(NRG LOGO)

NRG Energy, Inc.
211 Carnegie Center
Princeton, NJ 08540

Phone: 609-524-4702
Fax: 609-524-4515

May 14, 2007

Securities and Exchange Commission
Division of Corporation Finance
Mail Stop 3561
450 Fifth Street, N.W.
Washington, D.C. 20549

Attn: Jim Allegretto, Senior Assistant Chief Accountant

RE: NRG Energy, Inc.
Form l0-K for the year ended December 31, 2006
Filed February 28, 2007
File No. 1-15891

Dear Mr. Allegretto:

We hereby respond to the comments made by the Staff in your letter dated May 3, 2007 relating to NRG Energy, Inc.'s ("NRG" or the "Company") Annual Report on Form 10-K for the fiscal year ended December 31, 2006, filed on February 28, 2007 (the "Form 10-K"). We acknowledge that we are responsible for the accuracy and adequacy of the disclosure in the filings reviewed by the Staff to be certain that we have provided all information investors require for an informed decision. Since the Company and management are in possession of all the facts relating to the Company's disclosure, we are responsible for the accuracy and adequacy of the disclosures we have made. We hereby acknowledge that (i) the Company is responsible for the adequacy and accuracy of the disclosure in the filings; (ii) staff comments or changes to disclosures in response to staff comments do not foreclose the Commission from taking any action with respect to the filings; and (iii) the Company may not assert staff comments as a defense in any proceeding initiated by the Commission or any person under the federal securities laws of the United States. We look forward to working with the Staff and improving the disclosures in our filings.

The Staff's comments, indicated in bold and NRG's responses are as follows:

<u>Form 10-K for the year ended December 31, 2006</u>

<u>Hedge Reset, page 75</u>

1. **We have read your discussion of the hedge reset on pages 75 and 151. First, explain to us how such contracts were accounted for prior to renegotiation. We assume such contracts represented cash flow hedges and there is an associated amount that will remain in other comprehensive income subsequent to settlement. If our understanding is incorrect, please clarify it. If correct, please advise why the settlement amount was greater than the mark –to-market value that would be required under SFAS no. 133 for a cash flow hedge. In addition, please explain what you mean when you state you accounted for the transaction as a net settlement of current hedge positions and subsequent reestablishment of new hedge positions. We assume the information on page 151 would mirror the accounting entry necessary to be made to record the transaction. If not, provide the accounting entry(s) to further our understanding. In this regard, please explain what the $125 million reduction in derivative liability represents. We assume it is related to the gas swaps derivative liability discussed on page 75. Finally help us understand the reasons for your classification as contra-revenues in the statement of operations. We may have further comment.**

Accounting prior to Hedge Reset:

Acquisition of Texas Genco - as a part of the Texas Genco acquisition on February 2, 2006, we acquired power sales contracts and gas swaps as further disclosed in Note 3, *Business Acquisition and Dispositions*, of the Form 10K (pages 138-140). In accordance with FAS 141, we applied the purchase method of accounting to the assets acquired and liabilities assumed based on their estimated fair value. The total value of the subject matter was as follows:

(in millions) **Type of instrument**	**Purchase allocation** **asset/(liability) for all contracts**
Out-of-market power contracts	$(2,100)
In-market power contracts	39
Gas swaps	(472)

Out-of-market/In-market power contracts - The power contracts are for physical sales of power from our baseload generation. As of February 2, 2006, we elected a Normal Purchase and Normal Sale, or NPNS, exception for these contracts. The contracts spanned over a period of four and a half years and the liabilities are being amortized to revenue over that period consistent with delivery and their volumetric value.

Gas swaps – We have gas swaps designated as cash flow hedges for forecasted sales of power from our baseload generation as well as certain gas swaps which are not hedged transactions and are accounted for on a mark-to-market basis. With respect to the Hedge Reset transaction, all gas swaps were contracts acquired as part of the Texas Genco acquisition.

We confirm your understanding that there remains a balance in Other Comprehensive Income, or OCI. Following the Hedge Reset transaction, as the underlying hedged item (forecasted power sales) is still probable, we have frozen $87 million in OCI that will be released when the underlying power is physically delivered.

Hedge Reset; a net settlement of current hedge positions and subsequent reestablishment:
The Hedge Reset transaction “reset” the pricing in the power sales contracts and gas swaps described above to current market levels with all other contractual terms remaining in effect. We negotiated a payment (net settlement) with specific counterparties in order to attain this change in price for the outstanding contracts.

Power contracts - as the physical power delivery under these contracts from our base load generation is still probable, we elected an NPNS exception for these newly priced power sales contracts.

Gas swaps - as the physical power delivery under these gas swaps from our baseload generation is still probable, we designated the newly priced gas swaps as cash flow hedges for our forecasted sale of power from our baseload generation.

Accounting entry:

As described on page 151 of the Form 10-K, the following is the accounting entry to record the Hedge Reset transaction:

(in millions)		Detail
Dr. Revenue	1,347	Represents the cash paid for net settlement
Cr. Cash	1,347	
Dr. Derivative liability	145	Represents the fair value of the gas swaps as of the net settlement date
Cr. Revenue	145	
Dr. Out-of-market contract liability	1,073	Represents the unamortized carrying value of the power contracts
Cr. Revenue	1,073	established at acquisition

Classification as revenues:

We applied the guidance of EITF 02-03, paragraph 8, to the classification of the net settlement and write-off of the corresponding carrying values for the Hedge Reset transaction. Paragraph 8 states that:

“...all gains and losses (realized and unrealized) on energy trading contracts should be ***shown net in the income statement*** *whether or not settled physically*”.

