Natural Resources
Oil and Gas Reference Documents

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FASAB **Federal Accounting Standards Advisory Board**

DISCUSSION PAPER

ACCOUNTING FOR THE NATURAL RESOURCES OF THE FEDERAL GOVERNMENT

PREPARED BY

THE FASAB NATURAL RESOURCES TASK FORCE

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THE FEDERAL ACCOUNTING STANDARDS ADVISORY BOARD

The Federal Accounting Standards Advisory Board (the FASAB or "the Board") was established by the Secretary of the Treasury, the Director of the Office of Management and Budget (OMB), and the Comptroller General in October 1990. It is responsible for promulgating accounting standards for the United States Government.

An accounting standard is typically formulated initially as a proposal after considering the financial and budgetary information needs of citizens (including the news media, state and local legislators, analysts from private firms, academe, and elsewhere), Congress, Federal executives, Federal program managers, and other users of Federal financial information. The proposed standard is published in an Exposure Draft for public comment. A public hearing is sometimes held to receive oral comments in addition to written comments. The Board considers comments and decides whether to adopt the proposed standard with or without modification. The Board publishes adopted standards in a Statement of Federal Financial Accounting Standards.

Additional background information is available from the FASAB:

"Memorandum of Understanding among the General Accounting Office, the Department of the Treasury, and the Office of Management and Budget, on Federal Government Accounting Standards and a Federal Accounting Standards Advisory Board," amended on October 1, 1999.

"Mission Statement of the Federal Accounting Standards Advisory Board."

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Executive Summary

During the Board's deliberations relating to the development of an accounting standard for land, natural resources were excluded from the scope of the land project. Accordingly, the Board established a Natural Resources task force to address natural resources separately. On the basis of the guidance provided by the Board, the task force was charged to: (1) study the kinds of information (i.e., both financial data and nonfinancial data) which can be reported about natural resources, (2) provide options for reporting the information, (3) identify the related impacts on existing FASAB standards based on the options and, (4) identify existing laws and regulations that affect reporting information about natural resources. This report presents the findings of the task force based on its charge.

The report contains the following major sections:

- I. Natural Resources Project Overview
- II. Objectives of Natural Resources Reporting
- III. Context for Analysis -- Framework
- IV. General Reporting Principles
- V. Implication of Recommendations
- VI. Indian Natural Resource Assets
- Appendix A. Reporting by Individual Resource
- Appendix B. Minority Comments on General Reporting Principles

An overview of the sections is provided below:

Section I, *Natural Resources Project Overview*, provides an overview of how various aspects of the project were developed, as well as, the scope of the project. The Board provided the scope in which the task force would focus its work. The scope included economic mineral resources (e.g., oil, gas, coal, gold, silver, copper, sand, clay, and gravel); the following renewable resources: timber, forage, and water for which the Federal Government owned the rights; and the electromagnetic spectrum.

Section II, *Objectives of Natural Resources Reporting*, outlines the reporting objectives the task force used in developing the report. As its basis, the task force used Statement of Federal Financial Accounting Concept Statement (SFFAC) No. 1, *Objectives of Federal Financial Reporting*, to ensure that all of the major objectives were considered. The report specifically focuses on the premise that natural resource reporting can report on past performance from a budgetary, operating, or stewardship perspective. In this section it is noted that natural resource reporting could also serve natural resources accounting by providing information relevant to policy decisions about the future management and the disposition of Federal natural resources.

Section III of the report, *Context for Analysis -- Framework*, was developed by the task force to provide a framework for understanding how the many Federal natural resource programs are managed. This understanding became necessary as the task force began to discuss natural resource reporting options. This section also discusses the following natural resource management processes:

- undiscovered resources
- resources not available for transfer
  - -- legislatively withdrawn resources
  - -- administratively withdrawn resources
- resources available for transfer
  - -- resources planned to be offered
  - -- resources under contract but not conveyed
  - -- other available resources
- conveyed.

Section IV, *General Reporting Principles*, gives detailed discussions on the various reporting options considered by the task force. It addresses asset reporting, accounting and reporting for revenue, and accounting and reporting for cost. The task force's suggested reporting principles, as well as, advantages and disadvantages of these principles are presented for 1) asset reporting and 2) accounting and reporting for cost. However, the accounting and reporting for revenue discussion was heavily debated and a consensus was not reached on a suggested reporting principle. Therefore, two revenue accounting and reporting options have been provided.

The asset reporting segment outlines the various reporting options for reporting natural resource assets on the financial statements (i.e., recognition, disclosure, and stewardship reporting). Based on it findings, the task force agreed that stewardship reporting could be used as the primary tool for reporting natural resource information. The two revenue accounting and reporting options are 1) reporting all natural resource revenues on the Statement of Custodial Activities and, 2) reporting all natural resource revenues on the Statement of Net Costs. The accounting and reporting for cost section is divided into the following cost segments: cost of resources, cost of sale, cost of management, and transfer of revenue/distribution of receipts.

Section V, *Implication of Recommendations*, focuses on the implications of the task force's suggested reporting principles and revenue options on SFFAS No. 7, *Accounting for Revenue and Other Financing Sources and Concepts for Reconciling Budgetary and Financial Accounting* and the legal/regulatory statutes to be considered.

Section VI, *Indian Natural Resource Assets*, provides information on Indian natural resource assets from the standpoint of these assets being reported as trust assets. This section also provides an overview of FASAB Interpretation No. 1, *Interpretation of Federal Financial Accounting Standards -- Reporting on Indian Trust Funds in General Purpose Financial Reports of the Department of the Interior and in the Consolidated Financial Statements of the United States Government: an Interpretation of SFFAS No. 7*.

Appendix A, *Reporting by Individual Resource*, contains detailed information on eight natural resources related programs managed by the Federal Government. They are as follows:

- timber,
- outer continental shelf oil and gas,
- leasable minerals (solid),
- leasable minerals (fluid),
- locatable minerals,
- mineral materials,
- grazing uses , and
- electromagnetic spectrum (airwaves).

Appendix B, *Minority Comments on General Reporting Principles*, raises three concerns. First, it suggests that the basic concepts of SFFAS No. 7 are valid, and that sales of natural resources should not offset agencies' gross costs, unless the full costs of the natural resources sold are recognized. Second, it suggests that some natural resource assets -- in particular, those where the asset is held for remunerative operations or sale -- should be recognized on the balance sheet, and not solely in the stewardship report; this would also allow the full costs of natural resources that are sold to be recognized on the Statement of Net Cost. Finally, the comments suggest that the Federal Government develop basic data where it has valuable resources that it intends to sell or manage for remunerative purposes.

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I. Natural Resources Project Overview

Background

In earlier deliberation by the Federal Accounting Standards Advisory Board (FASAB) on Property, Plant, and Equipment (SFFAS No. 6) and Supplementary Stewardship Reporting (SFFAS No. 8), the land was defined as the solid part of the surface of the earth. For the purpose of those standards, natural resources that are in the custody of the Federal Government were excluded from the scope of the land project. The major reasons for addressing only surface land in the previous standards were: (1) the allotted time frame within which to complete the standard for land; (2) studies that pointed out the difficulties and complexities of accurately estimating and valuing natural resources; and (3) disputes regarding the boundaries of the outer-continental shelf.

As a follow-up effort, the Board established a Natural Resources Project task force to address natural resources separately. The purpose of the task force was to provide the framework for the development of a natural resources accounting standard.

The responsibilities assigned to the task force to accomplish this task were:

1) Study the kinds of information about extractable natural resources owned by the Federal Government, or under Federal stewardship, which can be obtained for reporting purposes, including information about the value of resources removed, what was received in exchange, the cost of allowing the resources to be taken, and the value of resources remaining;

2) Provide options for reporting information in an annual report, i.e., on face of the financial statements, in footnotes, as required supplemental stewardship information (RSSI), as required supplemental information (RSI), or in the Management Discussion and Analysis (MD&A); and

3) Identify areas in existing FASAB standards that would be impacted by the task force's recommended reporting options, and the required changes to the standards associated with each option.

In addition, the task force was asked to identify existing laws and regulations that affect the ability of the Federal Government to properly report on these natural resources to the extent that these laws and regulations were noted during the course of the study.

Scope

The task force was requested to address "traditional" natural resources associated with Federal lands. In addition, stocks of game, fisheries, and wildlife habitat were specifically excluded from the scope of the project.

The task force proposed to focus on extractable natural resources owned by the Federal Government, or under Federal stewardship, for which a commercial market existed for the resource. The revised scope included economic mineral resources (e.g., oil, gas, coal, gold, silver, copper, sand, clay, and gravel); the following renewable resources: timber, forage, and water for which the Federal Government owned the rights; and the electromagnetic spectrum. However, as the project progressed, the focus of the task force shifted from a commercial market orientation to a stewardship orientation over the natural resources associated with Federal lands.

Resources Addressed

In the process of studying the natural resources, the task force classified the natural resources into categories. These categories were established for purposes of analyzing the resources. The natural resources and/or categories of resources that the task force addressed in this project are presented below with a brief description for each. They are:

Timber

Timber is harvested from Federal lands on a sustained-yield basis through carefully managed reforestation programs. The private contractor who is selected to harvest the timber only purchases the timber designated for harvest, while the ownership of the land remains with the Federal Government. The contractor is responsible for the actual removal of the timber from the public land area. Actual harvesting may take up to two or three years after areas have been "marked for cut."

Outer Continental Shelf Oil & Gas

States have been granted the rights to natural resources within 3 nautical miles of their coastline, except for the Gulf of Mexico coasts of Texas and Florida, where State jurisdiction extends for 3 marine leagues. The Federal jurisdiction begins after the State jurisdiction ends and extends for at least 200 nautical miles seaward of the coastline. The Outer Continental Shelf (OCS) consists of over 1.4 billion acres of submerged lands seaward of State jurisdiction. The Federal Government manages the rights to oil, gas, and other minerals on the OCS. The Government issues leases that convey an exclusive right to explore for and develop oil and gas on the OCS, and maintain a royalty interest in any production saved, removed, or sold from a lease. Over 27 million acres of the OCS are currently under active lease. The OCS accounts for over 27% of the natural gas and 20% of the oil produced in the United States.

Leasable Minerals

Leasable minerals include solid minerals (e.g., coal, oil shales, asphalt, phosphate, potash, sodium) and fluid minerals (e.g., onshore oil & gas, geothermal energy). The Federal Government is responsible for managing the mineral estate owned by the Federal Government that underlies approximately 564 million acres of surface land it owns. In addition, the government holds the mineral rights on split-estate lands for which the surface has been conveyed. The government allows these minerals to be developed through leases. Lessees pay rental per acre to hold the leases and compensate the government for minerals removed with a royalty on the sales value.

Locatable Minerals

The class of economic minerals known as "locatable" minerals makes up a significant portion of the "economic" minerals. The class includes precious metals (e.g., gold and silver), ferrous metals, light metals, base metals, precious and semi-precious gemstones and a vast array of industrial minerals.

U.S. citizens and incorporated businesses are permitted to prospect for locatable minerals on Federal lands in nineteen states as long as those lands have not been closed or withdrawn from mining. If valuable mineral deposits are discovered, prospectors can file a claim giving them the right to use the land for mining-related activities and the right to sell the minerals extracted without paying a royalty to the Federal Government. A claimant desiring to obtain fee simple title to the land and the mineral rights can patent the claim for $2.50 or $5.00 an acre, depending on the type of claim. After the patent has been granted, the claim becomes private property.

Also, because mining operators are not required to report their production (extracted amount) from Federal lands and because the Federal Government is not required to collect such information, reliable figures may not be available to determine the total value of locatable minerals extracted from Federal lands.

Mineral Materials

Mineral materials include various common minerals, such as sand, gravel, and stones, which are considered part of the mineral estate owned by the Federal Government. The Federal Government manages these minerals on public lands and other lands under the jurisdiction of the government. Disposal of mineral materials is realized through sale contracts to private users or free use permits to states, counties, or other government entities for public projects. Also, a limited amount of mineral materials may be provided free to non-profit groups.

Grazing Uses

The United States owns public rangelands. Agencies of the United States Government are responsible for management of the natural resources on the surface of the lands for which stewardship has been entrusted to them. Federal agencies manage approximately 255,000,000 acres of grazing lands for domestic livestock use through 10-year permits or leases. In addition, 16 Alaska native corporations who own reindeer graze 5,000,000 acres without charge. The Federal Government does not transfer ownership or control of the rangelands because these public lands, by law, are held for multiple use.

Electromagnetic Spectrum

All sovereign nations own the rights to the electromagnetic spectrum within their boundaries. The U.S. Federal Government assigns the right to use portions of the spectrum to state and local governments and to the private sector for specific purposes. However, the Federal Government does not transfer ownership of the spectrum itself. A significant portion of the spectrum is reserved for defense and other government uses.

Nontraditional Resources

The term "nontraditional resources" is used in this document to categorize other natural resources that are not addressed in any of the other categories of natural resources presented above, but for which a commercial market exits. The principal limitation of reporting information about nontraditional resources individually is the lack of data on them.

The majority of nontraditional resources are non-timber vegetative products that are sold from public lands; however, there are others. Examples of nontraditional resources include Christmas trees and Christmas wreath materials, mushrooms, wild berries, medicinal herbs, cactus, and pine nuts. Through the Federal Government's forest management programs, the rights to remove non-timber vegetative products from public lands are conveyed upon payment of a permit fee to harvest them.

Though many people may question the value of these resources and the amount of revenue they generate, there has been a dramatic increase in public interest and the market for these resources over the past few years. For example, in 1995, less than 1 million pounds of matsutake mushrooms were harvested from national forests, but 1.2 million pounds were harvested during an eight-week period in 1997.

The natural resources identified and briefly described above are individually addressed in the **Reporting by Individual Resources** (Appendix A) of this paper.

Water Rights

Water is a resource that is managed by the states. Each state has its own organization to administer water rights. Interstate water rights are administered by the states, using: 1) an agreement between states which indicates states' rights to use the water, 2) adjudication by the Supreme Court, or 3) Congressional decision. States administer water rights for Federal lands within a state. Federal action can pre-empt this, however, for various reasons, for example: 1) navigability of the water, 2) Federal environmental laws, and 3) Federal hydroelectric dams. However, because water rights are managed by the states, the Federal Government is rarely the owner of water rights and it rarely sells them. As a result, it does not have stewardship responsibility over water rights. Therefore, water rights were ultimately determined to be outside the scope of the natural resource project.

II. Objectives of Natural Resources Reporting

Background

The objectives outlined in Statement of Federal Financial Accounting Concept Statement (SFFAC) No. 1, *Objectives of Federal Financial Reporting*, continue to provide the framework for all projects addressed by the FASAB. In developing objectives for natural resources reporting, the task force used the basis of SFFAC No. 1 to ensure that all of the major objectives were considered for natural resources.

SFFAC No. 1 defines the four major objectives for Federal financial reporting:

Budgetary Integrity:

> Federal financial reporting should assist in fulfilling the government's duty to be publicly accountable for monies raised through taxes and other means and for their expenditure in accordance with the appropriations laws that establish the government's budget for a particular fiscal year and related laws and regulations.

Operating Performance:

> Federal financial reporting should assist report users in evaluating the service efforts, costs, and accomplishments of the reporting entity; the manner in which these efforts and accomplishments have been financed; and the management of the entity's assets and liabilities.

Stewardship:

> Federal financial reporting should assist report users in assessing the impact on the country of the government's operations and investments for the period and how, as a result, the government's and the nation's financial conditions have changed and may change in the future.

Systems and Control:

> Federal financial reporting should assist report users in understanding whether financial management systems and internal accounting and administrative controls are adequate to ensure that
> - transactions are executed in accordance with budgetary and financial laws and other requirements, are consistent with the purposes authorized, and are recorded in accordance with Federal accounting standards;
> - assets are properly safeguarded to deter fraud, waste, and abuse; and
> - performance measurement information is adequately supported.

Based on the above objectives and discussions by the task force, the following major objectives were identified for natural resources reporting. The objectives are presented as those that relate to past performances and those that relate to future management. Reporting on our national wealth is also addressed.

Reporting on Past Performance

Natural resource reporting can report on past performance from a budgetary, operating, or stewardship perspective.

Budgetary integrity:

Financial reporting on natural resources can provide information for decision makers and the public that will be useful in determining whether the entity has complied with laws governing the use of revenues received related to natural resources.

Operating performance:

Financial reporting on natural resources can provide information for decision makers and the public that will be useful in evaluating the reporting entity's costs, accomplishments, and management of its assets and liabilities.

Stewardship:

Financial reporting on natural resources can provide information for decision makers and the public that will be useful in assessing the entity's stewardship of its assets, including whether and to what extent benefits and burdens are passed from present to future taxpayers.

Information that would help meet these objectives include:

- government receipts (revenue) and offsetting collections reported according to their source,
- information about the extent of compliance with the budget and laws (e.g. compliance with any restrictions on the use/distribution of sales revenues).
- the net costs of operating natural resources programs compared with revenues generated,
- the amount (expressed in terms of market value [if available] or physical units) and condition/availability of the entity's natural resources,
- information pertaining to the resources currently leased, licensed for use by others, or otherwise conveyed to others for their use (but not sold),
- annual changes in the amount and condition of the natural resources,
- liabilities arising from the operation of natural resources programs and plans for their liquidation,
- extraction/production/consumption information.
- the value (if available) foregone or the amount of resources restricted by law or administratively and a description of their alternative use (e.g. timber restricted from sale because it is in national parks).

Reporting to Support Future Management

Natural resource reporting could also serve natural resources accounting by providing information relevant to policy decisions about the future management and the disposition of Federal natural resources. Many of the types of natural resource information that might be reported in financial statements are relevant to key policy issues about stewardship and natural resources management. Such policy issues include the following questions:

- What new authorities should be enacted to sell natural resources?
- Under what conditions should commercially valuable natural resources be withdrawn from availability for sale?
- For resources available for sale, when should they be offered and in what amounts?
- What policy or standard should govern the amounts the Government is to receive in return for the resources it sells?

Consideration of such questions by policy makers in the Congress and the Executive Branch and by the interested public may focus on specific resources in specific geographic areas or on policies for managing resources in the future.

Although it may seem that financial reporting could structure relevant information in a manner that facilitates these considerations, there are several important limitations that need to be recognized:

- financial reporting, particularly on balance sheets and the statement of net cost, requires an accuracy that usually does not exist for resources far in advance of their sale;
- financial reporting provides information in the aggregate for an agency, whereas much policy discussion focuses on specific resources in specific areas;
- financial reporting does a better job at organizing information about past transactions than about prospective transactions.

The task force gave careful consideration to the possibilities for providing information of the sort that would facilitate such policy discussions in financial reports in light of these limitations.

Reporting on the National Wealth in our Natural Resources

The possibility has been suggested that Federal accounting practices could assist in providing information on the status of the national wealth that is embodied in our endowments of natural resources. As part of its efforts, the task force received briefings on natural resource information from resource agencies such as the US Geological Survey and the Bureau of Land Management; and from the Bureau of Economic Analysis on the status of efforts to develop Environmental Satellite Accounts to the National Accounts that would display non-renewable resources.[1] The task force also had the benefit of work done by the World Resources Institute on accounting for natural resources in Indonesia and Costa Rica.[2]

The task force concluded, based on its review of this information, that the financial statements of Federal agencies may not be the best way to display information on the natural resource assets of the nation. Several factors support this conclusion. First, although the Federal Government owns significant natural resources, there is no resource category for which the Federal Government is the sole owner of all the resources. Thus, a full accounting for the nation's natural resources could not be produced with information limited to Federally owned resources.

Second, the natural resources owned by the Federal Government have several characteristics that make it difficult to provide a full accounting for them as assets. Most important is the fact that large amounts of natural resources currently have little or no commercial value despite the fact that they may have value at some time in the future. A good example of such a resource is coal (see Figure 2.1). The processes by which some parcels of resources gain sufficient value to be regarded as assets are only partly under the control of the agencies that manage the resources. Most of the processes that can make these resources valuable occur within the context of the markets for the resources and the products to which they contribute. The Federal and State agencies that regulate firms in these markets also have strong effects in determining what parcels of resource become valuable. In addition, in some cases, the benefit to the country through other uses of the land, such as, national parks or wilderness areas, are considered more valuable than commercial development.

Third, the current activities of Federal agencies do not produce comprehensive information about the value of the natural resources owned by the Federal Government. Information on the value of specific portions of Federal natural resource assets is produced as part of the management processes that lead to the sale of those resources; much less is known about the value of resources not being prepared for sale. Ironically, this means that Federal agencies know the most about the value and extent of natural resources parcels just at the time when they leave Federal ownership.

It may be more appropriate to develop an accounting for the nation's natural resource wealth through efforts such as those begun by the Bureau of Economic Analysis or the Interagency Working Group on

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[1] See for example, Survey of Current Business, April 1994, U.S. Department of Commerce

[2] Repetto, Robert Accounts Overdue: Natural Resource Depreciation in Costa Rica, World Resources Institute, 1991. and Repetto, Robert, Wasting Assets: Natural Resources in National Income Accounts, World Resources Institute, 1989.

Sustainable Development Indicators which reports to the Council on Environmental Quality.

Figure 2.1
Example of Coal Resources

The Federal Government is the owner of a very substantial amount of coal resources, located primarily in western states. Of the 1.6 trillion tons of identified coal resources in the U.S., almost 1 trillion tons are in eight western states where about 60% are Federally owned. Because of the "checkerboard" land ownership patterns in the West, most coal mines in the West must combine reserves owned by Federal, State, private and Indian entities. Parcels of Federal coal become commercially valuable when there is a possibility of combining them into a mine with other nearby parcels.

Coal production in 1996 was about 1 billion tons. Assuming that mines generally have sufficient reserves to continue production from 20 to 50 years, only 20 to 50 billion tons of the 1.6 trillion tons are currently associated with operating mines. Of the remaining 1.55 trillion tons, only a small part will become commercially valuable over the next decade or two as new mines are needed to replace mines that have exhausted their reserves. Which parcels will become valuable at what time and at what values depend on variables such as regulation of emissions from coal burning, deregulation of the electric utility industry, and transportation costs.

It is clear from this example, that only a small portion of the Federal Government's coal resources could now be regarded as an asset for purposes of financial reporting. Parcels of Federal coal may become valuable only a matter of years before they are leased by the Department of the Interior. Estimates of their value become available months before leases are sold. These characteristics of coal resources and the processes through which they are managed lead the task force to the conclusion that information about quantities rather than dollar values would be most useful for financial reporting.

III. Context for Analysis -- Framework

Background

To properly address the area of accounting for natural resources, the task force needed a framework for understanding how natural resources are managed. Early in its work the task force recognized that natural resources managed by the Federal Government pass through a series of stages resulting from the sequence of management processes, i.e., decisions and transactions established under the Federal statutes that govern each resource. It was important for the task force to understand these stages, the nature of the information available about the quantity and value of resources at each stage, and the nature of the decisions and transactions that separate one stage from the next in the development of its recommendations.

Figure 3.1 shows a matrix of Federal natural resources stages, which identifies the categories of stocks and flows that are associated with the resources. This matrix was an analytical tool used by the task force to develop a common approach for understanding the various Federal natural resources management processes. The matrix presents the stages and flows closest to producing cash values first and those farthest from producing cash last.

For the most part, natural resources yield value to the Federal Government when the resources are sold or otherwise transferred from the government to the private sector. In some cases, the actual receipt of revenues occurs over a period of time in a manner that is specified to a permit, contract or lease. Further discussions relating to the stages and the stocks and flows of natural resources are presented in the following paragraphs.

Stages

The stages reflect decisions to make resources available for sale or change the status of the resource. The sequence of stages differs somewhat for different types of resources, because of differences in the processes used to manage the type of resource. It should be noted that a specific resource in a specific location may remain in a particular stage indefinitely, or for an extended period of time. The discussion below generally follows the chronological order of natural resources' management processes.

Although our natural resources matrix (see Figure 3.1 on page 16) recognizes an "undiscovered resources" stage, the natural resources management process sequence begins with the basic decision about whether or not the resource will be available for transfer to the private sector. It ends with the actual conveyance of ownership of the resource to a private entity. Once resources have been conveyed to the private sector, they are no longer under Federal management. However, several conveyance transactions require some type of continued Federal intervention. For example, the Bureau of Land Management is responsible for managing on-shore leasing and lease operations and the

Minerals Management Service is responsible for off-shore leasing and lease operations, as well as for collecting and distributing mineral revenues for both on-shore and off-shore minerals. The following stages are typical of Federal natural resources management:

<u>Undiscovered Resources</u>

Undiscovered resources are those resources postulated from geological information and theory to exist outside of known deposits.

<u>Resources Not Available for Transfer</u>

There are two conditions under which resources are not available for transfer. One is because the resources are legislatively withdrawn and the other is because the resources are administratively withdrawn. The two conditions are discussed below.

• Legislatively Withdrawn Resources -- those resources that by law can not be offered for transfer to private entities. Usually the resources are designated by geographical area. Examples include:

- Oil and gas in areas of the OCS under Congressional leasing moratoria.
- Timber and mineral resources in Wilderness Areas, National Parks, and Recreation Areas.
- Oil and gas in the Arctic National Wildlife Refuge.
- Coal resources in alluvial areas.
- Locatable minerals in wilderness areas.

• Administratively Withdrawn Resources -- those resources in areas which by law could be offered for transfer to private entities, but which have been administratively withdrawn. Such resources could be made available for future transfer by administrative decision without change in law. Examples include:

- Oil and gas resources in areas of the OCS not included in an approved 5-Year Leasing Program.
- Resources in Marine Sanctuaries that cannot be extracted or used under the conditions of the sanctuary designation.
- Resources in National Monuments that cannot be extracted or used under the conditions of the monument designation or management plan.
- Timber resources in conservation areas.
- Locatable minerals in scenic or recreational areas.

<u>Resources Available for Transfer</u>

There are three conditions under which resources are available for transfer. The three conditions are discussed below.

• Resources Planned to be Offered -- those resources for which it has been determined that specific types of resources in specific locations or within specific areas will be made available for transfer to private entities. Examples include:

- Oil and gas resources in areas selected for lease sales.
- Timber in areas to be included in planned timber sales.
- Areas open to claims under the Mining Law of 1872.

• Resources Under Contract but Not Conveyed -- those resources for which a prior transaction or process has resulted in a contract or other legal obligation under which Federal natural resources of a particular type and at a particular location will be conveyed to a private entity at some future time. Resources in this stage are still owned by the Federal Government and are expected to yield future revenues. Examples of resources under contract but not conveyed include:

- Oil and gas resources in tracts currently under lease under the OCS Lands Act.
- Timber in timber sale areas for which contracts have been sold.
- Locatable minerals in areas for which claims have been filed under the Mining Law of 1872.

• Other Available Resources -- those resources which are neither restricted by law nor administratively withdrawn, are outside of areas for which there are contracts to convey a resource, and are outside of areas for which the determination has been made to offer the resource for sale. Examples include:

- Unleased oil and gas resources in OCS planning areas in an approved 5 Year leasing program, but outside of areas in proposed lease sales.

<u>Conveyed</u>

Conveyance occurs when the ownership of the resource actually transfers from the government to a private entity. In many cases, a contract, lease or permit is sold or issued through an earlier transaction or transfer process. In some cases a consideration is paid at the time of this transaction as well as at the time the resource is conveyed to the private entity. In other cases, payment is made only when the resource is conveyed. In a few cases, the conveyance occurs without a prior contract.

Stocks and Flows

The stages identified above can be thought of in relationship to stocks and flows of resources. Whenever a decision is made or a transfer occurs, a flow results, which reduces the stock of the resource in one stage and increases the stock of the resource in another stage. In some cases a financial transaction and flow accompany the flow of resources from one stage to another. The final flow is the conveyance of the resource from Federal to private ownership.

At each stage, it is possible in principle to measure natural resource assets in both physical and financial terms. In practice, however, there are uncertainties about one or both types of measures, particularly in the early stages of management. Obviously, the greatest certainty occurs at the point in time when the resource is extracted and marketed. At this point, both the physical and financial measures of the resource are well known. Prior to that point, there are uncertainties that affect the ability to value a resource. Note that the conveyance of natural resources to the private sector is the primary flow associated with cash transactions.

Figure 3.1
Natural Resources Stages

<table>
<tr><th rowspan="3">STAGE</th><th colspan="2" rowspan="2">STOCKS</th><th colspan="6">FLOWS</th></tr>
<tr><th colspan="2">Increases & Decreases Due to Transfers (Government actions and transactions)</th><th colspan="2">Other Increases & Decreases *</th><th colspan="2">Extraction & Use</th></tr>
<tr><th>Physical</th><th>Financial</th><th>Physical</th><th>Financial</th><th>Physical</th><th>Financial</th><th>Physical</th><th>Financial</th></tr>
<tr><td>Conveyed</td><td colspan="2">Not applicable</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Available

Under contract but not conveyed</td><td></td><td></td><td></td><td></td><td></td><td></td><td colspan="2" rowspan="7">Not Applicable

Not Applicable</td></tr>
<tr><td>Planned to be offered</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Other Available</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Not Available

Administrative Withdrawal</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Legislative Withdrawal</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Undiscovered Resources</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

* Changes in estimated amounts or financial value of the resources due to technological developments, improved information, natural processes or market processes.

IV. General Reporting Principles

Background

In the process of developing the general reporting principles, the task force was faced with three major issues or questions. They were:

- Should a value be reported for natural resources? If so, at what point in time should a value for natural resources be reported? Should this reporting occur in the principal financial statements or elsewhere, such as, an accountability report?

- How should the revenue generated from the sale of natural resources be accounted for and reported?

- How should the costs associated with the ownership and sale of natural resources be accounted for and reported?

In general, the task force concluded that the primary mechanism for reporting information about the natural resource assets under an agency's management should be stewardship reporting. Stewardship reporting would allow an agency to report meaningful and complete information about natural resources for sale, as well as resources that are not available for sale (e.g., due to legislative and administrative withdrawals.)

The task force concluded that valuation of assets for purposes of Balance Sheet presentation would require assurance of the intended commercial use of the asset. Where the Federal Government is not assured that the asset will be used for commercial purposes, there is no basis for determination of the commercial value. Therefore, until a natural resource is placed on the commercial market (i.e., offered for sale) and the value is know (i.e., an actual offer is received), assurance cannot be made that the asset will be sold for commercial use.

The task force did, however, determine that the Federal Government has the responsibility to report natural resources that may be sold for commercial use and other data related to natural resources for which the Federal Government has stewardship responsibility. The task force believes that stewardship reporting would be the most effective way to discharge this reporting responsibility.

The task force did not reach a consensus on how revenue generated from the sale of natural resources should be recognized. The following two options discussed by the task force are provided in more detail later in this chapter for your consideration.

- Reporting all natural resource revenues on the Statement of Custodial Activities and

- Reporting all natural resource revenues on the Statement of Net Costs.

In relation to costs associated with the ownership and sale of natural resources, the task force reached specific conclusions on each type of cost. These conclusions are in accordance with SFFAS No. 4, *Managerial Cost Accounting Concepts and Standards for the Federal Government*.

Detailed discussions are provided on the pages to follow on:

- reporting information about natural resource assets,
- accounting and reporting revenues,
- accounting and reporting for costs, and
- prices set by law or regulators.

Appendix A, **Reporting by Individual Resource**, discusses the current accounting treatment and issues for each type of natural resource addressed by the task force.

Reporting Information about Natural Resource Assets

Within the existing scope of Federal accounting and reporting, there are multiple options for reporting information about natural resources owned by the Federal Government. Different options may be possible for a given natural resource according to the "stage" of the natural resource identified (i.e., undiscovered resources, not available for transfer, available for transfer, conveyed). Separate reporting options might also be chosen for various natural resources due to differences in the terms of sale or the attributes of natural resources. In addition, multiple options may be chosen for a single category of a resource (e.g. resources identified for sale might be both recognized and discussed in a footnote).

As illustrated in the Chart below, the options available to an entity for reporting information about natural resources include recognition of an asset in the accounting records of an agency, footnote disclosure, other reporting vehicles, and even silence (i.e., no reporting at all.) Each of these reporting options has specific advantages and disadvantages. A description of each reporting option follows the Chart.

<table>
<tr><th colspan="6">Reporting</th></tr>
<tr><th>Recognition</th><th>Disclosure</th><th colspan="3">Other Reporting</th><th>No Reporting</th></tr>
<tr><td>Principal Financial Statements</td><td>Footnotes</td><td>Stewardship Reporting</td><td>MD&A (Overview)</td><td>Other Reported Information</td><td>Silence</td></tr>
</table>

• Recognition -- Reporting of information in the principal financial statement when an accounting entry with a specific dollar amount is posted to an account in the entity's general ledger. The principal financial statements of the entity represent a summary of all of the general ledger accounts of the entity at a point in time. Recognition is only possible when the transaction is measurable in dollars and the amount can be reasonably estimated.

• Disclosure -- Disclosure refers to the reporting of information in the notes (footnotes) to principal financial statements. This information should be concise and either provides additional information about transactions recognized in the principal financial statements or explains why certain data or transactions may have been excluded from recognition. Footnote disclosure is regarded as an integral part of the basic financial statements.

• Other Reporting -- A reporting option used in this document to identify other mechanisms of reporting information about natural resources, in lieu of the principal financial statements. Included are:

- Stewardship Reporting -- Additional reporting used to provide more extensive information that is critical to understanding a reporting entity's financial condition, but which cannot be measured in purely financial terms and which cannot be adequately addressed by concise footnotes.

- Management's Discussion and Analysis -- Additional reporting used to provide a clear and concise description of the reporting entity and its mission; activities, program, and financial results; and financial position.

- Other Reported Information -- Other reporting mechanisms used to report relevant information not reported in any of the previously identified reporting options. Examples include required supplementary information (RSI) and other accounting information (OAI).

• No Reporting -- There are instances where nothing will be reported about some types of natural resources. These would include natural resources not included in the scope of this project (e.g., air, stock of game, fisheries, and wildlife habitat). This may be because the information about the natural resource is insignificant, immaterial, or too speculative, or because the natural resource is beyond the scope of required reporting. However, as conditions and/or information about these types of natural resources change, the reporting requirements for them can be revisited.

General Discussion

After reviewing all of the alternatives for reporting information about natural resources and the reporting requirements or principles for each, the task force determined that three options would be most likely to satisfy the natural resources reporting objectives. The three options considered and examined in detail were Recognition, Disclosure, and Stewardship Reporting. The task force believed that the other available reporting options--MD&A and other reported information--were not mechanisms intended to provide the amount of detail and/or focus on specific information that could be provided by recognition, disclosure, or stewardship reporting. For each of the three reporting options that was determined to be most likely to satisfy the natural resources reporting objectives, the paragraphs below contain a general discussion, an analysis of reporting alternatives, a suggested reporting principle, and the advantages and disadvantages of the suggested principle. Although the task force found it necessary to reach a conclusion in each area, it is aware that the Board, during its own deliberations, may not reach the same conclusion.

1. Recognition

Various Statements of Federal Financial Accounting Standards provide a definition for assets. The definition states that assets are tangible or intangible items owned by the Federal Government that would have probable economic benefits that can be obtained or controlled by a Federal Government entity. The term recognition (or recognize), as used in Statements of Federal Financial Accounting Standards, means the process of formally recording or incorporating an item into entity accounts to be reported in the financial statements as an asset, liability, revenue, expense, or the like. In theory, recognition is only possible when the transaction recording an item is measurable in dollars and the amount can be reasonably estimated.

Analysis of Recognition Alternative

Presented below are various points in time that were considered for recognizing a natural resource on the Balance Sheet. The points in time that were considered are:

- when discovered,
- at certain points prior to sale, and
- at time of sale.

a. Recognition when Discovered - The task force discussed Balance Sheet recognition of natural resource assets extensively. One of the alternatives considered was to recognize natural resources on the Balance Sheet as assets when their existence became known. However, briefings provided by various resource experts impressed upon the task force that the difficulty in reasonably estimating the quantity and value of natural resources impacts the ability to recognize these resources on the Balance Sheet. If these estimates were recognized, they may be likely to distort the Statement of Net Cost, as discussed more fully below. Thus, while natural resources should be properly recognized when they fall under existing standards, (e.g. the acquisition of helium for future sale is covered by SFFAS #3), they should also, as a general rule, be reported as stewardship information to provide a complete picture of natural resource activity and status.

b. Recognition at Certain Points Prior to Sale - The task force considered recognizing some natural resource assets when it becomes possible to estimate quantities to be offered for sale and the related market price. For example, there are two possible points when enough information is available prior to sale when the financial value of certain resources (e.g., timber and mineral materials resources) might be reasonably estimable. Specifically, these points are when:

- the natural resource is identified as "planned to be offered" -- At this point, the agency has determined that specific types of resources in specific locations will be made available for sale.

- the natural resource is under contract but not conveyed -- At this point, the quantity to be sold is reasonably certain, however the market price may fluctuate depending on when the resource is actually extracted or harvested. For example, timber is often placed under contract for sale months or years in advance of the actual cutting (and "conveyance") of the timber.

In both of these cases, the estimated value would be based on the potential sale price of the asset. However, in reviewing these options, the task force considered the impact that Balance

Sheet recognition of the sales value of a resource would have on the Statement of Net Cost. For example, if a resource is capitalized based on its future sale value, and the entity incurs any costs associated with the sale, the Statement of Net Cost would reflect a "loss" to the government on that transaction, regardless of whether the government conducted that transaction efficiently. Thus, this approach would misstate the value of the natural resource as recorded on the Balance Sheet by at least the amount of the sale costs.

In addition, while considering this alternative, the task force also considered "discounting" the sale value in some way, but found no reliable method to accomplish this. Specifically, the task force noted:

- Valuation of a natural resource based on discounted sales value would require numerous assumptions and estimates, making the range of possible values large and subject to wide fluctuations; and
- The use of an estimated asset value could cause distortions in the "Cost of Sales" and the "Net Cost of Operations" line items on the Statement of Net Cost.

c. Recognition At Time of Sale - The closer you get to the selling point, the better the estimate you can make as to how much you will get for the sale of a resource. As noted above, for most resources, the quantity and market value cannot be reasonably estimated prior to the point at which the asset is sold. Therefore, there is no relevance in recognizing the asset on the Balance Sheet at the time of sale.

Suggested Reporting Principle

Although the task force believes that the value of natural resources available for sale is important information that should be available to the user of financial statements, it was concluded that Balance Sheet recognition is not the most effective or reliable method of communicating this information. Rather, this information should be reported in the Notes to the Financial Statements and as stewardship information. Further, for entities with significant natural resources, a line with no dollar amount could be placed on the Balance Sheet to direct readers to the footnote reference. If a resource sale results in a large net profit in a given year, this should be explained in a footnote to include information about prices and quantities sold.

Advantages:

- Reporting is reliable and large fluctuations are minimized.
- Reporting is clear and not misleading.
- Management's discretion on the reported amounts is minimized.
- Reported amounts are accurate and verifiable.

Disadvantages:

- There is no recognition of assets available for sale.
- No reporting is provided on the face of the financial statements, although full reporting is obtained through the footnotes and stewardship reporting.

2. Disclosure

Disclosure refers to the reporting of information in the notes (footnotes) to principal financial statements. Footnotes traditionally include information necessary to understand the amounts presented on the principal financial statements, as well as information about any items that would be included in the financial statements if quantifiable financial information about the item where available.

Analysis of Disclosure Alternatives

Footnote disclosure is intended to enable the financial statement user to better interpret and assess the information contained in the financial statements. Generally, information presented in the footnotes tends to be precise, objective, verifiable, and historical. Information in the footnotes may include items such as:

- Qualitative information about items recognized in the financial statements.
- Quantitative information about items recognized in the financial statements.
- Information about items not recognized in the financial statements.

Suggested Reporting Principle

The footnotes could be used to convey information necessary for understanding natural resources. Footnote disclosures are intended to specifically include information about what has been presented on the face of financial statements as well as what has been excluded. In addition, footnotes could be used to refer the reader to stewardship reporting for more complete information.

Advantages:

- Disclosures are complete and informative.
- A clear link between Balance Sheet and stewardship reporting is provided.

Disadvantages:

- Information may appear in two locations (i.e., footnotes and stewardship reporting), with some duplication of information.

3. Stewardship Reporting

Stewardship reporting is used to present discussion, charts, graphs and other financial and nonfinancial information necessary for the reader's understanding of the resources entrusted the Federal Government and the reporting entity.

Analysis of Stewardship Reporting Alternatives

Stewardship reporting is a fairly new reporting vehicle, and the content of this type of reporting is still under development. However, stewardship reporting would generally be lengthier and include more analysis, interpretation, and discussion than the footnotes. Stewardship reporting would include information to highlight the long-term nature of natural resources and to demonstrate accountability over the items reported.

The Stewardship information may include any or all of the information listed below.

- Information on resources available for sale, including:

  -- Estimated quantity of the resource available for sale
  -- Changes in quantity during the period in total and by status (e.g., available for sale, withdrawn, etc.)
  -- Existing plans for sale
  -- Method for determining prices, (e.g., market price or regulation)

- Information on limitations and restrictions on sale, including Legislative and Administrative Withdrawals (acres and discussion):

  -- Quantities related to administratively and legislatively withdrawn resources would be reported only when that information is available and relevant to current circumstances and decisions (e.g., mineral resources under existing national parks would not be estimated or disclosed).

- Deferred maintenance estimates and assessment of condition (e.g., rangeland used for grazing)

- Other relevant information and discussion

Suggested Reporting Principle

Stewardship reporting could be used as the primary tool for reporting natural resource information. It is expected that stewardship reporting would provide a complete assessment of the natural resources of an agency, even if some of this information is also disclosed in the footnotes.

Advantages:

- Provides management with the flexibility necessary to ensure a complete assessment of natural resources.
- Provides the ability to display non-financial data, that may or may not be linked to financial data.
- Provides the ability to use graphics, charts, and other visual aids.
- Allows reporting even when management's knowledge is incomplete, for example when quantities or potential values are unknown.
- No single measure is necessary.
- Full reporting is provided even though a single measure of financial position does not exist.
- Data is provided within existing reporting framework.

Disadvantages:

- Data is not provided in a principal financial statement (therefore, the balance sheet may not provide a complete picture of financial position.)

Accounting and Reporting for Revenue

General Discussion

Revenue is an inflow of resources that the government demands, earns, or receives by donation. Revenue arises from exchange transactions and nonexchange transactions[3]. Exchange revenue is an inflow of resources to a government entity that the entity has earned. It arises from exchange transactions in which each party to the transaction sacrifices value and receives value in return. Such revenue should be recognized at established prices when services are performed or rendered or when goods from inventory are delivered. The following two paragraphs from SFFAS 7 outline the recognition of exchange revenue.

> Exchange revenue should be recognized in determining the net cost of operations of the reporting entity during the period. The exchange revenue should be recognized regardless of whether the entity retains the revenue for its own use or transfers it to other entities. Gross and net cost should be calculated as appropriate to determine the costs of outputs and the total net cost of operations of the reporting entity. The components of the net cost calculation should separately include the gross cost of providing goods or services that earned exchange revenue, less the exchange revenue earned, and the resulting difference. The components of net cost should also include separately the gross cost of providing goods, services, benefit payments, or grants that did not earn exchange revenue.
>
> The net amount of gains (or losses) should be subtracted from (or added to) gross cost to determine net cost in the same manner as exchange revenue is subtracted. Exchange revenue that is immaterial or cannot be associated with particular outputs should be deducted separately in calculating the net cost of the program, suborganization, or reporting entity as a whole as appropriate. Nonexchange revenues and other financing sources should not be deducted from the gross cost in determining the net cost of operations for the reporting entity.[4]

All sales of natural resources or the rights to use natural resources are exchange revenues of the Federal Government. The government may sell:

- the resource itself (e.g., timber, extracted oil and gas),

[3] Nonexchange revenues arise primarily from exercise of the government's power to demand payment form the public (e.g., taxes, duties, fines, and penalties), but also include donations. Nonexchange revenue should be recognized when a specifically identifiable, legally enforceable claim to resources arises, to the extent that collection is probable and the amount is measurable.

[4] SFFAS 7, paragraphs 43 & 44.

- the right to search for the resource in a specific location for a specific period of time (e.g. a mineral lease), in this case, the resource itself is not sold until extracted,
- the right to use the resource for a period of time, with ownership of the resource remaining with the government at all times (e.g. electromagnetic spectrum, land for grazing), or
- the land containing the resource, irrespective of the presence or absence of natural resources (e.g. 1872 mining law).

During the task force discussions, the issue of natural resource revenue recognition was heavily debated. The discussions were primarily focused on the fact that SFFAS No. 7, *Accounting for Revenue and Other Financing Sources and Concepts for Reconciling Budgetary and Financial Accounting*, provides an exception for entities, such as the rents and royalties collected by the Minerals Management Service (MMS) on the Outer Continental Shelf, that recognize "virtually no costs" (either during the current period or during past periods) in connection with earning revenue that it collects.

SFFAS 7 states that:

> The collecting entity should not offset its gross costs by such exchange revenue in determining its net cost of operations. If such exchange revenue is retained by the entity, it should be recognized as a financing source in determining the entity's operating results. If, instead, such revenue is collected on behalf of other entities (including the U.S. Government as a whole), the entity that collects the revenue should account for that revenue as a custodial activity, i.e., an amount collected for others.

The following excerpts are from the SFFAS 7 Basis for Conclusions that explains the Board's reasoning for this revenue recognition exception.

> Matching revenue with cost in a uniform manner is essential in evaluating agency performance and setting price. Cost and revenue must pertain to the same output in order to estimate the extent to which the revenue covers the cost. Therefore, costs should be matched against the provision of goods and services with revenue matched against those costs and thus with revenue also matched against the same provision of goods and services. When this is done, the gross and net cost of an entity can be compared with the related outputs and outcomes to evaluate its operating performance, pricing policy, and economic decisions. Similarly, when this is done, the net cost to the taxpayer can be estimated for the entity's related outputs provided to the public. *(Par 118)*
>
> In exceptional cases, an entity may recognize virtually no costs in connection with earning exchange revenue that it collects. A major example for many years has been the Minerals Management Service (MMS) of the Department of the Interior. It manages energy and other mineral resources on the Outer Continental Shelf (OCS) and collects rents,

royalties, and bonuses due the Government and Indian tribes from minerals produced on the OCS and other Federal and Indian lands. The rents, royalties, and bonuses are exchange revenues, earned by sales in the market. If the value of natural resources were recognized as an asset by MMS, then depletion could be recognized as a cost according to the units of production method as minerals were extracted. The revenue from rents, royalties, and bonuses could then be matched against MMS's gross cost, including depletion and minor other costs, to determine its net cost of operations. *(Par 140)*

MMS does not recognize a depletion cost for various reasons, including the fact that under present accounting standards the value of natural resources is not recognized as an asset. As a result, this exchange revenue cannot be matched against the economic cost of operations and bears little relationship to the recognized cost of MMS. Therefore, it should not be subtracted from MMS's gross cost in determining its net cost of operations. If it were subtracted, the relationship between MMS's net cost of operations and its measures of performance would be distorted. The net cost of operations of the Department of the Interior would likewise be distorted. *(Par 141)*

Views similar to the above Basis for Conclusions on the recognition of some Federal natural resource revenues are also expressed in Appendix B of this document, *Minority Comments on General Reporting Principles*.

Based on its discussions, the task force did not reach a consensus on how revenue generated from natural resources should be reported. They did agree that the standards created for recognizing and reporting natural resource revenue should reflect consistent treatment so that any natural resource revenue that may be encountered by a Federal agency will be treated in a similar manner. Therefore, the task force provides, for consideration, two options that were proposed and discussed by members of the task force. The two options are as follows:

- reporting all natural resource revenues on the Statement of Custodial Activities and
- reporting all natural resource revenues on the Statement of Net Costs.

Each of the above options is further discussed in the following paragraphs.

Option 1: *Reporting All Natural Resource Revenues on the Statement of Custodial Activities*

As noted above, SFFAS No. 7 requires that entities such as the Minerals Management Service report the revenues collected as rents and royalties on the Outer Continental Shelf (OCS) as a custodial activity. These revenues are reported on the Statement of Custodial Activities because the entity "recognizes virtually no costs in connection with the revenue collected." Based on research by the task force, it was determined that many other natural resource revenues are reported on the Statement of Net Cost of Operations. The task force discussed the option of recognizing all natural resource revenues that are collected and are used to finance the Government as a whole or programs of other entities rather than their own activities, on the Custodial Statement.[5]

The Custodial Statement is designed to match collections for others against the disposition of collections, and the primary focus of the Statement is the tracking of non-exchange tax revenue. The Custodial Statement in its current format does not allow for the presentation of natural resource revenues matched against those costs associated with managing and selling the natural resource. Any attempt to match direct costs against revenues on this Statement would require significant changes to content and presentation of the Statement as well as the Statement of Net Cost if costs were removed from it.

However, the option to report all natural resource revenues on the Custodial Statement would allow for consistency in reporting natural resource revenues of the Federal Government. See **Attachment A** for the task force's suggested changes to SFFAS No. 7 that would specifically require all natural

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[5] According to SFFAC No. 2, *Entity and Display:* A separate statement of custodial activities would be appropriate for those entities whose primary mission is collecting taxes or other revenues, particularly sovereign revenues that are intended to finance the entire Government's operations, or at least the programs of other entities, rather than their own activities. The revenues should be characterized by those agencies as custodial revenues. The statement should display the sources and amounts of the collections of custodial revenues, any increases or decreases in amounts collectable but not collected, the disposition of the collections through transfers to other entities, the amounts retained by the collecting entity, and any increase or decrease in the amounts to be transferred.

resource revenues to be reported as a custodial activity.

Option 2: *Reporting all natural resource revenues on the Statement of Net Costs.*

Revenue earned from the sale of natural resources is exchange revenue and costs are incurred by agencies to manage the assets and the programs that produce these revenues. The task force noted three elements of "cost of sales" to be considered when comparing the costs associated with a natural resource with the proceeds from the sale of that resource. All of these costs are reported on the Statement of Net Cost. The costs are:

- the cost of the natural resource to the government;
- the costs of managing the resource; and
- the costs of selling the resource.

In most cases, no direct, identifiable cost to the government is associated with acquisition of natural resources. There was some variability in the extent of natural resource management costs. However, those agencies that did incur management costs normally incurred those costs as part of the agency's overall stewardship responsibilities and would have incurred at least some portion of those costs even if no natural resources were sold. Cost of selling is normally incurred near the time of the earning of revenue, but these costs do not normally have a direct relationship to the revenue earned. Thus, on the whole, the revenue earned on the sale of any natural resource cannot be directly attributable to the costs associated with the acquisition, management, and selling of that resource. Rather, the revenue earned from the sale of any natural resources is generally dependent upon some combination of market value and regulatory requirements. For most Federal agencies, revenue generation is one of several goals of natural resource management, and general management costs cannot be directly assigned to natural resource sales. However, the revenue from the sale of natural resources is related to the agency operations and is related to the costs incurred in agency operations.

The natural resource asset itself may not have an acquisition cost that is comparable to its sale price. Many believe that presenting natural resource revenue on the Statement of Net Cost will distort this Statement. However, due to this lack of "acquisition costs," the reader should understand the nature of the sales transaction regardless of where the revenue is presented in the financial statements.

The natural resource revenues earned by various Federal agencies are fundamentally the same, that is, something of value is sold at a price. Currently, most natural resource revenues appear as revenue in the Statement of Net Costs of the agency that earns the revenue. However, according to SFFAS 7, under exceptional circumstances, such as oil and gas royalty and lease revenues collected by the Minerals Management Service, an entity that recognizes virtually no costs in connection with earning the revenue it collects should report that revenue on the Statement of Custodial Activity. All agencies incur some costs related to managing and selling the resource. However, the amount of identifiable cost that can be directly associated with the revenue stream may vary significantly according to the nature of the asset and the management goals of the agency. In some cases these costs are significant in comparison to revenue generated (e.g. USFS Timber sales), while in other cases the costs are minuscule (e.g. sale of pine nuts and other miscellaneous vegetative products by the Bureau of Land Management). However, there is no substantive difference in the nature of the different types of natural resource revenue (i.e., both oil and gas lease revenue is fundamentally the same as timber sales).

Since these exchange revenues are earned via agency operations, they should be reported on a statement that is linked with the other principal financial statements. Under current accounting standards, the assets, liabilities, and equity are reported on the Balance Sheet, and the flow accounts are reported in total on the Statement of Changes in Net Position. A portion of these flow accounts (expenses and exchange revenue) is presented in more detail on the Statement of Net Cost. Currently, the Statement of Net Cost is the reporting vehicle for exchange revenue, and the Statement of Custodial Activity is essentially a “memorandum” Statement that does not link directly with the other basic financial statements.

For example, the fiscal year 1997 government-wide consolidated financial statements disclose costs of $29.1 billion and revenue of $1.9 billion for “Natural Resources and Environment.” These amounts do not include the $6 billion from the sale and lease of Outer Continental Shelf resources. The fact that natural resources provide a revenue stream to the Federal Government and partially offset the cost of managing those resources for the nation is not disclosed to the reader. Likewise, at the agency level, it is true that the Minerals Management Service spends approximately $250 million per year to manage resources and sales activity that result in an inflow to the Federal Government of several billion dollars. The public should be aware that this particular activity of the Federal Government results in a gain, in cash terms. Of course, the MMS report, as with all other reports disclosing significant natural resource revenue, would include disclosures about the fact that the resources sold do not have an “acquisition cost” and so the reported gain should be considered in relationship to the depletion of natural resource reserves.

Based on the above discussion, the task force developed an option to eliminate the exception in SFFAS 7, paragraph 45. The existing Statement of Net Cost of Operations would then accommodate all natural resource reporting, both at the entity level and the consolidated statement level.

As illustrated below, presentation changes on the Statement of Net Cost would involve adding a subtotal to clearly separate natural resource revenues from the cost of operations not directly related to the sale of natural resources. In this way:

- all exchange revenues would be presented on one statement;
- costs of selling directly attributable to the natural resources revenues could be matched with that revenue without removing these costs from the Statement of Net Costs ;
- revenues would be presented on the same statement as the costs incurred to manage the related assets, although not directly matched against those costs; and
- net costs associated with agency operations would continue to be clearly identifiable.

