July 2, 2008

Mr. H. Christopher Owings
Assistant Director
United States Securities and Exchange Commission
Division of Corporate Finance
100 F. Street, N.E.
Washington, D.C. 20549

Re: *The Williams Companies, Inc.*
Form 10-K for the Fiscal Year Ended December 31, 2007
Filed February 26, 2008
File No. 1-4174

Dear Mr. Owings:

On behalf of The Williams Companies, Inc., I am writing in response to your letter dated June 13, 2008, setting forth comments of the Staff of the Division of Corporate Finance of the Securities and Exchange Commission with respect to our Annual Report on Form 10-K filed February 26, 2008. For your convenience, I have reproduced the full text of each of the Staff's comments above our responses below.

Form 10-K for the Fiscal Year Ended December 31, 2007

Customers and Operation, page 15

1. **We note here and in a Risk Factor that you believe that your Venezuelan assets are subject to escalating political risk. To the extent material, please quantify in your discussions the amount of assets at risk.**

   The net book value of long-lived assets of the Venezuelan operations in our Midstream Gas & Liquids segment discussed on page 15 was $351 million at December 31, 2007. This balance is included in the $713 million of total long-lived assets outside of the United States as disclosed in *Note 17. Segment Disclosures*. Additionally, in *Note 11. Debt, Leases and Banking Arrangements*, the $351 million net book value of Venezuelan fixed assets is disclosed in footnote (3) of the Long-Term Debt table on page 112 as collateral for certain debt balances. Finally, the Midstream Gas & Liquids segment MD&A provides information as to the relative size of the results of operations related to these Venezuelan assets.

   Based on the above disclosures, and because all long-lived assets outside of the United States as disclosed in *Note 17. Segment Disclosures* represented 4.2% of total long-lived assets, we concluded that specific disclosure of the balance of our Venezuelan assets was not necessary on page 15 or in the risk factors. In future annual filings, we will include the net book value of our Venezuelan long-lived assets in such Item 1 discussions in order for the reader to more readily ascertain the amount of assets subject to such risks.

<u>Management's Discussion and Analysis of Financial Condition and Results of Operations</u>

<u>Results of Operations, page 42</u>

2. **We note that most of your operating expenses are captured in the line titled "Costs and operating expenses." Tell us how you considered explaining the types of expenses that are captured in this line item, either in MD&A or in your footnotes, as we believe this is useful information to your investors. Also tell us how you considered quantifying the major expenses reflected in this line item, such as product purchases, production and manufacturing expenses, depreciation and depletion, etc. for each period for which you present an income statement, as we believe this would assist your readers in better understanding the fluctuations in this line item from year to year.**

   We agree that an understanding of the fluctuations in our costs and operating expenses is an important component of assisting readers to better comprehend the key drivers of our period results. Our reportable segments represent diverse businesses that have somewhat unique costs and operating expenses. Because the Results of Operations presented on page 42 represent our consolidated results, these explanations for fluctuations in costs and operating expenses are intended to be at a high level, consistent with a layered approach as mentioned in FRR Section 501.12.a. In addition to our high level explanation of the change in costs and operating expenses by major factor on page 43, further detail about changes in costs and operating expenses reflected in this line item are presented by segment in the subsequent discussions of results of operations, including quantification where considered necessary, with a focus upon their impact on segment profit.

   The primary types of costs and operating expenses by segment can be generally summarized as follows:

   - Exploration & Production — depreciation, depletion and amortization and lease operating expenses.
   - Gas Pipeline — depreciation and operation and maintenance expenses.
   - Midstream Gas & Liquids — commodity purchases (primarily for fuel, shrink, and natural gas liquid (NGL) marketing), depreciation, and operation and maintenance expenses.
   - Gas Marketing Services — commodity purchases primarily in support of commodity marketing and risk management activities.

   Commodity purchases are the most significant component of our consolidated costs and operating expenses. Fluctuations in this component are further discussed by segment to the extent they have a significant impact on segment profit. Depreciation, depletion, and amortization is the next largest component of our consolidated costs and operating expenses. In addition to the discussion by segment, depreciation, depletion and amortization is presented in total and by segment in *Note 17. Segment Disclosures*.

   To promote further understanding of the types of expenses captured in our costs and operating expenses, we will provide a discussion of the primary types of costs and operating expenses by segment, similar to the summary above, in future annual filings.