Since the settlement of the gas swaps and out-of-market power contracts are analogous to the transactions discussed in EITF 02-3, and because these gas swaps (realized and unrealized) and out-of-market power contracts (amortized) have been recorded to revenues until the consummation of the Hedge Reset transaction, the net loss of settlement is reflected in revenue.

Note 3 – Business Acquisitions and Dispositions, page 138

2. **We note your final allocation of the purchase price of Texas Genco LLC as well as the related changes and reasons for the changes from your preliminary allocation in preceding Exchange Act Reports. You state that "The acquisition of Texas Genco LLC included an element of premium, or goodwill, due to favorable market conditions for the acquired solid fuel plants." We would expect such market conditions to be captured in the valuation of the solid fuel plants as opposed to being included in goodwill. We assume such determination was made based on independent appraisal. Please explain in detail how the final determination of value for property plant and equipment incorporated such conditions. Please be detailed in your responses as we may have further comments. In this regard, tell us how the acquisition was treated for tax purposes. If you received stepped-up basis, please also show us how you allocated value for tax purposes and contrast that to the allocation performed under SFAS no. 141.**

Independent Appraisers:

Following the announcement for the acquisition of Texas Genco, NRG hired an independent appraisal firm, Duff & Phelps LLC, to conduct the appraisal of assets and liabilities of Texas Genco in accordance with the guidance of FAS141.

Valuation of PP&E and Goodwill:

The purchase price paid for Texas Genco was based on the expected cash flows which can be characterized into two portions:

- § The near-term of up to 5 years – cash flows from the substantially hedged portfolio of Texas Genco that were based on the acquired contract prices.
- § The long-term beyond 5 years – for purposes of our purchase price allocation, the forward gas price was approximately $7/mmBtu near the end of the forecasted curve in 2011.

The single largest factor supporting the goodwill disclosed in the Form 10-K, is the limitation of value attributable to the plant and equipment to the depreciated replacement cost, or DRC, plus a premium for immediate use. The excess purchase price over the values attributable to the assets acquired reflects the favorable market conditions at the date of acquisition.

Limitations of value – On a discounted cash flow basis, the values of the two coal-fired and one nuclear generation business units are greater than the DRCs including a premium for immediate use, but the DRC plus the premium is considered *the upper limit of the plant and equipment value*. The additional value is attributable *to favorable market conditions*. The immediate use value was included to account for the near term benefits of the favorable market conditions. The replacement cost of an asset is often considered to be the upper limit one would pay for an asset, the favorable market conditions might only exist for a limited period of time until the construction of additional competing assets. Under these circumstances, an investor would be willing to pay a premium to take advantage of the existing favorable market conditions *as if* a plant was already *in place to capture* these conditions. The immediate use value is measured as the present value of the expected "excess" future cash flows over the expected time frame to construct a replacement asset. The "excess" cash flows are measured as the cash flows beyond those of a normal return on an investment in a replacement plant (or a return on the DRC of the subject plants in the case of the existing, older plants).

Favorable market conditions and Goodwill – Based on our valuation, the favorable market conditions for these solid fuel plants is due to the cost advantage these plants have relative to natural gas-fired generation with the current and expected continuation of high natural gas prices. The power prices in the ERCOT market are largely driven by the natural gas prices as the marginal market power requirements are met by gas-fired, combined cycle plants. We expect this to continue for the foreseeable future in ERCOT, since natural gas-fired generation is expected to be the marginal supply for the foreseeable future, and we believe it would require an extended period of time to transition to alternative fuels that could have an effect on the future price expectations. We anticipate that the two coal-fired and one nuclear generation businesses will benefit from the higher power prices driven by the gas prices and the relatively lower cost of coal and uranium for an indefinite period of time. The favorable market conditions *are not considered a separable intangible asset* and are, therefore, the major contributor to the amount of goodwill.

Conclusion – the Company paid a premium for the assets of Texas Genco, due to the favorable market conditions of:

- § Projected high natural gas prices
- § Marginal market power requirements are met by gas-fired within the ERCOT market

The value of the associated plants is limited to:

- § The depreciated replacement cost
- § A premium for immediate use that represents the excess cash flows over the expected time frame to construct a replacement asset

The remaining value that was not allocated to the plants is considered goodwill that is explained by the favorable market conditions.

Allocation for tax purposes: For tax purposes, we acquired the equity interest of Texas Genco and elected a step up in the partnership basis under IRC Sect. 754. The allocation of partnership tax basis as prescribed under Treasury Reg. Sect. 1.743-1(b) states that the step up in value is based upon the relative appreciation in fair market value at the time of acquisition over the net tax value of the existing underlying assets, consisting of both ordinary and capital property.