Sample Statement of Net Cost

Operation of Agency Programs	
Operating Expenses	xxxx
Revenues Related to Operations	xx
Net	xxxx
Other Gains and Losses	xx
Net Cost of Agency Operations	xxxx
Other Programs	
Direct Sales and Management Costs	xxxx
Less: Natural Resource Revenue	x
Net Results of Other Programs	xxxx
Net Results of Federal Programs	x

Accounting and Reporting for Costs

General Discussion

The concepts of managerial cost accounting, presented in SFFAS No. 4, *Managerial Cost Accounting Concepts and Standards for the Federal Government*, describe the relationship among cost accounting, financial reporting, and budgeting. The five standards presented in SFFAS No. 4 set forth the fundamental elements of managerial cost accounting: (1) accumulating and reporting costs of activities on a regular basis for management information purposes, (2) establishing responsibility segments to match costs with outputs, (3) determining full costs of government goods and services, (4) recognizing the costs of goods and services provided among Federal entities, and (5) using appropriate costing methodologies to accumulate and assign costs to outputs.

These standards are based on sound cost accounting concepts and are broad enough to allow maximum flexibility for agency managers to develop costing methods that are best suited to their operational environment. Also, the managerial cost accounting standards and practices will evolve and improve as agencies gain experience in using them.

Analysis of Accounting and Reporting for Costs Alternatives

Various types of cost were identified by the task force during its examination of costs associated with natural resources. The types of cost that were discussed were:

- Cost of Resources Sold
- Cost of Selling
- Cost of Management
- Transfer of Revenue/Distribution of Receipts

The cost, a suggested reporting principle, and advantages and disadvantages for the suggested reporting principle are presented in the following paragraphs for each type of cost.

1. Cost of Resources Sold

   The possible options for the recognition of "cost of resources sold" are dependent upon whether the natural resource has or has not been previously recognized as an asset. If an asset has been recognized on the Balance Sheet, that asset must be removed from the Balance Sheet at time of sale resulting in an expense on the Statement of Net Cost. If natural resources are not capitalized, there is no capital consumption type cost associated with the sale of natural resources. Presently, most natural resources are not capitalized by reporting entities on the Balance Sheet because of the difficulty in reasonably estimating the quantity and value of natural resources.

The agencies' lack of reliable measures of acquisition costs of natural resources can be attributed to one or more of the following reasons:

a. The natural resources were acquired as a result of the Federal government's sovereign powers, e.g., the radio spectrum.
b. Acquisition costs were fully expensed at time of purchase and historical records no longer exist and/or are not relevant for Balance Sheet valuation.
c. Agencies would have to utilize large amounts of resources to survey large tracts of land to estimate the value of natural resources that are costly to locate and whose values are uncertain.
d. There are no recent market transactions that provide an objective measure of the specific natural resource's value.

As a result the cost associated with a natural resource valuation cannot be determined with accounting precision.

Thus, the agencies' gross costs during a fiscal year would be their administrative costs, selling costs, and the market value of the rights to natural resources that generated exchange revenues during the same fiscal year. In effect, in cases where the rights to natural resources are sold for market value, the exchange revenue and the gross costs would increase by the same amount, and the net costs would only reflect the much smaller administrative and selling costs of the agency. However, this approach would be likely to cause substantial distortions in the Balance Sheet and the Statement of Net Costs to handle the treatment of the acquisition cost based on the changing market value of assets reported.

Consequently, most methods of imputing a "cost of goods sold" would, in one form or another, merely match the sales price against itself. To report reliable information, when comparing the inherent value of resources sold against the value received, will require reporting beyond the presentation of one simple number, which can best be done in a footnote or stewardship information.

<u>Suggested Reporting Principle</u>

The cost of resources sold should reflect the removal of previously recognized assets from the Balance Sheet, but should not be “imputed” when no such value exists.

Advantages:

- This approach would minimize manipulation of the Statement of Net Cost (since the imputed value of assets sold would be subject to numerous assumptions).
- Known information about the value of natural resources sold as compared to value received would be reported in the text of the footnotes and/or stewardship report.

Disadvantages:

- The Statement of Net Cost does not recognize the value of natural resources sold.

2. Cost of Selling

The cost of selling consists of costs incurred for sale preparation and for activities that occur over the period of the sale of the natural resource. These costs include development of resource plans (e.g., 1 year, 5 year, 10 year) and environmental impact analysis prior to offering the resource for sale, and the costs of offering and awarding the resource sales. Currently, these costs are usually expensed in the period they are incurred. The alternative would be to capitalize and amortize these costs over the period that revenue is generated.

> **NOTE**: Prior to FY 1993, one reporting entity capitalized the costs associated with the sale of a particular natural resource and expensed the cost over the life of a sale contract. This methodology was developed by the reporting entity in conjunction with GAO as directed by the Congress. However, due to problems with a subsidiary system that was a feeder system for financial statement purposes, the entity's IG strongly advised the entity to discontinue using the subsidiary system as a feeder system. As a result, certain costs could no longer be capitalized and amortized over the life of a contract.

Suggested Reporting Principle

Accounting for the cost of selling natural resources should follow the general principles of SFFAS No. 4.

Advantages:

- Costs are matched with revenue.
- Costs of programs and the Net Cost are more complete and accurate.

Disadvantages:

- Since this approach may require change in reporting entities' accounting policies, it may take time to implement

3. Cost of Management

The cost of managing natural resources which will eventually be sold tend to be indistinguishable from the costs of managing other resources or carrying out legislatively mandated missions. For example, the land management activities of the Bureau of Land Management benefit both revenue producing and non-revenue producing lands.

In limited cases, such as timber management in areas designated for sale, it may be possible to separate management costs between those that benefit resources to be sold from those that benefit resources in general. On the other hand, the Bureau of Land Management manages its rangeland for multiple uses, including grazing, recreation and preservation, and any management activities performed would continue regardless of whether portions of the land are leased for grazing. In this case, no portion of this management cost should be allocated to “cost of goods sold”.

However, in identifying costs to match against future revenue, management must bear in mind the extent to which those costs are incurred because of the agency’s responsibility to manage the resources entrusted to it. Costs that are part of an agency’s stewardship responsibility that are not intended to increase the flow of future revenue should not be matched against revenue. For most agencies, revenue production is a byproduct of natural resource management, and the Statement of Net Cost should clearly reflect the cost of the agency’s primary mission (stewardship) rather than a secondary mission (revenue production). No costs should be capitalized and matched against revenue unless those costs were intended to enhance future revenue streams rather than to fulfill the agency’s stewardship responsibility.

In accounting for the cost of managing natural resources, the choices include expensing the cost in the period or capitalizing the cost to match it against future sale.

Suggested Reporting Principle

Costs that are intended to enhance future revenue should be considered costs of selling as discussed in the previous section. Accounting for the costs of managing natural resources should follow the general principles of SFFAS No. 4.

Advantages:

- Program costs are complete, accurate and clearly report the agency's operating activity and primary mission.
- Costs incurred during the period are presented in that period and are not hidden as capitalized assets.

Disadvantages:

- Net revenue may be overstated if a portion of management costs improved the revenue flow.

4. <u>Transfer of Revenue/Distribution of Receipts</u>

In many cases, the agency that earns exchange revenue must transfer some or all of the proceeds to other Federal agencies. In addition, under law, many Federal agencies must share the proceeds of grazing, timber sales and other natural resource sales with state and local governments. This "sharing" of revenue represents an outflow of resources from the Federal Government as a whole. In these cases, the revenues are earned from assets that are owned by the Federal Government. The sharing occurs under legislation or other provisions, but is essentially a voluntary transfer to state and local governments by the part of the Federal Government.

In limited cases, the underlying assets are actually owned by the other party (e.g. Indian lands held in trust by the Federal Government). In these cases, the Federal Government has no revenue for the collections or expense for the transfer out, but merely acts as agent for the other party.

The treatment of the transfers, especially transfers outside the Federal Government, is a critical component in the analysis of government sales activity. There is an ongoing political debate over whether the government "loses money" on revenue transaction due to legislative requirements to transfer a portion of the proceeds to state and local governments.

As provided in SFFAS No.7, transfers between Federal agencies are currently recognized as "transfers" that have no impact on the Statement of Net Cost. Theoretically, transfers of Federal resources to state and local governments could be considered an expense of the Federal Government or a reduction in Federal revenue (e.g. contra revenue).

Suggested Reporting Principle

For revenue transferred to other Federal agencies, as provided by SFFAS No. 7, the collecting agency would recognize the transfer out on the Statement of Changes in Net Position. These transactions should be clearly identified and explained (in footnotes and/or the stewardship report) so that the reader understands the difference between the costs of goods sold and cost of selling associated with the revenue stream, and independent decisions to share a portion of proceeds with other governments.

Advantages:

- The full cost of government activities and decisions are clearly disclosed.

Disadvantages:

- The transfers of revenue and the distribution of receipts are not recognized as a program cost.

Prices Set by Law or Regulations

General Discussion

During our research in the area of natural resources of the Federal Government, we determined that there are situations where law or regulation (e.g., the Mining Law of 1872) sets the sale price of the resource rather than market forces. As a result of these laws and regulations, the value received for the sale of a natural resource is much less than the fair value of that resource.

Analysis of Options

The task force is aware that major difficulties exist in recognizing such information because of the difficulty in reliably measuring a transaction that did not occur. In addition, for resources such as forage where the government controls a substantial amount of the resource, the current "market price" does not necessarily reflect what the market price would be if government-owned resources were subject to market forces.

Suggested Reporting Principle

Footnote disclosure and other accompanying information should be used to report situations where prices are set by regulation rather than market forces, including a discussion of how prices are determined and differences between market rates and government rates, if available, as outlined in paragraphs 46 & 47 in SFFAS 7.

Advantages:

- Management is given some flexibility to report what they can, based on the knowledge available, and fully explain the assumptions and limitations inherent in the information.
- The information reported is not misleading

Disadvantages:

- Amounts are not recognized in the financial statements.

Summary of Minority Comments on General Reporting Principles

Appendix B (*Minority Comments on General Reporting Principles)* raises three concerns related to the reporting options discussed in this section. First, Appendix B suggests that the basic concepts of SSFAS No. 7 are valid, and that sales of natural resources should not offset agencies' gross costs, unless the full costs of the natural resources sold are recognized. Second, it suggests that some natural resource assets -- in particular, those where the asset is held for remunerative operations or sale -- should be recognized on the Balance Sheet, and not solely in the stewardship report; this would also allow the full costs of natural resources that are sold to be recognized on the Statement of Net Cost. Finally, the comments suggest that the Government develop basic data where it has valuable resources that it intends to sell or manage for remunerative purposes.

V. Implications of the Suggested Reporting Principles

In addition to studying the various reporting options of natural resources, the task force was also instructed to identify the related impacts on existing FASAB standards based on the options and to identify existing laws and regulations that affect reporting information about natural resources.

Impact on Current FASAB Standards

SFFAS No. 7, *Accounting for Revenue and Other Financing Sources and Concepts for Reconciling Budgetary and Financial Accounting* provides that exchange revenue should generally be reported on the Statement of Net Cost of Operations of the agency earning the revenue. However, the Statement makes an exception to this principle for entities recognizing virtually no costs in connection with earning the revenue that it collects (e.g., Outer Continental Shelf revenue collected by the Minerals Management Service). Based on the work performed by the task force, it is the view of some of the task force members that the Outer Continental Shelf rents and royalties are not substantially different from other natural resource revenues and other exchange revenues.

With the exception of the fact that the acreage in question is underwater, MMS's resource management responsibilities over the Outer Continental Shelf are very similar to the resource management responsibilities of the Bureau of Land Management. While MMS royalty collections may be larger in size than certain other natural resource inflows, in substance they have much in common with other resources.

Various task force members believe that revenues earned from the sale of natural resources should be matched against its costs by the agency that collects that revenue and by the government as a whole. This is to ensure that the proceeds the government derives from its stewardship over natural resources are more clearly reported.

The task force also recommends that the Board take into account the following implementation considerations, if it does agree to revise SFFAS No. 7:

- changes necessary to agency/program system requirements,
- possible use of pilot programs, and
- allowing adequate time to implement the revisions.

Legal/Regulatory Considerations

In the course of its work the task force learned about the many statutory and regulatory authorities that affect the value of Federal natural resources and the revenues the Federal Government receives when they are conveyed to the private sector. For many resources, there are statutory requirements that require the Government to use competitive market processes to determine the price at which Federal resources will be conveyed. In general, such requirements have contributed to the development of management procedures that have promoted receipt of revenues that reflect the market value of the resources.

There are, however, a number of resources for which the statutory requirements limit the Federal Government's ability to develop management practices that assure receipt of market value. For example, there has been extended controversy about such limitations regarding mining claims and patents under the General Mining Law of 1872 and grazing permits under Public Rangelands Improvement Act of 1978.

VI. Indian Natural Resource Assets

The Bureau of Indian Affairs (BIA) currently administers more than 54 million acres of land that the Federal Government holds in trust for Indian tribes and individuals. The Indian trust funds are managed by Interior's Office of Special Trustee, Office of the Secretary. (Prior to FY 1996 the BIA managed the trust funds). Some of the funds belong to individual Indians others belong to tribes. The Federal Government manages the funds in a trust arrangement. Trust responsibilities include management of forest lands, development of agricultural and range lands, leasing mineral rights, protecting water and land rights, preparation and administration of probates, and maintaining land ownership and lease income records. Each year, trust lands generate significant resource revenue for beneficiaries, including about $550 million in agricultural production and $150 million in mineral royalties.

Legal Background

Lands under the jurisdiction of the BIA which are held in trust for tribes and individuals were placed in trust by treaties, statutes (e.g., the General Allotment Act), and Executive Orders. Resources on these lands (e.g., minerals, sand and gravel) are managed for the benefit of tribes and individual Indians. Neither the lands held in trust nor the resources associated with these lands are Federal Government assets. In contrast, the Government does own and the BIA administers about 635 thousand acres, with schools, hospitals, offices, roads, etc., which are accounted for in the same manner as other Federal lands and resources.

Reporting on Indian Trust Assets

The Government's responsibility for the trust funds is of a fiduciary nature. This has been confirmed in FASAB Interpretation No. 1 discussed below. The Federal government as a trustee has responsibility for managing certain assets on behalf of tribes and individual Indians, but does not have ownership of either the trust assets or the proceeds from the assets. Historically, a portion of the annual flow from some of these trust funds has been included in the *Budget of the United States Government*. This treatment is being corrected to properly exclude non-Federal assets from the *Budget of the United States Government*.

In addition, revenue generated from Indian trust assets is accounted for on behalf of the tribes and individual Indians. The Mineral Management Service generally acts a collection agency for oil and gas and other mineral resources. The Office of Trust Funds Management has the lead role in performing the accounting. BIA’s costs of managing and selling natural resources from trust lands are generally part of the costs of managing other resources and carrying out its mission.

FASAB Interpretation No. 1

In 1997 the FASAB issued Interpretation No. 1, *Interpretation of Federal*

Financial Accounting Standards -- Reporting on Indian Trust Funds in General Purpose Financial Reports of the Department of the Interior and in the Consolidated Financial Statements of the United States Government: an interpretation of SFFAS No.7. The Interpretation deals with what information about Indian trust funds should be included in the general-purpose financial report of the Department of Interior and of the United States Government. Interpretation No. 1 specifically addresses the question on whether the assets and activities of the Indian trust funds should be reported in the Department of Interior's general purpose financial statements.

The Interpretation states that the assets, liabilities and operating transactions of the Indian trust funds are not part of the Department of Interior and should not be included in the Balance Sheet, Statement of Net Cost, and Statement of Changes in Financial Position of the Department or of the United States Government. However, the Department of Interior does have a fiduciary responsibility for the Indian trust assets and is required to report on them in the Department's footnotes to the basic financial statements as stated in SFFAS No. 7, *Accounting for Revenue and Other Financing Sources*, paragraphs 83-87.

Additional Suggested Reporting

Some members of the task force believe that the footnote disclosures discussed in Interpretation 1 should contain sufficient information to provide an understanding of the fiduciary relationship and the assets and revenues involved. One member of the task force from Interior also believes that there must be more detailed reporting to tribes and individual Indians regarding trust lands and resources, including information on earned revenue and, if estimable, quantity and value of natural resources available for sale. When appropriate, reports to trust beneficiaries should also address financial management systems and internal accounting and administrative controls.

Appendix A. Reporting by Individual Resource

Appendix A contains detailed information for eight natural resource related programs managed by the Federal government. Each program section contains: general and legal background information; a description of the different "stages" of management processes; current reporting policies; and issues relating to the availability and existence of data. The following eight natural resource related programs are presented in the appendix.

- Timber
- Outer Continental Shelf Oil and Gas
- Leasable Minerals - Solid
- Leasable Minerals - Fluid
- Locatable Minerals
- Mineral Materials
- Grazing Uses
- Electromagnetic Spectrum (Airwaves)

Timber

A. Background

1. General Information and Legal Background

Ownership: Ownership of timber resources is based on the status and ownership of the land, including the trees thereon. Most of the timber on Federal land is in fee simple ownership. Approximately 73 percent of the 191 million acres of the National Forests, managed by the USDA Forest Service is considered forested. Of this forested land, 35 percent is available for regularly scheduled timber harvest and about ½ of 1 percent of those trees are harvested in any one-year. Of the Bureau of Land Management's (BLM) 264 million acres, about 47 million areas are classified as forestland, although only about 4 million acres outside of Alaska are actually classified as "productive" (capable of producing timber). Even though BLM in Alaska has 7 million acres that are capable of producing timber, most of this forestland is either inaccessible or too far from established markets to make timber harvest feasible.

Legal Authority: Management of Federal forestland is authorized by various statutes. For the USDA Forest Service (FS), these include the Organic Administration Act (Organic Act) of 1897 (16 USC 475); the Multiple-Use, Sustained-Yield Act of 1960 (16 USC 528-531); the Forest and Rangeland Renewable Resources Planning Act (RPA) of 1974 (16 USC 1600 et seq.); and the National Forest Management Act (NFMA) of 1976 (16 USC et seq.). For the USDI Bureau of Land Management, the applicable laws are the Federal Land Policy and Management Act (FLPMA) of 1976 (43 USC 1701 et seq.) and the Oregon and California (O&C) Grant Lands Act of 1937 (43 USC 1181). DoD conducts natural resource management activities under the Sikes Act (16 USC 670).

Sale of Timber: The Organic Act, RPA, and NFMA authorize Timber sales from National Forests. The regulations for Forest Service timber sales are in 36 CFR 223. The sale and disposal of timber from BLM managed land is authorized by the Material Disposal Act (30 USC 601 et seq.) and the O&C Act. The regulations for BLM timber sales are in 43 CFR 5400. Timber sales on DoD lands are authorized through 10 USC 2665.

National Forests and BLM public lands are managed under a "multiple use" mandate pursuant to the Multiple-Use, Sustained-Yield Act and FLPMA, respectively. This mandate and other factors cause timber sales to be part of a complex and integrated strategy to provide public values and benefits while maintaining or improving ecological integrity. In planning for timber sales, agencies conduct detailed, project-level environmental analyses and documentation pursuant to the National Environmental Policy

Act. In addition, extensive public participation is involved in the Forest Service and BLM timber sale planning processes.

Valuation: Prior to the advertisement of a timber sale, a timber appraisal is conducted in accordance with established agency policy and procedures. The appraisal is used to establish the minimum bid. Bids are solicited for each contract, and timber is sold to the highest bidder.

2. Description of "Stages" for Resource

Conveyed: Generally, conveyance of the timber resource takes place when the timber is paid for and severed from the ground in accordance with a timber sale contract. In the case of the Forest Service and Bureau of Land Management, conveyance occurs when the above conditions are met and when the timber is removed from the contract area.

Available for Sale: The amount of timber available for sale within an administrative unit (National Forest, BLM Resource Area, DoD installation) is generally stated in a land management plan for that administrative unit. The Federal sustained-yield mandate provides that the government not harvest more timber than is produced (through growth) over time. On much of the Forest Service and BLM productive forestland, the management emphasis or "highest and best use" is not necessarily timber, but rather a multitude of other values and benefits like recreation, aesthetics, water quality, wildlife (including threatened and endangered species) habitat, wilderness, and other values. The DoD actively manages its forests first to facilitate the military mission. Other uses, such as wildlife habitat, biological diversity, watershed protection, and timber, are secondary benefits from DoD forestlands. All agencies generally manage the forest for a multitude of values and benefits while maintaining the ecological integrity of the forest.

Administratively and Legislatively Withdrawn: For DoD, many areas are administratively withdrawn from timber harvest for military mission-related reasons. Many forested areas on Forest Service and BLM lands are legislatively withdrawn from timber harvest (e.g., wilderness areas under the Wilderness Act). Other areas are administratively withdrawn from timber harvest to protect sensitive areas or to enhance other values.

Unknown and Undiscovered Resource: Information regarding the extent of the forest and amount of timber available varies widely across agencies and administrative units. On some areas, very specific and accurate information is available on the timber resource while, on other areas, very little is known. This is a function of differing management emphases and funding levels. The Forest Service's Forest Inventory and Analysis (FIA) collects information at a course scale that can be used at the national or regional level to estimate timber levels on all land, including Federal land. However, this information is not specific enough to be used in the management of a specific administrative unit.

B. Current Reporting

1. **Asset Recognition:** BLM: Timber is recognized as an asset in agencies' accounting records at the time a timber sale contract is awarded. DoD: Timber is recognized as an asset when a contract is signed for the sale of that timber. FS: Currently, FS does not recognize timber as an asset on the financial statements. Department of Energy (DOE): Energy recognizes timber as an asset. The value recorded each year is based on the historical cost of the timber management program, and the cost for the current year is calculated at year-end and added to the asset account.

2. **Revenue Recognition:** BLM : Revenues are recognized upon receipt of advance payments or other periodic payments in accordance with the terms of the timber sale contract. DoD: Revenue from timber sales is recognized when proceeds from the sale of timber are collected. Advance payments received are recognized as unearned revenue and are recorded as a liability until the payment is earned. At such time, the revenue is recognized and the liability reduced. FS: Revenues are recognized as deferred exchange revenue and allocated to revenue monthly based on timber harvested and removed during the month. DOE: Energy recognizes revenues upon receipt of the payments from timber sale contracts.

3. **Cost Recognition**

   (a) **Cost of Resources Sold:** Timber production occurs over long periods of time and in concert with multiple land management objectives. Costs associated with timber production are not matched against timber sale revenues. DOE: Energy also recognizes the depletion of the asset in a contra asset account (an allowance for timber depletion). The calculation is based on the estimate of net merchantable volume of timber, which is calculated by the foresters, and the net "balance to deplete" of the timber asset, which is the net value of the asset account and the contra asset account.

   (b) **Cost of selling:** Administrative costs associated with timber sales are recognized in the period incurred. Although a portion of the proceeds emanating from certain types of timber sales can be retained by the managing agency and, in some instances, can be used for timber sale administration, much of the cost of timber sales is borne by agencies' operating appropriations. The DoD supplements most of the costs from timber sale proceeds, but may use operating appropriations if necessary.

(c) **Cost of Management:** Management costs are recognized in the period incurred. Although a portion of the proceeds emanating from timber sales can be retained by the managing agency and, in some instances, can be used for managing timber production and sales, much of this activity is funded through the agencies' operating appropriations. The DoD supplements most of the costs from timber sale proceeds, but may use operating appropriations if necessary.

(d) **Transfers of Revenue/Distribution of Receipts:** In general, receipts are distributed in accordance with the laws regulating the specific lands from which timber is sold. Proceeds from timber sales are collected by the managing agency and distributed to some combination of states, counties, the general fund of the Treasury, the Reclamation Fund, and other funds/entities as the various laws require. Typically, the managing agency is allowed by law to retain some portion of timber sale receipts for both general and specific purposes. The Forest Service reports these transfers and distributions as costs on the Statement of Net Cost and as transfers-out on the Statement of Changes in Net Position.

4. Other Reporting

(a) **Footnote Disclosure:** BLM: Agency financial statements include footnote disclosures covering both unmatured portions of timber sale contracts and the liability account for deferred credits (revenues).

(b) **Stewardship Reporting:** Stewardship reporting currently excludes natural resources.

C. Availability and Existence of Data

Data is available on the approximate acres of forestlands. Forest management planning data is available. Data is available on numbers of contracts, quantities offered, quantities sold, quantities removed, revenues collected, and the disposition of revenues. However, no value can be determined for timber owned by the Federal Government in its entirety.

Outer Continental Shelf Oil and Gas

A. Background

1. General Information and Legal Background

Ownership: The Outer Continental Shelf (OCS) consists of over 1.4 billion acres of submerged lands seaward of State jurisdiction. The Submerged Lands Act of 1953 granted states rights to the natural resources within 3 nautical miles of the coastline, except for the Gulf of Mexico coasts of Texas and Florida, where State jurisdiction extends for 3 marine leagues. The Federal Government manages the rights to oil, gas, and other minerals on the OCS. The Government issues leases that convey an exclusive right to explore for and develop oil and gas on the OCS, and maintain a royalty interest in any production saved, removed, or sold from a lease. Over 27 million acres are currently under active lease, and the OCS accounts for over 27% of the natural gas and 20% of the oil produced in the United States.

Legal Authority: The Outer Continental Shelf Lands Act, as amended, and the Federal Oil and Gas Royalty Management Act, as amended, are the primary legal authorities for managing oil and gas resources on the OCS, though authority for certain management activities resides in a number of other statutes as well. The Secretary of the Interior has jurisdiction over energy and mineral development on the OCS and has delegated much of that authority to the Minerals Management Service (MMS).

Sale of Leases: MMS conducts auctions for OCS leases under competitive sealed-bidding procedures and evaluates the high bids on each block to determine if each bid meets or exceeds bid adequacy criteria. Although various alternative bidding systems have been tested, MMS generally offers leases with fixed annual rentals and royalty rates (usually one-eighth or one-sixth) and with a cash bonus as the bid variable. Primary lease terms range from 5 to 10 years, at which time the lease expires unless the lessee is producing or conducting drilling or well-reworking operations, subject to regulations. The lease remains in force for as long as it's producing, which could be decades.

Valuation: The majority of OCS revenues come from three sources: cash bonuses, royalty revenues, and rentals. The following table summarizes these revenues.

OCS Mineral Revenues		
Revenue Type	**1998**	**1953-1998**
Royalties	$2.7 billion	$62 billion
Bonuses	$1.3 billion	$61 billion
Rentals	$258 million	$1.7 billion

MMS relies on its competitive bidding process and bid evaluation procedures to ensure the receipt of fair value for OCS leases. Royalties are generally a fixed percentage of gross proceeds to the lessee from the sale of lease production.

2. Description of Phases

Conveyed: Conveyance occurs when the Government issues a lease for exclusive rights to explore for and develop oil and gas on the OCS. In return, the Government receives a cash bonus at the time of lease issuance, annual rental payments until production begins, and a production royalty. Leased acreage returns to the Government's inventory when a lessee relinquishes a lease, the primary lease term expires and the lessee is not conducting operations that would extend the lease term, or the Government cancels a lease pursuant to the authorities in the OCS Lands Act.

Available for Sale: All OCS acreage not specifically withdrawn or under lease is potentially available for leasing. The Secretary of the Interior prepares a 5-Year Oil and Gas Leasing Program that identifies the size, timing, and location of possible lease sales. Interior consults extensively with States and other stakeholders in preparing the plan. Only acreage specifically identified in this plan may be offered for sale.

In addition, each individual lease sale has its own public planning process. This process could result in cancellation or delay of a sale or a reduction in the acreage to be offered for lease, but it cannot add acreage that was not included in the 5-Year Program.

Administratively and Legislatively Withdrawn: Both the Administration and Congress can withdraw portions of the OCS from the 5-year planning process, and thus prevent them from being leased. Withdrawals can occur for policy reasons or to reserve an area for other uses.

Undiscovered Resources: Much of the OCS remains unexplored and is believed to contain substantial volumes of undiscovered resources. The most recent national assessment of undiscovered, conventionally recoverable resources on the OCS estimated that 186.3 – 369.2 trillion cubic feet of natural gas and 37.1 – 55.3 billion barrels of oil remain undiscovered.

B. Current Reporting

1. **Asset Recognition:** Currently, oil and gas resources on the Outer Continental Shelf are not recognized as assets in the MMS Annual Financial Statements.

2. **Revenue Recognition:** Currently, the MMS Annual Financial Statements and DOI Consolidated Financial Statements recognize receipts from the initial leasing of OCS tracts in the period the lease sale is held. For leases that have entered into production, royalty receipts are recognized in the period the oil or gas production is saved, removed, or sold by the lessee. The receipts are presented in a Statement of Custodial Activity, but are not considered revenue to DOI. The receipts are considered revenue in the Government wide financial statements.

3. **Cost Recognition**

   (a) **Cost of Resources Sold:** There is currently no reporting of the cost of oil and gas sold.

   (b) **Cost of selling:** Currently, the MMS recognizes all costs associated with lease sales, royalty collections and disbursements, and other activities in support of OCS production.

   (c) **Cost of Management:** Currently, separate management costs are not recognized for OCS oil and gas resources.

   (d) **Transfers of Revenue/Distribution of Receipts:** Under section 8(g) of the OCSLA, MMS does distribute receipts from OCS leases to non-Federal agencies. In 1997 MMS transferred over $116 million of OCS revenues to states.

4. Other Reporting

(a) **Footnote Disclosure:** None

(b) **Stewardship Reporting:** None

C. Availability and Existence of Data

The data identified in the reporting section of this paper is generally available on an annual basis, with the following exceptions:

- Net present value of reserves — No such estimates are currently made for the OCS. However, if one makes a number of economic assumptions (e.g., future prices, costs and timing of production), uncertain estimates are feasible.

- Volume and net economic value of resources in the 5-Year Oil and Gas Leasing Program — These estimates are made during the preparation of each 5-Year Program and are not updated until a new program is prepared (roughly every 5 years).

- Undiscovered resources — These estimates are made periodically.

Leasable Minerals (Solid)

A. Background

1. General Information and Legal Background

Leasable minerals are broadly segregated into two general categories based on the physical properties of the minerals, and as such, are discussed separately. Fluid minerals are those minerals that generally occur in a fluid or gaseous state and include oil, gas, and geothermal resources. These fluid minerals are discussed in a section entitled "Leasable Minerals (Fluid)." Solid leasable minerals are those minerals that generally occur in a solid state and include coal, oil shale, asphalt, sulfur, phosphate, potassium, sodium, gilsonite, and other minerals.

The Bureau of Land Management is responsible for managing on-shore leasing and lease operations. The Minerals Management Service is responsible for off-shore leasing and lease operations as well as for collecting and distributing mineral revenues for both on-shore and off-shore minerals.

<u>Ownership</u>: The Federal Government is responsible for managing the mineral estate that underlies approximately 264 million acres of Federal ownership and an additional 300 million acres of mineral rights on split estate lands for which the surface has been conveyed. The government transfers title to certain minerals to private entities through leases. The lessee is required to pay an annual per-acre rental fee to hold the lease, as well as a royalty based on sales value when the mineral has been severed.

<u>Legal Authority</u>: The primary legislation governing leasable minerals is the Mineral Leasing Act of 1920, as amended. This legislation separated mineral fuels and fertilizer minerals (oil, gas, oil shales, asphalt, phosphate, potassium, and sodium) from the General Mining Law of 1872. The Mineral Leasing Act was amended by the Federal Coal Leasing Amendment Act of 1976, which provided for coal to be leased competitively through regional leasing or leasing by application.

The Federal Land Policy and Management Act of 1976 requires that the United States receive market value for the use of the public lands and their resources unless otherwise provided by statute. In practice, market value for solid leasable mineral is the combined value of future royalties, which are established by the Mineral Leasing Act, and a competitive lease bonus payment that is bid by the prospective lessee and is payable upon lease issuance.

Leasing of Minerals: The most common form of Federal leasing is known as "competitive leasing," which provides an opportunity for any interested party to competitively bid for a Federal lease. Prospecting permits and noncompetitive preference right leases may be issued for some noncoal solid minerals. Most leases have terms that require diligent development of the resource, with rents and royalties being paid for the right to hold the lease and mine the Federal resources.

Mineral leases are issued for an initial period of 20 years and are subject to readjustment or renewal at 10- and 20-year increments. Changes in royalty and rental rates, as well as revisions to other terms and conditions of the lease, can be made or attached during the readjustment or renewal of a lease.

Leasing of coal and noncoal minerals has occurred on about 1.1 million acres of mineral rights on Federal and split-estate private lands.

Valuation: Competitive leasing provides an opportunity for more than one party to bid on a lease tract. Non-competitive leases are awarded based on the mineral discovery from a prospecting permit or as a modification to an existing lease.

In all cases, solid mineral leases are sold only at or above the government's estimation of market value. Through a lease sale, the public may bid on mineral resources offered for competitive lease. The highest bid is awarded the lease. Lands leased through lease modification procedures require that the lessee pay a payment in lieu of a bonus bid. The lease also requires payment of an annual per-acre rental fee and may require advance royalties.

2. **Description of "Stages" for Resource**

Conveyed (Granted Rights): The government receives rentals, bonus bids, and other payments when leases are issued. Payment for the mineral resources in the form of royalties occurs when the mineral is severed and/or sold. Royalties on the sales value of resource production are paid at least quarterly to the United States through the Minerals Management Service.

Available for Sale (Lease): Not all public lands are available for mineral exploration or leasing. There is a rigorous land use planning process through which all public lands are reviewed for potential leasing. The land use plan must address multiple use, sustained yield, protection of critical environmental areas, application of specific unsuitability criteria, and coordination with other government agencies.

Administratively and Legislatively Withdrawn: Some Federal lands are closed to mineral leasing by legislative withdrawal and/or administrative decisions reached through the land use planning process.

Unknown/Undiscovered: The Federal Government does not attempt to identify the magnitude of leasable resources through exploration or prospecting. In some cases the agency has rough estimates of reserves, but many factors influence the mineability and marketability of leasable resources, including environmental constraints, world markets, and changes in technology.

B. Current Reporting

1. **Asset Recognition:** The value of solid leasable minerals is currently not recognized as an asset in the financial records of Federal agencies.

2. **Revenue Recognition:** Revenues generated from mineral leases are recognized at the time lease payments or royalties are collected.

3. **Cost Recognition**

   (a) **Cost of Resources Sold:** Solid minerals are not currently recognized as an asset in agencies' financial records. As such, there is there is no asset to be removed at the time of sale.

   (b) **Cost of selling:** Administration of the solid mineral leasing program is funded through operating appropriations. The cost of selling is recognized in the period incurred.

(c) **Cost of Management:** Management of the solid mineral leasing program is funded through operating appropriations. The cost of management is recognized in the period incurred.

(d) **Transfers of Revenue/Distribution of Receipts:** Revenues are not retained by the managing agency. They are distributed annually to the General Fund of the Treasury and to the states and counties from which the minerals were extracted.

4. Other Reporting

(a) **Footnote Disclosure:** None

(b) **Stewardship Reporting:** None

C. Availability and Existence of Data

Some data is available at the time a lease is executed, such as the number of leases, revenues generated from those leases, the distribution of lease revenues, and, for some minerals, the quantities extracted. However, no value can be determined for mineral rights owned by the Federal Government in their entirety. The quantities of leasable mineral reserves that would determine future production potential at identified deposits are generally unknown. Furthermore, estimates of the volumes of minerals that might exist in undiscovered deposits on Federal lands are not reliable enough to report on the face of the financial statements.

Leasable Minerals (Fluid)

A. Background

1. General Information and Legal Background

As previously stated, fluid minerals are those that generally occur in a fluid or gaseous state and include oil, gas, and geothermal energy.

Ownership: The BLM has exclusive jurisdiction over the mineral rights for about 264 million acres of public lands (with approximately one-third of this area being in Alaska). The BLM also managers an additional 300 million acres of subsurface mineral rights reserved by the Federal Government.

The management objective of the oil and gas program is to foster and encourage the exploration for and development of Federal and Indian oil and gas resources, to receive a fair return to the public and Indian lessors for those resources in an environmentally acceptable manner, and to provide for conservation of fluid mineral resources in a manner that is responsive to the Nation's economic and security needs and in conformance with the principles of balanced multiple-use management.

Legal Authority: The Mineral Leasing Act of 1920, as amended, the Mineral Leasing Act for Acquired Lands of 1947, the National Environmental Policy Act of 1969, the Federal Land Policy and Management Act of 1976, the Federal Oil and Gas Royalty Act of 1982, and the Federal Onshore Oil and Gas Reform Act of 1987 are the primary authorities under which the BLM leases and supervises oil and gas operations. The regulations are contained in Title 43 of the Code of Federal Regulations.

Leasing: Onshore oil and gas leasing is accomplished under competitive procedures. Current leasing procedures were established by the Federal Onshore Oil and Gas Leasing Reform Act of 1987 (30 U.S.C. 226, et seq.).

Valuation:

- *Bonus Bids:* In FY 1996, 2,477 competitive leases covering 1,589,795 acres with $31,979,336 in accepted bonus bids, along with 898 non-competitive oil and gas leases covering 933,763 acres, were issued.

- *Royalties*: In calendar year 1996 for Federal onshore lands, oil royalty income rose 20.2 percent to $232.4 million, while gas royalty income rose 23.9 percent to $309.9 million. Regarding geothermal energy, during 1996, MMS collected approximately

$19.9 million in royalties from geothermal leases on Federal lands in California, Nevada, and Utah. In 1997, approximately $20.8 million in royalties from geothermal leases was collected for these same 3 areas.

2. Description of "Stages" for Resource

Conveyed: Conveyance occurs when the government issues a lease for the exclusive right to explore for and develop oil and gas on the lands for which the government holds the mineral rights. The lessee is then responsible to remit to the government the following types of payments:

- *Bonuses:* Through the competitive bidding process, the bonus represents the cash amount successfully bid to win the rights to a lease.

- *Rents:* A rent schedule is established at the time a lease is issued. Rents are annual payments, normally a fixed dollar amount per acre, required to preserve the rights to a lease.

- *Royalties:* A royalty is due when production begins. Royalty payments represent a stated share or percentage of the value of the oil and gas produced. The royalty may be an established minimum value or a flat, step-scale, or sliding-scale rate. A step-scale royalty rate increases by steps as the average production on the lease increases. A sliding-scale royalty rate is based on average production and applies to all production on the lease.

Available for Sale (Lease): Not all public lands are available for oil and gas exploration or leasing. There is a rigorous land use planning process through which all public lands are reviewed for potential leasing. The land use plan must address multiple use, sustained yield, protection of critical environmental areas, application of specific unsuitability criteria, and coordination with other government agencies.

Administratively and Legislatively Withdrawn: Portions of Federal lands are withdrawn or otherwise closed to leasing and/or development.

Unknown/Undiscovered: In general, the Federal Government does not attempt to identify the magnitude of leasable oil and gas resources through exploration. In some cases, the government has rough estimates of reserves, but many factors influence the availability of the oil and gas resources, including environmental constraints, world markets, and changes in technology.[6]

[6] The most recent USGS National Assessment of undiscovered, conventionally recoverable resources on onshore Federal lands

B. Current Reporting

1. **Asset Recognition:** On-shore oil and gas deposits are not currently recognized as assets in the financial records of government agencies.

2. **Revenue Recognition:** Revenues emanating from oil and gas leases are recognized at the time lease payments (bonuses, rents, and royalties) are collected.

3. **Cost Recognition**

   (a) **Cost of Resources Sold:** Oil and gas deposits are not currently recorded as assets, so there is no resource cost to match against revenues.

   (b) **Cost of selling:** The cost of administering on-shore oil and gas leasing activities is currently recognized in the period incurred.

   (c) **Cost of Management:** The cost of managing the on-shore oil and gas program is currently recognized in the period incurred.

   (d) **Transfers of Revenue/Distribution of Receipts:** Revenues collected by the managing agency are generally not retained by that agency. They are distributed annually in various percentages to the General Fund of the Treasury, the Reclamation Fund, and to the states and counties from which the minerals were extracted in accordance with the laws applicable to the lands upon which the oil and gas lease resides.

4. **Other Reporting**

   (a) **Footnote Disclosure:** None.

   (b) **Stewardship Reporting:** None.

C. Availability and Existence of Data

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estimated 34 - 97 trillion cubic feet of natural gas and 4 to 13 billion barrels of oil remain undiscovered. Furthermore, an additional 72 to 202 trillion feed of gas was estimated to be contained in unconventional gas deposits (excluding coalbed gas) on onshore Federal Land. Coalbed gas deposits on Federal Lands were estimated to contain 13 to 20 trillion feet of gas. These estimates are general magnitudes of undiscovered volumes of onshore oil and gas. The USGS periodically assesses the undiscovered onshore oil and gas resources for the entire United States. The USGS then allocates, in a publication, that portion of the resources that it believes should be applied to Federal lands.

Certain data is available on the number of leases, including revenues generated, the distribution of revenues, and the quantities of the oil and gas extracted. However, no value can reasonably be determined for mineral rights owned by the Federal Government in their entirety.

Locatable Minerals

A. Background

1. General Information and Legal Background

Ownership: The class of economic minerals known as "locatable" minerals make up a significant portion of the "economic" minerals under government control. This class includes precious metals, ferrous metals, light metals, base metals, precious and semi-precious gemstones, and a vast array of industrial minerals. Nineteen states are open to the operation of the General Mining Law of 1872, as amended, which creates this class of minerals.

Legal Authority: Locatable minerals are made available under the Mining Law of 1872 (30 USC 22, et seq.), the Federal Land Policy and Management Act (43 USC 1732 and 1744), and continuing Appropriations Acts. On acquired lands, locatable minerals are leased.

Disposal/Sale Mechanisms: A citizen who makes a self-initiated discovery of a deposit of valuable minerals and who records a mining claim with the Federal Government has the right to produce the mineral deposit, subject to compliance with applicable Federal, state, and local health, safety, and environmental laws.

Recordation of a mining claim requires payment of a location fee, administrative costs, and payment of the annual maintenance fee. The annual maintenance fee is paid each year in advance. Initial recordation with the Federal Government requires advance payment of location, maintenance fee, and administrative fees (service charges) in the amount of $135.00. Maintenance fees currently run $100 per claim per year. Location fees are $25 per claim. Administrative fees are $10 per mining claim. Subsequent years require the payment of the maintenance fee of $100. Claimants who hold 10 claims or less are considered "small miners" and have the option to file a waiver of the $100 fee. There are approximately 320,000 mining claims of record.

The term "location" is used to identify posting of a location notice and marking the boundaries of a claim [*Smith v. Union Oil Co., 135 P 966 (1913), affirmed 249 US 337*]. The following Federal requirements for location must be accomplished:

1. The location must be distinctly marked on the ground so its boundaries can be readily traced.

2. The location notice must contain (a) the name or names of the locators, (b) the date of the location, and (c) a description of the claim(s)' location by reference to some natural or permanent monument that will identify the claim.

Valuation: There are no up-to-date or reliable estimates of the value of in-place reserves.

2. Description of "Stages" for Resource

Conveyed (Discovery, Location and Recordation, and Patenting): Citizens have standing permission to go on Federal lands that are not withdrawn from the mining law, to prospect for locatable mineral deposits. Discovery of a valuable mineral grants to the discoverer the conditional right to develop the minerals.

When a prospector locates a mining claim, the claim must be recorded with the county pursuant to state law and with the Federal Government within 90 days of location pursuant to Federal law. The validity of a claim is determined using the "Prudent Man [aka Person] Test." This test states, ". . . where minerals have been found and the evidence is of such a character that a person of ordinary prudence would be justified in further expenditure of his labor and means, with a reasonable prospect of success, in developing a valuable mine, the requirements of the statutes have been met."

A mining claimant can seek full fee title to the land by filing for patent (deed) to the mining claim. There are application/administrative fees paid for a mineral survey and the actual patent application. When the administrative processing of the application has reached a certain point, the purchase price (set by statute at $2.50/acre for placer claims or $5.00/acre for lode claims) is paid. If examination demonstrates the existence of a valuable mineral deposit, the title to the land and minerals passes to the mining claimant. Currently, there is a moratorium on accepting patent applications. The government receives no royalties from the production of locatable minerals.

Available for Exploration, Development, Production and Reclamation: There is no requirement to apply for a patent. Exploration and mining can be conducted to completion without the issuance of a patent.

Exploration and mining operations are subject to government review and approval, and must meet Federal and State laws. Financial guarantees are required of an operator to ensure reclamation is completed upon disturbed lands. No charges for either approval or oversight of activities are assessed of an operator; however, the BLM is currently preparing cost recovery regulations.

Administratively and Legislatively Withdrawn: The current estimate of lands withdrawn from locatable mineral production on the public domain land base is approximately 330 million acres out of a total of 564 million acres. No reliable value of withdrawn minerals has been developed.

Unknown and Undiscovered Resources: There are no reliable estimates of the value of unknown or undiscovered resource.

B. Current Reporting

1. **Asset Recognition:** The aggregate value of locatable minerals on or underlying the public lands is not recognized as an asset in agencies' accounting records.

2. **Revenue Recognition:** Revenues emanating from mining claim location and maintenance fees are recognized in the period in which they are collected.

3. **Cost Recognition**

   (a) **Cost of Resources Sold:** The value of locatable minerals removed from the public lands is not matched with revenues received.

   (b) **Cost of selling:** Costs associated with program administration are recognized in the period incurred and are matched against revenues received for fee collections.

   (c) **Cost of Management:** The cost of managing the locatable minerals program is funded through fee collections. This cost is recognized in the period incurred and matched against revenues.

   (d) **Transfers of Revenue/Distribution of Receipts:** Fee revenues emanating from the locatable minerals program are collected by the managing agency, but are appropriated by Congress.

4. **Other Reporting**

   (a) **Footnote Disclosure:** None

   (b) **Stewardship Reporting:** None

C. Availability and Existence of Data

Data is available on the number of mining claims and the revenues generated. Although data is diverse, no mandatory National reporting system for privately developed production data (e.g., produced reserves) or privately produced resource data (e.g., exploration information) exists.

Mineral Materials

A. Background

1. General Information and Legal Background

Ownership. Mineral materials include various common minerals such as sand, gravel, and stones that are considered part of the mineral estate owned by the Federal Government. The Federal Government manages these minerals on public lands and other lands under the jurisdiction of the government.

Legal authority. The Materials Acts of July 31, 1947 (61 Stat. 681), as amended, authorizes the disposal of mineral materials through sale contracts to private users. Disposal is also authorized through free use to non-profit organizations if the material is not to be used for commercial purposes, as well as to governmental entities.

Sale of Mineral Materials. Sale of mineral materials may not be made at less than market value as determined by an appraisal. Sales must be made on a competitive basis unless it can be shown that there is no competitive interest. Sales are made from either exclusive site used by one operator or nonexclusive sites (community pits or common use areas) for use by more than one operator.

Negotiated sales are generally for less than 100,000 cubic yards of mineral materials. The maximum duration of the contract term is for 5 years, with a one-time extension of 1 year.

Competitive sales are for mineral material disposal of over 100,000 cubic yards or where there is competitive interest even for smaller sales. The maximum term is for 10 years, with a one-time extension of one year.

Valuation. Valuation is made by conducting an appraisal of the material to be sold utilizing the Uniform Appraisal Standards for Federal Land Acquisition (602 DM 1.3).

2. Description of "Stages" for Resource

Conveyed: Conveyance of the right to remove Federal mineral materials is made at the time a contract or permit is issued. No mineral materials can be removed without a prior payment for the amount to be removed, except in cases where free use conveys a right to a governmental subdivision or non-profit organization to remove mineral materials without payment.

Available for Sale: Mineral materials on public lands are generally available for purchase under established procedures unless otherwise prohibited by law or withdrawn because of an agency's land use plan decisions. Limited assessments of the total quantities of mineral materials on the public lands have been made as a part of agencies' resource management planning initiatives.

<u>Administratively and Legislatively Withdrawn</u>: The government does not issue mineral material sales from lands identified in the land management planning process as unsuitable for such mineral development. The BLM also cannot sell mineral materials from lands encumbered by unpatented mining claims.

<u>Unknown / Undiscovered</u>: While mineral materials are generally of widespread surface occurrence, their usage varies with the degree of economic development of an area, with the greatest demand generally occurring during periods of high economic activity or infrastructure development. Demand for a material depends on the type of usage contemplated. To explore and test a deposit to determine the quality and quantity of available material, operators can obtain permits from the government. Such a permit does not convey to the permittee a preference right to a contract.

B. Current Reporting

1. **Asset Recognition:** Mineral materials are not currently recognized as an asset in the financial records of government agencies.

2. **Revenue Recognition:** Revenues from the sale of mineral materials are recognized in the period that payments are received by the government according to the payment schedule authorized by the executed agreement between the contractee and the government.

3. **Cost Recognition**

   (a) **Cost of Resources Sold:** Mineral materials are not currently recorded as an asset in the financial records of government agencies. Therefore, no cost is recognized at the time of sale.

   (b) **Cost of selling:** The cost of selling are recognized in the period incurred.

   (c) **Cost of Management:** The costs of managing the mineral materials program are recognized in the period incurred.

   (d) **Transfers of Revenue/Distribution of Receipts:** Receipts from the sale of mineral materials are generally not retained by the managing agency. They are distributed annually to the general fund of the Treasury, to states and counties where the materials were extracted, and to the Reclamation Fund.

4. Other Reporting

(a) Footnote Disclosure: None.

(b) Stewardship Reporting: None.

C. Availability and Existence of Data

Data is available on quantities extracted and revenues received from the sale of mineral materials. However, no comprehensive value can be determined for mineral materials.

Grazing Uses

A. Background

1. General Information and Legal Background

Ownership: The United States owns Public rangelands. Agencies of the Federal Government are responsible for stewardship of the public rangelands, including managing the natural resources on the surface of the lands. Federal agencies manage approximately 255,000,000 acres of grazing lands for domestic livestock use through 10-year permits or leases (Bureau of Land Management—165 million acres, and Forest Service—90 million acres). In addition, 16 Alaska native corporations graze reindeer without charge on 5 million acres of public land managed by the BLM.

The Federal Government does not transfer ownership or control of the rangelands because the public lands are, by law, managed for multiple use (mineral development; natural, scenic, scientific, and heritage values; outdoor recreation; range; timber; watershed; and wildlife and fish) and sustained yield for future generations. By law, these lands are also managed to avoid permanent impairment of the productivity of the land and to avoid permanent impairment of the quality of the environment.

Legal Authority: Legal authority for BLM's management of the public rangelands is found in three major laws: the Taylor Grazing Act of 1934 (43 USC 315), the Federal Land Policy and Management Act of 1976 (43 USC 1752), and the Public Rangelands Improvement Act of 1978 (43 USC 1901). Other laws containing rangeland administrative authority are the Oregon and California Railroad Grant Lands Act of 1937 and Coos Bay Wagon Grant Lands (43 USC 1181d), the Bankhead-Jones Farm Tenant Act of 1937 (7 USC 1012), the Carson-Folly Act of 1968, and the Federal Noxious Weed Act of 1974 (7 USC 2801).

Alaska reindeer grazing is governed by the Reindeer Act of 1937, the Taylor Grazing Act of 1934, and the Federal Land Policy and Management Act of 1976.

Legal authority for Forest Service management of the public rangelands is found in the Organic Administration Act of 1897 (16 USC 551), the Bankhead-Jones Farm Tenant Act of 1937 (7 USC 1010), the Granger-Thye Act of 1950 (16 USC 571), the Multiple Use-Sustained Yield Act of 1960 (16 USC 528), the National Forest Management Act of 1976 (16 USC 472), the Federal Land Policy and Management Act of 1976 (43 USC 1752), and the Public Rangelands Improvement Act of 1978 (43 USC 1901). The Department of the Defense (DoD) conducts natural resources management activities under the Sikes Act, 16 USC 670. DoD legal authority to lease lands for grazing and agricultural purposes is in 10 USC 2667(d)(4).

Sale of Forage: Approximately 27,400 permittees or lessees purchase forage from the Federal Government for the use of about 30,100 grazing allotments under 10-year grazing permits or leases. The BLM administers grazing on 21,600 allotments grazed by 18,800 permittees or lessees, while the Forest Service administers grazing on 8,500 allotments grazed by 8,600 permittees.

Valuation: The current grazing fee is $1.35 per Animal Unit Month (AUM). The grazing fee for public rangeland is computed from a fee formula established by Executive Order 12548 dated February 14, 1986, and incorporated rules (36 CFR 222.50 and 43 CFR 4130.8). The formula uses a base forage value established in the 1968 Western Livestock Grazing Survey, multiplied by the weighted averages for privately owned, non-irrigated pasture or rangeland rental rates in the 11 western states, plus the average price ranchers receive for the sale of beef cattle, minus the estimated cost for producing livestock on public lands. The DoD leases lands for grazing or agriculture on a competitive base and valuation is based on fair market value. The grazing fee has varied widely from year to year depending upon market forces. The Federal Government sells an average of 17,950,000 AUMs of forage each year (BLM, 10 million AUMs, and FS, 7.95 million AUMs).

Rules governing fees for grazing use and occupancy of National Forest System lands in the eastern and southern regions are set forth at 36 CFR 222. Procedures for permits awarded noncompetitively are at 36 CFR 222.53. Competitive bidding procedures are at 36 CFR 222.54. Grazing fees charged on eastern National Forests are based on fair market value as determined by either comparable private grazing use rates adjusted for the difference in the costs of grazing comparable private lands and National Forest System lands, or by prevailing prices in competitive markets for other Federal or state leased lands.

2. Description of "Stages" for Resource

Conveyed: Permits or leases are allocated to the holders of preference base properties. Permittees or lessees own or control the base property ranches through lease to which the Federal Government assigns grazing preference and the amount of permitted grazing use. Grazing permits or leases are renewable to the preference holders for 10-year terms when the permittee or lessee has demonstrated good stewardship through compliance with the rules, terms, and conditions of the grazing permit or lease. Most of the DoD leases are for 5 years or less in accordance with statute. However, leases may be extended beyond 5 years if the Secretary of Defense determines that a lease for a longer period will promote national defense or be in the public interest.

Available for Sale: Forage is sold annually through the grazing operation described on the permit or lease. Permittees or lessees may apply to amend their annual operation and are then authorized to make the described use when approved by the government. Grazing fees are due and payable before grazing use is made.

The Government recognizes approximately 13,070,000 AUMs of forage assigned to BLM preference holders and 9,244,000 AUMs of forage to holders of Forest Service permits. Of this amount, approximately 2,200,000 AUMs are permanently suspended from use by the BLM because the forage supply is limited. There are approximately 4,326,000 AUMs of forage that are placed in temporary nonuse (3,000,000 AUMs for the BLM and 1,326,000 AUMs for the FS) each year for various reasons, including drought, fire, operators' financial ability to buy livestock, livestock disease/quarantine, or conservation improvement of rangeland resources through short-term rest from use.

