Federal Accounting Standards Advisory Board

February 22, 2005

To: Members of the Board
From: Rick Wascak, Staff
Through: Wendy M. Comes, Executive Director
Subj: Oil and Gas Resources Project [1]

Enclosed is a document presented in the form of a Basis for Conclusions (BfC) and issue papers. Specific issues raised by Board members at the December 2004 meeting are addressed in the BfC or issue papers. The objectives for the December 2004 Board meeting are:

1. Discuss the BfC document and issue papers to determine if the material responds to identified issues.
2. Obtain general agreement on the BfC and issue papers.
3. Discuss staff's "next steps" to develop an Exposure Draft (ED).

<u>List of issues addressed</u>:

The following issues identified in the December minutes are addressed in the attached draft BfC or issue papers. Areas of the BfC, which have updated since the last meeting, are signified with an under score (<u>underscore</u>) to represent proposed additions and a strikeout (~~strikeout~~) to represent proposed deletions. The section of the BfC or an issue paper where the issue is addressed is referenced for each issue.

1. **BfC** - Provide a detailed definition and description of the term "average wellhead price". See page 22.

2. **BfC -** Provide supporting information in regard to the reliability of estimated EIA proved oil and gas reserve quantities. See page 22.

3. **BfC -** Provide a discussion on the pros and cons of using the discounted cash flow methodology to value the Federal governments royalty share of proved oil and gas reserves as of the end of a fiscal year reporting period. See pages 16 and 17.

    a. Determine if there is an estimated average period of time over which oil and gas is extracted from a producing well.

[1] The staff prepares Board meeting materials to facilitate discussion of issues at the Board meeting. This material is presented for discussion purposes only; it is not intended to reflect authoritative views of the FASAB or its staff. Official positions of the FASAB are determined only after extensive due process and deliberations.

4. **BfC -** Research who has the responsibility for the reclamation of Federal lands on which oil and gas are produced. See pages 28 and 29.

5. **Issue Paper 2 -** Identify proposed disclosures or information to be reported as required supplementary information (RSI). See Attachment 4 page 41.

   a. Contact the U.S. Geological Survey (USGS) to determine what information is available for undiscovered recoverable resources, unproved reserves, and proved undeveloped reserves; and, how reliable the information is.

6. **Issue Paper 1 -** Make a comparison between the FASB 69 oil and gas accounting standards and the SEC Rule on oil and gas accounting standards, and to provide the similarities and differences between the two. See Attachment 3 page 39.

   a. Determine if lessees, who are authorized to extract oil and gas reserves on lands under the control of the Federal government, are required to report proved undeveloped reserves to the Security and Exchange Commission (SEC).

7. **Issue Paper 3 -** Should an average annual price for the year be used for the national average wellhead price/first purchase price in the proposed accounting standards for proved oil and gas reserves?

8. **Attachment -** Provide the newspaper article relating to oil and gas leases in which there was limited or no production from the leases. See last page of document.

Issues not addressed

9. **BfC -** Provide accounting entries at the agency level.

10. **Issue Paper -** Review the amount of the bonus bids on oil and gas leases to determine if the bids are proportionate to the value of the Federal government's royalty share of proved oil and gas reserves.

If you have questions or comments before the meeting, please contact me at 202 512-7363 or wascakr@fasab.gov.

APPENDIX A: BASIS FOR CONCLUSIONS

1. This appendix summarizes some of the considerations deemed significant by the Board in reaching the proposals in this Exposure Draft. It includes the reasons for accepting certain approaches and rejecting others. Individual members gave greater weight to some factors than to others.

Background

2. The project initially began with the formation of a task force to conduct research. The task force produced a research report in June 2000 entitled *Accounting for the Natural Resources of the Federal Government*. (See http://www.fasab.gov/reports.htm to access the report.) In 2002, the Board resumed active consideration of the issues raised by the task force after a deferral to address other issues.

3. The Board members suggested that Staff initially address each type of natural resource in phases, (i.e., separately and individually) and to begin with developing accounting standards for natural resources. The Board was interested in determining whether values, or some surrogate, for natural resources could be capitalized and reported on the balance sheet. The Board members believed that capitalizing natural resources would increase accountability over them and improve the comprehensiveness and consistency of federal financial statements. The Board decided to proceed with developing standards for oil and gas resources first due to the ~~extensive~~ literature available in other ~~domains~~ domains, the extensive historical information on Federal lease programs and royalty collections, and the large amount of monies collected for oil and gas resources~~royalties~~.

4. Initially, The Board explored options for forecasting the anticipated revenue stream flowing to the Federal government from royalty collections based on historical information. When the Board learned that estimated proved oil and gas reserve quantities from lands under Federal jurisdiction were accessible, it decided that capitalizing the current value of the estimated Federal royalty share of proved oil and gas reserves was feasible. Under

current Federal regulations, the lessee has a "duty to market" the government's royalty share of proved reserves. Although in most cases, lessees pay their royalties in money rather than oil and gas, they tend to think of the royalty system as meaning that a certain percentage of the oil and gas product belongs to the government. Lessees refer to that product as the government's royalty share. The Board, therefore, believes this term should be used to refer to the asset to be capitalized on the balance sheet.

Overview of Federal Oil and Gas Resources

5. ~~Before describing how the current value of the estimated Federal royalty share of proved oil and gas reserves to be capitalized is calculated, this section provides an overview of all of the components of Federal oil and gas resources.~~

6. A Framework for Components of Federal Oil and Gas Resources illustration (hereafter referred to as “framework), which is presented on page 6, identifies the universe of federal oil and gas resources. The framework summarizes both the Accounting Standards and the Components of Federal Oil and Gas Resources (hereafter referred to as “components”) for *total resources*. Total resources incorporate “original in-place” resources, that is, resources in the earth before human intervention. ~~Definitions for the components are provided in the Glossary of this document on page 25.~~

7. The Accounting Standards consist of Current Accounting Standards and Proposed Accounting standards. The framework explains current and proposed accounting for each component of federal oil and gas resources. The components are defined based on terminology used in the industry. Information is available in varying degrees and with varying reliability for each component. The components are first separated into “undiscovered resources” and “discovered resources.” Generally, undiscovered resources are not under lease, while discovered resources are under lease. These ~~terms and sub~~components are explained below; and a definition for these components and their subcomponents are provided in a Glossary on page 33.

8. Undiscovered Resources

9. The first major component of Federal oil and gas resources is undiscovered resources. The undiscovered resources components and subcomponents are:

   1. undiscovered nonrecoverable resources
   2. undiscovered recoverable resources
      a. undiscovered conventionally recoverable resources
      b. undiscovered economically recoverable resources

10. Each component and subcomponent can be further divided between onshore and offshore resources. Onshore resources consist of resources on Federal lands and in state waters. Offshore resources consist of resources on the Outer Continental Shelf (OCS). This division between onshore and offshore resources is important operationally because the source and quality of information varies. ~~There is no information routinely available on undiscovered nonrecoverable resources.~~

11. There is no information available on **undiscovered nonrecoverable resources**. This is because they are not addressed or included in any type of assessment. These undiscovered resources are referred to as resources that are beyond conventional technologies to be estimated. However, in the total realm of "original in-place" resources, that is, resources in the Earth before human intervention, they may exist.

~~11.~~12. Information on the two subcomponents of **undiscovered recoverable resources** is available for offshore oil and gas resources. This information is based on National Assessments performed by the Minerals Management Service (MMS) approximately every 5 years, with updates on a yearly basis for certain geographic locations. The assessment considers recent geophysical, geological, technological, and economic information and uses a geologic play[2] analysis approach for resource appraisal. Information on undiscovered conventionally

[2] A play is a group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment. A pool is a discovered or undiscovered accumulation of hydrocarbons, typically within a single stratigraphic interval.

recoverable resources and undiscovered economically recoverable resources is provided in the MMS assessment.

~~12.~~13. For the onshore portion of undiscovered recoverable resources, the U.S. Geological Survey (USGS) formerly conducted National Assessments. The last comprehensive National Assessment was completed by the USGS in 1995, and since 2000 the USGS has been re-assessing basins of the U.S. that are considered to be priorities for the new assessment rather than assessing all of the basins of the U.S. Since 2000, the USGS has re-assessed sixteen priority basins, and has plans to re-assess sixteen more basins. These 32 basins represent about 97% of the discovered and undiscovered oil and gas resources of the United States. As each basin is re-assessed, the assessment results are added to the tables, and these new values replace the assessment results from 1995. A 2004 Assessment Update, which includes information from the first 16 basin re-assessments, represents the update to the 1995 National Assessment as of the end of September, 2004. The USGS assessment provides information on undiscovered conventionally recoverable resources but not on undiscovered economically recoverable resources like the MMS does. ~~However, since 1995, the USGS has not conducted an overall update for onshore and state waters, but has conducted assessment updates on a basin or area level. The USGS included undiscovered recoverable resources in its onshore and state waters assessments.~~

~~13.~~14. Under current accounting standards, there are no requirements to provide or present information about the undiscovered resource components in the financial statements. Under the proposed ~~the draft~~ accounting standards, information about onshore and offshore undiscovered conventionally recoverable resources ~~and undiscovered economically recoverable resources~~ (such as that presented in Table 1 for offshore resources ~~and Table 2~~ on page 34 ~~26~~) could be disclosed or required as supplemental information ~~pending the outcome of ongoing research into the reliability of estimates~~.

~~14.~~15. Discovered Resources

~~15.~~16. The second major component of Federal oil and gas resources is discovered resources. The discovered resources component is divided as follows:

1. unproved reserves
   a. unproved possible reserves
   b. unproved probable reserves
2. proved reserves
   c. proved undeveloped reserves
   d. proved developed reserves
      i. proved developed non-producing reserves
      ii. proved developed producing reserves
3. production

17. Quantitative information in relation to onshore and offshore proved ~~developed~~ reserves, including new discoveries, production, adjustments, etc., is submitted to the Energy Information Agency (EIA), Department of Energy, by oil and gas well operators once a year. The due date for operators to submit the information is April 15 for activities from the preceding calendar year.