Based on these guidelines, the Company recognized an incremental step up in the existing adjusted tax basis of partnership property of $4,205 million, which was allocated in the following manner at the acquisition date:

(in millions)	**Step up**
Property, Plant & Equipment	$1,213
Intangible – Immediate Use Value	1,473
Goodwill – Tax	972
Intangible – Emission Credits	393
Purchased Forward Sale Agreements	185
LT Notes Receivable and Other	(31)
Total Basis Adjustment	$4,205

Stock value - As part of the acquisition, the Company also purchased the stock of a subsidiary corporation, Texas Genco Holdings Inc., or TGHI, which holds the interest in the STP nuclear facility in Texas. The TGHI acquisition represented a stock purchase for tax purposes and accordingly no additional step up in value under IRC Sect. 754 to the adjusted tax basis would apply. Rather, the incremental value will reside in the outside basis of the stock and would be potentially recognized upon future sale to a third party.

Immediate use value - The Company allocated value of $1,473 million to the adjusted tax basis of an intangible asset referred to as Immediate Use Value. The allocated value for Immediate Use resides within the Property, Plant & Equipment asset category for financial reporting purposes but will be amortized as an IRC Sect. 197 Intangible asset over 15 years for tax purposes. This asset represents the premium paid at acquisition for the asset value that is in short supply due to favorable market conditions.

Tax goodwill - The Company recognized $972 million of goodwill for tax purposes. This amount represents the residual tax value of the relative appreciation in fair market value that has not been allocated to specific capital or ordinary property upon acquisition.

Tax allocation vs. Financial reporting allocation - NRG was unable to allocate any tax basis to a number of items including the out-of-market contracts, gas swap contracts, asset retirement obligations, etc. Rather, tax basis will be recognized going forward over the life of the respective contracts upon execution under the contract terms and physical delivery of power.

The final consolidated tax allocation as compared to the purchase price allocation for financial statement purposes is as follows:

(in millions)	Purchase Price Allocation Financial Reporting	Purchase Price Allocation Tax Purposes
Assets		
Current and non-current assets	$ 832	$ 1,176
Coal inventory	33	20
In-market contracts:		
Power contracts	39	433
Water contracts	64	16
Fuel contracts	171	1
Emission allowances	880	672
Immediate use value intangible	—	1,473
Property, plant and equipment	9,336	4,125
Deferred tax asset	2,868	—
Investment in STP	—	249
Loan receivable from STP	—	552
Goodwill	1,782	972
Total assets acquired	16,005	9,689
Liabilities		
Current and non-current liabilities	935	1,052
Pension and post-retirement liability	222	—
Out-of-market contracts:		
Coal	93	235
Gas swaps	472	—
Power contracts	2,100	—
Deferred tax liability	3,217	—
Loan payable from STP	—	535
Long term debt	2,735	2,735
Total liabilities assumed	9,774	4,557
Net assets acquired	$ 6,231	$ 5,132

Note 13 – Capital Structure, page 168

3. **It appears you used a combination of treasury shares and original issue shares to consummate the acquisition of Texas Genco LLC. Please advise how you treated any difference between the carrying amount of treasury shares and the average market price you used to value the transaction.**

The guidance as found in ARB43 chapter 1B paragraph 7 states as follows:

"7. 'Apparently there is general agreement that the difference between the purchase price and the stated value of a corporation's common stock purchased and retired should be reflected in capital surplus. Your committee believes that while the net asset value of the shares of common stock outstanding in the hands of the public may be increased or decreased by such purchase and retirement, such transactions relate to the capital of the corporation ***and do not give rise to corporate profits or losses****...'*

b. When a corporation's stock is acquired ***for purposes other than retirement*** *(formal or*

> *constructive), or when ultimate disposition has not yet been decided, the cost of acquired stock may be shown separately as a deduction from the total of capital stock, capital surplus, and retained earnings, or may be accorded the accounting treatment appropriate for retired stock.* ***"Gains" on sales of treasury stock not previously accounted for as constructively retired should be credited to capital surplus...."***

The cost of the acquired stock prior to issuance to the shareholders of Texas Genco was approximately $663 million, and the value when reissued was $924 million. This "gain" of $261 million was credited to Additional Paid in Capital, in accordance with the guidance noted above.

Treasury Stock, page 168

4. Please explain your accounting rationale for treating any payments to Credit Suisse relating to stock price appreciation as additional cost of treasury stock as opposed to financing cost. We presume such payments are designed to compensate Credit Suisse for the non-recourse financing it provided in lieu of taking the benefits associated with these assets of CSF I & II, LLC(s). Please explain in detail.

Stock Buyback with CSF I & II Structure:
During the fourth quarter 2006, the Company completed a $500 million stock buyback utilizing a structure implemented with two wholly owned subsidiaries, NRG Common Stock Finance I, LLC, or CSF I, and NRG Common Stock Finance II, LLC, or CSF II. These two subsidiaries were funded by a direct investment from NRG and debt from Credit Suisse in the form of Notes and Preferred Interests.

At maturity, Credit Suisse will have the right to receive additional payments equal to the excess, if any, of the market value of NRG common stock owned by such subsidiary over a threshold amount. The threshold amount is a factor of the weighted average share price on date of issue multiplied by a 20% Compounded Annual Growth Rate. This additional payment, or the CAGR, is an *embedded derivative* to both the Notes and Preferred Interests that NRG may pay in cash or in the form of NRG common stock at NRG's discretion.