Administratively and Legislatively Withdrawn: A few rangeland areas are withdrawn and devoted to other purposes that preclude livestock grazing. Before a permit or lease is canceled due to withdrawal, the preference holder is given a two-year notice. Some of the activities that preclude livestock grazing include military bombing ranges, community sanitary land fills, recreation sites and campgrounds, public land sales, and exchanges where public land becomes private or state owned.

Unknown and Undiscovered Resource: The total quantity of animal unit months of forage available for permitting/leasing is contingent upon uncontrollable environmental factors.

B. Current Reporting

1. **Asset Recognition:** The financial records of government agencies currently do not recognize forage as an asset.

2. **Revenue Recognition:** Revenue resulting from the sale of forage is recognized when lease or permit payments are collected.

3. **Cost Recognition**

   (a) **Cost of Resources Sold:** The value of forage is not matched against lease or permit revenue, as this value is not determinable.

   (b) **Cost of selling:** The cost of forage sales are borne by agency operating appropriations and are recognized in the period incurred. The DoD supplements most of the costs from lease proceeds, but may use operating appropriations if necessary.

(c) **Cost of Management:** Rangeland management is funded through operating appropriations. Costs are recognized in the period incurred. The DoD supplements most of the costs from lease proceeds, but may use operating appropriations if necessary.

(d) **Transfers of Revenue/Distribution of Receipts:**
BLM: Receipts from the sale of forage are distributed in accordance with Section 10 of the Taylor Grazing Act as amended by Section 401 (b) of the Federal Land Policy and Management Act. Fees collected from designated grazing districts under Section 3 of the Taylor Grazing Act are distributed as follows: 12 ½ percent to the state and county where collected, 50 percent to the managing Federal agency for on-the-ground rangeland improvement, and 37 ½ percent to the general fund of the U.S. Treasury. Fees collected from grazing lease or permits under Section 15 of the Taylor Grazing Act are distributed as follows: 50 percent to the state and county where collected and 50 percent to the managing Federal agency for on-the-ground rangeland improvement. DoD: The DoD retains all grazing and agricultural lease proceeds for lease administration, leased land improvements, and natural resource management. Forest Service: Grazing fees are collected in accordance with 43 United States Code, Section 1751, and subsequently deposited by the agency to manage and maintain range development on National Forest Systems. Fifty percent of the monies received as fees for grazing are deposited in the Treasury as miscellaneous receipts. As further directed under 36 Code of Federal Regulations, Section 222.10, the remaining fifty percent of all monies received as fees for grazing is credited to the range betterment fund to accomplish range development. Fifty percent of the monies from this fund are expended on the National Forest where the fees derived to arrest range deterioration and improve forage conditions. The remaining 50 percent of the fund are allocated within the Forest Service regions where the fees derived for rehabilitation, protection, and improvement of those National Forest lands. The Forest Service reports these transfers and distributions as costs on the Statement of Net Cost and as transfers-out on the Statement of Changes in Net Position.

4. Other Reporting

(a) **Footnote Disclosure:** BLM & FS: None.

(b) **Stewardship Reporting:** None

C. Availability and Existence of Data

Data is available on the number of grazing permits/leases and the AUM's leased. Data is available on revenues generated and the distributions of lease or permit revenues. Data is available on range improvement revenues retained by agencies and the use of those revenues at the budget sub-activity, object class, and location (State) levels. Data is available to discuss the cost of range management, including the cost of permit/lease management, at the budget sub-activity, object class, and location (State) levels. However, data is not available on the overall quantity or fair market value of rangeland forage.

Electromagnetic Spectrum (Airwaves)

A. Background

1. General Information and Legal Background

Ownership. All sovereign nations own the rights to the electromagnetic spectrum within their boundaries. The U.S. Federal Government assigns the right to use portions of the spectrum to state and local governments and to the private sector for specific purposes. However, the Federal Government does not transfer ownership of the spectrum itself. A significant portion of the spectrum is reserved for defense and other government uses.

Legal authority. Legal authority for management of the U.S. spectrum rests with the Federal Communications Commission (FCC) for private users and State and local government users, and with the National Telecommunications and Information Administration for Federal Government users.

Sale of Licenses. Currently, private sector lessees purchase licenses for the right to use specific bands of spectrum at public auctions. The authority for conducting spectrum auctions was legislated in Omnibus Budget Reconciliation Act of 1993. Prior to auctions, the Spectrum was first given away to those who filed first for the license; and later, the licenses were awarded by lottery. Generally, the license period is ten years and the license, once granted, can be renewed and retained indefinitely unless there is substantial reason for revoking the license, such as failure to pay license fees.

The FCC currently controls the use for any given portion of the spectrum (e.g. television, cellular phone). At some point in the future, the FCC may allow licensees greater control over the use of radio frequencies.

Valuation. Over the last three years, the FCC has auctioned bands of spectrum with a sale value of more than $23 billion. Installments are permitted for payment of licenses. The FCC does not put a value on the spectrum to be sold. The market, at the time of sale, determines the value of the spectrum, and many variables contribute to the sale value. The Congressional Budget Office has estimated previous sales, however, these estimates proved to be incorrect. The usefulness and value of any portion of the spectrum is dependent on technology. Lower frequencies generally have more uses, and technological advances are expected to provide uses for higher frequencies currently considered “unusable.”

2. Description of "Stages for" Resource

Conveyed

Conveyance of the spectrum takes place (a) when an auction is held to sell licenses to the private sector or (b) when portions are set aside at no cost for use by state and local governments (e.g. for use by emergency personnel). The "purchase price" paid at auctions can be significant, however, periodic license fees tend to be nominal.

Only the right to use the spectrum for a period of time is sold. The spectrum itself is not sold, and all rights revert to the government if license terms are not met. The spectrum is permanent and there is no known way in which the spectrum could be destroyed or damaged.

The government has the right to move licensees from one portion of the spectrum to another. This has been done in the past, for example to obtain a large block of the spectrum for auction to pager companies.

Available for Sale

Radio frequencies not currently under license or reserved by the Federal Government may be auctioned by the FCC under established procedures.

Administratively and Legislatively Withdrawn

The Federal Government reserves significant portions of the spectrum for use. The primary Federal use relates to national defense, however, most Federal agencies are assigned small portions of the frequency for radio communication and similar purposes.

Unknown / Undiscovered

The highest frequencies of the spectrum currently have no known use. However, technological advances continue to widen the "usable" portion of the spectrum.

B. Current Reporting

The FCC is not currently required to publish financial statements and subject them to an independent audit and as such does not do so.

C. Availability and Existence of Data

Extensive data is available regarding frequencies licensed for private sector and state and local uses, and in general what purposes those frequencies can be used for. No value can be determined for radio frequencies to be auctioned, or for the radio spectrum in its entirety. Some data related to government uses may be considered classified information.

Appendix B. Minority Comments on General Reporting Principles

The report of the FASAB Natural Resources Task Force provides useful information concerning the proper Federal accounting treatment of natural resources. However, some of the report's basic recommendations appear to fall short of providing the most useful accounting framework for management and policy making. This appendix explains those concerns.

The concerns fall into three main areas.

- First, we think that the basic concepts of SSFAS No.7 are valid, and that sales of natural resources should not offset agencies' gross costs, unless the full costs of the natural resources sold are recognized. In contrast, one alternative (*Option 2* on page 32) in the document does not promote recognition of the Government's true opportunity costs, and would enable revenue from seemingly costless asset sales to offset other costs in a manner that could encourage inefficient sales and management.

- Second, we think that it would be appropriate for some natural resource assets -- in particular, those where the asset is held for remunerative operations or sale -- to be recognized on the balance sheet, and not solely in the stewardship report. This would also allow the full costs of natural resources that are sold to be recognized on the Statement of Net Cost.

- Finally, the objective of the FASAB statements should be to develop an accounting framework that will assist program managers and policy makers in their decision making. The report raises a valid concern about the lack of good information on many Federal natural resources. Our view is that at least part of the solution to this problem is for the Government to develop basic data where it has valuable resources that it intends to sell or manage for remunerative purposes.

These concerns are discussed below.

Net Costs and SSFAS No.7

FASAB designed the Statement of Net Cost to relate the cost of operations to performance measures. To meet the operating objectives laid out in SFFAC No. 1, *Objectives of Federal Financial Reporting*, cost must be matched with the provision of goods and services to the public or other Government entities. To determine the net cost of an exchange activity -- i.e., the part of the cost that is not offset by revenue earned from the goods and services provided -- the related revenue must be matched with the cost. When this is done, the gross and net cost of an entity can be compared with its related outputs and outcomes to evaluate its operating performance, pricing policy, and economic decisions. Similarly, the net cost to the taxpayer can be estimated for the activity's related outputs provided to the public. The standards in SFFAS No. 7 therefore provide for matching exchange revenue against related cost as closely as practicable.

This ideal model breaks down when a major part of an entity's gross costs are not recognized. SFFAS No. 7 gives two examples: the rents and royalties collected by the Minerals Management Service (MMS) for natural resources on the Outer Continental Shelf and other lands, and the FCC's auction of the radio spectrum. Since the cost of the natural resource is not recognized, the Statement of Net Cost can report only a fraction of the gross cost of operations. As a result, the exchange revenue cannot be matched against the economic cost of operations and bears little relationship to the recognized cost of the entity. If the exchange revenue were subtracted from the recognized costs, the relationship between the entity's net cost of operations and its measures of performance would be distorted. It would appear as though the selling entity was very efficient in its operations, whereas it was merely disposing of Federal assets acquired for the most part by exercising sovereign powers. Our belief is that this would violate the concept of the Statement of Net Cost and undermine the reasons for instituting it.

We therefore believe that FASAB was correct in excluding such exchange revenue from the Statement of Net Cost and instead requiring it to be accounted for as a financing source in the Statement of Changes in Net Position (and, if collected on behalf of others, to be reported as a custodial activity by the collecting entity). The Statement of Net Cost is distorted less than under any other treatment, and full visibility and accountability are maintained through other basic financial statements.

Currently, most Federal natural resources do not have significant recognized costs; the one exception may be timber on land that has been reforested. The main costs that would be reflected on agencies' Statements of Net Cost, under *Option 2* (page 32), would be just the costs of holding the sales (e.g., costs of surveys) and ongoing management. *Option 2* does not include opportunity costs -- such as current cost, market value, net realizable value, or related measures of depletion -- be reported. The following sections discuss how this might be accomplished.

Economically Productive Assets and the Balance Sheet

The report notes that a key problem with showing resource costs on the balance sheet or on the Statement of Net Cost is that information is poor. For instance, for minerals for which mining patents can be issued under the 1872 law, the Government does not make an estimate of reserves prior to sale, nor does it receive information on extraction after the sale.

We realize that there are instances when it would not be cost-effective to value many Federal natural resource holdings. Nevertheless, we think there are some cases where the Government should report asset values on the balance sheet and full cost minus earned revenue on the Statement of Net Cost. These cases are characterized by the intent to use the resources in a remunerative fashion. Resources that are being kept for "stewardship" in the traditional sense of the word (e.g., in national parks or wilderness areas) would not be reported on the balance sheet but rather would be covered in the stewardship report. (While in principle one might estimate the value of such lands for recreation or wildlife habitat uses (as well as resource extraction), in practice this would not be necessary at this time, unless one is interested in comparing preservation with alternative uses.)

Some kinds of resource costs or values would be easier to estimate than others. Forest Service timber and Bureau of Land Management forage are prime examples of resources that could be placed on the balance sheet. These assets have values that can be adequately estimated with surveys, photographs, and consideration of market conditions. While it may be impractical to value all Federal timber (or forage), it could be useful to value parcels expected to be offered for sale in the next 5 to 10 years. (A five-year period would match the budget period considered under the pay-as-you-go rules of the House of Representatives; a ten-year period would match the budget period considered by the Senate.) Timber that is unlikely to be offered -- e.g., because it is in wilderness areas -- would not be reported. Conceivably OCS leases might also be reported on the balance sheet, too, so long as publishing such information does not conflict with the objective of getting market value for the leases. (While arguably such publication could sometimes reduce bids, it would probably not be biased against receipt of fair market value).

Recognizing Information Needs

The fact that existing information is poor, however, does not imply that this situation should continue. Rather, information should be improved in cases where the benefits to having that information for decision-making exceed its cost. When the government is contemplating sale of the natural resource, information on its cost and value are important to the decision and policy and would be estimable in many, if not most, cases where they are not now estimated. We agree that resources with values that cannot be estimated in a reliable and cost-effective manner should be considered in the stewardship report. The rebuttable presumption, however, should be that resources used for remunerative purposes should be reported on the balance sheet and Statement of Net Cost.

For example, if better information were available on the value of minerals and lands that are currently subject to the 1872 mining law, it is possible that Federal sales policy would change and result in higher Federal receipts. At a minimum, better estimates would inform policy makers and the public and would improve the quality of the government's financial statements. For these resources, possible information alternatives include 1) very aggregate estimates of mineral and land value based on regional surveys or 2) more detailed assessments for tracts that are sold. As noted above, to improve feasibility the focus could be on resources expected to be offered over the next 5 to 10 years, rather than all resources. We recognize one might argue that because current law allows these lands and minerals to be sold for trivial payments, researching the value of these lands would be "throwing good money after bad." While there are different views on this issue, we think it is consistent with financial accountability for there to be improved recognition of the costs and benefits of natural resource transfers.

In principle, the measure of natural resource costs could be based either on gross market value or on estimated net realizable value (estimated market value net of expected sale costs). The gross measure has the advantage of being easier to estimate and less susceptible to manipulation (such as overstatement of expected sale costs); the net measure has the advantage of recognizing that sale costs must generally be incurred to realize any receipts. To best recognize likely realizable benefits, we lean toward using the net realizable value measure. With this approach agencies would not tend to show losses from their activities, as they would if assets were valued at gross market value; rather, agencies' actual revenues from sales, minus their sale costs, would tend to equal the resources' estimated values on the balance sheet. While high estimates of sales costs could depress estimated net asset values -- and thereby enable agencies to mask inefficient sale and management practices -- agencies would also have incentives to incur actual sale costs below their estimates and thereby realize a net gain. Agencies which -- consistent with SSFAS No. 7 -- sell resources but do not report the net realizable costs and the corresponding sale revenues on the Statement of Net Cost would tend to show higher net costs (because sale costs would continue to be reported) than agencies that do report information on net realizable costs and associated revenues. Thus, there would be accounting incentives to move toward development of better information on the value of Federal resources.

The balance sheet should be based upon the same concept of the resource value or cost as the Statement of Net Cost (i.e., current cost, market value, or estimated net realizable value). While our inclination is toward estimated net realizable value, note that realizable value could be constrained by legal and regulatory limits on sale prices. Our inclination is that realizable value be based on market value, without exceptional constraints such as are present for mining or forage lands. Finally, if production (e.g., reforestation) costs are high, both gross-market and realizable value measures might understate the Government's opportunity costs. The balance sheet should show the asset value based on (net realizable) market valuation. Presumably this same value would also be reported on the Statement of Net Costs when an asset is sold; where production costs are greater than the asset's market value, this should be noted too, perhaps through use of footnotes. This treatment would be somewhat analogous with the treatment of inventory under "lower-of-cost-or-market " rules.

Attachment A. Suggested Clarifications to Existing Revenue Standard (SFFAS No. 7)

Presented below are the task force's suggested clarifications to SFFAS No. 7 that would require all natural resource revenues to be reported as a custodial activity. Proposed additions to SFFAS No. 7 are highlighted with an underline (underline) and proposed deletions are highlighted with a strike-out (~~strike-out~~.)

(paragraph numbers reference to SFFAS No. 7)

45. Under ~~exceptional~~ some circumstances, such as ~~rents and royalties on the Outer Continental Shelf,~~ revenues from the sale of most natural resources, an entity ~~recognizes virtually no costs (either during the current period or during past periods) in connection with earning revenue it collects.~~ has recognized no value on the balance sheet for an asset it sells. Thus, the entity cannot recognize a cost for the asset itself when it is sold.

A. In such cases, even though the collecting entity incurs some management and selling costs which could be related to the revenue, the collecting entity should not offset its gross costs by such exchange revenue in determining its net cost of operations. If such exchange revenue is retained by the entity, it should be recognized as a financing source in determining the entity's operating results. If, instead, such revenue is collected on behalf of other entities (including the U.S. government as a whole), the entity that collects the revenue should account for that revenue as a custodial activity, i.e., an amount collected for others.

B. If the collecting entity transfers the exchange revenue to other entities, similar recognition by other entities is appropriate.

a. If the other entities to which the revenue is transferred also recognize ~~virtually no costs in connection with the Government earning the revenue~~no value on the balance sheet for the asset which was sold, the amounts transferred to them should not offset their gross cost in determining their net cost of operations but rather should be recognized as a financing source in determining their operating results.

b. If the other entities to which the revenue is transferred ~~do~~ have recognized ~~costs in connection with the Government earning the revenue~~a value on the balance sheet for the asset which was sold, the amounts transferred to them should offset their gross cost in determining their net cost of operations.

c. Because the revenue is exchange revenue regardless of whether related asset costs are recognized, it should be recognized and measured under the exchange revenue standards.

[Skip to 139.]

139. The only exception to the general rule occurs when the entity recognizes ~~virtually~~ no asset cost in earning the exchange revenue, as explained in the following section.

140. **Exchange revenue unrelated to recognized cost.** In ~~exceptional~~some cases, such as revenues from the sale of most natural resources, an entity ~~may recognize virtually no costs in connection with earning revenue it collects.~~ has recognized no value on the balance sheet for the asset it sells. Thus, the entity cannot recognize a cost for the asset itself when it is sold. While it may incur some management and selling costs which could be related to the revenue, it should not offset its gross costs by the revenue to determine its net cost of operations. An ~~major~~example for many years has been the Mineral Management Service (MMS) of the Department of the Interior. It manages energy ...

141. MMS does not recognize a depletion cost ~~for various reasons, including the fact that under present accounting standards~~ because the value of natural resources is not recognized as an asset. As a result, this exchange revenue cannot be matched against the economic cost of operations and bears little relationship to the recognized cost of MMS. Therefore, it should not be subtracted from MMS's gross cost in determining its net cost of operations. If it were subtracted, the relationship between MMS's net cost of operations and its measures of performance would be distorted. This distortion would likely be greater than the distortion that will occur because of not matching any of the revenue with the management and selling costs of producing it. Similarly, the net cost of operations of the Department of the Interior would likewise be more distorted than it will be because of not matching any of the revenue with management costs.

142. No changes.

143. The rents, royalties, ~~and~~ bonuses, and other receipts from the sale of natural resources which are transferred to Treasury for the General Fund or to other Government reporting entities should be recognized similarly by these recipient entities. The revenue is exchange revenue and should be recognized and measured under the exchange revenue standards. However, neither the Government as a whole nor the other recipient entities recognize the natural resources as an asset and depletion as a cost. Therefore, the revenue should not offset the cost of operations for the U.S. Government as a whole or for these entities. As in the case of MMS, offsetting cost by this revenue would distort the relationship between the net cost of operations and the measures of the performance of these entities. This distortion would likely be greater than the distortion that will occur because of not matching revenue with the management costs which are incurred. The exchange revenue should instead be a financing source in determining the operating results and change in net position.

~~144. The Board is addressing the accounting for natural resources in a separate project. If it concludes that the value of mineral rights should be recognized as an asset and depletion as a cost, it would be~~

~~appropriate to recognize the exchange revenue from rents, royalties, and bonuses in determining the net cost of operations.~~

145. Although MMS is the most prominent case of an entity collecting exchange revenue for which it has recognizes~~s~~d ~~virtually~~ no asset cost, ~~there can be other instances.~~all natural resources present the same situation. For example, the Federal Communications Commission collects exchange revenue from the auction of the radio spectrum. Such revenue should be accounted for in the same way as the revenue collected by MMS.

146. One respondent to the Exposure Draft asked about the meaning of the term "virtually no costs." If an entity sells scrap metal or fully depreciated equipment, the exchange revenue or gain is not related to any cost that is recognized at the time of sale. These assets are recorded on the balance sheet as having no value at the time of sale, so the gross proceeds from the sale are not offset by any remaining book vale in calculating the entity's gain. However, unlike ~~the auctions of petroleum rights or the radio spectrum~~ the sale of natural resources, costs were recognized in past periods for the purchase of the materials or the use of the equipment. Therefore, offsetting the entity's cost by its gains from sale provides a more accurate measure of its net cost of operations over time for comparison with measures of performance over time. The standard has been ~~clarified to say that the term "virtually no costs" means that virtually no costs are recognized during past periods as well as during the current period~~ reworded so that the term "virtually no cost" is not used and has been clarified to specify that the entity has recognized no value on the balance sheet for an asset it sells because the asset is reported as required supplementary stewardship information.

Federal Accounting Standards Advisory Board
Task Force Discussion Paper
Accounting for the Natural Resources of the Federal Government
June 2000

Federal Accounting Standards Advisory Board

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FASAB

Federal Accounting Standards Advisory Board

Accounting for

Federal Oil and Gas Resources

Proposed Statement of Federal Financial Accounting Standards

Exposure Draft

~~Written comments are requested by September 21, 2007~~

Written comments are requested by January 11, 2008

May 21, 2007

THE FEDERAL ACCOUNTING STANDARDS ADVISORY BOARD

The Federal Accounting Standards Advisory Board (FASAB or "the Board") was established by the Secretary of the Treasury, the Director of the Office of Management and Budget (OMB), and the Comptroller General in October 1990. It is responsible for promulgating accounting standards for the United States Government. These standards are recognized as generally accepted accounting principles (GAAP) for the Federal Government.

An accounting standard is typically formulated initially as a proposal after considering the financial and budgetary information needs of citizens (including the news media, state and local legislators, analysts from private firms, academe, and elsewhere), Congress, Federal executives, Federal program managers, and other users of Federal financial information. The proposed standard is published in an Exposure Draft for public comment. In some cases, a discussion memorandum, invitation for comment, or preliminary views document may be published before an exposure draft is published on a specific topic. A public hearing is sometimes held to receive oral comments in addition to written comments. The Board considers comments and decides whether to adopt the proposed standard with or without modification. After review by the three officials who sponsor FASAB, the Board publishes adopted standards in a Statement of Federal Financial Accounting Standards. The Board follows a similar process for Statements of Federal Financial Accounting Concepts, which guide the Board in developing accounting standards and formulating the framework for Federal accounting and reporting.

Additional background information is available from the FASAB:

- "Memorandum of Understanding among the General Accounting Office, the Department of the Treasury, and the Office of Management and Budget, on Federal Government Accounting Standards and a Federal Accounting Standards Advisory Board."
- "Mission Statement: Federal Accounting Standards Advisory Board"

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Federal Accounting Standards Advisory Board

May 21, 2007

TO: ALL WHO USE, PREPARE, AND AUDIT FEDERAL FINANCIAL INFORMATION

The Federal Accounting Standards Advisory Board (FASAB) is requesting comments on the exposure draft (ED) of a proposed Statement of Federal Financial Accounting Standards entitled *Accounting for Federal Oil and Gas Resources*. Currently, there are no specific accounting standards for Federal oil and gas resources. This ED contains proposed standards that would address the recognition of an asset and a related liability, revenue and expense, gains and losses, and rights to future royalty streams identified for sale, as well as implementation guidance for the Federal government's royalty share of proved oil and lease condensate, natural gas plant liquids (NGPLs), and gas reserves. It would also address disclosure requirements and required supplementary information (RSI) for other Federal oil and gas resources not classified as proved reserves. The standards proposed in this ED would take effect for accounting periods beginning after September 30, 2009.

Specific questions for your consideration begin on page vii but you are welcome to comment on any aspect of this proposal. Your responses to the questions would be more helpful to the Board if you explain the reasons for your position and any alternative you propose. It should be noted that question two (Q2) deals with an alternative view to the measurement approach proposed to value the asset. (See alternative view beginning at paragraph A119.) Responses are requested by ~~September 21, 2007~~ **January 11, 2008**. All comments received by the FASAB are considered public information. Those comments may be posted to the FASAB's website and will be included in the project's public record.

We have experienced delays in mail delivery due to increased screening procedures. Therefore, please provide your comments in electronic form. Responses in electronic form should be sent by e-mail to fasab@fasab.gov. If you are unable to provide electronic delivery, we urge you to fax the comments to (202) 512-7366. Please follow up by mailing your comments to:

Wendy M. Payne, Executive Director
Federal Accounting Standards Advisory Board
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The Board's rules of procedure provide that it may hold one or more public hearings on any exposure draft. No hearing has yet been scheduled for this exposure draft. Notice of the date and location of any public hearing on this document will be published in the Federal Register and in the FASAB's newsletter.

Tom L. Allen
Chairman

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EXECUTIVE SUMMARY

What is the Board proposing?

This exposure draft (ED) proposes accounting standards for Federal oil and gas resources.[1] The proposed standards would result in the recognition of an asset and a related liability. The asset would be referred to as "estimated petroleum royalties." The asset's value would be the royalty share of the Federal oil and gas resources classified as "proved reserves."[2] The asset's value would be calculated by multiplying the estimated quantity of proved oil and lease condensate,[3] natural gas plant liquids (NGPLs),[4] and gas reserves by the effective average royalty rate for each quantity and by the average per unit price for each quantity. An alternative approach to valuing estimated petroleum royalties is fair value. One Board member believes that fair value is feasible and preferable (See alternative view beginning at paragraph A119). The Board member believes that fair value could be derived from market transactions or discounted cash flows.

The related liability would be for the royalty share of the Federal oil and gas resources classified as "proved reserves" designated to be distributed to others, i.e., state governments and – at the component entity level – other federal agencies and the general fund of the U.S. Treasury. The liability would be calculated by assessing the total estimated petroleum royalties to be distributed to others.

When oil and gas resources are extracted and royalties are earned, revenue and a depletion expense equal to the earned revenue would be recognized by the Federal government. When revenue collections are distributed a reduction in the liability for revenue distributions to others would be recognized. Gains and losses due to changes in the estimated quantity of proved oil and lease condensate, NGPLs, and gas reserves,[5] the effective regional average royalty rates, and the average per unit prices would be recognized based on an annual valuation of the asset with an associated adjustment to the liability for revenue distributions to others. In addition, when rights to a future royalty stream are identified to be sold, the value of the related rights would be disclosed.

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[1] Federal Oil and Gas Resources: Oil and gas resources over which the Federal government may exercise sovereign rights with respect to exploration and exploitation and from which the Federal government has the authority to derive revenues for its use. Federal oil and gas resources do not include resources over which the Federal government acts as a fiduciary for the benefit of a nonfederal party.

[2] A portion of the production value of proved oil and gas reserves are due the Federal government from the lessee in accordance with the royalty rate contained in the lease agreement.

[3] Lease condensate: A mixture consisting primarily of pentanes and heavier hydrocarbons which is recovered as a liquid from natural gas in lease separation facilities.

[4] Natural gas plant liquids (NGPLs): Those hydrocarbons in natural gas that are separated as liquids at natural gas processing plants, fractionating and cycling plants, and, in some instances, field facilities. Lease condensate is excluded. Products obtained include ethane; liquefied petroleum gases (propane, butanes, propane-butane mixtures, ethane-propane mixtures); isopentane; and other small quantities of finished products, such as motor gasoline, special naphthas, jet fuel, kerosene, and distillate fuel oil.

[5] Changes in the estimated quantity of proved oil and lease condensate, NGPLs, and gas reserves result from changing economic conditions, technological advancements, improved information, new leases, and other changes.

Transition to these proposed standards would require that the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves be recognized as an asset and a related liability be established as of the beginning of the reporting period in which the standards become effective. This net effect of recognizing the asset and establishing the related liability at the beginning of the reporting period would be a change in accounting principle that increases the entity's net position. Additional information about Federal oil and gas resources not classified as proved reserves would be disclosed in notes to the financial statements or reported as required supplementary information (RSI).

The proposed standards would be effective for periods beginning after September 30, 2009, with early implementation permitted.

Why is the Board making this proposal?

The Board issued accounting standards applicable to land in 1995 and 1996 but elected to specifically exclude natural resources from the scope of those standards. Extensive Federal oil and gas resources exist on public lands throughout the country and on the Outer Continental Shelf (OCS). Currently, federal financial reporting does not provide information about the quantity or value of these assets. In addition, royalty revenues are recognized but expenses are not recognized for the asset exchanged to produce those revenues. The Board is proposing standards that would fill this void in financial accounting standards and result in information that contributes to meeting federal financial reporting objectives.

Challenges regarding accounting for these assets include obtaining reliable estimates of the quantity of resources, determining a relevant value for the assets, and ensuring that the cost of doing so does not exceed the benefits. This proposal would make use of information currently available – estimates of proved reserves currently provided to the Energy Information Administration (EIA) on an annual basis, average regional prices and average regional royalty rates. This proposal would not result in new assessments of the quantity of reserves or require modeling of expected cash flows to be derived from current leases. This proposal would result in implementation of the existing exchange revenue accounting model for royalty revenues earned during each period. The Board believes that this proposal would fill a substantial void in the accounting standards in the most practical manner available.

How does this proposal improve Federal financial reporting?

Federal oil and gas resources represent Federal assets. Accounting for and reporting information about these assets would enhance:

a. Accountability for and stewardship over assets of the Federal government.
b. Consistency and understandability in accounting for assets of the Federal government.
c. Relevance, consistency, and comparability of information regarding revenue of the Federal government.

Recognizing the Federal government's royalty share of proved reserves as an asset with a related liability on the balance sheet would provide transparency regarding the value and changes in value of these significant assets. Federal financial reports would be more relevant, consistent, and complete. Additional disclosures about Federal oil and gas resources would provide comprehensive information about Federal assets, reveal changes in the quantity and status of oil and gas resources, and make quantity information more accessible to users of financial information.

Bonus bid, rent, and royalty collections – currently treated as nonexchange revenue due to the absence of cost information – would be accounted for and reported in accordance with exchange revenue standards. This treatment would improve the comparability of revenue information.

How does this proposal contribute to meeting the Federal financial reporting objectives?

Based on the objectives outlined in Statement of Federal Financial Accounting Concepts Statement (SFFAC) 1, *Objectives of Federal Financial Reporting*, the operating performance and stewardship objectives were identified as most important for natural resources reporting.

With respect to meeting the operating performance reporting objective, the proposed standard would provide information useful in evaluating the reporting entity's management of assets relating to oil and gas resources. The proposal would result in disclosure of the quantity of proved reserves at the end of each period, the average sales value of resources extracted during the period, the effective average royalty rate realized during the period and the end of period value of all estimated petroleum royalties. This information would allow financial report users to monitor changes in royalty rates and estimated reserve quantities; providing an indicator of how well the government's proved reserves were managed. In addition, the value of the estimated petroleum royalties at the end of each period would facilitate consideration of the potential cash flows from existing leases.

Operating Performance Objective
Federal financial reporting should assist report users in evaluating the service efforts, costs, and accomplishments of the reporting entity; the manner in which these efforts and accomplishments have been financed; and the management of the entity's assets and liabilities. Federal financial reporting should provide information that helps the reader to determine • the costs of providing specific programs and activities and the composition of, and changes in, these costs; • the efforts and accomplishments associated with federal programs and the changes over time and in relation to costs; and • the efficiency and effectiveness of the government's management of its assets and liabilities. Source: SFFAC 1

Currently, royalties from oil and gas leases are displayed on the Statement of Changes in Net Position with non-exchange revenue rather than on the Statement of Net Cost with other exchange revenue. Presentation of revenues arising from oil and gas leasing activities as exchange revenue would assist users in understanding how the government's efforts and accomplishments were financed. The current practice of combining revenues derived from the sale of assets with revenues derived from taxation or other non-exchange sources may obscure the fact that the gains were obtained through the exchange of resources—proved reserves for a future stream of royalty payments.

With respect to meeting the stewardship reporting objective, the proposed standard would provide information useful in assessing whether Federal government operations have contributed to the nation's current and future well-being. Recognition of estimated petroleum royalties as an asset would make available the value of an asset that generates cash to finance government operations over time. This would inform users about the financial position of the government and whether it was improving or deteriorating over time. Information about potential oil and gas production and changes in potential production over time would allow users to consider how government operations and economic conditions have impacted the availability of oil and gas resources to future generations.

Stewardship Objective
Federal financial reporting should assist report users in assessing the impact on the country of the government's operations and investments for the period and how, as a result, the government's and the nation's financial condition has changed and may change in the future. Federal financial reporting should provide information that helps the reader to determine whether • the government's financial position improved or deteriorated over the period, • future budgetary resources will likely be sufficient to sustain public services and to meet obligations as they come due, and • government operations have contributed to the nation's current and future well-being. Source: SFFAC 1

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REQUEST FOR COMMENTS

The FASAB encourages you to become familiar with all proposals in this proposed Statement before responding to the questions in this section. The paragraphs cited in a question are particularly relevant to that issue, but other portions of the document also may enhance your understanding of the question. The Board also would welcome your comments on other aspects of the proposals in this proposed Statement.

The Board believes that this proposal would improve Federal financial reporting and contribute to meeting the Federal financial reporting objectives. The Board has considered the perceived costs associated with this proposal. In responding, please consider the expected benefits and perceived costs and communicate any concerns that you may have in regard to implementing this proposal.

The Board believes that pilot tests are beneficial and can assist the Board in resolving complex issues not found in existing standards. This proposal introduces a new valuation technique. In addition, one member has recommended a different valuation technique -- fair value. The Department of the Interior will conduct a pilot test of the proposal during the comment period. The results of the pilot test will assist the Board in evaluating alternative methods and developing a final standard.

Because the proposals may be modified before a final Statement is issued, it is important that you comment on proposals that you agree with as well as any that you disagree with. Comments that include the reasons for your views will be especially appreciated.

The questions in this section are available in a Word file for your use at www.fasab.gov/exposure.html. Your responses to the Request for Comments questions should be sent by e-mail to fasab@fasab.gov. If you are unable to respond electronically, please fax your responses to (202) 512-7366 and follow up by mailing your responses to:

Wendy M. Payne, Executive Director
Federal Accounting Standards Advisory Board
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441 G Street, NW, Suite 6814
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All responses are requested by ~~September 21, 2007~~**January 11, 2008**.

Q1. The proposed standards would provide for recognition of the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves. These reserves are subcomponents of the total oil and gas resources of the Federal government. Please see page 20 for an illustration of Federal oil and gas resource components and subcomponents.

The Board's proposal for quantifying the Federal government's royalty share of proved reserves is to use a single best estimate of recovering reserves based on known geological, engineering, and economic data. This approach is known in the oil and gas industry as the deterministic method. This method would exclude reserves other than proved reserves. In contrast, a probabilistic method of estimation uses the known geological, engineering, and economic data to generate a range of estimates and their associated probabilities of recovering reserves. It would include more than proved reserves. See paragraphs A73 through A78 for additional information regarding the deterministic and probabilistic methods for measuring and reporting proved oil and lease condensate, NGPLs, and gas reserves.

Determination of Quantity:

a. Which of the following two options would you prefer?
    i. Capitalize estimated petroleum royalties from the proved reserves based on the deterministic method as proposed in the ED.
    ii. Capitalize estimated petroleum royalties from proved reserves, probable reserves, and possible reserves based on the methodology proposed in the alternative view. See the alternative view beginning at paragraph A119.
b. Please explain the reasons for your preference.
c. If you prefer a different basis for determining the quantity of reserves, please explain the alternative you propose and why you prefer it.

Q2. The Board proposes to value the Federal government's royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date. See paragraphs 16 through 19 and 37. Also, see paragraphs A48 through A53 for a discussion of measurement attributes that were considered and paragraphs A79 through A113 for a discussion of the valuation approach proposed. An alternative approach to valuing estimated petroleum royalties is fair value. Fair value is the price that would be received for an asset or paid to transfer a liability in a transaction between market participants at the measurement date. One Board member believes that fair value is feasible and preferable. See the alternative view beginning at paragraph A119. The Board member believes that fair value could be derived from market transactions or discounted cash flows. The view of the majority of the Board members is that fair value would not produce a more reliable valuation than the valuation method proposed in this ED due to the challenges in adopting a fair value method.

Determination of Value:

a. Which method do you believe is most appropriate for valuing estimated petroleum royalties?
    i. Value the royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date.
    ii. Value estimated petroleum royalties using the alternative view fair value method.
b. Please explain the reasons for your preference.
c. If you prefer a different method for valuing estimated petroleum royalties, please describe the method you propose and why you prefer it.

Q3. Some Board members believe that the amount of information proposed to be disclosed in the notes and provided as RSI is excessive. See the disclosure and RSI requirements presented in paragraphs 30 through 34 and Appendix D for a complete review of all proposed disclosures and RSI.

a. Do you believe that each item of information, whether disclosed in the notes or provided as RSI, is necessary to meet reporting objectives and is cost-beneficial to provide? Particularly, consider Table 1 on pages 68 and 69 and Table 2 on pages 70 and 71. It would be helpful if specific information that respondents believe could be deleted or added were identified.
b. How would each item of information be used for decision-making or assessing the financial position of the Federal government?
c. Please explain the reasons for your position and any alternative you propose.

Q4. The proposed standards would require that an estimated value for royalty relief be reported as RSI. The Minerals Management Service (MMS) has a variety of royalty relief programs. Royalty relief is the reduction, modification, or elimination of any royalty to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. See paragraphs A90 through A94 for additional information regarding MMS royalty relief programs.

a. Do you believe that a monetary value for royalty relief should be reported as RSI? Please explain the reasons for your position.
b. Do you believe the quantity of production for which relief was granted during the reporting period should be reported as RSI? Please explain the reasons for your position.

Q5. Statement of Federal Financial Accounting Standards (SFFAS) 7, *Accounting for Revenue and Other Financing Sources* (as amended), requires that agencies report on assets held in a fiduciary capacity.[6] The Board recently issued SFFAS 31, *Accounting for Fiduciary Activities*. SFFAS 31 will supersede SFFAS 7 with respect to fiduciary activities but continues the requirement to report on assets held in a fiduciary capacity. The Department of Interior (DOI) manages oil and gas resources on behalf of individual Indians and Indian tribes. This proposed standard – because it classifies oil and gas resources as assets – would result in additional information being disclosed for oil and gas assets managed in a fiduciary capacity. Note, however, that fiduciary reporting does not extend to inclusion of the additional disclosures or RSI that are proposed in this document for Federal oil and gas resources. Thus, with respect to fiduciary activities, only disclosure of the assets, liabilities, and related inflows and outflows would result from this proposal.

Some Board members have expressed concern that the costs may exceed the benefits of disclosing fiduciary assets and liabilities measured in conformance with this proposed standard. Since this proposal may significantly increase the fiduciary assets disclosed, we are requesting input on the cost-benefit of the requirement with respect to fiduciary activities. See paragraph 34.

[6] SFFAS 7, paragraphs 83 to 87.

a. Do you believe it is cost-beneficial to require disclosure of the value of estimated fiduciary petroleum royalty assets, liabilities, and related inflows and outflows? Please explain the basis for your beliefs.

Q6. The proposed standards would require the component entity to provide extensive disclosures and RSI. However, the Consolidated Financial Report (CFR) of the United States government would be required to include limited disclosures and no supplementary information. See paragraphs 31 through 33. These divergent reporting requirements are consistent with SFFAC 4, *Intended Audience and Qualitative Characteristics for the Consolidated Financial Report of the United States Government*. SFFAC 4 provides that the CFR should be highly aggregated and offer references to other reports.

a. Do you believe that the CFR disclosure requirements should be limited as proposed? Please explain the basis for your beliefs.

Q7. This proposal includes accommodations intended to reduce the cost or burden of implementation. These accommodations are identified below along with the alternatives considered and rejected by a majority of the members. Please comment on any accommodation that you believe is not appropriate or that you believe does not sufficiently reduce the cost or burden of the proposal.

a. Asset recognition is limited to proved reserves. However, the Board believes that other than proved reserves (e.g., unproved reserves and undiscovered resources) also are assets. See paragraphs A43 through A47 and A73 through A78.
b. The valuation technique provided relies on readily available information. However, fair value, which would require additional information, may be a more appropriate valuation technique. See paragraphs A48 through A54.
c. This proposal requires use of existing sales volume and sales value information to determine an average price for end of period valuation. Use of market prices as of the end of the reporting period was considered. In addition to the relative cost of obtaining market values, the Board does not believe the valuation would be improved. See paragraph A82.
d. Information to calculate effective royalty rates is readily available and the proposal provides for their use in valuing estimated petroleum royalties. An alternative considered was the use of statutory provisions for certain types of leases. See paragraph A101.
e. Regional data is readily available and the proposal provides for its use in valuing estimated petroleum royalties. An alternative considered was the use of field by field data. See paragraphs A56 and A101.

INTRODUCTION

1. The purpose of this document is to solicit comments on proposed accounting standards for Federal oil and gas resources.
2. In late 2002, the Board began its deliberations on Federal natural resources. The Board decided that each type of natural resource (e.g., fluid leasable minerals such as oil and gas, and solid leasable minerals such as coal and timber) would be separately addressed in phases beginning with Federal oil and gas resources. Federal oil and gas resources were addressed first due to the literature available, the extensive historical information on Federal lease programs and royalty collections, and the large amount of oil and gas royalty collections made by the Federal government.
3. The proposed standards address the recognition of an asset, liability, revenue, expense, and gains and losses based on valuation of the asset at year-end. Disclosures are proposed for rights to future royalty streams identified for sale. Implementation guidance for proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources is proposed. The proposed standards also address disclosure requirements and RSI for Federal oil and gas resources not classified as proved reserves.
4. The proposed standards, if adopted, would be effective for periods ending after September 30, 2009.

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PROPOSED ACCOUNTING STANDARDS

Definitions in paragraphs 5 through 15 are presented first in the proposed accounting standards because of their uniqueness in calculating the asset value of estimated petroleum royalties. Other terms shown in **boldface type** the first time they appear in this document are presented in the Glossary (see page 75). Reviewers of this document may want to examine all definitions before reviewing the proposed accounting standards and Basis for Conclusions.

Definitions

5. Federal Oil and Gas Resources: Oil and gas resources over which the Federal government may exercise sovereign rights with respect to exploration and exploitation and from which the Federal government has the authority to derive revenues for its use. Federal oil and gas resources do not include resources over which the Federal government acts as a fiduciary for the benefit of a non-Federal party.

6. Regional Estimated Quantity of Proved Oil and **Lease Condensate** Reserves: The regional estimated quantities of proved oil and lease condensate reserves are those quantities of oil and lease condensate from Federal oil and gas resources that are totaled for a specified region. Quantities of oil and lease condensate are estimated in barrels (one barrel holds 42 U.S. gallons) at 60 degrees Fahrenheit.

7. Regional Estimated Quantity of Proved **Natural Gas Plant Liquids** Reserves: The regional estimated quantities of proved natural gas plant liquids (NGPLs) reserves are those quantities of NGPLs from Federal gas resources that are totaled for a specified region. Quantities of NGPLs are estimated in barrels (one barrel holds 42 U.S. gallons) at 60 degrees Fahrenheit.

8. Regional Estimated Quantity of Proved Gas Reserves: The regional estimated quantities of proved gas reserves are those quantities of **dry gas** from Federal gas resources that are totaled for a specified region. Quantities of gas are estimated in thousands of cubic feet (Mcf) at 14.73 pounds per square inch absolute (PSIA) at 60 degrees Fahrenheit.

9. Regional Average First Purchase Price for Oil and Lease Condensate: The regional average **first purchase price** for oil and lease condensate is calculated by dividing the total regional **sales value** of oil and lease condensate produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months by the total regional **sales volume** of oil and lease condensate produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months. All types of crude **oil streams** and **gravity bands** are aggregated for this calculation.

10. Regional Average First Purchase Price for NGPLs: The regional average first purchase price for NGPLs is calculated by dividing the total regional sales value of NGPLs produced from Federal gas resources in each

associated region for the preceding twelve (12) months by the total regional sales volume of NGPLs produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months.

11. Regional Average Wellhead Price for Gas: The regional average wellhead price for gas is calculated by dividing the total regional sales value of dry gas produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months by the total regional sales volume of dry gas produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months.

12. Effective Regional Average Royalty Rate for Oil and Lease Condensate: The effective regional average royalty rate for oil and lease condensate is calculated by dividing the royalty value (royalties) earned on the oil and lease condensate reserves produced for each associated region for the preceding twelve (12) months by the total sales value of that production for the preceding twelve (12) months.

13. Effective Regional Average Royalty Rate for NGPLs: The effective regional average royalty rate for NGPLs is calculated by dividing the royalty value (royalties) earned on the NGPL reserves produced for each associated region for the preceding twelve (12) months by the total sales value of that production for the preceding twelve (12) months.

14. Effective Regional Average Royalty Rate for Gas: The effective regional average royalty rate for gas is calculated by dividing the royalty value (royalties) earned on the dry gas reserves produced for each associated region for the preceding twelve (12) months by the total sales value of that production for the preceding twelve (12) months.

15. Regional Estimated Petroleum Royalties: Regional estimated petroleum royalties means the estimated end-of-period value of the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources in each region.

Asset Recognition

16. The Federal government's estimated petroleum royalties shall be recognized as an asset on the balance sheet of the component entity that is responsible for collecting royalties. The value of the Federal government's estimated petroleum royalties shall be computed based on the calculation of oil and lease condensate estimated petroleum royalties, NGPLs estimated petroleum royalties, and gas estimated petroleum royalties on a regional basis. Formulas to be used to calculate the estimated petroleum royalties for oil and lease condensate, NGPLs, and gas on a regional basis are as follows:

For oil and lease condensate:

Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves X Regional Average First Purchase Price for Oil and Lease Condensate X Effective Regional Average Royalty Rate for Oil and Lease Condensate = Regional Estimated Petroleum Royalties for Oil and Lease Condensate

For NGPLs:

Regional Estimated Quantity of Proved NGPLs Reserves X Regional Average First Purchase Price for NGPLs X Effective Regional Average Royalty Rate for NGPLs = Regional Estimated Petroleum Royalties for NGPLs

For gas:

Regional Estimated Quantity of Proved Gas Reserves X Regional Average Wellhead Price for Gas X Effective Regional Average Royalty Rate for Gas = Regional Estimated Petroleum Royalties for Gas

17. For purposes of these standards, the regions used in determining and reporting regional amounts or factors shall be collaboratively developed by all the component entities involved in oil and gas resource activities. Regions used in calculating Regional Estimated Petroleum Royalties and in applying these standards shall be consistent and aligned with regions used internally by the component entities in administering Federal oil and gas resource activities.

18. The values of estimated petroleum royalties calculated for oil and lease condensate on a regional basis, NGPLs calculated on a regional basis, and gas calculated on a regional basis shall be added together to provide the total value of estimated petroleum royalties for the Federal government.

19. Detailed guidance for the valuation of estimated petroleum royalties is provided in the “Asset Valuation Guidance” section of these standards, beginning at paragraph 37.

Liability Recognition

20. A liability for revenue distributions to others shall be recognized on the balance sheet of the component entity that is responsible for collecting royalties in conjunction with the recognition of an asset for estimated petroleum royalties. The amount of the liability shall be estimated based on the royalty share of the Federal proved oil and gas reserves designated to be distributed to others, e.g., the states, the general fund of the U.S. Treasury and other federal agencies. For example, the average annual share of the revenue distributed to others over the preceding 12 months may be an acceptable basis for estimating petroleum royalties to be distributed to others. Other methodologies may be acceptable.

Revenue and Expense Recognition

21. Exchange revenue recognition is based on Statement of Federal Financial Accounting Standards (SFFAS) 7, *Accounting for Revenue and Other Financing Sources*, paragraph 34.
22. **Bonus bid** and **rent** revenue relating to Federal oil and gas resources shall be recognized as exchange revenue on the Statement of Net Cost of the component entity that is responsible for collecting royalty revenue. In addition, a liability[7] and corresponding expense and/or transfer out for bonus bid and rent revenue distributions to others shall be recognized by the component entity that is responsible for collecting royalties in conjunction with the recognition of the bonus bid and rent revenue. The amount of the liability shall be the bonus bid and rent revenues designated to be distributed to others, e. g., the states, the general fund of the U.S. Treasury and other federal agencies. The corresponding expense and/or transfer out shall be recognized in a manner consistent with existing standards.
23. **Royalties** from the production of proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources shall be recognized as exchange revenue on the Statement of Net Cost by the component entity that is responsible for collecting the royalty revenue. At the same time, an amount equal to the royalty revenue shall be recognized as depletion expense on the Statement of Net Cost of the component entity that is responsible for collecting the royalty revenue; and, the value of estimated petroleum royalties shall be reduced by the depletion expense amount.[8]

Future Royalty Rights Identified for Sale

24. When rights to a stream of future royalties are identified for sale, the calculated value of those rights shall be disclosed in the notes as "future royalty rights identified for sale." The "future royalty rights identified for sale" shall not be revalued or reclassified to a different asset category on the balance sheet and no gain or loss shall be reported prior to the sale.
25. The calculated value disclosed for future royalty rights identified for sale shall be based on the estimated quantity of proved reserves for the specific **field** to be sold; the first purchase price for oil and lease condensate, the

[7] SFFAS 1, *Accounting for Selected Assets and Liabilities,* par. 83-86, provides that other current liabilities may include unpaid expenses that are accrued for the fiscal year for which the financial statements are prepared and are expected to be paid within the fiscal year following the reporting date. Amounts of bonus bids and rent revenues to be distributed to others may be classified as an other current liability consistent with SFFAS 1 if the definition is met.

[8] The principle that a liability is reduced when funds are distributed is established in other FASAB standards. When bonus bid, rent, and royalties are distributed, the liability for bonus bid, rent, and royalty distributions should be reduced.

first purchase price for NGPLs, or the wellhead price for gas for the specific field to be sold; and the royalty rate for the specific field to be sold.

26. When the future royalty rights identified for sale are sold, the calculated value of the future royalty rights sold shall be based on the quantity of proved reserves sold, the first purchase price for oil and lease condensate, the first purchase price for NGPLs, or the wellhead price for gas for the specific field, and the royalty rate for the specific field. This calculated value shall be removed from the estimated petroleum royalties account at the time of the sale. Any difference between this calculated value and the actual sales proceeds results in a net gain or loss. The net gain or loss shall be reported on the Statement of Net Cost of the component entity that is responsible for collecting royalties. In addition, if the sale produced a net gain, the liability and a corresponding expense and/or transfer-out for the revenue distributions to others shall be increased by an amount equal to the amount of the gain designated to be distributed to others, e.g., the states, the general fund of the U.S. Treasury and other federal agencies. If the sale produced a net loss, the liability and a corresponding expense and/or transfer-out for the revenue distributions to others shall be decreased by an amount equal to the amount of the loss, which will reduce future distributions to others.

Valuing the Estimated Petroleum Royalties

27. The estimated petroleum royalties asset shall be valued at the end of each year for financial statement reporting. Detailed guidance for the calculation of the value of estimated petroleum royalties at year-end is provided in the "Asset Valuation Guidance" section of these standards, beginning at paragraph 37.

28. The calculated value of estimated petroleum royalties at year-end shall be compared to the existing book value of the estimated petroleum royalties asset. If the calculated value of the estimated petroleum royalties asset at year-end is greater than the book value,[9] the book value shall be increased to the new estimate and a gain shall be recorded on the Statement of Net Cost. If the calculated value of the estimated petroleum royalties asset at year-end is less than the book value, the book value shall be decreased to the new estimate and a loss shall be recorded on the Statement of Net Cost.

29. In addition, if the calculated value of the estimated petroleum royalties asset at year-end is greater or less than the book value, the liability for revenue distributions to others shall be increased or decreased to the amount expected to be distributed. For example, the average annual share of the revenue distributed to others over the preceding 12 months may be

[9] The estimated petroleum royalties beginning balance would have been reduced by the amount expensed on the Statement of Net Cost.

an acceptable basis to estimate future distributions. Other methodologies may be acceptable.

Disclosures and Required Supplementary Information

30. Notes to the financial statements are an integral part of the basic financial statements, essential for complete and fair presentation in conformity with generally accepted accounting principles for the Federal government.

Component Entity Disclosures

31. The component entity responsible for reporting the Federal government's estimated petroleum royalties on its balance sheet shall provide the following as note disclosures:

    a. A concise statement explaining how the management of Federal oil and gas resources is important to the overall mission of the entity.
    b. A brief description of the entity's stewardship policies for Federal oil and gas resources. The stewardship policies for Federal oil and gas resources shall describe the guiding principles established to: assess the oil and gas resource areas; offer those resources to interested developers; sell and assign leases to winning bidders; administer the leases; collect bonuses, rents, royalties, and royalty-in-kind; and distribute the collections consistent with statutory requirements, prohibitions, and limitations governing the entity.
    c. A narrative describing future royalty rights identified for sale. The narrative shall provide the value of the rights identified for future sale, the location of the field involved in the future sale, and the best estimate of when the rights would be sold.
    d. A narrative describing and a display showing earned revenue reported by category for the reporting period shall be presented for offshore and onshore revenues for the following categories: royalty revenue earned for oil and lease condensate, royalty revenue earned for NGPLs, royalty revenue earned for gas, earned rent revenue, earned bonus bid revenue for leases, and total revenue from all the above categories.
    e. A narrative describing and a display showing:

        i. The quantity of oil and lease condensate, NGPLs, and gas for each reporting period.
        ii. The average of the Regional Average First Purchase Prices for oil and lease condensate, the average of the Regional Average First Purchase Prices for NGPLs, and the average of the Regional Average Wellhead Prices for gas for each reporting period.
        iii. The average royalty rate oil and lease condensate, NGPLs, and gas for each reporting period.
        iv. The asset value for oil and lease condensate, the asset value for NGPLs, and the asset value for gas for each reporting period.
        v. The value of estimated petroleum royalties at the end of each reporting period.

