation charges, variable operations and maintenance costs, and the impact on forecasted generation for the baseload plants during the budget period. Under this sensitivity scenario, the fair value of NRG Texas was 16% below its carrying value at December 31, 2011. While not required, the Company further performed a high-level hypothetical step two analysis for this sensitivity scenario. Step two requires an allocation of fair value to the individual asset and liabilities using a hypothetical purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded. Under the hypothetical step two for the sensitivity scenario it was determined that no goodwill impairment was necessary as of December 31, 2011. If long-term natural gas prices remain depressed for an extended period of time, the Company's goodwill may become impaired in the future, which would result in a non-cash charge, not to exceed $1.7 billion, related to the NRG Texas reporting unit.

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 15 — Note 22, *Commitments and Contingencies,* to the Consolidated Financial Statements.

Recent Accounting Developments

See Item 15 — Note 2, *Summary of Significant Accounting Policies,* to the Consolidated Financial Statements for a discussion of recent accounting developments.

Item 7A — 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, liquidity risk, credit 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 NYMEX, 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, volatilities, and correlations between various commodities, such as natural gas, electricity, coal, oil, and emissions credits. 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 and purchases of electricity and fuel. These instruments include forwards, futures, swaps, and option contracts traded on various exchanges, such as NYMEX and Intercontinental Exchange, or ICE, 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 Value at Risk, or VaR. NRG uses a Monte Carlo simulation based VaR model to estimate 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 VaR model include: (i) lognormal distribution of prices; (ii) one-day holding period; (iii) 95% confidence interval; (iv) rolling 36-month forward looking period; and (v) market implied volatilities and historical price correlations.

As of December 31, 2011, the VaR for NRG's commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions calculated using the VaR model, was $45 million.

The following table summarizes average, maximum and minimum VaR for NRG for the years ended December 31, 2011, and 2010:

(In millions)	2011	2010
VaR as of December 31,	$ 45	$ 50
For the year ended December 31,		
Average	$ 60	$ 54
Maximum	77	70
Minimum	44	37

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, 2011, for the entire term of these instruments entered into for both asset management and trading, was $13 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.

NRG entered into interest rate swaps, which became effective on April 1, 2011, and are intended to hedge the risks associated with floating interest rates. For 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 London Inter-Bank Offer Rate, or 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 the swaps, which mature on February 1, 2013, is $900 million.

In addition to those discussed above, the Company's project subsidiaries enter into interest rate swaps, intended to hedge the risks associated with interest rates on non-recourse project level debt. See Item 15 - Note 12, *Debt and Capital Leases*, to the Consolidated Financial Statements, for more information about interest rate swaps of the Company's project subsidiaries.

If all of the above swaps had been discontinued on December 31, 2011, the Company would have owed the counterparties $100 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.

As part of the CVSR financing, the Company entered into swaptions with a notional value of $686 million in order to hedge the project interest rate risk. If the swaptions were discontinued on December 31, 2011, the counterparty would have owed the Company approximately $27 million.

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, 2011, a 1% change in interest rates would result in an $8 million change in interest expense on a rolling twelve month basis.

As of December 31, 2011, the fair value of the Company's debt was equal to its carrying value of $9.7 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 $797 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. The Company is currently exposed to additional collateral posting if natural gas prices decline primarily due to the long natural gas equivalent position at various exchanges used to hedge NRG's retail supply load obligations.

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 $123 million as of December 31, 2011 and a 1.25 MMBtu/MWh change in heat rates for heat rate positions would result in a change in margin collateral posted of approximately $68 million as of December 31, 2011. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of December 31, 2011.

Counterparty 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, 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 by having a diversified portfolio of counterparties. 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, 2011, counterparty credit exposure to a significant portion of the Company's counterparties was $1.2 billion and NRG held collateral (cash and letters of credit) against those positions of $261 million resulting in a net exposure of $919 million. Counterparty 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. As of December 31, 2011, the exposure is shown net of collateral held, and includes amounts net of receivables or payables.

Category	Net Exposure [(a)] (% of Total)
Financial institutions	57%
Utilities, energy merchants, marketers and other	39
Coal and emissions	1
ISOs	3
Total	100%

Category	Net Exposure [(a)] (% of Total)
Investment grade	70%
Non-rated [(b)]	27
Non-Investment grade	3
Total	100%

(a) Counterparty credit exposure excludes uranium and coal transportation contracts because of the unavailability of market prices.

(b) For non-rated counterparties, the majority are related to ISO and municipal public power entities, which are considered investment grade equivalent ratings based on NRG's internal credit ratings.

NRG has credit risk exposure to certain wholesale counterparties representing more than 10% of the total net exposure discussed above and the aggregate of credit risk exposure to such counterparties was $265 million. Approximately 89% of NRG's positions relating to this credit risk roll-off by the end of 2013. 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.

Counterparty credit exposure described above excludes credit risk exposure under certain long term contracts, including California tolling agreements, South Central load obligations, solar PPAs and a coal supply agreement. As external sources or observable market quotes are not available to estimate such exposure, the Company valued these contracts based on various 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. Based on these valuation techniques, as of December 31, 2011, credit risk exposure to these counterparties is approximately $866 million for the next five years. This amount excludes potential credit exposures for projects with long term PPAs that have not reached commercial operations. Many of these power contracts are with utilities or public power entities that have strong credit quality and specific public utility commission or other regulatory support. In the case of the coal supply agreement, NRG holds a lien against the underlying asset. These factors significantly reduce the risk of loss.

Retail Customer Credit Risk

NRG is exposed to retail credit risk through its retail electricity providers, which serve C&I customers and the Mass market. 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, 2011, the Company's credit exposure to C&I customers was diversified across many customers and various industries, with a significant portion of the exposure with government entities.

NRG is also exposed to credit risk relating to its Mass customers, which may result in a write-off of bad debt. During 2011, the Company continued to experience improved customer payment behavior, but 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.

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, or require the Company to post additional collateral if there were a one notch downgrade in the Company's credit rating. The collateral required for contracts that have adequate assurance clauses that are in a net liability position as of December 31, 2011, was $69 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of December 31, 2011, was $35 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 $15 million as of December 31, 2011.

Currency Exchange Risk

NRG's foreign earnings and investments may be subject to foreign currency exchange risk, which NRG generally does not hedge. As these earnings and investments are not material to NRG's consolidated results, the Company's foreign currency exposure is limited.

EXHIBIT 99.5

The information provided in this Exhibit is presented only in connection with the reporting changes described in the accompanying Form 8-K. This information does not reflect events occurring after February 28, 2012, the date we filed our 2011 Form 10-K, and does not modify or update the disclosures therein in any way, other than as required to reflect the change in reportable segments and the adoption of a new accounting standard, as described in the Form 8-K and set forth in Exhibits 99.1 through 99.5 attached thereto. You should therefore read this information in conjunction with the 2011 Form 10-K and any subsequent amendments on Form 10-K/A and with our reports filed with the Securities and Exchange Commission after February 28, 2012.

Part II, Item 8 — Financial Statements and Supplementary Data

The financial statements and schedules are listed in Part IV, Item 15 of this Form 8-K.

Part IV, Item 15 — Exhibits, 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, 2011, 2010, and 2009

Consolidated Statements of Comprehensive (Loss)/Income - Years ended December 31, 2011, 2010, and 2009

Consolidated Balance Sheets - December 31, 2011 and 2010

Consolidated Statements of Cash Flows - Years ended December 31, 2011, 2010, and 2009

Consolidated Statement of Stockholders' Equity - Years ended December 31, 2011, 2010, and 2009

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 15(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.

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, 2011.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011, has been audited by KPMG LLP, the Company's independent registered public accounting firm, as stated in its report which is included herein.

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, 2011, 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, 2011, 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, 2011 and 2010, and the related consolidated statements of operations, comprehensive (loss)/income, cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2011, and our report dated February 28, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

KPMG LLP

Philadelphia, Pennsylvania
February 28, 2012

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, 2011 and 2010, and the related consolidated statements of operations, comprehensive (loss)/income, cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, 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.

The accompanying consolidated financial statements and financial statement schedule have been retroactively adjusted, as applicable, for the update in segment structure and the change in method of presenting comprehensive income as described in Note 2 to the consolidated financial statements.

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, 2011, 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 28, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

KPMG LLP

Philadelphia, Pennsylvania

February 28, 2012, except as to the effects of the update in segment structure and the method of presenting comprehensive income as described in Note 2 to the consolidated financial statements, as to which the date is July 23, 2012.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions, except per share amounts)	For the Year Ended December 31, 2011	2010	2009
Operating Revenues			
Total operating revenues	$ 9,079	$ 8,849	$ 8,952
Operating Costs and Expenses			
Cost of operations	6,675	6,073	5,323
Depreciation and amortization	896	838	818
Impairment charge on emission allowances	160	—	—
Selling, general and administrative	668	598	550
Reliant Energy acquisition-related transaction and integration costs	—	—	54
Development costs	45	55	48
Total operating costs and expenses	8,444	7,564	6,793
Gain on sale of assets	—	23	—
Operating Income	635	1,308	2,159
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	35	44	41
Gain on sale of equity method investments	—	—	128
Impairment charge on investment	(495)	—	—
Other income/(expense), net	19	33	(5)
Loss on debt extinguishment and refinancing expense	(175)	(2)	(20)
Interest expense	(665)	(630)	(634)
Total other expense	(1,281)	(555)	(490)
(Loss)/Income Before Income Taxes	(646)	753	1,669
Income tax (benefit)/expense	(843)	277	728
Net Income	197	476	941
Less: Net loss attributable to noncontrolling interest	—	(1)	(1)
Net Income Attributable to NRG Energy, Inc.	197	477	942
Dividends for preferred shares	9	9	33
Income Available for Common Stockholders	$ 188	$ 468	$ 909
Earnings Per Share Attributable to NRG Energy, Inc. Common Stockholders			
Weighted average number of common shares outstanding — basic	240	252	246
Net Income per Weighted Average Common Share — Basic	$ 0.78	$ 1.86	$ 3.70
Weighted average number of common shares outstanding — diluted	241	254	271
Net Income per Weighted Average Common Share — Diluted	$ 0.78	$ 1.84	$ 3.44

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS)/INCOME

	For the Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Net Income	$ 197	$ 476	$ 941
Other comprehensive (loss)/income, net of tax			
Foreign currency translation adjustments, net of income tax benefit/(expense) of $1, $1, and $(21)	(2)	(3)	35
Reclassification adjustment for translation loss realized upon sale of MIBRAG, net of income tax benefit of $0, $0, and $13	—	—	(22)
Unrealized (loss)/gain on derivatives, net of income tax benefit/(expense) of $181, ($20), and ($53)	(309)	35	91
Available-for-sale securities, net of income tax expense of $0, $0, and $2	(1)	—	4
Defined benefit plan, net of income tax benefit of $27, $9, and $1	(46)	(16)	(2)
Other comprehensive (loss)/income	(358)	16	106
Comprehensive (loss)/income	(161)	492	1,047
Less: Comprehensive loss attributable to noncontrolling interest	—	(1)	(1)
Comprehensive (loss)/income attributable to NRG Energy, Inc.	(161)	493	1,048
Dividends for preferred shares	9	9	33
Comprehensive (loss)/income available for common stockholders	$ (170)	$ 484	$ 1,015

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2011	2010
	(In millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,105	$ 2,951
Funds deposited by counterparties	258	408
Restricted cash	292	8
Accounts receivable — trade, less allowance for doubtful accounts of $23 and $25	834	734
Inventory	308	453
Derivative instruments	4,216	1,964
Cash collateral paid in support of energy risk management activities	311	323
Prepayments and other current assets	273	296
Total current assets	7,597	7,137
Property, Plant and Equipment		
In service	15,704	14,913
Under construction	2,487	1,400
Total property, plant and equipment	18,191	16,313
Less accumulated depreciation	(4,570)	(3,796)
Net property, plant and equipment	13,621	12,517
Other Assets		
Equity investments in affiliates	640	536
Capital leases and notes receivable, less current portion	342	384
Goodwill	1,886	1,868
Intangible assets, net of accumulated amortization of $1,452 and $1,064	1,419	1,776
Nuclear decommissioning trust fund	424	412
Derivative instruments	450	758
Restricted cash supporting funded letter of credit facility	—	1,300
Other non-current assets	336	208
Total other assets	5,497	7,242
Total Assets	$ 26,715	$ 26,896

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

	As of December 31,	
	2011	2010
	(In millions, except share data)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 87	$ 463
Accounts payable	808	783
Derivative instruments	3,751	1,685
Deferred income taxes	127	108
Cash collateral received in support of energy risk management activities	258	408
Accrued interest expense	165	192
Other accrued expenses	281	307
Other current liabilities	194	274
Total current liabilities	5,671	4,220
Other Liabilities		
Long-term debt and capital leases	9,745	8,748
Funded letter of credit	—	1,300
Nuclear decommissioning reserve	335	317
Nuclear decommissioning trust liability	254	272
Postretirement and other benefit obligations	400	322
Deferred income taxes	1,389	1,989
Derivative instruments	464	365
Out-of-market commodity contracts	183	223
Other non-current liabilities	356	820
Total non-current liabilities	13,126	14,356
Total Liabilities	18,797	18,576
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)	249	248
Commitments and Contingencies		
Stockholders' Equity		
Common stock; $0.01 par value; 500,000,000 shares authorized; 304,183,720 and 304,006,027 shares issued and 227,519,521 and 247,197,355 shares outstanding at December 31, 2011 and 2010	3	3
Additional paid-in capital	5,346	5,323
Retained earnings	3,987	3,800
Less treasury stock, at cost — 76,664,199 and 56,808,672 shares at December 31, 2011 and 2010	(1,924)	(1,503)
Accumulated other comprehensive income	74	432
Noncontrolling interest	183	17
Total Stockholders' Equity	7,669	8,072
Total Liabilities and Stockholders' Equity	$ 26,715	$ 26,896

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Cash Flows from Operating Activities			
Net income	$ 197	$ 476	$ 941
Adjustments to reconcile net income to net cash provided by operating activities:			
Distributions and equity in earnings of unconsolidated affiliates	9	(19)	(41)
Depreciation and amortization	896	838	818
Provision for bad debts	59	54	61
Amortization of nuclear fuel	39	40	36
Amortization of financing costs and debt discount/premiums	32	32	44
Loss on debt extinguishment	58	—	—
Amortization of intangibles and out-of-market commodity contracts	167	4	153
Amortization of unearned equity compensation	28	30	26
Loss on disposals and sales of assets	14	4	13
Impairment charges and asset write downs	657	25	—
Changes in derivative instruments	(138)	(114)	(225)
Changes in deferred income taxes and liability for uncertain tax benefits	(859)	255	689
Gain on sale of equity method investment	—	—	(128)
Gain recognized on settlement of pre-existing relationship	—	—	(31)
Changes in nuclear decommissioning trust liability	20	34	26
Cash provided/(used) by changes in other working capital, net of acquisition and disposition effects:			
Accounts receivable - trade	(119)	138	88
Inventory	145	91	(83)
Prepayments and other current assets	59	(51)	26
Accounts payable	9	(261)	(176)
Accrued expenses and other current liabilities	(111)	(48)	48
Other assets and liabilities	4	95	(179)
Net Cash Provided by Operating Activities	1,166	1,623	2,106
Cash Flows from Investing Activities			
Acquisition of businesses, net of cash acquired	(377)	(1,006)	(427)
Capital expenditures	(2,310)	(706)	(734)
(Increase)/decrease in restricted cash, net	(35)	(4)	14
Increase in restricted cash to support equity requirements for U.S. DOE funded projects	(215) —	—	—
Decrease/(increase) in notes receivable	12	39	(22)
Proceeds from renewable energy grants	—	102	—
Purchases of emission allowances, net of proceeds	(19)	(34)	(38)
Investments in nuclear decommissioning trust fund securities	(406)	(341)	(305)
Proceeds from sales of nuclear decommissioning trust fund securities	385	307	279
Proceeds from sale of assets, net	7	43	6
(Investments in)/proceeds from sales of unconsolidated affiliates, net	(66)	(23)	278
Other	(23)	—	(5)
Net Cash Used by Investing Activities	(3,047)	(1,623)	(954)
Cash Flows from Financing Activities			
Payment of dividends to preferred stockholders	(9)	(9)	(33)
(Payments for)/net receipts from settlement of acquired derivatives that include financing elements	(83)	137	(79)
Payment for treasury stock	(430)	(180)	(500)
Cash proceeds from noncontrolling interest in subsidiary	29	50	50
Proceeds from issuance of common stock	2	2	2
Proceeds from issuance of long-term debt	6,224	1,484	892
(Payments for)/proceeds from term loan for funded letter of credit facility	(1,300)	1,300	—
Decrease/(increase) in restricted cash supporting funded letter of credit facility	1,300	(1,300)	—
Payment of debt issuance and hedging costs	(207)	(75)	(31)
Payments for short and long-term debt	(5,493)	(758)	(644)
Net Cash Provided By/(Used by) Financing Activities	33	651	(343)
Effect of exchange rate changes on cash and cash equivalents	2	(4)	1

Net (Decrease)/Increase in Cash and Cash Equivalents	(1,846)	647	810
Cash and Cash Equivalents at Beginning of Period	2,951	2,304	1,494
Cash and Cash Equivalents at End of Period	$ 1,105	$ 2,951	$ 2,304

See notes to Consolidated Financial Statements.

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

	Preferred Stock	Common Stock	Additional Paid-In Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Noncon-trolling Interest	Total Stockholders' Equity
					(In millions)			
Balances at December 31, 2008	$ 853	$ 3	$ 4,350	$ 2,423	$ (823)	$ 310	$ 7	$ 7,123
Net income/(loss)				942			(1)	941
Other comprehensive income						106		106
Equity-based compensation			26					26
Purchase of treasury stock					(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)		447					—
4.00% preferred stock conversion to common stock	(257)		257					—
Shares loaned to affiliate of CS			(291)		291			—
Shares returned from affiliate of CS			131		(131)			—
Other			(2)					(2)
Balances at December 31, 2009	$ 149	$ 3	$ 4,948	$ 3,332	$ (1,163)	$ 416	$ 12	$ 7,697
Net income/(loss)				477			(1)	476
Other comprehensive income						16		16
Equity-based compensation			28					28
Purchase of treasury stock					(180)			(180)
Preferred stock dividends				(9)				(9)
ESPP share purchases			3					3
NINA contribution, net of $17 tax			27				6	33
4.00% preferred stock conversion to common stock	(149)		149					—
Shares returned from affiliate of CS			160		(160)			—
Other			8					8
Balances at December 31, 2010	$ —	$ 3	$ 5,323	$ 3,800	$ (1,503)	$ 432	$ 17	$ 8,072
Net income				197				197
Other comprehensive loss						(358)		(358)
Equity-based compensation			28					28
Purchase of treasury stock					(430)			(430)
Preferred stock dividends				(9)				(9)
ESPP share purchases			(5)	(1)	9			3
NINA contribution							(17)	(17)
Ivanpah contribution							183	183
Balances at December 31, 2011	$ —	$ 3	$ 5,346	$ 3,987	$ (1,924)	$ 74	$ 183	$ 7,669

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 an integrated wholesale power generation and retail electricity company in the United States. First, NRG is a wholesale power generator engaged in the ownership and operation of power generation facilities; the trading of energy, capacity and related products; and the transacting in and trading of fuel and transportation services. Second, NRG is a retail electricity company engaged in the supply of electricity, energy services, and cleaner energy products to retail electricity customers in deregulated markets through Reliant Energy, Green Mountain Energy, and Energy Plus, (collectively, the Retail Businesses). Finally, NRG is focused on the deployment and commercialization of potential disruptive technologies, like electric vehicles, Distributed Solar and smart meter technology, which have the potential to change the nature of the power supply industry.

NRG's domestic generation facilities consist of intermittent, baseload, intermediate, and peaking power generation facilities. The following table summarizes NRG's global generation portfolio by operating segment, which includes 47 fossil fuel plants, three Utility Scale Solar facilities and four wind farms, as well as Distributed Solar facilities. Also included are one natural gas plant, six Utility Scale Solar facilities and additional Distributed Solar facilities currently under construction. All Utility Scale Solar and Distributed Solar facilities are described in megawatts on an alternating current, or AC, basis:

	Fossil Fuel, Nuclear, and Renewable (In MW)								
Generation Type	**Texas**	**Northeast**	**South Central**	**West**	**Other (Thermal)**	**Alter-native Energy**	**Total Domestic**	**Other (Inter-national)**	**Total Global**
Natural gas	4,930	1,300	2,630	2,130	105	—	11,095	—	11,095
Coal	4,190	1,600	1,495	—	15	—	7,300	1,005	8,305
Oil	—	4,015	—	—	—	—	4,015	—	4,015
Nuclear	1,175	—	—	—	—	—	1,175	—	1,175
Wind	—	—	—	—	—	450	450	—	450
Utility Scale Solar	—	—	—	—	—	65	65	—	65
Distributed Solar	—	—	—	—	—	30	30	—	30
Total generation capacity	10,295	6,915	4,125	2,130	120	545	24,130	1,005	25,135
Under Construction									
Natural gas	—	—	—	550	—	—	550	—	550
Utility Scale Solar (a)	—	—	—	—	—	855	855	—	855
Distributed Solar	—	—	—	—	—	5	5	—	5
Total under construction	—	—	—	550	—	860	1,410	—	1,410

(a) Includes 142 MW, representing 49% of Agua Caliente's capacity, which was sold to a partner on January 18, 2012

In addition, the Company's thermal assets provide steam and chilled water capacity of approximately 1,170 megawatts thermal equivalent, or MWt, through its district energy business.

NRG sells power from its generation portfolio and offers capacity or similar products to retail electric providers and others, and providing ancillary services to support system reliability.

NRG's Retail Businesses arrange for the transmission and delivery of electricity to customers, bill customers, collect payments for electricity sold and maintain call centers to provide customer service. Based on metered locations, as of December 31, 2011, the Retail Businesses combined to serve approximately 2.1 million residential, small business, commercial and industrial customers.

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 Company's consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the U.S., or U.S. GAAP. The Financial Accounting Standards Board, or FASB, Accounting Standards Codification, or ASC, is the source of authoritative U.S. GAAP to be applied by nongovernmental entities. In addition, the rules and interpretative releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants.

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 through arrangements that do not involve controlling voting interests. As such, NRG applies the guidance of ASC 810, *Consolidations,* or ASC 810, to determine when an entity that is insufficiently capitalized or not controlled through its voting interests, referred to as a variable interest entity, or VIE, should be consolidated.

2012 Business Segment Realignment

Effective in fiscal year 2012, NRG's segment structure and its allocation of corporate expenses were updated to reflect how management currently makes financial decisions and allocates resources. The Company has recast the data from prior periods to reflect this change in reportable segments to conform to the current year presentation. The Company's businesses are primarily segregated based on the Retail businesses, conventional power generation, alternative energy businesses and corporate activities. Within NRG's conventional 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 Other, which includes its international businesses, thermal and chilled water business and maintenance services. The Company's alternative energy businesses include solar and wind assets, electric vehicle services and carbon capture business.

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 with 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 as well as to fund required equity contributions, 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 Retail Businesses, 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. These businesses write-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, 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 South Texas Project, or 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, *Property, Plant, and Equipment*, or 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, *Investments-Equity Method and Joint Ventures*, or 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. The Company had no discontinued operations for the three years ended December 31, 2011.

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, 2011, 2010, and 2009, was $80 million, $36 million, and $37 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, marketing partnerships, development rights, 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, 2011.