Neither the Notes nor the Preferred Interests in these subsidiaries will be recourse to the Company or other subsidiaries, and the Notes and Preferred Interests will be secured by any shares of our common stock purchased through the buyback.

Our following analysis concluded that there was an embedded derivative that is:

§ Exempt from derivative accounting per the guidance in paragraph 11(a) of FAS133.

§ Considered stockholders equity per the conclusions of EITF 00-19.

When the CAGR is exercised, any payments – whether in stock or cash – will be recorded to Additional Paid in Capital. Our disclosure in Form 10-K states that this will be an increase to the cost of the treasury stock, and that is because it is our expectation to pay for the CAGR, if applicable, with stock in treasury. In future filings we will explain this concept more clearly.

Detail of debt instruments:

The transactions entered into by CSF I will have a term of approximately two years and the transactions entered into by CSF II will have a term of approximately three years. Maturities are as follows:

Subsidiary	Instrument	Maturity Date	Principal (in millions)
CSF I	Note	10/13/08	$ 137
CSF I	Preferred Interest	10/13/08	53
CSF II	Note	10/13/09	113
CSF II	Preferred Interest	10/13/09	31
	Total:		**$ 334**

Embedded derivative - At maturity, Credit Suisse will have the right to receive additional payments equal to the excess, if any, of the market value of NRG common stock owned by such subsidiary over a threshold amount – this is referred to as the CAGR.

Notes and Preferred Interests — equity or liability accounting

Notes – the Notes are considered a liability per Concept 6, *Elements of Financial Statements*, and are thereafter accounted for in accordance with APB21, *Interest on Receivables and Payables*.

Preferred Interests - the Preferred Interests are a liability per paragraph 9 of FAS150, as follows:

"Mandatorily Redeemable Financial Instruments

9. A mandatorily redeemable financial instrument shall be classified as a liability unless the redemption is required to occur only upon the liquidation or termination of the reporting entity. A financial instrument issued in the form of shares is mandatorily redeemable if it ***embodies an unconditional obligation*** *requiring the issuer to redeem the instrument by transferring its assets* ***at a specified or determinable date*** *(or dates) or upon an event certain to occur."*

As the Preferred Interests are mandatorily redeemable upon specified dates, and the Preferred Interests have an unconditional obligation for redemption, they are considered a liability.

Subsequent accounting – upon issuance, the Preferred Interests were recorded at fair value and subsequently interest expense accrued at the implicit rate at inception, as per the guidance of paragraphs 20 and 22 of FAS150:

"20. Mandatorily redeemable financial instruments shall be measured ***initially at fair value****...*

22. Forward contracts that require physical settlement by repurchase of a fixed number of the issuer's equity shares in exchange for cash and mandatorily redeemable financial instruments shall be measured subsequently in one of two ways. ***If both the amount to be paid and the settlement date are fixed, those instruments shall be measured subsequently at the present value of the amount to be paid at settlement, accruing interest cost using the rate implicit at inception****..."*

Embedded derivatives — equity or liability accounting

As the Preferred Interests follow the guidance of paragraph 22 of FAS150 and the Notes are recognized per APB21, we must now determine if embedded derivatives exist that must be bifurcated out.

As described above, the CAGR is a derivative embedded with the host contracts, i.e. Notes and Preferred Interests. For the derivative associated with the Notes, we must apply the guidance of FAS133. For the derivative associated with the Preferred Interests, we must apply the guidance of FAS150.

Per paragraph 15 of FAS150, we must apply the relative guidance and ***NOT*** apply FAS150:

"Embedded Features

15. *This Statement* ***does not apply to features embedded in a financial instrument that is not a derivative in its entirety****. An example is an option on the issuer's equity shares that is embedded in a no derivative host contract. For purposes of applying paragraph 11(a) of Statement 133 in analyzing an embedded feature as though it were a separate instrument****, paragraphs 9–12 of this Statement shall not be applied to the embedded feature****. Embedded features shall be analyzed by applying other applicable guidance."*

As described above, embedded derivatives are out of the scope of FAS 150, and the next applicable guidance for embedded derivatives is paragraph 12 of FAS 133, similar to the derivative embedded in the Notes:

*"**Embedded Derivative Instruments***

12. *Contracts that do not in their entirety meet the definition of a derivative instrument (refer to paragraphs 6–9), such as bonds, insurance policies, and leases, may contain* ***"embedded" derivative instruments****—implicit or explicit terms that affect some or all of the cash flows or the value of other exchanges required by the contract in a manner similar to a derivative instrument. The effect of embedding a derivative instrument in another type of contract ("the host contract") is that some or all of the cash flows or other exchanges that otherwise would be required by the host contract, whether unconditional or contingent upon the occurrence of a specified event, will be modified based on one or more underlyings.* ***An embedded derivative instrument shall be separated from the host contract and accounted for as a derivative instrument pursuant to this Statement if and only if all of the following criteria are met****:*

    a. *The* ***economic characteristics*** *and risks of the embedded derivative* ***instrument are not clearly and closely related*** *to the economic characteristics and risks of the host contract. Additional guidance on applying this criterion to various contracts containing embedded derivative instruments is included in Appendix A of this Statement.*

    b. *The contract ("the hybrid instrument") that embodies both the embedded derivative instrument and the host contract is not remeasured at* ***fair value under otherwise applicable generally accepted accounting principles*** *with changes in fair value reported in earnings as they occur.*

    c. *A separate instrument with the same terms as the embedded derivative instrument would, pursuant to paragraphs 6–11,* ***be a derivative instrument subject to the requirements of this Statement****. (The initial net investment for the hybrid instrument shall not be considered to be the initial net investment for the embedded derivative.) However, this* *criterion is not met if the separate instrument with the same terms as the embedded derivative instrument would be classified as a liability (or an asset in some circumstances) under the provisions of Statement 150 but would be classified in stockholders' equity absent the provisions in Statement 150."*