Component Entity Required Supplementary Information (RSI)

32. The component entity responsible for reporting the Federal government's estimated petroleum royalties on its balance sheet shall provide the following as RSI:

   a. A narrative describing and a display showing the most current and complete information available for **technically recoverable resources**. The most current information for technically recoverable resources maintained by the Energy Information Administration (EIA) shall serve as the basis for this information. The information shall include the estimated quantity of offshore technically recoverable resources from Federal oil and gas resources, the estimated quantity of onshore technically recoverable resources from Federal oil and gas resources, the as-of-date for the information being presented, and a brief explanation of changes to the information from the previous reporting period.
   b. A narrative describing and a display showing the following information for each region that was identified for use in calculating the Federal government's total estimated petroleum royalties:

      i. The sales volume, the sales value, the royalty revenue earned, and the **estimated value for royalty relief** for oil and lease condensate produced from Federal oil and gas resources for the reporting period shall be added together in each region and reported.
      ii. The sales volume, the sales value, the royalty revenue earned, and the estimated value for royalty relief for NGPLs produced from Federal gas resources for the reporting period shall be added together in each region and reported.
      iii. The sales volume, the sales value, the royalty revenue earned, and the estimated value for royalty relief for gas produced from Federal gas resources for the reporting period shall be added together in each region and reported.
   c. A narrative describing and a display showing the following historical information about proved oil and lease condensate, NGPLs, and gas reserves from Federal leases for each of the preceding ten calendar years: adjustments; net revisions; revisions and adjustments; net of sales and acquisitions; extensions; new field discoveries; discoveries in old fields; total discoveries; estimated production; proved reserves; and change from prior year. Definitions for these terms are contained in the Glossary under the subheading **"Historical Estimates of Proved Reserves."**

Consolidated Financial Report (CFR) of the United States Government Disclosures

33. The disclosure related to Federal oil and gas resources shall provide:

a. A concise statement explaining the nature and valuation of Federal oil and gas resources.
b. A narrative describing and a display showing:

   i. The quantity of oil and lease condensate, NGPLs, and gas for each reporting period.
   ii. The average of the Regional Average First Purchase Prices for oil and lease condensate, the average of the Regional Average First Purchase Prices for NGPLs, and the average of the Regional Average Wellhead Prices for gas for each reporting period.
   iii. The average royalty rate for oil and lease condensate, NGPLs, and gas for each reporting period.
   iv. The asset value for oil and lease condensate, the asset value for NGPLs, and the asset value for gas for each reporting period.
   v. The value of estimated petroleum royalties at the end of each reporting period.
c. A reference to specific agency reports for additional information about oil and gas resources.

Disclosure Requirements for Fiduciary Oil and Gas Resources

34. Fiduciary activities are defined in SFFAS 31, *Accounting for Fiduciary Activities*. Information consistent with the requirements of paragraphs 16 through 29 and 37 through 45 of this document shall be presented as an integral part of the fiduciary activities Schedules of Fiduciary Activity and Net Assets. No additional disclosures or RSI are required by this standard.

Implementation Guidance

35. The Federal government's estimated petroleum royalties shall be recognized as an asset as of the beginning of the reporting period in which the standards become effective. The estimated petroleum royalties shall be recognized on the balance sheet of the component entity responsible for collecting royalties. In addition, an offsetting liability shall be recognized for the amount of revenues designated for distribution to others.

36. The cumulative net effect of adopting this proposed accounting standard shall be reported as a "change in accounting principle." The adjustment shall be made to the beginning balance of cumulative results of operations on the Statement of Changes in Net Position for the period that the change is made in accordance with SFFAS 21, *Reporting Corrections of Errors and Changes in Accounting Principles*. In the initial year of implementation, prior year information shall not be restated.

Asset Valuation Guidance

37. The following detailed guidance describes how the value of estimated petroleum royalties should be calculated for transition to these proposed standards and for valuation of estimated petroleum royalties for financial statement reporting at subsequent years-end. The value of the Federal

government's estimated petroleum royalties is to be based on the calculation of oil and lease condensate estimated petroleum royalties, NGPLs estimated petroleum royalties, and gas estimated petroleum royalties on a regional basis. Formulas to be used to calculate the estimated petroleum royalties for oil and lease condensate, NGPLs, and gas on a regional basis are as follows:

<u>For oil and lease condensate:</u>

Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves X Regional Average First Purchase Price for Oil and Lease Condensate X Effective Regional Average Royalty Rate for Oil and Lease Condensate = Regional Estimated Petroleum Royalties for Oil and Lease Condensate

<u>For NGPLs:</u>

Regional Estimated Quantity of Proved NGPLs Reserves X Regional Average First Purchase Price for NGPLs X Effective Regional Average Royalty Rate for NGPLs = Regional Estimated Petroleum Royalties for NGPLs

<u>For gas:</u>

Regional Estimated Quantity of Proved Gas Reserves X Regional Average Wellhead Price for Gas X Effective Regional Average Royalty Rate for Gas = Regional Estimated Petroleum Royalties for Gas

38. Based on quantity information from an annual survey conducted by the EIA, the estimated quantities of proved oil and lease condensate reserves from Federal oil and gas resources are to be added together in each region, the estimated quantities of proved NGPLs reserves from Federal gas resources are to be added together in each region, and the estimated quantities of proved gas reserves from Federal gas resources are to be added together in each region. These calculations will provide the regional estimated quantity of proved oil and lease condensate reserves, the regional estimated quantity of NGPLs reserves, and the regional estimated quantity of proved gas reserves, respectively. The most recent survey conducted by the EIA, issued no more than twelve (12) months before the end of the reporting period, will serve as the basis for quantity, or volume, information. Adjustments for material known changes (e.g., new discoveries or adjustments in estimates) during the reporting period but after the date of the survey will be made; however, a comprehensive re-estimate is not required. For purposes of this standard, proved lease condensate reserves are to be included with the proved oil reserves.

39. Each regional estimated quantity of proved oil and lease condensate reserves combined is to be multiplied by the associated regional average first purchase price for oil and lease condensate. These calculations will provide the regional sales value of proved oil and lease condensate

reserves from oil and gas fields that are leased from the Federal government for each region.

40. Each regional estimated quantity of proved NGPLs reserves is to be multiplied by the associated regional average first purchase price for NGPLs. These calculations will provide the regional sales value of proved NGPL reserves from gas fields that are leased from the Federal government for each region.

41. Each regional estimated quantity of proved gas reserves is to be multiplied by the associated regional average wellhead price for gas. These calculations will provide the regional sales value of proved gas reserves from gas fields that are leased from the Federal government for each region.

42. Each regional sales value of proved oil and lease condensate reserves from oil fields that are leased from the Federal government is to be multiplied by the associated effective regional average royalty rate for oil and lease condensate. These calculations will provide the value of estimated petroleum royalties for oil and lease condensate from oil fields that are leased from the Federal government for each region.

43. Each regional sales value of proved NGPL reserves from gas fields that are leased from the Federal government is to be multiplied by the associated effective regional average royalty rate for NGPLs. These calculations will provide the value of estimated petroleum royalties for NGPLs from gas fields that are leased from the Federal government for each region.

44. Each regional sales value of proved gas reserves from gas fields that are leased from the Federal government is to be multiplied by the associated effective regional average royalty rate for gas. These calculations will provide the value of estimated petroleum royalties for gas from gas fields that are leased from the Federal government for each region.

45. The values of estimated petroleum royalties for oil and lease condensate for each region, the values of estimated petroleum royalties for NGPLs for each region, and the values of estimated petroleum royalties for gas for each region are to be added together to provide the total value of estimated petroleum royalties. This total value would be the Federal government's estimated petroleum royalties to be recognized as an asset and reported on the balance sheet of the component entity that is responsible for collecting royalty revenue.

Effect on Existing Standards

46. This standard affects existing standards dealing with "bonus bid, rent, and royalty revenues" in SFFAS 7. As a result, paragraph 45 of SFFAS 7 is amended as follows:

> [45] Under exceptional circumstances, such as revenues from the auction of the radio spectrum ~~rents and royalties on the~~

~~Outer Continental Shelf~~, an entity recognizes virtually no costs (either during the current period or during past periods) in connection with earning revenue that it collects.

47. In addition, paragraphs 275, 276, and 277 of SFFAS 7 are deleted.

Effective Date

48. These standards are effective for periods ending after September 30, 2009. Early implementation is permitted.

The provisions of this statement need not be applied to immaterial items.

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APPENDIX A: BASIS FOR CONCLUSIONS

This appendix discusses some factors considered significant by members in reaching the conclusions in the proposed standards. It includes the reasons for accepting certain approaches and rejecting others. Some factors were given greater weight than other factors. The guidance enunciated in the standards---not the material in this appendix---should govern the accounting for specific transactions, events, or conditions.

Current Project

A1. The project began with the formation of a task force to conduct research. The task force produced a discussion paper 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.

A2. The Board was interested in determining whether values for Federal natural resources, or some surrogate, should be capitalized and reported on the balance sheet. The Board members believed that capitalizing Federal natural resources could increase accountability for their management and improve the comprehensiveness, relevance, and consistency of Federal financial statements. The Board members agreed to address each type of natural resource (e.g., fluid leasable minerals such as oil and gas, solid leasable minerals such as coal and timber) in separate phases. Federal oil and gas resources were addressed first because of the literature available in other domains, the extensive historical information on Federal lease programs and royalty collections, and the large amount of revenue earned in exchange for oil and gas resources.

A3. The Board indicated that the pertinent questions were (1) what, if anything, should be recognized as an asset; and, (2) what is the source and reliability of quantity information. They believed the source and the reliability of the information would have a bearing on where information should be reported.

A4. The extractive industries' activities for oil and gas can be divided into two categories—upstream activities and downstream activities. Upstream activities are divided into the following phases:

a. Prospecting[10]
b. Acquisition of mineral rights
c. Exploration
d. Appraisal and evaluation
e. Development
f. Production

[10] Prospecting usually involves researching and analyzing an area's historic geologic data; and, carrying out topographical, geological, and geophysical studies.

A5. Downstream activities take place after the production phase of the upstream activities through to the point of sale.

A6. The national assessment of oil and gas resources performed by the Federal government is similar to the prospecting phase of the extractive industries' upstream activities. It is the only activity performed by the Federal government that is similar to the extractive industries' activities.

A7. The Board noted that, based on discussions about oil and gas lease activities in the private sector, new models for accounting and reporting the Federal government's oil and gas activities would be needed because Federal activities are not similar to private sector activities and the current Federal model is incomplete.

Overview of Federal Oil and Gas Resources

A8. A *Framework for Components of Federal Oil and Gas Resources* (framework) is presented on page 20, which identifies the universe of Federal oil and gas resources. The framework presents accounting standards requirements and the components of federal oil and gas resources (total resources*)*. Total resources incorporate "original in-place" resources, that is, resources in the earth before human intervention.

A9. The accounting standards presented in the framework include current accounting standards and proposed accounting standards for each component of Federal oil and gas resources. The components are those 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.

<u>Undiscovered Resources</u>

A10. The first major component of total resources is **undiscovered resources**. The undiscovered resources component is divided into the following subcomponents:

a. **undiscovered nonrecoverable resources**
b. **undiscovered recoverable resources**
    i. **undiscovered conventionally recoverable resources**
    ii. **undiscovered economically recoverable resources**.

A11. Each component and subcomponent can be further divided between onshore and offshore resources. Onshore resources consist of resources on Federal lands. 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 volume of information varies.

A12. There is no information available on undiscovered nonrecoverable resources. These resources are not addressed or included in any type of assessment. Undiscovered nonrecoverable resources are referred to as resources that are beyond conventional technologies to be estimated and are not assessed. However, in the realm of "original in-place" resources they may exist.

A13. 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 analysis approach for resource appraisal. Information on undiscovered conventionally recoverable resources and undiscovered economically recoverable resources is provided in the MMS assessment.

A14. 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. As each basin is re-assessed, the assessment results are added to the assessment tables, and these new values replace the assessment results from 1995. The USGS assessment provides information on undiscovered conventionally recoverable resources but not on undiscovered economically recoverable resources like the MMS does.

A15. Under current FASAB accounting standards, there are no requirements to provide or present information about the undiscovered resource components in the financial statements. Under the proposed accounting standards, information about onshore and offshore undiscovered recoverable resources would be included in the technically recoverable resources and reported as required supplementary information (RSI). Information about technically recoverable resources is gathered and maintained by the EIA.

<u>Discovered Resources</u>

A16. The second major component of total resources is **discovered resources**. The discovered resources component is divided into the following subcomponents as follows:

a. **unproved reserves**
   i. **unproved possible reserves**
   ii. **unproved probable reserves**

b. proved reserves
   i. **proved undeveloped reserves**

ii. **proved developed reserves**

i) **proved developed non-producing reserves**
ii) **proved developed producing reserves**

c. production

A17. Under current FASAB accounting standards, there are no requirements to provide or present information about the unproved reserves components in the financial statements.

A18. Quantitative information in relation to onshore and offshore proved reserves, including new discoveries, production, and adjustments is submitted to the EIA 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.

A19. Under current accounting standards, the bonus bid, rent (earned on the lease until oil and gas production begins), and royalty revenue (earned on production) are accounted for as a custodial activity (i.e., an amount collected for others) by MMS-the collecting entity. The revenue and its distribution are reported on MMS's Statement of Custodial Activities. Component entities receiving a distribution and the CFR of the United States government recognize the revenue as a financing source in their respective Statement of Changes in Net Position or Statement of Operations and Changes in Net Position.

A20. Under the proposed accounting standards, information about onshore and offshore unproved reserves would be included in the technically recoverable resources and reported as RSI. Information about technically recoverable resources is gathered and maintained by the EIA.

A21. In addition, under the proposed accounting standards, the estimated Federal royalty share of proved reserves would be recognized as estimated petroleum royalties by the component entity responsible for reporting the asset on its balance sheet. Also, royalty revenue earned would be recognized as revenue along with a depletion expense in equal amounts on the Statement of Net Cost. Changes in the asset amount due to year-end valuation would be reported as a gain or loss on the Statement of Net Cost of the component entity responsible for reporting the asset on its balance sheet. Also, collections for rent and bonus bids would be recognized as exchange revenue on the Statement of Net Cost. Any expenses incurred to collect the rent and bonus bids would be included in the operating expenses on the Statement of Net Cost. The CFR would include these amounts in the consolidated financial statements.

A22. 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 the quantity and consumption of proved reserves, including the sales volume of proved reserves, the sales value of proved reserves, the amount of royalty revenue earned, and the estimated value for royalty relief would be provided as RSI.

A23. On the following page, Illustration 1, entitled *Framework for Components of Federal Oil and Gas Resources*, provides a summary of the information presented in the preceding paragraphs. The shaded boxes in the illustration represent the availability of information as follows:

No quantity information available	
Technically recoverable resources quantity information provided by EIA	
Proved reserves quantity information provided by EIA	

A24. The terms in Illustration 1 are defined in the Glossary under the subheading *Definitions of Resource and Reserve Components and Subcomponents*.

Illustration 1 Framework for Components of Federal Oil and Gas Resources

<table>
<tr><td>Accounting Standards</td><td colspan="9">Components of Federal Oil and Gas Resources</td></tr>
<tr><td></td><td colspan="3">Undiscovered Resources</td><td colspan="6">Discovered Resources</td></tr>
<tr><td></td><td rowspan="2">Undiscovered Non-Recoverable Resources</td><td colspan="4">Technically Recoverable Resources</td><td colspan="3" rowspan="2">Proved Reserves</td><td rowspan="2">Production</td></tr>
<tr><td></td><td colspan="2">Undiscovered Recoverable Resources</td><td colspan="2">Unproved Reserves</td></tr>
<tr><td></td><td></td><td>Undiscovered Conventionally Recoverable Resources</td><td>Undiscovered Economically Recoverable Resources</td><td>Unproved Possible Reserves</td><td>Unproved Probable Reserves</td><td>Proved Undeveloped Reserves</td><td colspan="2">Proved Developed Reserves</td><td></td></tr>
<tr><td></td><td></td><td colspan="2"></td><td colspan="3"></td><td>Proved Developed Non-Producing Reserves</td><td>Proved Developed Producing Reserves</td><td></td></tr>
<tr><td>Current Accounting Standards</td><td colspan="3"></td><td colspan="5">Bonus Bid, Rent, Royalty Revenue Accounted as a Financing Source on the CFR Statement of Operations and Changes in Net Position</td><td></td></tr>
<tr><td>Proposed Accounting Standards</td><td></td><td colspan="2">Provide RSI Information for Undiscovered Recoverable Resources</td><td colspan="2">Recognize Bonus Bid and Rent Revenues as exchange revenue on SNC[11]
Provide RSI Information for Unproved Reserves</td><td colspan="3">• Recognize Federal Royalty Share on BS[12]
• Recognize Royalty Revenues as Revenue and Depletion Expense on SNC
• Recognize Gains/Losses on SCNP[13]
• Provide Disclosure for Proved Reserves</td><td>Provide RSI/ Disclosure Information – Quantitative and Financial</td></tr>
</table>

[11] Statement of Net Cost
[12] Balance Sheet
[13] Statement of Changes in Net Position

Federal Entities Involved in Federal Oil and Gas Resources

A25. There are three Federal government entities involved in the major Federal oil and gas resources 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.

A26. **BLM Overview**. BLM manages 262 million acres of mostly Western land and 700 million acres of subsurface mineral estate nationwide. These lands are managed for multiple-use and on a sustained-yield basis with BLM's 5-year Strategic Plan and Annual Performance Plan as the foundation. There is no 5-year plan for oil and natural gas lease sales. The BLM's management responsibilities include recreation opportunities, commercial activities, and other natural resource activities.

A27. 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, and the MMS makes bonus, rent, and royalty collections for these lands.

A28. **MMS Overview**. The mission of MMS is to manage the mineral resources on the nation's Outer Continental Shelf 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 two 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.

A29. **EIA Overview**. The primary focus of EIA's reserves program is providing accurate annual estimates of U.S. proved reserves of crude oil, dry gas, and natural gas plant liquids. These estimates are essential to 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.

A30. 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.

A31. The 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.

Conceptual Aspects of Oil and Gas Resources as a Federal Asset with a Related Liability

A32. The Board has undertaken a project to complete its conceptual framework. Currently, the conceptual framework does not include a statement addressing definitions and recognition of elements such as assets and liabilities. However, SFFAS 1, *Accounting for Selected Assets and Liabilities of the Federal Government*, presents an asset definition in the basis for conclusions and SFFAS 5, *Accounting for Liabilities of the Federal Government,* includes a liability definition and liability recognition criteria.

A33. The GAAP hierarchy provides that statements of federal financial accounting standards constitute level A (the highest level) guidance. Statements of federal financial accounting concepts are not GAAP. Instead, concepts statements constitute “other literature” and may only be relied upon by financial statement preparers and auditors to resolve specific accounting issues in the absence of GAAP literature. In developing and amending accounting standards, the Board looks to concepts statements for guiding principles and also considers relevant existing standards and guidance issued by the Board and other standard setting bodies. Until the Board amends existing standards, the Board expects practice to be governed by the definitions embodied in the four levels of the GAAP hierarchy. Thus, the Board distinguishes between definitions presented in concepts which are used to guide Board deliberations on future GAAP and definitions presented in standards which constitute current GAAP.

A34. The standards embodied in SFFAS 1 are based on the following definition of an asset:

> “The term asset as used in this document means an item that embodies a probable future economic benefit that can be obtained or controlled by

the federal government or a reporting entity as a result of past transactions or events."[14]

A35. The SFFAS 5 definition of liability is:

> "A liability is a probable future outflow or other sacrifice of resources as a result of past transactions."[15]

A36. The Board believes that the accounting for oil and gas resources presented in this proposed standard would be the same using either the definitions in SFFAS 1 and 5 or using the definitions contained in the proposed concepts statement. The following paragraphs provide an analysis of accounting for oil and gas resources based on the definitions in the proposed concepts statement.

Definition of Asset

A37. In the exposure draft (ED), Proposed Statement of Federal Financial Accounting Concepts: *Definition and Recognition of Elements of Accrual-Basis Financial Statements* (hereafter referred to as Elements ED), the proposed definition[16] of an asset is:

> "An asset is a resource that embodies economic benefits or services that the Federal government can control. To be an asset of the federal government, a resource must possess two characteristics. First, it embodies economic benefits or services that can be used in the future. Second, the government controls access to the economic benefits or services and, therefore, can obtain them and deny or regulate the access of other entities."[17]

A38. Assets may vary in specific form and nature; e.g., they may be tangible/intangible, monetary/non-monetary, current/non-current, and more certain benefits/less certain benefits.

Recognition Criteria

A39. Recognition criteria are the conditions an item should meet to be recognized in financial statements. The recognition criteria proposed in the Elements ED are (a) the item meets the definition of an element of financial statements and (b) the item is measurable. As used in the Elements ED, the term measurable

[14] SFFAS 1, paragraph 93.
[15] SFFAS 5, paragraph 19.
[16] While the Elements ED has not been finalized and wording changes are still being considered by the Board, the Board's considerable work on "asset" and "liability" definitions—including consideration of current and evolving notions of assets and liabilities by other standard setters—suggests that the issues of whether an asset exists and/or a liability arises in the context of oil and gas proved reserves and arrangements to distribute the related royalty revenue are not controversial. The Board does not believe that revisions to the proposed Elements ED would impact this proposal. Further, the Board believes that input from respondents regarding this application of the evolving definitions may be helpful to both ongoing projects.
[17] Elements ED, paragraphs 17 and 21.

means quantifiable in monetary units. In recent deliberations, the Board has considered modifying this definition of measurable to provide that an item is measurable if it can be determined with reasonable certainty or is reasonably estimable.

A40. Conclusions about the existence of an element require judgment as to whether, based on the available evidence, the item possesses the essential characteristics of that element. The measurement of an element being considered for recognition in the financial statements often will require estimates and approximations. Measurement also may require a more rigorous assessment of the probability of future inflows or outflows of resources to enhance the reliability of amounts recognized in the financial statements. Recognition decisions also are influenced by assessments of the materiality and benefit versus cost of recognizing the results of the measurement of elements.

A41. Given the Elements ED definition of 'asset' and criteria for 'recognition', the next step the Board took was to consider 'measurability.' In its Statement of Financial Accounting Concepts (SFAC) 5, the Financial Accounting Standards Board (FASB) acknowledges that its current standards as well as other literature related to generally accepted accounting principles (GAAP) for entities other than government entities 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 for the near term.

Oil and Gas Resources as a Federal Asset

A42. First, the Board established which Federal oil and gas resources were being considered. Illustration 1, entitled *Framework for Components of Federal Oil and Gas Resources*, presents the oil and gas resources that were considered. The two major components are "undiscovered resources" and "discovered resources." All of the Federal oil and gas resources meet the definition of asset. Federal oil and gas resources qualify as federal government assets because the government can obtain the economic benefits and regulate the access of other entities as provided under federal law.

Oil and Gas Resources to be Recognized as a Federal Asset

A43. Since all Federal oil and gas resources controlled by the Federal government are assets, the Board's next step was to decide whether the Federal oil and gas resources "asset" should be recognized on a Federal component entity balance sheet. As noted above, the second criterion for recognition is that the asset "…is measurable."

A44. Estimates of the quantity of oil and gas resources other than proved reserves are available through EIA. With this quantity information, a monetary measure is technically feasible and, therefore, the asset qualifies for consideration for recognition. However, the Board does not believe that the information is sufficiently reliable to be recognized in a cost-beneficial manner.

A45. Statement of Federal Financial Accounting Concepts (SFFAC) 1 provides the following with respect to reliability:

> 160. Financial reporting should be reliable; that is, the information presented should be verifiable and free from bias and should faithfully represent what it purports to represent. To be reliable, financial reporting needs to be comprehensive. Nothing material should be omitted from the information necessary to represent faithfully the underlying events and conditions, nor should anything be included that would likely cause the information to be misleading to the intended report user. Reliability does not imply precision or certainty, but reliability is affected by the degree of estimation in the measurement process and by uncertainties inherent in what is being measured. Financial reporting may need to include narrative explanations about the underlying assumptions and uncertainties inherent in this process. Under certain circumstances, a properly explained estimate provides more meaningful information than no estimate at all.

A46. Concerning the proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources, the Board believes that both the quantity and the estimated Federal royalty share would be reliable. Thus, in this case, since the quantity of the estimated Federal royalty share can be reliably estimated and converted to monetary terms, the Board believes the estimated Federal royalty share of proved oil and lease condensate, NGPLs, and gas reserves should be recognized on the balance sheet.

A47. The EIA information on other than proved reserves is derived from sporadic and incomplete national assessments and annual submissions by oil and gas producers. This makes it particularly uncertain. In addition, since these reserves are not currently under lease, determining the royalty share may be misleading since it is a current value measure but the underlying asset may be restricted and production may never occur. For those resources that are not restricted, production may occur but the timing and amount of royalties are very uncertain. Thus, applying the same measurement technique to other than proved reserves may not result in a value that represents what it purports to represent. Thus, Federal oil and gas resources not yet in the ‘proved reserves’ category would not be recognized on the Federal balance sheet due to concerns regarding reliability of the proposed measure. However, information on these quantities would be provided as RSI.

Measurement Attributes Considered

A48. Concerning the dollar amount to be recognized for the estimated Federal royalty share of proved reserves, the Board considered various measurement attributes,[18] including the following:

A49. 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 no ‘historical exchange price’ for the oil and gas reserves controlled by the Federal government.

A50. Fair value – When market transactions are available, fair value is the same as market value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. (FASB Statement of Financial Accounting Standards (SFAS) 157: *Fair Value Measurements*) Information needed to estimate fair value is not available as there are no current transactions between market participants involving the sale of the Federal royalty share for proved oil and lease condensate, NGPLs, and gas reserves. Nor are there current transactions between market participants for the sale of rights to comparable future revenue streams.

A51. Net realizable (settlement) value – The total non-discounted 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 amount of the future flows of the Federal royalty share for proved oil & gas reserves cannot be reliably estimated for various reasons. The amount cannot be reliably estimated due to volatile fluctuations in the first purchase price for oil and wellhead price for gas. Reasons for these variations include:

a. The permitting process for exploration, development, and production activities.
b. The lessee’s budget.
c. Other projects the lessee is focusing on.
d. The geological make-up of the earth.
e. The depth of the water or the depth of the wells for offshore wells.
f. The uncertainties of each well.
g. New discoveries.
h. Improved technology.
i. The economy and price volatility.
j. Production incentives provided by the Federal government.

[18] Measurement attribute – An attribute that can be quantified in monetary units with sufficient reliability. (Adapted from SFAC 5, *Recognition and Measurement in Financial Statements of Business Enterprises*, paragraph 65.)

A52. 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 because:

a. The timing of future inflows is not reliably estimable.
b. The discount rate should be commensurate with the riskiness of the stream and each well might be viewed as having a unique level of risk.
c. Prices are subject to fluctuation, making the amount of future inflows volatile.

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. Thus, the estimated present value would be unreliable and, therefore, not cost-beneficial for valuing oil and gas reserves.

A53. Based on the above, the Board determined that none of the measurement attributes currently used in practice is a feasible measure of the estimated Federal royalty share for proved oil and lease condensate, NGPLs, and gas reserves. In addition the Board believes 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 the Federal estimated petroleum royalties. The Board believes that defining a measurement attribute in terms that are common to the oil and gas industry would be the best approach. Therefore, the Board proposes to use a regional average first purchase price for oil and lease condensate, a regional average first purchase price for NGPLs, and a regional average wellhead price for gas to value the Federal royalty share of proved oil and lease condensate, NGPLs, and gas reserves and referred to as Federal estimated petroleum royalties.

Valuation of the Federal Asset "Estimated Petroleum Royalties"

A54. The Board believes that the most relevant, reliable, and cost-beneficial measurement of "estimated petroleum royalties" would be obtained by using regional information. Regional estimated petroleum royalties would be calculated by multiplying the regional estimated quantity of proved reserves by the regional average first purchase price or regional average wellhead price and an effective regional average royalty rate. This calculation would provide the value of the "estimated petroleum royalties" for proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources for each region. The formulas to calculate regional values of estimated petroleum royalties are as follows:

For oil and lease condensate:

Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves X Regional Average First Purchase Price for Oil and Lease Condensate X Effective Regional Average Royalty Rate for Oil and Lease Condensate = Regional Estimated Petroleum Royalties for Oil and Lease Condensate

For natural gas plant liquids:

Regional Estimated Quantity of Proved NGPLs Reserves X Regional Average First Purchase Price for NGPLs X Effective Regional Average Royalty Rate for NGPLs = Regional Estimated Petroleum Royalties for NGPLs

For gas:

Regional Estimated Quantity of Proved Gas Reserves X Regional Average Wellhead Price for Gas X Effective Regional Average Royalty Rate for Gas = Regional Estimated Petroleum Royalties for Gas

A55. Proved reserves comprise crude oil, natural gas liquids (lease condensate and NGPLs), and natural gas.

A56. Crude oil exists in a liquid state; it may be described on the basis of its American Petroleum Industry (API) gravity as "light" (i.e., approximately 20 degrees to 50 degrees API) or "heavy" (i.e., generally less than 20 degrees API). Condensate is a very high-gravity (i.e., generally greater than 50 degrees API) liquid. NGPLs are those hydrocarbons in natural gas that are separated as liquids (byproducts) at natural gas processing plants, fractionating and cycling plants, and, in some instances, field facilities. Natural gas is a gaseous hydrocarbon resource.

A57. It is common for industry to count lease condensate reserves with their crude oil reserves. Lease condensate liquids generally are mixed in with crude oil and transported to petroleum refineries. For valuation purposes, their value is not much different than that for crude oil. Therefore, the Board believes oil and lease condensate should be combined in the process of calculating the Federal government's estimated petroleum royalties and reported jointly in disclosures and RSI.

A58. NGPLs are extracted from natural gas, either at the production site or downstream at a natural gas processing plant. NGPLs include products like propane and butane. The market value for NGPLs is generally much lower than that for crude oil. In 2005, the average value of federal oil was $47 a barrel, and the average value for NGPLs was about $30 a barrel. (A difference of approximately $17 per barrel). The Board believes NGPLs should be separately valued in the process of calculating the Federal government's estimated petroleum royalties. In addition, disclosures and RSI should distinguish NGPLs from other components.

A59. Because of the diversity between natural gas and crude oil, including the price and measurement metric, the Board believes natural gas should be separately valued in the process of calculating the Federal government's estimated petroleum royalties. Disclosures and RSI should distinguish natural gas from other oil and gas components.

A60. The Board believes this approach would provide conservative, representative regional values of estimated petroleum royalties without having to use proved reserve, price, and royalty rate information on a field-by-field[19] basis. The Board believes it would not be practicable to make calculations on a field by field basis. There are more than 60,000 leases maintained by the DOI with approximately 115,000 producing wells. In addition, the EIA maintains only the proved reserve information for each field, which it aggregates; while, the DOI maintains only the price and royalty rate information for each field.

Definition of Liability

A61. In the Elements ED, the proposed definition of a liability[20] is:

> "A liability is a present obligation[21] of the federal government to provide assets or services to another entity at a determinable date, when a specified event occurs, or on demand." A liability of the federal government has two essential characteristics. First, it constitutes a present obligation to provide assets or services to another entity. Second, the federal government and the other entity have an agreement or understanding as to when settlement of the obligation is to occur.[22]

Recognition Criteria

A62. Recognition criteria for all elements of accrual-basis financial statements, including liability, are discussed in paragraphs A39 and A40 of this document.

Valuation of the Offsetting Liability for the "Estimated Petroleum Royalties" Asset

A63. In this draft ED, the Board proposes that the federal government's estimated petroleum royalties be recognized as an asset on the balance sheet of the component entity that is responsible for collecting royalties. The asset's value would be based on the royalty share of the Federal oil and gas resources classified as "proved reserves." In addition to the royalties that the component

[19] 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.
[20] See footnote 16 regarding the status of the Elements ED.
[21] The term *obligation* is used with its general meaning of a duty or responsibility to act in a certain way. It does not mean that an obligation of budgetary resources is required for a liability to exist in accounting or financial reporting or that a liability in accounting or financial reporting is required to exist for budgetary resources to be obligated.
[22] Elements ED, paragraphs 38 and 40.

entity collects on proved reserves that are produced, it also collects lease sale and rent revenue from federal government oil and gas leases. The component entity distributes nearly all of these proceeds to the general fund of the U.S. Treasury, other federal agencies, and states in accordance with legislated allocation formulas. The component entity also receives a very small portion of the revenue collected to fund its operations. The amount used to fund its operations is legislated by Congress as part of the component entity's annual appropriation. For example, the amount received by the component entity was approximately one percent (1%) of annual revenues collected in 2005.

A64. The Board considered and agreed that an offsetting liability should be recognized in conjunction with the recognition of an asset for estimated petroleum royalties. The Board believes an offsetting liability should be recognized because nearly all of the revenue from royalties, lease sales, and rent are ultimately distributed to the general fund of the U.S. Treasury, other federal agencies, and the states. As the proceeds are distributed, the liability would be reduced. In addition, upon consolidation, the portion of the liability related to other federal agencies and the general fund of the U.S. Treasury would be eliminated so that the balance sheet for the government as a whole reports only the liability for amounts allocated to non-federal entities.

A65. The Board believes that if a liability was not established, the component entity's and the federal government's net position would be overstated.

Regional Estimated Quantity of Proved Reserves

A66. The Board proposes that the regional estimates of proved oil and lease condensate reserves, proved NGPL reserves, and proved gas reserves from Federal oil and gas resources be used to calculate and value the Federal government's "estimated petroleum royalties" to be capitalized. The source for the regional estimates for these proved reserves would be the EIA, based on the required field-by-field filings by oil and gas operators.

A67. The EIA defines proved reserves as those volumes of crude oil and natural 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 quantities that can be counted; nor, are they direct measurements. They are estimates. Proved oil and lease condensate reserves are estimated in barrels at 60 degrees Fahrenheit. Proved NGPL reserves are estimated in barrels at 60 degrees Fahrenheit. Proved gas reserves are estimated in thousands of cubic feet (Mcf) at 14.73 PSIA and 60 degrees Fahrenheit.

A68. 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. The EIA requires the top 600 operators 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 for correction.

A69. 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 issues a report containing aggregated volume information for crude oil and lease condensate, natural gas plant liquids, and natural gas. The report is issued in the month of September containing volume information as of December 31 of the preceding calendar year. The information contained in the report has a very high probability that there is at least the physical volume that is estimated.

A70. Estimated proved reserves are calculated in the following manner:[23]
Published Proved Reserves at End of Previous Report Year
+ Adjustments
+ Revision Increase
- (Less) 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

A71. 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.

A72. 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 financial statement submissions on a yearly basis, which include financial statements from operators of oil and gas wells. Each submission is reviewed on a

[23] The source of information used to describe the calculation of estimated proved reserves is the EIA-23, *Annual Survey of Domestic Oil and Gas* instructions.

rotational basis every three years based on internal selection policies and criteria.

Alternative Quantity Information

A73. The Cambridge Energy Research Associates (CERA) developed a report on Oil and Gas Reserves Disclosure. The focus of the CERA report was that the 27-year-old U.S. system for measuring and reporting oil and gas reserves is no longer keeping pace with a changing, increasingly global industry and, as a result, falls short of accurately describing industry and individual companies' reserves. It was suggested by a Board member that the FASAB proposed accounting standards for oil and gas resources request comments on the possibility of estimating petroleum royalties using a probabilistic method of measuring proved reserves as suggested in the CERA report.

A74. The Board's proposal is to use a single best estimate of recovering reserves based on known geological, engineering, and economic data, and this approach is known in the oil and gas industry as the deterministic method. In contrast, the probabilistic method of estimation uses the known geological, engineering, and economic data to generate a range of estimates and their associated probabilities of recovering reserves. Using the probabilistic method, identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. The Society of Petroleum Engineers, the World Petroleum Congresses, and the American Association of Petroleum Geologists agree:

a. There should be at least a 90 percent probability that the quantities of proved reserves actually recovered will equal or exceed the estimate.
b. There should be at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.
c. There should be at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

A75. The Board proposes using only the "proved reserves" to calculate the estimated petroleum royalties of the Federal government for capitalization on the balance sheet. In addition, RSI would be displayed for other oil and gas resources.

A76. Information pertaining to "unproved probable reserves" or "unproved possible reserves" is not required to be submitted to any Federal government entity and no Federal entity has the information. Mandating that internal decision-making information about these two types of reserves be reported by producers and operators would impose an additional reporting requirement on these non-Federal entities.

A77. The MMS does study and report information about unproved reserves as a whole, i.e., without any delineation between "unproved probable reserves" and "unproved possible reserves." In addition, the information it reports about unproved reserves is not current. That is, up-to-date information is not available. For example, the most current information about the Gulf of Mexico region reserves was issued by the MMS in November 2006 for the period ending December 31, 2003. Information about the Pacific region is even less current; and, information about the Alaska region is not currently reported. In addition, there is no information available for onshore oil and gas reserves.

A78. In summary, the EIA's estimate of proved reserves is the only current and complete estimate of reserves the Federal government has. Developing a probabilistic model, acquiring the information from producers, and assessing reserves not under lease on a routine basis would be burdensome and would not be cost-beneficial. Therefore, the Board believes asset recognition should be based on proved reserves using the deterministic method.

Regional Average First Purchase and Regional Average Wellhead Price

A79. There are two prices used to calculate the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves.

A80. The first price is "first purchase price" and, for purposes of these standards, is used in the crude oil and lease condensate, and NGPLs environments. A "first purchase" constitutes a transfer of ownership during or immediately after the physical removal of the crude oil and lease condensate or NGPLs from a production property for the first time. The proposed regional average "first purchase price" would be calculated by dividing the total regional sales value of oil and lease condensate or NGPLs produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months by the total regional sales volume of oil and lease condensate or NGPLs produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months. All types of crude oil streams and gravity bands are aggregated for the oil and lease condensate calculation. For example, if the total financial sales value for oil and lease condensate in a region was $12,762,548,440 and the total sales volume in the associated region was 666,108,296 barrels of oil and lease condensate, the average first purchase price for the region would be $19.16 per barrel. This information is available to the MMS. Sales value and the sales volume information is provided to the MMS by oil producers on a monthly basis.

A81. The second price is "wellhead price" used in the gas environment. The wellhead price is the value of the purchased gas at the mouth of the well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction. The regional average wellhead price for gas would be calculated by dividing the total regional sales value of gas produced from Federal oil and gas resources in each region for the preceding twelve (12) months by the total regional sales volume of gas produced from Federal oil and gas resources in each associated region in the preceding twelve (12) months. For example, if the total financial sales value for gas in a region was $18,824,102,982 and the total sales volume in the associated region was 6,789,523,253 Mcf of gas, the average wellhead price for the region would be $2.77 per thousand cubic feet. This information is available to the MMS. Sales value and the sales volume information is provided to the MMS by gas producers on a monthly basis.

A82. The Board considered using market prices as of the end of the reporting period. However, the price in a specific market is not necessarily representative of the specific fields leased from the Federal government. In addition, the market price used in the spot market to value gas includes transportation charges. Producers do not pay royalties on transportation costs. Therefore, using the market price in the formula to calculate the value of federal petroleum royalties would cause the value to be inflated. In addition, the MMS sales volume and sales value information is more timely and more readily available.

Effective Regional Average Royalty Rate

A83. 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. 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 OCS 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 Act requires that all public lands 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.

A84. While the royalty rate is based on the lease agreement, the Secretary of the DOI 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 extraordinarily 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. Paragraphs A85 through A100 summarize possible royalty rates. Using an effective royalty rate is a means of adjusting the asset's value based on experience with reduced royalties.

Royalty Rate – Federal Onshore Leases

A85. 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:

a. Existing leases that have expired, terminated, or been cancelled or relinquished;
b. Parcels identified by informal expressions of interest from the public or by the BLM for management reasons; or
c. Lands included in offers filed for noncompetitive leases.

A86. Royalty rates are assigned for competitive leases in the following manner:

a. Leases issued under the Mineral Leasing Act of 1920 (prior to December 23, 1987): oil royalty assessed on production amount ranges from 12.5 percent to 25 percent; gas royalty assessed on production amount ranges from 12.5 percent to 16.67 percent.
b. Leases issued after December 23, 1987: flat rate of 12.5 percent in amount (dollars) or value of production.

A87. Royalty rates for noncompetitive leases are 12.5 percent of the amount or value of production.

A88. Royalty rates are assigned for the National Petroleum Reserve for Alaska Leases at 16.67 percent.

<u>Royalty Rate – Federal Offshore Leases</u>

A89. 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, the royalty rate, terms and conditions of the sale.

A90. The OCS Lands Act, 43 U.S.C. 1337, as amended by the OCS Deep Water Royalty Relief Act (DWRRA), Public Law 104-58, authorizes the MMS to grant royalty relief. Royalty relief is the reduction, modification, or elimination of any royalty to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. Some of the royalty-free production might not have occurred absent the royalty relief incentive. Therefore, not all of the nominal royalties waived on actual production in the presence of royalty relief may actually be foregone. To the extent that such incremental projects pay royalties, some or all of those royalties serve to reduce the aggregate amount of foregone royalties on other projects. In addition, the royalty relief program also affects the bonus bid amounts. That is, bonus bid amounts are larger on lease sales offering royalty relief. So, to a certain extent, the bonus bid amounts ahead of production compensate for the future relief.

A91. Royalty relief has two thresholds, price and quantity. Depending on when a lease sale took place determines the effective price threshold and quantity threshold for each lease authorized for royalty relief. If prices rise above a threshold (base price) for crude oil or natural gas, set by statute, full royalties must be paid. For quantity thresholds, statutes authorize the MMS to grant royalty relief in three situations:

a. Under 43 U.S.C. 1337(a)(3)(A), it may reduce or eliminate any royalty or a net profit share specified for an OCS lease to promote increased production.

b. Under 43 U.S.C. 1337(a)(3)(B), it may reduce, modify, or eliminate any royalty or net profit share to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. This authority is restricted to leases in the Gulf of Mexico (GOM) that are west of 87 degrees, 30 minutes West longitude.
c. Under 43 U.S.C. 1337(a)(3)(C), it may suspend royalties for designated volumes of new production from any lease if:
(1) The lease is in deep water (water at least 200 meters deep);
(2) The lease is in designated areas of the GOM (west of 87 degrees, 30 minutes West longitude);
(3) The lease was acquired in a lease sale held before the DWRRA (before November 28, 1995);
(4) That DOI finds that new production would not be economical without royalty relief; and
(5) The lease is on a field that did not produce before enactment of the DWRRA, or if a project is proposed to significantly expand production under a Development Operations Coordination Document (DOCD) or a supplementary DOCD, that MMS approved after November 28, 1995.

A92. A royalty and remittance report, which contains the reported sales value, reported sales volume, and other related production information is due the last day of the month following the month the product was sold or removed from the lease, in accordance with proscribed legislation.

A93. At the end of the calendar year, if it is found through an audit that an operator has exceeded either one of the thresholds, the operator must:

a. Pay royalties on all oil production for the previous year at the lease stipulated royalty rate plus interest (under 30 U.S.C. 1721 and Sec. 218.54 of this chapter) by March 31 of the current calendar year, and
b. Pay royalties on all oil production in the current year.

A94. As a result of exceeding either threshold, all royalty relief must be paid and would no longer be considered royalty relief. In addition, in the succeeding year, while the operator must pay all royalties during the year, the operator may be eligible for royalty relief for the year if the operator complies with all requirements of the lease in accordance with royalty relief. In this latter case, the appropriate amount of royalties would be refunded to the operator.

A95. 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.

A96. 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.

A97. 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.

A98. For leases not under the DWRRA, the royalty rate is set for each sale area in its Final Notice of Sale and may be:

a. 12.5 percent for water depths greater than 400 meters or 16.67 percent for water depths less than 400 meters.
b. Sliding scale (12.5 percent-65 percent) based on average of all production.
c. Step-scale which increases by steps as production increases.
d. Flat rate of 33.33 percent.
e. Net profit share, which require royalty only after certain expenditures are recovered.
f. 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 (i.e. 12.5 percent for water depths greater than 400 meters or 16.67 percent for water depths less than 400 meters).

A99. Leases Under Deepwater Royalty Relief Act. Certain Gulf of Mexico (GOM) deep water leases issued under DWRRA between November 28,1995 and November 28, 2000 receive royalty suspensions based on the following criteria:

a. 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.
b. 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.
c. *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.*

A100. GOM deep water leases issued under DWRRA beginning in 2002 receive royalty suspensions based on the following criteria:

a. 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.
b. 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.
c. 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.

A101. Because the Board believes using proved reserve, pricing and royalty information from each field would not be practicable, a meaningful and relevant royalty rate was needed in calculating the representative value of the Federal government's estimated petroleum royalties. The Board, therefore, proposes that effective regional average royalty rates for oil and lease condensate, NGPLs, and gas be used in calculating the Federal government's estimated petroleum royalties. Members believe using the effective regional average royalty rates, in contrast to a statutory rate, would be more representative and meaningful because of the varying degrees of royalty rates for onshore and offshore leases and the royalty relief program for offshore leases. The effect of calculating the rate in this manner is to reduce the asset value based on the royalty relief experience during the preceding twelve months. The Board believes this approach is a reasonable means to avoid overstating the asset in light of the variability in royalty relief in the future.

A102. The effective regional average royalty rate for oil and lease condensate is calculated by dividing the royalty value (royalties) earned on all of the oil and lease condensate reserves that were produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months by the sales value of that production for the preceding twelve (12) months. For example, if the total royalties earned on the produced reserves from the associated region was $4,406,985,439, and the total sales value for oil from a region was $31,586,651,422, the effective regional average royalty rate would be 13.952 percent. This information is available to the MMS. Sales value and the royalty information is provided to the MMS by oil and gas producers on a monthly basis.

A103. The effective regional average royalty rate for NGPLs would be calculated by dividing the royalty value (royalties) earned on the NGPL reserves produced for each associated region for the preceding twelve (12) months by the total sales value of that production for the preceding twelve (12) months.

A104. The effective regional average royalty rate for gas would be calculated by dividing the royalty value (royalties) earned on the gas reserves produced for each associated region for the preceding twelve (12) months by the total sales value of that production for the preceding twelve (12) months.

Calculating the Federal Government's "Estimated Petroleum Royalties"

A105. Using the described components in the formula, the Federal government's estimated petroleum royalties would be calculated in the following manner.

A106. The summarized quantity of proved oil and lease condensate reserves from oil and gas fields that are leased from the Federal government and included in the EIA survey for a region should be multiplied by the associated regional average first purchase price for oil and lease condensate. This calculation will equal the regional value of proved oil and lease condensate reserves from oil fields that are leased from the Federal government.

A107. Each regional value of proved oil and lease condensate reserves from oil fields that are leased from the Federal government would be multiplied by the associated effective regional average royalty rate. This calculation will equal the estimated petroleum royalties for oil and lease condensate from oil fields that are leased from the Federal government for each region.

A108. The summarized quantity of proved NGPL reserves for each region from gas fields that are leased from the Federal government and included in the EIA survey would be multiplied by the associated regional average first purchase price for NGPLs. This calculation will equal the value of proved NGPL reserves for each region from gas fields that are leased from the Federal government.

A109. Each regional value of NGPL reserves from gas fields that are leased from the Federal government would be multiplied by the associated effective regional average royalty rate. This calculation will equal the estimated petroleum royalties for NGPLs from gas fields that are leased from the Federal government for each region.

A110. The summarized quantity of proved gas reserves for each region from gas fields that are leased from the Federal government and included in the EIA survey would be multiplied by the associated regional average wellhead price for gas. This calculation will equal the value of proved gas reserves for each region from gas fields that are leased from the Federal government.

A111. Each regional value of proved gas reserves from gas fields that are leased from the Federal government would be multiplied by the associated effective regional average royalty rate for gas. This calculation will equal the estimated petroleum royalties from gas fields that are leased from the Federal government for each region.

A112. The regional values of estimated petroleum royalties for oil and lease condensate reserves from oil and gas fields that are leased from the Federal government, the regional values of estimated petroleum royalties for NGPLs reserves from gas fields that are leased from the Federal government, and the regional values of estimated petroleum royalties from gas fields that are leased from the Federal government would be added together. This calculation would provide the value of the Federal government's estimated petroleum royalties from proved reserves to be capitalized.

A113. The Board believes using the described components in the formula for calculating the regional estimated petroleum royalties would provide a representative value of the estimated proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources for the reporting period. The information provided for each component is verifiable and reliable. In addition, it is consistent and relevant. That is, it is aggregated and calculated at the regional level, it is based on recent oil and gas production activities, and it incorporates recent economic experience including royalty relief experience.

Future Rights to Royalty Stream Identified for Sale

A114. When rights to a future royalty stream are identified to be sold, the value of those rights should be disclosed as "future royalty rights identified for sale." Future royalty rights identified for sale should not be revalued or reclassified to a different asset category on the balance sheet because the point in time for the sale of the future royalty rights may be uncertain and the identified fields may continue to produce oil and/or gas and generate royalties. These two factors make it difficult to establish and maintain valuation information in advance of the sale. No gain or loss on the future royalty rights identified for sale should be calculated since the rights for sale are only disclosed and are not revalued and reclassified to a different asset category on the balance sheet. Disclosure of the approximate value at the balance sheet date alerts the reader to the pending sale and the potential value of the asset to be sold.

A115. The value of the disclosed future royalty rights identified for sale is based on the estimated quantity of proved reserves to be involved in the sale for a specific field; the first purchase price for oil and lease condensate, the first purchase price for NGPLs, or the wellhead price for gas for a specific field for which future royalty rights were identified for sale; and the royalty rate for a specific field identified for sale. Because the fields are known, this provides a more field specific value for the rights identified to be sold, instead of using an effective average royalty rate and an average unit price.

A116. At the time the future royalty rights identified for sale are sold, the calculated value of the future royalty rights sold would be calculated based on the quantity of proved reserves involved in the sale for a specific field; the first purchase price for oil and lease condensate, the first purchase for NGPLs, or the wellhead price for gas pertaining to a field at the time of sale; and the royalty rate for a specific field. An amount equal to this calculated value would be removed from the value of estimated petroleum royalties at the time of the sale. This calculation is used to reduce the estimated petroleum royalties since the values of a specific field are known and the value of the future royalty rights sold can be more accurately calculated, which would provide a more realistic gain or loss on the sale. In addition, the liability for revenue distributions to others should be adjusted by the amount of the gain or loss on the sale, if any, and reduced when the sale proceeds are distributed.

Disclosures

A117. The Board proposes that various types and amounts of information be disclosed in the notes or provided as RSI. For example, one proposed disclosure would require a narrative describing and a display showing earned revenue reported by category for the reporting period. That is, royalty revenue earned for oil and lease condensate, royalty revenue earned for NGPLs, royalty revenue earned for gas, earned rent revenue, earned bonus bid revenue for leases, and total revenue. The proposed RSI includes sales volume, the sales value, the royalty revenue earned, and the estimated value for royalty relief for oil and lease condensate, NGPLs, and gas produced from Federal oil and gas resources for the reporting period on a regional basis. Proposed RSI also includes a narrative describing and a display showing detailed historical information for the preceding ten calendar years. (See paragraphs 30 through 34 and Appendix D for a complete review of all proposed disclosures and RSI requirements.)

A118. Although the Board agreed that the proposed information be disclosed in the notes or provided as RSI, there are some Board members who are concerned about the type and level of information being proposed as disclosures or RSI. Some of the proposed information is available through reports other than financial reports. Therefore, the Board has posed a question in the Request for Comments section of this document, question number Q3, asking reviewers of this document for feedback on the value of the proposed information being presented in financial statements. Specifically, the Board is asking that reviewers describe how the types and levels of information would be used, if and how the information would be used for assessing the financial position of the Federal government, and how the information would be useful in decision-making. The Board also asks if there is information which is not proposed as a disclosure or RSI but would be useful for assessing the financial position of the Federal government and in decision-making.

Alternative View

A119. Individual members sometimes choose to express an alternative view when they disagree with the Board's majority position on one or more points in a proposed standard. The alternative view would discuss the precise point or points of disagreement with the majority position and the reasons therefore. The ideas, opinions and statements presented in the alternative view are those of the individual member alone. However, the individual member's view may contain general or other statements that may not conflict with the majority position, and in fact may be shared by other members. The following material was prepared by Board member Donald B. Marron.

Fair Value Is the Appropriate Basis for Valuing Oil and Gas Resources

A120. Financial accounting is moving toward greater use of fair value estimates for financial assets and liabilities for private sector reporting entities.[24] Fair value is the price that would be received for an asset or paid to transfer a liability in a transaction between market participants at the measurement date. In general, fair value measures provide relevant, timely, and relatively accurate valuations. The desirable attributes of fair values are equally appropriate to valuations of physical resources; where possible, the federal balance sheet should report the fair value of the nation's natural resources, including oil and gas. Establishing appropriate values for oil and gas is particularly important because that methodology may set a precedent for how other federal natural resources, such as coal and timber, are valued on the federal balance sheet.

A121. A standard for recognizing federal oil and gas resources as an asset must distinguish two categories of federal holdings: proved reserves and all other. For proved reserves, the fair value to the federal government is the present value of expected contract royalties.[25] For all other gas and oil holdings, including unproved resources that have not been offered for lease and resources that might never be tapped, fair value is the present value of expected bonuses, rents, and royalty payments.[26] But for both types of holdings, fair value is the appropriate valuation.

[24]FASB SFAS 159, "The Fair Value Option for Financial Assets and Financial Liabilities."
[25] For an analysis of how reserves should be measured, see Cambridge Energy Research Associates, *In Search of Reasonable Certainty: Oil and Gas Reserves Disclosure* (Cambridge, Mass., February 2005); statement of Bala G. Dharan, Professor of Accounting, Rice University, "Improving the Relevance and Reliability of Oil and Gas Reserves Disclosures," before the House Committee on Financial Services, July 21, 2004; and Society of Petroleum Engineers, "Why a Universal Language for Evaluating Reserves Is Needed" (white paper, February 27, 2006), available at www.spe.org/web/org/Resources_White_Paper.pdf.
[26] Some federal oil and gas resources are currently restricted from development by law. This alternative view does not take a position on whether to report those resources on the balance sheet.

Shortcomings of the Majority Proposal

A122. The Board proposal has two shortcomings. First, the Board proposes to recognize only proved reserves, even though other properties that the Federal government controls may have significant value. The value of proved reserves is thus an underestimate of the resources available from federal lands and offshore areas. Second, the Board proposes to value proved reserves using a means other than fair value. Experience with resource prices indicates that the estimated value of proved reserves, using the Board's approach, will typically be overstated, perhaps significantly.

A123. The exposure draft posits that information needed to estimate fair value is not available (paragraph A50). However, several methods are available for estimating the fair value of federal oil and gas reserves, including the value of comparable private market transactions and discounted cash flow valuations of the government's projected receipts from leases on federal lands. Some methods, such as discounted cash flows, appear to be more suitable for arriving at the fair value of proved reserves, while the value of comparable private market transactions may be more suitable for determining the fair value of other holdings.