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, *Goodwill - Intangibles and Others*, or 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, during the fourth quarter, and when events or changes in circumstances indicate that the carrying value may not be recoverable.

In September 2011, the FASB issued ASU No. 2011-08, *Intangibles - Goodwill and Other (Topic 350) Testing Goodwill for Impairment*, or ASU No. 2011-08. The objective of ASU 2011-08 is to simplify how entities test goodwill for impairment. The amendments in ASU No. 2011-08 permit an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in Topic 350. The more-likely-than-not threshold is defined as having a likelihood of more than 50 percent. ASU No. 2011-08 is effective for annual and interim goodwill impairment tests performed in fiscal years beginning after December 15, 2011. Early adoption is permitted. The Company adopted the provisions of ASU No. 2011-08, effective January 1, 2011, with no impact on its results of operations, financial position or cash flows.

In the absence of sufficient qualitative factors, 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 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 recognized 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 uncertain tax benefits as a component of income tax expense.

In accordance with ASC 805 and as discussed further in Note 19, *Income Taxes*, changes to existing net deferred tax assets or valuation allowances or changes to uncertain tax benefits, are recorded to 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 operating 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 are 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 retail 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 $186 million and $158 million for the years ended December 31, 2011, and 2010, respectively, and $251 million for the eight-month period ended December 31, 2009. These revenues represent the sale of excess supply to third parties in the market.

Accrued unbilled revenues are based on 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. NRG recorded receivables for unbilled revenues of $318 million and $282 million as of December 31, 2011 and 2010, respectively, for retail energy sales and services.

Cost of Energy for Retail Operations

The cost of energy for electricity sales and services to retail customers is based on estimated supply volumes for the applicable reporting period. A portion of the cost of energy ($87 million and $61 million as of December 31, 2011, and 2010, respectively) was accrued and consisted of estimated transmission and distribution charges not yet billed by the transmission and distribution utilities. In estimating supply volumes, the Company considers the effects of historical customer volumes, weather factors and usage by customer class. Transmission and distribution delivery fees are estimated using the same method used for electricity sales and services to retail customers. In addition, Independent System Operator, or ISO, fees are estimated based on historical trends, estimated supply volumes and initial Electric Reliability Council of Texas, or 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, *Derivatives and Hedging*, or ASC 815, which requires the Company to record all derivatives on the balance sheet at fair value unless they qualify for a Normal Purchase Normal Sale, or 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, if elected for hedge accounting, 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 accumulated OCI would be immediately reclassified into earnings. If the derivative instrument is terminated, the effective portion of this derivative deferred in accumulated 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 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, 2011, 2010, and 2009, amounts recognized as foreign currency transaction gains (losses) were immaterial. The Company's cumulative translation adjustment balances as of December 31, 2011, and 2010 were $72 million and $76 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, receivables, accounts payables, and accrued liabilities approximate fair value because of the short-term maturity of these instruments. See Note 5, *Fair Value of Financial Instruments* for a further discussion of fair value of financial instruments.

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, *Compensation — Retirement Benefits.* 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 determine 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, *Compensation — Stock Compensation,* or 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.

Gross Receipts and Sales Taxes

In connection with its Retail Businesses, the Company records gross receipts taxes on a gross basis in revenues and cost of operations in its consolidated statements of operations. During the years ended December 31, 2011, 2010, and the eight-month period ended December 31, 2009, NRG's revenues and cost of operations included gross receipts taxes of $64 million, $67 million, and $55 million, respectively. Additionally, the Retail Businesses record sales taxes collected from their 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.

Marketing and Advertising Costs

The Company expenses its advertising and marketing costs as incurred. The costs of tangible assets used in advertising campaigns are recorded as fixed assets or deferred advertising costs and amortized as advertising costs over the shorter of the useful life of the asset or the advertising campaign. The Company has several long-term sponsorship arrangements. Payments related to these arrangements are deferred and expensed over the term of the arrangement. Marketing and advertising expenses included within selling, general and administrative expense for the years ended December 31, 2011, 2010, and 2009 were $127 million, $81 million, and $47 million, respectively.

Business Combinations

The Company accounts for its business combinations in accordance with ASC 805, *Business Combinations,* or ASC 805. ASC 805 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 expensed as incurred.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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

ASU 2011-05 — In June 2011, the FASB issued ASU No. 2011-05, *Comprehensive Income (Topic 220) Presentation of Comprehensive Income*, or ASU No. 2011-05, which was further amended by ASU No. 2011-12, *Comprehensive Income (Topic 220) Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05,* issued in December 2011. The amendments in ASU No. 2011-05 require the Company to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single statement of comprehensive income or in two separate but consecutive statements. The Company is required to present, in either option, each component of net income, total net income, each component of other comprehensive income, total other comprehensive income and total comprehensive income. The provisions of ASU No. 2011-05 are required to be adopted retroactively. The Company adopted the provisions of ASU No. 2011-05 on January 1, 2012 and began presenting the total of comprehensive income, the components of net income and the components of other comprehensive income in two separate but consecutive statements. As this guidance provides only presentation requirements, the adoption of this standard did not impact the Company's results of operations, cash flows or financial position.

ASU 2011-11 — In December 2011, the FASB issued ASU No. 2011-11, *Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities*, or ASU No. 2011-11. The guidance provides enhanced disclosure requirements to evaluate the effect or potential effect of netting arrangements on an entity's financial position by improving information about financial instruments and derivative instruments that either (1) offset in accordance with either ASC 210-20-45 or ASC 810-20-45 or (2) are subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. Reporting entities will be required to disclose both gross and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The disclosures required by ASU No. 2011-10 are required to be adopted retroactively. ASU No. 2011-11 is effective for annual and interim periods in fiscal years beginning on or after January 1, 2013, and early adoption is permitted. 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.

Note 3 — Business Acquisitions and Dispositions

2011 Acquisitions

Energy Plus **—** On September 30, 2011, NRG acquired Energy Plus Holdings LLC, or Energy Plus, for $194 million in cash, net of $5 million cash acquired, funded from cash on hand. Energy Plus is a retail electricity provider with 188,000 customers as of December 31, 2011, a Northeast concentration and a unique sales channel involving exclusive loyalty and affinity program partnerships. Energy Plus will be run as a standalone retail business within NRG. The acquisition was recorded as a business combination under ASC 805, with identifiable assets acquired and liabilities assumed provisionally recorded at their estimated fair values on the acquisition date. The purchase price was primarily allocated to customer relationships of $63 million, marketing partnerships of $88 million, trade names of $10 million and goodwill of $29 million. 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 to be recognized are still in process. The provisional amounts are subject to revision until the evaluations are completed 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 acquisition-date fair value of goodwill. The factors that resulted in goodwill arising from the acquisition include the revenues associated with expanding the Energy Plus retail business and its unique sales channel in new regions, expanding its loyalty and affinity program partnerships and the synergies associated with combining the business with NRG's generation assets.

The provisional fair values of the intangible assets and liabilities 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 relationships* — The customer relationships, which reflect Energy Plus' residential and commercial customer base, were valued using a variation of the income approach. Under this approach, 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, workforce and trade names) utilized in the business were estimated and then discounted at an integrated utility peer group's weighted average cost of capital adjusted to be consistent with the risk inherent in the cash flows. The customer relationships are amortized to depreciation and amortization expense, over a weighted-average amortization period of five years, based on the expected discounted future net cash flows by year.

- *Loyalty and affinity program partnerships* — The marketing partnerships, which reflect Energy Plus' loyalty and affinity program partnerships, were valued using a variation of the income approach. These partnerships are based on contractual relationships typically structured for three to five year periods with options for renewal. Under this approach, the present value of expected future cash flows resulting from the existing marketing partnerships, including renewal expectations and charges for contributory assets (such as working capital, fixed assets, marketing costs, workforce and trade names) utilized in the business, were estimated and then discounted at an integrated utility peer group's weighted average cost of capital adjusted to be consistent with the risk inherent in the cash flows. The marketing partnerships are amortized to depreciation and amortization expense, over a weighted-average amortization period of 18 years, based on the expected discounted 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 avoided royalty revenues were discounted at an integrated utility peer group's weighted average cost of capital adjusted to be consistent with the risk inherent in the cash flows. 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 Energy Plus 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 five years.

Solar Acquisitions — During the year ended December 31, 2011, NRG acquired stakes in three Utility Scale Solar facilities for approximately $165 million in cash consideration, as part of the Company's initiative to capture opportunities for future growth in renewables. During 2011, subsequent to the acquisition dates, NRG made capital contributions into these projects of $420 million. In addition, NRG has a commitment to contribute additional amounts into the projects, comprised of $216 million in restricted cash and $815 million in letters of credit as of December 31, 2011. The Company may increase its letters of credit to replace the restricted cash at its discretion. In addition, the projects had $49 million in restricted cash for various agreements. NRG's minority partners had contributed approximately $29 million of equity during 2011, subsequent to the acquisition date, and had additional equity commitments of $115 million as of December 31, 2011. These acquisitions were recorded as business combinations under ASC 805, with identifiable assets acquired and liabilities assumed provisionally recorded at their estimated fair values on the acquisition date.

The acquisitions of these three solar facilities are further described below:

California Valley Solar Ranch — On September 30, 2011, NRG Solar LLC, a wholly-owned subsidiary of NRG, acquired 100% of the 250 MW California Valley Solar Ranch project, or CVSR, in eastern San Luis Obispo County, California. Power generated from CVSR will be sold to Pacific Gas and Electric under a 25 year Power Purchase Agreement, or PPA. In connection with the acquisition, High Plains Ranch II, LLC, a wholly-owned subsidiary of NRG, entered into the California Valley Solar Ranch Financing Agreement with the Federal Financing Bank, or FFB, which is guaranteed by the United States Department of Energy, or U.S. DOE, to borrow up to $1.2 billion to fund the costs of constructing this solar facility, or the CVSR Financing Agreement. The terms of the borrowings, which are non-recourse to NRG, are described further in Note 12, *Debt and Capital Leases*. The Company continues to work with its partners and the U.S. DOE to satisfy all of the U.S. DOE loan disbursement requirements and funding is anticipated by the end of the first quarter of 2012. Operations are expected to commence in phases beginning in the third quarter of 2012 through the fourth quarter of 2013.

Agua Caliente — On August 5, 2011, NRG, through its wholly-owned subsidiary, NRG Solar PV LLC, acquired 100% of the 290 MW Agua Caliente solar project, or Agua Caliente, in Yuma, AZ. Operations are scheduled to commence in phases beginning in the third quarter of 2012 through the first quarter of 2014. Power generated from Agua Caliente will be sold to Pacific Gas and Electric under a 25 year PPA. In connection with the acquisition, Agua Caliente Solar, LLC, a wholly-owned subsidiary of NRG, entered into the Agua Caliente Financing Agreement with the FFB, which is guaranteed by the U.S. DOE, to borrow up to $967 million to fund the construction of this solar facility, or the Agua Caliente Financing Agreement. The terms of the borrowings, which are non-recourse to NRG, are described further in Note 12, *Debt and Capital Leases*.

In addition, on January 18, 2012, the Company completed the sale of a 49% interest in NRG Solar AC Holdings LLC, the indirect owner of the Agua Caliente project entity, to MidAmerican Energy Holdings Company, or MidAmerican. A portion of the cash consideration received at closing represented 49% of construction costs funded by NRG's equity contributions. MidAmerican will fund its proportionate share of future equity contributions and other credit support for the project. NRG will continue to hold a majority interest in the project, which will continue to be consolidated. MidAmerican's non-controlling interest on the Company's balance sheet will represent the fair value of their capital contributions.

Ivanpah — On April 5, 2011, NRG acquired a 50.1% stake in the 392 MW Ivanpah Solar Electric Generation System, or Ivanpah, from BrightSource Energy, Inc., or BSE. BSE maintained a 21.8% interest in Ivanpah and the remaining 28.1% was acquired by a wholly-owned subsidiary of Google. Ivanpah is composed of three separate facilities - Ivanpah 1 (126 MW), Ivanpah 2 (133 MW), and Ivanpah 3 (133 MW), all of which are expected to be fully operational by the end of 2013. Power generated from Ivanpah will be sold to Southern California Edison and Pacific Gas and Electric, under multiple 20 to 25 year PPAs. The non-controlling interest represents the fair value of the capital contributions from the minority investors in Ivanpah. Ivanpah has entered into the Ivanpah Credit Agreement with the FFB, which is guaranteed by the U.S. DOE, to borrow up to $1.6 billion to fund the construction of this solar facility, or the Ivanpah Credit Agreement. The terms of the borrowings, which are non-recourse to NRG, are described further in Note 12, *Debt and Capital Leases*.

The purchase price for these acquisitions, considered business combinations, was provisionally allocated as follows:

(In millions)		
Assets		
Restricted cash	$	25
Property, plant and equipment		767
Other current and non-current assets		35
Total assets	$	827
Liabilities		
Accrued expenses	$	489
Long-term debt		4
Other non-current liabilities		15
Total liabilities		508
Less: Non-controlling interest (Ivanpah)		154
Net assets acquired	$	165

Significant considerations in determining fair value measurements as defined in ASC 820 of the assets acquired and liabilities assumed are as follows:

- *Property, plant & equipment* — The fair values of property, plant and equipment acquired were valued utilizing the cost approach. Under this approach, the fair value approximates the current cost of replacing an asset with another of equivalent economic utility adjusted for functional obsolescence and physical depreciation. The assets acquired have been classified as construction in progress and will commence depreciation upon the commercial operation date of each respective facility.

- *Power purchase agreements* — The fair values of the power purchase agreements acquired were determined utilizing a variation of the income approach and were determined to be zero for each facility. Under this approach, the expected future cash flows resulting from the acquired power purchase agreements, considering operating costs of the solar facility and charges for contributory assets utilized in the business, including working capital and property, plant and equipment were estimated and then discounted to present value at the weighted average cost of capital of an integrated utility peer group adjusted for project-specific financing attributes. Charges for contributory assets are largely driven by costs incurred to construct the facilities under the related Engineering, Procurement & Construction, or EPC, agreements. Since the expected contracted revenues to be recognized over the term of the acquired PPAs are largely offset by the costs to operate the facility and a return of and on the investment in the property, plant and equipment, the acquisition date fair value for each of these PPAs was determined to be zero. To corroborate this outcome, the Company examined available market data and concluded that an appropriate benchmark for fair value of the acquired PPAs would be a similar PPA with a delivery date consistent with the expected commercial operations date of each facility, which would likely have been negotiated during the same period as the PPAs acquired. Accordingly, the acquired PPAs are considered to be at market, which is consistent with the outcome of the income approach.

2010 Acquisitions

The Company made several acquisitions in 2010, which were recorded as business combinations under ASC 805. Those acquisitions for which purchase accounting was not finalized as of December 31, 2010, are briefly summarized below. See Note 3, *Business Acquisitions and Dispositions* and Note 12, *Debt and Capital Leases*, in the Company's 2010 Form 10-K for additional information related to these acquisitions.

Green Mountain Energy — On November 5, 2010, NRG acquired Green Mountain Energy for $357 million in cash, net of $75 million cash acquired, funded from cash on hand. The acquisition was recorded as a business combination under ASC 805, with identifiable assets acquired and liabilities assumed provisionally recorded at their estimated fair values on the acquisition date. The purchase price was primarily allocated to customer relationships of $158 million, trade names of $130 million, favorable commercial customer contracts of $54 million, net deferred tax liabilities of $78 million, net derivative liabilities of $60 million, and goodwill of $155 million. The factors that resulted in goodwill arising from the acquisition include the revenues associated with expanding the Green Mountain Energy business of providing renewable energy products and services to new customers in new regions and through new providers and the synergies associated with combining a renewable retail business with NRG's renewable generation assets. The accounting for the Green Mountain Energy acquisition was completed as of September 30, 2011, at which point the provisional fair values became final with no material changes.

Cottonwood — On November 15, 2010, NRG acquired the Cottonwood Generating Station, or Cottonwood, a 1,265 MW combined cycle natural gas plant in the Entergy zone of east Texas for $507 million in cash, funded from cash on hand. The acquisition was recorded as a business combination under ASC 805 and the purchase price was allocated to the assets acquired and liabilities assumed, which were recorded at provisional fair value on the acquisition date. The purchase price was primarily allocated to fixed assets. The accounting for the Cottonwood acquisition was completed as of March 31, 2011, at which point the provisional fair values became final with no material changes.

2010 Disposition

Padoma — On January 11, 2010, NRG sold its terrestrial wind development company, Padoma Wind Power LLC, or Padoma to Enel North America, Inc. NRG recognized a gain on the sale of Padoma of $23 million, which was recorded as a component of operating income in the statement of operation during the year ended December 31, 2010.

2009 Disposition

MIBRAG — On June 10, 2009, NRG completed the sale of its 50% ownership interest in MIBRAG, which owned and managed a coal mining operation, three lignite-fueled power generation facilities and other related businesses in Germany. For its share, NRG received €203 million ($284 million), net of transaction costs, and recognized an after-tax gain of $128 million for the year ended December 31, 2009. In addition, NRG entered into a foreign currency forward contract to hedge the impact of exchange rate fluctuations on the sale proceeds. and recorded an exchange loss of $24 million on the contract within Other (loss)/income, net for the year ended December 31, 2009.

Note 4 — Nuclear Innovation North America LLC Developments, Including Impairment Charge

Nuclear Innovation North America LLC, or NINA, which is majority-owned by NRG, was established in May 2008 to focus on marketing, siting, developing, financing and investing in new advanced design nuclear projects in select markets across North America, including the planned South Texas Project Units 3 and 4 Project, or STP 3 & 4. Toshiba America Nuclear Energy Corporation, or TANE, a wholly-owned subsidiary of Toshiba Corporation, is the minority owner of NINA. NINA is a bankruptcy remote entity under NRG's corporate structure and designated as an Excluded Project Subsidiary under NRG's 2011 Senior Credit Facility and senior unsecured notes, which require that NRG not be obligated to contribute any capital to service NINA's debt or fund the repayment of any NINA debt in the event of a default. Furthermore, NRG is not required to continue the funding of NINA and any capital provided to NINA by any other equity partner could result in the dilution of NRG's equity interest.

On March 11, 2011, Japan was hit by a devastating earthquake and tsunami which, in turn, triggered a nuclear incident at the Fukushima Daiichi Nuclear Power Station owned by The Tokyo Electric Power Company of Japan, Inc., or TEPCO. The nuclear incident in Japan introduced multiple and substantial uncertainties around new nuclear development in the United States and the availability of debt and equity financing to NINA. Consequently, NINA announced, on March 21, 2011, that it was reducing the scope of development at the STP 3 & 4 expansion to allow time for the U.S. Nuclear Regulatory Commission, or NRC, and other nuclear stakeholders to assess the impacts from the events in Japan. NINA suspended indefinitely all detailed engineering work and other pre-construction activities and, as a result, dramatically reduced the project workforce. The decision to reduce the scope of activities was made jointly by NINA, NRG and Toshiba. Further, on April 19, 2011, NRG announced that, while it will cooperate with and support its current partners and any prospective future partners in attempting to develop STP 3 & 4 successfully, NRG was withdrawing from further financial participation in NINA's development of STP 3 & 4. NINA, going forward, will be focused solely on securing a combined operating license from the NRC and on obtaining the loan guarantee from the U.S. DOE, two items that are essential to the success of any future project development. TANE agreed, for the time being, to assume responsibility for NINA's ongoing costs associated with continuation of the licensing process.

Due to the events described above, NRG evaluated its investment in NINA for impairment. As part of this process, NRG evaluated the contractual rights and economic interests held by the various stakeholders in NINA, and concluded that while it continues to hold majority legal ownership, NRG ceased to have a controlling financial interest in NINA at the end of the first quarter of 2011. Consequently, NRG deconsolidated NINA as of March 31, 2011, in accordance with ASC 810. This resulted in the removal of the following amounts from NRG's consolidated balance sheet: $930 million of construction in progress; $154 million of accounts payable and accrued expenses; $297 million of long-term debt; $17 million of non-controlling interest; and $19 million of other assets and liabilities. Furthermore, NRG assessed the impact of the diminished prospects for the STP 3 & 4 project on the fair value of NINA's assets relative to NINA's existing liabilities as well as NINA's potential contingent liabilities. Based on this assessment, the Company concluded it was remote that NRG would recover any portion of the carrying amount of its equity investment in NINA and, consequently, recorded an impairment charge of $481 million as of March 31, 2011 for the full amount of its investment. In concurrence with the substantial reduction in NINA's project workforce, and to support NINA's reduced scope of work, NRG contributed an additional $14 million during the remainder of 2011, bringing the total impairment charge to $495 million for the year ended December 31, 2011. NRG expects to incur additional one-time costs, related to contributions to NINA in future periods, of up to $6 million, bringing these total expected costs to $20 million. These additional contributions are expensed as incurred to "Impairment charge on investment." This impairment charge included net assets contributed from all of NINA's equity investors, both NRG and TANE, which the Company previously consolidated.

As part of a March 1, 2010, settlement of litigation with CPS Energy, or CPS, NRG had agreed to pay $80 million to CPS, subject to the U.S. DOE's approval of a fully executed term sheet for a conditional U.S. DOE loan guarantee for STP 3 & 4. NRG also had agreed to donate an additional $10 million, unconditionally, over four years in annual payments of $2.5 million to the Residential Energy Assistance Partnership, or REAP, in San Antonio. Payments of $5 million were made to REAP through December 31, 2011. As a result of the events stemming from the nuclear incident in Japan, the Company no longer believes it probable that the conditional U.S. DOE loan guarantee will be received or accepted. Therefore, as of March 31, 2011, the Company reversed the $80 million contingent liability to CPS previously recorded within other current liabilities, along with the $80 million of associated amounts capitalized to construction in progress within property, plant and equipment. At December 31, 2011, $5 million in liabilities remains on the condensed consolidated balance sheet for the obligations to REAP.

Note 5 — Fair Value of Financial Instruments

For cash and cash equivalents, funds deposited by counterparties, restricted cash, cash collateral paid and received in support of energy risk management activities, and restricted cash supporting the funded letter of credit facility, the carrying amount approximates fair value because of the short-term maturity of those instruments. Debt securities, equity securities, trust fund investments, which are comprised of various U.S. debt and equity securities, and derivative assets and liabilities are carried at fair market value.

The estimated carrying values and fair values of NRG's recorded financial instruments not carried at fair market value are as follows:

	As of December 31,			
	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Assets				
Notes receivable	$ 156	$ 161	$ 177	$ 190
Liabilities				
Long-term debt, including current portion	9,729	9,716	9,104	9,236
Funded letter of credit	—	—	1,300	1,295

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 the remaining long-term debt and the funded letter of credit 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 forward contracts.

- 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

For cash and cash equivalents, funds deposited by counterparties, restricted cash, cash collateral paid and received in support of energy risk management activities, and restricted cash supporting the funded letter of credit facility, the carrying amount approximates fair value because of the nature and short-term maturity of those instruments and are classified as Level 1 within the fair value hierarchy.