In accordance with paragraph 12 of FAS133, the embedded derivative needs to be analyzed for potential bifurcation and application of FAS 133. In order to bifurcate, the following three criteria must be met:

a. The economic characteristics and risks of the embedded derivative *is not clearly and closely related* to the host contract.

b. The hybrid instrument (host and embedded derivative) *are not remeasured at fair value* per other GAAP.

c. If it was a freestanding instrument, the embedded derivative *must meet the criteria of derivatives* per paragraphs 6-11 of FAS133.

Clearly and closely related - due to the fact that the CAGR's value is only related to the change in price of the Company's stock and the host contract's fair value is derived from changes in interest rates, the CAGR and host contracts are not clearly and closely related.

Are not remeasured at fair value - there is no other applicable GAAP that requires that the financial instruments be valued at fair value with changes in fair value impacting earnings.

Must meet the criteria of derivatives - the three criteria for financial instruments to be considered derivatives are:

1. The instrument has one or more underlyings and notional amount
2. The instrument has a minimal initial net investment
3. The instruments terms require or permit net settlement

The following applies to the CAGR:

Underlyings and notional – the CAGR has an underlying of the Company's stock price. The notional amounts are the "strips" of Notes and Preferred Interests. *No initial investment* – the CAGR does not have an initial investment. *Permit net settlement* – the CAGR creates a net settlement amount.

Based on the above criteria, the embedded derivative must be bifurcated from the host contracts.

How to account for embedded derivatives:

The next phase is to test whether any additional exclusions from derivative accounting are applicable. Paragraph 11(a) of FAS133 says as follows:

"11. Notwithstanding the conditions of paragraphs 6–10, the reporting entity shall ***not*** *consider the following contracts* ***to be derivative instruments*** *for purposes of this Statement:*

a. ***Contracts issued or held by that reporting entity that are both (1) indexed to its own stock and (2) classified in stockholders' equity in its statement of financial position****."*

When analyzing the characteristics of the CAGR, we concluded that the CAGR is both indexed to NRG's stock price, however we must conclude on its classification as stockholders equity to comply with paragraph 11(a) of FAS133. This analysis is done by applying the guidance of EITF 00-19, *Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company's Own Stock*.

Analysis per EITF 00-19 - EITF 00-19 includes a number of logical steps when analyzing the classification of embedded derivatives. The primary characteristics that drive the classification as stockholders equity are:

1. It is at the *issuers* discretion whether to pay for the embedded derivative in cash or stock
2. There are no situations, no matter how extreme, in which NRG would have to settle the embedded derivative with cash
3. If the embedded derivative was a freestanding financial instrument – would it be considered stockholders' equity?

Due to the fact that:

- It is NRG's discretion whether to pay for the embedded derivative in cash or stock
- There are no situations in which NRG would have to settle the embedded derivative with cash
- If the embedded derivative was a freestanding financial instrument, it would be considered stockholders' equity

The CAGR is classified as stockholders' equity.

Conclusions of above analysis:

The embedded derivative is:

1. Exempt from derivative accounting per the guidance in paragraph 11(a) of FAS133.
2. Considered stockholders equity per the conclusions of EITF 00-19.

When the CAGR is exercised, any payments – whether in stock or cash – will be recorded to Additional Paid in Capital. Our disclosure in the Form 10-K states that this will be an increase to the cost of the treasury stock, and that is because it is our expectation to pay for the CAGR, if applicable, with stock in treasury. In future filings we will explain this concept more clearly.

<u>Note 16 – Earnings Per Share, page 175</u>

5. **Please supplementally explain the reason for the difference between preferred stock dividends in this note versus the face of the income statement. If the 2006 difference is due to a portion of preferred dividends being included in discontinued operations, please explain your basis for associated preferred stock with discontinued operations. Please also explain why the add back of 2006 dividends for diluted per share earnings differs from the amount subtracted in the numerator for basic EPS. We assumed dividends paid on preferred stock**

are not deductible for tax. If other wise please explain.

Difference between preferred stock dividends in the income statement vs. the footnote:
The Company has three types of outstanding cumulative preferred stock whose dividends must be paid on the 15th of the last month for each quarter, i.e. March, June, September and December. The following preferred stock was outstanding as of December 31, 2006:

Type	Issue Date	Principal	Annual Div.
4% Preferred Stock	12/30/2004	$420,000,000	$16.8 million
3.625% Preferred Stock	8/11/2005	250,000,000	$9.1 million
5.75% Preferred Stock	2/2/2006	500,000,000	$28.7 million

Cash dividends ordinarily cannot be rescinded by the board of directors once the shareholders have notice of the declaration unless the shareholders consent to rescission. As such, a cash dividend is recorded when it has been *declared* and *notice given to the shareholders* regardless of the date of record or date of settlement.