3. **Based on the description of your business, it appears that some of your segments provide services to third parties. Please tell us how you considered quantifying and analyzing changes in revenues from selling gas as opposed to revenues from providing gas services, as part of providing transparency into and context around your results.**

We believe our segment presentation indicates that our Exploration & Production segment is focused on producing and selling gas, while our other segments are primarily focused on providing services. We also believe that the same discussions adequately quantify and analyze changes in revenues so that a reader can understand the changes in segment revenue contributions as they relate to service functions or commodity sales.

4. **Please tell us why you do not separately present the "costs and operating expenses" of each reportable segment within your year-over-year operating results disclosures in MD&A. In future filings, please consider presenting segment costs and operating expenses in the segment operating result tables on pages 49, 53, 58, and 63.**

In conjunction with the narrative discussion of mark-to-market versus realized results in our Gas Marketing Services segment, we separately present the costs and operating expenses of this segment in the table on page 63. Given the greater transparency of costs associated with our other segments, we rely on the narrative discussion of changes in costs and operating expenses with respect to those segments to provide a reader with an understanding of the relative impact of changes in these items on segment profit. We believe this provides the reader with the perspective of management as we evaluate performance based on segment profit and our approach explains the significant changes in costs and operating expenses within the context of their impact on segment profit.

We have developed our current presentation of results of operations with respect to costs and operating expenses for our reporting segments considering all applicable MD&A guidance, including Regulation S-K Item 303 and FRR Section 501. We have also considered the guidance in FRR Section 501.06.a Segment Analysis, which states:

> In formulating a judgment as to whether a discussion of segment information is necessary to an understanding of the business, a multi-segment registrant preparing a full fiscal year MD&A should analyze revenues, profitability, and the cash needs of its significant segments.

We believe our presentation of our results of operations by segment analyzes the revenues and profitability of these segments, addressing those items that management believes are important to understanding the changes in each segment.

<u>Gas Marketing Services, page 63</u>

5. **You disclose that you recorded a loss of $166 million during fiscal year 2007 related to certain legacy derivative natural gas contracts that you expect to assign to another party in fiscal year 2008 under an asset transfer agreement that you executed in December 2007. We further note that the legacy contract assigned in the asset transfer agreement was originally accounted for on an accrual basis under the normal purchase and normal sales exception of SFAS 133 and that you recognized the loss since you no longer consider the contract to be in the normal course of business due to the pending assignment transaction. Citing authoritative accounting guidance, where applicable, please provide us with further information regarding these legacy contracts and the assignment transaction:**

- **Tell us the nature of the legacy contracts and their key terms and provisions.**

On November 11, 2002, we executed a Base Contract for Sale and Purchase of Natural Gas and a Transaction Confirmation for Immediate Delivery, (collectively, the Contract) with a third party (the Gas Purchaser). The Contract required the firm delivery of specified volumes of natural gas from January 2004 through December 2010 at specified delivery points. In conjunction with this transaction, we also executed certain forward physical and financial purchases of natural gas (the Hedges) to hedge our exposure to price volatility. We determined that the Contract and the Hedges (together, the Gas Portfolio) each met the definition of a derivative under SFAS 133, "Accounting for Derivatives and Hedging Activities."

- **Explain how you accounted for the legacy contracts at the time of and subsequent to removal of their normal purchase and normal sales designation.**

Effective April 1, 2003, we elected the normal purchases and normal sales exception, allowed by paragraph 10(b) of SFAS 133, on the Contract. Generally, a contract qualifies for the normal purchases and normal sales (NPNS) exception under paragraph 10(b) if it provides for the purchase or sale of something other than a financial instrument (i.e. it is probable that the contract will not settle on a net basis) that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business at delivery locations relevant to the Company's operations.

We did not elect the normal purchases and normal sales exception or hedge accounting on the Hedges. As a result, they are accounted for on a mark-to-market basis consistent with SFAS 133.

On November 9, 2007, we closed on the sale of substantially all of our power business. In conjunction with the sale of the power business, we significantly reduced the scope and exposure of our gas trading business. As a result, we decided to dispose of the Gas Portfolio.

On December 21, 2007, we executed a Gas Portfolio Transfer Agreement with another third party (the Transferee), which transferred to the Transferee the risks and rewards of ownership, but not the legal title, in the Gas Portfolio. Assignment of the legal title to the contracts in the Gas Portfolio requires consent of the counterparties. The Transfer Agreement required that commercially reasonable efforts would be subsequently made to obtain such consents, at which time legal title would be assigned to the Transferee. Upon execution of the Transfer Agreement, we paid approximately $10 million to the Transferee, representing the net negative fair value of the Gas Portfolio.