The following tables present 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, 2011			
	Fair Value			
	Level 1	Level 2	Level 3	Total
	(In millions)			
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	$ —	$ —	$ 7	$ 7
Marketable equity securities	1	—	—	1
Trust fund investments:				
Cash and cash equivalents	2	—	—	2
U.S. government and federal agency obligations	44	—	—	44
Federal agency mortgage-backed securities	—	63	—	63
Commercial mortgage-backed securities	—	7	—	7
Corporate debt securities	—	54	—	54
Equity securities	209	—	42	251
Foreign government fixed income securities	—	4	—	4
Derivative assets:				
Commodity contracts	2,661	1,930	75	4,666
Total assets	$ 2,917	$ 2,058	$ 124	$ 5,099
Derivative liabilities:				
Commodity contracts	$ 2,757	$ 1,283	$ 67	$ 4,107
Interest rate contracts	—	108	—	108
Total liabilities	$ 2,757	$ 1,391	$ 67	$ 4,215

	As of December 31, 2010			
	Fair Value			
	Level 1	Level 2	Level 3	Total
	(In millions)			
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	$ —	$ —	$ 8	$ 8
Marketable equity securities	3	—	—	3
Trust fund investments:				
Cash and cash equivalents	9	—	—	9
U.S. government and federal agency obligations	27	—	—	27
Federal agency mortgage-backed securities	—	57	—	57
Commercial mortgage-backed securities	—	11	—	11
Corporate debt securities	—	56	—	56
Equity securities	213	—	39	252
Foreign government fixed income securities	—	2	—	2
Derivative assets:				
Commodity contracts	652	2,046	24	2,722
Total assets	$ 904	$ 2,172	$ 71	$ 3,147
Derivative liabilities:				
Commodity contracts	$ 660	$ 1,251	$ 51	$ 1,962
Interest rate contracts	—	88	—	88
Total liabilities	$ 660	$ 1,339	$ 51	$ 2,050

There have been no transfers during the year ended December 31, 2011, between Levels 1 and 2. The following tables reconcile, for the years ended December 31, 2011, and 2010, 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:

	For the Year Ended December 31, 2011			
	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, 2011	$ 8	$ 39	$ (27)	$ 20
Total gains and losses (realized/unrealized):				
Included in OCI	(1)	—	—	(1)
Included in earnings	—	—	28	28
Included in nuclear decommissioning obligations	—	(6)	—	(6)
Purchases	—	9	4	13
Transfers into Level 3 [b]	—	—	(3)	(3)
Transfers out of Level 3 [b]	—	—	6	6
Ending balance as of December 31, 2011	$ 7	$ 42	$ 8	$ 57
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, 2011	$ —	$ —	$ 3	$ 3

	For the Year Ended December 31, 2010			
	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, 2010	$ 9	$ 37	$ (13)	$ 33
Total gains and losses (realized/unrealized):				
Included in OCI	1	—	—	1
Included in earnings	3	—	28	31
Included in nuclear decommissioning obligations	—	2	—	2
Purchases	—	—	(8)	(8)
Sales	(5)	—	—	(5)
Transfers into Level 3 [(b)]	—	—	(26)	(26)
Transfer out of Level 3 [(b)]	—	—	(8)	(8)
Ending balance as of December 31, 2010	$ 8	$ 39	$ (27)	$ 20
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, 2010	$ —	$ —	$ 5	$ 5

(a) Consists of derivatives assets and liabilities, net.

(b) Transfers in/out of Level 3 are related to the availability of external broker quotes, and are valued as of the end of the reporting period. All transfers in/out are with Level 2.

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 investments 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. government and federal agency obligations are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of corporate debt 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. Certain equity securities, classified as commingled funds, 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 the equity securities classified as 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 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 2% 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, 2011, the credit reserve resulted in a $4 million decrease in fair value which is composed of a $2 million loss in operating revenue and cost of operations and a $2 million decrease in OCI.

The fair values in each category reflect the level of forward prices and volatility factors as of December 31, 2011, 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, 2011, the Company recorded $311 million of cash collateral paid and $258 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, 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 by having a diversified portfolio of counterparties. 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, 2011, counterparty credit exposure to a significant portion of the Company's counterparties was $ 1.2 billion and NRG held collateral (cash and letters of credit) against those positions of $261 million, resulting in a net exposure of $919 million. Counterparty credit exposure is discounted at the risk free rate. The following table highlights the counterparty 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 as of December 31, 2011 is shown net of collateral held, and includes amounts net of receivables or payables.

Category	Net Exposure (a) (% of Total)
Financial institutions	57%
Utilities, energy merchants, marketers and other	39
Coal and emissions	1
ISOs	3
Total	100%

Category	Net Exposure [a] (% of Total)
Investment grade	70%
Non-rated [b]	27
Non-Investment grade	3
Total	100%

(a) Counterparty credit exposure excludes uranium and coal transportation contracts because of the unavailability of market prices.

(b) For non-rated counterparties, the majority of the exposure is related to ISO and municipal public power entities, which are considered investment grade equivalent ratings based on NRG's internal credit ratings.

NRG has counterparty credit risk exposure to certain counterparties representing more than 10% of total net exposure discussed above and the aggregate of such counterparties was $265 million. Approximately 89% of NRG's positions relating to this credit risk roll-off by the end of 2013. 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.

Counterparty credit exposure described above excludes credit risk exposure under certain long term agreements, including California tolling agreements, South Central load obligations, solar PPAs, and a coal supply agreement. As external sources or observable market quotes are not available to estimate such exposure, the Company valued these contracts based on various 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. Based on these valuation techniques, as of December 31, 2011, credit risk exposure to these counterparties is approximately $866 million for the next five years. This amount excludes potential credit exposures for projects with long term PPAs that have not reached commercial operations. Many of these power contracts are with utilities or public power entities that have strong credit quality and specific public utility commission or other regulatory support. In the case of the coal supply agreement, NRG holds a lien against the underlying asset. These factors significantly reduce the risk of loss.

Retail Customer Credit Risk

NRG is exposed to retail credit risk through the Company's retail electricity providers, which serve C&I customers and the Mass market. Retail credit risk results when a customer fails to pay for services rendered. The losses may result from both nonpayment of customer accounts receivable and the loss of 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, 2011, the Company's retail customer credit exposure to C&I customers was diversified across many customers and various industries, with a significant portion of the exposure with government entities.

NRG is also exposed to retail customer credit risk relating to its Mass customers, which may result in a write-off of bad debt. During 2011, the Company continued to experience improved customer payment behavior, but 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 NPNS exception. NRG may elect to designate certain derivatives as cash flow hedges, if certain conditions are met, and defer the effective portion of the change in fair value of the derivatives to accumulated 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.

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. 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. 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 unit's 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 retail supply and fuels supply contracts are recorded under mark-to-market accounting. All of NRG's hedging and trading activities are subject to limits within 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 power sales from the Company's electric generation facilities and retail power sales from Retail Businesses, NRG enters into a variety of derivative and non-derivative hedging instruments, utilizing the following:

- Forward contracts, which commit NRG to purchase or sell 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 to the option holder the right but not the obligation to purchase or sell a commodity.
- Extendable swaps, which include a combination of swaps and options executed simultaneously for different periods. This combination of instruments allows NRG to sell out-year volatility through call options in exchange for natural gas swaps with fixed prices in excess of the market price for natural gas at that time. The above-market swap combined with its later-year call option are priced in aggregate at market at the trade's inception.
- 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 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 power purchases for the Company's retail sales.

As of December 31, 2011, NRG had cash flow hedge energy-related derivative financial instruments extending through December 2013.

NRG's trading and hedging activities are subject to limits within 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, 2011, NRG had energy-related derivative financial instruments, and other energy-related contracts that did meet the definition of derivative instruments extending through December 2039. As of December 31, 2011, 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 2017.
- Forward and financial contracts for the purchase of fuel commodities relating to the forecasted usage of NRG's generation assets through 2017.

Also, as of December 31, 2011, NRG had other energy-related contracts that qualified for the NPNS exception and were therefore exempt from fair value accounting treatment as follows:

- Power sales and capacity contracts extending through 2025.

Also, as of December 31, 2011, NRG had other energy-related contracts that did not meet the definition of derivatives as follows:

- Load-following forward electric sale contracts extending through 2026;
- Power Tolling contracts through 2039;
- 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, 2011, NRG had interest rate derivative instruments on recourse debt extending through 2013 and on non-recourse debt extending through 2029, the majority of which are designated as cash flow hedges.

Volumetric Underlying Derivative Transactions

The following table summarizes the net notional volume buy/(sell) of NRG's open derivative transactions broken out by commodity, excluding those derivatives that qualified for the NPNS exception as of December 31, 2011, and December 31, 2010. 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.

		Total Volume	
Commodity	**Units**	**December 31, 2011**	**December 31, 2010**
		(In millions)	
Emissions	Short Ton	(2)	—
Coal	Short Ton	37	34
Natural Gas	MMBtu	13	(175)
Oil	Barrel	1	1
Power	MWh	4	5
Capacity	MW/Day	—	(1)
Interest	Dollars	$ 2,121	$ 2,782

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 permitted in ASC 815. As of December 31, 2011, the Company recorded $311 million of cash collateral paid and $258 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:

	Fair Value			
	Derivative Assets		Derivative Liabilities	
(In millions)	December 31, 2011	December 31, 2010	December 31, 2011	December 31, 2010
Derivatives Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	$ —	$ —	$ 39	$ 17
Interest rate contracts long-term	—	—	68	71
Commodity contracts current	318	392	—	2
Commodity contracts long-term	—	217	1	—
Total Derivatives Designated as Cash Flow or Fair Value Hedges	318	609	108	90
Derivatives Not Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts long-term	—	—	1	—
Commodity contracts current	3,898	1,572	3,712	1,666
Commodity contracts long-term	450	541	394	294
Total Derivatives Not Designated as Cash Flow or Fair Value Hedges	4,348	2,113	4,107	1,960
Total Derivatives	$ 4,666	$ 2,722	$ 4,215	$ 2,050

Accumulated Other Comprehensive Income

The following tables summarize the effects on NRG's accumulated OCI balance attributable to cash flow hedge derivatives, net of tax:

	Year Ended December 31, 2011		
	Energy Commodities	Interest Rate	Total
		(In millions)	
Accumulated OCI balance at December 31, 2010	$ 488	$ (47)	$ 441
Reclassified from accumulated OCI to income:			
- Due to realization of previously deferred amounts	(374)	12	(362)
Mark-to-market of cash flow hedge accounting contracts	74	(21)	53
Accumulated OCI balance at December 31, 2011, net of $87 tax	$ 188	$ (56)	$ 132
Gains/(losses) expected to be realized from OCI during the next 12 months, net of $71 tax	$ 145	$ (23)	$ 122
Gains recognized in income from the ineffective portion of cash flow hedges	$ 28	$ 3	$ 31

	Year Ended December 31, 2010		
	Energy Commodities	Interest Rate	Total
		(In millions)	
Accumulated OCI balance at December 31, 2009	$ 461	$ (55)	$ 406
Reclassified from accumulated OCI to income:			
- Due to realization of previously deferred amounts	(474)	1	(473)
Mark-to-market of cash flow hedge accounting contracts	501	7	508
Accumulated OCI balance at December 31, 2010, net of $268 tax	$ 488	$ (47)	$ 441
Gains recognized in income from the ineffective portion of cash flow hedges	$ —	$ 1	$ 1

	Year Ended December 31, 2009		
	Energy Commodities	Interest Rate	Total
		(In millions)	
Accumulated OCI balance at December 31, 2008	$ 406	$ (91)	$ 315
Reclassified from accumulated OCI to income:			
- 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, net of $247 tax	$ 461	$ (55)	$ 406
Gains/(losses) recognized in income from the ineffective portion of cash flow hedges	$ 45	$ (4)	$ 41

Amounts reclassified from accumulated OCI into income and amounts recognized in income from the ineffective portion of cash flow hedges are recorded to operating revenue for commodity contracts and interest expense for interest rate contracts.

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, 2011, 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 2011. As a result, the Company de-designated its 2011 ERCOT cash flow hedges as of July 31, 2011, and prospectively marked these derivatives to market through the income statement.

The following table summarizes the amount of unrealized gain/(loss) resulting from fair value hedges reflected in interest income/(expense) for interest rate contracts:

	Year Ended December 31,		
(In millions)	2011	2010	2009
Derivative	$ —	$ (8)	$ (6)
Senior Notes (hedged item)	—	11	6

Impact of Derivative Instruments on the Statement of Operations

Unrealized gains and losses associated with changes in the fair value of derivative instruments not accounted for as cash flow hedges and ineffectiveness of hedge derivatives are reflected in current period earnings.

The following table summarizes the pre-tax effects of economic hedges that have not been designated as cash flow hedges, 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,		
	2011	2010	2009
		(In millions)	
Unrealized mark-to-market results			
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$ 54	$ (171)	$ (68)
Reversal of loss positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	72	223	656
Reversal of previously recognized unrealized losses due to the termination of positions related to the CSRA unwind	—	—	80
Reversal of loss positions acquired as part of the Green Mountain Energy acquisition as of November 5, 2010	35	13	—
Net unrealized (losses)/gains on open positions related to economic hedges	(33)	(153)	22
Gains on ineffectiveness associated with open positions treated as cash flow hedges	28	—	45
Total unrealized mark-to-market gains/(losses) for economic hedging activities	156	(88)	735
Reversal of previously recognized unrealized losses/(gains) on settled positions related to trading activity	21	68	(157)
Net unrealized gains/(losses) on open positions related to trading activity	42	(5)	(26)
Total unrealized mark-to-market gains/(losses) for trading activity	63	63	(183)
Total unrealized gains/(losses)	$ 219	$ (25)	$ 552

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Revenue from operations — energy commodities	$ 388	$ (136)	$ (290)
Cost of operations	(169)	111	842
Total impact to statement of operations	$ 219	$ (25)	$ 552

Reliant Energy's loss positions were acquired as of May 1, 2009, and valued using forward prices on that date. Green Mountain Energy's loss positions were acquired as of November 5, 2010, and valued using forward prices on that date. The roll-off amounts were offset by realized losses at the settled prices and are reflected in the cost of operations during the same period.

For the year ended December 31, 2011, the $33 million loss from economic hedge positions was the result of a decrease in value of forward purchases and sales of natural gas, electricity and fuel due to a decrease in forward power and gas prices.

For the year ended December 31, 2010, the $153 million loss from economic hedge positions was the result of forward purchases and sales of natural gas, electricity and fuel due to decrease in forward power and gas prices.

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, or require the Company to post additional collateral if there were a one notch downgrade in the Company's credit rating. The collateral required for contracts that have adequate assurance clauses that are in net liability positions as of December 31, 2011, was $69 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of December 31, 2011, was $35 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 $15 million as of December 31, 2011.

See Note 5, *Fair Value of Financial Instruments,* for discussion regarding concentration of credit risk.

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 Public Utility Commission of Texas, or 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 rates charged to rate payers 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 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 well as information about the contractual maturities of those securities.

	As of December 31, 2011				As of December 31, 2010			
(In millions, except otherwise noted)	Fair Value	Unrealized Gains	Unrealized Losses	Weighted-average maturities (in years)	Fair Value	Unrealized Gains	Unrealized Losses	Weighted-average maturities (in years)
Cash and cash equivalents	$ 2	$ —	$ —	—	$ 9	$ —	$ —	—
U.S. government and federal agency obligations	43	3	—	10	25	1	—	9
Federal agency mortgage-backed securities	63	3	—	23	57	2	—	24
Commercial mortgage-backed securities	7	—	—	28	11	—	—	29
Corporate debt securities	54	3	1	10	56	3	1	10
Equity securities	251	113	1	—	252	117	1	—
Foreign government fixed income securities	4	—	—	8	2	—	—	8
Total	$ 424	$ 122	$ 2		$ 412	$ 123	$ 2	

The following table summarizes 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,		
	2011	2010	2009
	(In millions)		
Realized gains	$ 4	$ 8	$ 2
Realized losses	(3)	(5)	(1)
Proceeds from sale of securities	385	307	279

Note 8 — Inventory

Inventory consisted of:

	As of December 31,	
	2011	2010
	(In millions)	
Fuel oil	$ 59	$ 72
Coal/Lignite	82	215
Natural gas	10	8
Spare parts	157	157
Other	—	1
Total Inventory	$ 308	$ 453

Note 9 — Capital Leases and Notes Receivable

Notes receivable primarily consisted of fixed and variable rate notes secured by equity interests in partnerships and joint ventures. NRG's notes receivable and capital leases were as follows:

	As of December 31,	
	2011	2010
	(In millions)	
Capital Leases Receivable — non-affiliates		
Vattenfall Europe Generation AG & Co. KG., due August 31, 2021, 11.00% (a)	$ 199	$ 233
Other	1	3
Capital Leases — non-affiliates	200	236
Notes Receivable — non-affiliates (b)	36	—
Notes Receivable — affiliates		
Kraftwerke Schkopau GBR, indefinite maturity date, 6.91%-7.00% (c)	112	115
GCE Holding LLC which wholly-owns GenConn Energy LLC, indefinite maturity date, LIBOR +3% (d)	—	62
Avenal Solar Holdings LLC, indefinite maturity date, 4.5% (e)	8	—
Notes receivable — affiliates	120	177
Subtotal — Capital leases and notes receivable	356	413
Less current maturities:		
Capital leases (f)	14	29
Total Capital leases and notes receivable — noncurrent	$ 342	$ 384

(a) Saale Energie GmbH, or SEG, has sold 100% of its share of capacity from the Schkopau power plant to Vattenfall Europe Generation AG & Co. KG 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) Agua Caliente and CVSR have entered into agreements with their respective transmission owners to provide financing for required network upgrades. The notes will be repaid within a five year period following the date each facility reaches commercial operations.

(c) SEG entered into a note receivable with Kraftwerke Schkopau GBR, a partnership between SEG 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 $122 million note receivable facility with GCE Holding LLC to fund project liquidity needs in 2009. Per the terms of the facility, $63 million of the outstanding balance, including accrued interest was converted into equity in GenConn Energy LLC when the Middletown project reached commercial operations in 2011. See Note 12, *Debt and Capital Leases* for further discussion.

(e) NRG entered into a long-term $35 million note receivable facility with Avenal Solar Holdings LLC, to fund project liquidity needs in 2011.

(f) The current portion of capital leases is recorded in Prepayments and other current assets on the Consolidated Balance Sheet.

Note 10 — Property, Plant, and Equipment

NRG's major classes of property, plant, and equipment were as follows:

	As of December 31,		Depreciable
	2011	2010	Lives
	(In millions)		
Facilities and equipment	$ 14,483	$ 13,820	1-40 Years
Land and improvements	602	580	
Nuclear fuel	365	314	5 Years
Office furnishings and equipment	254	199	2-10 Years
Construction in progress	2,487	1,400	
Total property, plant, and equipment	18,191	16,313	
Accumulated depreciation	(4,570)	(3,796)	
Net property, plant, and equipment	$ 13,621	$ 12,517	

Note 11 — Goodwill and Other Intangibles

Goodwill — NRG's goodwill balance was $1.9 billion as of both December 31, 2011, and 2010. The Company recorded approximately $1.7 billion of goodwill in connection with the acquisition of Texas Genco in 2006. The Company recorded $144 million of goodwill in connection with the 2010 acquisition of Green Mountain Energy and $29 million in connection with the 2011 acquisition of Energy Plus. The Green Mountain Energy and Energy Plus acquisitions are discussed further in Note 3, *Business Acquisitions and Dispositions*. As of December 31, 2011, there was no impairment to goodwill. As of December 31, 2011, and 2010, NRG had approximately $594 million and $660 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, 2011, primarily reflect intangible assets established with the acquisitions of various companies in 2011, 2010, 2009, and 2006, and are comprised of the following:

- *Emission Allowances* — These intangibles primarily consist of SO_2 and NO_x emission allowances established with the 2006 Texas Genco acquisition and also include RGGI emission credits which NRG began purchasing in 2009. These emission allowances are held-for-use and are amortized to cost of operations, with NO_x allowances amortized on a straight-line basis and SO_2 allowances and Regional Greenhouse Gas Initiative, or RGGI, credits amortized based on units of production. During the year ended December 31, 2011, the Company recorded an impairment charge of $160 million on the Company's Acid Rain Program SO_2 emission allowances in order to comply with the Acid Rain Program as discussed in Note 24, *Environmental Matters.*
- *Development rights* — Arising primarily from the acquisition of solar businesses in 2010 and 2011, these intangibles are amortizable to depreciation and amortization expense on a straight-line basis over the estimated life of the related project portfolio.
- *Energy supply contracts* — Established with the acquisitions of Reliant Energy and Green Mountain Energy, these represent the fair value at the acquisition date of in-market contracts for the purchase of energy to serve retail electric customers. The contracts are amortized to cost of operations based on the expected delivery under the respective contracts.
- *In-market fuel (gas and nuclear) contracts* — These intangibles were established with the Texas Genco acquisition in 2006 and are amortized to cost of operations over expected volumes over the life of each contract.
- *Customer contracts* — Established with the acquisitions of Reliant Energy, Green Mountain Energy, and Northwind Phoenix, these intangibles represent the fair value at the acquisition date of contracts that primarily provide electricity to Reliant Energy's and Green Mountain Energy's C&I customers. These contracts are amortized to revenues based on expected volumes to be delivered for the portfolio.
- *Customer relationships* — These intangibles represent the fair value at the acquisition date of acquired businesses' customer base, primarily for Energy Plus, Reliant Energy and Green Mountain Energy. The customer relationships are amortized to depreciation and amortization expense based on the expected discounted future net cash flows by year.

- *Marketing partnerships* — Established with the acquisition of Energy Plus, as further discussed in Note 3, *Business Acquisitions and Dispositions*, these intangibles represent the fair value at the acquisition date of existing agreements with loyalty and affinity partners. The marketing partnerships are amortized to depreciation and amortization expense based on the expected discounted future net cash flows by year.
- *Trade names* — Established with the Energy Plus, Reliant Energy and Green Mountain Energy acquisitions, these intangibles are amortized to depreciation and amortization expense, on a straight-line basis.
- *Other* — Consists of renewable energy credits, wind intangible assets, costs to extend the operating license for STP Units 1 and 2, the intangible asset related to a purchased ground lease and the value of acquired power purchase agreements.