18. The MMS prepares periodic reports for offshore proved reserves. The reports are based on aggregation of MMS field studies. The most current report for the Gulf of Mexico Region is based on information as of December 31, 2001. It was issued in October 2004. The most current report for the Pacific Region is based on information as of December 31, 1998. It was issued in July 2000. Federal offshore reserves in the Alaska Region are modest and are attributable to only a single field, which makes information on the reserves proprietary. The Atlantic Region has no reserves. The MMS also collects, distributes, and reports collections for bonus bid, rent or royalties for unproved and proved reserves. Besides the proved reserves information provided to the EIA, there is no other information available for onshore proved reserves.

~~17.~~19. Under current accounting standards, the bonus bid, rent (paid on the lease until oil and gas production begins), and royalty collections (paid on production) are recognized as a financing source on the Statement of Operations and Changes in Net Position in the consolidated financial statements of the US government (CFR). [Note that this activity is accounted for as a custodial activity (i.e., an amount collected for others) by MMS-the collecting entity. The collections and the distribution of the collections are reported on MMS's custodial statement. Entities receiving the distribution of collections recognize the receipt of the collection as a financing source in its respective statement of changes in net position. For simplicity, staff has omitted the component entity treatment so that we can focus on the ultimate effect of the current and proposed accounting standards on the US Government. Staff will provide a comprehensive illustration including component entity accounting at a later meeting.]

~~18.~~20. Under the proposed accounting standards, the estimated Federal royalty share of proved developed reserves would be recognized on the balance sheet and royalty collections would be recognized equally as revenue and expense on the Statement of Net Cost. Changes in the asset amount each period would be reported as a gain or loss on the Statement of Operations and Changes in Net Position of the CFR. Also, information on the consumption, remaining estimated quantity of proved reserves, and the future outlook for proved reserves could be disclosed or required as supplemental information.

~~19.~~21. In regard to the production, there are no current requirements to provide or present information about the production of oil and gas in the financial statements. However, under the proposed accounting standards, historical information on proved reserves including the production of reserves, could be disclosed. An example is presented in **Attachment 1** on page ??~~29~~.

~~20.~~22. Illustration 1, entitled **Accounting Framework for Components of Federal Oil and Gas Resources**, is presented on the following page. The boxes in the illustration are shaded as follows:

No quantity information	

Periodic and ~~but~~ incomplete quantity information ~~(appr. 5 years)~~	
Quantity information provided by EIA	

Illustration 1 Framework for Components of Federal Oil and Gas Resources

Accounting Standards	Components of Federal Oil and Gas Resources								
	Undiscovered Resources			Discovered Resources					
	Undiscovered Non-Recoverable Resources	Undiscovered Recoverable Resources		Unproved Resources		Proved Resources			Production
		Undiscovered Conventionally Recoverable Resources	Undiscovered Economically Recoverable Resources	Unproved Possible Reserves	Unproved Probable Reserves	Proved Undeveloped Reserves	Proved Developed Reserves		
							Proved Developed Non-Producing Reserves	Proved Developed Producing Reserves	
Current Accounting Standards				Bonus Bid, Rent, Royalty Collections Accounted for as a Financing Source on the CFR Statement of Operations and Changes in Net Position					
Proposed Accounting Standards		Provide Disclosure or RSI Information – Undiscovered Conventionally and Undiscovered Economically Recoverable Resources		Account for Bonus Bid and Rent Collections as Financing Source on the CFR's Statement of Operations and Changes in Net Position		• Recognize Federal Royalty Share on BS[3] • Recognize Royalty Collections as Revenue and Expense on SNC[4] • Provide Disclosure Information – Quantitative • Recognize Gains/Losses on SOCNP[5]			Provide RSI/ Disclosure Information – Quantitative and Financial

[3] Balance Sheet
[4] Statement of Net Cost
[5] Statement of Operations and Changes in Net Position

Federal Entities Involved in Components of Federal Oil and Gas Resources

~~21.~~23. There are three Federal government entities involved in the proved oil and gas reserves activities. They are: 1.) Bureau of Land Management (BLM), Department of Interior; 2.) Minerals Management Service (MMS), Department of Interior; and 3.) Energy Information Administration (EIA), Department of Energy. Each entity's involvement is described in the following overview paragraphs.

~~22.~~24. **BLM Overview**. The Bureau of Land Management (BLM), an agency of the Department of the Interior, manages 262 million acres of mostly Western land and 700 million acres of subsurface mineral estate nationwide. These lands extend across rangelands, forests, high mountains, arctic tundra, and deserts. The BLM manages these lands for multiple-use and on a sustained-yield basis with its 5-year Strategic Plan and Annual Performance Plan as the foundation. It does not have a 5-year plan for oil and natural gas lease sales.

~~23.~~25. The BLM administers some of the most ecologically and culturally diverse and scientifically important lands in Federal ownership. The agency's management responsibilities include:

- recreation opportunities, including interpretation and other visitor education activities
- commercial activities, including energy and mineral development and timber sales
- wild free-roaming horses and burros
- paleontological, archaeological, and historical sites
- fish and wildlife habitat
- transportation systems, including roads, trails, and bridges
- wilderness areas and wild and scenic rivers
- rare and vulnerable plant communities
- public land survey system

~~24.~~26. Under its "commercial activities" management responsibility, the BLM is responsible for leasing oil and gas resources on all Federally owned lands, including those lands managed by other Federal agencies. BLM is responsible for review and approval of permits and licenses to explore, develop, and produce oil and gas resources on both Federal and

Indian lands. BLM is also responsible for inspection of oil and gas wells and other development operations to ensure through enforcement authorities that lessees and operators comply with lease requirements and regulations. Although the Bureau of Indian Affairs issues leases on Indian lands, BLM handles the operational approvals and supervision of operations on these lands.

~~25.~~27. **MMS Overview**. The mission of MMS is to manage the mineral resources on the Nation's Outer Continental Shelf (OCS) in an environmentally sound and safe manner; and, to collect, verify, and distribute, in a timely fashion, mineral revenues generated from Federal (onshore and offshore) and Indian lands. These activities are performed under the following 2 programs:

- *Offshore Minerals Management.*—This program provides for (1) performance of environmental assessments to ensure compliance with the National Environmental Policy Act (NEPA); (2) conduct of lease offerings; (3) selection and evaluation of tracts offered for lease by competitive bidding; (4) assurance that the Federal Government receives fair market value for leased lands; and (5) regulation and supervision of energy and mineral exploration, development, and production operations on the OCS lands.
- *Minerals Revenue Management.*—This program provides for the collection and distribution of royalties, rents, and bonuses due the Federal Government and Indian lessors from minerals produced on Federal onshore, OCS, and Indian lands in accordance with various laws.

~~26.~~28. **EIA Overview**. The primary focus of EIA's reserves program is providing accurate annual estimates of U.S. proved reserves of crude oil[6,] dry natural gas[7,] and natural gas liquids[8]. These estimates are essential to

[6] Crude oil is a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include: 10 small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well gas in lease separators, and that subsequently are commingled with the crude oil stream without being separately measured; and, 2) small amounts of nonhydrocarbons produced with the oil.

[7] Dry natural gas is the actual or calculated volumes of natural gas which remain after: 1) the liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation); or, any volumes

the development, implementation, and evaluation of national energy policy and legislation. In the past, the Government and the public relied upon industry estimates of proved reserves. However, the industry ceased publication of reserve estimates after its 1979 report.

~~27.~~29. In response to a recognized need for credible annual proved reserves estimates, Congress, in 1977, required the Department of Energy to prepare such estimates. To meet this requirement, the EIA developed a program that established a unified, verifiable, comprehensive, and continuing annual statistical series for proved reserves of crude oil and natural gas. It was expanded to include proved reserves of natural gas liquids for the 1979 and subsequent reports.

~~28.~~30. The Energy Information Administration (EIA) makes energy forecasts to help government, industry, and the public understand the direction and trends implied by current events and decisions. Most of EIA's forecasts focus on energy supply, demand, and price projections for the United States and for the world. EIA has two general projection periods -- the short term (next six-to-eight quarters) and the mid-term (approximately the next 20 years). The projections integrate all fuel types, using the British thermal unit (Btu) as a common unit of measure, for a comprehensive overview balancing energy supply with energy demand.

~~29.~~31. EIA's short-term forecasts are updated monthly. Forecasts are released each month on the Internet (http://www.eia.doe.gov/emeu/steo/pub/contents.html) and quarterly (January, April, July, and October) in a hard-copy report titled the Short-Term Energy Outlook (STEO). The short-term projections primarily focus on the United States' demand, supply, and prices for petroleum, natural gas, coal, electricity, and renewable energy and the world's demand, supply, and prices for petroleum.

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of nonhydrocarbons gases have been removed where they occur in sufficient quantity to render the gas unmarketable.

[8] Natural gas liquids are those hydrocarbons in natural gas, which are separated from the gas through the processes of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as condensate, natural gasoline, or liquefied petroleum gases.

~~30.~~32. The primary mechanism for EIA's short-term forecasts is the Short-Term Integrated Forecasting System (STIFS), a personal computer based model. The STIFS model is principally affected by macroeconomic variables, world oil price assumptions, and weather assumptions. Copies of the model are available on the Internet site (see above). Users can download the model and enter their own assumptions to produce alternative results.

~~31.~~33. EIA's mid-term forecasts (national and international) are updated annually. Both forecasts are released on the Internet (http://www.eia.doe.gov/oiaf/aeo/ and http://www.eia.doe.gov/oiaf/ieo/) and in hard copy reports titled the Annual Energy Outlook (AEO) and the International Energy Outlook (IEO). The mid-term projections primarily focus on energy market supply, demand, and prices and related economic and environmental issues.

~~32.~~34. EIA's domestic forecasting capability relies primarily on the National Energy Modeling System (NEMS). NEMS contains computer modules that are designed to approximate the interactions of energy markets and provide insights into future changes in supply, demand, economic conditions, etc. NEMS is used for forecasting and also to analyze economic policies, technological changes, changes in legislation, and other energy topics. NEMS operates on three RS/6000 workstations and its documentation is available to the public. EIA's international forecasting capability makes use of modules of NEMS as well as the World Energy Projection System and other special purpose models. Documentation for these models is available to the public. A directory of all EIA models is located at http://www.eia.doe.gov/bookshelf/models2002/index.html.