A124. FASAB proposes to value federal oil and gas resources on the basis of expected federal royalty receipts on current proved reserves. The formula used to calculate those receipts would be: estimated quantity of proved reserves multiplied by the average price at the wellhead multiplied by the average royalty rate (paragraphs 16 through 19).

A125. FASAB's proposed valuation methodology for the federal government's future stream of royalty receipts is a departure from fair value and ignores the available information about the market value of those resources. First, the proposed valuation fails to discount the stream of future royalty payments to the government to reflect the time value of money and thus overstates the present value of those future receipts. The exposure draft acknowledges in principle the desirability of discounting future streams of payments but states that the uncertainty surrounding the average life of a lease, production schedules, and future prices is too great to project cash flows reliably (paragraph A52). The standard's approach to valuation, however, does not address that uncertainty or risk. The aggregate cash flow stream for each region could be estimated from reserve levels and historic and forecast levels of economic aggregates such as oil prices and production rates.[27] Second, the valuation relies on current prices and hence ignores expected changes in energy prices over time.

A126. Under some circumstances, these two flaws in the majority's valuation approach—the lack of discounting and the use of current rather than future prices—will tend to offset each other. In particular, the majority's valuation method would be reasonably accurate if future oil and gas prices are expected

[27] In general, production rates from developed fields are relatively stable, varying only little with current prices. Government rules and standard engineering practices specify production rates and development paths for a field that will maximize total output over time.

to increase over time at a rate equal to the appropriate risk-adjusted discount rate. Such a relationship between prices and the discount rate could occur, but only if resource prices follow one well-known theoretical model of resource prices, the Hotelling model. Unfortunately, current oil and gas markets do not appear to satisfy the specific conditions that are assumed in the Hotelling model.[28] Moreover, the Hotelling model has performed poorly in explaining the actual time path of resource prices.[29] It is therefore unlikely that the majority approach—which ignores both discounting and the potential for resource prices to change in the future—will, by happenstance, provide valuation estimates that approximate fair value. A more accurate assessment of the value of oil and gas reserves thus requires projecting the nominal value of future oil and gas royalties and discounting those royalties to determine the fair value of the resources.

Fair Value Measures

A127. When market transactions are available, fair value is the same as market value. In the absence of active trading markets that would provide a current quote for identical assets, the Financial Accounting Standards Board has proposed a hierarchy of fair value measurement methodologies.[30] Estimates can be based on observable prices from transactions involving comparable assets. In the absence of comparable prices, reporters may estimate fair value by converting future cash flows to present values by discounting. It will be up to preparers (and then the auditors) to decide how to best estimate fair value.

Private Market Transactions

A128. Prices from private market transactions have the potential to serve as fair value estimates of oil and gas reserves.[31] Oil and gas producers regularly exchange individual properties and leases that include proved reserves, reservoirs that

[28] The Hotelling model implies that the net price (sales price less extraction costs) of an exhaustible resource, such as oil and natural gas, will increase over time at the rate of interest (if this relationship did not hold, producers would have an incentive to increase or decrease their current production in such a way that would equate the growth of net prices with the rate of interest). This model relies on numerous assumptions—for example, that extraction costs are constant, there is no market uncertainty and market participants have perfect foresight, the amount of the resource is fixed in supply, and markets are perfectly competitive—that do not apply in current oil and gas markets. Moreover, even if these conditions did hold, the model would imply that sales prices would grow more slowly than the rate of interest as long as extraction costs are significant.

[29] Differences between the Hotelling valuation and reserve prices can be significant and persist over long periods. For example, one analysis estimates that the Hotelling valuation was more than double the estimated reserve price in 2003. M.A. Adelman and G.C. Watkins, *Oil and Natural Gas Reserve Prices: Addendum to CEEPR WP 03-016 Including Results for 2003 and Revisions to 2001,* Working Paper No. 20015-013 (Cambridge Mass.: MIT Center for Energy and Environmental Policy Research, March 2005), available at http://web.mit.edu/ceepr/www/2005-013.pdf.

[30] Financial Accounting Standards Board, Statement of Financial Accounting Standards No. 157, “Fair Value Measurements.”

[31] This is one of several methods approved for use by the Department of the Interior; see Bureau of Land Management, *Economic Evaluation of Oil & Gas Properties*, available at www.blm.gov/nhp/efoia/wo/handbook/h3070-2.html.

have been found and are being developed, or merely “probable” reserves. The market values for those properties reflect the present discounted value of future earnings—including the cost and levels of production over time, expected changes in oil and gas prices, and discount rates that encompass appropriate risks. Those transactions totaled over $600 billion for existing oil and gas fields between 1979 and 2003.[32]

A129. Sales of oil and gas reserves indicate that energy resources in the ground are worth much less than the wellhead prices because the reserves cannot be produced and delivered to a buyer immediately. Expectations about production costs and future wellhead price changes also affect valuations. On average, proved oil and gas reserves have sold for only about 20-25 percent and 30-40 percent of their respective wellhead prices for the 1991-2001 period. About 15 percent of the change in oil prices at the wellhead is reflected in proved reserve prices.[33]

Discounted Cash Flow Models

A130. Discounting the government’s expected receipts from bonus bids, royalty payments, and rents is an alternative approach to estimating fair market values when comparable transactions are unavailable. That approach has been used by the Department of the Interior. Discounted cash flow models require estimates of risk-adjusted discount rates, future prices, and production flows.[34] Risk-adjusted discount rates rather than Treasury rates are appropriate because of uncertainty about future prices and production flows.[35] Texas

[32] See James L. Smith, *Petroleum Property Valuations*, Working Paper No. 2003-11 (Cambridge, Mass.: MIT Center for Energy & Environmental Policy Research, June 2, 2003), available at http://web.mit.edu/ceepr/www/2003-011.pdf. (Note: this paper was published as James L. Smith, “Petroleum Property Valuation,” *Encyclopedia of Energy*, Cutler J. Cleveland, ed., Academic Press (March 2004)).

[33] Transaction prices for oil and gas reserves tend to be less volatile than wellhead prices. See Smith (June 2, 2003), pp. 6-8 and Figure 3. For natural gas, about 10 percent of the change in field prices would be reflected in proved reserve prices. See M.A. Adelman and G.C. Watkins, *Oil and Natural Gas Reserve Prices: Addendum to CEEPR WP 03-016 Including Results for 2003 and Revisions to 2001*, Working Paper No. 2005-013 (Cambridge, Mass.: MIT Center for Energy & Environmental Policy Research, March 2005), available at http://web.mit.edu/ceepr/www/2005-013.pdf. For a detailed discussion of the data sources see, M.A. Adelman and G.C. Watkins, *Oil and Natural Gas Reserve Prices: 1982-2002: Implications for Depletion and Investment Cost*, Working Paper No. 2003-016 (Cambridge, Mass.: MIT Center for Energy & Environmental Policy Research, October 2003), pp. 11-1, available at http://web.mit.edu/ceepr/www/2003-016.pdf.

[34] An alternative approach would be to use a (real) options-pricing model. That approach, which requires an estimate of the market price of reserves and its volatility, recognizes that management can decide whether and when to develop an energy field and at what production rate. These strategic decisions affect the risk of production cash flows over time, which means that a constant risk-adjusted rate is not appropriate. Options-pricing methods provide a systematic method for discounting cash flows when risks change over time. See Smith (June 2, 2003), p. 11

[35] See Smith (June 2, 2003), pp. 3-4. For an analysis of the relevance of market risk to the government, see Congressional Budget Office, *Estimating the Value of Subsidies for Federal Loans and Loan Guarantees* (August 2004), available at www.cbo.gov/ftpdocs/57xx/doc5751/08-19-CreditSubsidies.pdf.

assesses property taxes on the fair value of oil and gas reserves and provides guidance on acceptable risk-adjusted discount rates of future cash flows.[36]

A131. The expected future prices of oil and gas can be observed in the futures market.[37] While most trading is for contracts for delivery in less than a year, contracts for delivery in December 2012 are also currently available.[38] Prices for the period beyond 2012 could be projected using economic models.

A132. To project flows, the Energy Information Administration and others generally assume in their forecasts that the ratio of production to proved reserves will remain constant, which is consistent with historical data. Thus, the current production to reserve ratio can be used to represent a constant rate of decline for future production.

[36] For a discussion of Texas's guidelines, see www.window.state.tx.us/taxinfo/proptax/ogman/index.html.
[37] Researchers have found that spot market prices are much more volatile than longer term futures contracts. See Miguel Herce, John E. Parsons and Robert C. Ready, *Using Futures Prices to Filter Short-Term Volatility and Recover a Latent, Long-Term Price Series for Oil,* Working Paper No. 2006-005 (Cambridge, Mass: MIT Center for Energy and Environmental Policy Research, April 2006), available at http://web.mit.edu/ceepr/www/2006-005.pdf.
[38] Oil and natural gas futures trade on the New York Mercantile Exchange; see www.nymex.com/lsco_fut_csf.aspx?product=CL and www.nymex.com/ng_fut_csf.aspx?product=NG.

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APPENDIX B: LIST OF ABBREVIATIONS

API	American Petroleum Industry
Bbl	Barrels
BLM	Bureau of Land Management
Btu	British Thermal Unit
CERA	Cambridge Energy Research Associates
CFR	Consolidated Financial Report
CFR	Code of Federal Regulations
DOI	Department of Interior
DWRRA	Deep Water Royalty Relief Act
ED	Exposure Draft
EIA	Energy Information Administration
FASAB	Federal Accounting Standards Advisory Board
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
GOM	Gulf of Mexico
Mcf	Thousand Cubic Feet
MMBOE	Million Barrels of Oil Equivalent
MMS	Minerals Management Service
OCS	Outer Continental Shelf
NEPA	National Environmental Policy Act
NGPLs	Natural Gas Plant Liquids
PSIA	Pounds Per Square Inch Absolute
RSI	Required Supplementary Information
SEC	Securities and Exchange Commission
SFAC	Statement of Financial Accounting Concepts
SFFAC	Statement of Federal Financial Accounting Concepts
SFAS	Statement of Financial Accounting Standards
SFFAS	Statement of Federal Financial Accounting Standards
U.S.	United States
USGS	U.S. Geological Survey

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APPENDIX C: PRO FORMA TRANSACTIONS AND FINANCIAL STATEMENTS

PLEASE NOTE: The sample accounting entries and financial statements in Appendix C illustrate pro forma accounting transactions pertaining to Federal oil and gas resources and the resulting financial statements. Data used in the pro forma transactions have been estimated by judgmentally extrapolating hypothetical numbers. These illustrative examples are not intended to provide guidance on determining the application of materiality.

The following pro forma transactions are compressed and simplified, and appropriately do not contain all of the detail associated with an event. For example, in transaction number two, the one-fifth bonus is invested until leases are accepted. Any interest accrued is refunded on bids subsequently rejected and returned. The illustration omits transactions internal to the entity. For example, transfers between sub-component entities are omitted.

Readers should not rely on the pro forma accounting transactions and resulting financial statements as a complete model for agency accounting. Certain omitted entries may be required in actual practice but are omitted since they are not required to understand the effect of the proposal on agency financial statements.

At the beginning of the fiscal year for which the accounting standards for oil and gas resources are effective, the following transaction is recorded by the component entity responsible for collecting royalties.

1. Record initial value of estimated petroleum royalties and the related liability for revenue distributions to others.

The initial value of estimated petroleum royalties used in this pro forma transaction is calculated for illustrative purposes only. The value of the Federal government's estimated petroleum royalties would be calculated based on the valuation of oil and lease condensate estimated petroleum royalties, natural gas plant liquids (NGPLs) estimated petroleum royalties, and gas estimated petroleum royalties on a regional basis. Formulas to be used to calculate the estimated petroleum royalties for oil and lease condensate, NGPLs, and gas on a regional basis are as follows:

For oil and lease condensate:

Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves X Regional Average First Purchase Price for Oil and Lease Condensate X Effective Regional Average Royalty Rate for Oil and Lease Condensate = Regional Estimated Petroleum Royalties for Oil and Lease Condensate

For NGPLs:

Regional Estimated Quantity of Proved NGPLs Reserves X Regional Average First Purchase Price for NGPLs X Effective Regional Average Royalty Rate for NGPLs = Regional Estimated Petroleum Royalties for NGPLs

For gas:

Regional Estimated Quantity of Proved Gas Reserves X Regional Average Wellhead Price for Gas X Effective Regional Average Royalty Rate for Gas = Regional Estimated Petroleum Royalties for Gas

The initial value of estimated petroleum royalties is a hypothetical number used for illustrative purposes only. The hypothetical initial value of estimated petroleum royalties is $150,677,667,470. The illustrative pro forma transaction to record the initial value of the Federal government's estimated petroleum royalties and related liability is presented below. The asset's value would be the royalty share of the Federal oil and gas resources classified as "proved reserves." The related liability would be for the royalty share of the Federal oil and gas resources classified as "proved reserves" designated to be distributed to others, i.e., the states, the general fund of the U.S. Treasury and other Federal component entities, including the component entity responsible for collecting royalties. The proposed treatment of distribution of revenue to others creates a Federal and a non-Federal liability for the component entity responsible for collecting royalties.

The cumulative effect of adopting this accounting standard would be reported as a "change in accounting principle" in accordance with SFFAS 21, *Reporting Corrections of Errors and Changes in Accounting Principles*. The adjustment would be made to the beginning net position on the component entity responsible for collecting royalties Statement of Changes in Net Position for the period the change is made. To obtain the value of the adjustment, the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the component entity responsible for collecting royalties. For this illustration, one percent was used as the average annual share of the revenue distributed to the component entity responsible for collecting royalties based on the average distribution for 2005.[39] To record the related liabilities the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the states. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[40] For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005.[41] These calculations are presented below:

$150,677,667,470 X .01 = $1,506,776,675

$150,677,667,470 X .84 = $126,569,240,675

$150,677,667,470 X .15 = $22,601,650,120

Dr Estimated Petroleum Royalties	150,677,667,470	
Cr Prior Period Adjustment: Change In Accounting Principle		1,506,776,675
Cr Liability for Revenue Distribution to Others-Federal		126,569,240,675
Cr Liability for Revenue Distribution to States-Non-Federal		22,601,650,120

To record initial value of estimated petroleum royalties due to change in accounting principle, the related liabilities to state and local governments, and the related liabilities to other Federal component entities. (The 1% expected to be retained by the entity responsible for making royalty collections increases its net position.)

<u>*Other Federal component entity entry:*</u>

For component entities, amounts must be recognized in a manner that supports elimination of Federal assets and liabilities and flow amounts. Therefore, the receiving Federal component entities

[39] The one percent was derived by dividing [Note 21. Custodial Distributions to MMS, Revenues to Fund Operations] by [Total Revenue on the Statement of Custodial Activity] for 2005.

[40] The 15 percent was derived by dividing [Note 21. Payments to States] by [Total Revenue on the Statement of Custodial Activity] for 2005.

[41] The 84 percent was derived by dividing [Transfers-out to other Federal component entities on the Statement of Custodial Activity] by [Total Revenue on the Statement of Custodial Activity] for 2005.

would be required to book the asset related to their respective interest in the estimated petroleum royalties.

Dr Long-Term A/R for Oil and Gas-Federal	126,569,240,675	
Cr Prior Period Adjustment: Change In Accounting Principle		126,569,240,675

To book the asset by other Federal entities for their respective interest in the estimated petroleum royalties.

2. Record payment of the one-fifth bonus bid amounts.

For a competitive lease sale, a notice of lease sale is published in the *Federal Register.* Each lease bid must include a payment for one-fifth of the bonus bid amount unless the bidder is otherwise directed by the Secretary. For purposes of this illustrative accounting event, four bonus bids were received with payment of the one-fifth bonus bid amount. Bonus bid number one was $1,850,000, bonus bid number two was $1,900,000, bonus bid number three was $1,950,000, and bonus number four was $2,000,000. The total payment relating to the four bonus bids was $1,540,000 (bonus bid number one for $370,000, bonus bid number two for $380,000, bonus bid number three for $390,000, and bonus bid number four for $400,000) and was recorded with the following entry by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	1,540,000	
Cr Unearned Revenue		1,540,000

To record collection of the one-fifth bonus bids for the four bonus bids.

3. Record remaining payment by the successful bidder and the annual rental fee and the related liability for revenue distributions to others.

Payment of the unpaid balance of the bonus bid amount and the first year's rental fee are to be received from the successful bidder on the 11th business day after receipt of the lease forms by the successful bidder. The successful bid was bonus bid number four in the amount of $2,000,000. The remaining four-fifths bonus bid of $1,600,000 and the first year rental fee in the amount of $360,000 is received. According to various legislative requirements, rental fees are required to be paid one year in advance and are recorded as revenue from rent when received because there is no obligation to refund unearned portions. The following entries are recorded by the component entity responsible for collecting royalties.

Dr Unearned Revenue		400,000	
Dr Fund Balance with Treasury	(1,600,000+360,000)	1,960,000	
Cr Revenue from Rent			360,000
Cr Revenue from Bonus Bid			2,000,000

To record remaining bonus payment and the annual rental fee by the successful bidder.

The related increase in the liability for the future revenue distributions to others from the rent and the bonus bid is calculated in two parts. One part is based on revenue designated as payments to the States. The other part is based on designated transfers-out to other Federal component entities. The revenue from rent and bonus bid is multiplied by the average share of the revenue distributed to the States to obtain the value of the rent and bonus bid revenue to be distributed to the States. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[42] The revenue from rent and bonus bid is multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent and bonus bid revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other component entities based on the average distribution for 2005.[43] These calculations are presented below:

$2,360,000 X .15 = $354,000

$2,360,000 X .84 = $1,982,400

Dr Revenue Designated for the States[44]	354,000	
Dr Transfers-Out	1,982,400	
Cr Liability for Revenue Distribution to Others-Federal		1,982,400
Cr Liability for Revenue Distribution to States-Non-Federal		354,000

To record the related increase in the liability for the future revenue distributions to others.

<u>*Other Federal component entity entry:*</u>

Dr Long-Term A/R for Gas and Oil-Federal	1,982,400	
Cr Transfer-In		1,982,400

To record the related accrual of a transfer-in and a reduction in the long-term A/R.

4. Receive the annual rental fee from pre-existing leases and record the related liability for revenue distributions to others.

For illustrative purposes, the total amount of annual rent collected for the year for offshore leases was $193,273,613 and the rental fee for onshore leases was $46,588,068 for a total of $239,861,681. Since $360,000 was received in connection with the new lease, the rental payments remaining are $239,501,681 ($239,861,681 less $360,000). The following entry is recorded by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	239,501,681	
Cr Revenue from Rent		239,501,681

To record rental payments on leases for the year.

The related increase in the liability for the future rent revenue to be distributed to others is calculated in two parts. One part is based on revenue designated as payments to the States. The other part is based on designated transfers-out to other Federal component entities. The revenue from rent is multiplied by the average share of the revenue distributed to the States to obtain the value of the rent revenue to be distributed to the States. For this illustration, 15 percent was used as an average

[42] See footnote 40.
[43] See footnote 41.
[44] This and certain other titles were selected for illustrative purposes. The entity has the option of selecting another account title, such as grant, that may be more appropriate.

annual share of the revenue distributed to the States based on the average distribution for 2005.[45] The revenue from rent is multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005.[46] These calculations are presented below:

$239,501,681 X .15 = $35,925,252

239,501,681 X .84 = $201,181,412

Dr Revenue Designated for the States	35,925,252	
Dr Transfers-out	201,181,412	
Cr Liability for Revenue Distribution to Others-Federal		201,181,412
Cr Liability for Revenue Distribution to States-Non-Federal		35,925,252

To record the related increase in the liability for the future revenue distributions to others.

Other Federal component entity entry:

Dr Long-Term A/R for Gas and Oil-Federal	201,181,412	
Cr Transfer-In		201,181,412

To record the related accrual of a transfer-in and a reduction in the long-term A/R.

5. Refund unsuccessful bidders' bonus bid deposits.

Bonus bid deposits submitted by unsuccessful bidders are refunded to respective bidders after bids are opened, recorded, and ranked. Bonus bid #1 in the amount of $370,000, bonus bid #2 in the amount of $380,000, and bonus bid #3 in the amount of $390,000 for a total of $1,140,000 are returned to respective bidders. The following entry is recorded by the component entity responsible for collecting royalties.

Dr Unearned Revenue	1,140,000	
Cr Fund Balance with Treasury		1,140,000

To record refund of losing bonus bids.

The remaining pro-forma transactions and financial statements are presented as of the end of the Federal government's fiscal year (FY).

6. Record earned royalty revenue and depletion expense.

Earned royalty revenue should be recognized as exchange revenue by the component entity that is responsible for collecting the royalties. At the same time, an amount equal to the royalty collections should be recognized as depletion expense; and, the value of estimated petroleum reserves should be reduced by the depletion expense amount. Sales value and royalty payment information are due

[45] See footnote 40.
[46] See footnote 41.

on or before the last of the month following the month the oil or gas product from Federal oil and gas resources was sold or removed from the lease. For example, oil or gas sold in June must be reported by July 31, the end of the following month.

For illustrative purposes, the total amount of royalty revenue earned for the fiscal year for offshore and onshore rental leases was used in this calculation. The royalty revenue earned during the fiscal year for offshore leases was $3,563,921,973 and the royalty revenue earned during the fiscal year for onshore leases was $852,330,828 for a total of $4,416,252,801. The following entries are recorded by the component entity responsible for collecting royalties.

Dr Accounts Receivable	4,416,252,801	
Cr Revenue from Royalties for Federal Oil and Gas Reserves		4,416,252,801
To record earned royalty revenue.		
Dr Oil and Gas Depletion Expense	4,416,252,801	
Cr Estimated Petroleum Royalties		4,416,252,801
To record depletion expense for Federal oil and gas resources.		

7. Record collection of royalty revenue.

Royalty payments are due on or before the last of the month following the month the oil or gas product from Federal oil and gas resources are sold or removed from the lease, unless lease terms state that royalties are due otherwise. A year-to-date total of royalty revenue collected is in the amount of $4,048,231,734. The following entry is recorded by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	4,048,231,734	
Cr Accounts Receivable		4,048,231,734
To record collection of royalty revenue.		

8. Record distribution of bonus bid, rent, and royalty collections and the reduction in the liability for the revenue distributed to others.

The component entity responsible for collecting royalty revenue is required to distribute the bonus bid, rent, and royalty revenue in accordance with authoritative formulas to recipients designated by law upon matching the revenue collections to specific leases. The component entity distributing bonus bid, rent, and royalty revenue from Federal oil and gas resources should recognize the distribution to component entities in accordance with existing accounting standards. The Federal component entity receiving the distribution should recognize the receipt as a transfer in when calculating its operating results. For purposes of this illustrative accounting event, the bonus bid collected was $2,000,000, the rent collected was $239,861,681 and the royalties collected was $4,048,231,734 for total collections of $4,290,093,415.

The bonus bid, rent, and royalty revenue collections to be distributed and the related reduction in the liability for revenue distribution to others is calculated in two parts. One part is based on revenue collections designated as payments to the States. The other part is based on collections designated as payments to other Federal component entities. The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to the States to obtain the value of the collections to be distributed to the States. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[47] The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005.[48] These calculations are presented below:

$4,290,093,415 X .15 = $643,514,012

$4,290,093,415 X .84 = $3,603,678,469

Dr Liability for Revenue Distribution to Others-Federal	3,603,678,469	
Dr Liability for Revenue Distribution to States-Non-Federal	643,514,012	
Cr Fund Balance with Treasury		4,247,192,481

To record distribution of bonus bid, rent, and royalty revenue collections and the reduction in liabilities for revenue distribution to others.

<u>*Other Federal entity entry:*</u>

Dr Fund Balance with Treasury	3,603,678,469	
Cr Long-Term A/R for Oil and Gas-Federal		3,603,678,469

To increase the fund balance with treasury and reduce the long-term accounts receivable for oil and gas in relation to distributions received.

9. Disclose rights to future royalty streams identified for sale.

When rights to a future royalty stream are identified to be sold, the value of those rights should be disclosed as future royalty rights held for sale. They should be disclosed rather than reclassified because (1) the point in time for the sale of the future royalty rights may be uncertain or undecided and (2) the identified fields may continue to produce oil and/or gas and generate royalties. These two factors make it difficult to establish and maintain precise valuation information in advance of the sale. Disclosure of the approximate value at the balance sheet date alerts the reader to the pending sale and the potential value of the asset to be sold. The value of the rights identified for sale should be based on the estimated quantity of proved reserves, the first purchase price for oil or the wellhead price for gas, and the royalty rate for each specific field identified for potential sale.

Future royalty streams from two specific oil fields have been identified to be sold.

The estimated value of the future royalty stream identified to be sold from field number one is $5,305,000 based on the following calculation: 1,000,000 barrels to be sold X $42.44 per barrel per field number one first purchase price for oil X the 12.5% royalty rate for field number one.

The estimated value of the future royalty stream identified to be sold from field number two is $3,244,688 based on the following calculation: 750,000 barrels to be sold X $34.61 per barrel per

[47] See footnote 40.
[48] See footnote 41.

field number two first purchase price for oil X the 12.5% royalty rate for field number two. The future royalty streams are expected to be sold sometime during the next fiscal year.

10. Record sale of future royalty streams identified for sale and the related change in the liability for revenue distributions to others.

At the time the future royalty rights identified for sale are sold, the asset value is calculated based on the quantity of proved oil reserves involved in the sale, the first purchase price or the wellhead price for the field at the time of sale, and the royalty rate for the specific field. Any difference between the asset value of the future royalty rights sold and the sales proceeds results in a net gain or loss. The net gain or loss should be reported on the Statement of Net Cost of the component entity responsible for collecting royalty revenue. For purposes of this illustrative accounting event, the rights to future royalty rights held for sale for field number one had an asset value of $5,375,000 based on the following calculation: 1,000,000 barrels of proved oil reserves involved in the sale multiplied by an arbitrary $43.00 per field number one first purchase price per barrel further multiplied by the arbitrary 12.5 percent royalty rate for field number one. The rights to a future royalty stream from field number one were sold for $3,950,000. As a result, there is a loss of $1,425,000 on the sale of the future royalty stream from field number one, which should be reported on the Statement of Net Cost.

Dr. Fund Balance with Treasury	3,950,000	
Dr. Loss on Sale of Estimated Petroleum Royalties	1,425,000	
Cr. Estimated Petroleum Royalties		5,375,000

To record sale of future royalties.

The loss on the sale of estimated petroleum royalties is multiplied by the average share of the revenue distributed to the States and other Federal component entities to obtain the related reduction in the liabilities for revenue distributions to others. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[49] The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005.[50] This calculation is presented below:

$1,425,000 X .15 = $213,750

$1,425,000 X .84 = $1,197,000

Dr Liability for Revenue Distributions to Others- Federal	1,197,000	
Dr Liability for Revenue Distributions to States-Non-Federal	213,750	
Cr Revenue Designated for the States		213,750
Cr Transfers-Out		1,197,000

49 See footnote 40.
50 See footnote 41.

To record the related reduction in the liabilities for the future revenue distributions to others, revenue designated for the States, and transfers-out as a result of the loss on the sale of estimated petroleum royalties.

Dr Liability for Revenue Distributions to Others- Federal	3,318,000	
Dr Liability for Revenue Distributions to States-Non-Federal	592,500	
Cr Fund Balance with Treasury		3,910,500

To record the distribution of collections from the sale of revenue streams and the related reduction in the liability for revenue distributions to others.

Other Federal entity entry:

Dr. Fund Balance with Treasury	3,318,000	
Cr. Long-Term A/R for Oil and Gas-Federal		3,318,000

To increase the fund balance with treasury and reduce the long-term accounts receivable for oil and gas in relation to distributions received.

Dr. Transfers-In	1,197,000	
Cr Long-Term A/R for Oil and Gas-Federal		1,197,000

To decrease the transfers-in and long-term accounts receivable as a result of the loss on the sale of estimated petroleum royalties.

11. Record annual valuation of estimated petroleum royalties and the related change in the liability for revenue distributions to others.

The calculated value of the Federal government's estimated petroleum royalties for financial statement reporting at year-end should be compared to the book value of estimated petroleum royalties at year-end. If the calculated value of estimated petroleum royalties at year-end is greater than the year-end book value,[51] the book value should be increased to the new estimate and a gain should be recorded on the Statement of Net Cost of the reporting entity responsible for collecting revenue. If the calculated value of estimated petroleum royalties at year-end is less than the year-end book value, the book value should be decreased to the new estimate and a loss should be recorded on the Statement of Net Cost of the reporting entity responsible for collecting royalty revenue. For illustrative purposes, the valuation of estimated petroleum royalties as of as of the year ended September 30 produced a gain of $25,210,225,331 that is based on the following calculations.

The revaluation value of estimated petroleum royalties for oil and lease condensate from Federal leases is $83,357,750,000: ((14,000,000,000 barrels of proved oil and lease condensate reserves multiplied by an arbitrary price of $47.50 per barrel) further multiplied by an arbitrary 12.535 percent royalty rate)). The revaluation value of estimated petroleum royalties for NGPLs from Federal leases is $9,401,250,000: ((2,500,000,000 barrels of proved NGPLs reserves multiplied an arbitrary price of $30.00 per barrel) further multiplied by an arbitrary 12.535 percent royalty rate)). The revaluation value of estimated petroleum royalties for gas from Federal leases is $78,707,265,000:

[51] The estimated petroleum royalties beginning balance would have been reduced by the amount expensed on the statement of net cost.

((105,000,000,000 thousand cubic feet of proved gas reserves multiplied by an arbitrary price of $5.98 per thousand cubic feet) further multiplied by an arbitrary 12.535 percent royalty rate)).

The total revaluation value of estimated petroleum royalties for oil and lease condensate, NGPLs, and gas is $171,466,265,000. The current value of estimated petroleum royalties ($171,466,265,000) less the book value of estimated petroleum royalties (the initial value of estimated petroleum royalties at the beginning of the year (October) less depletion expense for estimated petroleum royalties through the end of the year (September 30), less the asset value of estimated petroleum royalties sold), equals the net gain to be recorded:

$171,466,265,000 – (150,677,667,470 – 4,416,252,801 – 5,375,000) = $25,210,225,331

Dr Estimated Petroleum Royalties	25,210,225,331	
Cr Gain on Revaluation of Estimated Petroleum Royalties		25,210,225,331

To record revaluation of estimated petroleum royalties.

To record the related increase in the liability for the future revenue distributions to others, the amount that the total estimated petroleum royalties was increased due to revaluation is multiplied by the average share of the revenue distributed to the states. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[52] For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005.[53] These calculations are presented below:

$25,210,225,331 X .15 = $3,781,533,800

$25,210,225,331 X .84 = $21,176,589,278

Dr Revenue Designated for the States	3,781,533,800	
Dr Transfers-Out	21,176,589,278	
Cr Liability for Revenue Distributions to Others-Federal		21,176,589,278
Cr Liability for Revenue Distributions to States-Non-Federal		3,781,533,800

To record the related year-end increase in the liabilities for the future revenue distributions to others.

<u>Other Federal component entity entry:</u>

For component entities, amounts must be recognized in a manner that supports elimination of Federal assets and liabilities and flow amounts. Therefore, the receiving Federal component entities would be required to book the revaluation amount related to their respective interest in the estimated petroleum royalties.

Dr Long-Term A/R for Oil and Gas-Federal	21,176,589,278	
Cr Transfers-In		21,176,589,278

To book the revalued asset amount by other Federal entities for their respective interest in the estimated petroleum royalties.

[52] See footnote 40.
[53] See footnote 41.

The trial balance, closing entries, and pro forma financial statements on the next two pages are illustrative of the departmental entries presented in this appendix. The “other Federal component entity” entries and the consolidated financial statements of the United States Government are not illustrated.

Pre-closing trial balance after pro forma transactions:

Fund Balance with Treasury	42,940,434
Accounts Receivable	368,021,067
Estimated Petroleum Royalties	171,466,265,000
Liability for Revenue Distributions to Others-Federal	(144,340,800,296)
Liability for Revenue Distributions to States-Non-Federal	(25,775,142,910)
Revenue from Bonus Bid	(2,000,000)
Revenue from Rents	(239,861,681)
Revenue from Royalties	(4,416,252,801)
Transfers-Out	21,378,556,090
Oil and Gas Depletion Expense	4,416,252,801
Revenue Designated for the States	3,817,599,302
Gain on Revaluation of Estimated Petroleum Royalties	(25,210,225,331)
Loss on Sale of Future Royalty Rights	1,425,000
Prior Period Adjustment: Change in Accounting Principle	(1,506,776,675)
Total	0

Closing Entries:

Revenue from Bonus Bid	2,000,000	
Revenue from Rent	239,861,681	
Revenue from Royalties	4,416,252,801	
Gain on Revaluation of Estimated Petroleum Royalties	25,210,225,331	
Prior Period Adjustments: Change in Accounting Principle	1,506,776,675	
Cumulative Results of Operations		1,761,283,295
Transfers-Out		21,378,556,090
Oil and Gas Depletion Expense		4,416,252,801
Revenue Designated for the States		3,817,599,302
Loss on Sale of Future Royalty Rights		1,425,000

Post-closing trial balance:

Fund Balance with Treasury	42,940,434
Accounts Receivable	368,021,067
Estimated Petroleum Royalties	171,466,265,000
Liability for Revenue Distributions to Others-Federal	(144,340,800,296)
Liability for Revenue Distributions to States- N0n-Federal	(25,775,142,910)
Cumulative Results of Operations	(1,761,283,295))
Total	0

Pro Forma Financial Statements – for fiscal year ended 9/30/20XX

Balance Sheet

Assets	
Fund Balance with Treasury	42,940,434
Accounts Receivable	368,021,067
Estimated Petroleum Royalties	171,466,265,000
Total Assets	$ 171,877,226,501
Liability for Revenue Distributions to Others-Federal	144,340,800,296
Liability for Revenue Distributions to States-Non-Federal	25,775,142,910
Total Liabilities	170,115,943,206
Net Position	
Cumulative Results of Operations	1,761,283,295
Total Liabilities and Net Position	$ 171,877,226,501

Statement of Net Cost

Oil and Gas Resources Program

Leasing Activities:	
Costs (Oil and Gas Depletion Expense)	$ 4,416,252,801
Less: Earned Revenue	(4,658,114,482)
Net Cost/(Revenue) from Leasing Operations	(241,861,681)
Loss/(Gain) on Revaluation of Estimated Petroleum Royalties	(25,210,225,331)
Less: Revenue Designated for the States	3,817,599,302
Less: Loss on Sale of Future Royalty Rights	1,425,000
Net Cost/(Revenue) for Program	$(21,633,062,710)

Statement of Changes in Net Position

Beginning Net Position	$ 0
Adjustment: Change in Accounting Principle	1,506,776,675
Beginning Balance, as adjusted	1,506,776,675
Net Revenue for Program	21,633,062,710
Transfers In/(Out)	(21,378,556,090)
Ending Net Position	$ 1,761,283,295

APPENDIX D: ILLUSTRATIVE DISCLOSURE AND RSI PRESENTATIONS

PLEASE NOTE: Appendix D illustrates the type of reporting contemplated by the Board. Information presented in the illustrative disclosure and RSI presentations are based on hypothetical numbers. Therefore, readers should not rely on the validity of the data in the sample presentations.

NOTE X -- ESTIMATED PETROLEUM ROYALTIES

Management of Federal Oil and Gas Resources

The Minerals Management Service (MMS) plays an integral part in the implementation of the President's national energy policy (NEP). The NEP is a comprehensive strategy designed to secure America's energy future by reducing dependence on foreign sources, increasing domestic fossil fuel production, improving energy conservation efforts, and developing alternative and renewable energy sources. The MMS is responsible for managing the nation's oil and natural gas resources on the Outer Continental Shelf (OCS) and the mineral revenues from the OCS and Federal lands. The MMS management process can be broken down into six essential analysis components: pre-leasing, post-leasing and pre-production, production and post-production, revenue collection, fund disbursement, and revenue compliance.

Stewardship Policies for Federal Oil and Gas Resources

The MMS's responsibilities as stewards of the physical oil and gas resources on the OCS begin when the MMS conducts pre-leasing analysis activities, which include the assessment of oil and gas resources that may be offered for lease. Following the pre-leasing assessment, the MMS develops a plan for offering those resources to developers. In the case of oil and gas development, this planning process is designed to consider both the environmental and economic concerns of the nation by providing opportunities for input from the public, the private sector, states, and Congress. The MMS conducts public planning processes for each individual lease sale.

Once a sale is completed, the MMS evaluates the bids to ensure that the government receives fair market value. The evaluation determines whether the bid can be accepted and a lease issued. Once a lease is assigned to a winning bidder, the MMS begins post-leasing and pre-production activities. These activities include a permitting and approval process for all exploration, development, and production activities proposed by the lease operators. MMS staff inspects each operation in order to confirm that all activities are conducted in an environmentally and physically safe manner. Similar inspections also occur during the production and post-production activities with the added responsibility of ensuring the Federal government is receiving accurate royalties from production, while inspections during the post-production phase help ensure that facilities are decommissioned in a manner that protects the environment.

Once a lease is in place, the Federal government's share of production from both offshore and onshore operations may be recovered as royalty-in-value (RIV) or royalty-in-kind (RIK). Through royalty revenue collection and fund disbursement, the MMS achieves optimal value by ensuring that all revenues from Federal oil and gas lease are efficiently, effectively, and accurately collected, accounted for, and disbursed to states, other Federal component entities, and the U.S. Treasury. The MMS also performs revenue compliance activities to ensure the Federal government has received fair market value and that companies comply with applicable laws, regulations, and lease terms.

Through this robust mineral asset management process, the MMS serves as a leading mineral asset manager for the Federal government, the states, and the American people.

Future Royalty Streams Identified for Sale

Future royalty streams from two specific oil fields have been identified to be sold.

The estimated value of the future royalty stream identified to be sold from field number one in the Gulf of Mexico is $5,305,000 based on the following calculation: The royalty stream from 1,000,000 barrels are to be sold at a $42.44 sale price per barrel per field number one first purchase price for oil with a 12.5 percent royalty rate for field number one.

The estimated value of the future royalty stream identified to be sold from field number two in the Gulf of Mexico is $3,244,688 based on the following calculation: The royalty stream from 750,000 barrels are to be sold at a $34.61 sale price per barrel per field number two first purchase price for oil with a 12.5 percent royalty rate for field number two.

The future royalty streams are expected to be sold sometime during the next fiscal year.

Revenue Reported by Category
Fiscal year 20XX

	Federal Offshore	Federal Onshore	Total
Oil and Lease Condensate Royalty	1,703,801,070	401,102,615	2,104,903,685
NGPLs Royalty	340,110,343	150,120,157	490,230,500
Gas Royalty	$1,520,010,560	$301,108,056	$1,821,118,616
Subtotal	$3,563,921,973	$852,330,828	$4,416,252,801
Rent	$193,273,613	$46,588,068	$239,861,681
Bonus Bid	2,000,000	0	2,000,000
Subtotal	$195,273,613	$46,588,068	$241,861,681
Total	$3,759,195,586	$898,918,896	$4,658,114,482

The disclosure for revenue reported by category presents oil and lease condensate royalty revenue, natural gas plant liquids (NGPLs) royalty revenue, gas royalty revenue, rent revenue, and bonus bid revenue by offshore leases and by onshore leases for the current reporting period. In addition, totals for the gas royalty revenue category, NGPLs royalty revenue category, the oil and lease condensate royalty revenue category, the rent revenue category, and the bonus bid revenue category are reported, with a total for all revenue reported.

ESTIMATED PETROLEUM ROYALTIES
Fiscal Year 20XX

Beginning of FY[54]	Quantity	Purchase Price ($)	Royalty Rate (%)	Asset Value ($)
Oil and Lease Condensate (Barrels)	13,555,200,000	$40.56/Barrel	13.58%	$74,662,692,250
NGPLs (Barrels)	2,347,450,000	$23.00/Barrel	9.5%	5,129,178,250
Gas (Mcf)[55]	100,106,760,000,000	$4.86/Mcf	14.57%	70,885,796,070
Beginning of FY Total				$150,677,667,470

End of FY	Quantity	Purchase Price ($)	Royalty Rate (%)	Asset Value ($)
Oil and Lease Condensate (Barrels)	14,000,000,000	$47.50/Barrel	12.535%	$83,357,750,000
NGPLs (Barrels)	2,500,000,000	$30.00/Barrel	12.535%	9,401,250,000
Gas (Mcf)	105,000,000,000,000	$5.98/Mcf	12.535%	78,707,265,000
End of FY Total				$171,466,265,000

This disclosure provides estimated petroleum royalties for the beginning of the current reporting period and the end of the current reporting period.

The increase in the asset value was a result in the changes involved in valuing the asset. During the current reporting period, there was an increase in the quantity of proved oil and lease condensate, NGPLs, and gas reserves. There was a decrease in the royalty rates for oil and lease condensate and gas leases in effect, but an increase for NGPLs. However, there was a 17 percent increase in the unit price of oil and lease condensate (price per barrel), a 30 percent increase in the unit price for NGPLs (price per barrel), and a 23 percent increase in the unit price of gas (price per 1000 cubic feet) during the reporting period.

54 Fiscal Year.
55 Thousand cubic feet.

REQUIRED SUPPLEMENTARY INFORMATION

Federal Regional Oil and Gas Sales Information

Table 1 on the following page reflects sales volume, sales value, royalty revenue earned, and estimated value for royalty relief information for fiscal year 20XX.

Sales volume represents the quantity of a mineral commodity sold during the reporting period. Sales value represents the dollar value of the mineral commodity sold during the reporting period. Royalty revenue earned represents a stated share or percentage of the value of the mineral commodity produced.

Royalty relief is the reduction, modification, or elimination of any royalty payment due to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. The estimated value for royalty relief is an approximated calculation of royalty relief. The estimated value for royalty relief is calculated based on a formula developed by the Department of the Interior.

The sales volume, sales value, royalty revenue earned, and the estimated value for royalty relief are presented on a regional basis. The information is presented on a regional basis to provide users of the financial statements with the regional variances in the prices of oil and gas for decision-making purposes, to reflect the amount of royalty relief granted and to forecast future royalty revenue.

Table 1
Federal Regional Oil and Gas Information

FY 20XX Natural Gas Plant Liquids (NGPLs) Information

Region	Sales Volume (Barrels)	Sales Value ($)	Royalty Revenue Earned ($)	Estimated Value for Royalty Relief ($)
Alaska	504,907,460	$7,182,415,240	$1,055,380,640	N/A[56]
Pacific	455,613,460	5,737,146,080	822,800,200	N/A
Gulf of Mexico	562,808,260	10,272,610,500	1,470,661,910	3,250,000,000
Onshore Region I	453,335,320	8,912,195,960	1,345,077,330	N/A
Onshore Region II	399,821,380	7,290,095,980	1,108,931,700	N/A
Totals	2,376,485,880	$39,394,463,760	$5,802,851,780	$3,250,000,000

FY 20XX Oil and Lease Condensate Information

Region	Sales Volume (Barrels)	Sales Value ($)	Royalty Revenue Earned ($)	Estimated Value for Royalty Relief ($)
Alaska	366,036,900	5,091,864,970	783,276,870	N/A
Pacific	408,378,420	6,298,080,860	946,205,710	N/A
Gulf of Mexico	120,825,580	2,098,806,440	216,537,590	N/A
Onshore Region I	5,103,168,000	12,884,627,080	2,045,301,890	N/A
Onshore Region II	5,005,101,640	10,170,031,760	1,934,356,820	N/A
Totals	11,003,510,540	$36,543,411,110	$5,925,678,880	N/A

FY 20XX Gas Information

Region	Sales Volume (Mcf[57])	Sales Value ($)	Royalty Revenue Earned ($)	Estimated Value for Royalty Relief ($)
Alaska	4,700,496,060	$13,601,758,780	$2,093,260,060	N/A
Pacific	4,983,485,730	12,221,150,850	1,934,356,820	N/A
Gulf of Mexico	5,103,168,000	12,884,627,080	2,045,301,890	4,050,100,000
Onshore Region I	4,700,952,680	10,345,025,220	1,649,297,130	N/A
Onshore Region II	4,658,177,090	7,653,957,630	1,198,395,780	N/A
Totals	24,146,279,560	$56,706,519,560	$8,920,611,680	$4,050,100,000

[56] N/A means not applicable.
[57] Thousand cubic feet.

Historical Comparisons of Proved Reserves

This overview summarizes the 2004 proved reserves balances of oil and lease condensate, gas (dry), and natural gas plant liquids on a national level and provides historical comparisons between 2004 and prior years. **Table 2**, on the following page, lists the estimated annual reserve balances since 1994 for oil and lease condensate, gas, and natural gas plant liquids.

Oil and Lease Condensate. The United States (U.S.) had 21,371 million barrels of oil and lease condensate proved reserves as of December 31, 2004. Oil and lease condensate proved reserves declined by two percent in 2004 owing mostly to a large nine percent decrease in the Gulf of Mexico. Boosted by reserves additions in Wyoming, Montana, North Dakota, and Texas, the oil and lease condensate proved reserves of the onshore lower 48 States increased by 0.1 percent. However, three of the four largest crude oil reserves areas, the Gulf of Mexico, Alaska, and California, registered reserves declines. U.S. new field discoveries were the lowest in 12 years and as a result operators only replaced 71 percent of oil and lease condensate production with reserves additions.

Total discoveries are those new reserves attributable to extensions of existing fields, new field discoveries, and new reservoir discoveries in old fields. They result from the drilling of new wells. Total discoveries of oil and lease condensate were 782 million barrels in 2004, 37 percent less than those of 2003. The U.S. discovered an average of 1,105 million barrels of new oil and lease condensate proved reserves per year in the prior 10 years. Total discoveries in 2004 were 29 percent lower than that average.

Gas (Dry). The net of revisions, adjustments, sales, and acquisitions was 2,474 billion cubic feet in 2004, 37 percent lower than the post-1976 U.S. average (3,911 billion cubic feet per year). For the sixth year in a row (and 10 out of the last 11 years, the annual change to the national total of gas reserves has been positive, not negative. The U.S. had 192,513 billion cubic feet of dry natural gas reserves as of December 31, 2004, a two percent increase over the 2003 level. All natural gas proved reserves data shown in this report exclude natural gas held in underground storage. U.S. natural gas reserves increased for the sixth year in a row in 2004. The U.S. total went up even though Gulf of Mexico natural gas proved reserves dropped an unusually large 15 percent primarily due to low new discoveries. Discoveries of new gas fields nationwide were the lowest in 12 years. Nevertheless, because onshore lower 48 States total discoveries were almost 18 trillion cubic feet, total U.S. reserves additions replaced 118 percent of 2004 dry gas production. U.S. dry gas production declined one percent in 2004. Twenty percent of U.S. dry natural gas production comes from the Gulf of Mexico Federal Offshore which reported a 10 percent drop in production in 2004. Hurricane Ivan caused infrastructure damage that impacted oil and gas production in the Gulf in the last quarter of 2004 and will also reduce 2005 Gulf production from what it could have been.

Total discoveries are those reserves attributable to field extensions, new field discoveries, and new reservoir discoveries in old fields; they result from drilling exploratory wells. Total discoveries of dry natural gas reserves were 20,163 billion cubic feet in 2004, a five percent increase from the level reported in 2003. About 32 percent of the total discoveries were in Texas, 16 percent were in Wyoming, 10 percent were in the Gulf of Mexico Federal Offshore, 10 percent were in Louisiana, 10 percent were in Oklahoma, and six percent were in New Mexico.

Natural Gas Plant Liquids. U.S. natural gas plant liquids proved reserves increased 6 percent to 7,928 million barrels in 2004, rebounding from the decline observed in 2003. Reserve additions replaced 157 percent of 2004 natural gas plant liquids production. The reserves of seven areas account for 88 percent of the nation’s natural gas plant liquids proved reserves: Texas- 35 perecent, Utah – Wyoming-12 percent, New Mexico-11 percent, Oklahoma-10 percent, Gulf of Mexico Federal Offshore-9 percent, Colorado-6 percent, and Alaska-5 percent.

Total discoveries of natural gas plant liquids reserves were 814 million barrels in 2004, an increase of 11 percent from 2003 (736 million barrels).

Table 2. Total U.S. Proved Reserves of Oil and Lease Condensate, Dry Gas, and Natural Gas Plant Liquids, 1994-2004

Year	Adjustments (1)	Net Revisions (2)	Revisions and Adjustments (3)	Net of Sales and Acquisitions (4)	Extensions (5)	New Field Discoveries (6)	Discoveries in Old Fields (7)	Total Discoveries (8)	Estimated Production (9)	Proved Reserves (10)	Change from Prior Year (11)
	Oil and Lease Condensate (million barrels of 42 U.S. gallons)										
1994	189	1,007	1,196	NA	397	64	111	572	2,268	22,457	-500
1995	122	1,028	1,150	NA	500	114	343	957	2,213	22,351	-106
1996	175	737	912	NA	543	243	141	927	2,173	22,017	-334
1997	520	914	1,434	NA	477	637	119	1,233	2,138	22,546	+529
1998	-638	518	-120	NA	327	152	120	599	1,991	21,034	-1,512
1999	139	1,819	1958	NA	259	321	145	725	1,952	21,765	+731
2000	143	746	889	-20	766	276	249	1,291	1,880	22,045	+280
2001	-4	-158	-162	-87	866	1,407	292	2,565	1,915	22,446	+401
2002	416	720	1,136	24	492	300	154	946	1,875	22,677	+231
2003	163	94	257	-398	426	705	101	1,232	1,877	21,891	-786
2004	74	420	494	23	617	33	132	782	1,819	21,371	-520
	Dry Gas (billion cubic feet, 14.73 psia, 60 degrees Fahrenheit)										
1994	1,945	5,484	7,429	NA	6,941	1,894	3,480	12,315	18,322	163,837	+1,422
1995	580	7,734	8,314	NA	6,843	1,666	2,452	10,961	17,966	165,146	+1,309
1996	3,785	4,086	7,871	NA	7,757	1,451	3,110	12,318	18,861	166,474	+1,328
1997	-590	4,902	4,312	NA	10,585	2,681	2,382	15,648	19,211	167,223	+749
1998	-1,635	5,740	4,105	NA	8,197	1,074	2,162	11,433	18,720	164,041	-3,182
1999	982	10,504	11,486	NA	7,043	1,568	2,196	10,807	18,928	167,406	+3,365
2000	-891	6,962	6,071	4,031	14,787	1,983	2,368	19,138	19,219	177,427	+10,021
2001	2,742	-2,318	424	2,630	16,380	3,578	2,800	22,758	19,779	183,460	+6,033
2002	3,727	937	4,664	380	14,769	1,332	1,694	17,795	19,353	186,946	+3,486
2003	2,841	-1,638	1,203	1,034	16,454	1,222	1,610	19,286	19,425	189,044	+2,098
2004	-114	744	630	1,844	18,198	759	1,206	20,163	19,168	192,513	+3,469
	Natural Gas Plant Liquids (million barrels of 42 U.S. gallons)										
1994	43	197	240	NA	314	54	131	499	791	7,170	-52
1995	192	277	469	NA	432	52	67	551	791	7,399	+229
1996	474	175	649	NA	451	65	109	625	850	7,823	+424
1997	-14	289	274	NA	535	114	90	739	864	7,973	+150
1998	-361	208	-153	NA	383	66	88	537	833	7,524	-449
1999	99	727	826	NA	313	51	88	452	896	7,906	+382
2000	-83	459	376	145	645	92	102	839	921	8,345	+439
2001	-429	-132	-561	102	717	138	142	997	890	7,993	-352
2002	62	31	93	54	612	48	78	738	884	7,994	+1
2003	-338	-161	-499	30	629	35	72	736	802	7,459	-535
2004	273	97	370	112	734	26	54	814	827	7,928	+469

Technically Recoverable Oil and Gas Resources

Technically recoverable resources is the term used to describe the total quantity of undiscovered recoverable resources and unproved reserves. Proved reserves are not included in the estimated quantity of technically recoverable resources. Technically recoverable resources that underlie Federally administered lands pertaining to Federal oil and gas resources are listed in **Table 3** on the following page. These estimates are based on national assessments performed by the United States Geological Survey (USGS) for onshore areas and those offshore waters subject to State jurisdiction, and the Minerals Management Service (MMS) for those offshore waters under Federal jurisdiction. It is estimated that 78.6 percent of the technically recoverable resources of crude oil, 61.6 percent of the dry gas resources, and 22.4 percent of the natural gas liquids resources underlie Federal lands.

While the specific locations of estimated undiscovered recoverable resources are not yet known, they are believed to exist in geologically favorable settings. Discovered recoverable resources are those economically recoverable quantities of oil and gas for which specific locations are known. 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 from being classified as proved.

While the estimation of technically recoverable resources is certainly a more imprecise endeavor than is the estimation of proved reserves, it is clear that substantial volumes of technically recoverable oil and gas resources remain to be found and produced domestically. Current estimates indicate that as much domestic gas remains to be found and then produced as has been to date. Of course, much effort, investment and time will be required to bring this gas to market.

There is a perception that the oil resource base has been more intensively developed than the gas resource base. And in fact, more oil has been produced in the U.S. than is estimated as remaining recoverable. Nevertheless, the ratio of unproven technically recoverable oil resources to 2004 oil production (**Table 3**) was about 88 to 1, higher than the comparable gas ratio.

TABLE 3

TECHNICALLY RECOVERABLE RESOURCES
As of December 31, XXXX

Area	Jurisdiction	Oil and Lease Condensate (billion barrels)	Gas (Dry) (trillion cubic feet)	Natural Gas Plant Liquids (billion barrels)
Technically Recoverable Resources				
Alaska Onshore + State Offshore	Federal	3.75	33.97	0.54
Alaska Onshore + State Offshore	Other	4.68	95.37	0.61
Alaska Federal Offshore	Federal	24.90	122.60	0.00
Lower 48 States Onshore + State Offshore	Federal	3.79	23.97	1.26
Lower 48 States Onshore + State Offshore	Other	17.83	166.41	5.64
Lower 48 States Federal Offshore	Federal	50.10	239.60	0.00
Alaska Subtotal		33.33	251.94	1.15
Alaska Percentage Federal		86.0%	62.1%	47.0%
Lower 48 States Subtotal		71.72	429.98	6.90
Lower 48 States Percentage Federal		75.1%	61.3%	18.3%
Total Technically Recoverable Resources		**105.05**	**681.92**	**8.05**
Percentage Federal		**78.6%**	**61.6%**	**22.4%**

Notes:
1. Proved Reserves are not included in these estimates.
2. Federal Onshore excludes Indian and Native lands even when federally managed in trust.
3. Zero (0.00) indicates either that none exists in this area or that no estimate of this resource has been made for this area.
4. Federal Offshore indicates MMS estimates for Federal Offshore jurisdictions (Outer Continental Shelf and deeper water areas seaward of State Offshore).