The following tables summarize the components of NRG's intangible assets subject to amortization:

Year Ended December 31, 2011	Emission Allowances	Development Rights	Contracts: Energy Supply	Contracts: Fuel	Contracts: Customer	Customer Relationships	Marketing Partnerships	Trade Names	Other	Total
	(In millions)									
January 1, 2011	$ 935	$ 18	$ 54	$ 72	$ 859	$ 571	$ —	$ 308	$ 23	$ 2,840
Purchases	8	6	—	—	—	—	—	—	26	40
Acquisition of businesses	—	—	—	—	—	63	88	10	13	174
Usage	—	—	—	—	—	—	—	—	(19)	(19)
Impairment charge on emission allowances	(160)	—	—	—	—	—	—	—	—	(160)
Other	—	—	—	—	—	—	—	—	(4)	(4)
Adjusted gross amount	783	24	54	72	859	634	88	318	39	2,871
Less accumulated amortization	(335)	—	(25)	(57)	(675)	(317)	—	(42)	(1)	(1,452)
Net carrying amount	$ 448	$ 24	$ 29	$ 15	$ 184	$ 317	$ 88	$ 276	$ 38	$ 1,419

Year Ended December 31, 2010	Emission Allowances	Development Rights	Contracts: Energy Supply	Contracts: Fuel	Contracts: Customer	Customer Relationships	Trade Names	Other	Total
	(In millions)								
January 1, 2010	$ 919	$ —	$ 54	$ 71	$ 790	$ 399	$ 178	$ 14	$ 2,425
Purchases	19	—	—	—	—	—	—	20	39
Acquisition of businesses	—	18	—	—	69	172	130	4	393
Usage	—	—	—	—	—	—	—	(15)	(15)
Other	(3)	—	—	1	—	—	—	—	(2)
Adjusted gross amount	935	18	54	72	859	571	308	23	2,840
Less accumulated amortization	(269)	—	(21)	(55)	(490)	(208)	(20)	(1)	(1,064)
Net carrying amount	$ 666	$ 18	$ 33	$ 17	$ 369	$ 363	$ 288	$ 22	$ 1,776

The following table presents NRG's amortization of intangible assets for each of the past three years:

Amortization	Years Ended December 31, 2011	2010	2009
	(In millions)		
Emission allowances	$ 66	$ 70	$ 63
Energy supply contracts	4	3	18
Fuel contracts	2	7	15
Customer contracts	185	232	258
Customer relationships	109	91	117
Trade names	22	12	8
Other	—	1	—
Total amortization	$ 388	$ 416	$ 479

The following table presents estimated amortization of NRG's intangible assets for each of the next five years:

Year Ended December 31,	Emission Allowances	Development Rights	Contracts: Energy Supply	Contracts: Fuel	Contracts: Customer	Customer Relationships	Marketing Partnerships	Trade Names	Total
					(In millions)				
2012	$ 50	$ 1	$ 5	$ 2	$ 119	$ 98	$ 3	$ 23	$ 301
2013	54	1	6	2	53	68	9	23	216
2014	33	1	6	2	1	48	15	23	129
2015	41	1	6	2	1	36	14	23	124
2016	46	1	6	2	1	26	9	22	113

The following table presents the weighted average remaining amortization period related to NRG's intangible assets purchased in 2011 business acquisitions:

As of December 31, 2011	Marketing Partnerships	Trade Names	Customer Relationships	Other	Total
			(In years)		
Weighted average remaining amortization period	18	5	5	18	11

Intangible assets held for sale — From time to time, management may authorize the transfer from the Company's emission bank of emission allowances held-for-use 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, 2011, the value of emission allowances held-for-sale is $19 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 business acquisitions and upon the adoption of Fresh Start accounting, NRG acquired certain out-of-market contracts, which are classified as non-current liabilities on NRG's consolidated balance sheet. The power and customer contracts are amortized to revenues, while the energy supply 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: Power	Total
		(In millions)		
2012	$ 2	$ 6	$ 21	$ 29
2013	1	2	19	22
2014	—	—	17	17
2015	—	—	17	17
2016	—	—	17	17

Note 12 — Debt and Capital Leases

Long-term debt and capital leases consisted of the following:

	As of December 31, 2011	As of December 31, 2010	Interest Rate	
	(In millions except rates)			
NRG Recourse Debt:				
Senior notes, due 2021	$ 1,200	$ —	7.875	
Senior notes, due 2020	1,100	1,100	8.250	
Senior notes, due 2019	800	—	7.625	
Senior notes, due 2019 [a]	691	690	8.500	
Senior notes, due 2018	1,200	—	7.625	
Senior notes, due 2017	1,090	1,100	7.375	
Senior notes, due 2016	—	2,400	7.375	
Senior notes, due 2014 [b]	—	1,205	7.250	
Term loan facility, due 2018 [c]	1,588	—	L+3.00	(f)
Term loan facility, due 2013-2015	—	1,759	L+3.25/L+1.75	(f)
Indian River Power LLC, tax exempt bonds, due 2040	57	1	6.000	
Indian River Power LLC, tax exempt bonds, due 2045	148	66	5.375	
Dunkirk Power LLC, tax exempt bonds, due 2042	59	59	5.875	
Subtotal NRG Recourse Debt	7,933	8,380		
NRG Non-Recourse Debt:				
Ivanpah financing:				
Solar Partners I, due 2014 and 2033	290	—	1.126 - 3.991	
Solar Partners II, due 2014 and 2038	314	—	1.116 - 4.195	
Solar Partners VIII, due 2014 and 2038	270	—	1.381 - 4.256	
NRG Peaker Finance Co. LLC, bonds, due 2019 [d]	190	206	L+1.07	(f)
Agua Caliente Solar, LLC, due 2037	181	—	2.730 - 3.256	
NRG West Holdings LLC, term loan, due 2023	159	—	L+2.25 - 2.75	(f)
NRG Energy Center Minneapolis LLC, senior secured notes, due 2013, 2017, and 2025 [e]	151	163	5.95 - 7.31	
South Trent Wind LLC, financing agreement, due 2020	75	78	L+ 2.50	(f)
Solar Power Partners - SPP Fund II/IIB LLC term loans, due 2017	17	—	L+3.50	(f)
Solar Power Partners - SPP Fund III LLC term loan, due 2024	42	—	L+3.50	(f)
NRG Roadrunner LLC, due 2031	61	—	L+2.01	(f)
NRG Solar Blythe LLC, credit agreement, due 2028	27	29	L+ 2.50	(f)
NRG Connecticut Peaking Development LLC, equity bridge loan facility, due 2010 and 2011	—	61	L + 2.00	(f)
NINA TANE and Shaw facilities, due 2012 and 2013	—	167	L+2.00 - 6.00	(f)
Other	19	20	various	
Subtotal NRG Non-Recourse Debt	1,796	724		
Subtotal	9,729	9,104		
Capital leases:				
Saale Energie GmbH, Schkopau capital lease, due 2021	103	107		
Subtotal	9,832	9,211		
Less current maturities [g]	87	463		
Total long-term debt and capital leases	$ 9,745	$ 8,748		
Funded letter of credit	$ —	$ 1,300	L+1.75-L+3.25	(f)

(a) Includes discount of $(9) million and $(10) million as of December 31, 2011, and 2010, respectively. On June 5, 2009, NRG issued these $700 million aggregate principal amount bonds at a yield of 8.75%.
(b) Includes fair value adjustment of $5 million as of December 31, 2010, reflecting an adjustment for an interest rate swap.
(c) Includes discount of $(3) million as of December 31, 2011.
(d) Includes discount of $(20) million and $(25) million as of December 31, 2011, and 2010, respectively.
(e) Includes premium of $1 million and $1 million as of December 31, 2011, and 2010, respectively.
(f) L+ equals LIBOR plus x%.
(g) Includes discount of $(5) million and $(5) million on the NRG Peaker Finance debt as of December 31, 2011, and 2010, respectively.

Senior Notes

Redemption of Senior Notes

On January 26, 2011, the Company redeemed $945 million of the 2014 Senior Notes through a tender offer, at an early redemption percentage of 102.063%. An additional $2 million was tendered at a redemption percentage of 100.063% and the remaining $253 million of 2014 Senior Notes were called on February 25, 2011, at a redemption percentage of 101.813% A $28 million loss on the extinguishment of the 2014 Senior Notes was recorded, which primarily consisted of the premiums paid on the redemption and the write-off of previously deferred financing costs.

On May 24, 2011, the Company redeemed $1.7 billion of the 2016 Senior Notes through a tender offer, at an early redemption percentage of 103.938%. An additional $0.4 million was tendered at a redemption percentage of 102.938% and the remaining $666 million of 2016 Senior Notes was called on June 23, 2011, at a redemption percentage of 103.688% A $115 million loss on the extinguishment of the 2016 Senior Notes was recorded, which primarily consisted of the premiums paid on the redemption and the write-off of previously deferred financing costs.

Senior Notes Outstanding

As of December 31, 2011, NRG had six 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.) 7.375% senior notes, issued November 21, 2006 and due January 15, 2017, or the 2017 Senior Notes;

(ii.) 8.500% senior notes, issued June 5, 2009 and due June 15, 2019, or the 2019 Senior Notes;

(iii.) 8.250% senior notes, issued August 20, 2010 and due September 1, 2020, or the 2020 Senior Notes;

(iv.) 7.625% senior notes, issued January 26, 2011 and due January 15, 2018, or the 2018 Senior Notes;

(v.) 7.625% senior notes, issued May 24, 2011 and due May 15, 2019, or the 7.625% 2019 Senior Notes; and

(vi.) 7.875% senior notes, issued May 24, 2011 and due May 15, 2021, or the 2021 Senior Notes.

The Company periodically enters into supplemental indentures for the purpose of adding entities under the Senior Notes 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 stockholders, grant liens on assets to lenders and incur additional debt. Interest is payable semi-annually on the Senior Notes until their maturity dates.

2017 Senior Notes

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 January 31, 2013	103.688%
February 1, 2013 to January 31, 2014	102.458%
February 1, 2014 to January 31, 2015	101.229%
February 1, 2015 and thereafter	100.000%

2019 Senior Notes

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	104.250%
June 15, 2015 to June 14, 2016	102.830%
June 15, 2016 to June 14, 2017	101.420%
June 15, 2017 and thereafter	100.000%

2020 Senior Notes

Prior to September 1, 2013, NRG may redeem up to 35% of the aggregate principal amount of the 2020 Senior Notes with the net proceeds of certain equity offerings, at a redemption price of 108.25% of the principal amount. Prior to September 1, 2015, NRG may redeem all or a portion of the 2020 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 note; or (ii) the excess of the principal amount of the note over the following: the present value of 104.125% of the note, plus interest payments due on the note from the date of redemption through September 1, 2015, discounted at a Treasury rate plus 0.50%. In addition, on or after September 1, 2015, 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
On or after September 1, 2015	104.125%
On or after September 1, 2016	102.750%
On or after September 1, 2017	101.375%
September 1, 2018 and thereafter	100.000%

2018 Senior Notes

On January 26, 2011, NRG issued $1.2 billion aggregate principal amount at par of 7.625% Senior Notes due 2018, or the 2018 Senior Notes. The 2018 Senior Notes were issued under the Indenture. The Indenture and the form of the notes provide, among other things, that the 2018 Senior Notes will be senior unsecured obligations of NRG. The net proceeds of $1.195 billion were used primarily to complete the tender offer of the 2014 Senior Notes. Interest is payable semi-annually beginning on July 15, 2011, until their maturity date of January 15, 2018.

Prior to maturity, NRG may redeem all or a portion of the 2018 Senior Notes at a redemption price equal to 100% of the principal amount of the notes redeemed plus a premium and 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 present value of the principal amount at maturity plus all required interest payments due on the note through the maturity date discounted at a Treasury rate plus 0.50%.

7.625% 2019 Senior Notes and 2021 Senior Notes

On May 24, 2011, NRG issued $800 million aggregate principal amount at par of 7.625% Senior Notes due 2019, or the 7.625% 2019 Senior Notes, and $1.2 billion aggregate principal amount at par of 7.875% Senior Notes due 2021, or the 2021 Senior Notes.

The net proceeds of $2 billion for both the 7.625% 2019 Senior Notes and the 2021 Senior Notes were used to complete the tender offer of the 2016 Senior Notes. Interest is payable semi-annually beginning on November 15, 2011, until their maturity dates of May 15, 2019, and May 15, 2021, respectively.

Prior to May 15, 2014, NRG may redeem up to 35% of the aggregate principal amount of the 7.625% 2019 Senior Notes with the net proceeds of certain equity offerings, at a redemption price of 107.625% of the principal amount. Prior to May 15, 2014, NRG may redeem all or a portion of the 7.625% 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 103.813% of the note, plus interest payments due on the note from the date of redemption through May 15, 2014, discounted at a Treasury rate plus 0.50%. In addition, on or after May 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
May 15, 2014 to May 14, 2015	103.813%
May 15, 2015 to May 14, 2016	101.906%
May 15, 2016 and thereafter	100.000%

Prior to May 15, 2016, NRG may redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes with the net proceeds of certain equity offerings, at a redemption price of 107.875% of the principal amount. Prior to May 15, 2016, NRG may redeem all or a portion of the 2021 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 103.938% of the note, plus interest payments due on the note from the date of redemption through May 15, 2016, discounted at a Treasury rate plus 0.50%. In addition, on or after May 15, 2016, 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
May 15, 2016 to May 14, 2017	103.938%
May 15, 2017 to May 14, 2018	102.625%
May 15, 2018 to May 14, 2019	101.313%
May 15, 2019 and thereafter	100.000%

Senior Credit Facility

On July 1, 2011, NRG replaced its Senior Credit Facility, consisting of its Term Loan Facility, Revolving Credit Facility and Funded Letter of Credit Facility, with a new senior secured facility, or the 2011 Senior Credit Facility, which includes the following:

- A $2.3 billion revolving credit facility, or the 2011 Revolving Credit Facility, with a maturity date of July 1, 2016, which will pay interest on amounts drawn at a rate of LIBOR plus 2.75%. In addition, the related Funded Letter of Credit loan was repaid, the non-current restricted cash balance was returned to the lenders and the related balances were removed from NRG's balance sheet. A $13 million loss on extinguishment of the Revolving Credit Facility and Funded Letter of Credit Facility was recorded, which consisted of the write-off of previously deferred financing costs. As of December 31, 2011, a total of $1.627 billion letters of credit were issued under the 2011 Revolving Credit Facility, with $673 million remaining available to be issued. Commitment fees of 0.50% are charged on the unused portion of the 2011 Revolving Credit Facility.

- A $1.6 billion term loan facility, or the 2011 Term Loan Facility, with a maturity date of July 1, 2018, which will pay interest at a rate of LIBOR plus 3.00%, with a LIBOR floor of 1.00%. The debt was issued at 99.75% of face value; the discount will be amortized to interest expense over the life of the loan. Repayments under the 2011Term Loan Facility will consist of 0.25% per quarter, with the remainder due at maturity. The proceeds of the new term loan facility were used to repay the existing Term Loan Facility balance outstanding. A $19 million loss on extinguishment of the Term Loan Facility was recorded, which consisted of the write-off of previously deferred financing costs.

The 2011 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 2011 Senior Credit Facility's lenders.

The 2011 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 2011 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 stockholders.

Interest Rate Swaps - NRG entered into interest rate swaps, which became effective on April 1, 2011, and are intended to hedge the risks associated with floating interest rates. The Company pays 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 counterparty are made monthly and the LIBOR is determined in advance of each interest period. The total notional amount of the swaps, which mature on February 1, 2013, is $900 million with changes in the fair value through June 30, 2011 recorded in OCI and subsequent changes in the fair value reported in interest expense.

Indian River Power LLC Tax-Exempt Bonds

On October 12, 2010, NRG executed a $190 million tax-exempt bond financing through its wholly-owned subsidiary, Indian River Power LLC. The bonds were issued by the Delaware Economic Development Authority and will be used for construction of emission control equipment on the Indian River Generating Station in Millsboro, DE, or Indian River. The bonds were issued at a rate of 5.375%, have a maturity date of October 1, 2045, and are supported by an NRG guarantee. The proceeds received through December 31, 2011, were $148 million, and the remaining balance will be received over time as construction costs are paid.

On December 10, 2010, NRG executed an additional $57 million tax-exempt bond financing through Indian River Power LLC. The bonds were issued by Sussex County, Delaware, and will be used for construction of emission control equipment on Indian River. The bonds were issued at a rate of 6.0%, have a maturity date of October 1, 2040, and are supported by an NRG guarantee. The proceeds received through December 31, 2011, were $57 million, and the remaining balance will be received over time as construction costs are paid.

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, whereby all the proceeds were received as of December 31, 2011. The bonds were issued by the County of Chautauqua Industrial Development Agency and are being used for the construction of emission control equipment on the Dunkirk Generating Station in Dunkirk, NY. The bonds initially bore weekly interest based on the Securities Industry and Financial Markets Association, or SIFMA, rate, and on February 1, 2010, the Company fixed the rate on the bonds at 5.875%, with interest payable semiannually. The bonds have a maturity date of April 1, 2042, and are supported by an NRG guarantee.

NRG Non-Recourse Debt

Project Financings

The following are descriptions of certain indebtedness of NRG's project subsidiaries that are outstanding as of December 31, 2011. The indebtedness described below is non-recourse to NRG, unless otherwise noted.

Ivanpah Financing

On April 5, 2011, NRG acquired a majority interest in Ivanpah, as discussed in Note 3, *Business Acquisitions and Dispositions*. On April 5, 2011, Ivanpah entered into the Ivanpah Credit Agreement with the FFB to borrow up to $1.6 billion to finance the costs of constructing the Ivanpah solar facilities. Each phase of the project is governed by a separate financing agreement and is non recourse to both the other projects and to NRG. Funding requests are submitted to the FFB on a monthly basis and the loans provided by the FFB are guaranteed by the U.S. DOE. Amounts borrowed under the Ivanpah Credit Agreement accrue interest at a fixed rate based on U.S. Treasury rates plus a spread of 0.375% and are secured by all the assets of Ivanpah. Ivanpah intends to submit an application to the U.S. Department of Treasury for a cash grant; any proceeds received will be utilized to repay the borrowings that mature in 2014.

The following table reflects the borrowings under the Ivanpah Credit Agreement as of December 31, 2011:

	Maximum borrowings available under Ivanpah Credit Agreement	Amounts borrowed	Weighted average interest rate on amounts borrowed
		(In millions, except rates)	
Solar Partners I, due June 27, 2014 (a)	$ 159	$ 154	1.678%
Solar Partners I, due June 27, 2033	392	136	3.181%
Solar Partners II, due February 27, 2014 (a)	132	129	1.609%
Solar Partners II, due February 27, 2038	387	185	3.458%
Solar Partners VIII, due October 27, 2014 (a)	117	111	1.997%
Solar Partners VIII, due October 27, 2038	440	159	3.561%
	$ 1,627	$ 874	

(a) The cash portion of the loan is fully drawn; additional amounts will be utilized for capitalized interest.

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, 2011, $210 million in principal remained outstanding on these bonds. Upon emergence from bankruptcy, NRG issued a $36 million letter of credit to 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 31, 2011, the collateral agent drew $18 million on the letter of credit to meet the debt service requirements and as of December 31, 2011, $4 million remains available for additional letters of credit issuances.

Agua Caliente Financing

On August 5, 2011, NRG acquired Agua Caliente, as discussed in Note 3, *Business Acquisitions and Dispositions*. In connection with the acquisition, Agua Caliente Solar LLC, a wholly-owned subsidiary of NRG, entered into the Agua Caliente Financing Agreement with the FFB, to borrow up to $967 million to finance the costs of constructing this solar facility. The Agua Caliente Financing Agreement, which matures in 2037, is non-recourse to NRG. Funding requests will be submitted to the FFB on a monthly basis and the loans provided by the FFB are guaranteed by the U.S. DOE. Amounts borrowed under the Agua Caliente Financing Agreement accrue interest at a fixed rate based on U.S. Treasury rates plus a spread of 0.375%, and are secured by the assets of Agua Caliente. As of December 31, 2011, $181 million had been drawn under this agreement.

NRG West Holdings Credit Agreement

On August 23, 2011, NRG, through its wholly-owned subsidiary, NRG West Holdings LLC, or West Holdings, entered into a credit agreement with a group of lenders in respect to the El Segundo Energy Center, or the West Holdings Credit Agreement. The West Holdings Credit Agreement, which establishes a $540 million, two tranche construction loan facility with additional facilities for the issuance of letters of credit or working capital loans, is secured by the assets of West Holdings.

The two tranche construction loan facility consists of the $480 million Tranche A Construction Facility, or the Tranche A Facility, and the $60 million Tranche B Construction Facility, or the Tranche B Facility. The Tranche A and Tranche B Facilities, which mature in August 2023, convert to a term loan and have an interest rate of LIBOR, plus an applicable margin which increases by 0.125% periodically from conversion through year eight for the Tranche A Facility and increases by 0.125% upon term conversion and on the third and sixth anniversary of the term conversion and by 0.250% on the eighth anniversary of the term conversion for the Tranche B Facility. The Tranche A and Tranche B Facilities amortize based upon a predetermined schedule over the term of the loan with the balance payable at maturity.

The West Holdings Credit Agreement also provides for the issuance of letters of credit and working capital loans to support the El Segundo Energy Center collateral needs. This includes letter of credit facilities on behalf of West Holdings of up to $90 million in support of the PPA, up to $48 million in support of the collateral agent, and a working capital facility which permits loans or the issuance of letters of credit of up to $10 million.

As of December 31, 2011, under the West Holdings Credit Agreement, West Holdings borrowed $159 million under the Tranche A Facility, issued a $30 million letter of credit in support of the PPA, and issued a $6 million letter of credit under the working capital facility.

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 $12 million remained outstanding as of December 31, 2011. In 2002, NRG Thermal Minneapolis issued an additional $55 million of 7.25% Series A notes due August 2017, of which $29 million remained outstanding as of December 31, 2011, and $20 million of 7.12% Series B notes due August 2017, of which $10 million remained outstanding as of December 31, 2011. In 2010, NRG Thermal Minneapolis issued $100 million of 5.95% Series C notes due June 23, 2025, of which $100 million remained outstanding as of December 31, 2011.

The indebtedness under these notes 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.

South Trent Financing Agreement

In connection with the acquisition, on June 14, 2010, South Trent Wind LLC entered into a financing agreement, or the South Trent Financing Agreement, with a group of lenders, which matures on June 14, 2020. The South Trent Financing Agreement includes a $79 million term loan, as well as a $10 million letter of credit facility in support of the PPA. The South Trent Financing Agreement also provides for up to $7 million in additional letter of credit facilities. The term loan accrues interest at LIBOR plus a margin based upon a grid, which is initially 2.5% and increases every two years by 12.5 basis points. The term loan amortizes quarterly based upon a predetermined schedule with the unamortized portion due at maturity. As of December 31, 2011, $75 million was outstanding under the term loan and $10 million was issued under the letter of credit facility.

Solar Power Partners Financing

NRG acquired Solar Power Partners, or SPP, on November 7, 2011. The following is a description of the long-term debt acquired in connection with the acquisition.

SPP Fund II/II-B — In order to finance the construction of solar assets, SPP Fund II entered into a term loan agreement with a bank. Under the agreement, SPP Fund II borrowed $20 million, which matures on June 30, 2024, and bears interest at LIBOR plus 3.50% and SPP Fund II-B borrowed $3 million, which matures on September 30, 2024 and bears interest at LIBOR plus 3.50%. The term loans are secured by substantially all of the assets of the respective fund and contain certain non-financial reporting covenants. The outstanding balance under the Fund II term loan was $15 million and under the Fund II-B term loan was $2 million as of the acquisition date and as of December 31, 2011.

SPP Fund III — In order to finance the construction of solar assets, SPP Fund III entered into a credit facility for a $75 million construction loan with two banks. The construction phase was completed in 2011 with the Company having borrowed $44 million. In June 2011 the construction loan converted to a term loan which amortizes quarterly with the remaining balance due on March 31, 2017, and bears interest at LIBOR plus 3.50%. SPP Fund III also issued a $1 million letter of credit in support of its agreements with one of its customers. The term loans are secured by substantially all of the assets of the respective fund and contain certain nonfinancial reporting covenants. As of the acquisition date and as of December 31, 2011, $42 million was outstanding under the credit facility.

Roadrunner Financing

On May 25, 2011, NRG, through its wholly-owned subsidiary, NRG Roadrunner LLC, or Roadrunner, entered into a credit agreement with a bank, or the Roadrunner Financing Agreement, for a $47 million construction loan that converted to a term loan on January 10, 2012 and a $21 million cash grant loan, both of which have an interest rate of LIBOR plus an applicable margin of 2.01%. The term loan has an interest rate of LIBOR plus an applicable margin which escalates 0.25% every five years and ranges from 2.10% at closing to 2.76% in year fifteen through maturity. The term loan, which is secured by all the assets of Roadrunner, matures on September 30, 2031, and amortizes based upon a predetermined schedule. The cash grant loan matures upon the earlier of the receipt of the cash grant or March 31, 2012. The Roadrunner Financing Agreement also includes a letter of credit facility on behalf of Roadrunner of up to $5 million. Roadrunner pays an availability fee of 100% of the applicable margin on issued letters of credit. As of December 31, 2011, $47 million was outstanding under the construction loan, $14 million was outstanding under the cash grant loans and $2 million in letters of credit in support of the PPA were issued. On January 10, 2012, in connection with the conversion of the construction loan to a term loan, the Company borrowed an additional $4 million of cash grant loans and issued a $3 million letter of credit in support of debt service.