Per paragraph 10(b) of SFAS 133, election of the normal purchases and normal sales exception is generally irrevocable; gains/losses from such contracts are either recognized over the life of the contract on an accrual basis or upon settlement or termination of the contract. In our judgment, we effectively settled the Contract in the 4th quarter of 2007 through the Transfer Agreement and thus needed to recognize the related embedded loss. Support for our conclusion includes:

- It was highly probable that the Gas Purchaser would consent to the assignment of the Contract to the Transferee because:
    - The Contract stipulated that such consent was not to be unreasonably withheld and we would have legal recourse against the Gas Purchaser if it failed to provide consent without demonstrating reasonable basis.
    - The Gas Purchaser provided verbal indications of its willingness to provide the consent.
    - The Transferee is a credit worthy and reputable counterparty.
- The Transferee is obligated under the Transfer Agreement to use "commercially reasonable" efforts to work with the Gas Purchaser and us in obtaining the consent.
- The Transfer Agreement is not subject to consent of the Gas Purchaser to be effective. Cash was paid in full settlement to the Transferee upon execution of the Transfer Agreement, which represents a binding commitment for both parties.

Based on the terms of Transfer Agreement and the high probability of assignment of the Contract, we concluded that the Contract no longer qualified for the normal purchases and normal sales exception because it was no longer probable that the Contract would not be settled net (the expected assignment constituting a "net settlement") and that it was necessary to recognize the previously unrecognized loss on the contract in the same period. Because the normal purchases and normal sales election was "called into question" by the expected assignment of the Contract, it will be accounted for on a mark-to-market basis until assignment is completed. Mark-to-market gains or losses from the Contract and the Hedges are perfectly offset by mark-to-market gains or losses from the reciprocal transaction under the Transfer Agreement.

As noted above, the Contract had been recorded on the accrual basis since the April 1, 2003 election of the normal purchases and normal sales election, and the Hedges had been accounted for on a mark-to-market basis since inception. At the date of transfer, the Contract had an unrecognized negative fair value of approximately $166 million and the Hedges had a recognized positive fair value of approximately $156 million, such that the net fair value of the Gas Portfolio was a negative $10 million. The entry to record the unrecognized negative fair value of the Contract is as follows (in millions):

Revenue	$166	
Derivative Liability		166

We recorded the recognized loss as a debit to revenue consistent with our policy as stated on page 89 of our Form 10-K.

- **Provide us with the key terms and provisions of the asset transfer agreement, including the consideration you received and/or relinquished. Please also explain how you recorded the assignment transaction in your financial statements. Please provide illustrative journal entries to assist in our review.**

As noted above, the reciprocal transactions created by the Gas Portfolio Transfer Agreement have equal but opposite commercial terms as the Contract and the Hedges so that our economic position under the Gas Portfolio was transferred to the Transferee. Under the agreement, we paid approximately $10 million to compensate the Transferee for assuming the $10 million net obligation related to the Gas Portfolio. We determined that the reciprocal transactions meet the definition of a derivative under SFAS 133. The following entry was made to record the reciprocal derivative asset and liability and the cash payment under the Transfer Agreement (in millions):

Derivative Asset	$166	
Cash		10
Derivative Liability		156

We have not elected hedge accounting or the normal purchases and normal sales exception on the reciprocal derivatives and we thus record them on a mark-to-market basis. Upon execution of the Transfer Agreement, we also began the process of assigning the Contract and the Hedges to the Transferee on a contract-by-contract basis. When each such assignment occurs, the related reciprocal transaction will be automatically and simultaneously terminated.

To provide further clarity, the following table summarizes the relevant elements of these transactions:

			Hedges	Contract	
(Dollars in Millions)	Revenue	Cash	Recognized Derivative Asset (Liability)		NPNS Unrecognized Fair Value
Pre-Transfer Agreement			$ 156		$(166)
Recognition of NPNS Contract Liability	$166			$(166)	$ 0
Cash Payment and Reciprocal Derivatives under Transfer Agreement		$(10)	$(156)	$ 166	

Consolidated Statement of Stockholders' Equity, page 82

6. **Please tell us how you considered providing a roll forward of the number of shares of common stock and the number of shares of treasury stock that were outstanding for each period presented. Refer to Article 5-02(30) of Regulation S-X.**

Article 5-02(30) of Regulation S-X requires disclosure, in a note or statement, of the changes in each class of common shares for each period for which an income statement is required to be filed. We have provided this information as follows:

- Because our common stock has a $1 par value, as disclosed on the face of our Consolidated Balance Sheet, the dollar amounts presented in the Common Stock column of our Consolidated Statement of Stockholders' Equity also represent the number of shares. Thus the activity presented in this column represents a roll forward of the number of shares issued.