~~33.~~35. The U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Report may be reviewed by going to http://www.eia.doe.gov/oil_gas/petroleum/data_publications/pet_data_publications.html and scrolling down to the Annual publications.

Conceptual Aspects of Oil and Gas Resources as a Federal Asset

~~34.~~36. Definition of Asset

~~35.~~37. The tentative FASAB definition of ‘asset’ is: “Assets are resources controlled by a particular entity that could provide economic benefits or services in the future.” Two essential characteristics that a resource must have to be an ‘asset’ are (1) it could provide economic benefits or services in the future and (2) the entity must at the present time control access to the resource such that the entity can obtain the resulting economic benefits or services for itself and deny or regulate the access of others. Assets may vary in specific form and nature; e.g., they may be tangible/intangible, monetary/non-monetary, current/non-current, more certain benefits/less certain benefits, etc. This definition differs from the FASB definition in that (a) it explicitly sets a very low probability threshold (viz., “could provide”), (b) it focuses on the ‘resource’ rather than the ‘future economic benefits”, and (c) it omits the ‘as a result of past events’ because the FASAB tentatively concluded that feature was captured by the requirement that the resource be controlled by the entity.

~~36.~~38. Recognition of Assets

~~37.~~39. As FASAB is still at the asset ‘definition’ stage and hasn’t formally adopted ‘recognition’ criteria, and because much of what FASAB has adopted in the asset definition stage has been based in part on FASB, the Board invokes the FASB ‘recognition’ criteria. According to paragraph 63 of FASB Concepts Statement 5 (“Recognition”):

“An item and information about it should meet four fundamental recognition criteria to be recognized and should be recognized when the criteria are met, subject to a cost-benefit constraint and a materiality threshold. Those criteria are:

Definitions—The item meets the definition of an element of financial statements.
Measurability—It has a relevant attribute measurable with sufficient reliability.
Relevance—The information about it is capable of making a difference in user decisions.
Reliability—The information is representationally faithful, verifiable, and neutral.”

~~38.~~40. Given a FASAB definition of ‘asset’ and these criteria for ‘recognition’, the next step the Board took was to consider ‘measurability’. In Concepts Statement #5, FASB acknowledges that current GAAP are based on a variety of measurement attributes and that it expects that practice to continue. Although many of the assets recognized under FASAB principles are measured using some form of historical cost, FASAB also currently follows a multi-attribute measurement approach; e.g, net realizable value for some receivables, present value for capital leases, etc. FASAB will continue to follow a multi-attribute approach and will adopt something similar to “a relevant attribute measurable with sufficient reliability” as a criterion for measurability.

~~39.~~41. Oil and Gas Resources as a Federal Asset

~~40.~~42. First, the Board established which oil and gas resources were being considered. Illustration 1, entitled **Framework for Components of Federal Oil and Gas Resources**, provides the context of oil and gas resources that were considered. The two major components are “undiscovered resources” and “discovered resources.” Given the FASAB draft definition of assets (“Assets are resources controlled by a particular entity that could provide economic benefits or services in the future”), it appeared to the Board that all of the oil and gas resources ~~beyond the “undiscovered” category~~ fit the definition of asset. The resources are controlled by the federal government and could produce future benefits or services.[9]

~~41.~~43. Oil and Gas to be Recognized as a Federal Asset

~~42.~~44. Given that ~~discovered~~ oil and gas resources controlled by the federal appear to meet the definition of “asset”, the Board’s next step was to decide whether the oil and gas resources “asset” should be recognized on a federal entity balance sheet. In order to pursue the ‘recognition’ criteria, the Board believed it was useful to first consider the nature of the

[9] Note that the FASAB intentionally set a very low probability hurdle in its definition of ‘asset’; thus, the ‘control’ aspect of the definition may be a more binding constraint when determining whether an asset exists~~in many circumstances~~.

future economic benefits or services embodied in the oil and gas resources from the federal point of view. The Board believed the key would appear to be the purpose for which the oil and gas resources are maintained. Among the reasons could be: (a) to provide a near-term source of domestic energy, (b) to provide a domestic source of oil in the future and reduce the Nation's dependency on foreign energy sources, and (c) to generate revenues for the federal government from oil and gas resources, which represent one of the government's greatest sources of non-tax income. As noted above, the core criterion for recognition is that the resource: "…has a relevant attribute measurable with sufficient reliability".

~~43.~~45. Quantities of oil and gas resources are not reliably measurable until the oil and gas reach the 'proved reserves' category. Thus, all oil and gas resources not yet in the 'proved reserves' category, ~~that is, unproved resources and proved undeveloped reserves as noted in the framework illustration,~~ would not be eligible for recognition on the federal balance sheet.

~~44.~~46. Concerning the proved ~~developed~~ oil and gas reserves available for near-term development, the Board believes that both the quantity and the estimated Federal royalty share would be relevant. Thus, in this second case, since the quantity and the value of the estimated Federal royalty share can be reliably measured, the proved oil and gas reserves would be recognized on the balance sheet.

Measurement of the Federal Asset

~~45.~~47. Concerning the dollar amount to be recognized for the estimated Federal royalty share of proved reserves, FASAB reviewed various measurement attributes[10], including the following:

Historical cost (historical proceeds) – The amount of cash, or its equivalent, paid to acquire an asset, commonly adjusted after acquisition for amortization or other allocations. (SFAC 5, Par 67.a.) 'Historical cost' was not a feasible option for valuing the oil and gas reserves because there is

[10] Measurement attribute – An attribute that can be quantified in monetary units with sufficient reliability. (Adapted from SFAC 5, Par65)

no 'historical exchange price' for the oil and gas reserves controlled by the federal government.

Fair value – The price at which an asset or liability could be exchanged in a current transaction between knowledgeable, unrelated willing parties. (Exposure Draft of proposed SFAS: Fair Value Measurements, June 23, 2004) In regard to 'fair value', the FASB Exposure Draft states that, "The objective of the measurement is to estimate the price for an asset or liability in the absence of an actual exchange transaction for that asset or liability." Information needed to estimate fair value is not available as there are no current transactions involving the sale of the Federal royalty share for proved oil and gas reserves or the sale of rights to similar future revenue streams.

Current market value – The amount of cash, or its equivalent, that could be obtained by selling an asset in orderly liquidation. (SFAC 5, Par 67.c.) A 'current market value' cannot be used because (1) due to the nature of the asset there is no evidence regarding cash obtainable "by selling an asset in liquidation" and (2) using 'current market value' would cause the estimated Federal royalty share to be overstated. In calculating royalties, regulations allow lessees to deduct certain costs from their sales proceeds for moving oil and gas beyond the lease site (or central accumulation point) and for processing before determining their payments. The lessees are in effect calculating federal royalties on the basis of the proceeds they would have received had the sale taken place back at the lease site (well head or central accumulation point) and before processing. Thus a value other than current market value must be used.

48. Net realizable (settlement) value – The nondiscounted amount of cash, or its equivalent, into which an asset is expected to be converted in due course of business less direct costs, if any, necessary to make that conversion. (SFAC 5, Par 67.d~~.~~ The 'net realizable value' (NRV) requires a reasonable estimate of future flows (receipts and costs) associated with converting assets to cash. However, the timing or amount of the future flows of the Federal royalty share for proved oil & gas reserves cannot be reliably estimated for various reasons. The timing cannot be reliably

estimated because of the variable period of time from when a lease is signed until production begins (from 3 years to 20 years or more) and the variable period of time that a well will be productive. The amount cannot be reliably estimated due to fluctations in the market price of the product. Reasons for these variations include:

- The permitting process for exploration, development, and production activities.
- The lessee's budget.
- Other projects the lessee is focusing on.
- The geological make-up of the earth.
- The depth of the water for offshore wells.
- The uncertainties of each well.
- New discoveries.
- Improved technology.
- The economy and price volatility.
- Government provided production incentives.

49. Present (or discounted) value of future cash flows – The present or discounted value of future cash inflows into which an asset is expected to be converted in due course of business less present values of cash outflows necessary to obtain those inflows. (SFAC 5, Par 67.e.) An estimate of the 'present (or discounted cash) value' of the estimated Federal royalty share appeared to be most appropriate because the asset will be converted in future periods. However, the 'present (or discounted cash) value' attribute poses measurement challenges similar to the NRV because the timing of future inflows is not reliably estimable. Thus, the estimated present value would be too unreliable for valuing oil and gas reserves on the balance sheet.

~~46.~~50. ~~There is no 'historical exchange price' for the oil and gas reserves controlled by the federal government. Thus, 'historical cost' was not a~~

~~feasible option for valuing the oil and gas reserves. In addition, since the reserves in question are being held for near-term development and federal revenue, their historical costs would seem to be irrelevant. In this setting, an estimate of the present (or discounted cash) value of the estimated Federal royalty share appeared to be most appropriate. However, the timing of future inflows is not reliably estimable. Thus, the estimated present value would be too unreliable for valuing oil and gas reserves on the balance sheet.~~

~~47.~~51. ~~The net realizable value attribute poses similar measurement challenges. The oil and gas royalties cannot ve obtained immediately. Thus, estimating net realizable value would pose many of the same as present value estimation. Also, a current market value cannot be used because using it would cause the estimated Federal royalty share to be overstated. In calculating royalties, regulations allow lessees to deduct certain costs from their sales proceeds for moving oil and gas beyond the lease site (or central accumulation point) and for processing before determining their payments. The lessees are in effect calculating federal royalties on the basis of the proceeds they would have received had the sale taken place back at the lease site (well head or central accumulation point) and before processing. Thus a value other than current market value must be used.~~

52. Based on the reviews, the Board determined that none of the measurement attributes currently used in practice is a feasible ~~would appropriately~~ measure of the ~~current value of the~~ estimated Federal royalty share for proved oil and gas reserves. In addition they believed that assigning any one of the measurement attribute terms currently in use would only cause confusion once entities are required to apply the measurement attribute to their oil and gas reserves. They believed that defining a measurement attribute in terms that are common to the oil & gas industry would be the best approach. Therefore, the Board proposes to use an 'average wellhead price/first purchase price' measurement to value the Federal royalty share for proved oil & gas reserves.