Blythe Credit Agreement

On June 24, 2010, NRG Solar Blythe LLC, or Blythe, entered into a credit agreement with a bank, or the Blythe Credit Agreement, for a $30 million term loan which has an interest rate of LIBOR plus an applicable margin which escalates 0.25% every three years and ranges from 2.5% at closing to 3.75% in year fifteen. The term loan matures in June 2028, amortizes based upon a predetermined schedule, and is secured by all of the assets of Blythe. The bank has also issued two letters of credit on behalf of Blythe, totaling $6 million. Blythe pays an availability fee of 100% of the applicable margin on these issued letters of credit. As of December 31, 2011, $27 million was outstanding under the term loan and $6 million in letters of credit were issued.

CVSR Financing

On September 30, 2011, NRG acquired CVSR, as discussed in Note 3, *Business Acquisitions and Dispositions*. In connection with the acquisition, High Plains Ranch II LLC, a wholly-owned subsidiary of NRG, entered into the CVSR Financing Agreement with the FFB, to borrow up to $1.2 billion to finance the costs of constructing this solar facility. The CVSR Financing Agreement, which matures in 2037, is non-recourse to NRG. Funding requests will be submitted to the FFB on a monthly basis and the loans provided by the FFB are guaranteed by the U.S. DOE. Amounts borrowed under the CVSR Financing Agreement accrue interest at a fixed rate based on U.S. Treasury rates plus a spread of 0.375%, and are secured by the assets of CVSR. As of December 31, 2011, no amounts were drawn under this agreement. CVSR intends to submit an application to the U.S. Department of Treasury for a cash grant; any proceeds received will be utilized to repay borrowings under the CVSR Financing Agreement.

Under the terms of the CVSR Financing Agreement, on November 17, 2011, CVSR entered into a series of swaptions with a notional value of $686 million, or 80% of the guaranteed term loan amount, in order to hedge the project interest rate risk. These swaptions mature over a series of seven scheduled settlement dates to correspond with the completion dates of the project.

GenConn Energy LLC related financings

NRG Connecticut Peaking Development LLC, or NRG Connecticut Peaking, a wholly-owned subsidiary of NRG, had an equity bridge loan facility, or EBL, in the amount of $122 million from a syndicate of banks. The purpose of the EBL was 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 bore interest at a rate of LIBOR +2% on drawn amounts, and was backed by a letter of credit issued by NRG under its Funded Letter of Credit Facility equal to at least 104% of amounts outstanding under the EBL. On September 29, 2010, GenConn's Devon project reached its commercial operations date, or COD, as defined in the financing documents and NRG Connecticut Peaking repaid the $55 million portion of the EBL used to fund the Devon project, and converted $56 million of a promissory note from GenConn into equity. On June 29, 2011, when GenConn's Middletown project reached COD, as defined in the financing documents, NRG Connecticut Peaking repaid the remaining $61 million outstanding under the EBL. The commitment was terminated and the collateral held under the EBL, including the letter of credit issued by NRG under the Funded Letter of Credit Facility, was returned.

NRG Repowering Holdings LLC

NRG Repowering Holdings LLC, or NRG Repowering, had $5 million outstanding under a revolving credit facility as of December 31, 2011. On January 25, 2012, the facility was repaid and terminated and a supporting letter of credit issued by NRG was returned.

On January 25, 2012, NRG Repowering entered into a Credit and Reimbursement Agreement which provides for a $10 million working capital facility that can be used for general corporate purposes or to issue letters of credit, and an $80 million letter of credit facility. Interest on the letters of credit accrues at 3.5% and on loans under the working capital facility at LIBOR plus 3.5%. The facility is secured by NRG Repowering's investments in GenConn and South Trent Wind LLC, and matures January 25, 2015. As of January 23, 2012, NRG Repowering had issued a $10 million letter of credit under the working capital facility and $80 million in letters of credit under the letter of credit facility.

NINA Financing Arrangements

TANE and Shaw Facilities — NINA and TANE entered into a credit facility, wherein TANE committed up to $500 million to finance purchases of long-lead materials and equipment for the construction of STP Units 3 and 4. NINA also entered into a credit facility with Shaw, wherein Shaw committed up to $100 million to finance working capital needs and the expenses of Shaw related to the construction of STP Units 3 and 4. As described further in Note 4, *Nuclear Innovation North America LLC Developments, Including Impairment Charge* , NRG deconsolidated NINA as of March 31, 2011; therefore any amounts outstanding under these facilities are no longer consolidated into NRG's financial statements.

Interest Rate Swaps — Project Financings

Many of NRG's project subsidiaries entered into interest rate swaps, intended to hedge the risks associated with interest rates on non-recourse project level debt. These swaps amortize in proportion to their respective loans and are floating for fixed where the project subsidiary pays its counterparty the equivalent of a fixed interest payment on a predetermined notional value and will receive quarterly the equivalent of a floating interest payment based on the same notional value. All interest rate swap payments by the project subsidiary and its counterparty are made quarterly and the LIBOR is determined in advance of each interest period. The following table summarizes the swaps, some of which are forward starting as indicated, related to NRG's project level debt as of December 31, 2011.

Non-Recourse Debt	% of Principal	Fixed Interest Rate	Floating Interest Rate	Notional Amount at December 31, 2011 (In millions)	Effective Date	Maturity Date
NRG Peaker Finance Co. LLC	100%	6.673%	3-mo. LIBOR + 1.07%	$ 210	June 18, 2002	June 10, 2019
NRG West Holdings LLC	75%	2.4165%	3-mo. LIBOR	135	November 30, 2011	August 31, 2023
South Trent Wind LLC	75%	3.265%	3-mo. LIBOR	56	June 14, 2010	June 14, 2020
South Trent Wind LLC	75%	4.95%	3-mo. LIBOR	21	June 14, 2020	June 14, 2028
NRG Solar Roadrunner LLC	75%	4.313%	3-mo. LIBOR	36	September 30, 2011	December 31, 2029
NRG Solar Blythe LLC	75%	3.563%	3-mo. LIBOR	20	June 25, 2010	June 25, 2028
Solar Power Partners II	75%	7.14%	3-mo. LIBOR + 3.5%	11	June 30, 2009	June 30, 2024
Solar Power Partners II-B	75%	6.72%	3-mo. LIBOR + 3.5%	2	October 1, 2009	September 30, 2024
Solar Power Partners III	100%	3.67%	3-mo. LIBOR	42	April 30, 2010	September 30, 2026

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, 2011, the capital lease obligation at SEG was $103 million.

The KSGbR issued debt to fund Schkopau pursuant to multiple facilities totaling €785 million. As of December 31, 2011, €117 million (approximately $152 million) remained outstanding at Schkopau. Interest accrues on the individual loans at fixed rates averaging 6.70% per annum, with maturities occurring between 2012 and 2020. 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 debt and capital leases, for the years ending after December 31, 2011 are as follows:

	(In millions)
2012	$ 87
2013	71
2014	496
2015	129
2016	137
Thereafter	8,912
Total	$ 9,832

NRG's future minimum lease payments for capital leases included above as of December 31, 2011, are as follows:

	(In millions)
2012	$ 11
2013	10
2014	8
2015	7
2016	5
Thereafter	82
Total minimum obligations	123
Interest	20
Present value of minimum obligations	103
Current portion	8
Long-term obligations	$ 95

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, 2011, and 2010, along with the additions, reductions and accretion related to the Company's ARO obligations for the year ended December 31, 2011:

	(In millions)
Balance as of December 31, 2010	$ 432
Revisions in estimates for current obligations	(10)
Spending for current obligations	(5)
Accretion — Expense	8
Accretion — Nuclear decommissioning	18
Balance as of December 31, 2011	$ 443

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 $23 million to the Company's three pension plans in 2012.

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. 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		
	2011	2010	2009
	(In millions)		
Service cost benefits earned	$ 14	$ 14	$ 12
Interest cost on benefit obligation	21	21	20
Expected return on plan assets	(21)	(20)	(16)
Amortization of unrecognized net gain	—	—	1
Net periodic benefit cost	$ 14	$ 15	$ 17

	Year Ended December 31,		
	Other Postretirement Benefits		
	2011	2010	2009
	(In millions)		
Service cost benefits earned	$ 2	$ 2	$ 2
Interest cost on benefit obligation	6	6	6
Amortization of unrecognized prior service cost	—	—	1
Net periodic benefit cost	$ 8	$ 8	$ 9

A comparison of the pension benefit obligation, other postretirement benefit obligations, and related plan assets for NRG's plans on a combined basis is as follows:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
	(In millions)			
Benefit obligation at January 1	$ 404	$ 357	$ 106	$ 104
Service cost	14	14	2	2
Interest cost	21	21	6	6
Plan amendments	—	—	—	(5)
Actuarial loss	34	24	9	—
Employee and retiree contributions	—	—	1	1
Benefit payments	(17)	(12)	(2)	(2)
Benefit obligation at December 31	456	404	122	106
Fair value of plan assets at January 1	297	263	—	—
Actual return on plan assets	10	30	—	—
Employee contributions	—	—	1	1
Employer contributions	18	16	1	1
Benefit payments	(17)	(12)	(2)	(2)
Fair value of plan assets at December 31	308	297	—	—
Funded status at December 31 — excess of obligation over assets	$ (148)	$ (107)	$ (122)	$ (106)

Amounts recognized in NRG's balance sheets were as follows:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
	(In millions)			
Current liabilities	$ —	$ —	$ 3	$ 2
Non-current liabilities	148	107	119	104

Amounts recognized in NRG's accumulated OCI 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	
	2011	2010	2011	2010
	(In millions)			
Unrecognized loss	$ 88	$ 42	$ 11	$ 1
Prior service (credit)/cost	(2)	(2)	(1)	—

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	
	2011	2010	2011	2010
	(In millions)			
Unrecognized loss	$ 46	$ 13	$ 9	$ —
Prior service cost/(credit)	—	—	—	(5)
Amortization for prior service cost/(credit)	—	1	—	—
Total recognized in other comprehensive loss/(gain)	$ 46	$ 14	$ 9	$ (5)
Total recognized in net periodic pension cost and other comprehensive income	$ 60	$ 28	$ 17	$ 3

The Company's estimated unrecognized loss for NRG's domestic pension plan that will be amortized from accumulated OCI to net periodic cost over the next fiscal year is approximately $4 million. The Company's estimated unrecognized loss for NRG's postretirement plan that will be amortized from accumulated OCI 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	
	2011	2010
	(In millions)	
Projected benefit obligation	$ 456	$ 404
Accumulated benefit obligation	392	347
Fair value of plan assets	308	297

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 by asset category and their level within the fair value hierarchy are as follows:

	Fair Value Measurements as of December 31, 2011		
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Total
	(In millions)		
U.S. equity investment	$ 47	$ —	$ 47
International equity investment	18	—	18
Corporate bond investment-fixed income	37	—	37
Common/collective trust investment — U.S. equity	—	78	78
Common/collective trust investment — international equity	—	32	32
Common/collective trust investment — fixed income	—	96	96
Total	$ 102	$ 206	$ 308

	Fair Value Measurements as of December 31, 2010		
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Total
	(In millions)		
U.S. equity investment	$ 46	$ —	$ 46
International equity investment	19	—	19
Corporate bond investment-fixed income	31	—	31
Common/collective trust investment — U.S. equity	—	80	80
Common/collective trust investment — international equity	—	35	35
Common/collective trust investment — fixed income	—	85	85
Short-term investment fund	—	1	1
Total	$ 96	$ 201	$ 297

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. The fair value of the U.S. and international equity investments and the corporate bond investment is based on quoted prices in active markets, and is categorized as 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 is 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. There are no investments categorized as Level 3.

The following table presents the significant assumptions used to calculate NRG's benefit obligations:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
Weighted-Average Assumptions	2011	2010	2011	2010
Discount rate	4.98%	5.47%	5.18%	5.77%
Rate of compensation increase	4.00-4.50%	4.00-4.50%	N/A	N/A
Health care trend rate	—	—	8% grading to 5% in 2019	8% grading to 5% in 2019

The following table presents the significant assumptions used to calculate NRG's benefit expense:

	As of December 31,					
	Pension Benefits			Other Postretirement Benefits		
Weighted-Average Assumptions	2011	2010	2009	2011	2010	2009
Discount rate	5.47%	5.93%	6.88%	5.77%	6.14%	6.88%
Expected return on plan assets	7.25%-7.50%	7.50%	7.50%	—	—	—
Rate of compensation increase	4.00-4.50%	4.00-4.50%	4.00-4.50%	—	—	—
Health care trend rate	—	—	—	8.0% grading to 5.0% in 2019	9.5% grading to 5.5% in 2016	9.5% grading to 5.5% in 2016

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, 2011, were based on the Aon Hewitt AA Above Median (AAM) yield curve; which was designed by Aon Hewitt to provide a means for corporate plan sponsors to value the liabilities of defined benefit and other post retirement benefit plans. The AAM is a hypothetical Aa yield curve represented by a series of annualized individual discount rates from 0.5 to 99 years. Each bond issue is required to have an average rating of AA, when averaging all available ratings by Moody's Investor Services, Standard &

Poor's and Fitch. The discount rate assumptions used to determine future pension obligations as of December 31, 2010, and 2009 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 47% to 73% invested in equity securities of which 34% to 51% is 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 reasonableness 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 allocations were as follows:

	As of December 31,	
	2011	2010
U.S. equity	33.5-50.5%	33.5-50.5%
International equity	13.5-22.5%	13.5-22.5%
U.S. fixed income	30-50%	30-50%

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:

		Other Postretirement Benefit	
	Pension Benefit Payments	Benefit Payments	Medicare Prescription Drug Reimbursements
		(In millions)	
2012	$ 21	$ 3	$ —
2013	23	3	—
2014	24	4	—
2015	26	4	—
2016	29	5	—
2017-2021	182	33	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*. South Texas Project Nuclear Operating Company, or STPNOC, which 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, 2011, and 2010 NRG reimbursed STPNOC approximately $12 million and $4 million, respectively, towards its defined benefit plans. In 2012, NRG expects to reimburse STPNOC $15 million for its contributions towards the plans.

The Company has recognized the following in its statement of financial position, statement of operations and accumulated OCI related to its 44% interest in STP:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
	(In millions)			
Funded status — STPNOC benefit plans	$ (67)	$ (55)	$ (49)	$ (40)
Net periodic benefit costs	9	8	6	4
Other changes in plan assets and benefit obligations recognized in other comprehensive income	15	8	3	7

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 as follows:

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Company contributions to defined contribution plans	$ 24	$ 28	$ 22

Note 15 — Capital Structure

For the period from December 31, 2008, to December 31, 2011, the Company had 10,000,000 shares of preferred stock authorized and 500,000,000 shares of common stock authorized. The following table reflects the changes in NRG's preferred and common shares issued and outstanding for each period presented:

	Preferred Stock Issued and Outstanding			Common		
	3.625%	4%	5.75%	Issued	Treasury	Outstanding
Balance as of December 31, 2008	250,000	420,000	1,841,680	263,599,200	(29,242,483)	234,356,717
Shares issued under 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 Plan repurchases	—	—	—	—	(19,305,500)	(19,305,500)
Shares issued from LTIP	—	—	—	367,858	—	367,858
4.00% Preferred Stock conversion	—	(265,870)	—	13,293,500	—	13,293,500
4.00% Preferred Stock redeemed for cash	—	(73)	—	—	—	—
5.75% Preferred Stock conversion	—	—	(1,841,680)	18,601,201	—	18,601,201
Balance as of December 31, 2009	250,000	154,057	—	295,861,759	(41,866,451)	253,995,308
Shares issued under ESPP	—	—	—	—	120,990	120,990
Shares returned by affiliate of CS	—	—	—	—	(6,600,000)	(6,600,000)
Capital Allocation Plan repurchases	—	—	—	—	(8,463,211)	(8,463,211)
Shares issued from LTIP	—	—	—	442,818	—	442,818
4.00% Preferred Stock conversion	—	(154,029)	—	7,701,450	—	7,701,450
4.00% Preferred Stock redeemed for cash	—	(28)	—	—	—	—
Balance as of December 31, 2010	250,000	—	—	304,006,027	(56,808,672)	247,197,355
Shares issued under ESPP	—	—	—	—	120,127	120,127
Shares issued under LTIP	—	—	—	177,693	—	177,693
Capital Allocation Plan repurchases	—	—	—	—	(19,975,654)	(19,975,654)
Balance as of December 31, 2011	250,000	—	—	304,183,720	(76,664,199)	227,519,521

Common Stock

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, 2011.

Equity Instrument	Common Stock Reserve Balance
3.625% Convertible perpetual preferred	16,000,000
Long-term incentive plan	18,573,196
Total	34,573,196

Capital Allocation Plan — As part of the Company's Capital Allocation Program, the Company returns capital to shareholders through NRG common stock repurchases under the Capital Allocation Plan. Shares repurchased are included in treasury stock.

Employee Stock Purchase Plan — Under the NRG Energy, Inc. Employee Stock Purchase Plan, or ESPP, 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. As of December 31, 2011, there remained 177,351 shares of treasury stock reserved for issuance under the ESPP, and in the first quarter of 2012, 76,423 shares of common stock were issued to employee accounts from treasury stock.

Share Lending Agreements — On February 20, 2009, Common Stock Finance, or CSF, I and II entered into Share Lending Agreements, or SLAs, with affiliates of Credit Suisse Group, or CS, relating to the shares of NRG common stock held by CSF I and II in connection with the CSF Debt. CSF I and CSF II loaned 12,000,000 shares of NRG common stock to affiliates of CS in the first quarter 2009. The shares were treated as outstanding for corporate law purposes, but were not considered outstanding for the purpose of computing and reporting the Company's basic or diluted earnings per share, because the CS affiliates were required to return all borrowed shares (or identical shares).

In the fourth quarter 2009, CS returned 5,400,000 of these shares in connection with the maturity of the CSF II Debt, and 6,600,000 common shares, with a fair value of $156 million, remained outstanding at December 31, 2009. CS returned these 6,600,000 shares of NRG as part of the CSF I Debt unwind on March 2, 2010. The 12,000,000 shares of NRG common stock were returned to treasury stock and are no longer be treated as outstanding for corporate law purposes.

Preferred Stock

5.75% Preferred Stock

On February 2, 2006, NRG completed the issuance of 2,000,000 shares of 5.75% Mandatory Convertible Preferred Stock, or 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 $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. The 5.75% Preferred Stock agreement provided for automatic conversion into common stock on March 16, 2009, and for earlier conversion under certain circumstances. All conversions and redemptions were completed by March 25, 2009.

4% Preferred Stock

The Company's 4% Convertible Perpetual Preferred Stock, or 4% Preferred Stock, had a liquidation preference of $1,000 per share, and its holders were entitled to receive 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 was 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. In the fourth quarter of 2009, NRG notified the holders of the Company's intention to redeem the 4% Preferred Stock, and the majority of the holders elected to convert their shares in response to this notification. All conversions and redemptions were completed by January 21, 2010.

Redeemable Preferred Stock

3.625% Preferred Stock

On August 11, 2005, NRG issued 250,000 shares of 3.625% Convertible Perpetual Preferred Stock, or 3.625% Preferred Stock, which is treated as Redeemable Preferred Stock, to CS in a private placement. 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 stockholder. 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 in value 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 twenty consecutive scheduled trading days starting on the date thirty 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, 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 and Variable Interest Entities

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, 2011:

Name	Geographic Area	Economic Interest
Avenal Solar Holdings LLC	United States	50.0%
GenConn Energy LLC	United States	50.0%
Saguaro Power Company	United States	50.0%
Sherbino I Wind Farm LLC	United States	50.0%
Texas Coastal Ventures, LLC	United States	50.0%
Gladstone Power Station	Australia	37.5%
Energy Technology Ventures	United States	33.3%

	As of December 31,	
	2011	2010
	(In millions)	
Undistributed earnings from equity investments	$ 150	$ 160

Variable Interest Entities, or VIEs

NRG accounts for its interests in certain entities that are considered VIEs under ASC 810, but NRG is not the primary beneficiary, under the equity method.

GenConn Energy LLC — Through its subsidiary, NRG Connecticut Peaking, NRG owns a 50% interest in GenConn, a limited liability company formed to construct, own and operate two 200MW peaking generation facilities in Connecticut at NRG's Devon and Middletown sites. Each of these facilities was constructed pursuant to 30-year cost of service type contracts with the Connecticut Light & Power Company. All four units at the GenConn Devon facility reached commercial operation in 2010 and were released to the ISO-NE by July 2010. In June 2011, the GenConn Middletown facility reached commercial operation and was released to the ISO-NE.

The project was funded through equity contributions from the owners and non-recourse, project level debt. As of December 31, 2010, NRG Connecticut Peaking had $61 million, of outstanding borrowings under an EBL, as described in Note 12, *Debt and Capital Leases* and had a note receivable due from GenConn for $62 million as discussed in Note 9, *Capital Leases and Notes Receivable*. When the Middletown project reached its commercial operations date, NRG Connecticut Peaking repaid the $61 million portion of the EBL used to fund the Middletown project, and converted $62 million of the note receivable from GenConn into equity. As of December 31, 2011, NRG had a $131 million equity investment in GenConn. NRG's maximum exposure to loss is limited to its equity investment.

In April 2009, GenConn secured financing for 50% of the Devon and Middletown project construction costs through a seven-year term loan facility, and also entered into a five-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 working capital facility. GenConn began to draw under the GenConn Facility to cover costs related to the Devon project in August 2009, and the Middletown project in June 2010. During 2011, the GenConn Facility was fully drawn and GenConn repaid $6 million of the GenConn Facility. As of December 31, 2011, $237 million was outstanding for the GenConn facility.

As discussed in Note 21, *Related Party Transactions*, NRG earned revenues from construction management agreements with Devon and Middletown and interest income from the note receivable with GenConn.

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 150 MW wind farm, which commenced commercial operations in October 2008. In December 2008, Sherbino entered into a 15-year term loan facility which is non-recourse to NRG. As of December 31, 2011, the outstanding principal balance of the term loan facility was $125 million, and is secured by substantially all of Sherbino's assets and membership interests. NRG's maximum exposure to loss is limited to its equity investment, which was $100 million as of December 31, 2011.

Texas Coastal Ventures, LLC — NRG owns a 50% interest in Texas Coastal Ventures, LLC, or TCV, a joint venture with Hilcorp Energy I, L.P., through its subsidiary Petra Nova LLC. Texas Coastal Ventures was formed by Petra Nova and Hilcorp for the purpose of using carbon dioxide captured from flue gas from certain of NRG's coal-generating power plants in the United States Gulf Coast in an enhanced oil recovery process. TCV is managed by the joint venture participants and operated by Hilcorp. TCV entered into service agreements with Petra Nova LLC, which include a management services agreement for the operation and management of the joint venture's pipeline assets, as well as a CO_2 supply agreement having an initial term of twenty years. NRG's maximum exposure to loss is limited to its equity investment, which was $48 million as of December 31, 2011.

Other Equity Investments

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.

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. Share borrowed under the SLA (see Note 15, *Capital Structure*) were not treated as outstanding for earnings per share purposes.