- The only treasury stock activity during the periods presented in our Consolidated Statement of Stockholders' Equity references *Note 12. Stockholders' Equity*. This note details the number of shares of treasury stock associated with this activity.

Notes to Consolidated Financial Statements

General

7. **We assume that you do not disclose detailed information regarding your regulatory assets and liabilities due to immateriality. Please confirm that our understanding is correct and quantify for us your regulatory asset and liability balances as of December 31, 2006 and 2007.**

The balances of our regulatory assets and liabilities are as follows:

	December 31, 2007	December 31, 2006
	(Dollars in millions)	
Regulatory Assets — Current	$ 24	$ 15
Regulatory Assets — Noncurrent	209	258
	$ 233	$ 273
Regulatory Liabilities — Current	$ 9	$ 20
Regulatory Liabilities — Noncurrent	56	74
	$ 65	$ 94

We do not disclose detailed information regarding these balances due to their insignificance in relation to our Consolidated Balance Sheet. We would further note that these balances do not require separate disclosure on the face of our Consolidated Balance Sheet under the rules of Article 5-02 of Regulation S-X.

Note 1. Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies

Gas Pipeline revenues, page 89

8. **We note the discussion of your gas pipeline revenue recognition policies and have the following comments:**

- **We read that revenues from the transportation of gas are recognized in the period the service is provided. Please explain to us in more detail when and how you recognize this revenue, and provide a more detailed description of your policy to your investors in future filings.**
- **We note from the description of your gas pipeline business elsewhere in the filing that you also provide storage services. Please tell us in reasonable detail your revenue recognition policy for these storage services. Either disclose this policy in future filings, or tell us how you determined this policy did not need to be disclosed.**
- **We read that revenues for sales of products are recognized in the period of delivery. We assume that you are referring to the sale of natural gas that you own, and that this revenue is recognized in your Gas Pipeline segment because you used your pipelines to transport the gas to your customers. Please confirm our understanding, if true, and consider clarifying this to your readers.**

Background Information — Transportation and Storage Revenues

Transportation and storage revenues were approximately 78 percent and 10 percent, respectively, of Gas Pipeline 2007 total revenues of $1.6 billion.

Gas Pipeline's interstate transmission and storage activities are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC), and, as such, its rates and charges for the transportation and storage of natural gas in interstate commerce are subject to regulation. Transportation and storage rates are established primarily through the FERC ratemaking process.

We provide a significant portion of our transportation services pursuant to long-term firm transportation agreements that obligate our customers to pay us monthly a demand (reservation) charge that is owed for reserving an agreed upon monthly volume of pipeline capacity regardless of the pipeline capacity actually utilized by a customer during the month. Absent a change in rates, the demand charge is generally constant from month to month over the term of the agreement. When a customer utilizes the capacity it has reserved under a firm transportation agreement, we also collect a commodity charge based on the volume of natural gas transported. Commodity charges are a small percentage of the total charges received under long-term firm agreements. We also derive a small portion of our transportation revenues from interruptible transportation agreements under which customers pay charges for transportation based on the volume of natural gas transported.

We provide a significant portion of our storage services pursuant to firm storage agreements that obligate our customers to pay us monthly demand (deliverability) and capacity charges that are owed for reserving an agreed upon monthly volume of daily deliverability and an agreed upon volume of total storage capacity regardless of the storage service actually utilized by a customer during the month. When a customer utilizes the storage service it has reserved under a firm storage agreement, we also collect a volume based charge when natural gas is injected into or withdrawn from storage. Injection and withdrawal charges are a small percentage of the total charges received under firm agreements.

As a result of the ratemaking process, certain revenues collected by us may be subject to possible refunds upon final orders in pending rate proceedings with the FERC. We record estimates of rate refund liabilities considering our and third party regulatory proceedings, advice of counsel and estimated total exposure, as discounted and risk weighted, as well as collection and other risks. Depending on the results of these proceedings, the actual amounts allowed to be collected from customers could differ from management's estimate.