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APPENDIX E: GLOSSARY

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Definitions of Resource and Reserve Components and Subcomponents

Provided below are definitions used by Federal entities to describe oil and gas resource and reserve components and subcomponents. 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 known 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 onshore and state waters. The last such assessment was in 1995. MMS updates their assessment approximately every five years in accordance with the Department of Interior's five-year leasing program, with the last update in 2000. Since 1995, the USGS has not conducted an overall update for onshore and state waters, but has conducted assessments updates on a basin or area level.

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

<u>Undiscovered Resources</u>

Undiscovered resources are hydrocarbons estimated on the basis of geologic knowledge and theory to exist outside of known accumulations. They are presumed to occur in unmapped and unexplored areas. The speculative and hypothetical resource categories comprise undiscovered resources. Undiscovered resources are classified as either “undiscovered non-recoverable resources” or “undiscovered recoverable resources”.

- Undiscovered Non-Recoverable Resources

The portion of undiscovered petroleum-initially-in-place quantities not currently considered to be recoverable. A portion of these quantities may become recoverable in the future as commercial circumstances change, technological developments occur, or additional data is acquired.

- Undiscovered Recoverable Resources

An assessment provides estimates of undiscovered recoverable resources in two categories for Federal offshore oil and gas resources. However assessments for Federal onshore oil and gas resources provide information for only one, the undiscovered, conventionally recoverable resources. Both are described below:

1. <u>Undiscovered, conventionally recoverable resources</u>: The portion of the hydrocarbon potential that is producible, using present or reasonably foreseeable technology, without any consideration of economic feasibility.

2. <u>Undiscovered, economically recoverable resources</u>: The portion of the undiscovered conventionally recoverable resources that is economically recoverable under imposed economic scenarios.

<u>Discovered Resources</u>

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.

<u>Reserves</u>

In accordance with the Society of Petroleum Engineers (SPE), the World Petroleum Congresses (WPC), and the American Association of Petroleum Geologists (AAPG), the definition for "reserves" and the following explanatory paragraphs are presented as follows[58]:

> "Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data."

The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either 1) unproved or 2) proved.

<u>Unproved Reserves</u>

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 from being classified as proved.

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

[58] WPC/SPE/AAPG Petroleum Reserves and Resources Definitions.

"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 represents the proved oil and gas reserves that were extracted from existing reserves.[59]

End of the terms in Illustration 1 that are defined under the subheading **Definitions of Resource and Reserve Components and Subcomponents**

\- -

Historical Estimates of Proved Reserves

Acquisitions: The volume of proved reserves gained by the purchase of 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.

Change from Prior Year: the net change between proved reserves reported for the prior reporting period and proved reserves reported for the current reporting period.

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.

Net of Sales and Acquisitions: the net change in the quantity of reserve estimates, either positive or negative, as a result of reserves gained through purchase and deducted through sale during the report year.

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.

Estimated 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

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

differences between opening and closing lease inventories, and for (2) basic sediment and water. Oil used on the lease is considered production.

Estimated 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.

Estimated 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.

Proved Reserves: The total quantity of proved reserves which is calculated by adding the quantity of reserves reported as revisions and adjustment, net of sales and acquisitions, total recoveries and deducting estimated production 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.

Revisions and Adjustments: the net change in the quantity of reserve estimates, either positive or negative, as a result of adding changes reported as revisions and adjustments during the report year.

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

Total Discoveries: the total quantity of additional discovered reserves which is calculated by adding the quantity of reserves reported as a result of extensions, the quantity of reserves reported as a result of new field discoveries, and the quantity of reserves reported as a result of discoveries in old fields during the report year.

End of the terms under the subheading **Historical Estimates of Proved Reserves**

\- -

Other Definitions

Basin: The site of accumulation of a large thickness of sediments.[60]

[60] U.S. Geological Survey, Geologic Glossary.

Bonus Bid: Leases issued in areas known to contain minerals are awarded through a competitive bidding process. A bonus bid**,** as used in these standards, represents the cash amount successfully bid to win the rights to a lease.[61]

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: 1) 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.

Dry Gas: 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) 2. Any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable.

Estimated petroleum royalties means the estimated end-of-period value of the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources.

Estimated Value for Royalty Relief: Existing statutes authorize the Minerals Management Service (MMS) to grant royalty relief to operators on the production of oil and gas resources from Federal oil and gas leases. Royalty relief is the reduction, modification, or elimination of any royalty to operators to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. The estimated value for royalty relief is the calculated approximation of royalty relief. The estimated value for royalty relief is calculated based on a formula developed by the Department of the Interior.

Federal Oil and Gas Resources: Oil and gas resources over which the Federal government may exercise sovereign rights with respect to exploration and exploitation and from which the Federal government has the authority to derive revenues for its use. Federal oil and gas resources do not include resources over which the Federal government acts as a fiduciary for the benefit of a nonfederal party.

Federal jurisdiction is defined under accepted principles of international law. The seaward limit is defined as the farthest of 200 nautical miles seaward of the baseline from which the breadth of the territorial sea is measured or, if the continental shelf can be shown to exceed 200 nautical miles, a distance not greater than a line 100 nautical miles from the 2,500-meter isobath or a line 350 nautical miles from the baseline.

Field is 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.

[61] Glossary of Mineral Terms, Minerals Revenue Management, Minerals Management Service, U.S. Department of the Interior

First purchase price is the actual amount paid by the first purchaser for crude oil as it leaves the lease on which it was produced.[62] 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.

Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions.

Gravity Bands: The density of oil compared to the density of water, i.e., the specific gravity of the oil. The gravity is measured in degrees by the American Petroleum Institute (API). Oil with a low number is less valuable than with a high number. For example, oil is classified as light, medium or heavy, according to its measured API gravity. Light crude oil is defined as having an API gravity higher than 31.1°API. Medium oil is defined as having an API gravity between 22.3°API and 31.1°API. Heavy oil is defined as having an API gravity below 22.3°API.

Hydrocarbon: An organic chemical compound of hydrogen and carbon in the gaseous, liquid, or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest (methane, a constituent of natural gas) to the very heavy and very complex.

Lease: "Lease," as used in these standards, means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, extraction of, and/or removal of oil or gas.[63]

Lease condensate: A mixture consisting primarily of pentanes and heavier hydrocarbons which is recovered as a liquid from natural gas in lease separation facilities. This category excludes natural gas plant liquids, such as butane and propane, which are recovered at downstream natural gas processing plants or facilities.

Natural gas plant liquids (NGPLs): Those hydrocarbons in natural gas that are separated as liquids at natural gas processing plants, fractionating and cycling plants, and, in some instances, field facilities. Lease condensate is excluded. Products obtained include ethane; liquefied petroleum gases (propane, butanes, propane-butane mixtures, ethane-propane mixtures); isopentane; and other small quantities of finished products, such as motor gasoline, special naphthas, jet fuel, kerosene, and distillate fuel oil.

Oil: 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.

Oil Stream: Crude oil produced in a particular field or a collection of crude oils with similar qualities from fields in close proximity, which the petroleum industry usually describes with a specific name, such as West Texas Intermediate.

[62] EIA-182 Domestic Crude Oil First Purchase Report Instructions.
[63] 30 U.S.C. §1702 (5).

Outer Continental Shelf: The Federal Government administers the submerged lands, subsoil, and seabed lying between the seaward extent of the **States' jurisdiction** and the seaward extent of **Federal jurisdiction**.[64]

Play: A group of **pools** that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment.[65]

Pool: A discovered or undiscovered accumulation of hydrocarbons, typically within a single stratigraphic interval.[66]

Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves: The regional estimated quantities of proved oil and lease condensate reserves are those quantities of oil and lease condensate from Federal oil and gas resources that are totaled for a specified region. Quantities of oil and lease condensate are estimated in barrels (of 42 U.S. gallons) at 60 degrees Fahrenheit.

Regional Estimated Quantity of Proved Natural Gas Plant Liquids Reserves: The regional estimated quantities of proved natural gas plant liquids (NGPLs) reserves are those quantities of NGPLs from Federal gas resources that are totaled for a specified region. Quantities of NGPLs are estimated in barrels (of 42 U.S. gallons) at 60 degrees Fahrenheit.

Regional Estimated Quantity of Proved Gas Reserves: The regional estimated quantities of proved gas reserves are those quantities of dry gas from Federal gas resources that are totaled for a specified region. Quantities of gas are estimated in thousands of cubic feet (Mcf) at 14.73 PSIA67 and 60 degrees Fahrenheit.

Rent: A rent schedule is established at the time a lease is issued. Rents, as used in these standards, are annual payments, normally a fixed dollar amount per acre, required to preserve the rights to a lease while the lease is not in production.[68]

Reservoir: A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.[69]

Royalty: Royalty, as used in these standards, means any payment based on the value or volume of production which is due to the United States on production of oil, lease condensate, NGPLs, or gas

[64] Glossary of Mineral Terms, Minerals Revenue Management, Mineral Management Service, U.S. Department of the Interior.
[65] Glossary of Mineral Terms, Minerals Revenue Management, Minerals Management Service, U.S. Department of the Interior.
[66] Ibid.
[67] PSIA means pounds per square inch absolute. PSIA describes an absolute pressure per square inch that starts from a perfect vacuum. PSIA is influenced by weather and elevation. As a good frame of reference, there is 14.73-PSIA at sea level.
[68] Glossary of Mineral Terms, Minerals Revenue Management, Minerals Management Service, U.S. Department of the Interior.
[69] Ibid.

from the Outer Continental Shelf or Federal lands, or any minimum royalty owed to the United States under any provision of a lease.[70]

Royalty rate: A proportionate interest in the production value of mineral deposits due the lessor from the lessee in accordance with a lease agreement.

Sales Value: The proceeds received for the sale of a product. Sales value is calculated by multiplying the sales volume by unit price.

Sales Volume: The volume, or quantity, of the product that is sold. The sales volume for gas is measured in thousand cubic feet (mcf) and in barrels (bbl) for oil, lease condensate and NGPLs.

States' jurisdiction is defined as follows:

- Texas and the Gulf coast of Florida are extended 3 marine leagues (9 nautical miles) seaward from the baseline from which the breadth of the territorial sea is measured.
- Louisiana is extended 3 imperial nautical miles (imperial nautical mile = 6080.2 feet) seaward of the baseline from which the breadth of the territorial sea is measured.
- All other States' seaward limits are extended 3 nautical miles (approximately 3.3 statute miles) seaward of the baseline from which the breadth of the territorial sea is measured.

Technically recoverable resources: For purposes of these standards, the term used to describe the total quantity of undiscovered recoverable resources and unproved reserves. Proved reserves are not included in the estimated quantity of technically recoverable resources.

Wellhead price is the value of the purchased natural gas at the mouth of the well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction. Posted prices, requested prices, or prices as defined by lease agreements, contracts, or tax regulations should be used where applicable.[71]

[70] Adapted from 30 U.S.C. § 1702 (14).
[71] Energy Information Administration Glossary, http://www.eia.doe.gov/glossary/glossary_w.htm.

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FASAB

Federal Accounting Standards Advisory Board

February 4, 2008

Memorandum

To: Members of the Board

From: Rick Wascak, Assistant Director

Through: Wendy M. Payne, Executive Director

Subj: Accounting for Federal Oil and Gas Resources **Summary of Comment Letters Received through February 4, 2008[1] - Tab D-1**

MEETING OBJECTIVES

Staff requests that the Board respond to the following questions:

a. Should a public hearing be scheduled?

b. If not, are there individual respondents from whom you wish to seek clarification directly? (Note that staff expects to work closely with respondents who proposed alternatives to ensure that technical provisions are clear.)

Following the meeting, staff will continue analyzing the responses and developing an issue paper for discussion at a later meeting.

BRIEFING MATERIALS

This memo is included as Tab D-1 and provides a brief summary of responses. Tab D-2 presents the actual responses received. Tabs D-3 and D-4 present the results of the

[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.

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Department of Interior filed test of the proposal and the alternative view presented in the ED respectively.

BACKGROUND

The exposure draft (ED), *Accounting for Federal Oil and Gas Resources*, proposed accounting standards for Federal oil and gas resources. The proposed standards would result in the recognition of an asset and a related liability. The asset would be referred to as “estimated petroleum royalties” and would present the royalty share of the Federal oil and gas resources classified as “proved reserves.” The asset’s value would be calculated by multiplying the estimated quantity of proved oil and lease condensate, natural gas plant liquids (NGPLs), and gas reserves by the effective average royalty rate for each quantity and by the average per unit price for each quantity.

The related liability would be for the royalty share of the Federal oil and gas resources classified as “proved reserves” designated to be distributed to others, i.e., state governments and – at the component entity level – other federal agencies and the general fund of the U.S. Treasury. The liability would be calculated by assessing the total estimated petroleum royalties to be distributed to others.

When oil and gas resources are extracted and royalties are earned, revenue and a depletion expense equal to the earned revenue would be recognized by the Federal government. When revenue collections are distributed a reduction in the liability for revenue distributions to others would be recognized. Gains and losses due to changes in the estimated quantity of proved oil and lease condensate, NGPLs, and gas reserves, the effective regional average royalty rates, and the average per unit prices would be recognized based on an annual valuation of the asset with an associated adjustment to the liability for revenue distributions to others. In addition, when rights to a future royalty stream are identified to be sold, the value of the related rights would be disclosed.

Additional information about Federal oil and gas resources not classified as proved reserves would be disclosed in notes to the financial statements or reported as required supplementary information (RSI).

An alternative approach to valuing estimated petroleum royalties is fair value and the CBO member believes that fair value is feasible and preferable. The member’s alternative view proposed that fair value be derived from market transactions or discounted cash flows.

The proposed standards would be effective for periods beginning after September 30, 2009 (FY2010), with early implementation permitted.

SUMMARY OF OUTREACH EFFORTS

The ED was issued May 21, 2007 with comments requested by September 21, 2007. However, because the Board received a request for the comment period to be extended and because few responses had been received, the Board agreed to extend the comment period until January 11, 2008. Upon release of the exposure draft, notices and press releases were provided to:

a) The Federal Register;

b) *FASAB News;*

c) The *Journal of Accountancy, AGA Today, the CPA Journal, Government Executive, the CPA Letter,* and *Government Accounting and Auditing Update;*

d) The CFO Council, the Presidents Council on Integrity and Efficiency, Financial Statement Audit Network, and the Federal Financial Managers Council; and

e) Committees of professional associations generally commenting on exposure drafts in the past.

This broad announcement was followed by direct mailings or e-mails of the exposure draft to the following:

a) Relevant congressional committees:

   a. Senate Committee on Energy and Natural Resources
   b. Senate Committee on Finance
   c. Senate Committee on Indian Affairs
   d. House Committee on Financial Services
   e. House Committee on Natural Resources

b) Federal agencies:

   a. Office of Financial Management, Department of the Interior (DOI)
   b. Office of the Special Trustee (OST), DOI
   c. Office of Financial Management, Department of Energy
   d. Reserves and Products Division, Office of Oil and Gas, Energy Information Administration (EIA), Department of Energy
   e. Office of the Chief Accountant, Securities and Exchange Commission (SEC)

c) Public interest groups:

   a. National Congress of American Indians (NCAI) President and Area (Regional) Vice Presidents

d) Oil and gas industry companies/professional organizations:

   a. World Petroleum Congress (WPC)
   b. American Petroleum Institute (API)
   c. Society of Petroleum Engineers (SPE)
   d. Ryder Scott Company
   e. National Petroleum Council (NPC)
   f. International Energy Agency (IEA)
   g. British Petroleum (BP)

h. Royal Dutch Shell
i. Chevron
j. Exxon Mobil

To encourage responses, a reminder notice was provided on September 12, 2007 and January 9, 2008 to our Listserv. In addition, we contacted professional associations and affected agencies directly.

RESULT

As of February 4, 2008, we have received eight responses from the following sources:

	FEDERAL (Internal)	NON-FEDERAL (External)
Users, academics, others		4
Auditors	1	
Preparers and financial managers	3	

Staff previously sent you individual letters one through eight in the first distribution of Board meeting material. An index of all respondents in the order the letters were received is presented at the end of this memorandum.

STAFF SUMMARY AND ANALYSIS

The staff summary presented below is intended to support your consideration of the comments and not to substitute for reading the individual letters. Individual comment letters are provided in Tab D-2. The following table provides a quick reference to the overall response to individual questions.

Note that Letters 1 and 8 are excluded from the question by question tally because none of the individual questions were addressed. These two respondents object to the proposal in its entirety. Staff believes that the Letter 1 respondent objects to the proposal in its entirety based on the assertion that “the belief of estimating proved reserves on estimation distorts the financial statements.” The respondent submitting Letter 8 believes the concept of potential assets is “not fully developed” and suggests – among other things - that all such resources be addressed in a single standard. These letters will receive greater attention as staff identifies specific issues for discussion at a later meeting.

Also, most letters did not address every question. Therefore, the count does not equal six (eight less the two omitted letters) in all cases.

Table 1 - Tally of Responses By Question

<table>
<tr><th>QUESTION</th><th>YES /AGREE</th><th>NO /DISAGREE</th><th>COMMENTS</th></tr>
<tr><td colspan="4">Q1. The Board’s proposal for quantifying the Federal government’s royalty share of proved reserves is to use a single best estimate of recovering reserves based on known geological, engineering, and economic data. This approach is known in the oil and gas industry as the deterministic method. This method would exclude reserves other than proved reserves. In contrast, a probabilistic method of estimation uses the known geological, engineering, and economic data to generate a range of estimates and their associated probabilities of recovering reserves. It would include more than proved reserves. <u>Determination of Quantity</u>:
a. Which of the following two options would you prefer?</td></tr>
<tr><td>i. Capitalize estimated petroleum royalties from the proved reserves based on the deterministic method as proposed in the ED.</td><td>5</td><td colspan="2">An emphasis was placed on the need for EIA to partner with DOI (#5).
Option i:
Consistency and Objectivity
Conservatism
Authoritative source
Desires conformance to SEC definition
Readily available information</td></tr>
<tr><td>ii. Capitalize estimated petroleum royalties from proved reserves, probable reserves, and possible reserves based on the methodology proposed in the alternative view.</td><td></td><td></td><td>No respondents supported this option.</td></tr>
</table>

<table>
<tr><th>QUESTION</th><th>YES/AGREE</th><th>NO/DISAGREE</th><th>COMMENTS</th></tr>
<tr><td colspan="4">Q2. The Board proposes to value the Federal government’s royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date. An alternative approach to valuing estimated petroleum royalties is fair value. Fair value is the price that would be received for an asset or paid to transfer a liability in a transaction between market participants at the measurement date. One Board member believes that fair value is feasible and preferable. The Board member believes that fair value could be derived from market transactions or discounted cash flows. The view of the majority of the Board members is that fair value would not produce a more reliable valuation.

<u>Determination of Value</u>:

Which method do you believe is most appropriate for valuing estimated petroleum royalties?</td></tr>
<tr><td>iii. Value the royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date.</td><td>3</td><td></td><td>Consistency (fair value is subjective)

Reliable</td></tr>
<tr><td>iv. Value estimated petroleum royalties using the alternative view fair value method.</td><td></td><td></td><td>Interior proposes a present value measurement but does not assert that it is a fair value approach.</td></tr>
</table>

QUESTION	YES /AGREE	NO/DISAGREE	COMMENTS
Q3. Some Board members believe that the amount of information proposed to be disclosed in the notes and provided as RSI is excessive. a. Do you believe that each item of information, whether disclosed in the notes or provided as RSI, is necessary to meet reporting objectives and is cost-beneficial to provide? Particularly, consider Table 1 on pages 68 and 69 and Table 2 on pages 70 and 71. It would be helpful if specific information that respondents believe could be deleted or added were identified.		3 *Plus one comment that agency disclosure should mirror the CFR disclosure.	Interior has not objected to the information and states that it can be readily produced but seeks clarification of requirements.
b. How would each item of information be used for decision-making or assessing the financial position of the Federal government?			Not of general interest to readers. Cost outweighs benefits.
c. Please explain the reasons for your position and any alternative you propose.			Develop an IT solution to report
Q4. The proposed standards would require that an estimated value for royalty relief be reported as RSI. The Minerals Management Service (MMS) has a variety of royalty relief programs. Royalty relief is the reduction, modification, or elimination of any royalty to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. a. Do you believe that a monetary value for royalty relief should be reported as RSI? Please explain the reasons for your position.	2		
b. Do you believe the quantity of production for which relief was granted during the reporting period should be reported as RSI? Please explain the reasons for your position.	1		*One respondent supported this disclosure if disclosures and RSI are not reduced. (#3)

QUESTION	YES/AGREE	NO/DISAGREE	COMMENTS
Q5. Statement of Federal Financial Accounting Standards (SFFAS) 7, Accounting for Revenue and Other Financing Sources (as amended), requires that agencies report on assets held in a fiduciary capacity. The Board recently issued SFFAS 31, Accounting for Fiduciary Activities. SFFAS 31 will supersede SFFAS 7 with respect to fiduciary activities but continues the requirement to report on assets held in a fiduciary capacity. The Department of Interior (DOI) manages oil and gas resources on behalf of individual Indians and Indian tribes. This proposed standard – because it classifies oil and gas resources as assets – would result in additional information being disclosed for oil and gas assets managed in a fiduciary capacity. Note, however, that fiduciary reporting does not extend to inclusion of the additional disclosures or RSI that are proposed in this document for Federal oil and gas resources. Thus, with respect to fiduciary activities, only disclosure of the assets, liabilities, and related inflows and outflows would result from this proposal. Some Board members have expressed concern that the costs may exceed the benefits of disclosing fiduciary assets and liabilities measured in conformance with this proposed standard. Since this proposal may significantly increase the fiduciary assets disclosed, we are requesting input on the cost-benefit of the requirement with respect to fiduciary activities. See paragraph. a. Do you believe it is cost-beneficial to require disclosure of the value of estimated fiduciary petroleum royalty assets, liabilities, and related inflows and outflows? Please explain the basis for your beliefs.	1	2	No analysis performed but appearance of cost outweighing benefit. Note that Interior asserts that the provision is inconsistent with guidance provided regarding SFFAS 31. Staff will develop this as an issue but wishes to note that the referenced letter addresses aggregation and not omission.

QUESTION	YES/AGREE	NO/DISAGREE	COMMENTS
Q6. The proposed standards would require the component entity to provide extensive disclosures and RSI. However, the Consolidated Financial Report (CFR) of the United States government would be required to include limited disclosures and no supplementary information. These divergent reporting requirements are consistent with SFFAC 4, *Intended Audience and Qualitative Characteristics for the Consolidated Financial Report of the United States Government*. SFFAC 4 provides that the CFR should be highly aggregated and offer references to other reports. a. Do you believe that the CFR disclosure requirements should be limited as proposed? Please explain the basis for your beliefs.	3		

QUESTION	YES/AGREE	NO/DISAGREE	COMMENTS
Q6. This proposal includes accommodations intended to reduce the cost or burden of implementation. These accommodations are identified below along with the alternatives considered and rejected by a majority of the members. Please comment on any accommodation that you believe is not appropriate or that you believe does not sufficiently reduce the cost or burden of the proposal. a. Asset recognition is limited to proved reserves. However, the Board believes that other than proved reserves (e.g., unproved reserves and undiscovered resources) also are assets. b. The valuation technique provided relies on readily available information. However, fair value, which would require additional information, may be a more appropriate valuation technique. c. This proposal requires use of existing sales volume and sales value information to determine an average price for end of period valuation. Use of market prices as of the end of the reporting period was considered. In addition to the relative cost of obtaining market values, the Board does not believe the valuation would be improved. d. Information to calculate effective royalty rates is readily available and the proposal provides for their use in valuing estimated petroleum royalties. An alternative considered was the use of statutory provisions for certain types of leases. e. Regional data is readily available and the proposal provides for its use in valuing estimated petroleum royalties. An alternative considered was the use of field by field data.	1		Interior concurred with items a and e. An alternative approach was proposed for the remaining items.

An index of respondents is presented below in the order the letters were received. Individual comment letters follow the index in Sub-tab 2:

#1 – Helene A. Baker ,Texas/Oklahoma Regional AGA Vice President Elect.

#2 – Office of Financial Management, Environmental Protection Agency, Christopher S. Osborne, Financial Manager.

#3 – AGA Financial Management Standards Board, Robert L. Childree, Chair.

#4 – Office of the Under Secretary Of Defense, Department of Defence, James E. Short, Deputy Chief Financial Officer.

#5 – Office of Financial Management, Department of the Interior, Daniel L. Fletcher, Director

#6 – Accounting Committee, American Petroleum Institute, Joseph H. Bakies, Chair.

#7 – Financial Management and Assurance, Government Accountability Office, McCoy Williams, Managing Director.

#8 – Federal Issues and Standards Committee, Greater Washington Society of Certified Public Accountants, Daniel L. Kovlak, Chair.

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441 G Street NW
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Dear Ms. Comes,

The FASAB extended an invitation in seeking input to proposed Statement of Federal Financial Accounting Standards entitled *Accounting for Federal Oil and Gas Resources* Exposure Draft. This ED proposes standards that would result in recognition of the estimated value of royalties from federal oil and gas leases and changes in those values over time as well as the amount of royalties designated for distribution to other entities such as state governments.

In response to Q1 through Q7 in a nutshell:

As benefits are derived from proper accountability of royalties the belief of estimating proved reserves on estimation distorts the financial statements. In the oil and gas industry estimation is based on production for purchase of government federal leases for drilling and capital cost estimates. The Department of Interior pursued issues on estimation of royalties that were unattainable through trends or other market data. Spot market prices are best measurement of value when not in formal contracts that attains lower than market costs. The Energy Information Service at http://www.eia.doe.gov is best source for estimations throughout the United States as they receive voluntary reports from the oil and gas industry disclosing production and area costs.

Thank you for the opportunity to have comment on this proposal.

Sincerely,

S//
Helene A. Baker
TX OK Regional VP-Elect

Cc: Susan Fritzlen (sfritzlen@agacgfm.org)

CGFM

>>> <Osborne.Christopher@epamail.epa.gov> 9/19/2007 2:15 PM >>>

Ms. Comes:

Attached are comments that the Office of Financial Management (OFM) within the Office of the Chief Financial Officer compiled in response to the exposure draft. Please feel free to contact me if you require any clarification in our response.

Thank you...

(See attached file: Accounting for Federal Oil and Gas Resources.doc)

Christopher S. Osborne, Financial Manager
Office of Financial Management

EPA Office of Financial Management (OFM) Comments on FASAB Exposure Draft: "Accounting for Federal Oil and Gas Resources"
Contact with Questions: Christopher Osborne, Financial Manager, 202 564 5070

Q1. The proposed standards would provide for recognition of the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves. These reserves are subcomponents of the total oil and gas resources of the Federal government. Please see page 20 for an illustration of Federal oil and gas resource components and subcomponents.

The Board's proposal for quantifying the Federal government's royalty share of proved reserves is to use a single best estimate of recovering reserves based on known geological, engineering, and economic data. This approach is known in the oil and gas industry as the deterministic method. This method would exclude reserves other than proved reserves. In contrast, a probabilistic method of estimation uses the known geological, engineering, and economic data to generate a range of estimates and their associated probabilities of recovering reserves. It would include more than proved reserves. See paragraphs A73 through A78 for additional information regarding the deterministic and probabilistic methods for measuring and reporting proved oil and lease condensate, NGPLs, and gas reserves.

<u>Determination of Quantity</u>:

a. Which of the following two options would you prefer?
   i. Capitalize estimated petroleum royalties from the proved reserves based on the deterministic method as proposed in the ED.
   ii. Capitalize estimated petroleum royalties from proved reserves, probable reserves, and possible reserves based on the methodology proposed in the alternative view. See the alternative view beginning at paragraph A119.

OFM Response:
a i. Capitalize estimated petroleum royalties from the proved reserves based on the deterministic method as proposed in the exposure draft.

b. Please explain the reasons for your preference.

OFM Response:
This method would provide more consistency since the deterministic method is based on objective criteria vs subjective criteria. The use

of "proved reserves" in estimating petroleum royalties would offer the most accurate measure.

c. If you prefer a different basis for determining the quantity of reserves, please explain the alternative you propose and why you prefer it.

Q2. The Board proposes to value the Federal government's royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date. See paragraphs 16 through 19 and 37. Also, see paragraphs A48 through A53 for a discussion of measurement attributes that were considered and paragraphs A79 through A113 for a discussion of the valuation approach proposed. An alternative approach to valuing estimated petroleum royalties is fair value. Fair value is the price that would be received for an asset or paid to transfer a liability in a transaction between market participants at the measurement date. One Board member believes that fair value is feasible and preferable. See the alternative view beginning at paragraph A119. The Board member believes that fair value could be derived from market transactions or discounted cash flows. The view of the majority of the Board members is that fair value would not produce a more reliable valuation than the valuation method proposed in this ED due to the challenges in adopting a fair value method.

Determination of Value:

a. Which method do you believe is most appropriate for valuing estimated petroleum royalties?
    i. Value the royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date.
    ii. Value estimated petroleum royalties using the alternative view fair value method.

OFM Response
a.i. Value the royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date.

b. Please explain the reasons for your preference.
OFM Response
This method would provide more consistency since the basis for the calculation is more clearly defined. Fair values leave a lot up to subjectivity. The valuation based on proved reserves and the corresponding value provides a known quantity in the valuation process that has an actual objective basis.

c. If you prefer a different method for valuing estimated petroleum royalties, please describe the method you propose and why you prefer it.

==

OFM General Comments on Document:

- ***In the 1st bullet on p.2 of the cover sheet to the document, the date of the MOU referred should be stated:***

  Additional background information is available from the FASAB:

  - ***"Memorandum of Understanding among the General Accounting Office, the Department of the Treasury, and the Office of Management and Budget, on Federal Government Accounting Standards and a Federal Accounting Standards Advisory Board." Insert date of MOU***

  - ***"Mission Statement: Federal Accounting Standards Advisory Board"***

- ***Suggest that disclosure requirements for Agencies mirror those for the government-wide consolidated financial reporting.***

AGA

Advancing
Government
Accountability

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(703) 684-6931
(703) 548-9367 (fax)

September 21, 2007

Wendy M. Payne, Executive Director
Federal Accounting Standards Advisory Board
441 G Street, NW, Suite 6814
Washington, DC 20548

Dear Ms. Payne:

The Association of Government Accountants (AGA) Financial Management Standards Board (FMSB) appreciates the opportunity to provide comments on the proposed Statement of Federal Financial Accounting Standards, *Accounting and Financial Reporting for Federal Oil and Gas Resources* by the Federal Accounting Standards Advisory Board (the Board) The FMSB, comprising 22 members with accounting and auditing backgrounds in federal, state and local government, academia and public accounting, reviews and responds to proposed standards and regulations of interest to AGA members. Local AGA chapters and individual members are also encouraged to comment separately.

Overall, we think the proposed statement is appropriate as it enhances accountability of federal government assets and worth. We do have a concern with the large volume of new and additional data that will now be reported/disclosed and the efforts and resources needed to obtain and report that data and hope that the Board will take this into consideration when they finalize the standard.

We also urge the Board to consider communicating with the GASB concerning development of this guidance. If the federal agencies have to recognize the liability for the royalties they will be distributing, should the GASB be taking action to decide (specific to these revenue flows) how to recognize such distributions on the state side?

The FMSB has the following specific comments. They are drafted as responses to the questions posed in the exposure draft, which are reproduced here in italic script.

Q.1 The proposed standards would provide for recognition of the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves. These reserves are subcomponents of the total oil and gas resources of the Federal government. The Board's proposal for quantifying the Federal government's royalty share of proved reserves is to use a single best estimate of recovering reserves based on known geological, engineering, and economic data. This approach is known in the oil and gas industry as the deterministic method. This method would exclude reserves other than proved reserves. In contrast, a probabilistic method of estimation uses the known geological, engineering, and economic data to generate a range of estimates and their associated probabilities of recovering reserves. It would include more than proved reserves.
Which of the following two options would you prefer?

i. Capitalize estimated petroleum royalties from the proved reserves based on the deterministic method as proposed in the ED.

ii. Capitalize estimated petroleum royalties from proved reserves, probable reserves, and possible reserves based on the methodology proposed in the alternative view.

Please explain the reasons for your preference. If you prefer a different basis for determining the quantity of reserves, please explain the alternative you propose and why you prefer it.

The FMSB fully supports the proposal that a Federal Financial Accounting Standard (FFAS) should to be in place for Federal Oil and Gas Resources. Oil and Gas Resources should also be included in the Federal Financial Statements.

We agree with Option i, which is to capitalize estimated petroleum royalties from proved reserves based on the deterministic method as proposed in the ED. We need to be conservative with our asset recognition. Many large oil companies treat their reserves on their 10Ks using the proven reserve method. How they account for exploration costs depends on whether they are a large or small company. Large companies like Exxon Mobil use successful efforts to account for its exploration and production activities, where a small company uses the full cost concept.

As described in the ED, information to implement the probabilistic method is not readily available, or even available at all. Using proven reserves provides the “best” estimate of oil and gas reserves, at least those for which the federal government can generate revenues in the foreseeable future. We think financial decisions using possible reserves would not be useful to management.

The Board needs to consider what decisions will be made based on the reported data and not make complying with the final standard too cost prohibitive.

In addition to the proved reserves shown in the financial statement, there should be a footnote in the accounting policy section explaining the reserves if they are probable (para A74b) and material in nature. The rationale for this position is that there is at least a 50 percent probability that the quantities actually recovered will eventually be proved probable reserves, so the material amount should be annotated in notes to the financial statements.

Q2. The Board proposes to value the Federal government’s royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date. See paragraphs 16 through 19 and 37. Also, see paragraphs A48 through A53 for a discussion of measurement attributes that were considered and paragraphs A79 through A113 for a discussion of the valuation approach proposed. An alternative approach to valuing estimated petroleum royalties is fair value. Fair value is the price that would be received for an asset or paid to transfer a liability in a transaction between market participants at the measurement date. One Board member believes that fair value is feasible and preferable. See the alternative view beginning at paragraph A119. The Board member believes that fair value could be derived from market transactions or discounted cash flows. The view of the majority of the Board members is that fair value would not produce a more reliable valuation than the valuation method proposed in this ED due to the challenges in adopting a fair value method.

Which method do you believe is most appropriate for valuing estimated petroleum royalties?

i. Value the royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date.

ii. Value estimated petroleum royalties using the alternative view fair value method.

Please explain the reasons for your preference. If you prefer a different method for valuing estimated petroleum royalties, please describe the method you propose and why you prefer it.

We fully support Option i which is to value the royalty share of proved resources based on the average regional prices and effective regional royalty rates experienced during 12 months preceding the balance sheet date. The rationale for supporting this position is that other assets on the balance sheet are reported using historical costs. Thus, reporting them at an average regional price would be more reliable than reporting them at Fair Market Value. It is appears to be the most cost-effective method to use for valuation and the suggestion for calculating the related liability was very reasonable.

One member preferred a different method, something like the fair value or market price method. In some ways, this is like valuing securities, they have to be "marked to market" periodically, in this case, it would be annually. He thought in the ED there was a lack of discounting for future revenue streams and that each of the definitions of average regional sales prices seemed to lead to a misleading resulting value for oil and gas reserves. The average regional price is defined as the average of the first purchase prices. That does not seem to take into account market changes since the time of the first purchase and is therefore unrealistic. Depending on market fluctuations, this could either overvalue or undervalue the reserves. In addition, the assumption is being made that all of the oil and gas will be taken over a very short time period. In fact, oil and gas will be taken from the earth over a period of a year, thus the need for discounting or some other method to recognize the time value of money.

Q3. Some Board members believe that the amount of information proposed to be disclosed in the notes and provided as RSI is excessive. See the disclosure and RSI requirements presented in paragraphs 30 through 34 and Appendix D for a complete review of all proposed disclosures and RSI.

Do you believe that each item of information, whether disclosed in the notes or provided as RSI, is necessary to meet reporting objectives and is cost-beneficial to provide? Particularly, consider Table 1 on pages 68 and 69 and Table 2 on pages 70 and 71. It would be helpful if specific information that respondents believe could be deleted or added were identified. How would each item of information be used for decision-making or assessing the financial position of the Federal government? Please explain the reasons for your position and any alternative you propose.

It appears that an excessive amount of information is being provided for the general reader of these statements. Normally, for readers requiring the level of information being presented, other more readily and timely sources would be available. Since this information would be provided in annual statements, it would be of minimum value to the real decision makers who would likely not wait for annual information. However, while it seems to us that a great deal of information is being proposed for disclosure, we would rely on management experts from the Department of the Interior or other agencies to closely examine the usefulness of the proposed disclosures. We do think that the item on page 8 is not useful since it does not relate to the assets or liabilities recorded in the financial statements.

As to the general public desiring this level of information, it is doubtful that they would fully comprehend what is being presented. The six pages of information presented would be more than the general reader would likely want to know. However, they likely would find it informative that the Federal Government and three agencies within the government are involved in these types of activities, and the general overall explanation of the activities.

As far as whether the level of information is what decision makers really need, that question should be specially addressed to those within the three agencies and possibly those in the private sector that are familiar with these type of operations.

Q4. The proposed standards would require that an estimated value for royalty relief be reported as RSI. The Minerals Management Service (MMS) has a variety of royalty relief programs. Royalty relief is the reduction, modification, or elimination of any royalty to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. See paragraphs A90 through A94 for additional information regarding MMS royalty relief programs.

a. *Do you believe that a monetary value for royalty relief should be reported as RSI? Please explain the reasons for your position.*
b. *Do you believe the quantity of production for which relief was granted during the reporting period should be reported as RSI? Please explain the reasons for your position.*

If the amount of detail in the proposed RSI is not reduced (see question 3 above), then it does appear logical to disclose a value for the royalty relief.

Q5. Statement of Federal Financial Accounting Standards (SFFAS) 7, Accounting for Revenue and Other Financing Sources (as amended), requires that agencies report on assets held in a fiduciary capacity.[1] *The Board recently issued SFFAS 31, Accounting for Fiduciary Activities. SFFAS 31 will supersede SFFAS 7 with respect to fiduciary activities but continues the requirement to report on assets held in a fiduciary capacity. The Department of Interior (DOI) manages oil and gas resources on behalf of individual Indians and Indian tribes. This proposed standard – because it classifies oil and gas resources as assets – would result in additional information being disclosed for oil and gas assets managed in a fiduciary capacity. Note, however, that fiduciary reporting does not extend to inclusion of the additional disclosures or RSI that are proposed in this document for Federal oil and gas resources. Thus, with respect to fiduciary activities, only disclosure of the assets, liabilities, and related inflows and outflows would result from this proposal.*

Some Board members have expressed concern that the costs may exceed the benefits of disclosing fiduciary assets and liabilities measured in conformance with this proposed standard. Since this proposal may significantly increase the fiduciary assets disclosed, we are requesting input on the cost-benefit of the requirement with respect to fiduciary activities. See paragraph 34.

a. *Do you believe it is cost-beneficial to require disclosure of the value of estimated fiduciary petroleum royalty assets, liabilities, and related inflows and outflows? Please explain the basis for your beliefs.*

We believe that accounting standards should be consistent. Based on that premise, the disclosure for fiduciary petroleum royalty assets should be disclosed. The amount and/or level of disclosure could be made after considering (1) cost of getting that information versus its usefulness and (2) the overall "additional" amount of information and disclosure provided by the proposed standard. We also think it is also important to report assets held for the benefit of Indian tribes and individual Indians, particularly in light of difficulties in such reporting related to other Indian assets.

[1] SFFAS 7, paragraphs 83 to 87.

Q6. The proposed standards would require the component entity to provide extensive disclosures and RSI. However, the Consolidated Financial Report (CFR) of the United States government would be required to include limited disclosures and no supplementary information. See paragraphs 31 through 33. These divergent reporting requirements are consistent with SFFAC 4, Intended Audience and Qualitative Characteristics for the Consolidated Financial Report of the United States Government. SFFAC 4 provides that the CFR should be highly aggregated and offer references to other reports.

a. *Do you believe that the CFR disclosure requirements should be limited as proposed? Please explain the basis for your beliefs.*

We fully support that limited disclosure and no supplementary information be included in the Consolidated Financial Report (CFR). The CFR, by its nature, should reflect information at the highest level. Realistically, senior management decisions will normally not be based on this information contained in the CFR. With adequate references as to where the detailed information could be obtained, decision makers at various levels would be able to obtain the level of information they would need to address their question. If this level of detail were included for each line of the CFR, the report would be so voluminous that it would literally be incomprehensible.

Q7. This proposal includes accommodations intended to reduce the cost or burden of implementation. These accommodations are identified below along with the alternatives considered and rejected by a majority of the members. Please comment on any accommodation that you believe is not appropriate or that you believe does not sufficiently reduce the cost or burden of the proposal.

a. *Asset recognition is limited to proved reserves. However, the Board believes that other than proved reserves (e.g., unproved reserves and undiscovered resources) also are assets. See paragraphs A43 through A47 and A73 through A78.* Agree
b. The valuation technique provided relies on readily available information. However, fair value, which would require additional information, may be a more appropriate valuation technique. See paragraphs A48 through A545. As noted above, one member believes that fair value or something like fair value is a better valuation method.
c. This proposal requires use of existing sales volume and sales value information to determine an average price for end of period valuation. Use of market prices as of the end of the reporting period was considered. In addition to the relative cost of obtaining market values, the Board does not believe the valuation would be improved. See paragraph A82. As noted above, one member is concerned that the proposed method of using first purchase price is unrealistic in that it does not consider changes in market pricing.
d. Information to calculate effective royalty rates is readily available and the proposal provides for their use in valuing estimated petroleum royalties. An alternative considered was the use of statutory provisions for certain types of leases. See paragraph A101. Agree
e. *Regional data is readily available and the proposal provides for its use in valuing estimated petroleum royalties. An alternative considered was the use of field by field data. See paragraphs A56 and A101.* Agree

We think the question is "who and what" is going to use all this information? What kind of decisions does the Board anticipate will be made based on the disclosed and reported data? If the Board anticipates that this "new" information will be extremely important to decision making, then more detailed and exact (i.e. include estimates and not just proved) disclosure is likely merited. Otherwise, the amount of detail could be limited and estimates and conservative approaches that are less costly and less "intimidating" (i.e., in regard to the quantity of information, which could be overwhelming) could be used.

We appreciate the opportunity to comment on this exposure draft and would be pleased to discuss this letter with you at your convenience. No member objected to its issuance. If you have questions on the letter, please contact Anna D. Gowans Miller, CPA, AGA's Director of Research and staff liaison for the FMSB, and facilitator for this project, at amiller@agacgfm.org or (703) 562-0087.

Sincerely,

Robert L Childree

Robert L. Childree, Chair,
AGA Financial Management Standards Board

cc: Richard L. Fair, CPA
AGA National President

Association of Government Accountants
Financial Management Standards Board

July 2007 – June 2008

Robert L. Childree, Chair
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Relmond P. Van Daniker, Executive Director, AGA (Ex-Officio Member)
Anna D. Gowans Miller, Technical Manager, AGA, Staff Liaison

OFFICE OF THE UNDER SECRETARY OF DEFENSE
1100 DEFENSE PENTAGON
WASHINGTON, DC 20301-1100

COMPTROLLER

Ms. Wendy M. Payne, Executive Director
Federal Accounting Standards Advisory Board
Mailstop 6K17V
441 G Street, NW, Suite 6814
Washington, DC 20548

Dear Ms. Payne:

This letter is in response to the Federal Accounting Standards Advisory Board request for comments on its proposed Statement of Federal Financial Accounting Standard, "Accounting for Federal Oil and Gas Resources." The Department of Defense detailed comments are attached.

In addition to the attached responses, we request the standard clarify the recognition of restoration costs. The Exposure Draft does not address the accounting treatment of land restoration to previous condition if resource extraction or well survey is undertaken. It is unclear whether this restoration cost should be recorded as a liability and what entity should record it.

The Department appreciates the opportunity to comment on the Exposure Draft. My staff point of contact is Ms. Regina Kearney. She may be reached by email at regina.kearney@osd.mil or by telephone at (703) 697-0538.

Sincerely,

James E. Short

James E. Short
Deputy Chief Financial Officer

Enclosure:
As stated

Accounting for Federal Oil and Gas Resources
FASAB Exposure Draft
September 21, 2007

General Comment: The Exposure Draft (ED) does not address land restoration to previous condition if resource extraction or well survey is undertaken. Is this restoration cost something that needs to be recorded as a liability; if so, what entity should book it (i.e. The land holding entity? The entity licensed to exploit?).

1.A Which of the following two options would you prefer?

i. Capitalize estimated petroleum royalties form the proved reserves based on the deterministic method as proposed in the ED.

ii. Capitalize estimated petroleum royalties from proved reserves, probable reserves, and possible reserves based on the methodology proposed in the alternative view.

Response: We recommend option i.

1.B Please explain the reasons for your preference.

Response: This method is a more conservative approach. It better meets the intent of SFFAC 1 for reliability. Using other than proved reserves introduces unacceptable uncertainty.

1.C If you prefer a different basis for determining the quantity of reserves, please explain the alternative you propose and why you prefer it.

Response: N/A

2.A Which method do you believe is most appropriate for valuing estimated petroleum royalties?

i. Value the royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date.

ii. Value estimated petroleum royalties using the alternative view fair value method.

Response: We recommend option i, using first purchase price or wellhead price.

2.B Please explain the reasons for your preference.

Response: The federal government's asset is the royalty revenue streams once the reserves have been produced; in this way its royalty value is based on the produced reserves valued at the purchase price or wellhead price. Therefore, the valuation should be based on the first purchase price or wellhead price and not a market price.

2.C If you prefer a different basis for estimated petroleum royalties, please describe the method you propose and why you prefer it.

Response: N/A

3.A Do you believe that each item of information, whether disclosed in the notes or provided as RSI, is necessary to meet reporting objectives and is cost-beneficial to provide?

Response: No. RSI should not extend to the Regional breakdowns exemplified in Table 1. This information does not appear relevant to the Stewardship Objective of determining whether the government's financial position has improved or deteriorated over time, nor does it appear relevant to the Operating Performance Objective to determine the efficiency and effectiveness of the government's management of its assets and liabilities. In this regard, the cost of the information appears to outweigh the benefit.

3.B How would each item of information be used for decision-making or assessing the financial position of the federal government?

Response: Reference 3.A above, the cost of the information appears to outweigh the benefit.

3.C Please explain the reasons for your position and any alternative you propose.

Response: We recommend a development of an IT solution to report this information into a Federal repository that would allow for federal review. This would enable a better understanding of Federal reserves and foreign deposit dependencies. If the RSI remains as a requirement as currently presented in Table 1, suggest extending the effective date of the ED to September 30, 2010. The extension of the effective date allows suffice time for data collection mechanisms necessary to comply with the ED.

4.A Do you believe that a monetary value for royalty relief should be reported as RSI?

Response: Yes. The offset of potential income by the use of royalty relief could be weighed to the true cost of the depletion of the assets in total across the Federal government. We request the Board to review the GAO report GAO-07-590R that illustrates the need for understanding of this information.

4.B Do you believe the quantity of production for which relief was granted during the reporting period should be reported as RSI?

Response: Yes, for the same reason as in comment 4.A.

5.A Do you believe it is cost-beneficial to require disclosure of the value of estimated fiduciary petroleum royalty assets, liabilities, and related inflows and outflows?

Response: We have not performed a cost benefit analysis to support a response to this question. However, reference question 3 above, the cost of the information appears to outweigh the benefit.

6.A Do you believe that the CFR disclosures requirements should be limited as proposed?

Response: Yes. Aggregation of the CFR provides for ease of use by the intended audience.

7.A Please comment on any accommodation that you believe is not appropriate or that you believe does not sufficiently reduce the cost or burden of the proposal.

Response: We have no issues with the proposed accommodations.

United States Department of the Interior

OFFICE OF THE SECRETARY
Washington, DC 20240

TAKE PRIDE IN AMERICA

JAN 1 0 2008

Ms. Wendy M. Payne
Executive Director
Federal Accounting Standards Advisory Board
441 G Street, NW
Mailstop 6K17V
Washington, DC 20548

RE: FASAB Exposure Draft, Accounting for Federal Oil and Gas, dated 21 May 2007

The Department of the Interior (Department) appreciates the opportunity to provide comments on the proposed Statement of Federal Financial Accounting Standards, *Accounting for Federal Oil and Gas Resources*. The Department, the Minerals Management Service (MMS), and the Bureau of Land Management (BLM) also appreciate the unique opportunity to participate in a field test study to consider and develop a potential alternative valuation methodology, gather information on the effects of the proposed Statement, and develop material for a possible Implementation Guide.

Experts engaged on the field test study team (Team) included economists, petroleum engineers, resource evaluation experts and accountants with MMS Offshore Minerals Management (OMM), MMS Custodial Reporting Branch (CRB), MMS Minerals Revenue Management (MRM), and BLM, Inspection and Enforcement. Based on the Team's results, formal responses to FASAB's questions below are attached in enclosures A, B, and C.

On behalf of the Team, the Department respectfully offers the following observations and comments, as requested in the FASAB's formal "*Request for Comments*." All of the comments below are more fully addressed in the field test (enclosures B and C) provided to the Board.

Overall, we agree with the intent of the proposed Statement, to enhance accountability and provide readers of Federal financial reports with greater information about the quantity and estimated value of assets that generate cash to finance government operations over time. Moreover, there is a considerable amount of complexity and some uncertainty related to certain components of this estimate. Establishing quality data and systems are critical to having meaningful data and this will take time.

<u>Disclosure Requirements for Fiduciary Oil and Gas Resources</u>
With regard to paragraph 34 of the Exposure Draft (ED), the Department wishes to reemphasize the position that the documentation requirements for fiduciary activities should not include disaggregated financial information as the gathering of such information would be labor intensive, is not readily available, and conflicts with the position the Board presented to the Department. This position is also consistent with that presented in the October 5, 2006, FASAB letter to the Secretary of the Interior. In

that letter, the FASAB members stated "neither existing standards nor proposed SFFAS 31 require disaggregated information to be presented in a note disclosure." The FASAB members further state:

> "To this end, the accrual of fiduciary activities should be implemented as a single aggregate accrual that supports information presented in the schedule of net assets and fiduciary activity in a note to the Department's financial statements. FASAB did not intend the DOI to either develop or report accruals at the beneficiary ownership level for purposes of its financial statements, and FASAB does not believe that it would be reasonable to interpret or implement SSFAS 31, once issued and effective, in that manner."

Accordingly, we ask the Board to strike this paragraph in the final version of the standard and reaffirm its aforementioned position with respect to the disclosure requirements for Fiduciary Oil and Gas Resources. In addition, the Department cannot currently determine quantity information for Indian Lands nor the beneficiary participation in our program at an aggregated level.

Valuation

The Team reached consensus that the most appropriate method for valuing the asset 'estimated proved reserves' is neither the view presented in the exposure draft, nor the alternative view, but rather a modified alternative method, called the 'present value method'. This valuation method, based upon the deterministic model for ascertaining quantity, is presented in detail in the field test questionnaire (Enclosure C). It is considered a superior method because the value of total proved reserves at any point in time must include a factor to account for the reserves that cannot be extracted and recognized as revenue at the measurement date. By estimating production declines, potential additions, and estimated depletion, the net estimated present value of the asset will provide the readers with a more realistic picture of the assets value at the financial reporting date.

Accounting Treatment

The proposed Statement as presented in the ED would require extensive and costly changes to existing business processes, system requirements, and accounting models, regardless of the valuation method selected. These changes, impacts and costs are presented in detail in the field test questionnaires for both the ED view (Enclosure B) and the Present Value view (Enclosure C). As well, many of the proposed requirements could lead to potentially negative ramifications, such as the collecting and recipient entities inability to meet accelerated financial reporting due dates and related issues potentially giving rise to audit findings.

We believe that the Board's objectives can be more efficiently and effectively achieved by making some modifications to the proposed accounting treatment and related provisions described and detailed in the field test questionnaires.

For example, we believe that reporting depletion expense and the gain on revaluation on the Statement of Net Cost does not provide the reader with more meaningful information. In the field study, although the overall asset value declined over a year period, depletion expense recorded in the year exceeded the straight difference in the ending valuation, and required a gain on revaluation to be recorded. This gain would likely not be reflected in subsequently published Energy Information Agency (EIA) data. For the reader, we believe that disclosures regarding the asset valuation and royalties reported over a given span of time, combined with financial statement presentation of any custodial gain or loss on revaluation would provide an equally clear picture of the overall asset and will more efficiently and cost effectively meet the Board's objectives.

Accordingly, we recommend that the asset be capitalized as a custodial asset, that custodial accounting for royalty and related activity be continued, and that the asset be revalued annually with the associated gain or loss recorded on the Statement of Custodial Activity. Other reporting objectives can be efficiently accomplished with associated disclosures.

Commodities Covered in the Proposed Standard

The Statement as proposed provides guidance on the valuation and accounting for oil and gas, and does not address other commodities reported and collected by MMS, such as solid minerals. This means that different accounting treatment and models would be required for oil and gas and all other commodities, and any other activity currently classified as custodial. The Department strongly recommends that implementation be delayed until all commodities and related business activities are addressed. This standard will require significant business process and system modification that would require two separate accounting operations systems if segregated.

Rescissions of SFFAS 7 Provisions for Royalty Activity as Custodial

The ED includes text rescinding provisions in SFFAS 7 related to royalty activity and its treatment as custodial. The disparity in accounting treatment resulting from the Standard covering only oil and gas would result in the capitalization of only oil and gas, while other commodities would not be capitalized. As a result, other commodities would not be covered under any FASAB provisions. We are presuming that all commodities not covered under the ED would continue to be treated as custodial, according to established provisions in SFFAS 7, pp. 45, 275, 276, and 277. We recommend that implementation be delayed until all commodities and related business activities are addressed. Otherwise, we request that the Statement clearly provide for these other commodities, and allow current practices related to them to continue as custodial under existing guidance in SFFAS 7 until they are addressed.