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 — Prior to their conversion, NRG's 4% and 5.75% Preferred Stock were not considered outstanding for purposes of computing basic earnings per share. However, these instruments were 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.

The reconciliation of NRG's basic earnings per share to diluted earnings per share is shown in the following table:

	Year Ended December 31,		
	2011	2010	2009
	(In millions, except per share amounts)		
Basic earnings per share attributable to NRG common stockholders			
Numerator:			
Net income attributable to NRG Energy, Inc.	$ 197	$ 477	$ 942
Preferred stock dividends	(9)	(9)	(33)
Net income attributable to NRG Energy, Inc. available to common stockholders	$ 188	$ 468	$ 909
Denominator:			
Weighted average number of common shares outstanding	240	252	246
Basic earnings per share:			
Net income attributable to NRG Energy, Inc.	$ 0.78	$ 1.86	$ 3.70
Diluted earnings per share attributable to NRG common stockholders			
Numerator:			
Net income attributable to NRG Energy, Inc.	$ 188	$ 468	$ 909
Add preferred stock dividends for dilutive preferred stock	—	—	23
Net income attributable to NRG Energy, Inc. available to common stockholders	$ 188	$ 468	$ 932
Denominator:			
Weighted average number of common shares outstanding	240	252	246
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	1	1	1
Incremental shares attributable to the assumed conversion features of outstanding preferred stock (if-converted method)	—	1	24
Total dilutive shares	241	254	271
Diluted earnings per share:			
Net income attributable to NRG Energy, Inc.	$ 0.78	$ 1.84	$ 3.44

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,		
	2011	2010	2009
	(In millions of shares)		
Equity compensation — NQSOs and PUs	7	6	6
Embedded derivative of 3.625% redeemable perpetual preferred stock	16	16	16
Total	23	22	22

Note 18 — Segment Reporting

2012 Business Segment Realignment

Effective in fiscal year 2012, NRG's segment structure and its allocation of corporate expenses were updated to reflect how management currently makes financial decisions and allocates resources. The Company has recast the data from prior periods to reflect this change in reportable segments to conform to the current year presentation. The Company's businesses are primarily segregated based on the Retail businesses, conventional power generation, alternative energy businesses and corporate activities. Within NRG's conventional 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 Other, which includes its international businesses, thermal and chilled water business and maintenance services. The Company's alternative energy businesses include solar and wind assets, electric vehicle services and carbon capture business. Intersegment sales are accounted for at market.

For the years ended December 31, 2011, 2010, and 2009, there were no customers from whom the Company derived more than 10% of the Company's consolidated revenues.

	Year Ended December 31, 2011									
		Conventional Power Generation								
	Retail[a][b]	Texas[a]	North-east[a]	South Central	West	Other[a]	Alternative Energy[a]	Corporate	Elimination	Total
	(In millions)									
Operating revenues	$ 5,642	$ 2,832	$ 924	$ 817	$ 149	$ 323	$ 44	$ 11	$ (1,663)	$ 9,079
Operating expenses	5,113	1,910	858	703	92	282	63	30	(1,663)	7,388
Depreciation and amortization	159	463	118	89	10	14	31	12	—	896
Impairment charge on emission allowances	—	160	—	—	—	—	—	—	—	160
Operating income/(loss)	370	299	(52)	25	47	27	(50)	(31)	—	635
Equity in earnings/(loss) of unconsolidated affiliates	—	—	11	—	9	9	6	—	—	35
Impairment charge on investment	—	—	—	—	—	—	—	(495)	—	(495)
Other income/(loss), net	—	1	2	2	—	5	3	21	(15)	19
Loss on debt extinguishment and refinancing expense	—	—	—	—	—	—	—	(175)	—	(175)
Interest (expense)/income	(4)	16	(47)	(41)	(2)	(15)	(16)	(571)	15	(665)
Income/(loss) before income taxes	366	316	(86)	(14)	54	26	(57)	(1,251)	—	(646)
Income tax expense/(benefit)	(3)	—	—	—	—	7	—	(847)	—	(843)
Net income/(loss)	$ 369	$ 316	$ (86)	$ (14)	$ 54	$ 19	$ (57)	$ (404)	$ —	$ 197

Balance sheet										
Equity investments in affiliates	$ —	$ —	$ 136	$ —	$ 28	$ 308	$ 168	$ —	$ —	$ 640
Capital expenditures [c]	23	99	188	25	281	40	1,809	137	—	2,602
Goodwill	173	1,713	—	—	—	—	—	—	—	1,886
Total assets	$ 2,725	$ 13,006	$ 2,042	$ 1,436	$ 669	$ 1,006	$ 3,154	$ 19,694	$ (17,017)	$ 26,715

[a] Includes intersegment sales of:	$ 5	$ 1,586	$ 43	$ —	$ —	$ 18	$ 16	$ —

[b] Includes Green Mountain Energy results, and Energy Plus results for the period October 1, 2011 to December 31, 2011.

[c] Includes accruals.

	Year Ended December 31, 2010									
		Conventional Power Generation								
	Retail[(a)(b)]	Texas[(a)]	North-east	South Central	West	Other[(a)]	Alternative Energy[(a)]	Corporate	Elimination	Total
	(In millions)									
Operating revenues	$ 5,055	$ 3,040	$ 1,025	$ 608	$ 138	$ 301	$ 41	$ 1	$ (1,360)	$ 8,849
Operating expenses	4,547	1,749	847	506	98	260	38	41	(1,360)	6,726
Depreciation and amortization	127	466	122	67	9	12	27	8	—	838
Gains on sale of asset	—	—	—	—	—	—	—	23	—	23
Operating income/(loss)	381	825	56	35	31	29	(24)	(25)	—	1,308
Equity in earnings of unconsolidated affiliates	—	—	1	—	6	24	14	(1)	—	44
Other income/(loss), net	—	2	4	1	1	18	—	24	(17)	33
Loss on debt extinguishment and refinancing expense	—	—	—	—	—	—	—	(2)	—	(2)
Interest (expense)/income	(5)	79	(57)	(46)	(2)	(14)	(13)	(589)	17	(630)
Income/(loss) before income taxes	376	906	4	(10)	36	57	(23)	(593)	—	753
Income tax expense	—	—	—	—	—	17	—	260	—	277
Net income/(loss)	376	906	4	(10)	36	40	(23)	(853)	—	476
Less: Net loss attributable to noncontrolling interest	—	(1)	—	—	—	—	—	—	—	(1)
Net income/(loss) attributable to NRG Energy, Inc.	$ 376	$ 907	$ 4	$ (10)	$ 36	$ 40	$ (23)	$ (853)	$ —	$ 477
Balance sheet										
Equity investments in affiliates	$ —	$ —	$ 67	$ —	$ 42	$ 312	$ 115	$ —	$ —	$ 536
Capital expenditures [(c)]	12	88	206	18	67	29	33	646	—	1,099
Goodwill	147	1,713	—	—	—	—	—	8	—	1,868
Total assets	$ 2,190	$12,695	$ 1,891	$ 1,350	$ 348	$ 1,082	$ 783	$ 29,812	$ (23,255)	$26,896

[(a)] Includes intersegment sales of: $ 2 $ 1,304 $ — $ — $ — $ 25 $ 23 $ —
[(b)] Includes Green Mountain Energy results for the period November 5, 2010 to December 31, 2010.
[(c)] Includes accruals.

	Year Ended December 31, 2009									
		Wholesale Power Generation								
	Retail[(b)]	Texas[(a)]	North-east[(a)]	South Central	West	Other	Alternative Energy	Corporate	Elimination	Total
	(In millions)									
Operating revenues	$ 4,182	$ 2,938	$ 1,201	$ 581	$ 150	$ 286	$ 8	$ 28	$ (422)	$ 8,952
Operating expenses	3,044	1,636	740	508	110	227	8	127	(425)	5,975
Depreciation and amortization	137	459	118	67	8	10	13	6	—	818
Operating income/(loss)	1,001	843	343	6	32	49	(13)	(105)	3	2,159
Equity in earnings/(loss) of unconsolidated affiliates	—	—	—	—	10	31	—	—	—	41
Gains on sales of equity method investments	—	—	—	—	—	128	—	—	—	128
Other income, net	—	3	2	1	—	(16)	—	27	(22)	(5)
Loss on debt extinguishment and refinancing expense	(1)	—	—	—	—	—	—	(19)	—	(20)
Interest expense	(34)	6	(54)	(48)	(2)	(13)	(10)	(497)	18	(634)
Income/(loss) before income taxes	966	852	291	(41)	40	179	(23)	(594)	(1)	1,669
Income tax expense	—	171	—	—	—	9	—	548	—	728
Net income/(loss)	966	681	291	(41)	40	170	(23)	(1,142)	(1)	941
Less: Net loss attributable to noncontrolling interest	—	(1)	—	—	—	—	—	—	—	(1)
Net income/(loss) attributable to NRG Energy, Inc.	$ 966	$ 682	$ 291	$ (41)	$ 40	$ 170	$ (23)	$ (1,142)	$ (1)	$ 942

[(a)] Includes intersegment sales of: $ — $ 381 $ 37 $ — $ — $ — $ — $ —
[(b)] Results are for the period May 1, 2009, to December 31, 2009.

Note 19 — Income Taxes

The income tax provision from continuing operations consisted of the following amounts:

	Year Ended December 31,		
	2011	2010	2009
	(In millions, except percentages)		
Current			
U.S. Federal	$ (538)	$ 211	$ 99
State	10	35	20
Foreign	16	23	18
	(512)	269	137
Deferred			
U.S. Federal	(317)	23	599
State	(5)	(9)	1
Foreign	(9)	(6)	(9)
	(331)	8	591
Total income tax	$ (843)	$ 277	$ 728
Effective tax rate	130.5%	36.8%	43.6%

The following represents the domestic and foreign components of income before income tax expense:

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
U.S.	$ (680)	$ 691	$ 1,508
Foreign	34	62	161
Total	$ (646)	$ 753	$ 1,669

A reconciliation of the U.S. federal statutory rate of 35% to NRG's effective rate is as follows:

	Year Ended December 31,		
	2011	2010	2009
	(In millions, except percentages)		
(Loss)/Income Before Income Taxes	$ (646)	$ 753	$ 1,669
Tax at 35%	(226)	264	584
State taxes, net of federal benefit	15	18	23
Foreign operations	(3)	(3)	(53)
Federal and state tax credits	(1)	(7)	—
Valuation allowance	(63)	(34)	119
Expiration/utilization of capital losses	45	—	249
Reversal of valuation allowance on expired/utilized capital losses	(45)	—	(249)
Change in state effective tax rate	—	—	(5)
Foreign earnings	4	17	33
Non-deductible interest	—	4	10
Interest accrued on uncertain tax positions	2	25	9
Production tax credit	(14)	(11)	(10)
Reversal of uncertain tax position reserves	(561)	—	—
Other	4	4	18
Income tax (benefit)/expense	$ (843)	$ 277	$ 728
Effective income tax rate	130.5%	36.8%	43.6%

The effective tax rate for the year ended December 31, 2011, differs from the statutory rate of 35% primarily due to a benefit of $633 million resulting from the resolution of the federal tax audit. The benefit is predominantly due to the recognition of previously uncertain tax benefits that were settled upon audit in 2011 and that were mainly composed of net operating losses of $536 million which had been classified as capital loss carryforwards for financial statement purposes.

The effective tax rate for the year ended December 31, 2010, differs from the statutory rate of 35% primarily due to the impact of state and local income taxes and interest on uncertain tax positions, which were partially offset by the reduction in the valuation allowance resulting from realized capital gains as well as federal and state tax credits generated during the current year.

The effective income tax rate for the year ended December 31, 2009, differs from the U.S. statutory rate of 35% primarily due to an increase in the valuation allowance as a result of capital 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 facility which resulted in minimal tax due to the local jurisdiction.

The temporary differences, which gave rise to the Company's deferred tax assets and liabilities consisted of the following:

	As of December 31,	
	2011	2010
	(In millions)	
Deferred tax liabilities:		
Discount/premium on notes	$ 7	$ 9
Emissions allowances	92	116
Difference between book and tax basis of property	1,604	1,652
Derivatives, net	244	362
Goodwill	139	117
Anticipated repatriation of foreign earnings	—	6
Cumulative translation adjustments	27	28
Intangibles amortization (excluding goodwill)	229	180
Investment in projects	111	71
Other	8	—
Total deferred tax liabilities	2,461	2,541
Deferred tax assets:		
Deferred compensation, pension, accrued vacation and other reserves	80	67
Differences between book and tax basis of contracts	225	59
Pension and other postretirement benefits	137	111
Non-depreciable property	—	19
Equity compensation	36	30
Bad debt reserve	15	12
U.S. capital loss carryforwards	1	92
U.S. Federal net operating loss carryforwards	84	—
Foreign net operating loss carryforwards	70	74
State net operating loss carryforwards	53	23
Foreign capital loss carryforwards	1	1
Deferred financing costs	—	6
Federal and state tax credits	64	34
Federal benefit on state uncertain tax positions	20	31
Contingent liability reserve	—	30
NINA impairment	183	—
Emission allowance impairment	59	—
Other	—	46
Total deferred tax assets	1,028	635
Valuation allowance	(83)	(191)
Net deferred tax assets	945	444
Net deferred tax liability	$ 1,516	$ 2,097

The following table summarizes NRG's net deferred tax position:

	As of December 31,	
	2011	2010
	(In millions)	
Current deferred tax liability	$ 127	$ 108
Non-current deferred tax liability	1,389	1,989
Net deferred tax liability	$ 1,516	$ 2,097

Tax Receivable and Payable

As of December 31, 2011, NRG recorded a current tax payable of $17 million that represents a tax liability due for domestic state taxes of $14 million, as well as foreign taxes payable of $3 million. NRG has a domestic tax receivable of $56 million, of which $25 million relates to federal cash grants applied for eligible solar energy projects under development in New Mexico and Arizona, $18 million is related to property tax refunds due to the New York State Empire Zone program and $13 million primarily is due to federal refunds on prior year returns. In addition, we have recorded a $49 million non-current asset for Empire Zone credits generated in 2010 and 2011 that are being deferred pursuant to New York State law.

Deferred tax assets and valuation allowance

Net deferred tax balance — As of December 31, 2011, and 2010, NRG recorded a net deferred tax liability of $1.4 billion and $1.9 billion, 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 $83 million and $191 million of tax assets, thus a valuation allowance has remained, resulting in a net deferred tax liability of $1.5 billion and $2.1 billion as of December 31, 2011, and 2010, 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, 2011.

NOL carryforwards — At December 31, 2011, the Company had domestic net operating losses, or NOLs, consisting of carryforwards for federal income tax purposes of $84 million and cumulative state NOLs of $53 million. In addition, NRG has cumulative foreign NOL carryforwards of $70 million of which $20 million will expire starting 2012 through 2019 and of which $50 million do not have an expiration date. At December 31, 2010 the Company had state NOLs of $23 million and cumulative foreign NOL carryforwards of $74 million.

Valuation allowance — As of December 31, 2011, the Company's valuation allowance was reduced by $108 million, primarily due to resolution of the federal tax audit.

Uncertain tax benefits

NRG has identified uncertain tax benefits whose after-tax value was $178 million that if recognized, would impact the Company's income tax expense.

As of December 31, 2011, and 2010, NRG has recorded a non-current tax liability of $58 million and $582 million, respectively. As of December 31, 2011, the balance primarily related to positions taken on various state returns, including accrued interest. As of December 31, 2010, the balance primarily related to 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 uncertain tax benefits in income tax expense. During the year ended December 31, 2011, the Company recognized a benefit of $32 million in interest and penalties due to the IRS settlement and accrued interest of $2 million. For the year ended December 31, 2010, the Company recognized $25 million in interest and penalties. As of December 31, 2011, and 2010, NRG had accrued interest and penalties related to these uncertain tax benefits of $12 million and $42 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 operations located in Germany and Australia. The Company is no longer subject to U.S. federal income tax examinations for years prior to 2007. 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 2004.

During 2011, the Company settled the Internal Revenue Service's audit examination for the years 2004 through 2006 and recognized a benefit of $633 million. The benefit is predominantly due to the recognition of previously uncertain tax benefits mainly composed of net operating losses of $536 million which had been classified as capital loss carryforwards for financial statement purposes. The Company continues to be under examination for various state jurisdictions for multiple years.

The following table reconciles the total amounts of uncertain tax benefits:

	As of December 31,	
	2011	2010
	(In millions)	
Balance as of January 1	$ 663	$ 643
Increase due to current year positions	12	27
Decrease due to current year positions	(6)	(15)
Increase due to prior year positions	6	16
Decrease due to prior year positions	(2)	(7)
Decrease due to settlements and payments	(495)	—
Decrease due to statute expirations	—	(1)
Uncertain tax benefits as of December 31	$ 178	$ 663

Included in the balance at December 31, 2011, are $30 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductions. 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.

Note 20 — Stock-Based Compensation

Long-Term Incentive Plan, or LTIP

As of December 31, 2011, and 2010, a total of 22,000,000 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 7,957,697 and 10,141,819 shares of common stock remaining available for grants under NRG's LTIP as of December 31, 2011, and 2010, respectively.

Non-Qualified Stock Options, or NQSOs

NQSOs granted under the LTIP typically have three or five-year graded vesting schedules beginning on the grant date and become exercisable at the end of the requisite service period. NRG recognizes compensation costs for NQSOs over the requisite service period for the entire award. The maximum contractual term is ten years for 3.0 million of NRG's outstanding NQSOs, and six years for the remaining 2.6 million NQSOs.

The following table summarizes the Company's NQSO activity and changes during the year:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In millions)
	(In whole)			
Outstanding at December 31, 2010	5,079,399	$ 24.22	4	$ 8
Granted	1,168,000	19.86		
Forfeited	(564,433)	28.21		
Exercised	(99,777)	22.28		
Outstanding at December 31, 2011	5,583,189	22.93	4	7
Exercisable at December 31, 2011	3,706,813	23.72	2	7

The following table summarizes the weighted average grant date fair value of options granted, the total intrinsic value of options exercised, and the cash received from the exercises of options:

	Year Ended December 31,		
	2011	2010	2009
	(In millions, except for weighted average)		
Weighted average grant date fair value per option granted	$ 8.73	$ 10.22	$ 8.64
Total intrinsic value of options exercised	0.2	0.3	1.4
Cash received from the exercise of options exercised	2	2	2

The fair value of the Company's NQSOs is estimated on the date of grant using the Black-Scholes option-pricing model. Significant assumptions used in the fair value model with respect to the Company's NQSOs are summarized below:

	Year Ended December 31,		
	2011	2010	2009
Expected volatility	42.38%-42.57%	41.28%-42.57%	44.36%-48.29%
Expected term (in years)	6	6-6.5	4
Risk free rate	1.42%-2.71%	1.54%-3.01%	1.43%-1.93%

For the years ended December 31, 2011, 2010, and 2009, 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 NQSOs 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 RSUs

Typically, RSUs granted under the Company's LTIP fully vest three years from the date of issuance. Fair value of the RSUs 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 and changes during the year:

	Units	Weighted Average Grant-Date Fair Value per Unit
	(In whole)	
Non-vested at December 31, 2010	1,439,839	$ 26.30
Granted	1,186,900	21.22
Forfeited	(182,880)	22.97
Vested	(101,344)	36.44
Non-vested at December 31, 2011	2,342,515	23.54

The total fair value of RSUs vested during the years ended December 31, 2011, 2010, and 2009, was $2 million, $9 million and $8 million, respectively. The weighted average grant date fair value of RSUs granted during the years ended December 31, 2011, 2010, and 2009 was $21.22, $22.78, and $26.13, respectively.

Deferred Stock Units, or DSUs

DSUs 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. DSUs granted under the Company's LTIP are fully vested at the date of issuance. Fair value of the DSUs, 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 and changes during the year:

	Units	Weighted Average Grant-Date Fair Value per Unit
	(In whole)	
Outstanding at December 31, 2010	334,721	$ 19.63
Granted	53,896	24.31
Conversions	(14,933)	25.41
Outstanding at December 31, 2011	373,684	20.07

The aggregate intrinsic values for DSUs outstanding as of December 31, 2011, 2010, and 2009 were approximately $8 million, $7 million, and $7 million respectively. The aggregate intrinsic values for DSUs converted to common stock for the years ended December 31, 2011, 2010, and 2009 were $0.4 million, $0.7 million and $0.5 million, respectively. The weighted average grant date fair value of DSUs granted during the years ended December 31, 2011, 2010, and 2009 was $24.31, $22.18 and $22.77, respectively.

Performance Units, or PUs

PUs granted under the Company's LTIP fully vest three years from the date of issuance. PUs 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. PUs 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 and changes during the year:

	Outstanding Units	Weighted Average Grant-Date Fair Value per Unit
	(In whole)	
Non-vested at December 31, 2010	819,000	$ 23.71
Granted	504,800	20.80
Forfeited	(284,300)	24.98
Non-vested at December 31, 2011	1,039,500	21.95

The weighted average grant date fair value of PUs granted during the years ended December 31, 2011, 2010, and 2009 was $20.80, $22.70, and $22.91, respectively.

The fair value of PUs 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 with respect to the Company's PUs are summarized below:

	2011	2010	2009
Expected volatility	46.96%-53.15%	44.77%-53.81%	48.48%-53.00%
Expected term (in years)	3	3-5	3
Risk free rate	0.50%-1.41%	0.59%-1.66%	1.14%-1.48%

For the years ended December 31, 2011, 2010, and 2009, 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 for the years presented 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, 2011, for each of the four types of awards issued under the Company's LTIP. Minimum tax withholdings of $1 million, $4 million, and $3 million during 2011, 2010, and 2009, 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			Non-vested Compensation Cost: Unrecognized Total Cost	Non-vested Compensation Cost: Weighted Average Recognition Period Remaining (In years)
	Year Ended December 31			As of December 31	
Award	2011	2010	2009	2011	2011
	(In millions, except weighted average data)				
NQSOs	$ 8	$ 8	$ 9	$ 10	$ 0.6
RSUs	12	15	11	28	1.9
DSUs	2	1	1	—	—
PUs	5	6	5	10	1.4
Total	$ 27	$ 30	$ 26	$ 48	
Tax benefit recognized	$ 1	$ 2	$ 4		

Other Compensation Arrangements

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 $0.1 million, $1 million, and $2 million for the years ended December 31, 2011, 2010, and 2009, 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,		
	2011	2010	2009
	(In millions)		
Revenues from Related Parties Included in Operating Revenues			
MIBRAG [(a)]	$ —	$ —	$ 2
Gladstone	7	3	2
GenConn [(b)(c)]	3	5	7
Total	$ 10	$ 8	$ 11
Expenses from Related Parties Included in Cost of Operations			
Cost of purchased coal — MIBRAG [(a)]	$ —	$ —	$ 43
Interest income from Related Parties Included in Other Income and Expense			
GenConn [(b)(c)]	1	3	2
Kraftwerke Schkopau GBR	4	4	4
Total	$ 5	$ 7	$ 6

(a) The period in 2009 is from January 1, 2009, to June 10, 2009.

(b) The period in 2009 is from April 1, 2009, to December 31, 2009.

(c) The period in 2011 is from January 1, 2011 to June 30, 2011.

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 — Under a construction management agreement, or CMA, with GenConn , NRG has received fees for management, design and construction services. The construction at GenConn was completed in June 2011. In addition, NRG entered into a loan agreement with GenConn during 2009, pursuant to which it received interest income, which was converted into equity during 2011. See further discussion in Note 16, *Investments Accounted for by the Equity Method and Variable Interest Entities.*

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. Subsequent to the sale, MIBRAG is no longer a related party.