The 5.75% Preferred Stock were outstanding only as of February 2, 2006, and the dividend was payable on March 15, 2006. As such, the Company's board of directors only declared a month and a half's worth of dividend. However, the 5.75% Preferred Stock was outstanding for two months.

In accordance with SFAS 128, paragraph 9, for earnings per share purposes, the Company computes the income available to common stockholders by deducting dividends *accrued* on all outstanding preferred stock as they are all cumulative.

2006 annual dividends *declared* on 5.75% Preferred Stock	$24 million
2006 annual dividends *accrued* on 5.75% Preferred Stock	$26 million

The difference reflects approximately two weeks of cumulative undeclared dividends for this stock.

Add back of 2006 dividends:

The add back of 2006 dividends for diluted earnings per share differs from the amount subtracted in the numerator for basic earnings per share because the 3.625% Preferred Stock is *redeemable* and not *convertible* into common stock. As such, SFAS 128 paragraph 26(a) does not apply and the respective dividend is not added back to the numerator.

Note 22 – Regulatory Matters, page 197

6. We assume you consolidate the assets of the decommissioning trusts with respect to your interest in STP. We further assume such investments are included in trust fund investments. If otherwise, please explain your basis in GAAP for exclusion. Assuming such assets are "on balance sheet" please provide illustrative entries for typical activity in the trusts. Show us whether and how the asset amortization or obligation accretion affects income. Explain in detail your basis for balance sheet only treatment. Explain to us how you would view such securities under SFAS no. 115; trading, available for sale or held to maturity. Finally, explain in detail why the disclosure requirements of SFAS no. 115 have been omitted. We may have further comment.

Is the decommissioning trust fund consolidated by NRG?

Yes, NRG consolidates its 44% interest in the decommissioning trust fund related to its undivided interest in the STP nuclear facility.

Transactional entries:

None of the activities related to the decommissioning of the STP nuclear facility are recorded in the income statement as ultimately the Texas ratepayers are liable for decommissioning the facility when applicable. The following is a description of the relevant entries that are recorded on an ongoing basis:

Entry type 1 – for any movement in the Nuclear Decommissioning Trust Fund – gains/losses on assets, payments received by the trustee from ratepayers; account is Dr./Cr. with an offsetting entry to Nuclear Decommissioning Liability to Ratepayers.

Dr. Nuclear Decommissioning Trust Fund	XXX
Cr. Nuclear Decommissioning Liability to Ratepayers	XXX

Entry type 2 – for all entries related to the Asset Retirement Obligation – accretion, payments for decommissioning and updated forecasts; account is Dr./Cr. with an offsetting entry to the Nuclear Decommissioning Liability to Ratepayers.

Dr. Nuclear Decommissioning Liability to Ratepayers	XXX
Cr. Nuclear Decommissioning Asset Retirement Obligation	XXX

Entry type 3 – for all entries related to the Nuclear Decommissioning ARO Asset – depreciation and changes in value due to updated forecasts, account is Dr./Cr. with an offsetting entry to the Nuclear Decommissioning Liability to Ratepayers.

Dr. Nuclear Decommissioning Liability to Ratepayers	XXX
Cr. Nuclear Decommissioning ARO Asset	XXX

All the entries above affect the balance sheet only and are not recorded through the income statement.

Decommissioning mechanism for STP:

Currently, the Company's funding for the decommissioning obligation is contained within two separate trusts. The funding of the trusts is managed by way of the original owners of STP — CenterPoint Energy Houston Electric, LLC, or CenterPoint Houston, and American Electric Power, or AEP.

In accordance with the terms of its current Texas Utility Commission rate order, CenterPoint Houston is currently authorized to collect funds from transmission and distribution customers and is obligated to deposit the amounts collected into the STP decommissioning trust created by them to cover decommissioning of their original 30.8% interest in STP. Similarly, AEP is currently authorized by the Texas Utility Commission to collect funds from its transmission and distribution customers and is obligated to deposit the amount collected into the STP decommissioning trust created by them to fund decommissioning of the additional 13.2% interest in STP.

In the event that the funds from the trusts are ultimately determined to be inadequate to decommission the STP facilities, CenterPoint Houston and AEP will be required to collect through their Texas Utility Commission-authorized non-bypassable charges to customers all additional amounts required to fund the decommissioning obligations relating to the Company's 44.0% share, provided that the Company has complied with the Texas Utility Commission's rules and regulations regarding decommissioning trusts. Following the completion of the decommissioning, if surplus funds remain in the decommissioning trusts, any excess will be refunded to the respective rate payers of CenterPoint Houston or AEP (or their successors). The fair value of the trust assets are reflected as a non-current asset by the Company with an associated long-term liability to reflect the future obligation to fund the decommissioning from the trust assets or to refund or collect additional amounts from the ratepayers or CenterPoint Houston, AEP or their successors. Each month, accounting updates the trust balance asset for the new activity and, in addition, updates the corresponding liability.

The owners of STP must provide a report on the current status of decommissioning funding to the NRC every two years. However, if a sale, merger or acquisition occurs, the report is required for during the year of such event as well. The report compares the current external trust funding levels to that year's minimum decommissioning amounts calculated in accordance with NRC requirements. The NRC requirements determine the decommissioning cost estimate by escalating the NRC's estimated decommissioning cost of $105 million per unit, expressed in 1986 dollars, for the effects of inflation between 1986 and the most recent year-end and then multiplying by 44.0% to reflect the Company's share of each unit of STP. This estimate is the minimum required level of funding as of the most recent year-end.