53. The Board believes that the most relevant and sufficiently reliable estimate of Federal royalty share would be obtained by multiplying the estimated quantity of proved oil and gas reserves on a field-by-field basis by the average wellhead price/first purchase price and the respective royalty rate. This calculation would provide the value of the estimated Federal royalty share of proved oil and gas reserves as of the end of the reporting period on lands under the control of the Federal government. The formula is provided is:

(Estimated Quantity of Proved Reserves X Average Wellhead Price/First Purchase Price) X Royalty Rate = Estimated Federal Royalty Share

~~3.~~54. A description of each element in the formula is provided in the following paragraphs.

~~4.~~55. **Quantity of Proved Reserves**. Based on the mission of the EIA, it is proposed that the EIA estimates of proved oil and gas reserves on lands owned or under the control of the Federal government, on a field-by-field[11] basis, be used to estimate the current value of the estimated Federal royalty share of proved oil and gas reserves to be capitalized. The EIA names a field by geographic location. The field may have many reservoirs at various depths. Each reservoir is an isolated pressure system. After the oil and gas is extracted from one reservoir, the company moves on to the next reservoir. So, while the EIA requires operators to submit a report about proved reserves on a field-by-field basis, the operators almost always do their estimates at the reservoir level and, for the EIA's convenience, summarize them to a field level.

~~5.~~56. The EIA defines proved reserves as those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves, however, are not

[11] Field: An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or by both. The area may include one lease, a portion of a lease, or a group of leases with one or more wells that have been approved as producible.

things that can be counted; nor, are they direct measurements. They are estimates. Proved oil reserves are estimated in thousands of barrels at 60 degrees Fahrenheit. Proved gas reserves are estimated in millions of Cubic Feet (MMCF) at 14.73 PSIA and 60 degrees Fahrenheit . For purposes of this standard, proved “natural gas liquids” reserves are included in the proved oil reserves.

57. EIA’s proved reserves estimates are based on data filed by: 1) large, intermediate, and a select group of small operators of oil and gas wells; and, 2) operators of all natural gas processing plants. ~~Of the top 600 operators, t~~The EIA requires the top 600 operators ~~them~~ to submit a direct report of the proved reserves they carry for each field as of December 31. The reports are required to be submitted by April 15 of the year following the December 31 cut-off date. The EIA checks and edits all of the reports at the field level and that number would exceed 20,000 operator field reports. On all the checks and edit steps, the EIA relies on its own engineering staff. In addition, the EIA staff independently checks about 20 fields a year. This can be described as an audit procedure performed by the EIA staff. The fields are selected either because they are new or there is something that might attract attention to the EIA about the field. The EIA points out significant errors or misinterpretations to the operators.

58. The EIA has been reviewing the domestic numbers of proved reserves estimates independently for more than 25 years. The EIA observes that if one looks at an individual field you almost always find it to be within professional competence; and, if you look at an aggregate of a number of fields those numbers are even more reliable. The EIA believes all of the proved reserves reported by the EIA will be recovered with a probability rate of 99.99%.

~~7.~~59. Estimated proved reserves are calculated in the following manner (definitions for the terms presented below are contained in Attachment 2 of this paper on page 30):

Published Proved Reserves at End of Previous Report Year
+ Adjustments
+ Revision Increase

-- Revision Decreases
-- Sales
+ Acquisitions
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
-- Report Year Production
= Published Proved Reserves at End of Report Year

~~8.~~60. The published reserves estimates include an additional term, adjustments, calculated by the EIA, which preserves an exact annual reserves balance. Adjustments are the annual changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories. They result from the survey and statistical estimation methods employed. For example, variations caused by changes in the operator frame, different random samples, different timing of reporting, incorrectly reported data, or imputations for missing or unreported reserve changes can contribute to adjustment.

61. The proved reserve information provided by the operators to the EIA is generally the same information the operators are required to send to the U.S. Securities and Exchange Commission (SEC) in their annual report for oil and gas producing activities. The SEC receives approximately 14,000 oil and gas submissions on a yearly basis. Each submission is reviewed on a rotational basis every three years based on internal selection policies and criteria.

62. **Average Wellhead Price/First Purchase Price**. This measurement attribute refers to two terms. The first is average wellhead price and is used in the natural gas environment. Preliminary values for the monthly U.S. natural gas wellhead price are estimated from the New York Mercantile Exchange (NYMEX) futures final settlement price for near-month delivery at the Henry Hub, and reported cash market prices at 5 major trading hubs: Henry Hub, LA; Carthage, TX; Katy, TX; Waha, TX; and Blanco, NM. The NYMEX price is publicly available and is reported in numerous trade publications, including NGI's Daily Gas Price Index (published by Intelligence Press, Inc.). The cash market prices are published in another trade publication, Natural Gas Week (Energy

Intelligence Group, Inc.), and they reflect the spot delivered-to-pipeline, volume-weighted average prices for natural gas bought and sold at the specified trading hubs. Prices include processing, gathering, and transportation fees to the hubs. The estimated wellhead prices are derived with a statistical procedure based on analysis of monthly time series data for the period 1995 through 2000. The preliminary estimates are replaced when annual survey data become available, usually about 10 months after the end of the report year.

63. Final monthly data are provided through the Form EIA-895, which requests State agencies to report monthly values of marketed production. Form EIA-895 requests State agencies to report the quantity and value of marketed production. When complete data are unavailable, the form instructs the State agency to report the available aggregate value and the quantity of marketed production associated with this value. Information for several States that are unable to provide data is estimated based on price information submitted by neighboring producing States. Preliminary monthly gas price data are replaced by these final monthly data.

64. In these proposed accounting standards, the natural gas wellhead price as of the last day of the month for the reporting period should be used to value proved gas reserves.

65. The second term referred to in the proposed measurement attribute is ‘first purchase price’. This term is used in the crude oil environment. Each month, the Form EIA-182 collects data from first purchase buyers of domestic crude oil. A “first purchase” constitutes a transfer of ownership of crude oil during or immediately after the physical removal of the crude oil from a production property for the first time. Transactions between affiliated companies are reported as if they were “arms-length” transactions. (This definition is consistent with the Windfall Profits Tax (WPT) concepts of “first sale” and “removal price.”) The primary objective is to calculate an average first purchase price at various levels of aggregation.

66. A company's monthly average first purchase prices are volume weighted across given geographical areas for selected crude streams and gravity bands. Prices are computed from the following reported data elements:

Area of production. The producing State or non-State production "area" (i.e., Alaska North Slope, Alaska South, Federal Offshore California and Federal Offshore Gulf—about one-fifth off the coastline of Texas and the remainder off Louisiana).

Average cost. Reported at the lease boundary and based on the actual purchase expenditures, including any taxes, discounts or premiums paid.

Total volume purchased. The amount of crude bought and paid for as it is measured at the lease boundary (usually at a lease automatic custody transfer unit—a LACT unit), adjusted for basic sediment and water (BS&W) and temperature.

The proposed annual 'first purchase price' should be calculated from data collected on Form EIA-182 by dividing the sum of the total average costs paid from all areas of production by the sum of the total volumes purchased from all areas of production as of the last day of the month for the reporting period. This amount should be used to value proved gas reserves.

~~9~~.67. ~~Wellhead price is the value given to oil and gas at the mouth of the well; which is the sales price to the initial purchaser (the sales price is not net of any additional costs). The a average well price is the median price paid at the wellhead, taking into account different pricing locations throughout the U.S. and all grades of oil and gas. (To be expanded)~~

~~10~~.68. **Royalty Rate**. Royalty rate is a proportionate interest in the production value of mineral deposits due the lessor from the lessee in accordance with a lease agreement. In order to estimate the current market value of the federal interest or share in proved reserves, the royalty rate for each field is required.

~~11~~.69. For many years, the federal government made oil and gas resources available to developers under the terms of the Mining Law of

1872, which offered properties on a noncompetitive basis for flat, per-acre fees. The current federal royalty program originated in the Minerals Leasing Act of 1920. Later, the Acquired Lands Act of 1947 extended the leasing authority of the 1920 act over lands in the public domain to include areas that the federal government acquired from states and individuals. The Outer Continental Shelf Lands Act of 1953 revised the oil and gas leasing program to make offshore leases available through competitive auctions. The most recent major changes to the program came with the Federal Onshore Oil and Gas Leasing Reform Act of 1987. The Congress passed the Federal Onshore Oil and Gas Leasing Reform Act of 1987 to require that all public lands that are available for oil and gas leasing be offered first by competitive leasing. Noncompetitive oil and gas leases may be issued only after the lands have been offered competitively at an oral auction and a bid was not received. Those basic laws establish procedures for leasing public lands to developers, collecting compensation from the developers in the form of initial payments and royalties on subsequent production, and disbursing the receipts to various government accounts and to the states.