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 $81 million, $111 million, and $102 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Future minimum lease commitments under operating leases for the years ending after December 31, 2011, are as follows:

Period	(In millions)
2012	$ 67
2013	63
2014	62
2015	57
2016	49
Thereafter	280
Total	$ 578

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, 2011, 2010, and 2009, the Company purchased $1.6 billion, $1.5 billion, and $1.4 billion, respectively, under such arrangements.

As of December 31, 2011, the Company's commitments under such outstanding agreements are estimated as follows:

Period	(In millions)
2012	$ 891
2013	130
2014	136
2015	103
2016	101
Thereafter	484
Total (a)	$ 1,845

(a) Includes those coal transportation and lignite commitments for 2012 as no other nominations were made as of December 31, 2011. Natural gas nomination is through February 2016.

Purchased Power Commitments

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, 2011. Minimum purchase commitment obligations are as follows as of December 31, 2011:

Period	(In millions)
2012	$ 37
2013	21
2014	11
2015	9
2016	9
Thereafter	9
Total (a)	$ 96

(a) As of December 31, 2011, the maximum remaining term under any individual purchased power contract is six years.

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 extends through 2018 with an option to further 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 $108 million on TWCC for the reclamation of this lignite mine. Pursuant to the contract with TWCC, NRG supports this obligation as follows: $50 million is guaranteed by NRG Energy, Inc., $32 million is supported by letters of credit posted by NRG, and NRG pays the cost of TWCC bonding the remaining $26 million. Additionally, NRG is required to provide additional performance assurance over TWCC's current bond obligations if required by the Railroad Commission of Texas.

First Lien Structure

NRG has granted first liens to certain counterparties on substantially all of the Company's assets 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. The Company's lien counterparties may have a claim on NRG's assets to the extent market prices exceed the hedged price. As of December 31, 2011, all hedges under the first lien were in-the-money for NRG on a counterparty aggregate basis.

Nuclear Insurance

STP maintains required insurance coverage for liability claims arising from nuclear incidents pursuant to the Price-Anderson Amendment to the Energy Policy Act of 2005, referred to as the Price-Anderson Act. As of December 31, 2011, the current liability limit per incident was $12.6 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every five years with the most recent adjustment effective October 29, 2008. Under the Price-Anderson Act, owners of nuclear power plants in the U.S. are required to purchase primary insurance limits of $375 million for each operating site. In addition, the Price-Anderson Act requires an additional layer of protection through mandatory participation in a retrospective rating plan for power reactors resulting in an additional $12.2 billion in funds available for public liability claims. The current maximum assessment per incident, per reactor, is $117.5 million, payable at no more than $17.5 million per year. NRG would be responsible for 44% of the maximum assessment, or $7.7 million per year. In addition, the U.S. Congress retains the ability to impose additional financial requirements on the nuclear industry to pay liability claims that exceed $12.6 billion for a single incident. The liabilities of the co-owners of STP with respect to the retrospective premium assessments for nuclear liability insurance are joint and several.

STP purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Limited, or NEIL, an industry mutual insurance company, of which STP is a member. STP has purchased $2.75 billion in limits, the maximum available from NEIL. The upper $1 billion in limits (excess of the first $1.75 billion in limits) is a single limit blanket policy shared with the DC Cook and Diablo Canyon nuclear reactors, two reactors that have no affiliation with the Company. This shared limit is not subject to automatic reinstatement in the event of a loss. The NEIL policy covers both nuclear and non-nuclear property damage events, and includes coverage for 6 weeks of lost revenue following a property damage event, at a weekly indemnity limit of $3.5 million, subject to a 17 week waiting period. NRG also purchased an Accidental Outage policy from NEIL, which provides additional protection for lost revenue due to an insurable event. This coverage allows for reimbursement up to $3.5 million per week up to a maximum of $473.2 million, and is subject to a 23 week waiting period. Under the terms of the NEIL policies, member companies may be assessed up to 10 times their annual premium if the NEIL Board of Directors determines their surplus has been depleted due to the payment of property losses at any of the licensed reactors in a single policy year. NEIL requires that its members maintain an investment grade credit rating or insure their annual retrospective obligation by providing a financial guarantee, letter of credit, deposit premium, or an insurance policy. NRG has purchased an insurance policy from NEIL to guarantee the Company's obligation; however this insurance will only respond to retrospective premium adjustments assessed within 24 months after the policy term, whereas NEIL's Board of Directors can make such an adjustment up to 6 years after the policy expires.

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, *Contingencies* 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 California Department of Water Resources, or 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 Federal Energy Regulatory Commission, 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, the FERC has not acted on remand.

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.

Louisiana Generating, LLC

On February 11, 2009, the U.S. Department of Justice, or U.S. DOJ, acting at the request of the U.S. Environmental Protection Agency, or U.S. EPA, commenced a lawsuit against Louisiana Generating, LLC, or LaGen, 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 LaGen 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 U.S. DOJ 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, LaGen 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. LaGen also filed a complaint, or adversary proceeding, in the same bankruptcy proceeding, 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 with respect to environmental liabilities arising prior to the acquisition; and (iii) Cajun Electric and/or the Bankruptcy Trustee are exclusively liable for any of the violations alleged in the February 11, 2009, lawsuit to the extent that such claims are determined to have merit. On April 15, 2010, the bankruptcy court signed an order granting LaGen's stipulation of voluntary dismissal without prejudice of the adversary proceeding. The bankruptcy proceeding has since closed.

On August 24, 2009, LaGen filed a motion to dismiss this lawsuit, and on September 25, 2009, the U.S. DOJ filed its opposition to the motion. Thereafter, on February 18, 2010, the Louisiana Department of Environmental Quality, or LDEQ, filed a motion to intervene in the above lawsuit and a complaint against LaGen for alleged violations of Louisiana's Prevention of Significant Deterioration, or PSD, regulations and Louisiana's Title V operating permit program. LDEQ seeks substantially similar relief to that requested by the U.S. DOJ. On February 19, 2010, the district court granted LDEQ's motion to intervene. On April 26, 2010, LaGen filed a motion to dismiss the LDEQ complaint. On July 21, 2010, the motions to dismiss the U.S. DOJ and LDEQ complaints were argued to the district court. On August 20, 2010, the parties submitted proposed findings of fact and conclusions of law, and thereafter submitted additional briefing on emerging jurisprudence from other jurisdictions touching on the issues at stake in the lawsuit. On February 4, 2011, LaGen filed motions for summary judgment requesting that the court dismiss all of the U.S. DOJ's claims. Also on February 4, 2011, the U.S. DOJ filed three motions for partial summary judgment. Additional summary judgment briefing was filed by the parties on April 4, 2011. On November 2, 2011, the court heard oral argument on three motions for summary judgment. On December 1, 2011, the court issued an order denying two of LaGen's motions for summary judgment addressing potential legal defenses to CAA liability. In the same Order, the court also granted, in part, the U.S. DOJ's motion for summary judgment on its successor liability theory. The court held that LaGen could be found to have assumed liability for alleged PSD violations under the terms of the agreement through which LaGen acquired Big Cajun II in 2000, but ruled that the facts necessary to determine whether any such liabilities were actually assumed must be determined at a liability-phase trial, if necessary. In its December 1, 2011, decision, the court also ruled that any potential civil penalties would not be available for the periods prior to the five year period preceding the filing of the lawsuit on February 11, 2009.

Three additional motions for summary judgment and multiple motions in limine, including motions that could result in dismissal of the governments' claims before trial if resolved in LaGen's favor, remain pending before the court, with some of these motions set to be argued on March 21, 2012. On January 17, 2012, LaGen filed a demand for a jury trial. On January 20, 2012, the court scheduled a liability-phase trial for October 15, 2012, should the case proceed to that stage, and a remedy-phase trial set to occur at a later date to be determined in the event of an adverse decision in a liability-phase trial. Because of the inherent uncertainty of litigation, including the fact that no determination of liability has yet been made by the Court, NRG cannot predict the impact, at this time, that this matter may have on the Company's business, results of operations, financial position, or cash flows.

In a related matter, soon after the filing of the above referenced U.S. DOJ lawsuit, LaGen sought insurance coverage from its insurance carrier, Illinois Union Insurance Company, or ILU. ILU denied coverage and thereafter LaGen filed this lawsuit (which was consolidated with a prior suit filed by ILU) seeking a declaration that ILU must provide coverage to LaGen for the defense costs incurred in defending the U.S. DOJ lawsuit. LaGen and ILU both filed motions for summary judgment and on January 30, 2012, the court issued an order granting LaGen's motion finding that ILU has a duty to defend LaGen.

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 Energy, Inc. (formerly Reliant Energy, Inc.), 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, and 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's Petition for Review with the Supreme Court of Texas was accepted. Oral argument occurred on October 6, 2009, and on March 18, 2011, the Texas Supreme Court reversed the Court of Appeals, finding no basis for deducting EMCs credited to RERS. Motions for rehearing were filed on May 4, 2011. On June 10, 2011, the Texas Supreme Court denied all motions for rehearing, thereby ending the matter.

In November 2008, CenterPoint Energy and Reliant Energy Inc., or REI, 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. The agreed upon suspension of unexpired deadlines ceased on August 29, 2011. 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.

Wise v. Energy Plus Holdings, LLC

On October 18, 2011, plaintiff filed a purported class action lawsuit on behalf of New York consumers against Energy Plus in the U.S. District Court for the Southern District of New York. Claiming statutory damages in excess of $5 million, the plaintiff alleges violations of New York business laws as well as unjust enrichment. Specifically, the plaintiff claims that Energy Plus misrepresents that its rates are competitive in the market; fails to disclose that its rates are substantially higher than those in the market and that Energy Plus has engaged in deceptive practices in its marketing of energy services. Plaintiff seeks that this matter be certified as a class action, with treble damages, interest, costs, attorneys fees, and any other relief that the court deems just and proper. On January 11, 2012, plaintiff filed an amended complaint in which they added another co-plaintiff, made additional claims as to how they became customers of Energy Plus and made some additional allegations as to alleged representations on the Energy Plus website. On February 1, 2012, Energy Plus filed a motion to dismiss the amended complaint. Oral argument on the motion to dismiss is scheduled to be heard on March 23, 2012.

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.

California — On May 4, 2010, in *Southern California Edison Company v. FERC,* the U.S. Court of Appeals for the D.C. Circuit vacated FERC's acceptance of station power rules for the CAISO market, and remanded the case for further proceedings at FERC. On August 30, 2010, FERC issued an Order on Remand effectively disclaiming jurisdiction over how the states impose retail station power charges. Due to reservation-of-rights language in the California utilities' state-jurisdictional station power tariffs, FERC's ruling arguably requires California generators to pay state-imposed retail charges back to the date of enrollment by the facilities in the CAISO's station period program (February 1, 2009, for the Company's Encina and El Segundo facilities; March 1, 2009, for the Company's Long Beach facility). On February 28, 2011, FERC issued an order denying rehearing. The Company, together with other generators, filed an appeal and briefing of the case is currently underway. On November 18, 2011, Southern California Edison Company filed with the California Public Utilities Commission, or CPUC, seeking authorization to begin charging generators station power charges, and to assess such charges retroactively, which the Company and other generators have challenged. The Company has filed a protest with the CPUC objecting to Southern California Edison's filing. The Company believes it has established an appropriate reserve.

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. Retail Electric Providers, 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. 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. 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. On October 6, 2010, the parties argued the appeal before the Court of Appeals for the Third District in Austin, Texas. On September 28, 2011, the Court of Appeals reversed the trial court decision, reinstating the PUCT's order, consistent with REPS' position. On January 13, 2012, Constellation filed a Petition for Review in the Supreme Court of Texas asking the Court to grant review of and reverse the Court of Appeals decision.

Retail (Midwest ISO SECA) - Green Mountain Energy previously provided competitive retail energy supply in the Midwest ISO region during the relevant period of January 1, 2002, to December 31, 2005. By order dated November 18, 2004, FERC eliminated certain regional through-and-out transmission rates charged by transmission owners in the regional electric grids operated by the Midwest Independent Transmission Systems Operator, Inc., or MISO, and PJM Interconnection, L.L.C., or PJM. In order to temporarily compensate the transmission owners for revenue lost as a result of the elimination of the through-and-out transmission rates, FERC also ordered MISO, PJM and their respective transmission owners to provide for the recovery of certain Seams Elimination Charge/Cost Adjustments/Assignments, or SECA, charges effective December 1, 2004, through March 31, 2006, based on usage during 2002 and 2003. The tariff amendments filed by MISO and the MISO transmission owners allocated certain SECA charges to various zones and sub-zones within MISO, including a sub-zone called the Green Mountain Energy Company Sub-zone. Over the last several years, there has been extensive litigation before FERC relating to these charges, seeking, among other things, to recover monies from Green Mountain Energy, and before the federal appellate courts. Green Mountain Energy has not paid any asserted SECA charges.

On May 21, 2010, FERC issued two orders. In its Order on Rehearing, FERC denied all requests for rehearing of its past orders directing and accepting the SECA compliance filings of MISO, PJM, and the transmission owners. In its Order on Initial Decision, FERC: (1) affirmed an order by the Administrative Law Judge granting Green Mountain Energy partial summary judgment and holding Green Mountain Energy not liable for SECA charges for January - March 2006; and (2) reversed an August 2006 determination by the Administrative Law Judge that Green Mountain Energy could be held directly liable for some amount of SECA charges. The Order on Initial Decision also directed that the two RTOs and their respective transmission owners submit further compliance filings, which were filed on August 19, 2010. FERC has not yet ruled on those compliance filings.

With regard to the SECA charges that had been invoiced to Green Mountain Energy, FERC determined that most of those charges, approximately $22 million plus interest, were owed not by Green Mountain Energy but rather by BP Energy — one of Green Mountain Energy's suppliers during the period at issue. On August 19, 2010, the transmission owners and MISO made compliance filings in accordance with FERC's Orders allocating SECA charges to a BP Energy Sub-zone, and making no allocation to a Green Mountain Energy sub-zone. BP Energy has not asserted any contractual claims against Green Mountain Energy. The Company believes it has established an appropriate reserve.

On September 30, 2011, FERC issued orders denying BP Energy's request for rehearing of the May 2010 Order on Rehearing, denying all requests for rehearing of the Order on Initial Decision, and again determined that SECA charges were not owed by Green Mountain Energy. Numerous parties have sought judicial review of FERC's Order on Initial Decision, and BP Energy has sought judicial review of the May 2010 Order on Rehearing. These appeals have been consolidated with previous appeals of orders relating to the SECA before the U.S. Court of Appeals for the DC Circuit. Green Mountain Energy has been granted intervenor status in the consolidated appeals. A briefing schedule has not yet been set.

Note 24 — Environmental Matters

NRG is subject to a wide range of environmental regulations across a broad number of jurisdictions in the development, ownership, construction and operation of domestic and international projects. These laws and regulations generally require that governmental permits and approvals be obtained before construction and during operation of power plants. Environmental laws have become increasingly stringent and NRG expects this trend to continue. The electric generation industry will face new requirements to address air emissions, climate change, combustion byproducts and water use. In general, future laws and regulations are expected to require the addition of emission controls or other environmental quality equipment or the imposition of certain restrictions on the operations of the Company's facilities. NRG expects that future liability under, or compliance with, environmental requirements could have a material effect on the Company's operations or competitive position.

Environmental Capital Expenditures

Based on current rules, technology and plans as well as preliminary plans based on proposed rules, NRG has estimated that environmental capital expenditures from 2012 through 2016 to meet NRG's regulatory environmental commitments will be approximately $553 million. These costs are primarily associated with mercury controls to satisfy the Mercury and Air Toxics Standards, or MATS, on the Company's Big Cajun II, W.A. Parish and Limestone facilities and a number of intake modification projects across the fleet under state or proposed federal 316(b) rules. NRG continues to explore cost effective compliance alternatives to reduce costs. While this estimate reflects anticipated schedules and controls related to the proposed 316(b) Rule, the full impact on the scope and timing of environmental retrofits from any new or revised regulations cannot be determined until these rules are final. However, NRG believes it is positioned to meet more stringent environmental regulations through its planned capital expenditures, existing controls, and increasing generation from renewable resources.

NRG's current contracts with the Company's rural electric cooperative customers in the South Central region allow for recovery of a portion of the region's environmental capital costs incurred as the result of complying with any change in environmental law. Cost recoveries begin once the environmental equipment becomes operational and include a capital return. The actual recoveries will depend, among other things, on the timing of the completion of the capital projects and the remaining duration of the contracts.

The U.S. EPA released the final Cross-State Air Pollution Rule, or CSAPR, on July 7, 2011, which was scheduled to replace the Clean Air Interstate Rule, or CAIR, on January 1, 2012. On December 30, 2011, the U.S. Court of Appeals for the D.C. Circuit stayed the rule pending resolution of the numerous petitions for judicial review. Under CSAPR, use of discounted Acid Rain SO_2 and CAIR NO_x allowances would be discontinued and replaced with completely distinct allowance programs. Acid Rain allowances would still be required on a 1:1 basis under the Acid Rain Program. Consequently, in the third quarter 2011, the Company recorded an impairment charge of $160 million on the Company's Acid Rain Program SO_2 emission allowances, which were recorded as an intangible asset on the Company's balance sheet. The impairment charge reflects the write-off of the value of emission allowances in excess of those required for compliance with the Acid Rain Program.

Northeast Region

In January 2006, NRG's Indian River Operations, Inc. received a letter of informal notification from Delaware Department of Natural Resources and Environmental Control, or 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 DNREC to investigate the site through the Voluntary Clean-up Program. On February 4, 2008, DNREC issued findings that no further action is required in relation to surface water and that a previously planned shoreline stabilization project would satisfactorily address shoreline 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 is approved, the Company is unable to predict the impact of any required remediation. On May 29, 2008, 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 DNREC and other trustees to close out the assessment phase.

Pursuant to a consent order dated September 25, 2007, and amended July 21, 2010, between NRG and DNREC regarding the Indian River plant, NRG agreed to limit the emissions of NO_x and SO_2, and to mothball Unit 1. Unit 1 was mothballed as planned on May 1, 2011.

South Central Region

On February 11, 2009, the U.S. DOJ acting at the request of the U.S. EPA commenced a lawsuit against LaGen 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 LaGen on February 15, 2005, and on December 8, 2006. Further discussion on this matter can be found in Note 22, *Commitments and Contingencies - Louisiana Generating, LLC.*

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. 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.

Note 25 — Cash Flow Information

Detail of supplemental disclosures of cash flow and non-cash investing and financing information was:

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Interest paid, net of amount capitalized	$ 642	$ 609	$ 587
Income taxes paid [(a)]	26	20	47
Non-cash investing and financing activities:			
Additions to fixed assets for accrued capital expenditures	292	393	44
Decrease to fixed assets for accrued grants and related tax impact	(32)	—	(132)
Decrease to 4.0% preferred stock from conversion to common stock	—	149	257
Decrease to notes receivable for equity conversion	63	56	—
Decrease to 5.75% preferred stock from conversion to common stock	—	—	447
(Increase)/decrease to treasury stock from the net impact of shares loaned to and returned by affiliates of CS	—	(160)	160

(a) 2011, 2010, and 2009 income taxes paid are net of $8 million, $14 million, and $3 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 the Retail Businesses. 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, *Guarantees*, or ASC 460, NRG has estimated that the current fair value for issuing these guarantees was $4.5 million as of December 31, 2011, and the liability in this amount is included in the Company's non-current liabilities.

The following table summarizes the maximum potential exposures that can be estimated for NRG's guarantees, indemnities, and other contingent liabilities by maturity:

	By Remaining Maturity at December 31,					
	2011					
Guarantees	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2010 Total
	(In millions)					
Letters of credit and surety bonds	$ 1,562	$ 108	$ —	$ —	$ 1,670	$ 887
Asset sales guarantee obligations	60	—	567	8	635	1,022
Commercial sales arrangements	91	100	91	1,123	1,405	1,285
Other guarantees	1	—	—	460	461	171
Total guarantees	$ 1,714	$ 208	$ 658	$ 1,591	$ 4,171	$ 3,365

Letters of credit and surety bonds — As of December 31, 2011, NRG and its consolidated subsidiaries were contingently obligated for a total of $1.7 billion 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 and in support of equity contribution requirements for solar projects in construction, as well as for 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.

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 guarantees and 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. NRG has no reason to believe that the Company currently has any material liability relating to such routine indemnification obligations.

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 United States, 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 also executed a guarantee with related parties for one of its subsidiary's obligations as construction manager under EPC contracts for the construction of the peaking power plant at GenConn's Middletown site. See Note 16, *Investments Accounted for by the Equity Method and Variable Interest Entities,* for more information on this equity investment. The Company does not believe that it will be required to perform under these guarantees.

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, as 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 expenses 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, 2011	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%	$ 3,101	$ (980)	$ 9
Big Cajun II Unit 3, New Roads, LA	58.00%	175	(75)	10
Cedar Bayou Unit 4, Baytown, TX	50.00%	213	(27)	1
Keystone, Shelocta, PA	3.70%	90	(27)	1
Conemaugh, New Florence, PA	3.72%	79	(30)	3

Note 28 — Unaudited Quarterly Financial Data

Summarized unaudited quarterly financial data is as follows:

	Quarter Ended			
	2011			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$ 2,132	$ 2,674	$ 2,278	$ 1,995
Operating income	9	43	269	314
Net (loss)/income attributable to NRG Energy, Inc.	$ (109)	$ (55)	$ 621	$ (260)
Weighted average number of common shares outstanding — basic	229	240	243	247
Net (loss)/income per weighted average common share — basic	$ (0.48)	$ (0.24)	$ 2.54	$ (1.06)
Weighted average number of common shares outstanding — diluted	229	240	244	247
Net (loss)/income per weighted average common share — diluted	$ (0.48)	$ (0.24)	$ 2.53	$ (1.06)

	Quarter Ended			
	2010			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$ 1,816	$ 2,685	$ 2,133	$ 2,215
Operating income	152	454	444	258
Net (loss)/income attributable to NRG Energy, Inc.	$ (15)	$ 223	$ 211	$ 58
Weighted average number of common shares outstanding — basic	248	252	255	254
Net (loss)/income per weighted average common share — basic	$ (0.07)	$ 0.88	$ 0.82	$ 0.22
Weighted average number of common shares outstanding — diluted	248	253	256	257
Net (loss)/income per weighted average common share — diluted	$ (0.07)	$ 0.87	$ 0.81	$ 0.22

Note 29 — Condensed Consolidating Financial Information

As of December 31, 2011, the Company had $1.1 billion of 7.375% Senior Notes due 2017, $1.2 billion of 7.625% Senior Notes due 2018, $700 million of 8.50% Senior Notes due 2019, $800 million of 7.625%Senior Notes due 2019, $1.1 billion of 8.25% Senior Notes due 2020, and $1.2 billion of 7.875% Senior Notes due 2021. These notes are guaranteed by certain of NRG's current and future wholly-owned domestic subsidiaries, or guarantor subsidiaries.