Revenue Recognition Policy — Transportation and Storage

We will disclose our revenue recognition policy for Gas Pipeline transportation and storage services in future annual filings reflecting the following more detailed descriptions:

Revenues for the transportation of gas under long-term firm agreements are recognized considering separately the demand and commodity charges. Demand revenues are recognized monthly over the term of the agreement regardless of the volume of natural gas transported. Commodity revenues from both firm and interruptible transportation are recognized in the period transportation services are provided based on volumes of natural gas physically delivered at the agreed upon delivery point.

Revenues for the storage of gas under firm agreements are recognized considering separately the demand, capacity, and injection and withdrawal charges. Demand and capacity revenues are recognized monthly over the term of the agreement regardless of the volume of storage service actually utilized. Injection and withdrawal revenues are recognized in the period when volumes of natural gas are physically injected into or withdrawn from storage.

As discussed above, due to the ratemaking process, certain revenues collected by us may be subject to possible refunds and we record estimates of rate refund liabilities considering the factors discussed above.

Background Information — Gas Sales Revenues

Gas sales revenues were approximately 11 percent of Gas Pipeline 2007 total revenues of $1.6 billion.

These revenues primarily represent the settlement of gas imbalances with Gas Pipeline's customers. In the course of providing transportation services to our customers, we may receive different quantities of gas from our shippers than the quantities delivered on behalf of those shippers. The resulting gas transportation and exchange imbalances are settled pursuant to the provisions in our FERC tariffs. Substantially all imbalances are settled through a cash-out mechanism whereby Gas Pipeline buys or sells gas with our shippers under terms provided for in the tariffs. Accordingly, the purchases and sales are recognized by Gas Pipeline as they are party to the imbalance settlements.

Revenue Recognition Policy — Gas Sales

We will clarify the nature of our gas sales revenues in future annual filings reflecting the following:

In providing transportation services, we may receive different quantities of gas from our customers than the quantities delivered on their behalf. The resulting imbalances are primarily settled through the purchase and sale of gas with our customers under terms provided for in our FERC tariffs. Revenue is recognized from the sale of gas upon settlement of the transportation and exchange imbalances.

9. You appear to have provided detailed revenue recognition policies for your Exploration & Production segment and your Gas Pipeline segment. Please tell us how you considered providing detailed revenue recognition policies for your remaining segments: Midstream Gas & Liquids and Gas Marketing Services. In this regard, we note that these remaining segments account for the vast majority of your total revenues, and it is unclear to us that your current disclosure for “all other revenues” has fully explained how you considered the four criteria for revenue recognition as indicated in SAB Topic 13.A.1. Alternatively, you may wish to address each of your revenue generating activities in a revenue recognition policy footnote without regard for the segment(s) containing such activity, and explain somewhere appropriate in your footnotes the revenue generating activities that are reflected in each segment. If you propose to revise your revenue recognition disclosures, please show us what such disclosures will look like.

We recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer’s price is fixed or determinable and (iv) collectibility is reasonably assured.

Our disclosure of Midstream Gas & Liquids and Gas Marketing Services revenue recognition policies will be expanded in future annual filings to reflect the information set forth below under the revenue recognition policy sections. With these changes, disclosures in the revenue recognition policies section of our summary of significant accounting policies will individually address each of our four business segments.

Midstream Gas & Liquids — Background Information

Midstream Gas & Liquids businesses primarily include: natural gas gathering and processing; NGL fractionation and storage; olefins extraction and fractionation; and the marketing of NGLs and olefins.

Natural gas gathering services are primarily performed under long-term volume based fee contracts. Natural gas processing services are primarily performed under long-term volume based fee contracts, keep whole agreements and percent of liquids arrangements. Under keep whole and percent of liquids processing contracts we receive the rights to all or a portion of the NGLs extracted at our processing plants from the producers’ natural gas stream.

Olefins extraction and fractionation services primarily involve the following types of arrangements. For our services under our long-term olefins extraction and fractionation contract in Canada we receive the rights to retain certain products extracted and fractionated at our plants from the producer’s off gas stream. We also have operations where we produce olefins from purchased feed stock.

We market NGLs and olefins. This activity includes marketing of customers’ products from our natural gas processing activities and marketing products purchased from third parties on the open market. These sales are based on supply contracts of both long and short term durations.

Midstream Gas & Liquids — Revenue Recognition Policy

Revenues under volume based fee contracts are recorded when gathering and processing services have been performed. For keep whole and percent of liquids processing contracts, we recognize revenues when the extracted NGLs are sold and delivered to the third party purchasers under NGL sales contracts.

We recognize revenues under our Canada olefins extraction and fractionation contract when the extracted products are sold and delivered to the third party purchasers under sales contracts. For our olefins production operations, we recognize revenues when the olefins are sold and delivered to the third party purchasers under sales contracts.