Asset retirement obligation, or ARO - In addition to the nuclear decommissioning trust fund, the Company has recorded an asset retirement obligation asset and liability in accordance with SFAS No. 143. The assets and liabilities were recorded on the acquisition date based on the estimated future costs of decontamination and decommissioning of the Company's 44.0% interest in STP. The asset is being depreciated over the remaining licensing period for STP and is reflected as a component of property plant and equipment. Accretion is being recognized with the associated liability.

Accounting guidance:
Regulated operations that meet certain criteria are accounted for per FAS71, as follows:

"*5. This Statement applies to general-purpose external financial statements of an enterprise that has* ***regulated operations that meet all of the following criteria****:*

a. The enterprise's rates for regulated services or products provided to its customers are established by or ***are subject to approval by an independent, third-party regulator*** *or by its own governing board empowered by statute or contract to establish rates that bind customers. 3*

b. The regulated rates ***are designed to recover the specific enterprise's costs*** *of providing the regulated services or products.*

c. In view of the demand for the regulated services or products and the level of competition, direct and indirect, ***it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers****. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs.*

6. If ***some of an enterprise's operations are regulated and meet the criteria of paragraph 5, this Statement shall be applied to only that portion of the enterprise's operations****..."*

In respect to the decommissioning of STP, although NRG is not a regulated company per FAS71, this operation is regulated by the PUCT directly with CenterPoint Houston and AEP, and per paragraph 6 of FAS71 – regulatory accounting may apply. Per the guidance quoted above, as the decommissioning activity is:

§ Subject to approval by an independent third party regulator, i.e. NRC

§ Are designed to recover all the decommissioning costs

§ The charges are legitimate and will be collected from the ratepayers per the PUCT mandate to CenterPoint Houston and AEP

Conclusion - Regulatory accounting is applicable for all the decommissioning activity related to STP.

<u>*Regulatory accounting for the Trust Fund and Liability to Ratepayer:*</u>

Paragraph 11(b) of FAS71 states as follows:

"*11. Rate actions of a regulator* ***can impose a liability on a regulated enterprise****. Such liabilities are usually* ***obligations to the enterprise's customers****. The following are the usual ways in which liabilities can be imposed and the resulting accounting:...*

b. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. ***If current rates are intended to recover such costs and the regulator requires the enterprise to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose, the enterprise shall not recognize as revenues amounts charged pursuant to such rates. Those amounts shall be***

recognized as liabilities and taken to income only when the associated costs are incurred.

As the funds in the Trust Fund are intended to recover costs that will be incurred in the future, i.e. decommissioning of the STP nuclear facility, the Fund Asset and Liability to the Ratepayer are increased/decreased as the ratepayers make payments and trading is recorded at the Fund.

Regulatory accounting for the ARO asset and ARO Liability:

FAS143, *Accounting for Asset Retirement Obligations*, governs the accounting for ARO's and adds special provisions in paragraph 19 and 20 for regulated entities, as follows:

"19. This Statement applies to rate-regulated entities that meet the criteria for application of FASB Statement No. 71, Accounting for the Effects of Certain Types of Regulation, as provided in paragraph 5 of that Statement. Paragraphs 9 and 11 of Statement 71 provide specific conditions that must be met to recognize a regulatory asset and a regulatory liability, respectively.

20. Many rate-regulated entities currently provide for the costs related to the retirement of certain long-lived assets in their financial statements and recover those amounts in rates charged to their customers. Some of those costs result from asset retirement obligations within the scope of this Statement; others result from costs that are not within the scope of this Statement. The amounts charged to customers for the costs related to the retirement of long-lived assets may differ from the period costs recognized in accordance with this Statement and, therefore, may result in a difference in the timing of recognition of period costs for financial reporting and rate-making purposes. An additional recognition timing difference may exist when the costs related to the retirement of long-lived assets are included in amounts charged to customers but liabilities are not recognized in the financial statements. ***If the requirements of Statement 71 are met, a regulated entity also shall recognize a regulatory asset or liability for differences in the timing of recognition of the period costs associated with asset retirement obligations for financial reporting*** *pursuant to this Statement and rate-making purposes."*

Based on FAS143, due to timing differences, regulatory assets and liabilities are recognized for differences between actual funding and the decommissioning activities. As the Company has the responsibility for decommissioning the STP nuclear facility, we have established the appropriate ARO asset (as a component of Property, Plant and Equipment) and liability. However, due to the fact that the Company *is not the utility that receives the cash and the Company does not recognize revenue from charging the ratepayers* (CenterPoint and AEP are the entities that do), and the Fund assets cannot be used by the Company until decommissioning commences, revenue from these funds will not be recognized by the Company. As such, in accordance with the guidance above, all ARO related expenses – both the depreciation of an ARO asset as well as the accretion of the ARO liability – are treated as balance sheet transactions only.

Application of FAS115:

Accounting - Due to the nature of the Trust Fund's trading, the appropriate classification of the Trust Fund's activity is trading. However, as discussed above, as the Trust Fund is accounted for in accordance with FAS71, gains/losses from the Trust Fund's activity are recorded as an increase/decrease to the Company's Liability to the Ratepayers and not through the income statement per FAS115.