~~12.~~70. While the royalty rate is based on the lease agreement, the Secretary of the Department of the Interior may, upon application from a lease holder, reduce the royalty rate for good cause. Examples where rates have been reduced have been operating conditions that caused costs to be very very high and where a well is approaching the end of its production life. Sometimes the reductions are for the remaining lease term, but more often they are for some limited period of time. Presented below is a summary of possible royalty rates:

Royalty Rate – Federal Onshore Leases

~~13.~~71. Oral auctions of all oil and gas leases are conducted by most BLM State Offices not less than quarterly when parcels are available. A Notice of Competitive Lease Sale, which lists lease parcels to be offered at the auction, are published by each BLM State Office at least 45 days before the auction is held. Lease stipulations applicable to each parcel are specified in the Sale Notice. Lands Included In The Sale Notice Come From Three Sources:

1. Existing leases that have expired, terminated, or been cancelled or relinquished;

2. Parcels identified by informal expressions of interest from the public or by the BLM for management reasons; or

3. Lands included in offers filed for noncompetitive leases.

~~14.~~72. Royalty rates are assigned in accordance with US Code Title 30, paragraph 223, in the following manner:

~~1.~~4. Competitive Leases

- *Leases issued under the Mineral Leasing Act of 1920 (prior to 12/23/87): oil royalty assessed on production amount ranges from 12.5% to 25%; gas royalty assessed on production amount ranges from 12.5% to 16.67%.*

- *Leases issued after12/23/87: flat rate of 12.5% in amount (dollars) or value of production.*

~~2.~~73. Royalty rates are assigned for noncompetitive leases in the following manner:

- *Based on 12.5% in amount or value of production.*

~~3.~~74. National Petroleum Reserve-Alaska Leases

- *Set by regulation at 16.67%.*

Royalty Rate – Federal Offshore Leases

~~15.~~75. The MMS Director publishes the notice of lease sale in the Federal Register. The publication must be at least 30 days prior to the date of the sale. The notice contains or references a description of the areas to be offered for lease and any stipulations, terms and conditions of the sale. Tracts are offered for lease by competitive sealed bidding. Each lease bid must include a payment for one-fifth of the bonus bid amount. The payment will be invested in public securities and accrue interest. Interest accrued for the successful bid will accrue to the Government.

~~16.~~76. The lease will not be executed with the successful bidder until payment of the remaining four-fifths bonus bid amount and the first year's rental payment is received. Failure to remit payment within the time-frame specified will result in forfeiture of the one-fifth bonus bid amount. The one-fifth bonus bid amount and any interest accrued shall be refunded on high bids subsequently rejected. Bonus checks submitted with bids other than the highest valid bid shall be returned to respective bidders after bids are opened, recorded, and ranked.

~~17.~~77. Royalty payments are due at the end of the month following the month during which the oil and gas is produced and sold except when the last day of the month falls on a weekend or holiday. In such cases, payments are due on the first business day of the succeeding month or the business day following the holiday.

~~18.~~78. Royalty rates are assigned in accordance with Us Code Title 43, paragraph 1337, in the following manner:

~~1.~~5. Leases Not Under Deepwater Royalty Relief Act (DWRRA). Is set for each sale area in its Final Notice of Sale. It may be:

- 12.5% for water depths greater than 400 meters or 16.67% for water depths less than 400 meters.
- Sliding scale (12.5%-65%) based on average of all production.
- Step-scale which increases by steps as production increases.
- Flat rate of 33.33%.
- Net profit share, which require royalty only after certain expenditures are recovered.
- Royalty suspension (variable according to water depth for deep water royalty relief and depth of well for shallow water deep gas royalty relief) followed by royalty rates under 1. above.

~~2.~~79. Leases Under Deepwater Royalty Relief Act. Certain Gulf of Mexico (GOM) deep water leases issued under DWRRA between 11/28/95 and 11/28/00 receive royalty suspensions based on the following criteria:

- Leases in fields located in between 200 and 400 meters of water do not pay royalties until 17.5 million barrels of oil equivalent (MMBOE) have been produced from the field.
- Leases in fields located in between 400 and 800 meters of water do not pay royalties until 52.5 MMBOE have been produced from the field.

- Leases in fields located in deeper than 800 meters of water do not pay royalties until 87.5 MMBOE have been produced from the field.

~~3.~~80. GOM deep water leases issued beginning in 2002 receive royalty suspensions based on the following criteria:

- Leases in fields located in between 400 and 800 meters of water do not pay royalties until 5 MMBOE have been produced from the field.
- Leases in fields located in between 800 and 1,600 meters of water do not pay royalties until 9 MMBOE have been produced from the field.
- Leases in fields located in deeper than 1,600 meters of water do not pay royalties until 12 MMBOE have been produced from the field.

81. A lease will expire at the end of its primary term, which is usually 10 years. However, leases may be extended if:

1. Qualifying drilling operations are in progress;
2. The lease contains a well capable of producing paying quantities; or
3. The lease is entitled to receive an allocation of production from an off-lease well[12].

82. If a lease does not have a producible well, or a producible well attributed to it, it will automatically terminate if annual rent is not paid in full and on time. Part of the lease may be given up by filing a written relinquishment. A relinquishment takes effect on the date the document is filed. Abandoned wells must be plugged and other work as may be required so the lease is in proper condition for abandonment and decommissioning (offshore) or reclamation (onshore) must be performed. The lease account must also be brought into good standing. Failure to abide by any of these conditions may require the bond to be forfeited and the lessee may be prohibited from leasing any additional Federal lands.

83. Before drilling can begin, the lessee, sublessee, or operator must post a bond to ensure compliance with the terms of the lease, including environmental protection. More than one bond may be required. Types of bonds that may be required include a generic lease bond, an area bond, a

[12] A drilling platform may exist within the boundary of one lease, yet drill a well within the boundary of another lease (e.g., diagonal drilling).

pipeline bond, and a supplemental bond. Sufficient safeguards have been established for the MMS offshore bond process that the MMS has not had to pay for any bankruptcies that occurred. In practice, bonds for onshore leases have fallen far short of actual cleanup costs. According to a 2001 report by four citizens groups, "BLM recognizes that all bonding amounts are dramatically low in contrast to costs of full reclamation. Recent Wyoming examples illustrate this point: operators posting $25,000.00 statewide bonds have left clean-up costs, for one well, of $37,000.00. In addition, BLM recognizes that it has approximately 90 orphan wells nationwide, with expected liability to the taxpayer at $1.7 million, yielding an average cost of reclamation (and just plugging and abandoning), per well, of approximately $19,000.00. BLM acknowledges that full reclamation of some orphaned natural oil and gas wells can cost up to $75,000.00. Accordingly, BLM recognizes that bonding amounts are far too low for federal oil and gas activities" (Protecting Wyoming 2001).

84. In recent years, the BLM announced that amounts for oil and gas bonds would increase. Under proposed rules, oil and gas companies would increase for wells drilled on particular leases and for statewide bonds. But nationwide bonds would remain unchanged. Thus far, these changes have not been implemented (Gillette News-Record 2002, Chakrabarty 2003).

~~49.~~85. **Estimated Federal Royalty Share**. Under current Federal regulations, the lessee has a "duty to market" the government's royalty share of proved reserves. Although in most cases, lessees pay their royalties in money rather than oil and gas, they tend to think of the royalty system as meaning that a certain percentage of the oil and gas product belongs to the government. Lessees refer to that product as the government's royalty share. The value of the estimated Federal royalty share would be measured by multiplying the estimated quantity of proved oil and gas reserves on a field-by-field basis by the average wellhead price/first purchase price and the respective royalty rate. The Board believes ~~this~~ the term estimated Federal royalty share should be used to refer to the asset to be capitalized on the balance sheet.

Existing and Proposed Accounting Entries for Oil and Gas

~~19.~~86. The following page presents the existing accounting entries for oil and gas resources and the proposed accounting entries for oil and gas resources. Entries are presented for the following accounting events:

1. Record initial estimated Federal royalty share;
2. Record bonus bid and rent collections;
3. Record royalty collections;
4. Record distribution of collections; and,
5. Record year-end adjustment to estimated Federal royalty share.

Illustration 2 **Existing and Proposed Accounting Entries for Oil and Gas**

Existing Entries	Proposed Entries
Record initial estimated Federal royalty share	
	Dr 184X Proved Oil and gas Reserves Cr Cumulative Results of Operation adjustment
Record bonus bid and rent collections	
Dr 1016 Fund Balance With Treasury Cr 590R Custodial Revenue	Dr 1016 Fund Balance With Treasury Cr 590R Custodial Revenue
Record royalty collections	
Dr 1016 Fund Balance With Treasury Cr 590R Custodial Revenue	Dr 101X Fund Balance With Treasury Cr 52XX Royalty Revenue, and Dr 67XX Depletion Expense Cr 184X Accumulated Depletion of Reserves

Record distribution of collections	
Dr 5990 Cr 101X Fund Balance With Treasury Federal entity recipients: Is recognized as a financing source by the entity in determining its operating results and change in net position.	Dr 57XX Transfer Out Cr 101X Fund Balance With Treasury Federal entity recipients: Dr 57XX Transfer In Cr 101X Fund Balance With Treasury
Record year-end adjustment to estimated Federal royalty share	
	Dr 184X Proved Oil and gas Reserves Cr 7010 Unrealized Gains

Definitions of Resource and Reserve Components

Provide below are definitions used by Federal entities to describe oil and gas resource and reserve components. The source of these definitions is OCS Report MMS 2003-050 unless otherwise noted.

Resources estimated from broad geologic knowledge or theory and existing outside of know fields or known accumulations are undiscovered resources. Undiscovered resources can exist in untested prospects on unleased acreage, or on undrilled lease acreage, or in known fields. In known fields, undiscovered resources occur in undiscovered pools that are controlled by distinctly separate structural features or stratigraphic conditions.

The Mineral Management Service (MMS) and the U.S. Geological Survey (USGS) formerly conducted National Assessments of undiscovered oil and gas resources together. The former was responsible for the offshore while the latter was responsible for on shore and state waters. The last such assessment was in 1995. MMS updates their assessment approximately every 5 years in accordance with the Department of Interior's 5-Year leasing program, with the last update in 2000. Since 1995, the USGS has not conducted an overall update for on shore and state waters, but has conducted assessments updates on a basin or area level.

The MMS assessment considers recent geophysical, geological, technological, and economic information and uses a geologic play[13] analysis approach for resource appraisal.

Undiscovered Resources

Undiscovered resources are hydrocarbons estimated on the basis of geologic knowledge and theory to exist outside of known accumulations

The assessment provides estimates of undiscovered resources in two categories, which are presented below:

1. Undiscovered, conventionally recoverable resources: The portion of the hydrocarbon potential that is producible, using present or reasonably foreseeable technology, without any consideration of economic feasibility. (An example of this information is presented in **Table 1** on the following page 34.