Revenues from marketing NGLs and olefins are recognized when the products have been sold and delivered to the third party purchasers under sales contracts.

Gas Marketing Services — Background Information

Gas Marketing Services markets the gas produced by Exploration & Production, buys and sells gas in association with managing transportation and storage contracts and providing services to third-parties, such as producers.

Gas Marketing Services — Revenue Recognition Policy

Revenues for sales of gas are recognized when the product is sold and delivered to the third party purchasers under sales contracts.

Employee stock-based awards, page 90

10. You disclose on page 91 that the performance targets for certain performance-based restricted stock units have not been established and, therefore, expense is not currently recognized. While it appears that a grant date for these awards has not been established since the performance condition has not been defined and a mutual understanding of the award terms has not been reached, please tell us how you determined the service inception date did not precede the grant date. Please refer to paragraphs A79 through A85 of SFAS 123(R), and explain to us in reasonable detail how your accounting complies with SFAS 123(R), including whether these awards are classified as liabilities or as equity.

The performance based restricted stock units to which this disclosure pertains were awarded in 2004 and 2005 (Units). The Units have different terms and performance structure than the performance based restricted stock units awarded in 2006 and 2007. Compensation expense associated with the Units was $3.1 million, $5.9 million and $11.8 million in 2005, 2006 and 2007, respectively. The Units were all vested by early 2008 and therefore no further compensation expense will be recognized.

The vesting provisions of the Units are subject to service and performance conditions. The Units are earned in one third increments based on achievement of performance conditions for each of three individual performance years (e.g. the units awarded in 2005 have performance years 2005, 2006 and 2007). The performance objectives for each performance year are established at the beginning of that year.

The grant date for each one third increment occurs after the end of that particular performance year upon certification by the Compensation Committee of the Board of Directors that the performance objectives have been achieved. Although performance objectives are established at the beginning of each performance year, the Compensation Committee has discretion to make adjustments to actual results when assessing achievement of the performance objectives and therefore we concluded that a mutual understanding of the terms is not established until performance is certified by the Compensation Committee.

We begin recognizing compensation cost at the service inception date. Each one third increment has a different service inception date. We determined that the service inception date occurred when the initial performance objectives were established (which preceded the grant date) since this is when all of the criteria in paragraph A79 are met (most notably, a performance condition had been established which, although subject to discretion, if not achieved by the grant date will result in forfeiture of the awards for the performance year).

Compensation cost recognized in periods prior to the grant date is based on the fair value of the Units at the end of each reporting period and is remeasured at each reporting date until the grant date occurs.

These Units are classified as equity because upon vesting the units are settled by issuing common stock of Williams.

<u>**Note 7. Employee Benefit Plans, page 102**</u>

11. Please explain to us how you calculate the market related value of plan assets as that term is defined in SFAS 87. Since there is an alternative to how you can calculate this item, and it has a direct effect on pension expense, we believe you should disclose how you determine this amount in accordance with paragraph 12 of APB 22.

In future annual filings, we will disclose how we determine the market-related value of pension plan assets and other postretirement plan assets. For assets held in our pension plans, the market-related value of plan assets is equal to the fair value of plan assets adjusted to reflect amortization of the gains or losses associated with the difference between the expected return on plan assets and the actual return on plans assets over a five year period. The market-related value of plan assets for our other postretirement benefit plans is equal to the unadjusted fair value of plan assets at the beginning of the year.

<u>**Note 9. Property, Plant and Equipment, page 110**</u>

12. We note that your property, plant and equipment comprises approximately 64% of your total assets, and given the significance of this asset, we believe you should provide the disclosures indicated by paragraph 5 of APB 12 at a reasonable level of detail. Please tell us how you considered presenting your gross balances of property, plant and equipment within this footnote using the same categories presented on page 86 in your discussion of depreciation rates and estimated useful lives, including separately presenting regulated and non-regulated assets, as we believe this would provide useful information to your investors.