Reporting - In its discussions and conclusions, the Board notes the following in paragraph 2 and paragraph 119 of FAS115:

"2. This Statement was undertaken mainly in response to concerns expressed by regulators and others about the ***recognition and measurement of investments in debt securities****, particularly those held by financial institutions...*

119. The Board believes that the financial statement disclosures required by this Statement ***provide information that is useful in analyzing an enterprise's investment strategies and exposures to risk..."***

Due to the nature of the Trust Fund as well as the necessity for the Ratepayers to provide the funding of decommissioning regardless of the Trust Funds activity, the Company believes that the basis of conclusions for disclosure requirements of FAS115 are not applicable as they are not material to the Company's financial statements and are potentially misleading.

Note 19 – Stock Based Compensation page 185

7. **Prospectively, please disclose the recognized tax benefit related to your share based payment arrangements for each year an income statement is provided. If applicable, please disclose any compensation cost capitalized. See paragraph A240.g(1) of SFAS no. 123R.**

In accordance with SFAS 123R paragraph A240.g(1), for each of the three years presented, the Company disclosed the recognized tax benefit related to share based payment arrangements in Note 19 of the Form 10-K. This disclosure can be found in the table below the Supplemental Information section on page 190 of the Form 10-K, as follows:

Award	Compensation Expense Year ended December 31 2006	2005	2004	Total Non-vested Compensation Cost Not Yet Recognized As of December 31 2006	Weighted Average Life Remaining As of December 31 2006
	(In millions, except weighted average data)				
NQSO's	$ 5	$ 4	$ 7	$ 8	1.1
RSU's	10	8	5	16	1.1
DSU's	1	3	2	—	—
PU's	2	—	—	5	2.1
Total	18	15	14	29	
Tax Benefit recognized	$ 7	$ 6	$ 6		

The Company did not capitalize any equity compensation cost during the periods reported.

In accordance with the guidance noted above, in future filings, we will disclose the recognized tax benefit to our share based payment arrangements.

8. **Please refer to the disclosure requirements of paragraph A240.i regarding the amount of cash received from the exercise of options and the tax benefit realized from the options exercised. Please be aware that excess tax benefits associated with the exercise of options are now required to be reflected as financing cash inflow on the statement of cash flows pursuant to paragraph 68e of Statement 123R.**

   Cash received and tax benefit realized:

   During the periods reported, there were exercises of stock options during the year ended December 31, 2006 of an immaterial amount of approximately $1 million. There were no exercises of stock options for the years ending December 31, 2005 and 2004. NRG did not disclose the cash received from the exercise of stock options for any of the three years an income statement was presented, in accordance with SFAS 123(R), A240.i, because the Company considered these amounts immaterial to NRG's consolidated results of operations, financial position and cash flows. As these amounts become material, the Company's future filings with the Commission shall disclose these amounts.

   Excess tax benefit:

   In accordance with SFAS123R A94, Footnote 82, a share option exercise may result in a tax deduction prior to the actual realization of the related tax benefit because the entity has a net operating loss carryforward, and in that situation, a tax benefit and a credit to additional paid-in capital for the excess deduction would *not be recognized* until that deduction reduces taxes payable.

   The Company did not disclose any tax benefit realized from stock options exercised during the reported periods because the Company has been in a net operating loss position. Also see footnote 18 – Income Taxes as found on page 184 of the Form 10-K for a further discussion regarding the Company's net operating losses.

   In the future filings with the Commission the Company will provide the noted disclosures and cash flow statement applications with respect to tax benefit realized from the exercise of options as the Company's net operating loss is fully utilized or expired.

<u>**Note 26 – Jointly Owned Plants, page 202**</u>

9. **We note your interests in jointly owned plants. In future filings please disclose the amount of your share of direct expenses that are included in the corresponding operating expenses on your Consolidated Statements of Operations. See SAB Topic 10C.**

   As required per SAB Topic 10C, on page 202 of the Form 10-K we state that our share of the joint plants operating expenses and income is included in each line item of NRG's income statement. As we do not record direct expenses to purchased power, we believe we have met the requirements of SAB Topic 10C, which states as follows:

"The note ***should state*** *that the participating utility's share of direct expenses of the joint plants is included in the corresponding operating expenses on it's income statements.* ***If the share of direct expenses is charged to purchased power*** *then the note should disclose the amount so charged and the proportionate amounts charged to specific operating expenses on the records maintained for the joint plants.*

In future filings we will clarify that our proportionate share in each joint plant is both the relevant share for both balance sheet and income statement items and that share is recorded in each line item.

*** * * * * ***

We hope that we were able to clarify your comments and eagerly await the Staff's response. Please contact Carolyn Burke, Controller, at (609) 524-4703 or me at (609) 524-4702 if you have questions regarding our responses or related matters.

Sincerely,

/s/ ROBERT C. FLEXON
Robert C. Flexon
Executive Vice President and
Chief Financial Officer

cc: Robert Babula, Staff Accountant, Securities and Exchange Commission
Drew Murphy, General Counsel, NRG Energy, Inc.
Carolyn Burke, Controller, NRG Energy, Inc.