New Accounting Treatment, SGL Accounts and Accounting Models Required

In discussions with United States Government Standard General Ledger (USSGL) staff, new accounts and posting models will need to be developed, approved, and incorporated into Department of the Treasury (Treasury) financial statement guidance. For example, some transfer accounts will involve transfers from a clearing to a special fund, some with and some without budget authority. Also, there is no established methodology or need for recording equity in a general fund or a clearing account. Accordingly, the details of implementation will require significant effort to be developed. Until formal Treasury approved accounts and models are in place, we can not engage the system contractor on the cost of the modifications to accounts and models needed for implementation. Adequate time is requested for Statement implementation, to facilitate this significant and costly effort.

New Fund or Reporting Exception Required

Currently, MMS/MRM records royalty and related activity by posting to clearing account F3875. Amounts are received from the public and distributed to other federal entities through this account. To capture and report on the capital asset, a new fund would be required, or an exception granted to report this activity, including equity, in the clearing account. While Treasury is in the midst of prohibiting or limiting use of the F3875 clearing account, a waiver request is in process for MRM royalty activity and Treasury has indicated that it will likely be granted. Historically, Treasury and OMB required that MRM use this clearing account for their royalty and related activity, and it is hard-coded throughout the royalty accounting system (MRMSS).

Recommended Depletion Method

As a result of timing issues related to royalty reporting, and the use of estimates and accruals in revenue figures, the field test questionnaire provides a detailed discussion of factors requiring clarification in the Statement. The recommended method would be to record depletion based upon royalty reporting lines received and accepted for the preceding twelve sales months for which royalty production data is available at fiscal year end. This would preclude the need to include estimates in the depletion calculations, which may not relate to oil or gas, and would represent a realistic value of true asset depletion based on actual royalty reporting. This method would likely yield a more accurate picture of current asset depletion over a year time period. This method would also provide the ability, with sophisticated queries and reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, region, onshore vs. offshore and other necessary details.

Timing and Availability of Published EIA Data

The ED view proposes to base values on, "...the most recent survey conducted by the EIA, issued no more than twelve (12) months before the end of the reporting period..." However, the most recent published EIA reserve estimates available to calculate the value would likely be a full 21 months prior to the financial reporting date. Accordingly, we recommend the ED be worded to base valuation simply on the most recent survey available from EIA.

Onshore quantities of proved reserves fall under multiple layers of ownership. Information on onshore estimated proved reserves under federal domain is presently not published by EIA. In order to obtain onshore quantity, estimation methods had to be employed. The Team reached agreement on the estimation methodology described in the field test questionnaire (Enclosure B), and determined that in the absence of specific information, this would be an acceptable method to use for implementation as well.

Ideally, EIA estimates of offshore proved reserves would need to be divided according to commodity (crude oil, lease condensate, and natural gas – wet after lease separation), and, in the Gulf of Mexico (GOM), further for each commodity by the water depth category of the field. For example, the proved reserves estimates for oil and lease condensate would further have to be divided into proved reserves from fields in water depths less than 400 meters and proved reserves from fields in water deeper than 400 meters. The water depth subdivision at 400 meters is to facilitate the calculations using the appropriate royalty rate. For pre-2007 GOM leases, those in water shallower than 400 meters have a one-sixth royalty rate and those in deeper than 400 meters have a one-eighth royalty rate. Beginning with GOM leases sold in 2007, all have a one-sixth royalty rate, regardless of water depth. Proved reserves from other Federal OCS Regions would not need to be divided according to water depth for those regions, as they generally have a single royalty rate per Region.

The Department strongly recommends that an agreement be reached with the Department of Energy (DOE)/EIA to provide the necessary proved reserves data in the appropriate form and format for this or any method adopted for the reserves valuation. Alternatively, the Department has devised a means for estimating the proportions of EIA proved reserves for the GOM applicable to royalty rates of one-sixth and one-eighth. This has been accomplished by applying the water depth proportions from the most recent proved reserves estimates to the published proved reserve estimates from EIA.

Lead Time for Implementation

If the Statement is implemented as proposed, new accounting treatments and significant changes to existing Treasury models and business processes will require additional time. As discussed in the field test questionnaire of the ED view (Enclosure B), the performance of a 12 month 'look back' of certain activity implies that changes to certain business process would have to be implemented at least one year prior to implementation. Additionally, it would take at least one year after new models are designed and approved to develop, script, test and implement the revisions to system processes. Depending on the timing of any revisions to the proposed Statement, the Department requests that ample lead time be provided.

Conclusion

In conclusion, we would again like to thank the Board for the opportunity to conduct the field test studies and to provide input, expertise, and comments on the Exposure Draft. We believe that information derived from these studies will help to craft a meaningful yet efficient and cost effective Standard that will enhance accountability for this federal asset.

Again, thank you for the opportunity to respond to these questions. If you need any additional information, please contact me or Ernest Goebel at (202) 208-4701.

Sincerely,

Daniel L. Fletcher
Director, Office of Financial Management

Enclosures

The Department's responses to the FASAB's "Request for Comments" are as follows:

<u>Question 1.</u> *Which of the following two options would you prefer? i. Capitalize estimated petroleum royalties from the proved reserves based on the deterministic method as proposed in the ED. ii. Capitalize estimated petroleum royalties from proved reserves, probable reserves, and possible reserves based on the methodology proposed in the alternative view.*

Department response to Question 1: The Department prefers proved reserves estimates prepared by EIA only, with no resource levels below proved reserves to be capitalized:

> i. Capitalize estimated present value of petroleum royalties from the proved reserves based on the deterministic method as proposed in the ED.

The Department believes that the deterministic proved reserves estimates reported by the EIA provide the only available, consistently accumulated, authoritative source of proved reserves for all applicable areas under the Federal domain. To assure the quality of their product, the EIA performs regular audits of company estimates and has a rigorous quality assurance program. There is no similar source for any level of resources or reserves at levels below proved reserves. The Department emphasizes the importance of having EIA as a partner in the capitalization effort and that they provide the proved reserves data by royalty rate or water depth category for the Federal offshore and for Federal only proved reserves for the Federal onshore. Further, by definition of levels of resources below proved, the uncertainty as to whether and when such volumes will be recovered, precludes them from being considered for capitalization. The Team concurred that only proved reserves should be recognized as assets.

<u>Question 2.</u> *Which method do you believe is most appropriate for valuing estimated petroleum royalties? i. Value the royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date. ii. Value estimated petroleum royalties using the alternative view fair value method.*

Department response to Question 2: The Department notes that MMS/OMM prefers a different method than methods i. or ii. as presented. MMS/OMM prefers a method of estimating the present value of the future stream of Federal royalties from proved reserves. The present value method is preferred because it more accurately reflects the best estimate of the value at the moment of future production. A detailed description of the preferred methodology appears in the field test questionnaire (Enclosure C). We have also included a discussion of issues related to the treatment of production and other anticipated changes in estimates of proved reserves that occur during the interval between the effective date of the reserves estimate and the estimate of the value of the royalty stream.

The Department also notes that BLM also prefers a different method than methods for onshore estimation than i. or ii. as presented. BLM prefers an alternate method similar to that discussed above, called the present value method, to value estimated petroleum royalties. The present value method is preferable as it takes into consideration the fact that most of the proved reserves will be produced over a multi-year period. Based on the number of producing wells onshore there is no way to determine produce the total Federal onshore proved reserves within a one year period. The alternate method allows for a realistic estimate of the true value of these reserves.

Question 3. *Do you believe that each item of information, whether disclosed in the notes or provided as RSI, is necessary to meet reporting objectives and is cost-beneficial to provide?*

Departmental response to Question 3: The Department has ascertained that the information provided in Table 1 on page 68 and 69 of the ED can be readily produced, but it is critical to clarify and specify exactly what this data includes. As discussed at length in the field test questionnaires, we believe that it must be based upon the royalty reporting lines received and accepted for the preceding twelve sales months for which royalty production data is available at fiscal year end. This would be the only way to ensure that prior period adjustments to previous royalty reporting are not included in current period statistics.

The information presented in Table 2 on pages 70 and 71 of the ED is derived from published EIA data that is nationwide in scope, covering both federal and non-federal ownership. More updated or current data presented in the Table specific to federal domain estimated proved reserves is not available, and could not be provided at the report date. As discussed in the valuation process above, EIA nationwide data were obtained and a rough estimation methodology was developed to derive estimated proved reserves under federal domain. Additional offshore calculations were required as well. The additional information required in the ED for RSI disclosure, such as federal domain technically recoverable resources, onshore and offshore, and historical 10-year information on federal domain estimated proved reserves could only be provided by EIA. If the Board intends that estimated calculations be produced, we request clarification. However, such things as net revisions, extensions, new field discoveries, etc. could not be reasonably ascertained. Readers of federal financial information should be referred to EIA published statistics for that information.

Question 4. *Do you believe that a monetary value for royalty relief should be reported as RSI? Do you believe the quantity of production for which relief was granted during the reporting period should be reported as RSI?*

Department response to Question 4: The Department has no problems with reporting the monetary or estimated future quantities of royalty free production resulting from royalty relief policies. Most of these policies contain price threshold provisions where royalties become due as prices surpass specified levels.

The Department has determined that the values for royalty relief could be fairly readily obtained and values reasonably estimated. Again, 'production' would need to be based upon royalty reported sales months.

Question 5. *Do you believe it is cost-beneficial to require disclosure of the value of estimated fiduciary petroleum royalty assets, liabilities, and related inflows and outflows?*

Department response to Question 5: The Department has verified that currently, EIA does not publish numbers related to proved reserves on Indian lands. Further, the Department only receives a small portion of royalties related to Indian leases, which are disbursed at once to OST for subsequent funds management and distribution to beneficiaries. Accordingly, there is not a verifiable data source from which the Department could estimate an asset value. While estimates can always be developed, the validity of the data could likely be proved to be incorrect, and would be a very broad estimate at best.

We believe it would not be cost-beneficial to require such disclosures relating to fiduciary assets, liabilities, and related inflows and outflows. We explain the basis for our belief below.

First, the FASAB made it clear in a letter dated October 5, 2006, that disaggregated financial information was not required to be presented in a fiduciary note disclosure. Specifically, the Board stated:

"In developing Federal accounting standards, among FASAB's responsibilities is to support cost effective implementation of its standards. To this end, FASAB considers alternative approaches so that a standard's demand on resources is balanced against the benefits to be gained from the standard. In particular case of Indian Trust funds, the Board believes the costs to implement proposed SFFAS 31 by developing accruals for receivables at the beneficiary ownership level, as some have suggested, would greatly outweigh the benefits of reporting fiduciary activities conducted by the Department of the Interior (DOI) (in the event that SFFAS were to be finalized). The Board did not intend the proposed SFFAS 31 to establish a requirement for such highly disaggregated financial reports.

"Instead, neither existing standards nor proposed SFFAS 31 require disaggregated financial information to be presented in a note disclosure. To this end, the accrual of fiduciary activities should be implemented as a single aggregate accrual that supports information presented in the schedule of net assets and fiduciary activity in a note to the Department's financial statements."

Unfortunately, this Exposure draft would require just that; disaggregated accrual and asset information. Per paragraph 34, specific information regarding estimates of reserves, and inflows and outflows, would require research down to the lease level in order to determine the split between tribal and individual Indian ownership. Additionally, further analysis would be necessary to distinguish between leases on tribal land where the payments are made directly to the tribal entity and do not flow through the U.S. government. This would defeat the purpose of a single aggregate accrual and be very costly to implement as well as requiring an information system to obtain and track this data.

Secondly, there are many components to Indian trust assets and activities. Required disclosure of oil and gas assets as well as the inflows and outflows would put an undeserved emphasis on this activity in the note disclosure, especially since oil and gas revenues typically encompass only approximately 25% of revenues (similar to farming and grazing, forestry, and land sales). With a number of non-monetary assets held by Indian and tribal beneficiaries, such as land, timber, coal, and other minerals, disclosure of estimated values of oil and gas assets could lead to questions regarding land valuation as well as other non-monetary asset valuations mentioned above. If we are showing oil and gas asset valuation, why are we not showing land asset valuation, or other asset valuations, etc.? It creates a dichotomy between oil and gas and other non-monetary trust assets.

Where will additional disclosure requirements end with respect to fiduciary note disclosure? We request removal of paragraph 34 as unnecessary, costly, and in direct conflict with Board issued guidance and the intent of SFFAS 31.

Question 6. *Do you believe that the CFR disclosure requirements should be limited as proposed?*

Department response to Question 6: The Department believes that the CFR disclosure requirements should be limited as proposed. References to source information can be provided, to direct the readers of federal financial reports to other necessary information. This will streamline federal financial reporting processes, be more cost effective, and help keep the CFR from becoming overly detailed.

Question 7 a. *This proposal includes accommodations intended to reduce the cost or burden of implementation. Please comment on any accommodation that you believe is not appropriate or that you believe does not sufficiently reduce the cost or burden of the proposal. Asset recognition is limited to proved reserves. However, the Board believes that other than proved reserves (e.g., unproved reserves and undiscovered resources) also are assets.*

Department response to Question 7a: The Department believes that only proved reserves should be recognized as assets and reiterates its response to Q1. The Department believes that the deterministic proved reserves estimates reported by the EIA provide the only available, consistently accumulated, authoritative source of proved reserves for all applicable areas under the Federal domain. To assure the quality of their product, the EIA performs regular audits of company estimates and has a rigorous quality assurance program. There is no similar source for any level of resources or reserves at levels below proved reserves. The Department emphasizes the importance of having EIA as a partner in the capitalization effort and that they provide the proved reserves data by royalty rate or water depth category for the Federal offshore and for Federal only proved reserves for the Federal onshore. Further, by definition of levels of resources below proved, the uncertainty as to whether and when such volumes will be recovered, precludes them from being considered for capitalization. The Team concurred that only proved reserves should be recognized as assets.

Question 7 b. *This proposal includes accommodations intended to reduce the cost or burden of implementation. Please comment on any accommodation that you believe is not appropriate or that you believe does not sufficiently reduce the cost or burden of the proposal. The valuation technique provided relies on readily available information. However, fair value, which would require additional information, may be a more appropriate valuation technique.*

Department response to Question 7b: The Department prefers a present value valuation approach to the valuation technique provided or the "fair value" approaches suggested. The Department's preferred approach appears at the end of this document. The Team concurred that a present value method was most appropriate and meaningful.

Question 7 c. *This proposal includes accommodations intended to reduce the cost or burden of implementation. Please comment on any accommodation that you believe is not appropriate or that you believe does not sufficiently reduce the cost or burden of the proposal. This proposal requires use of existing sales volume and sales value information to determine an average price for end of period valuation. Use of market prices as of the end of the reporting period was considered. In addition to the relative cost of obtaining market values, the Board does not believe the valuation would be improved.*

Department response to Question 7c: The Department's preferred approach, being a present value valuation, involves the use of estimated future product prices, inflation rates, and widely accepted public-sector discount rates. The Department recommends such values estimated by the Office of Management and Budget be employed for this purpose. The Team concurred with the a present value approach overall for valuation, and where reported sales value and volume data are utilized otherwise, averages based on reported sales month data are most meaningful and cost effective.

Question 7 d. *This proposal includes accommodations intended to reduce the cost or burden of implementation. Please comment on any accommodation that you believe is not appropriate or that you believe does not sufficiently reduce the cost or burden of the proposal. Information to calculate effective royalty rates is readily available and the proposal provides for their use in valuing estimated petroleum royalties. An alternative considered was the use of statutory provisions for certain types of leases.*

Department response to Question 7 d: The Department's preferred approach for offshore estimated proved reserves would employ the statutory royalty rate provisions to estimate future royalty values for broad groups of leases within a Region that share the same royalty rate. The Team concurred with the present value approach overall for valuation, and where reported royalty value and volume data are utilized otherwise, average royalty rates based on reported sales month data are most meaningful and cost effective.

Question 7 e. *This proposal includes accommodations intended to reduce the cost or burden of implementation. Please comment on any accommodation that you believe is not appropriate or that you believe does not sufficiently reduce the cost or burden of the proposal. Regional data is readily available and the proposal provides for its use in valuing estimated petroleum royalties. An alternative considered was the use of field by field data.*

Department response to Question 7 e: The Department strongly believes that a Regional approach is superior to any field by field approach. The Department's preferred approach provides a workable methodology to estimate the present value of future royalties for broad groupings of fields that share the same contract royalty rate and for which a proved reserves estimate exists. For the Federal offshore, such groupings are by product and by royalty rate (one-sixth and one-eighth) in the Gulf of Mexico Region and simply by product in the Pacific Region. The Team concurred with the use of a Regional approach for onshore as well.

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Ms. Wendy M. Payne
Executive Director
Federal Accounting Standards Advisory Board
Suite 6814 -- Mail Stop 6K17V
441 G Street, NW
Washington, D.C. 20548

January 11, 2008

Dear Ms. Payne:

This letter is in response to the invitation by the Federal Accounting Standards Advisory Board (FASAB) to comment on the Proposed Statement of Federal Financial Accounting Standards, *Accounting for Federal Oil and Gas Resources.*

The comments herein are from the perspective of the Accounting Committee of the American Petroleum Institute (API), which is the only national trade association that represents all aspects of America's oil and natural gas industry. Our 400 corporate members, from the largest major oil company to the smallest of independents, come from all of the industry's segments.

Our response is limited to the Exposure Draft's first question, which deals with crude oil and natural gas volumetric information our member companies may be required to provide under one of the described reporting alternatives.

FASAB question:

Q1. The proposed standards would provide for recognition of the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves. These reserves are subcomponents of the total oil and gas resources of the Federal government. Please see page 20 for an illustration of Federal oil and gas resource components and subcomponents.

The Board's proposal for quantifying the Federal government's royalty share of proved reserves is to use a single best estimate of recovering reserves based on known geological, engineering, and economic data. This approach is known in the oil and gas industry *as the deterministic method. This method would exclude reserves other than proved reserves. In contrast, a probabilistic method of estimation uses the known geological, engineering, and economic data to generate a range of estimates and their associated probabilities of recovering reserves. It would include more than proved reserves. See paragraphs A73 through A78 for additional information regarding the deterministic and probabilistic methods for measuring and reporting proved oil and lease condensate, NGPLs, and gas reserves.*

Determination of Quantity:

a. Which of the following two options would you prefer?
   i. Capitalize estimated petroleum royalties from the proved reserves based on the deterministic method as proposed in the ED.
   ii. Capitalize estimated petroleum royalties from proved reserves, probable reserves, and possible reserves based on the methodology proposed in the alternative view. See the alternative view beginning at paragraph A119.

b. Please explain the reasons for your preference.

c. If you prefer a different basis for determining the quantity of reserves, please explain the alternative you propose and why you prefer it.

Response:

Q.1.a.: We strongly prefer option *i*. – "Capitalize estimated petroleum royalties from the proved reserves based on the deterministic method as proposed in the ED" – if the definition of proved reserves conforms to the definition of proved reserves under Rule 4-10(a) of Regulation S-X of the Securities Exchange Act of 1934. If the definitions are different, we recommend the FASAB conform to the SEC definition.

Q.1.b.: The reason for preferring option i. is that the proved reserve quantities calculated under SEC rules are readily available and consistent with volumes already reported annually to the Energy Information Administration of the U.S. Department of Energy and included in registrants' Annual Report on SEC Form 10-K.

We strongly disagree with reporting volumes other than proved reserves, as described in option ii. Although organizations such as the Society of Petroleum Engineers have developed a process for quantifying and classifying reserves and resources other than proved, companies in our industry are not required to follow any standardized process (as companies are required to follow for proved reserves). Moreover, Item 102 of SEC Regulation S-K prohibits companies from disclosing volumetric data for other than proved reserves. Thus, any FASAB request to our member companies for other than proved reserves data would directly conflict with our reporting responsibilities under SEC regulations.

We note also that in December 2007 the SEC issued Concept Release No. 33-8870 – "Concept Release on Possible Revisions to the Disclosure Requirements Relating to Oil and Gas Reserves."

The Concept Release is available at http://sec.gov/rules/concept/2007/33-8870.pdf. We believe the FASAB should monitor the developments of this SEC project and continue to follow SEC guidelines with respect to classifying and reporting crude oil and natural gas reserves and resources.

We appreciate the opportunity to comment on this FASAB Exposure Draft. If you have any questions, please feel free to contact me at (713) 296-1816.

Sincerely,

/s/ Joseph H. Bakies

Joseph H. Bakies
Chair, Accounting Committee
American Petroleum Institute

cc: Desiree Burnley – API
Don Whittaker – API

GAO
Accountability * Integrity * Reliability
United States Government Accountability Office
Washington, DC 20548

January 11, 2008

Ms. Wendy M. Payne
Executive Director
Federal Accounting Standards Advisory Board

Dear Ms. Payne:

We appreciate the opportunity to comment on the Federal Accounting Standards Advisory Board's (FASAB) proposed exposure draft (ED) entitled Accounting for Federal Oil and Gas Resources.

We have concerns about the significant amount of information proposed for disclosure in Required Supplementary Information (RSI), as discussed in paragraph 32, and the costs versus the benefits of accumulating and reporting this information in the general purpose financial statements. While this information might be relevant and useful to sophisticated users, such detailed information may not be necessary for the broader set of intended users of the general purpose financial statements. Our comments are directed at the requirements for component entities only, as we agree with the required disclosures for the CFR without additional supplementary information.

Also, we have concerns about the costs versus the benefits of accumulating, reparing, and auditing information required by paragraph 34 to be reported in disclosures for fiduciary activities. Requiring the Federal entities to disclose the value of oil and gas reserves for fiduciary activities will incur additional costs and result in information that is inconsistent with information currently reported to beneficiaries of these fiduciary activities. In addition, it will reflect only the value of reserves for which the entity has fiduciary responsibility, which may not represent all reserves owned by beneficiaries.

The Board should obtain specific information from the management of affected entities concerning the costs of developing and reporting the RSI and fiduciary information, and should reconsider the requirements of the ED based on this information. Further, the Board should clearly document the basis for its determination of whether such information is appropriate for general purpose financial statements and whether it can be prepared and audited at a reasonable cost in relation to its usefulness.

In addition, for clarity, the standard should specifically require disclosure of the basis of accounting for estimated petroleum royalties and describe the nature of such disclosures. Appendix D should include illustrative language for such disclosure.

Finally, the Board should consider whether changes in long-term assumptions related to oil and gas reserves should be reported as a separate component of net cost similar to changes in long-term assumptions for liabilities as proposed in the ED entitled Reporting the Gains and Losses from Changes in Assumptions and Selecting Discount Rates and Valuation Dates.

We appreciate the opportunity to provide our comments on the exposure draft and would be pleased to discuss our comments with you at a convenient time. If we can be of further assistance, please call me at (202) 512-2600.

Sincerely yours,

McCoy Williams

McCoy Williams
Managing Director
Financial Management and Assurance

Greater Washington Society of CPAs and GWSCPA Educational Foundation

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January 23, 2008

Wendy W. Payne, Executive Director
Federal Accounting Standards Advisory Board
Mail Stop 6K17V
441 G Street, NW – Suite 6814
Washington, DC 20548

Dear Ms. Payne:

The Greater Washington Society of Certified Public Accountants (GWSCPA) Federal Issues and Standards Committee (FISC) appreciates the opportunity to provide comments on the Federal Accounting Standards Advisory Board's (FASAB) Exposure Draft (ED), *Accounting for Federal Oil and Gas Resources*, dated May 21, 2007.

FISC consists of 19 GWSCPA members who are active in accounting and auditing in the Federal sector. This comment letter represents the consensus comments of our members.

General Comments

The Concept of "Potential Assets" Is Not Fully Developed. While FISC agrees that full and understandable *disclosure* of future potential revenues from royalties on extraction of subsurface and surface resources is desirable, limiting this disclosure to solely oil and gas resources and requiring an asset to be recorded seems inappropriate, especially on the valuation basis provided in the ED.

- **FASAB's Eventual Standard Should Include All Resources** – In addition to oil and gas, subsurface resources include copper, cadmium, nickel, zinc, gold, silver, liquid sulfur, uranium, molybdenum, coal and even water. Surface resources include forestry assets, farming and grazing rights, water and electricity revenues, and even sale of lands. These resources may well equal or exceed any valuation of proved oil and gas resources. Importantly, the ED does not explain why the disclosures and asset recordation is limited solely to oil and gas proved reserves.

- **Record Known "Liabilities" as Well as "Assets"** - If subsurface and/or surface resources potential revenues are recognized as an asset, the costs of realizing such assets should be accrued as an offsetting liability. In many cases, such costs may be significant. Netting such potential revenue is consistent with some of the projection methods for future liabilities of social benefits, e.g., the estimated payments thereunder are netted against the estimated employee withholdings and premium receipts therefor.

- **Disclose vs. Valuation** – The ED comprises 83 pages for oil and gas resources alone. Covering all possible items that could be converted into cash at some date would constitute likely the most complex accounting standard ever issued. FISC recommends that the eventual Standard be broken into parts with an initial Standard focusing on *disclosure* of potential resources, and proceed with a subsequent Standard on *valuation* (if this is the eventual FASAB decision). FISC does not concur that potential oil and gas royalties is an asset that should be recorded at this time.

- **Avoid a "Cookbook" Type of Standard** – The specificity of determining the various classes and subclasses of potential oil and gas resources and sources of information thereon will likely require numerous additional Standards as the sources of information change, new and better sources are identified, or current sources are discontinued. If FASAB goes forward with the Standard, the "how to do it" section should be considerably shortened to permit flexibility of the Federal agency responsible for administering subsurface and surface resources to select the best available source of data upon which to make estimates of recoverable resources and valuation thereof. FISC also recommends that actual journal entries are unnecessary if properly described in the eventual Standard; a FASAB Implementation Guide or Treasury/OMB directive should address journal entries to insure that entries meet Treasury's SGL requirements.

"Potential Assets" From Oil and Gas Resources Not Distinguished From Other "Potential Assets." The Federal government has significant unrecorded assets. For example, gold is recorded at $42.22/fine troy ounce, while the market value was $743.00/fine troy ounce, at September 30, 2007 (see page 55 of the 2007 *Annual Financial Report*.) Certainly, the largest potential revenue source of the Federal government is its ability to enact and collect the individual income tax (state and local governments previously used to report such an asset in the caption "Amount to be Provided" – This concept has been abandoned under recent GASB standards). Both gold holdings and future income tax revenues are far easier to quantify and value than potential oil and gas royalty income. The ED does not clarify why oil and gas resources have been singled out for valuation and asset recognition, or whether the ED is the first of numerous future Standards for other resources. If so, serious comparison issues will arise as "new potential assets" are recorded pursuant to future additional Standards.

The Eventual Standard Would Present Significant "Lack of Symmetry" in Society. The ED properly proposes that a liability for the Federal government's agreements to share potential royalty assets with state governments, generally about 50% for most states and 90% for Alaska. However, it is unlikely that any state government preparer of financial statements or independent auditors thereof would concur that the "assets" at the state level should be recorded. Attachment A hereto includes the list of recipients of all mineral royalties shared with states, and these amounts are significant for the principal recipients. The "liability" payable to states can change; for example during the past fiscal year 2007 alone, the royalties provided to states changed in two ways – first, for states along the coastline, royalty sharing was increased for offshore royalties and second, the "pool" of royalties available for distribution to states changed to net the pool for MMS' costs, legislatively established at 4% (incidentally, this provision was in the Omnibus Budget Bill signed on December 26, 2007, after the end of the closing of the books on November 15, 2007) reducing the net royalties to the Federal government and states by 2% each.

Major Fluctuations Will Occur in the Ultimate Amounts Recorded as Assets and Offsetting Payments to States. Knowledgeable industry observers have very mixed views on the short- and long-term production of oil and gas, likely prevailing prices thereof, and even the continued use thereof in the world economy. An article in the January 2008 issue of *Conde Nast Portfolio* magazine in Attachment B hereto is just one such prediction that the current $100/barrel of crude will not continue indefinitely due to improved technology in recovering resources already discovered or even "capped out," new discoveries, changes in usage of petroleum, alternate energy sources, the overhang of the shale oil and tar sands with oil prices in excess of recovery costs, etc. Others predict that, in the short-term, oil prices could increase to $200/barrel. Since future economic extraction of any subsurface resource depends on a plethora of uncertainties over long periods of times, FISC questions whether it is wise to record assets subject to such fluctuations over which the Federal government has no control. FISC contrasts this with the relatively known metrics for estimating liabilities for social programs since population, age, gender and other factors are reasonably well estimable.

There are also situations that, regardless of potential recoverable or realizable resources that may exist, public policy will prevent such recovery, including resources currently recoverable or realizable, but will be prohibited by future legislation. Our National Parks, Fish and Wildlife Refuges, including the Alaska National Wildlife Refuge (ANWR) are good examples of this. This clouds the distinction between proved reserves and all other potential resources.

Specific Comments

If some form of the ED advances to a Standard, FISC has a number of comments.

- **Throughout Text** – The ED uses the plural form "standards" while the eventual Standard will be singular.

- **Valuation** – Paras. 5 through 15 specify how the "current regional average prices" are to be established and Para. 15 values the proved reserves at that price. This effectively will result in an adjustment of the "asset" even if no oil or gas is extracted during the year because these resources are subject to world prevailing prices. In a falling market, this overstates the "asset" and in a rising market, this understates the "asset." FISC favors a "fair value" approach to minimize such fluctuation as explained in the Alternate View beginning in Para. A119.

- **Valuation** – FISC questions why, if discounted valuations are to be used in the many types of liabilities recorded (pensions, Social Security, post-employment health/life insurance benefits, etc.), discounted values would not be used for oil and gas "assets."

- **Statement of Net Cost/Para. 28** – Since oil and gas royalty "assets" are a "sovereign asset", FISC does not understand why gains or losses are a part of Net Cost since neither the gain or loss has been realized. This will cause fluctuations that could exceed the otherwise "bottom line" of net operating costs in excess of revenues (i.e., annual operating deficit). What Administration, for example, would want a loss in value of future royalties wiping out an entire surplus?

- **Effective Date of Eventual Standard/Para. 48** – The "periods ending after September 30, 2009," which is FY 2010, should be changed to move the date forward several years to permit Federal government agencies, principally Interior, to develop systems to estimate quantities of proved reserves and all other reserves, and value proved reserves.

- **Basis for Conclusions -** The ED cites numerous sources of data, e.g., Cambridge Energy Research Associates, and Department of Energy's Energy Information Administration – numerous laws, years of events, etc., all of which are well known "data literate" users of these statistics. FISC believes that changes are most likely to occur for this information, which immediately may render the eventual Standard obsolete or require it to be amended. FISC believes that this ED area in particular is in need of revision to minimize premature life of the Standard.

- **ED Appendix C** – FISC suggests that this guidance be incorporated in an Implementation Guide or some other FASAB, Treasury or OMB document. See "cookbook" comment above.

Responses to Questions

Q1 – "The proposed standards would provide for recognition of the Federal government's royalty share of proved oil…"

FISC believes that it is premature to capitalize any value for proved reserves under either method. FASAB has not explained why capitalization is restricted solely for proved oil and gas resources, why only subsurface minerals are solely considered (vs. surface resources), and why the capitalization concept is not extended to other assets, e.g., gold holdings and future income tax revenues. In short, FISC believes that FASAB is incurring a risk of discrediting the entire financial reporting standards that it has worked diligently and successfully to establish by literally "counting the chickens before they are hatched."

Q2 – "The Board proposes to value the Federal government's royalty share of proved reserves based on average regional prices…"

FASAB should seriously consider the evolving world financial reporting movement to fair value accounting – See Alternate View – and value any proved resources at prevailing market prices as of fiscal year end on September 30. Also, considering the use in other FASAB Standards of discounting valuations for future events, FASAB should consider standardizing its valuation methods.

Q3 – "Some Board members believe that the amount of information proposed to be disclosed …is excessive…"

FISC agrees that simplification is necessary. Since the users of reserve data are well aware of the data sources cited in the ED and their limitations, these "reserve-literate" experts already have all the data they need.

FISC does favor some additional disclosure of all subsurface and surface resources in RSI or elsewhere in the financial statements of the overall Federal Government.

Q4 – "The proposed standards would require that an estimated value for royalty relief be reported as RSI…"

This disclosure appears to be a reaction to the publicity raised by royalty relief in general or errors in the granting thereof. This is another source of "tax expenditures" or "foregone revenue." FISC concurs that all such foregone revenues be disclosed as was the practice in the early years of the prototype consolidated financial statements. Many readers of financial statements will be as interested in foregone revenues due to other types of relief as they would be in royalty relief.

Pages 285 through 313 of the FY 2008 President's Budget Submission contain "tax expenditures" estimates for tax provisions effective as of December 31, 2006. This 28-page tome should be condensed into a table, to which royalty relief, together with forms of subsidy other than tax provisions, should be added.

Q5 – "…SFFAS 7…requires that agencies report on assets held in a fiduciary capacity…Interior manages oil and gas resources …"

The Uniform Principal and Income Act, enacted by at least 43 states limits responsibility of a fiduciary to cash received, invested and disbursed, and prudent holding of non-cash assets. While SFFAS 31 will require disclosure of land assets held in the two Indian Trust Funds, it will be extraordinarily difficult to record proved oil and gas resources in the financial statements of the two Indian Trust Funds, and certainly a challenge for a November 15 completion of the audits thereof. The number of oil and gas leases on Indian lands (approximately 55 million acres – 45 million tribally-owned and 11 million owned by individual Indians) is disproportionately large since the individual holdings are small compared to other Federal Government leases on its own holdings.

FISC concurs that extension of reporting of oil and gas leases and valuing the proved reserves related thereto would cost far more than any useful information provided therewith. Interior now reports undivided and divided land interests owned by tribes and individual Indians and leases thereon (exploratory, producing and non-producing) in quarterly statements to the tribal and individual account holders. This can be seen in the following data taken from the Mineral Management Service web site. (This information has either been taken directly from the web site or has been derived from information taken from the website.)

MMS Summary of Oil and Gas Lease Data
Producing and Non-Producing Leases – Fiscal Year 2007

	American Indian Leases	Total Federal Government Leases
Number of Leases	4,119*	63,610
Percentage of Total Leases	6.1%	93.9%
Leased Acreage	2,069,459**	91,595,981**
Percentage of Leased Acreage	2.2%	97.8%
Average Acreage Per Lease	502	1,440
Total Oil & Gas Royalties	$317,735,000	$9,256,032,000
Percentage of O & G Royalties	3.3%	96.7%

*Many of these leases cover lands jointly owned by one or more tribes and many undivided individual Indian interests.

**67,792,121 (74.0%) Federal Government acres are non-producing vs. 152,971 (7.4%) non-producing Indian acres.

Q6 - "The proposed standards would require the component entity to provide extensive disclosures and RSI…"

FISC recommends a reversal of the degree of proposed disclosures. Since subsurface and surface potential revenue sources are sovereign assets, the major disclosures more properly should be included in the overall U.S. Government *Consolidated Report*. The particular agency administering a revenue source, which relates to the sovereign, is not particularly significant, especially since the administrator can be changed in agency reorganizations, e.g., the recent establishment of the Department of Homeland Security.

Q7 –"The proposal includes accommodations intended to reduce the cost and burden of implementation…"

a. Proved reserves may well be economically non-recoverable due to recovery costs, existing or future environmental laws or regulations, changed technology, changes in prevailing world market prices, etc. FISC believes that the eventual Standard must provide guidance for such limitations on proved reserves, particularly if other subsurface or surface revenue sources eventually come under a capitalization provision.

b. FISC recommends fair value.

c. FISC believes that value is determined by what a seller accepts and a buyer is willing to pay as of the end of the fiscal year.

d. We are a nation of laws, and statutory or contractual rates must prevail over market rates where statutory or contractual rates apply. Differences may be equivalent to “revenue forgone” or contracting errors in the case of lower rates than market, and favorable rates in cases of market rates below statutory or contractual rates.

e. Fair value would consider regional variations.

*****

This comment letter was reviewed by the members of FISC, and represents the consensus views of our members.

Very truly yours,

Daniel L. Kovlak
FISC Chair

Attachment A: http://www.mms.gov/ooc/press/2007/press1204.htm

Attachment B: http://www.portfolio.com/views/columns/economics/2007/12/17/Why-Oil-Prices-Will-Drop

The NewsRoom

Release: # 3759
Date: December 4, 2007

Thirty-four States Earn $1.9 Billion in Royalty Receipts

MMS Reports FY 2007 Disbursements

DENVER – Thirty-four states earned more than $1.9 billion during Fiscal Year 2007 as part of their share of federal revenues collected by the Department of the Interior's Minerals Management Service (MMS).

"These revenues from mineral production on federal lands play a crucial role in many state budgets," said Randall Luthi, MMS director. "The funds support everything from education to infrastructure improvements and capital projects."

MMS is the federal bureau within the Department of the Interior responsible for collecting, auditing and disbursing revenues associated with mineral leases on federal and American Indian lands. Disbursements are made to states on a monthly basis from royalties, rents, bonuses and other revenues collected by MMS.

The $1,972,322,944 distributed to states during the Fiscal Year that ended Sept. 30, 2007 compares with Fiscal Year 2006 payments to states that totaled more than $2.2 billion. A preliminary analysis indicates the slight decline is the result of several factors, including lower natural gas prices during the fiscal year and a drop in lease sale bonuses from the previous year, among others.

Fiscal Year 2007 marked the first full year that MMS distributed funds from geothermal energy production directly to the individual counties where that production occurs. Luthi noted that the Energy Policy Act of 2005 mandated that 25 percent of receipts from geothermal energy production be disbursed directly to counties where that production occurs, in an effort to increase use of that alternative energy resource. As part of that mandate, and included in the $1.9 billion distributed overall, MMS distributed more than $4.3 million to 32 counties in the states of California, Idaho, New Mexico, Nevada, Oregon and Utah.

During Fiscal Year 2007, the state of Wyoming led all states by receiving more than $925 million as its share of revenues collected from mineral production on federal lands within its borders, including oil, gas and coal production. New Mexico’s share was nearly $553 million, while the state of Utah received more than $135 million. Other energy-producing states sharing revenues included Colorado with more than $122 million; California with more than $61 million; Montana with $39.1 million; Louisiana at $24 million; Alaska at $21.7 million; and Texas, which received approximately $21.6 million in Fiscal Year 2007.

The disbursements represent the states’ cumulative share of revenues collected from mineral production on federal lands located within their borders, and from federal offshore oil and gas tracts adjacent to their shores. For the majority of onshore federal lands, states receive 50 percent of the revenues while the other 50 percent goes to various funds of the U.S. Treasury, including the Reclamation Fund for water projects. Alaska receives a 90 percent share as prescribed by the Alaska Statehood Act. States may also receive matching appropriations from the offshore oil and gas royalty-funded Land and Water Conservation Fund, the Reclamation Fund, and other special-use funds.

In addition, Texas, Alabama, Louisiana and Mississippi with producing federal offshore tracts adjacent to state waters receive 27 percent of those mineral royalties. Remaining offshore revenues collected by the MMS are deposited in various accounts of the U.S. Treasury, with the majority of those revenues going to the General Fund.

States receiving revenues through Fiscal Year 2007 include:

Alabama	$14,173,908.88
Alaska	$21,796,671.52
Arizona	$41,792.37
Arkansas	$8,143,230.86
California	$61,240,940.54
Colorado	$122,894,226.71
Florida	$6,649.38
Idaho	$4,729,812.55
Illinois	$205,558.80
Indiana	$8,046.75
Kansas	$1,876,305
Kentucky	$714,750.97
Louisiana	$24,029,594.03

Michigan	$616,971.05
Minnesota	$13,126.30
Mississippi	$2,226,547.50
Missouri	$3,598,352.32
Montana	$39,158,279.03
Nebraska	$24,176.98
Nevada	$7,663,678.82
New Mexico	$552,934,465.33
North Dakota	$13,775,447.53
Ohio	$493,091.99
Oklahoma	$6,988,592.26
Oregon	$558,122.83
Pennsylvania	$55,584.87
South Carolina	$277.50
South Dakota	$1,007,068.91
Texas	$21,667,264.63
Utah	$135,429,658.25
Virginia	$233,474.14
Washington	$366,365.07
West Virginia	$389,004.34
Wyoming	$925,261,906.81
Total:	$1,972,322,944.82

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Tab 3 - Comment Letters

ECONOMICS

by John Cassidy

The Coming Oil Crash

Dec 17 2007

Crude at $100 a barrel makes good headlines but ignores basic economics. Why oil prices are in for a 50 percent drop.

Crude Awakening

For now, oil prices are near record levels. But anyone who believes high prices will last forever ignores these trends, which will, sooner or later, make a slump inevitable.

Photoillustration by: Reena De La Rosa

If you haven't got the message that something disturbing is happening in the oil world, stop by my office. On my desk, I have a pile of books a foot high with titles like *Out of Gas, The End of Oil,* and *Twilight in the Desert.* The authors range from geologists to journalists to policy wonks, and they all tell the same story.

For years, oil industry executives dismissed fears of an energy crisis, attributing rising gasoline prices to unrest in the Middle East, Wall Street speculation, and temporary interruptions in supply. But recently, as the price of crude has bounced around $100 a barrel, even some establishment figures have been making alarmist noises. The Paris-based International Energy Agency warned of a possible "supply crunch" within five years. Its chief economist, Fatih Birol, said prices could reach such a high level that "the wheels may fall off" the global economy. In the U.S., the National Petroleum Council, a federal advisory group, said that as the economies of China and India continue to expand, global energy consumption will rise by 50 percent over the coming quarter of a century. "There is no quick fix," said Lee Raymond, former chairman of Exxon Mobil, who leads the council.

Perhaps not. But the experts who are predicting the worst, based on geology and geopolitics, are missing the crucial role that economic incentives play in determining the price of crude. The tripling of oil prices since the summer of 2003 has unleashed forces that within the next two or three years will bring oil prices tumbling back down to below $50 a barrel. Looking even further ahead, prices could easily fall to $30 a barrel or even lower. So before you trade in your Cadillac Escalade for a Toyota Prius, think twice: $1.50-a-gallon gas might not be gone forever.

The key to understanding where prices are headed is distinguishing between the short run and the long run. In a time frame of anything shorter than five years, the supply of crude is more or less fixed. Drilling for oil is an arduous and unpredictable process. Even after a new hydrocarbon reservoir is discovered, ramping up output takes years. Current production capacities reflect investment decisions made in the late 1990s or earlier.

Today, OPEC has the ability to produce about 35 million barrels of crude a day; the rest of the world can produce perhaps 50 million barrels a day. As recently as 2003, this seemed like plenty. Since then, though, global demand has grown rapidly, and a series of catastrophes—some natural (hurricanes Rita and Katrina), some man-made (war in Iraq and unrest in Nigeria and Venezuela)—have curtailed production, causing supply to dip below demand. In September, the global demand for crude reached 85.9 million barrels a day, whereas global supply was just 85.1 million barrels a day, according to I.E.A. figures.

When shortages emerge in any market, prices spike. If the imbalance is expected to continue, speculators move in and drive prices even higher. Oil is no exception. In the fall, as crude inventories declined and the rhetorical battle between the U.S. and Iran escalated, trading volume shot up.

With prices close to the inflation-adjusted record, energy companies and governments are investing heavily in facilities that generate crude and crude substitutes. Consumers of fuel oil and gasoline are starting to economize, and over time, these changes in behavior will shift the balance of power in their favor. When that happens, an oil glut will emerge, and the price will plummet.

Already, in Texas and California, hundreds of mothballed, low-producing stripper wells have been brought back into production. In Africa, the Chinese government is making development deals with Sudan, Chad, the Congo Republic, and other impoverished nations with unexploited reserves. In the Canadian province of Alberta, Shell and other energy companies are building massive strip mines to access local tar sands, which can be converted into synthetic oil or refined directly into petroleum at a cost of roughly $30 a barrel. Some experts believe the sands contain more oil than the subdeserts of Saudi Arabia.

Not very long ago, energy companies were slashing their exploration and drilling budgets, refusing to finance any project unless it could generate crude for $15 or $20 a barrel. But since 2003, when the price of crude rose above $30 a barrel, the industry has relaxed its financial assumptions and beefed up capital spending. In the past four years, Exxon Mobil, the world's largest oil company, has invested more than $60 billion in exploration and development. Between now and 2010, the company plans to begin pumping oil or gas from no fewer than 20 new projects.

Besides Canada, the oil majors are also returning to areas that weren't economically viable when oil was cheap, including the Arctic Ocean and the deep waters of the Gulf of Mexico. The industry's efforts aren't confined to searching for new reserves. It is also investing heavily in high-tech imaging machines and steerable drills that raise yields from existing reservoirs, where historically only the most readily available crude, typically 30 to 40 percent of the total, was recovered. (Extracting the rest was considered too costly, so it was left alone.)

When experts claim that oil is running out, what they really mean is that cheap oil is running out. About this, they may be right. Outside of Saudi Arabia, Iraq, and a few other countries, it is no longer possible to recover large quantities of crude for a dollar or two a barrel. But there are plenty of places where oil can be produced for $20 or $30 a barrel, let alone the $100 range where it has been trading recently.

And the list of potential substitutes for crude is long. Natural gas can be converted to a liquid fuel that produces few pollutants. Venezuela has big reserves of tar sands, as does Utah. Neighboring Colorado has oil trapped in shale, which industry engineers are trying to extract by slowly heating the rock under the Green River Basin. Corn, sugar, and potatoes can be distilled into ethanol, a perfectly good transport fuel, as can wood chips, straw, and other biomass. And as demand for ethanol has surged in recent years, farmers throughout the Midwest have taken advantage of generous federal subsidies to convert their fields to corn, the price of which doubled in the past 18 months. (When oil prices fall, such crop switching may prove to be a costly mistake.)

With energy supplies expanding and the demand for oil showing signs of faltering, it won't be very long before economic fundamentals reassert themselves. If oil were a normal commodity, competition would eventually drive the price down to a level close to the current cost of production, which at the margin is probably somewhere between $20 and $30 a barrel.

Of course, the oil market is hardly a textbook case of open competition: The OPEC cartel controls 40 percent of the supply, and geopolitics is an ever-present factor, as is speculation. The recent surge toward $100 a barrel was a dramatic demonstration of how traders can cause prices to become unmoored from costs for a lengthy period. But that also means that once market sentiment turns, the fall in prices could be just as dramatic.

Nobody in the oil market—not Wall Street, not Exxon Mobil, not even OPEC—can sustain prohibitively high prices for very long, a point that Sheik Yamani, the Saudi oil minister during the oil price shocks of the '70s and '80s, recognized. "If we force Western governments to invest heavily in finding alternative sources of energy, they will," he said in 1981, shortly after OPEC production cuts caused the price of crude to hit a record of $39.50 a barrel—roughly $100 a barrel in 2007 dollars. "This will take them no more than seven to 10 years and will result in their reduced dependence on oil as a source of energy to a point which will jeopardize Saudi Arabia's interests."

Most people ignored Yamani's warning, but he was right. Between 1979 and 1983, oil consumption in the non-Communist world fell by 6 billion barrels a day, or more than 10 percent. Motorists bought smaller cars. Homeowners threw out their oil furnaces. Power stations switched to coal, nuclear fuel, and natural gas. And this all happened at a time when new oil fields in Alaska, Mexico, and the North Sea were coming onstream in a big way. The result was an excess supply of crude and a huge drop in prices. In 1986, the cost of a barrel of crude fell to as low as $11.

The oil industry entered a prolonged slump, devastating Texas and other producing areas. For most of the '90s, the cost of a barrel of crude stayed below $20. At the end of 1988 and the start of 1989, it fell below $10, and you could get change out of a dollar for a gallon of gas.

I'm not saying that the oil price will slink all the way back to $10 a barrel. But a reckoning is inevitable. Serious divisions are emerging within OPEC about 2008 production levels. Presidential candidates in the U.S. are calling for tougher fuel-economy standards. Many Western countries, the U.S. and Britain included, have been making plans for a new generation of nuclear power plants. In the oil market, the laws of supply and demand sometimes appear to have been suspended. Ultimately, however, they do work.

Field Test Questionnaire

Yellow highlighting marks the differences between this field test response and the exposure draft.

Accounting for Federal Oil and Gas Resources
ED View

This field test is intended to assist the Board to:

- Gather information on the effects the valuation methodology proposed in the ED would have on financial statements versus the valuation methodology presented in the Alternative View.
- Discover issues preparers might have in applying each methodology.
- Discover material for a possible Implementation Guide.

Organization Name	Minerals Management Service (MMS)
Contact Name	Kelly West, Chief MMS Custodial Reporting Branch (CRB)
Contact Telephone Number	303-231-3035
Contact E-mail Address	kelly.west@mms.gov

Pro Forma Transactions

1. Please prepare pro forma transactions in accordance with:

    a. the proposed standards presented in the ED for the following accounting events:

        i. recording the initial value of the estimated petroleum royalties;
        ii. recording the one-fifth bid amounts;
        iii. recording the remaining payment by the successful bidder and the annual rental fee and the related liability for revenue distributions to others;
        iv. recording the annual rental fee from pre-existing leases and the related liability for revenue distributions to others;
        v. refunding the unsuccessful bidders' bonus bid deposits;
        vi. recording earned royalty revenue and depletion expense;
        vii. recording the collection of royalty revenue;
        viii. recording the distribution of bonus bid, rent, and royalty collections and the reduction in the liability for the revenue distributed to others;
        ix. recording the sale of future royalty streams identified for sale and the related change in the liability for revenue distributions to others; and,
        x. recording the annual valuation of estimated petroleum royalties and the related change in the liability for revenue distributions to others.

The following pro forma transactions are compressed, simplified, **and reflect only the transactions presented in the Exposure Draft (ED)**. They appropriately do not contain all of the detail associated with an event. For example, in transaction number two, the one-fifth bonus is invested until leases are accepted. Any interest accrued is refunded on bids subsequently rejected and returned. The illustration omits transactions internal to the entity. Transfers between sub-component entities are omitted.

Readers should not rely on the pro forma accounting transactions and resulting financial statements as a complete model for agency accounting. **Certain omitted entries may be required in actual practice** but are omitted since they are not required to understand the effect of the proposal on agency financial statements. **Additional nominal account entries would be made by the collecting entity, to track and report on greater detail than is presented in the ED. Also, a greater degree of detail and certain reclassifications would occur in practice, because the asset 'estimated petroleum royalties' would give rise to a long term receivable, while royalty reports and undisbursed cash are current assets.**

At the beginning of the fiscal year for which the accounting standards for oil and gas resources are effective, the following transaction is recorded by the component entity responsible for collecting royalties.

1. Record initial value of estimated petroleum royalties and the related liability for revenue distributions to others.

The initial value of estimated petroleum royalties used in this pro forma transaction is calculated for illustrative purposes only. The value of the Federal government's estimated petroleum royalties was calculated based on the valuation of oil and lease condensate estimated petroleum royalties, natural gas plant liquids (NGPLs) estimated petroleum royalties, and gas estimated petroleum royalties on a regional basis. Formulas to be used to calculate the estimated petroleum royalties for oil and lease condensate, NGPLs, and gas on a regional basis are as follows:

For oil and lease condensate **(Computed Separately and then Summed)**:

Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves X Regional Average First Purchase Price for Oil and Lease Condensate X Effective Regional Average Royalty Rate for Oil and Lease Condensate =
Regional Estimated Petroleum Royalties for Oil and Lease Condensate

For NGPLs:

Regional Estimated Quantity of Proved NGPLs Reserves X Regional Average First Purchase Price for NGPLs X Effective Regional Average Royalty Rate for NGPLs = Regional Estimated Petroleum Royalties for NGPLs

For **wet and** dry gas **(Computed Separately and then Summed)**:

Regional Estimated Quantity of Proved Gas Reserves X Regional Average Wellhead Price for Gas X Effective Regional Average Royalty Rate for Gas = Regional Estimated Petroleum Royalties for Gas

When computing regional average unit prices and regional average royalty rates by commodity, each component in common between EIA and MMS should be averaged separately and then summed. For example, when computing averages for oil and lease condensate, they should be computed separately, as their average unit price and rate are different. In order to have a more accurate estimate, they should not be folded together and then averaged, or the results may be notably different than if averaged separately and then summed. In the field study, folding just oil & lease condensate together and then computing the average made a $500M difference in the overall asset value. We recommend that the Statement and Appendices **clarify that the major commodity categories in common between EIA and MMS be disaggregated, the averages computed separately, and then summed to derive the asset value.**

Royalty information reported to MMS/MRM is reported as the commodity was sold or removed from the lease. This is important to note, as some assumptions had to be made in conducting the study of the ED view, and will exist at implementation. As regards wet vs. dry gas, MMS can only retrieve it as it was reported.

For purposes of the field test of the ED view, regions were divided simply into Onshore and Offshore. However, for implementation of the Statement, we would recommend a greater degree of division, to better reflect price differentials in different basins and regions.

The first step was to determine what portion of all proved reserves fall under federal domain, before the federal royalty share of those proved reserves could be estimated. This information is presently not published by EIA, so an estimation methodology had to be developed. The MMS/OMM/BLM Team reached agreement on the estimation methodology described herein, and ascertained that **in the absence of better information, this would be an acceptable method to use for implementation as well.**

In order to maintain some consistency and comparability with the most recent available EIA data published for calendar year 2005, MRM performed queries from their published statistics module of royalties reported for the 12 sales (production) months in calendar year 2005, which would include any adjustments for sales months in that time frame made up through September, 2007, when the final refined queries were run. Data obtained included region, product code, commodity description, reported sales volume, reported sales value, and reported royalty value.

MMS Custodial Reporting Branch (CRB) obtained the published EIA 2005 Annual Report of total nationwide estimated proved reserves, both Federal and non-Federal. MMS CRB then estimated the Federal portion of onshore proved reserves by using a ratio of 2005 onshore estimated production nationwide published by EIA, compared to 2005 total production volumes from Federal leases reported to MRM on royalty reports. The ratios of Federal to total 2005 production then became a proxy for the ratio of Federal proved reserves to total proved reserves reported by EIA. Offshore quantities are under Federal domain by definition, so were excluded from the estimation process. This differs from the computation method developed in the ED.

Royalty reported data was used for volumes sold or extracted from the lease, rather than straight production data, because production (OGOR) data is not broken out in the required detail, and it is not as up to date as royalty reported data.

It is important to consider that many assumptions had to be made in developing this model. As regards wet vs. dry gas, MMS can only retrieve the data as it is reported by industry, as it is sold or removed from the lease. Below describes the stratification of data that was retrieved by MRM for our field study, and how each commodity was categorized.