Our Gas Pipeline business is comprised primarily of regulated gas transmission assets, and also includes gathering and storage facilities. We do not believe a quantification of each of these asset groups would be meaningful to our investors; however, we have provided specific depreciation policies for each of these regulated assets on page 86. Our Exploration & Production business is comprised primarily of proved and unproved property assets, the detail of which is set forth on page 141. We have disclosed our depreciation policy for these assets on page 87. Finally, our Midstream Gas & Liquids business is comprised primarily of gathering and processing facilities, and also includes transportation equipment. We do not believe a quantification of each of these asset groups would be meaningful to our investors; however, we have provided specific depreciation policies for each of these assets groups on page 86. Accordingly, we address the requirements of paragraph 5 of APB 12 within *Note 9. Property, Plant and Equipment*, by presenting:

- Depreciation, depletion and amortization expense for all periods.
- Gross balances of property, plant and equipment by reporting segment, which represents the major classes of depreciable assets by function.
- Accumulated depreciation, depletion and amortization in total.

Note 1. Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies provides a general description of the depreciation methods with respect to our different types of assets.

We have elected to present the gross balances of our property, plant and equipment on a functional basis by segment as this is representative of the major classes of assets considering the distinct activities of each segment. This presentation precludes any further segregation of our regulated assets, as those are primarily held by our Gas Pipeline segment.

13. Based on your current disclosures, it is unclear to us how you considered the reconciliation required by paragraph 22(c) of SFAS 143. Please explain this to us, or disclose this reconciliation in future filings.

Because our asset retirement obligation and the associated periodic activity (as disclosed in *Note 9. Property, Plant and Equipment*) is not significant to our property, plant and equipment balance and Consolidated Balance Sheet in total, we have elected to provide a qualitative discussion of significant changes in our obligation rather than a detailed tabular reconciliation.

<u>Note 14. Financial Instruments, Derivatives. Guarantees and Concentration of Credit Risk</u>

14. We note from your disclosures here and in Note 1 that certain of your energy derivatives do not qualify for or do not use hedge accounting under SFAS 133. Please tell us how you considered quantifying, either here or in your MD&A analysis of results, the impact on revenues for each year from marking these derivatives to market. In this regard, we believe this disclosure could be an important part of providing transparency into your revenues, particularly if the amounts generated by these derivatives vary significantly from year to year. Please also tell us how you considered quantifying the impact on each line item in your income statement for derivatives that are reported on a gross basis.

Unrealized mark-to-market revenue on derivatives not designated as hedges is primarily recognized by the Gas Marketing Services segment. Unrealized mark-to-market revenue on derivatives not designated as hedges for the Gas Marketing Services segment, by year, is disclosed in the Gas Marketing Services Results of Operations on page 63 of our Form 10-K.

The only other unrealized mark-to-market revenue on derivatives not designated as hedges was recognized by the Exploration & Production segment. For the periods presented in our Form 10-K, total unrealized mark-to-market revenue on derivatives not designated as hedges for the Exploration & Production segment never exceeded 0.5% of Exploration & Production’s total revenue and was thus not significant for disclosure.

Please also tell us how you considered quantifying the impact on each line item in your income statement for derivatives that are reported on a gross basis.

As disclosed on page 89 of our Form 10-K, the only derivative activity recorded on a gross basis is realized gains and losses on derivatives that require physical delivery, and which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement. This represents a small portion of our derivatives activity. Revenue related to this activity do not exceed 2% of the total revenue in any of the periods presented in our Form 10-K. Likewise, costs related to this activity do not exceed 2% of the total costs and operating expenses in any of the periods presented. Neither the revenue nor costs related to derivative activity reported on a gross basis aggregate to amounts that we believe are meaningful for disclosure.

<u>Note 15. Contingent Liabilities and Commitments, page 126</u>

15. **You disclose on page 131 that you paid the city of Redondo Beach, California approximately $57 million for back taxes and penalties and, despite the payment, you do not believe a contingent loss is probable. Please tell us if you expensed this payment and, if so, whether or not you recorded an offsetting contingent gain. Please also explain in further detail why you believe a contingent loss is not probable. If you did not expense the payment or have recorded an expense with an offsetting gain, please explain your accounting treatment and tell us how your treatment complies with GAAP.**

The unfavorable ruling from the city hearing officer was not a final non-appealable resolution of this disputed matter; however in order to preserve our right to appeal to state courts, we were required to make a payment, under protest, to the city of $57 million. Had we not made such payment, we would have forfeited our right to challenge the decision in state court. For a number of reasons, including our view that the city and the hearing officer had misinterpreted and misapplied the relevant tax ordinance, we believed, together with our outside counsel, that it was not probable that we would ultimately lose this matter once it was heard at the state court level.

As a result, we accounted for the protested payment to the city as a deposit made in order to preserve our rights to appeal the matter to the state courts. We applied SFAS 5 criteria in assessing our ultimate contingent loss for this dispute, and given our belief that loss was not probable once heard at the state court level, and that our deposit would be refunded, we did not accrue a loss expense for the matter.