2. Undiscovered, economically recoverable resources: The portion of the undiscovered conventionally recoverable resources that is economically recoverable under imposed economic scenarios. ~~(An example of this information is presented in **Table 2** on the following)~~

[13] A play is a group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment. A pool is a discovered or undiscovered accumulation of hydrocarbons, typically within a single stratigraphic interval.

Table 1. Estimates of Undiscovered, Conventionally Recoverable Resources for the United States OCS[1]

[Tcf = trillion cubic feet; Bbbl = billion barrels; BOE = barrels of oil equivalent]

Region	Oil (Bbbl)			Natural Gas (Tcf)			BOE (Bbbl)		
	Low	High	Mean	Low	High	Mean	Low	High	Mean
Alaska	16.5	35.4	24.9	55.0	226.8	122.6	28.0	71.9	46.7
Atlantic	1.9	2.8	2.3	23.9	34.1	28.0	6.2	8.9	7.3
Gulf of Mexico	33.4	44.9	37.1	180.4	207.2	192.7	65.5	81.8	71.4
Pacific	9.0	12.6	10.7	15.2	23.2	18.9	11.8	6.6	14.1
Total OCS2	63.7	88.3	75.0	292.1	468.6	362.2	117.8	166.9	139.5

[1] *Low and High* values refer to those estimates that occur at the 95th and 5th percentiles, respectively, on a cumulative distribution curve (see fig. 3). The *Mean* value is the arithmetic average of all values in the distribution. 5.62 MCF equates to 1.0 BOE.

[2] *Low and High* values are not additive to reach the *Total* values; only *Mean* values are additive.

~~**Table 2.** Mean Estimates of Undiscovered, Economically Recoverable Resources for the United States OCS (at $18 and $30 per barrel of oil and $2.11 and $3.52 per Tcf natural gas)~~

~~[Tcf = trillion cubic feet; Bbbl = billion barrels]~~

~~Region~~	~~$18 Oil (Bbbl)~~	~~$2.11 Natural Gas (Tcf)~~	~~$30 Oil (Bbbl)~~	~~$3.52 Natural Gas (Tcf)~~
~~Alaska~~	~~3.3~~	~~1.6~~	~~10.1~~	~~3.0~~
~~Atlantic~~	~~0.5~~	~~6.6~~	~~1.3~~	~~12.8~~
~~Gulf of Mexico~~	~~17.5~~	~~100.3~~	~~28.1~~	~~140.7~~
~~Pacific~~	~~5.3~~	~~8.3~~	~~7.2~~	~~11.6~~
~~Total OCS~~	~~26.6~~	~~116.8~~	~~46.7~~	~~168.1~~

Source: MMS Outer Continental Shelf Petroleum Assessment, 2000

Undiscovered Resources

Undiscovered resources are hydrocarbons estimated on the basis of geologic knowledge and theory to exist outside of known accumulations

Discovered Resources

Once leased acreage is drilled and is determined to contain oil or gas under Code of Federal Regulations (CFR) Title 30, Part 250, Subpart A, Section 11, Determination of Well Producibility (hereinafter referred to as 30 CFR 250.11), the lease is considered to have discovered resources.

Identified resources are resources whose location and quantity are known or are estimated from specific geologic or engineering evidence and include economic, marginally economic, and subeconomic components.

Unproved Reserves

After a lease qualifies under 30 CFR 250.11, the MMS Field Naming Committee reviews the new producible lease to assign it to an existing field or, if the lease is not associated with an established geologic structure, to a new field. Regardless of where the lease is assigned, the reserves associated with the lease are initially considered to be unproved reserves. Unproved reserves are based on geologic or engineering information similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved.

Unproved reserves may be divided into two subclassifications, possible and probable, which are similarly based on the level of uncertainty.

> "Unproved possible reserves are less certain than unproved probable reserves and can be estimated with a low degree of certainty, which is insufficient to indicate whether they are more likely to be recovered than not. Reservoir characteristics are such that a reasonable doubt exists that the project will be commercial" (SPE, 1987). After a lease qualifies under 30 CFR 250.11, the reserves associated with the lease are initially classified as unproved possible.

> "Unproved probable reserves are less certain than proved reserves and can be estimated with a degree of certainty sufficient to indicate they are more likely to be recovered than not" (SPE, 1987). Reserves in fields for which a schedule leading to a Development and Production Plan (DPP) has been submitted to the MMS have been classified as unproved probable.

Proved Reserves

"Proved reserves can be estimated with reasonable certainty to be recoverable under current economic conditions, such as prices and costs prevailing at the time of the estimate. Proved reserves must either have facilities that are operational at the time of the estimate to process and transport those reserves to market or a commitment or reasonable expectation to install such facilities in the future" (SPE, 1987). Proved reserves can be subdivided into undeveloped and developed.

> Proved undeveloped reserves are classified proved undeveloped when a relatively large expenditure is required to install production and/or transportation facilities, a commitment by the operator is made, and a timeframe to begin production is established. Proved

undeveloped reserves are reserves expected to be recovered from (1) yet undrilled wells, (2) deepening existing wells, or (3) existing wells for which a relatively large expenditure is required for recompletion.

Proved developed reserves are classified as proved developed when the reserves are expected to be recovered from existing wells (including reserves behind pipe). Reserves are considered developed only after necessary production and transportation equipment have been installed or when the installation costs are relatively minor. Proved developed reserves are subcategorized as producing or non-producing" (SPE, 1987). This distinction is made at the reservoir level and not at the field level.

- Any developed reservoir in a developed field that has not produced or has not had sustained production during the past year is considered to contain proved developed nonproducing reserves. This category includes reserves contained in nonproducing reservoirs, contained reserves behind-pipe, and reservoirs awaiting well workovers or transportation facilities.

- Once the first reservoir in a field begins production, the reservoir is considered to contain proved developed producing reserves, and the field is considered on production. If a reservoir had sustained production during the last year, it is considered to contain proved developed producing reserves.

Production

Production represents the proved oil and gas reserves that were extracted from existing reserves[14].

[14] Adapted from Gas Energy Review, Gas Supply and Demand Committee, July 1995, Vol.23 No.7.

Illustration 3 Historical Estimates of Proved Reserves

Table 1. Total U.S. Proved Reserves of Crude Oil, Dry Natural Gas, and Natural Gas Liquids, 1992-2002

Year	Adjustments	Net Revisions	Revisions[a] and Adjustments	Net of Sales and Acquisitions	Extensions	New Field Discoveries	New Reservoir Discoveries in Old Fields	Total[b] Discoveries	Estimated Production	Proved[c] Reserves 12/31	Change from Prior Year
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
				Crude Oil (million barrels of 42 U.S. gallons)							
1992	290	735	1,025	NA	391	8	85	484	2,446	23,745	-937
1993	271	495	766	NA	356	319	110	785	2,339	22,957	-788 (-3%)
1994	189	1,007	1,196	NA	397	64	111	572	2,268	22,457	-500 (-2%)
1995	122	1,028	1,150	NA	500	114	343	957	2,213	22,351	-106 (-.5%)
1996	175	737	912	NA	543	243	141	927	2,173	22,017	-334 (-1%)
1997	520	914	1,434	NA	477	637	119	1,233	2,138	22,546	+529 (+2%)
1998	-638	518	-120	NA	327	152	120	599	1,991	21,034	-1,512 (-7%)
1999	139	1,819	1958	NA	259	321	145	725	1,952	21,765	+731 (+3%)
2000	143	746	889	-20	766	276	249	1,291	1,880	22,045	+280 (+1%)
2001	-4	-158	-162	-87	866	1,407	292	2,565	1,915	22,446	+401 (+2%)
2002	416	720	1,136	24	492	300	154	946	1,875	22,677	+231 (+1%)
										Over 10 yrs	-1,068 (-4.5%)
				Dry Natural Gas (billion cubic feet, 14.73 psia, 60°				Fahrenheit)			
1992	2,235	6,093	8,328	NA	4,675	649	1,724	7,048	17,423	165,015	-2,047
1993	972	5,349	6,321	NA	6,103	899	1,866	8,868	17,789	162,415	-2,600 (-2%)
1994	1,945	5,484	7,429	NA	6,941	1,894	3,480	12,315	18,322	163,837	+1,422 (+1%)
1995	580	7,734	8,314	NA	6,843	1,666	2,452	10,961	17,966	165,146	+1,309 (+8%)
1996	3,785	4,086	7,871	NA	7,757	1,451	3,110	12,318	18,861	166,474	+1,328 (+1%)
1997	-590	4,902	4,312	NA	10,585	2,681	2,382	15,648	19,211	167,223	+749 (+.5%)
1998	-1,635	5,740	4,105	NA	8,197	1,074	2,162	11,433	18,720	164,041	-3,182 (-2%)
1999	982	10,504	11,486	NA	7,043	1,568	2,196	10,807	18,928	167,406	+3,365 (+2%)
2000	-891	6,962	6,071	4,031	14,787	1,983	2,368	19,138	19,219	177,427	+10,021 (+6%)
2001	2,742	-2,318	424	2,630	16,380	3,578	2,800	22,758	19,779	183,460	+6,033 (+3%)
2002	3,727	937	4,664	380	14,769	1,332	1,694	17,795	19,353	186,946	+3,486 (+2%)
										Over 10 yrs	+21,933 (+13%)
				Natural Gas Liquids (million barrels of 42 U.S. gallons)							
1992	225	261	486	NA	190	20	64	274	773	7,451	-13
1993	102	124	226	NA	245	24	64	333	788	7,222	-229 (-3%)
1994	43	197	240	NA	314	54	131	499	791	7,170	-52 (-1%)
1995	192	277	469	NA	432	52	67	551	791	7,399	+229 (+3%)
1996	474	175	649	NA	451	65	109	625	850	7,823	+424 (+6%)
1997	-15	289	274	NA	535	114	90	739	864	7,973	+150 (+2%)
1998	-361	208	-153	NA	383	66	88	537	833	7,524	-449 (-6%)
1999	99	727	826	NA	313	51	88	452	896	7,906	+382 (+5%)
2000	-83	459	376	145	645	92	102	839	921	8,345	+439 (+6%)
2001	-429	-132	-561	102	717	138	142	997	890	7,993	-352 (-4%)
2002	62	31	93	54	612	48	78	738	884	7,994	+1 (0%)
										Over 10 yrs	+543 (+7%)

[a] Revisions and adjustments = Col. 1 + Col. 2.