Unless otherwise noted below, each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of December 31, 2011:

Arthur Kill Power LLC
Astoria Gas Turbine Power LLC
Cabrillo Power I LLC
Cabrillo Power II LLC
Carbon Management Solutions LLC
Clean Edge Energy LLC
Conemaugh Power LLC
Connecticut Jet Power LLC
Cottonwood Development LLC
Cottonwood Energy Company LP
Cottonwood Generating Partners I LLC
Cottonwood Generating Partners II LLC
Cottonwood Generating Partners III LLC
Cottonwood Technology Partners LP
Devon Power LLC
Dunkirk Power LLC
Eastern Sierra Energy Company
Elbow Creek Wind Project LLC
Energy Plus Holdings LLC
Energy Plus Natural Gas LLC
El Segundo Power LLC
El Segundo Power II, LLC
Energy Protection Insurance Company
GCP Funding Company LLC
Green Mountain Energy Company
Huntley Power LLC
Independence Energy Alliance LLC
Independence Energy Group LLC
Independence Energy Natural Gas LLC
Indian River Operations Inc.
Indian River Power LLC
Keystone Power LLC
Langford Wind Power, LLC
Louisiana Generating LLC
Meriden Gas Turbines LLC
Middletown Power LLC
Montville Power LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Power Services Inc.
New Genco GP, LLC
Norwalk Power LLC
NRG Affiliate Services Inc.
NRG Artesian Energy LLC
NRG Arthur Kill Operations Inc.
NRG Astoria Gas Turbine Operations Inc.
NRG Bayou Cove LLC
NRG Cabrillo Power Operations Inc.
NRG California Peaker Operations LLC
NRG Cedar Bayou Development Company, LLC
NRG Connecticut Affiliate Services Inc.
NRG Construction LLC
NRG Development Company Inc.
NRG Devon Operations Inc.
NRG Dunkirk Operations Inc.
NRG El Segundo Operations Inc.
NRG Energy Labor Services LLC
NRG Energy Services Group LLC
NRG Energy Services LLC
NRG Generation Holdings Inc.
NRG Huntley Operations Inc.
NRG Ilion Limited Partnership
NRG Ilion LP LLC
NRG International LLC
NRG Maintenance Services LLC
NRG Mextrans Inc.
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 PacGen Inc.
NRG Power Marketing LLC
NRG Retail LLC
NRG Rockford Acquisition LLC
NRG Saguaro Operations Inc.
NRG Services Corporation
NRG SimplySmart Solutions LLC
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.
O'Brien Cogeneration, Inc. II
ONSITE Energy, Inc.
Oswego Harbor Power LLC
Pennywise Power LLC
RE Retail Receivable LLC
Reliant Energy Northeast LLC
Reliant Energy Power Supply LLC
Reliant Energy Retail Holdings LLC
Reliant Energy Retail Services LLC
Reliant Energy Texas Retail LLC
RERH Holdings LLC
Saguaro Power LLC
Somerset Operations Inc.
Somerset Power LLC
Texas Genco Financing Corp.
Texas Genco GP, LLC
Texas Genco Holdings, Inc.
Texas Genco LP, LLC
Texas Genco Operating Services LLC
Texas Genco Services, LP
Vienna Operations, Inc.
Vienna Power LLC
WCP (Generation) Holdings LLC
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, 2011

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations [(a)]	Consolidated Balance
			(In millions)		
Operating Revenues					
Total operating revenues	$ 8,730	$ 381	$ —	$ (32)	$ 9,079
Operating Costs and Expenses					
Cost of operations	6,430	266	—	(21)	6,675
Depreciation and amortization	843	40	13	—	896
Impairment charge on emission allowances	160	—	—	—	160
Selling, general and administrative	393	27	252	(4)	668
Development costs	—	(1)	46	—	45
Total operating costs and expenses	7,826	332	311	(25)	8,444
Operating Income/(Loss)	904	49	(311)	(7)	635
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	24	(7)	593	(610)	—
Equity in earnings of unconsolidated affiliates	10	25	—	—	35
Impairment charge on investment	(495)	—	—	—	(495)
Other income, net	2	13	4	—	19
Loss on debt extinguishment and refinancing	—	—	(175)	—	(175)
Interest expense	(59)	(56)	(550)	—	(665)
Total other expense	(518)	(25)	(128)	(610)	(1,281)
Income/(Loss) Before Income Taxes	386	24	(439)	(617)	(646)
Income tax (benefit)/expense	(214)	7	(636)	—	(843)
Net Income/(Loss) attributable to NRG Energy, Inc.	$ 600	$ 17	$ 197	$ (617)	$ 197

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)
For the Year Ended December 31, 2011

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
			(In millions)		
Net Income/(Loss)	$ 600	$ 17	$ 197	$ (617)	$ 197
Other comprehensive (loss)/income, net of tax					
Unrealized (loss)/gain on derivatives, net	(303)	(27)	(345)	366	(309)
Foreign currency translation adjustments, net	—	(2)	—	—	(2)
Available-for-sale securities, net	—	—	(1)	—	(1)
Defined benefit plan, net	(34)	—	(12)	—	(46)
Other comprehensive (loss)/income	(337)	(29)	(358)	366	(358)
Comprehensive income/(loss) attributable to NRG Energy, Inc.	263	(12)	(161)	(251)	(161)
Dividends for preferred shares	—	—	9	—	9
Comprehensive income/(loss) available for common stockholders	$ 263	$ (12)	$ (170)	$ (251)	$ (170)

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2011

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [(a)]	Consolidated Balance
			(In millions)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ 44	$ 85	$ 976	$ —	$ 1,105
Funds deposited by counterparties	258	—	—	—	258
Restricted cash	8	231	53	—	292
Accounts receivable-trade, net	789	45	—	—	834
Inventory	300	8	—	—	308
Derivative instruments	4,222	—	—	(6)	4,216
Cash collateral paid in support of energy risk management activities	311	—	—	—	311
Prepayments and other current assets	1,229	28	(983)	(1)	273
Total current assets	7,161	397	46	(7)	7,597
Net Property, Plant and Equipment	10,456	3,116	67	(18)	13,621
Other Assets					
Investment in subsidiaries	225	491	16,169	(16,885)	—
Equity investments in affiliates	33	607	—	—	640
Capital leases and notes receivable, less current portion	1	341	172	(172)	342
Goodwill	1,886	—	—	—	1,886
Intangible assets, net	1,340	84	33	(38)	1,419
Nuclear decommissioning trust fund	424	—	—	—	424
Derivative instruments	450	—	—	—	450
Other non-current assets	55	72	209	—	336
Total other assets	4,414	1,595	16,583	(17,095)	5,497
Total Assets	$ 22,031	$ 5,108	$ 16,696	$ (17,120)	$ 26,715
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ —	$ 72	$ 15	$ —	$ 87
Accounts payable	(407)	122	1,093	—	808
Derivative instruments	3,712	23	22	(6)	3,751
Deferred income taxes	534	(51)	(356)	—	127
Cash collateral received in support of energy risk management activities	258	—	—	—	258
Accrued expenses and other current liabilities	371	23	247	(1)	640
Total current liabilities	4,468	189	1,021	(7)	5,671
Other Liabilities					
Long-term debt and capital leases	264	1,999	7,654	(172)	9,745
Nuclear decommissioning reserve	335	—	—	—	335
Nuclear decommissioning trust liability	254	—	—	—	254
Postretirement and other benefit obligations	367	—	33	—	400
Deferred income taxes	950	273	166	—	1,389
Derivative instruments	394	66	4	—	464
Out-of-market commodity contracts	208	6	—	(31)	183
Other non-current liabilities	177	96	83	—	356
Total non-current liabilities	2,949	2,440	7,940	(203)	13,126
Total liabilities	7,417	2,629	8,961	(210)	18,797
3.625% Preferred Stock	—	—	249	—	249
Stockholders' Equity	14,614	2,479	7,486	(16,910)	7,669
Total Liabilities and Stockholders' Equity	$ 22,031	$ 5,108	$ 16,696	$ (17,120)	$ 26,715

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2011

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [(a)]	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 600	$ 17	$ 197	$ (617)	$ 197
Adjustments to reconcile net income to net cash provided/(used) by operating activities:					
Distributions and equity in earnings of unconsolidated affiliates and consolidated subsidiaries	(11)	3	776	(759)	9
Depreciation and amortization	843	40	13	—	896
Provision for bad debts	59	—	—	—	59
Amortization of nuclear fuel	39	—	—	—	39
Amortization of financing costs and debt discounts/premiums	—	6	26	—	32
Loss on debt extinguishment	—	—	58	—	58
Amortization of intangibles and out-of-market contracts.	166	1	—	—	167
Changes in deferred income taxes and liability for uncertain tax benefits	(214)	7	(652)	—	(859)
Changes in nuclear decommissioning liability	20	—	—	—	20
Changes in derivative instruments	(137)	(1)	—	—	(138)
Impairment charges and asset write downs	648	9	—	—	657
Loss on disposals and sales of assets	13	1	—	—	14
Amortization of unearned equity compensation	—	—	28	—	28
Other assets and liabilities	(1,405)	211	1,174	7	(13)
Net Cash Provided/(Used) by Operating Activities	621	294	1,620	(1,369)	1,166
Cash Flows from Investing Activities					
Intercompany loans to subsidiaries	796	—	287	(1,083)	—
Investment in Subsidiaries	—	(1,300)	—	1,300	—
Acquisition of business, net of cash acquired	—	(115)	(262)	—	(377)
Capital expenditures	(383)	(1,882)	(45)	—	(2,310)
Increase in restricted cash, net	(5)	(29)	(1)	—	(35)
Increase in restricted cash - U.S. DOE projects	—	(162)	(53)	—	(215)
Decrease in notes receivable	—	12	—	—	12
Purchases of emission allowances, net of proceeds	(19)	—	—	—	(19)
Investments in nuclear decommissioning trust fund securities	(406)	—	—	—	(406)
Proceeds from sales of nuclear decommissioning trust fund securities	385	—	—	—	385
Proceeds/(purchases) from sale of assets, net	13	(6)	—	—	7
Equity investment in unconsolidated affiliates	(2)	(64)	—	—	(66)
Other	(2)	(8)	(13)	—	(23)
Net Cash Provided/(Used) by Investing Activities	377	(3,554)	(87)	217	(3,047)
Cash Flows from Financing Activities					
(Payments)/proceeds from intercompany loans	(1,112)	825	(796)	1,083	—
Payment of dividends to preferred stockholders	—	—	(9)	—	(9)
Payments of intercompany dividends	(65)	(4)	—	69	—
Payment for treasury stock	—	—	(430)	—	(430)
Net payments to settle acquired derivatives that include financing elements	(83)	—	—	—	(83)
Proceeds from issuance of long-term debt	138	1,290	4,796	—	6,224
Decrease in restricted cash supporting funded letter of credit facility	—	1,300	—	—	1,300
Payment for settlement of funded letter of credit	—	—	(1,300)	—	(1,300)
Cash proceeds from noncontrolling interest in subsidiaries	—	29	—	—	29
Proceeds from issuance of common stock	—	—	2	—	2
Payment of debt issuance and hedging costs	—	(92)	(115)	—	(207)
Payments for short and long-term debt	—	(116)	(5,377)	—	(5,493)
Net Cash (Used)/Provided by Financing Activities	(1,122)	3,232	(3,229)	1,152	33
Effect of exchange rate changes on cash and cash equivalents	—	2	—	—	2
Net Decrease in Cash and Cash Equivalents	(124)	(26)	(1,696)	—	(1,846)

Cash and Cash Equivalents at Beginning of Period	168	111	2,672	—	2,951
Cash and Cash Equivalents at End of Period	$ 44	$ 85	$ 976	$ —	$ 1,105

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2010

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations [(a)]	Consolidated Balance
			(In millions)		
Operating Revenues					
Total operating revenues	$ 8,507	$ 374	$ —	$ (32)	$ 8,849
Operating Costs and Expenses					
Cost of operations	5,849	256	—	(32)	6,073
Depreciation and amortization	796	32	10	—	838
Selling, general and administrative	325	12	261	—	598
Development costs	—	10	45	—	55
Total operating costs and expenses	6,970	310	316	(32)	7,564
Gain on sale of assets	—	—	23	—	23
Operating Income/(Loss)	1,537	64	(293)	—	1,308
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	38	(1)	979	(1,016)	—
Equity in earnings of unconsolidated affiliates	6	38	—	—	44
Other income, net	4	25	4	—	33
Loss on debt extinguishment and refinancing expense	—	—	(2)	—	(2)
Interest expense	(11)	(52)	(567)	—	(630)
Total other income/(expense)	37	10	414	(1,016)	(555)
Income Before Income Taxes	1,574	74	121	(1,016)	753
Income tax expense/(benefit)	593	40	(356)	—	277
Net Income	981	34	477	(1,016)	476
Less: Net loss attributable to noncontrolling interest	(1)	—	—	—	(1)
Net Income attributable to NRG Energy, Inc.	$ 982	$ 34	$ 477	$ (1,016)	$ 477

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)
For the Year Ended December 31, 2010

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
			(In millions)		
Net Income/(Loss)	$ 981	$ 34	$ 477	$ (1,016)	$ 476
Other comprehensive income/(loss), net of tax					
Unrealized gain/(loss) on derivatives, net	21	(11)	10	15	35
Foreign currency translation adjustments, net	—	(6)	3	—	(3)
Defined benefit plan, net	(19)	—	3	—	(16)
Other comprehensive income/(loss)	2	(17)	16	15	16
Comprehensive income/(loss)	983	17	493	(1,001)	492
Less: Comprehensive income attributable to noncontrolling interest	(1)	—	—	—	(1)
Comprehensive income/(loss) attributable to NRG Energy, Inc.	984	17	493	(1,001)	493
Dividends for preferred shares	—	—	9	—	9
Comprehensive income/(loss) available for common stockholders	$ 984	$ 17	$ 484	$ (1,001)	$ 484

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2010

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [(a)]	Consolidated Balance
			(In millions)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ 168	$ 111	$ 2,672	$ —	$ 2,951
Funds deposited by counterparties	408	—	—	—	408
Restricted cash	2	6	—	—	8
Accounts receivable-trade, net	693	38	3	—	734
Inventory	445	8	—	—	453
Derivative instruments	1,964	—	—	—	1,964
Cash collateral paid in support of energy risk management activities	321	2	—	—	323
Prepayments and other current assets	112	60	1,313	(1,189)	296
Total current assets	4,113	225	3,988	(1,189)	7,137
Net Property, Plant and Equipment	10,816	1,515	186	—	12,517
Other Assets					
Investment in subsidiaries	811	248	22,046	(23,105)	—
Equity investments in affiliates	47	489	—	—	536
Notes receivable - affiliate and capital leases, less current portion	6,507	380	2,130	(8,633)	384
Goodwill	1,868	—	—	—	1,868
Intangible assets, net	1,716	58	33	(31)	1,776
Nuclear decommissioning trust fund	412	—	—	—	412
Derivative instruments	758	—	—	—	758
Restricted cash supporting funded letter of credit facility	—	1,300	—	—	1,300
Other non-current assets	42	22	144	—	208
Total other assets	12,161	2,497	24,353	(31,769)	7,242
Total Assets	$ 27,090	$ 4,237	$ 28,527	$ (32,958)	$ 26,896
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 1,150	$ 223	$ 240	$ (1,150)	$ 463
Accounts payable	(2,665)	229	3,219	—	783
Derivative instruments	1,665	3	17	—	1,685
Deferred income taxes	515	(51)	(356)	—	108
Cash collateral received in support of energy risk management activities	408	—	—	—	408
Accrued expenses and other current liabilities	399	34	379	(39)	773
Total current liabilities	1,472	438	3,499	(1,189)	4,220
Other Liabilities					
Long-term debt and capital leases	1,857	991	14,533	(8,633)	8,748
Funded letter of credit	—	—	1,300	—	1,300
Nuclear decommissioning reserve	317	—	—	—	317
Nuclear decommissioning trust liability	272	—	—	—	272
Postretirement and other benefit obligations	309	(1)	14	—	322
Deferred income taxes	1,464	279	246	—	1,989
Derivative instruments	294	34	37	—	365
Out-of-market commodity contracts	248	6	—	(31)	223
Other non-current liabilities	195	30	595	—	820
Total non-current liabilities	4,956	1,339	16,725	(8,664)	14,356
Total liabilities	6,428	1,777	20,224	(9,853)	18,576
3.625% Preferred Stock	—	—	248	—	248
Stockholders' Equity	20,662	2,460	8,055	(23,105)	8,072
Total Liabilities and Stockholders' Equity	$ 27,090	$ 4,237	$ 28,527	$ (32,958)	$ 26,896

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2010

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [a]	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 981	$ 34	$ 477	$ (1,016)	$ 476
Adjustments to reconcile net income to net cash provided by operating activities:					
Distributions and equity (earnings)/losses of unconsolidated affiliates and consolidated subsidiaries	14	(12)	(914)	893	(19)
Depreciation and amortization	796	32	10	—	838
Provision for bad debts	54	—	—	—	54
Amortization of nuclear fuel	40	—	—	—	40
Amortization of financing costs and debt discounts/premiums	—	6	26	—	32
Amortization of intangibles and out-of-market contracts.	4	—	—	—	4
Impairment charges and asset write downs	20	—	5	—	25
Changes in deferred income taxes and liability for uncertain tax benefits	593	27	(365)	—	255
Changes in nuclear decommissioning liability	34	—	—	—	34
Changes in derivatives	(113)	(1)	—	—	(114)
Loss/(gain) on disposals and sales of assets	27	—	(23)	—	4
Amortization of unearned equity compensation	—	—	30	—	30
Other assets and liabilities	(625)	(187)	776	—	(36)
Net Cash Provided/(Used) by Operating Activities	1,825	(101)	22	(123)	1,623
Cash Flows from Investing Activities					
Intercompany (loans to)/receipts from subsidiaries	(1,620)	—	(195)	1,815	—
Investment in subsidiaries	—	1,727	(1,727)	—	—
Capital expenditures	(308)	(323)	(75)	—	(706)
Acquisition of businesses, net of cash acquired	—	(142)	(864)	—	(1,006)
Decrease/(increase) in restricted cash, net	1	(5)	—	—	(4)
Decrease in notes receivable	—	39	—	—	39
Purchases of emission allowances, net of proceeds	(34)	—	—	—	(34)
Investments in nuclear decommissioning trust fund securities	(341)	—	—	—	(341)
Proceeds from sales of nuclear decommissioning trust fund securities	307	—	—	—	307
Proceeds from renewable energy grants	84	18	—	—	102
Proceeds from sale of assets, net	14	—	29	—	43
Equity investment in unconsolidated affiliate	4	(22)	(5)	—	(23)
Net Cash (Used)/Provided by Investing Activities	(1,893)	1,292	(2,837)	1,815	(1,623)
Cash Flows from Financing Activities					
Proceeds/(payments) from intercompany loans	69	126	1,620	(1,815)	—
Payment of intercompany dividends	(58)	(65)	—	123	—
Payment of dividends to preferred stockholders	—	—	(9)	—	(9)
Net receipts from acquired derivatives that include financing elements	137	—	—	—	137
Payment for treasury stock	—	—	(180)	—	(180)
Installment proceeds from sale of noncontrolling interest in subsidiary	—	50	—	—	50
Proceeds from issuance of common stock	—	—	2	—	2
Proceeds from issuance of long-term debt	73	306	1,105	—	1,484
Proceeds from issuance of term loan for funded letter of credit facility	—	—	1,300	—	1,300
Increase in restricted cash supporting funded letter of credit facility	—	(1,300)	—	—	(1,300)
Payment of debt issuance and hedging costs	(5)	(9)	(61)	—	(75)
Payments of short and long-term debt	—	(304)	(454)	—	(758)
Net Cash Provided/(Used) by Financing Activities	216	(1,196)	3,323	(1,692)	651
Effect of exchange rate changes on cash and cash equivalents	—	(4)	—	—	(4)
Net Increase/(Decrease) in Cash and Cash Equivalents	148	(9)	508	—	647
Cash and Cash Equivalents at Beginning of Period	20	120	2,164	—	2,304
Cash and Cash Equivalents at End of Period	$ 168	$ 111	$ 2,672	$ —	$ 2,951

(a) All significant intercompany transactions have been eliminated in consolidation.

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.	Eliminations [a]	Consolidated Balance
			(In millions)		
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/(expense), 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 Before Income Taxes	2,508	119	711	(1,669)	1,669
Income tax expense/(benefit)	964	(5)	(231)	—	728
Net Income	1,544	124	942	(1,669)	941
Less: Net loss attributable to noncontrolling interest	(1)	—	—	—	(1)
Net Income 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

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)
For the Year Ended December 31, 2009

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
			(In millions)		
Net Income/(Loss)	$ 1,544	$ 124	$ 942	$ (1,669)	$ 941
Other comprehensive income/(loss), net of tax					
Unrealized gain/(loss) on derivatives, net	64	11	99	(83)	91
Foreign currency translation adjustments, net	—	29	6	—	35
Reclassification adjustment for translation loss realized upon sale of MIBRAG, net	—	(22)	—	—	(22)
Available-for-sale securities, net	—	—	4	—	4
Defined benefit plan, net	1	—	(3)	—	(2)
Other comprehensive income/(loss)	65	18	106	(83)	106
Comprehensive income/(loss)	1,609	142	1,048	(1,752)	1,047
Less: Comprehensive income attributable to noncontrolling interest	(1)	—	—	—	(1)
Comprehensive income/(loss) attributable to NRG Energy, Inc.	1,610	142	1,048	(1,752)	1,048
Dividends for preferred shares	—	—	33	—	33
Comprehensive income/(loss) available for common stockholders	$ 1,610	$ 142	$ 1,015	$ (1,752)	$ 1,015

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2009

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Elimin-ations [(a)]	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 1,544	$ 124	$ 942	$ (1,669)	$ 941
Adjustments to reconcile net income to net cash provided/(used) 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 discount/premiums	—	13	31	—	44
Amortization of intangibles and out-of-market contracts	153	—	—	—	153
Changes in deferred income taxes and liability for uncertain tax benefits	934	(16)	(229)	—	689
Change in nuclear decommissioning trust liability	26	—	—	—	26
Changes in derivatives	(228)	3	—	—	(225)
Loss on disposals and sales of assets	13	—	—	—	13
Gain on sales of equity method investments	—	(128)	—	—	(128)
Gain recognized on settlement of pre-existing relationship	—	—	(31)	—	(31)
Amortization of unearned equity compensation	—	—	26	—	26
Other assets and liabilities	(640)	29	335	—	(276)
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 business, net of cash acquired	(72)	(67)	(288)	—	(427)
Increase in restricted cash	6	8	—	—	14
(Increase)/decrease in notes receivable	—	(58)	36	—	(22)
Purchases of emission allowances, net of proceeds	(38)	—	—	—	(38)
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 sales of/(investments in) unconsolidated affiliates, net	—	284	(6)	—	278
Other	—	—	(5)	—	(5)
Net Cash (Used)/Provided 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 for dividends to preferred stockholders	—	—	(33)	—	(33)
Net payments to settle acquired derivatives including financing elements	(79)	—	—	—	(79)
Payment for treasury stock	—	—	(500)	—	(500)
Installment proceeds from sale of noncontrolling interest of 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 (Used)/Provided 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.

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2011, 2010, and 2009

	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, 2011	$ 25	$ 60	$ —	$ (62) [a]	$ 23
Year Ended December 31, 2010	29	54	—	(58) [a]	25
Year Ended December 31, 2009	3	61	—	(35) [a]	29
Income tax valuation allowance, deducted from deferred tax assets					
Year Ended December 31, 2011	$ 191	$ (63)	$ (45)	$ —	$ 83
Year Ended December 31, 2010	233	(34)	(8)	—	191
Year Ended December 31, 2009	359	(130)	4	—	233

(a) Represents principally net amounts charged as uncollectible.