On March 14, 2008, the Los Angeles Superior Court ruled in our favor, finding, among other things, that the city's assessment was not supported by the city's utility users tax ordinance and was issued in violation of the California State Constitution. We have recently reached a settlement, subject to the satisfaction of certain conditions, with the city of Redondo Beach for the return of the $57 million plus interest.

<u>Note 18. Subsequent Events, page 137</u>

16. **We note your disclosures here and in your subsequent March 31, 2008 Form 10-Q concerning your sale of a contractual right to a production payment on certain future international hydrocarbon production for approximately $148 million during January 2008. We further note that you obtained the rights through a business combination in fiscal year 2001. Since you have recognized all proceeds received from this sale as income, please clarify why it appears that these rights had no carrying value in your December 31, 2007 balance sheet. If you did not separately recognize the rights in your original purchase price allocation, please clarify why the rights did not meet the criteria for separate**

recognition of intangible assets discussed in paragraphs 39 and A10-A14 of SFAS 141, and provide us with any other relevant information to help us better understand your accounting for these transactions.

In 2001, we acquired Barrett Resources Corporation (BRC) and its subsidiaries, including a Peruvian subsidiary company that held a License Contract with Perupetro, the Peruvian state oil company, to explore, develop and produce oil in an area of Peru termed Block 67. Perupetro would receive a royalty payment for any production from Block 67. The License Contract represents an interest in oil and gas properties, similar to a working interest. Block 67 is in a remote location and the reserves in this area produce heavy oil that requires upgrading in order to transport. Due to the substantial investment required to develop this area and declining oil prices at the time, BRC was unable to find a financial partner to invest in development. As discussed in BRC's December 31, 1998 Form 10-K filing, during 1998 BRC deemed it uneconomic to further pursue exploration and development of Block 67. In 1998, BRC substantially impaired its Peruvian oil and gas properties as a result of the ceiling test under the full cost method.

At the time of our acquisition of BRC in 2001, similar circumstances continued to exist, making development of Block 67 uneconomical. In negotiating the consideration to be paid for the acquisition of BRC, we did not assign value to the Block 67 License Contract. Our purpose in acquiring BRC was to develop their domestic reserves. We decided not to direct any investment in these oil and gas properties and instead focused efforts toward exiting activities in Peru. Given the uncertainty and risks associated with these properties, our assessment around exiting Block 67 was that we would not be able to locate a buyer for our interests in the properties. Therefore, our objective was to minimize the costs of abandoning these properties. As such, at the time of our acquisition of BRC, the Block 67 License Contract was determined to have no value and we assigned no value to these oil and gas properties in the purchase price allocation. The Block 67 License Contract we obtained through our acquisition of BRC represented an interest in oil and gas properties to be accounted for as property. SFAS 141 paragraphs 39 and A10 — A14 relate specifically to intangible assets. Therefore we did not apply the accounting guidance specified in these paragraphs in relation to the Block 67 License Contract acquired.

In continuing to evaluate exit strategies subsequent to the BRC acquisition, in 2003 we granted a third-party an option that, if exercised, allowed them to acquire our interest in the Block 67 License Contract. As consideration for the option, the third-party agreed to perform the work commitments necessary to perpetuate the license. In 2005, the third-party located a financial backer to invest in Block 67 development and exercised its option to acquire our interests in the Block 67 License Contract. We conveyed our interest in the Block 67 License Contract and retained a contractual right to either receive a production payment, or, in the event of a sale of the interest owned by the third-party, participate in the sale proceeds. At the time of this transaction, there was no value assigned to this contractual right as the Block 67 oil and gas properties had no value assigned to them at the time of the BRC acquisition. The very significant increase in oil prices subsequent to the 2005 transaction has enhanced the prospects of developing these properties and in January 2008, the third-party sold its interests and we participated in the sale proceeds pursuant to the terms of the 2005 transaction.

In addition, we acknowledge the Staff's comment that we are responsible for the accuracy and adequacy of the disclosures made. We formally acknowledge that:

The adequacy and accuracy of the disclosure in the filing is the responsibility of The Williams Companies, Inc. Staff comments or changes to disclosure in response to Staff comments do not foreclose the Commission from taking any action with respect to a filing. The Williams Companies, Inc. 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.

Please feel free to contact me with any further questions or comments.

Very truly yours,

Ted T. Timmermans
Vice President Controller and
Chief Accounting Officer