[b] Total discoveries = Col. 5 + Col. 6 + Col. 7.

[c] Proved reserves = Col. 10 from prior year + Col. 3 + Col. 4 + Col. 8 - Col. 9.

NA=Not available.

Notes: Old means discovered in a prior year. New means discovered during the report year. The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." They may differ from the official EIA production data for crude oil, natural gas, and natural gas liquids for 2002 contained in the *Petroleum Supply Annual 2002*, DOE/EIA-0340(02) and the *Natural Gas Annual 2002*, DOE/EIA-0131(02).

Acquisitions: The volume of proved reserves gained by the purchase of an existing fields or properties, from the date of purchase or transfer.

Adjustments: The quantity which preserves an exact annual reserves balance within each State or State subdivision of the following form:

> These adjustments are the yearly changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories because of the survey and statistical estimation methods employed. For example, variations as a result of changes in the operator frame, different random samples or imputations for missing or unreported reserve changes, could contribute to adjustments.

Extensions: The reserves credited to a reservoir because of enlargement of its proved area. Normally the ultimate size of newly discovered fields, or newly discovered reservoirs in old fields, is determined by wells drilled in years subsequent to discovery. When such wells add to the proved area of a previously discovered reservoir, the increase in proved reserves is classified as an extension.

New Field Discoveries: The volumes of proved reserves of crude oil, natural gas and/or natural gas liquids discovered in new fields during the report year.

New Reservoir Discoveries in Old Fields: The volumes of proved reserves of crude oil, natural gas, and/or natural gas liquids discovered during the report year in new reservoir(s) located in old fields.

Production, Crude Oil: The volumes of crude oil which are extracted from oil reservoirs during the report year. These volumes are determined through measurement of the volumes delivered from lease storage tanks, (i.e., at the point of custody transfer) with adjustment for (1) net differences between opening and closing lease inventories, and for (2) basic sediment and water. Oil used on the lease is considered production.

Production, Natural Gas, Dry: The volume of natural gas withdrawn from reservoirs during the report year less (1) the volume returned to such reservoirs in cycling, repressuring of oil reservoirs and conservation operations; less (2) shrinkage resulting from the removal of lease condensate and plant liquids; and less (3) nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Volumes of gas withdrawn from gas storage reservoirs and native gas, which has been transferred to the storage category, are not considered production. This is not the same as marketed production, since the latter also excludes vented and flared gas, but contains plant liquids.

Production, Natural Gas Liquids: The volume of natural gas liquids removed from natural gas in lease separators, field facilities, gas processing plants or cycling plants during the report year.

Revisions: Changes to prior year--end proved reserves estimates, either positive or negative, resulting from new information other than an increase in proved acreage (extension). Revisions include increases of proved reserves associated with the installation of improved recovery techniques or equipment. They also include correction of prior report year arithmetical or clerical errors and adjustments to prior year--end production volumes to the extent that these alter reported prior year reserves estimates.

Sales: The volume of proved reserves deducted from an operator's total reserves when selling an existing field or property, during the calendar year.

ISSUE 1

a) Make a comparison between the FASB 69 oil and gas accounting standards and the SEC Rule on oil and gas accounting standards, and provide the similarities and differences between the two.

The FASB accounting standards for oil and gas activities and the SEC Regulations for oil and gas activities are the same. Both FASB and SEC permit the use of either the 'successful effort' or the 'full cost' method of accounting for costs incurred in oil and gas producing activities. In regard to supplementary financial information (i.e., proved oil and gas reserve quantities, capitalized costs relating to oil and gas producing activities, costs incurred in oil and gas property acquisition, exploration, and development activities, results of operations for oil and gas producing activities, and standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities) the SEC directs users to follow paragraphs 9 through 34 in SFAS 69. See below:

> UNITED STATES SECURITIES AND EXCHANGE COMMISSION
> REGULATION S-K
> Subpart 229:302 - Supplementary Financial Information
> Item (b) - *Information about oil and gas producing activities.* Registrants engaged in oil and gas producing activities shall present the information about oil and gas producing activities (as those activities are defined in Regulation S-X, §210.4-10(a)) specified in paragraphs 9-34 of Statement of Financial Accounting Standards ("SFAS") No. 69, "Disclosures about Oil and Gas Producing Activities," if such oil and gas producing activities are regarded as significant under one or more of the tests set forth in paragraph 8 of SFAS No. 69.

b) Determine if lessees, who are authorized to extract oil and gas reserves on lands under the control of the Federal government, are required to report proved undeveloped reserves to the Security and Exchange Commission (SEC).

The FASB SFAS 69 and the SEC Regulation S-K require that proved reserves and proved developed reserves be disclosed as supplementary information. See Figure 1on the following page.

FASB SFAS 69, paragraph 10. Net quantities of an enterprise's interests in proved reserves and proved developed reserves of (a) crude oil (including condensate and natural gas liquids) 5 and (b) natural gas shall be disclosed as of the beginning and the end of the year. "Net" quantities of reserves include those relating to the enterprise's operating and nonoperating interests in properties as defined in paragraph 11(a) of Statement 19. Quantities of reserves relating to royalty interests owned shall be included in "net" quantities if the necessary information is available to the enterprise; if reserves relating to royalty interests owned are not included because the information is unavailable, that fact and the enterprise's share of oil and gas produced for those royalty interests shall be disclosed for the year. "Net" quantities shall not include reserves relating to interests of others in properties owned by the enterprise.

Figure1

RESERVE QUANTITY INFORMATION
FOR THE YEAR ENDED DECEMBER 31, 20XX

	Total		United States		Foreign Geographic Area A		Foreign Geographic Area B		Other Foreign Geographic Areas	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Proved developed and undeveloped reserves:										
Beginning of year	X	X	X	X	X	X	X	X	X	X
Revisions of previous estimates	X	X	X	X	X	X	X	X	X	X
Improved recovery	X	X	X	X	X	X	X	X	X	X
Purchases of minerals in place	X	X	X	X	X	X	X	X	X	X
Extensions and discoveries	X	X	X	X	X	X	X	X	X	X
Production	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)
Sales of minerals in place	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)
End of year	X	X	X	X	X	X	X	X	X	X
Proved developed reserves:										
Beginning of year	X	X	X	X	X	X	X	X	X	X
End of year	X	X	X	X	X	X	X	X	X	X

Issue 2

Identify proposed disclosures or information to be reported as required supplementary information (RSI).

Illustration 1, on page 8 of this document, provides a framework for components of Federal oil and gas reserves. The components and subcomponents are:

- Undiscovered Resources
  - Undiscovered Non-Recoverable Resources
  - Undiscovered Recoverable Resources
    - Undiscovered Conventionally Recoverable Resources
    - Undiscovered Economically Recoverable Resources

- Discovered Resources
  - Unproved Resources
    - Unproved Possible Reserves
    - Unproved Probable Reserves
  - Proved Resources
    - Proved Undeveloped Reserves
    - Proved Developed Reserves
      - ✓ Proved Developed Non-Producing Reserves
      - ✓ Proved Developed Producing Reserves
  - Production

With respect to disclosing quantifiable information for the oil and gas resources, the quantifiable information for the subcomponents may not exist, may be incomplete, and/or may only be updated periodically. A description of what information is available for the subcomponents is presented below:

- **Undiscovered Non-Recoverable Resources**. There is <u>not of information available for this subcomponent</u>.

- **Undiscovered Recoverable Resources**. Information is available for some portions of this subcomponent. The MMS is able to provide information on offshore resources for both Undiscovered Conventionally Recoverable Resources and Undiscovered Economically Recoverable Resources. However, the information is based on a national assessment which is performed every 5 years. The most recent national assessment was completed in 2000. A new assessment should be available in early 2006.

  The BLM can only provide information for onshore Conventionally Recoverable Resources. The information is also based on a national assessment, which is performed by the USGS. However, the last complete national assessment was completed in 1995. Since 2000 the USGS has been re-assessing basins of the U.S. that are considered to be priorities for the new assessment rather than assessing all of the basins of the U.S. Since 2000, the USGS has re-assessed sixteen priority basins, and has plans to re-assess sixteen more basins. These 32 basins represent about 97% of the discovered and undiscovered oil and gas resources of the United States. As each basin is re-assessed, the assessment results are added to the tables, and these new values replace the assessment results from 1995. A 2004 Assessment Update, which includes information from the first 16 basin re-assessments, represents the update to the 1995 National Assessment as of the end of September, 2004.

Based on the assessments performed by the MMS and the USGS, both onshore and offshore information is available for only the Undiscovered Conventionally Recoverable Resources subcomponent. In addition, information for offshore Undiscovered Economically Recoverable Resources is available. However, none of the information is updated on an annual basis and updates cannot be obtained for a consistent "end of period."

- **Unproved Resources**. There is not information available for this subcomponent.

- **Proved Resources**. The MMS prepares periodic reports for offshore proved reserves, both developed and undeveloped. The reports are based on aggregation of MMS field studies. The most current report for the Gulf of Mexico Region is based on information as of December 31, 2001. It was issued in October 2004. The most current report for the Pacific Region is based on information as of December 31, 1998. It was issued in July 2000. Federal offshore reserves in the Alaska Region are modest and are attributable to only a single field, which makes information on the reserves proprietary. The Atlantic Region has no reserves. There is no information available for onshore proved reserves.

There is proved resources information available for two of four regions offshore regions, however it is not current information from another is proprietary for another, and the fourth region has none. The EIA has both onshore and offshore proved reserves information, which is proposed to be used to calculate the estimated Federal royalty share. on a field by field basis. There is no onshore proved resources information.

Question for the Board:

Should the most current available information for each category be disclosed or required as supplemental information (similar to Table 1 on page 34), with an explanation of the related assessment date, what the plans are for updating the information, and updates to the information as it becomes available in subsequent years? Or, does the Board wish to require full disclosure or full RSI reporting in spite of the current limitations on available information?

- **Production**. The MMS has summary type information for oil and gas production. The EIA has more detailed production information (similar to that which is presented Attachment 1 on page 37).

Question for the Board:

Should information such as that presented in Attachment 1 be provided by the EIA?

ISSUE 3

Should an average annual price for the year be used for the national average wellhead price/first purchase price in the proposed accounting standards for proved oil and gas reserves?

FASB SFAS 69 and SEC Regulation S-X require that the standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities be computed by applying year-end prices of oil and gas to the year-end quantities of those reserves. However, the EIA and certain professional organizations do not agree with using year end prices. They believe an average price for the year should be used to because of the fluctuations in the price throughout the year.

Following the example of the FASB and the SEC, our proposed accounting standards propose that the national average wellhead price for all gas wells and the national average first purchase price for all oil wells, as of the last day of the month for the reporting period (year end), be used to calculate the estimated Federal royalty share. Should an annual average price for the year, instead of a year end price, be used to calculate the estimated Federal royalty share?

Figure 2 (for Oil) and Figure 3 (for Gas) on the following pages contain monthly prices for the preceding three years for your review.

Figure 2

Year Month	Domestic First Purchase Price	Average F.O.B Cost of Crude	Average Landed Cost of Crude	Refiner Acquisition Cost of Crude Oil		
				Domestic	Imported	Composite
2002						
January...	15.89	16.01	17.29	17.84	17.04	17.38
February..	16.93	17.67	19.17	18.70	18.24	18.43
March.....	20.28	21.60	22.24	21.61	22.29	22.00
April.....	22.52	23.04	24.15	24.26	23.98	24.10
May.......	23.51	23.16	24.49	25.78	24.44	25.03
June......	22.59	22.63	23.95	24.81	23.45	24.05
July......	23.51	23.72	25.01	25.37	24.99	25.16
August....	24.76	24.57	25.93	26.87	25.68	26.19
September.	26.08	25.80	26.78	28.40	27.14	27.66
October...	25.29	24.32	25.58	27.82	25.99	26.70
November..	23.38	22.42	24.22	26.02	23.68	24.60
December..	25.29	25.86	27.08	27.25	26.68	26.93
2002	22.51	22.63	23.91	24.65	23.71	24.10
2003						
January...	28.42	29.15	30.34	30.82	30.30	30.52
February..	31.85	29.78	31.34	34.05	32.23	33.00
March.....	30.10	26.32	28.86	32.70	29.23	30.65
April.....	25.45	22.74	25.20	28.55	24.48	26.02
May.......	24.95	23.48	25.40	26.75	25.15	25.74
June......	26.84	25.34	27.36	29.07	27.22	27.92
July......	27.52	26.10	27.72	29.54	27.95	28.55
August....	27.94	26.87	28.01	30.28	28.50	29.15
September.	25.23	24.07	25.91	27.75	25.66	26.39
October...	26.53	26.06	27.37	28.43	27.32	27.75
November..	27.21	26.03	27.68	29.55	27.47	28.28
December..	28.53	26.77	28.80	30.27	28.63	29.28
2003......	27.56	25.86	27.69	29.82	27.71	28.53
2004						
January...	30.35	28.16	30.76	32.01	30.24	30.92
February..	31.21	28.50	31.14	33.19	30.77	31.72
March.....	32.86	30.02	32.30	34.53	32.25	33.09
April.....	33.23	30.98	32.88	35.25	32.42	33.46
May.......	36.07	33.81	35.09	37.23	35.82	36.31
June......	34.53	32.20	34.37	36.57	33.58	34.65
July......	36.54	34.92	36.82	37.90	35.98	36.67
August....	40.10	37.33	39.56	41.54	39.57	40.29
September.	40.62	38.82	41.09	42.77	40.51	41.34
October...	46.28	42.41	44.39	47.22	45.53	46.12
November..	42.99	35.94	39.10	45.74	39.83	41.76
December..	NA	NA	NA	E40.69	E35.33	E37.98

E = Estimated data.
NA = Not available.

ATTACHMENT 5

Figure 3

Year and Month	Wellhead Price[a]	City Gate Price	Consumer Prices: Residential Price	Commercial Price	Commercial % of Total[b]	Industrial Price	Industrial % of Total[b]	Electric Power Price[c]
	2.19	3.10	6.69	5.33	66.1	3.12	18.8	2.62
2000 Annual Average	**3.68**	**4.62**	**7.76**	**6.59**	**63.9**	**4.45**	**19.8**	**4.38**
2001 Annual Average	**4.00**	**5.72**	**9.63**	**8.43**	**66.0**	**5.24**	**20.8**	**4.61**
2002								
January	2.50	3.79	R7.38	R6.51	R79.8	4.05	R20.3	3.10
February	2.19	3.76	R7.23	R6.40	R80.7	3.70	R20.6	2.86
March	2.40	3.84	R7.10	R6.28	R81.5	3.78	R20.2	3.37
April	2.94	4.21	R7.66	R6.56	R76.8	3.64	R26.3	3.80
May	2.94	4.07	R8.54	R6.68	R73.0	4.07	R24.0	3.78
June	2.96	4.15	R9.58	R6.80	R73.2	3.86	R25.6	3.61
July	2.92	3.95	R10.31	R6.62	R71.2	3.80	R24.0	3.49
August	2.76	3.67	R10.44	R6.45	R71.6	3.62	R22.6	3.42
September	2.97	3.99	R10.23	R6.54	R69.5	3.89	R22.5	3.71
October	3.24	4.32	R8.61	R6.64	R73.2	4.18	R21.7	4.19
November	3.59	4.65	R7.99	R6.89	R78.7	4.72	R21.9	4.35
December	3.96	4.74	R7.87	R7.16	R79.6	4.92	R23.2	4.72
Annual Average	**2.95**	**4.12**	**R7.89**	**R6.63**	**R77.4**	**4.02**	**R22.7**	**3.68**
2003								
January	RE4.43	R5.28	R8.08	R7.40	R79.1	R5.52	R22.2	R5.36
February	RE5.05	R5.83	R8.46	R7.86	R79.8	R6.24	R23.0	R6.47
March	RE6.96	R7.63	R9.64	R9.00	R80.1	R8.01	R22.0	R7.08
April	RE4.47	R5.60	R10.05	R8.76	R76.7	R5.81	R21.7	R5.37
May	RE4.77	R5.69	R10.67	R8.64	73.5	R5.65	R21.0	R5.67
June	RE5.41	R6.40	R11.96	R8.90	R72.4	R6.42	R19.8	R6.03
July	RE5.08	R5.83	R12.62	R8.77	R71.0	R5.64	R25.2	R5.42
August	RE4.46	R5.48	R12.72	R8.40	R73.3	R5.21	R23.4	R5.21
September	RE4.59	R5.58	R12.19	8.35	R72.2	R5.27	R23.4	R5.09
October	RE4.32	R5.33	R10.52	R8.26	R72.7	R5.26	R24.6	R4.96
November	RE4.26	R5.54	R9.66	R8.24	R77.6	R5.15	R23.0	R4.79
December	RE4.76	R5.89	R9.39	R8.49	R80.2	R5.70	R24.5	R5.65
Annual Average	**RE4.88**	**R5.85**	**R9.52**	**R8.29**	**77.3**	**R5.81**	**R22.9**	**R5.54**
2004								
January	E5.53	6.39	R9.70	R8.92	80.7	R6.63	R22.7	6.38
February	E5.15	R6.37	R9.84	R8.95	R80.9	6.39	R23.7	5.75
March	E4.97	6.24	R10.00	R8.93	R78.3	5.86	R22.6	5.47
April	E5.20	R6.32	10.52	R8.91	R76.4	R5.96	R23.1	5.76
May	E5.63	R6.47	R11.61	9.06	73.1	6.27	R23.1	R6.27
June	E5.85	6.92	13.05	9.60	R71.5	R6.71	R24.8	6.52
July	E5.60	R6.68	R13.44	R9.53	R71.0	R6.25	R24.9	R6.46
August	E5.36	R6.50	R13.77	R9.55	70.4	R6.20	R24.2	R5.69
September	E4.86	6.07	R13.27	R9.19	R70.7	R5.54	R22.9	5.40
October	E5.45	6.31	11.65	9.07	R72.7	R5.84	R23.1	NA
November	E6.07	7.48	11.44	10.06	77.7	7.47	23.3	NA
2004 YTD[d]	**E5.42**	**6.51**	**10.67**	**9.15**	**76.9**	**6.30**	**23.5**	**5.97**
2003 YTD[d]	**E4.89**	**5.85**	**9.54**	**8.26**	**76.9**	**5.82**	**22.7**	**5.66**
2002 YTD[d]	**2.86**	**4.03**	**7.90**	**6.54**	**77.0**	**3.93**	**22.7**	**3.48**

[a] See Appendix A, Explanatory Note 10, for discussion of wellhead prices. [b] Percentage of total deliveries represented by onsystem sales, see Figure 6. See Table 25 for State data. [c] The electric power sector comprises electricity-only and combined-heat-and-power plants within the NAICS 22 category whose primary business is to sell electricity, or electricity and heat, to the public. Through 2001, data are for regulated electric utilities only; beginning in 2002, data also include nonregulated members of the electric power sector. [d] Year-to-date price represents months for which price information is available in the current year. The electric power year-to-date price is 2 month behind the wellhead, city gate, residential, commercial, and industrial year-to-date prices.

R Revised Data. E Estimated Data. RE Revised Estimated Data. NA Not Available.**Notes:** Data for 1999 through 2003 are final. All other data are preliminary unless otherwise indicated. Geographic coverage is the 50 States and the District of Columbia. **Sources:** 1999-2003: Energy Information Administration (EIA)*Natural Gas Annual 2003.*January 2004 through current month: EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers," Form EIA-910, "Monthly Natural Gas Marketer Survey," Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report," and EIA estimates.