The Oil and Lease Condensate category contains product codes of:

01	Oil	(Oil)
02	Condensate	(Lease Condensate)
05	Drip or Scrubber Condensate	(Lease Condensate)

06	Inlet Scrubber	(Lease Condensate)
13	Fuel Oil	(Oil)
14	Oil Lost	(Oil)
20	Other Liquid Hydrocarbons	(Oil)

The Gas Category contains product codes of:

03	Processed (Residue) Gas	(Dry Gas)
04	Unprocessed (Wet) Gas	(Wet Gas)
09	Nitrogen	(Wet Gas)
12	Flash Gas	(Wet Gas)
15	Fuel Gas	(Wet Gas)
16	Gas Lost - Flared or Vented	(Wet Gas)
39	Coal Bed Methane	(Dry Gas)

The NGL Category contains the product code of:
07 Gas Plant Products

Where reported and paid separately, dry gas had to be analyzed separately from wet gas, and NGL's were also analyzed separately, averages computed and the totals then summed, in order to derive a more accurate estimate. This differs somewhat from the Exposure Draft, which reports only dry gas and NGL's. However, as a result of the field test, it is apparent that not only is this the reported information that is available, analyzing and computing each commodity category separately also produces a more accurate overall estimate. However, this is limited to the commodity categories reported in common between EIA and MRM. For purposes of the field study only, coal bed methane was added to onshore dry gas, as the rate and price were fairly comparable. But in practice, since proved reserve and estimated production data are available from EIA, this commodity could be computed and reported separately.

Commodity categories and units were at the common level between EIA and MMS:

Dry Gas	(mcf)
Wet Gas	(mcf)
NGL's	(bbl 42 us gal)
Oil	(bbl)
Lease Condensate	(bbl)

Next, to compute the estimated beginning balance of the federal royalty share of the asset to capitalize, MMS CRB utilized the existing royalty reported data for sales months in calendar year 2005 which had been provided by MRM to aid in computing the estimated quantity, as it had already been refined and was available. This was done solely for illustrative purposes to obtain a beginning balance. In actual practice this unique scenario would not exist, where the EIA published data and the MRM reported royalty data would cover the exact same time frame for computing the averages. In practice, the MRM reported data used to compute the averages would be more current, and reflect more current volumes, prices and rates. **It would be based upon the preceding 12 sales months royalties reported for which royalty production data is**

available, or July through June when measured at September 30 (please refer to pp. 12 in the ED).

Average royalty rates were computed by dividing the total regional royalty value by the total regional sales value by commodity categories for sales months in calendar year 2005. Average unit prices were similarly derived by dividing the total regional sales value by the total regional sales volume. Then, the asset value was computed by simply multiplying average rate X average unit price X estimated quantity for each region and commodity category. The totals were then summed to arrive at the total asset estimated value to capitalize.

In deriving the averages, numerous factors had to be included, such as excluding royalty relief volumes and estimating the value of commodity received in kind and delivered to DOE to fill the Strategic Petroleum Reserve (SPR). For purposes of the study, since SPR royalty reports contain volumes but no value, the average rate and unit price computed for Gulf oil were imputed to the SPR volumes, and the value computed from these averages. In practice, this method could be used, or alternatively the volumes could be obtained from royalty reports, the value from the manual journals used to record the activity in the period, and the average rate and average unit price then computed. The summary calculations are presented below.

Summary; Calculations of Estimated Proved Reserves

Federal Offshore Royalties Reported
Calendar Year 2005 Sales Months as of September 4, 2007
Categories Consolidated - Offshore

		Volume	**Value**	**Royalty Value**	**Calc Royalty Rate**	**Calc Unit Price**
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	1,634,243,775.24	12,891,342,243.25	1,874,938,867.11	0.145442	7.89
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	1,396,328,369.82	9,594,581,770.75	1,469,886,320.24	0.153200	6.87
	Gas Total	**3,030,572,145.06**	**22,485,924,014.00**	**3,344,825,187.35**	**0.148752**	**7.42**
NGL (gal)	Gas Plant Products (gal)	2,106,307,734.15	1,611,579,527.38	135,731,752.01	0.084223	0.77
NGL (bbl 42 gal)	**Gas Plant Products Total (bbl 42 gal)**	**50,150,184.15**	**1,611,579,527.38**	**135,731,752.01**	**0.084223**	**32.14**
Oil (bbl)		331,872,511.54	15,603,826,996.48	2,133,366,086.08	0.136721	47.02
Condensate (bbl)		39,613,036.74	1,291,839,143.91	195,812,132.70	0.151576	32.61
Oil & Cond (bbl)	**Oil & Condensate Total**	**371,485,548.28**	**16,895,666,140.39**	**2,329,178,218.78**	**0.137857**	**45.48**

Calculated Estimated Proved Reserves Under Federal Domain - Federal Royalty Share, as of 9/4/2007 - Offshore

		Onshore Est Proved Reserves	Offshore Est Proved Reserves	Total Est Proved Reserves	Est Asset Val (Avg Rate X Avg Price X Est Quantity)
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	-	18,604,000,000.00	18,604,000,000.00	**21,344,038,883.42**
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	-	19,040,000,000.00	19,040,000,000.00	**20,043,018,635.35**
	Gas Total	-	**37,644,000,000.00**	**37,644,000,000.00**	**41,387,057,518.77**
NGL (gal)	Gas Plant Products (gal)				
NGL (bbl 42 gal)	**Gas Plant Prod Total (bbl 42 gal)**	-	**740,000,000.00**	**740,000,000.00**	**2,002,814,111.19**
Oil (bbl)		-	4,758,000,000.00	4,758,000,000.00	**30,585,708,320.54**
Condensate (bbl)		-	293,000,000.00	293,000,000.00	**1,448,335,184.64**
Oil & Cond (bbl)	**Oil & Condensate Total**	-	**5,051,000,000.00**	**5,051,000,000.00**	**32,034,043,505.19**

Total Est Proved Reserves, Asset Value - Fed Royalty Share - CY 2005 Sales Months - Offshore **75,423,915,135.15**

Federal Onshore Royalties Reported

Calendar Year 2005 Sales Months as of September 4, 2007

Categories Consolidated - Onshore

		Volume	Value	Royalty Value	Calc Royalty Rate	Calc Unit Price
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	1,146,151,633.04	7,426,469,521.60	838,167,362.52	0.112862	6.48
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	1,467,970,348.00	10,602,363,010.95	1,283,204,061.34	0.121030	7.22
	Gas Total	**2,614,121,981.04**	**18,028,832,532.55**	**2,121,371,423.86**	**0.117665**	**6.90**
NGL (gal)	Gas Plant Products (gal)	1,593,967,707.03	1,286,266,838.18	126,132,310.29	0.098061	0.81
NGL (bbl 42 gal)	**Gas Plant Prod Total (bbl 42 gal)**	**37,951,612.07**	**1,286,266,838.18**	**126,132,310.29**	**0.098061**	**33.89**
Oil (bbl)		86,644,381.56	4,304,809,820.77	379,491,776.77	0.088155	49.68
Condensate (bbl)		10,335,920.75	566,071,089.71	69,487,330.46	0.122754	54.77
Oil & Cond (bbl)	**Oil & Condensate Total**	**96,980,302.31**	**4,870,880,910.48**	**448,979,107.23**	**0.092176**	**50.23**

Calculated Estimated Proved Reserves Under Federal Domain - Federal Royalty Share, as of 9/4/2007 - Onshore

		Onshore Est Proved Reserves	Offshore Est Proved Reserves	Total Est Proved Reserves	Est Asset Val (Avg Rate X Avg Price X Est Quantity)
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	15,227,904,771.19	-	15,227,904,771.19	**11,135,989,698.78**
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	19,425,200,893.36	-	19,425,200,893.36	**16,980,245,352.14**
	Gas Total	**34,653,105,664.55**	**-**	**34,653,105,664.55**	**28,116,235,050.92**
NGL (gal)	Gas Plant Products (gal)				
NGL (bbl 42 gal)	**Gas Plant Prod Total (bbl 42 gal)**	**470,294,072.95**	**-**	**470,294,072.95**	**1,563,023,932.26**
Oil (bbl)		1,480,091,280.44	-	1,480,091,280.44	**6,482,618,488.16**
Condensate (bbl)		118,169,090.91	-	118,169,090.91	**794,438,625.14**
Oil & Cond (bbl)	**Oil & Condensate Total**	**1,598,260,371.35**	**-**	**1,598,260,371.35**	**7,277,057,113.30**

Total Est Proved Reserves, Asset Value Est - Fed Royalty Share - CY 2005 Sales Months - Onshore	**36,956,316,096.47**
Total Estimated Proved Reserves, Asset Value Estimate - CY 2005 Sales Months	**112,380,231,231.63**

The initial value of estimated petroleum royalties is a hypothetical number used for illustrative purposes only. The hypothetical initial value of estimated petroleum royalties based on the methodologies described above is $**112,380,231,231**. The illustrative pro forma transaction to record the initial value of the Federal government's estimated petroleum royalties and related liability is presented below. The asset's value represents the **effective average** royalty share of the Federal oil and gas resources classified as "proved reserves." The related liability represents the **effective average** royalty share of the Federal oil and gas resources classified as "proved reserves" designated to be distributed to others, i.e., the states, the general fund of the U.S. Treasury and other Federal component entities, **not** including the component entity responsible for collecting royalties. The proposed treatment of distribution of revenue to others creates a Federal and a non-Federal liability for the component entity responsible for collecting royalties.

The cumulative effect of adopting this accounting standard would be reported as a "change in accounting principle" in accordance with SFFAS 21, *Reporting Corrections of Errors and Changes in Accounting Principles*. The adjustment would be made to the beginning net position on the component entity responsible for collecting royalties Statement of Changes in Net Position for the period the change is made **and the other Federal component entities for their allocable share of the related asset**. To obtain the value of the adjustment, the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the component entity responsible for collecting royalties. For this illustration, one percent was used as the average annual share of the revenue distributed to the component entity responsible for collecting royalties based on the average distribution for 2005.[1] To record the related liabilities the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the states. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[2] For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005.[3] These calculations are presented below:

$112,380,231,231 X .01 = $ 1,123,802,312

$112,380,231,231 X .84 = $94,399,394,234

$112,380,231,231 X .15 = $16,857,034,685

Dr Estimated Petroleum Royalties	112,380,231,231	
Cr Prior Period Adjustment: Change In Accounting Principle		1,123,802,312
Cr Liability for Revenue Distribution to Others-Federal		94,399,394,234
Cr Liability for Revenue Distribution to States-Non-Federal		16,857,034,685

To record initial value of estimated petroleum royalties due to change in accounting principle, the related liabilities to state and local governments, and the related liabilities to other Federal component entities. (The 1% expected to be retained by the entity responsible for making royalty collections increases its net position.)

Other Federal component entity entry:

For component entities, amounts must be recognized in a manner that supports elimination of Federal assets and liabilities and flow amounts. Therefore, the receiving Federal component entities would be required to book the asset related to their respective interest in the estimated petroleum royalties.

Dr Long-Term A/R for Oil and Gas-Federal	94,399,394,234	
Cr Prior Period Adjustment: Change In Accounting Principle		94,399,394,234

To book the asset by other Federal entities for their respective interest in the estimated petroleum royalties.

It must be noted that currently when recording the corresponding liabilities for end of period assets, MMS employs an agreed-upon procedure whereby we estimate the percentages allocable to our three largest recipients; U.S. Treasury, Reclamation Fund and the States. In the proposed ED models, due to the magnitude of the asset value, even the estimated 1% that MMS receives in annual appropriations becomes material.

[1] The one percent was derived by dividing [Note 21. Custodial Distributions to MMS, Revenues to Fund Operations] by [Total Revenue on the Statement of Custodial Activity] for 2005.
[2] The 15 percent was derived by dividing [Note 21. Payments to States] by [Total Revenue on the Statement of Custodial Activity] for 2005.
[3] The 84 percent was derived by dividing [Transfers-out to other Federal component entities on the Statement of Custodial Activity] by [Total Revenue on the Statement of Custodial Activity] for 2005.

This creates a situation where each recipient will require a liability entry based on some estimation method, and each designated federal recipient will be required to record a corresponding receivable and transfer in their statements, with eliminations between entities to prevent double counting government wide. You will see later in the text that any adjustment made to the asset results in an effect upon the recipient which will require an entry. **This becomes especially critical at quarter ends and at fiscal year end, where late adjustments required to accruals that are deemed related to oil and gas revenue (and hence, depletion) will also require late adjustments by all downstream recipients, thus significantly hampering entities ability to meet accelerated financial reporting due dates and potentially giving rise to audit findings.**

2. Record payment of the one-fifth bonus bid amounts.

For a competitive lease sale, a notice of lease sale is published in the *Federal Register.* Each lease bid must include a payment for one-fifth of the bonus bid amount unless the bidder is otherwise directed by the Secretary. For purposes of this illustrative accounting event, four bonus bids were received with payment of the one-fifth bonus bid amount. Bonus bid number one was $1,850,000, bonus bid number two was $1,900,000, bonus bid number three was $1,950,000, and bonus number four was $2,000,000. The total payment relating to the four bonus bids was $1,540,000 (bonus bid number one for $370,000, bonus bid number two for $380,000, bonus bid number three for $390,000, and bonus bid number four for $400,000) and was recorded with the following entry by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	1,540,000	
Cr Unearned Revenue		1,540,000

To record collection of the one-fifth bonus bids for the four bonus bids.

3. Record remaining payment by the successful bidder and the annual rental fee and the related liability for revenue distributions to others.

Payment of the unpaid balance of the bonus bid amount and the first year's rental fee are to be received from the successful bidder on the 11th business day after receipt of the lease forms by the successful bidder. The successful bid was bonus bid number four in the amount of $2,000,000. The remaining four-fifths bonus bid of $1,600,000 and the first year rental fee in the amount of $360,000 is received. According to various legislative requirements, rental fees are required to be paid one year in advance and are recorded as revenue from rent when received because there is no obligation to refund unearned portions. The following entries are recorded by the component entity responsible for collecting royalties.

Dr Unearned Revenue	400,000	
Dr Fund Balance with Treasury (1,600,000+360,000)	1,960,000	
Cr Revenue from Rent		360,000

Cr Revenue from Bonus Bid

To record remaining bonus payment and the annual rental fee by the successful bidder, and associated liability and nominal accounts, less MMS 1% (23,600).

The related increase in the liability for the future revenue distributions to others from the rent and the bonus bid is calculated in two parts. One part is based on revenue designated as payments to the States. The other part is based on designated transfers-out to other Federal component entities. The revenue from rent and bonus bid is multiplied by the average share of the revenue distributed to the States to obtain the value of the rent and bonus bid revenue to be distributed to the States. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005. The revenue from rent and bonus bid is multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent and bonus bid revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other component entities based on the average distribution for 2005. These calculations are presented below:

$$\$2,360,000 \times .15 = \$354,000$$

$$\$2,360,000 \times .84 = \$1,982,400$$

Dr Revenue Designated for Others – States – Non-Federal [4]	354,000	
Dr Transfers-Out	1,982,400	
Cr Liability for Revenue Distribution to Others-Federal		1,982,400
Cr Liability for Revenue Distribution to States-Non-Federal		354,000

To record the related increase in the liability for the future revenue distributions to others.

<u>*Other Federal component entity entry:*</u>

Dr Accounts Receivable	1,982,400	
Cr Transfer-In		1,982,400

To record the related accrual of a transfer-in and a reduction in the long-term A/R.

4. Receive the annual rental fee from pre-existing leases and record the related liability for revenue distributions to others.

For illustrative purposes, the total amount of annual rent collected for the year for offshore leases was $193,273,613 and the rental fee for onshore leases was $46,588,068 for a total of $239,861,681. Since $360,000 was received in connection

[4] This and certain other titles were selected for illustrative purposes. The entity has the option of selecting another account title that may be more appropriate.

with the new lease, the rental payments remaining are $239,501,681 ($239,861,681 less $360,000). The following entry is recorded by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	239,501,681	
Cr Revenue from Rent		239,501,681

To record rental payments on leases for the year.

The related increase in the liability for the future rent revenue to be distributed to others is calculated in two parts. One part is based on revenue designated as payments to the States. The other part is based on designated transfers-out to other Federal component entities. The revenue from rent is multiplied by the average share of the revenue distributed to the States to obtain the value of the rent revenue to be distributed to the States. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005. The revenue from rent is multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005. These calculations are presented below:

$239,501,681 X .15 = $35,925,252

239,501,681 X .84 = $201,181,412

Dr Revenue Designated for Others – States – Non-Federal	35,925,252	
Dr Transfers-Out	201,181,412	
Cr Liability for Revenue Distribution to Others-Federal		201,181,412
Cr Liability for Revenue Distribution to States-Non-Federal		35,925,252

To record the related increase in the liability for the future revenue distributions to others.

<u>Other Federal component entity entry:</u>

Dr Accounts Receivable	201,181,412	
Cr Transfer-In		201,181,412

To record the related accrual of a transfer-in and a reduction in the long-term A/R.

5. Refund unsuccessful bidders' bonus bid deposits.

Bonus bid deposits submitted by unsuccessful bidders are refunded to respective bidders after bids are opened, recorded, and ranked. Bonus bid #1 in the amount of $370,000, bonus bid #2 in the amount of $380,000, and bonus bid #3 in the amount of

$390,000 for a total of $1,140,000 are returned to respective bidders. The following entry is recorded by the component entity responsible for collecting royalties.

Dr Unearned Revenue	1,140,000	
Cr Fund Balance with Treasury		1,140,000

To record refund of losing bonus bids.

<u>The remaining pro-forma transactions and financial statements are presented as of the end of the Federal government's fiscal year (FY).</u>

6. Record earned royalty revenue and depletion expense.

The ED states that, *"Earned royalty revenue should be recognized as exchange revenue by the component entity that is responsible for collecting the royalties. At the same time, an amount equal to the royalty collections should be recognized as depletion expense; and, the value of estimated petroleum reserves should be reduced by the depletion expense amount. Sales value and royalty payment information are due on or before the last of the month following the month the oil or gas product from Federal oil and gas resources was sold or removed from the lease. For example, oil or gas sold in June must be reported by July 31, the end of the following month."*

There are extensive issues discussed below around the many components of revenue recognized by the collecting entity, the relationship of that revenue to depletion expense, and the present or future ability to obtain information at the level of detail presented in the ED. This is a significant set of issues that we believe must be addressed before the ED is finalized.

The ED proposes to base depletion expense upon oil & gas 'royalty revenue earned' for the fiscal year (pp. 23, and Appendix C, entry #6), and is silent regarding what components would comprise this value, except that pp. 23 refers to 'royalties from the production' of proved reserves. This introduces many complexities, including whether or how to include estimates such as the 'royalty accrual' (discussed below), and **the relationship between revenue recorded in the current fiscal year for royalty reporting adjustments made to prior years and current year depletion expense**.

Revenue earned by the collecting entity generally consists of amounts reported or billed, cash for which no royalty report has been received (unmatched cash), and amounts accrued as estimates. There is not a simple means at this time to obtain detail which reconciles to the general ledger and financial statements, of all components of earned revenue specifically related to oil and gas and more specifically related to offshore vs. onshore leases.

<u>**Earned Revenue Based Upon Royalty Reports; Royalty Adjustments to Prior Periods:**</u>

In addition to current royalty amounts, MMS records earned revenue in the current period for the sum of both positive and negative amounts resulting from upward or downward adjustments to prior royalty reporting, related to previous months when the commodity had been either sold or removed from the lease **(sales months).** This is a standard business process in oil and gas industry reporting, resulting from the receipt of subsequent information related to previous reporting periods that was unknown when the compulsory reporting was legally due, such as revised pipeline statements. These adjustments frequently cross monthly, quarterly, and fiscal year boundaries, can be large amounts, and are routine.

If depletion expense is linked across the board with overall revenue earned in the current year, then it must be understood that it would be at least partially based on revenue earned in the current year that is related to adjustments to prior periods falling outside the fiscal year. Therefore, the asset would be depleted in the current year based upon activity that does not actually reflect true depletion in the actual year.

If depletion expense were alternatively based upon revenue earned for oil & gas royalty reports related to current year production only, to most closely reflect the actual asset depletion in the current year, it would be applicable to only the **sales months** falling within the fiscal year. This would exclude prior period adjustments to royalty reporting that would be deemed unrelated to depletion in the current year.

However, complete royalty reporting covering production in the current fiscal year measured at 9/30 can only be ascertained through August, which covers actual reported royalty production through June (for which delayed reporting would not be due until August if a paid estimate were in place). In other words, only 9 months of complete sales month (production) data within a given fiscal year are available at 9/30 if basing 'revenue earned' and depletion expense only on current fiscal year sales months; October through June. Clearly, this would not present a complete picture of current year asset depletion, because it would not even include a full 12 months of royalty reporting.

The recommended alternative is to record depletion based upon royalty reporting lines received and accepted for the preceding 12 <u>sales months</u> available at fiscal year end; July through June (received through August, fully available in September). This would preclude the need to include estimates in the depletion calculations (discussed below), and would represent a realistic value of true asset depletion based on actual royalty reporting. **Revenue earned would not be a perfect match in the fiscal year, but in this case *it should not*, because depletion in the current year should not be linked to prior adjustments not related to the current year.** To do otherwise would *include* prior period adjustments not related to depletion in the year, and would involve complex and extensive inclusion of current year estimates that also include prior period adjustments. **This method would likely yield a more accurate picture of current asset depletion over a year span. This method would also provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, onshore vs. offshore and other necessary details.**

Another alternative would be to record depletion based solely upon all royalty lines received and accepted during the fiscal year, excluding all accruals and regardless of sales month. Again, revenue earned would not be a perfect match in the fiscal year, because accruals would be excluded. But including all lines accepted in a year would eliminate the need to include complex and extensive current year-end estimates for which disclosure detail is not available (see discussion below) because actuals over a 12 month span would be fully included. This method would, however, include all adjustments to prior reporting received in the current fiscal year, and while it may provide a closer tie to actual revenue reported in the financial statements, it would not be as fair a measure of asset depletion in the year. This method, like the recommended method above, would provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, and other necessary details.

Earned Revenue; Document Level Royalty Reporting Accruals vs. Line Level Royalty Detail:
When a royalty document is received, it usually includes numerous individual 'lines' of reporting. Each line contains specific detail about the royalty, such as the individual lease number, sales month and product code. If even one line of the royalty document passes edits and accepts in the royalty accounting system (MRMSS), then revenue is recorded for the full 'document calculated total'. If all lines reject, then a manual accrual is made for the full 'document calculated total'. Priority is placed on clearing rejected lines as quickly as possible, generally in the month following receipt. In subsequent periods, as the previously rejected royalty lines are corrected and accept in the MRMSS, they do not give rise to revenue, as it was already properly accrued when the document was first received.

As you can see, the detail required in the ED for 'earned revenue' by oil or gas and onshore vs. offshore is not readily obtainable for this portion of the population (rejected lines in the last month of the year). For purposes of the field study, CRB undertook an initial effort to ascertain in a 1-month period, the detail related to line level royalty revenue earned by oil or gas and onshore vs. offshore. In instances where the doc calc total giving rise to revenue in the period did not equal the sum of the accepted lines in the system, CRB developed a method to allocate (estimate) earned revenue to detail associated with existing lines. **This identified a significant problem in our ability to report accurately on the detail associated with 'earned revenue' based on current month royalty reporting. In many cases, the revenue was allocated to oil or gas based upon an estimate that may or may not be correct, and which may not prove to be correct in subsequent periods when the rejected lines are corrected and accept in the system. This issue further supports the premise that depletion be based solely upon accepted royalty reporting lines for given sales months, as presented above, and not on accruals and estimates.**

Earned Revenue; Estimates and Manual Accruals: When examining 'earned revenue' and its relationship to asset depletion, CRB performed an extensive analysis for the field study, of estimates and manual accruals related to current period royalty revenue.

MMS records numerous manual accruals to fairly present assets, liabilities and revenue in the financial statements. One such entry is the ‘royalty accrual’, a large accrual that represents estimated production in the current month for oil, gas and solid minerals, where the royalty reports are not yet received. The royalty accrual is not computed based on sales month (production month), but rather upon when the royalty report was received. It is computed based on a 12-month average of previous royalty reports received. Revenue recognition for royalty is consistent therefore, because **prior period adjustments to previous royalty reporting are treated as current year revenue, upward or downward, and factored into the current period royalty accrual. The royalty accrual is subject to extensive year-end audit review, and a large subsequent adjustment may be required annually, later in the financial reporting process (early November). If included in the revenue matched with depletion expense, this would also then, require that the proved reserves asset be adjusted accordingly, and would impact materially, all allocated downstream recipients as well.**

The royalty accrual is required to be performed fairly quickly, at the high level, to meet accelerated financial reporting objectives. **It includes adjustments to prior reporting periods, and it does not contain the detail required in the ED, to break out oil vs. gas and onshore vs. offshore.** Of course, a rough estimation method could always be developed, but its accuracy and validity when compared to subsequent actual information could potentially prove to be incorrect.

Another significant manual accrual involves **unmatched cash** for which no royalty report has been received at the end of the reporting period. This occurs monthly, and this large unmatched cash balance can not accurately be linked to oil or gas, onshore or offshore. In some instances, large compliance settlement amounts may be included in the cash balance, not related to current year royalties. Large amounts could be related to interest payments. It would be incorrect to allocate current year depletion to unmatched amounts that may not be related. **Also, this unmatched cash, when applied to subsequent royalty reports, will likely relate to adjustments to prior reporting, and also not bear a relationship to current year asset depletion.**

Previous discussions with FASAB Staff indicated that in order to provide matching of royalty revenue earned in the fiscal year, the royalty accrual would be included in the ‘revenue earned’ that would be offset by depletion expense, because the accrual estimates production in the current month for which royalty reports will not be yet be received. Also, it was discussed that revenue recognition overall should remain consistent, and that revenue earned in the fiscal year, regardless of sales (production) month and subsequent adjustments, would still apply. Accordingly, the text in pp. #23 and throughout the Statement was going to be revised to include, “Royalties received and accrued...”

However, upon analysis **as a result of the field test study,** it is apparent that the degree of detail required to be estimated, allocated and reported is very extensive, labor intensive, **includes adjustments to prior period reporting which may not relate to current period asset depletion at all,** and **poses significant risks to meeting audit and accelerated financial reporting objectives.** Again, including these and other estimates, by default, **includes adjustments to prior reporting, or other activity not necessarily related to actual current period asset depletion. The degree of detail for disclosure required in the ED would not be readily available from these estimates, and would have to be extensively estimated.** And the inclusion of these estimates would likely not yield a better, and perhaps a worse, measure of actual asset depletion in the year, as opposed to the recommended sales month method described above. For the many complex accruals currently performed by MMS, estimation methods would have to be developed to allocate some portion of the earned revenue to oil and gas, and then of that subset, to onshore vs. offshore.

For purposes of this field test study, revenue overall is presented in aggregate, includes estimates and is based upon royalty reporting lines received and accepted in the fiscal year, regardless of sales months, to tie with current practices. This is done to illustrate the many estimates performed, their relationship to earned revenue, and to explain why the detail required in the ED can not currently be provided. However, it is <u>not the recommended method</u> for deriving depletion expense. Also, disclosures were not attempted.

As we have discussed, estimations pose significant challenges to MMS' ability to produce adequate detail in the required disclosures regarding revenue earned by oil and gas and onshore vs. offshore categories. **It currently could not be readily done with existing resources or information.** Each line of each component of earned revenue would have to be carefully analyzed, an allocation method developed for oil and gas and onshore vs. offshore, and would be an extensive and labor intensive process. A sophisticated system report and queries could be developed to help provide some of this degree of detail, but it would not resolve issues around allocations of estimates, and **timing would be crucial, as reconciliations and adjusting entries would need to be made quickly, to meet accelerated financial reporting deadlines, and to pass audit requirements.**

The matrix below presents some of the key components of 'earned royalty revenue' presently recorded by MMS, and demonstrates how the earned royalty revenue value was estimated for the illustrative pro forma entries. It must be noted that in actual practice, the previous year-end estimate would be reversed in the subsequent year, so that actual revenue recorded in any given year related to estimates would essentially reflect the **change** associated with those estimates over the year. In this example, for the study, the full values were presented, to give the reader a general idea of the relative sizes of the estimates under discussion.

Again, the primary concerns related to recording depletion expense based on revenue which includes estimates revolve around mismatching unrelated

portions of estimates with actual asset depletion, potential material audit findings and a potential inability to meet accelerated financial reporting objectives.

As an aside, if using the recommended sales month method described above for ascertaining the amount of depletion to record in a fiscal year, then the actual royalty value for oil and gas reported to MMS was approximately $9.2 billion for the most recent sales months available when performing the field test, June 2006 through May 2007, obtained in mid-August 2007.

Analysis of Components - Oil & Gas Revenue Earned - Entry #6, FASAB ED

Amounts are representational and illustrative only, to present basic concepts, and are not necessarily based on final or actual numbers

Total Royalty Report Line Level Data Received in Period (Royalty Value Less Allowances - RVLA)	**10,731,532,649**
Royalty line amounts that do not give rise to revenue by collecting entity in period	
Document calculated total equals zero (non-value related adjustments)	246,825,251
No system receivable created, such as for Indian direct pay or Strategic Petroleum Reserve (SPR)	789,559,441
Royalty documents accepted in prior periods where previously rejected lines now accept	17,170,452
Total Royalty Line Amounts That Do Not Give Rise to Revenue by Collecting Entity in Period	**1,053,555,144**
Revenue From Royalty Lines - Other (Currently Reported in 'Rents and Royalties')	**5,333,009**
Remainder - Royalty Lines Giving Rise to Revenue Received in Fiscal Year, Attributable to Oil & Gas	**9,672,644,496**
Accrued Revenue and Estimates - O&G (Illustrative Ending Balances Only - Revenue would be recorded for change in accruals)	
Estimated Portion of Year-End Royalty Accrual Estimating Current Month Production, Oil & Gas	760,179,551
Year-End SPR Accrual Estimating Current Month Production Delivered to DOE, Oil Only	105,216,449
Annual Actual Revenue for Oil Taken In Kind to Fill Strategic Petroleum Reserve (SPR)	200,974,551
Other Invoices In Lieu of Royalty Reports Presumed to be Related to Oil and Gas Royalties	30,000,000
Estimated Royalty Portion of Enforcement Settlements if Related to Current Year - Oil & Gas	50,000,000
Estimated Portion of Numerous Other Revenue Accruals Estimated Allocated to Oil & Gas	200,000,000
Estimated Portion of Unmatched Cash Revenue - No Royalty Report – Allocated to Oil & Gas	500,000,000
Total of Accrued Revenue and Estimates To Be Estimated Allocated to Oil and Gas	**1,846,370,551**
Total Estimated Royalty Related Revenue and Depletion Expense, Oil & Gas, Fiscal Year 20XX	**11,519,015,047**
Other Revenue - Non-CY Oil & Gas Royalty	
Revenue from Onshore lease sale bonus and 1st year rents (does not tie to pro forma entries – informational only)	286,344,000
Revenue from Offshore lease sale bonus and 1st year rents (does not tie to pro forma entries – informational only)	387,689,000
Revenue from PY Settlements including Civil Penalties and Interest (Currently reported in 'Rents and Royalties')	80,000,000
Revenue from Royalties - Other Commodities i.e. Solid Minerals (Currently reported in 'Rents and Royalties')	615,752,400
Revenue from Late Payment Interest (Currently reported in 'Rents and Royalties')	60,000,000
Other Commodity Related Miscellaneous Revenue Including Compliance (Currently reported in 'Rents and Royalties')	12,000,000
Total Other Revenue - Non-CY Oil & Gas Royalty	**1,441,785,400**
Total Revenue Reported on Fiscal Year 20XX Statement of Custodial Activity	**12,960,800,447**

To restate, some of the key concerns around recording depletion expense based upon the sum of current year royalty reports and estimates include:

- Revenue and depletion expense would be mismatched due to prior period adjustments not related to current period depletion captured as revenue in the current year.
- The revenue estimate including accruals would also include estimates of production anticipated through year-end, and estimates of unmatched cash with estimates sub-allocated to oil & gas, and then sub-allocated to onshore vs. offshore. The estimated allocations will likely be later found to be incorrect. Also, the estimates include adjustments to prior periods, not attributable to depletion in the current period.
- Each estimate is already complex to derive, and currently does not include a method for allocating to oil or gas, or onshore vs. offshore.
- Revising each estimate accordingly will decrease the likelihood of meeting accelerated financial reporting objectives, and will increase the likelihood of audit failures, and their severity based on materiality.
- Estimates and subsequent changes to estimates will impact the asset value through depletion expense, and so, all designated downstream recipients.
- Estimates measured against subsequent actuals at fiscal year end will likely result in material adjustments near the close of the annual financial audit process in early November, and also require adjustment by designated downstream recipients.

For illustrative purposes, the hypothetical numbers previously discussed are presented. The **estimated** royalty revenue **earned and accrued** for the fiscal year for offshore and onshore rental leases **estimated allocated to oil and gas only** was used in this calculation. The **estimated** royalty revenue **earned and accrued** during the fiscal year for offshore **and onshore** leases was roughly estimated to be **$11,519,015,047**. [<u>This amount was requested to be separated into offshore and onshore amounts in the ED</u>.]

The following entries are recorded by the component entity responsible for collecting royalties.

Dr Accounts Receivable (Billed and Unbilled Accrued)	11,519,015,047	
Cr Revenue from Royalties for Federal Oil and Gas Reserves		11,519,015,047

To record earned royalty revenue.

Dr Oil and Gas Depletion Expense	11,519,015,047	
Cr Estimated Petroleum Royalties		11,519,015,047

To record depletion expense for Federal oil and gas resources.

7. Record collection of royalty revenue.

Royalty payments are due on or before the last of the month following the month the oil or gas product from Federal oil and gas resources are sold or removed from the lease, unless lease terms state that royalties are due otherwise. A year-to-date total estimate of royalty revenue collected is in the amount of $10,048,231,734. The following entry is recorded by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	10,048,231,734	
Cr Accounts Receivable		10,048,231,734

To record collection of royalty revenue.

8. Record distribution of bonus bid, rent, and royalty collections and the reduction in the liability for the revenue distributed to others.

The component entity responsible for collecting royalty revenue is required to distribute the bonus bid, rent, and royalty revenue in accordance with authoritative formulas <u>to recipients designated by law upon matching the revenue collections to specific leases</u>. The component entity distributing bonus bid, rent, and royalty revenue from Federal oil and gas resources should recognize the distribution to component entities in accordance with existing accounting standards. The Federal component entity receiving the distribution should recognize the receipt as a transfer in when calculating its operating results. For purposes of this illustrative accounting event, the bonus bid collected was $2,000,000, the rent collected was $239,861,681 and the royalties collected was $10,048,231,734 for total collections of $10,290,093,415.

The bonus bid, rent, and royalty revenue collections to be distributed and the related reduction in the liability for revenue distribution to others is calculated in two parts. One part is based on revenue collections designated as payments to the States. The other part is based on collections designated as payments to other Federal component entities. The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to the States to obtain the value of the collections to be distributed to the States. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005. The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005. These calculations are presented below:

$10,290,093,415 X .15 = $1,543,514,012

$10,290,093,415 X .84 = $8,643,678,469

Dr Liability for Revenue Distribution to Others-Federal	8,643,678,469	
Dr Liability for Revenue Distribution to States-Non-Federal	1,543,514,012	
Cr Fund Balance with Treasury		10,187,192,481

To record distribution of bonus bid, rent, and royalty revenue collections and the reduction in liabilities for revenue distribution to others.

Other Federal entity entry:

Dr Fund Balance with Treasury	8,643,678,469	
Cr Accounts Receivable		8,643,678,469

To increase the fund balance with treasury and reduce the accounts receivable in relation to distributions received.

Please Note: The illustrative entry above demonstrates that the collecting entity (MMS) retains 1% of all cash received, regardless of its nature or amount. In practice, it is only upon appropriation, dependant upon specific terms and legislated maximums that certain amounts are received.

9. Disclose rights to future royalty streams identified for sale.

Please Note: Key subject matter experts have indicated that this scenario is very highly unlikely. Because such extensive analysis and work was required to satisfy other aspects of the field study, this valuation and item #10 were not revised from the original proposal in the ED. There is no disagreement with the proposed disclosure and accounting treatment. However, if the alternative valuation method is selected, then valuation based upon the known quantities would be developed using that method.

When rights to a future royalty stream are identified to be sold, the value of those rights should be disclosed as future royalty rights held for sale. They should be disclosed rather than reclassified because (1) the point in time for the sale of the future royalty rights may be uncertain or undecided and (2) the identified fields may continue to produce oil and/or gas and generate royalties. These two factors make it difficult to establish and maintain precise valuation information in advance of the sale. Disclosure of the approximate value at the balance sheet date alerts the reader to the pending sale and the potential value of the asset to be sold. The value of the rights identified for sale should be based on the estimated quantity of proved reserves, the first purchase price for oil or the wellhead price for gas, and the royalty rate for each specific field identified for potential sale.

Future royalty streams from two specific oil fields have been identified to be sold.

The estimated value of the future royalty stream identified to be sold from field number one is $5,305,000 based on the following calculation: 1,000,000 barrels to be sold X

$42.44 per barrel per field number one first purchase price for oil X the 12.5% royalty rate for field number one.

The estimated value of the future royalty stream identified to be sold from field number two is $3,244,688 based on the following calculation: 750,000 barrels to be sold X $34.61 per barrel per field number two first purchase price for oil X the 12.5% royalty rate for field number two. The future royalty streams are expected to be sold sometime during the next fiscal year.

10. Record sale of future royalty streams identified for sale and the related change in the liability for revenue distributions to others.

At the time the future royalty rights identified for sale are sold, the asset value is calculated based on the quantity of proved oil reserves involved in the sale, the first purchase price or the wellhead price for the field at the time of sale, and the royalty rate for the specific field. Any difference between the asset value of the future royalty rights sold and the sales proceeds results in a net gain or loss. The net gain or loss should be reported on the Statement of Net Cost of the component entity responsible for collecting royalty revenue. For purposes of this illustrative accounting event, the rights to future royalty rights held for sale for field number one had an asset value of $5,375,000 based on the following calculation: 1,000,000 barrels of proved oil reserves involved in the sale multiplied by an arbitrary $43.00 per field number one first purchase price per barrel further multiplied by the arbitrary 12.5 percent royalty rate for field number one. The rights to a future royalty stream from field number one were sold for $3,950,000. As a result, there is a loss of $1,425,000 on the sale of the future royalty stream from field number one, which should be reported on the Statement of Net Cost.

Dr. Fund Balance with Treasury	3,950,000	
Dr. Loss on Sale of Estimated Petroleum Royalties	1,425,000	
Cr. Estimated Petroleum Royalties		5,375,000

To record sale of future royalties.

The loss on the sale of estimated petroleum royalties is multiplied by the average share of the revenue distributed to the States and other Federal component entities to obtain the related reduction in the liabilities for revenue distributions to others. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005. The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005. This calculation is presented below:

$1,425,000 X .15 = $213,750

$1,425,000 X .84 = $1,197,000

Dr Liability for Revenue Distributions to Others- Federal	1,197,000	
Dr Liability for Revenue Distributions to States-Non-Federal	213,750	
Cr Revenue Designated for Others – States – Non-Federal		213,750
Cr Transfers-Out		1,197,000

To record the related reduction in the liabilities for the future revenue distributions to others, revenue designated for the States, and transfers-out as a result of the loss on the sale of estimated petroleum royalties.

Dr Liability for Revenue Distributions to Others- Federal	3,318,000	
Dr Liability for Revenue Distributions to States-Non-Federal	592,500	
Cr Fund Balance with Treasury		3,910,500

To record the distribution of collections from the sale of revenue streams and the related reduction in the liability for revenue distributions to others.

Other Federal entity entry:

Dr Fund Balance with Treasury	3,318,000	
Cr Long-Term A/R for Oil and Gas-Federal		3,318,000

To increase the fund balance with treasury and reduce the long-term accounts receivable for oil and gas in relation to distributions received.

Dr Transfers-In	1,197,000	
Cr Long-Term A/R for Oil and Gas-Federal		1,197,000

To decrease the transfers-in and long-term accounts receivable as a result of the loss on the sale of estimated petroleum royalties.

11. Record annual valuation of estimated petroleum royalties and the related change in the liability for revenue distributions to others.

The calculated value of the Federal government's estimated petroleum royalties for financial statement reporting at year-end should be compared to the book value of estimated petroleum royalties at year-end. If the calculated value of estimated petroleum royalties at year-end is greater than the year-end book value,[5] the book value should be increased to the new estimate and a gain should be recorded on the Statement of Net Cost of the reporting entity responsible for collecting revenue. If the calculated value of estimated petroleum royalties at year-end is less than the year-end book value, the book value should be decreased to the new estimate and a loss should be recorded on the Statement of Net Cost of the reporting entity responsible for collecting royalty revenue. For illustrative purposes, the valuation of estimated

[5] The estimated petroleum royalties beginning balance would have been reduced by the amount expensed on the statement of net cost.

petroleum royalties as of as of the year ended September 30 produced a **gain** of **$5,180,638,314** that is based on the following calculations.

To compute the illustrative revaluation of estimated petroleum royalties at fiscal year end, MMS CRB obtained royalty reported data from MRM for the sales months of June, 2006 through May, 2007, available in mid-August. Since the most recent quantity of estimated proved reserves had already been calculated from 2005 EIA data and the federal domain portion derived for entry #1, that same quantity information was used for this entry.

As in entry #1, average royalty rates were computed by dividing the total regional royalty value by the total regional sales value by commodity categories for sales months June, 2006 through May, 2007. Average unit prices were similarly derived by dividing the total regional sales value by the total regional sales volume. Then, the asset value was computed by simply multiplying average rate X average unit price X estimated quantity for each region and commodity category. The totals were then summed to arrive at the total asset estimated value to capitalize.

Again, various factors had to be included in deriving the averages, such as estimating the value of commodity received in kind and delivered to DOE to fill the Strategic Petroleum Reserve (SPR). For purposes of the study, since SPR royalty reports contain volumes but no value, the average rate and unit price computed for Gulf oil were imputed to the SPR volumes, and the value computed from these averages. In practice, this method could be used, or alternatively the volumes could be obtained from royalty reports, the value from the manual journals used to record the activity in the period, and the average rate and average unit price then computed.

It is interesting to note that when holding the quantity constant and applying more current reported average values, the overall asset value went down significantly, despite rising oil prices. Variance analysis of the detailed components revealed that a significant decrease in gas prices caused the overall asset value's decline. However, when computing the revaluation, depletion recorded in the year exceeded the straight difference in the valuation, and required a gain on revaluation to be recorded. This gain may not be reflected in subsequently published EIA data.

Summary; Calculations of Estimated Proved Reserves

Federal Offshore Royalties Reported June, 2006 to May, 2007 Sales Months as of August 15, 2007 Categories Consolidated - Offshore

		Volume	Value	Royalty Value	Calc Royalty Rate	Calc Unit Price
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	2,088,693,513.54	13,493,038,817.61	1,963,716,512.72	0.145536	6.46
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	758,644,042.71	4,165,696,246.68	623,387,373.83	0.149648	5.49
	Gas Total	**2,847,337,556.25**	**17,658,735,064.29**	**2,587,103,886.55**	**0.146506**	**6.20**
NGL (gal)	Gas Plant Products (gal)	2,289,128,385.61	2,047,619,575.04	193,561,353.26	0.094530	0.89
NGL (bbl 42 gal)	**Gas Plant Products Total (bbl 42 gal)**	**54,503,056.80**	**2,047,619,575.04**	**193,561,353.26**	**0.094530**	**37.57**
Oil (bbl)		491,623,190.94	27,520,020,148.59	3,603,798,670.67	0.130952	55.98
Condensate (bbl)		38,674,635.52	1,704,927,445.35	263,563,951.89	0.154590	44.08
Oil & Cond (bbl)	**Oil & Condensate Total**	**530,297,826.46**	**29,224,947,593.94**	**3,867,362,622.56**	**0.132331**	**55.11**

Calculated Estimated Proved Reserves Under Federal Domain - Federal Royalty Share, as of 8/15/2007 - Offshore

		Onshore Est Proved Reserves	Offshore Est Proved Reserves	Total Est Proved Reserves	Est Asset Val (Avg Rate X Avg Price X Est Quantity)
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	-	18,604,000,000.00	18,604,000,000.00	**17,490,829,442.34**
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	-	19,040,000,000.00	19,040,000,000.00	**15,645,408,030.00**
	Gas Total	-	**37,644,000,000.00**	**37,644,000,000.00**	**33,136,237,472.33**
NGL (gal)	Gas Plant Products (gal)	-			
NGL (bbl 42 gal)	**Gas Plant Prod Total (bbl 42 gal)**	-	**740,000,000.00**	**740,000,000.00**	**2,628,025,102.10**
Oil (bbl)		-	4,758,000,000.00	4,758,000,000.00	**34,878,082,220.37**
Condensate (bbl)		-	293,000,000.00	293,000,000.00	**1,996,767,050.69**
Oil & Cond (bbl)	**Oil & Condensate Total**	-	**5,051,000,000.00**	**5,051,000,000.00**	**36,874,849,271.06**

Total Est Proved Reserves, Asset Value Est - Fed Royalty Share - 6/06 to 5/07 Sales Months as of 8/15/07 - Offshore	**72,639,111,845.50**

Federal Onshore Royalties Reported
June, 2006 to May, 2007 Sales Months as of August 15, 2007
Categories Consolidated - Onshore

		Volume	Value	Royalty Value	Calc Royalty Rate	Calc Unit Price
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	1,335,325,242.52	7,149,054,757.47	807,926,266.69	0.113012	5.35
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	1,461,302,585.74	7,881,940,499.31	936,048,075.19	0.118759	5.39
	Gas Total	**2,796,627,828.26**	**15,030,995,256.78**	**1,743,974,341.88**	**0.116025**	**5.37**
NGL (gal)	Gas Plant Products (gal)	1,705,354,307.56	1,501,187,761.04	154,766,267.17	0.103096	0.88
NGL (bbl 42 gal)	**Gas Plant Products Total (bbl 42 gal)**	**40,603,673.99**	**1,501,187,761.04**	**154,766,267.17**	**0.103096**	**36.97**
Oil (bbl)		90,998,797.02	5,050,212,566.76	558,100,866.72	0.110510	55.50
Condensate (bbl)		12,126,857.50	723,064,486.06	89,367,733.60	0.123596	59.63
Oil & Cond (bbl)	**Oil & Condensate Total**	**103,125,654.52**	**5,773,277,052.82**	**647,468,600.32**	**0.112149**	**55.98**

Calculated Estimated Proved Reserves Under Federal Domain - Federal Royalty Share, as of 8/15/2007 - Onshore

		Onshore Est Proved Reserves	Offshore Est Proved Reserves	Total Est Proved Reserves	Est Asset Val (Avg Rate X Avg Price X Est Quantity)
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	15,227,904,771.19	-	15,227,904,771.19	**9,213,503,841.27**
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	19,425,200,893.36	-	19,425,200,893.36	**12,442,954,719.88**
	Gas Total	**34,653,105,664.55**	-	**34,653,105,664.55**	**21,656,458,561.15**
NGL (gal)	Gas Plant Products (gal)	-	-		
NGL (bbl 42 gal)	**Gas Plant Prod Total (bbl 42 gal)**	**470,294,072.95**		**470,294,072.95**	**1,792,587,985.05**
Oil (bbl)		1,480,091,280.44	-	1,480,091,280.44	**9,077,485,126.06**
Condensate (bbl)		118,169,090.91	-	118,169,090.91	**870,835,980.06**
Oil & Cond (bbl)	**Oil & Condensate Total**	**1,598,260,371.35**	-	**1,598,260,371.35**	**9,948,321,106.12**

Total Est Proved Reserves, Asset Value Est - Fed Royalty Share - 6/06 to 5/07 Sales Months as of 8/15/07 - Onshore	**33,397,367,652.32**
Total Est Proved Reserves, Asset Value Est - Fed Royalty Share - 6/06 to 5/07 Sales Months as of 8/15/07	**106,036,479,497.82**

The total illustrative revaluation of estimated petroleum royalties for oil and lease condensate, NGPLs, and gas is **$106,036,479,498**. The current value of estimated petroleum royalties less the book value of estimated petroleum royalties (the initial value of estimated petroleum royalties at the beginning of the year (October) less depletion expense for estimated petroleum royalties through the end of the year (September 30), less the asset value of estimated petroleum royalties sold), equals the net **gain** to be recorded:

Dr Estimated Petroleum Royalties	5,180,638,314	
Cr Gain on Revaluation of Estimated Petroleum Royalties		5,180,638,314

To record revaluation of estimated petroleum royalties.

To record the related increase in the liability for the future revenue distributions to others, the amount that the total estimated petroleum royalties was increased due to revaluation is multiplied by the average share of the revenue distributed to the states. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005. These calculations are presented below:

$5,180,638,314 X .15 = $777,095,747

$5,180,638,314 X .84 = $4,351,736,184

Dr Revenue Designated for Others – States – Non-Federal	777,095,747	
Dr Transfers-Out	4,351,736,184	
Cr Liability for Revenue Distributions to Others-Federal		4,351,736,184
Cr Liability for Revenue Distributions to States-Non-Federal		777,095,747

To record the related year-end increase in the liabilities for the future revenue distributions to others.

<u>*Other Federal component entity entry:*</u>

For component entities, amounts must be recognized in a manner that supports elimination of Federal assets and liabilities and flow amounts. Therefore, the receiving Federal component entities would be required to book the revaluation amount related to their respective interest in the estimated petroleum royalties.

Dr Long-Term A/R for Oil and Gas-Federal	4,351,736,184	
Cr Transfers-In		4,351,736,184

To book the revalued asset amount by other Federal entities for their respective interest in the estimated petroleum royalties.

Pro Forma Statements

2. Please prepare a pro forma pre-closing trial balance, closing entries, a post-closing trial balance, a balance sheet, a statement of net cost, and a statement of changes in net position for the component entity responsible for collecting royalties based on the following:

   a. the pro forma transactions developed in accordance with the proposed standards;

The pro forma trial balances, closing entries, and financial statements following are illustrative of the bureau entries presented in this document. The “other Federal component entity” entries and statements are also illustrated. Some of the ‘other Federal component entities’ are within the same Department (Interior), and some, without. The consolidated financial statements of the United States Government are not illustrated. Small rounding differences may be present.

Pre-closing trial balance after pro forma transactions:

Collecting Entity

Pre-closing trial balance after pro forma transactions:

Fund Balance with Treasury	102,940,434
Accounts Receivable	1,470,783,313
Estimated Petroleum Royalties	106,036,479,498
Liability for Revenue Distributions to Others - Federal	(90,306,100,761)
Liability for Revenue Distributions to States - Non-Federal	(16,126,089,421)
Revenue from Bonus Bids and Rents	(241,861,681)
Revenue from Royalties	(11,519,015,047)
Transfers-Out	4,553,702,996
Oil & Gas Depletion Expense	11,519,015,047
Revenue Designated for the States	813,161,249
Gain on Revaluation of Estimated Petroleum Royalties	(5,180,638,314)
Loss on Sale of Future Royalty Rights	1,425,000
Prior Period Adjustment: Change in Accounting Principle	(1,123,802,312)
Total	0

Other Federal Entities

Pre-closing trial balance after pro forma transactions:

Fund Balance	8,646,996,469
Accounts Receivable	90,306,100,761
Transfers-In	(4,553,702,996)
Prior Period Adjustment: Change in Accounting Principle	(94,399,394,234)
Total	0

Closing Entries:

Collecting Entity
Closing Entries:

Revenue from Bonus Bid and Rents	241,861,681	
Revenue from Royalties	11,519,015,047	
Gain on Revaluation of Estimated Petroleum Royalties	5,180,638,314	
Prior Period Adjustment: Change in Accounting Principle	1,123,802,312	
Cumulative Results of Operations		1,178,013,062
Transfers-Out		4,553,702,996
Oil and Gas Depletion Expense		11,519,015,047
Revenue Designated for the States		813,161,249
Loss on Sale of Future Royalty Rights		1,425,000

Other Federal Entities
Closing Entries:

Transfers-In	4,553,702,996	
Prior Period Adjustment: Change in Accounting Principle	94,399,394,234	
Cumulative Results of Operations		98,953,097,230

Post-closing trial balance:

Collecting Entity
Post-closing trial balance:

Fund Balance with Treasury	102,940,434
Accounts Receivable	1,470,783,313
Estimated Petroleum Royalties	106,036,479,498
Liability for Revenue Distributions to Others - Federal	(90,306,100,761)
Liability for Revenue Distributions to States - Non-Federal	(16,126,089,421)
Cumulative Results of Operations	(1,178,013,062)
Total	0

Other Federal Entities
Post-closing trial balance:

Fund Balance	8,646,996,469
Accounts Receivable	90,306,100,761
Cumulative Results of Operations	(98,953,097,230)
Total	0

Pro Forma Financial Statements – for fiscal year ended 9/30/20XX

Balance Sheet

Collecting Entity Balance Sheet

Assets	
Fund Balance with Treasury	102,940,434
Accounts Receivable	1,470,783,313
Estimated Petroleum Royalties	106,036,479,498
Total Assets	$107,610,203,245
Liabilities	
Liability for Revenue Distribution to Others - Federal	90,306,100,761
Liability for Revenue Distribution to States - Non-Federal	16,126,089,421
Total Liabilities	106,432,190,183
Net Position	
Cumulative Results of Operations	1,178,013,062
Total Liabilities and Net Position	$107,610,203,245
	0

Other Federal Entities Balance Sheet

Assets	
Fund Balance	8,646,996,469
Accounts Receivable - MMS	90,306,100,761
Total Assets	$98,953,097,230
Net Position	
Cumulative Results of Operations	98,953,097,230
Total Net Position	$98,953,097,230
	0

Statement of Net Cost

Collecting Entity Statement of Net Cost

Oil & Gas Resources Program	
Leasing Activities:	
Costs (Oil & Gas Depletion Expense)	$11,519,015,047
Less Earned Revenue	(11,760,876,728)
Net Cost/(Revenue) from Leasing Operations	(241,861,681)
Loss/(Gain) on Revaluation of Estimated Petroleum Royalties	(5,180,638,314)
Less: Revenue Designated for States - Non-Federal	813,161,249
Less: Loss on Sale of Future Royalty Rights	1,425,000
Net Cost/(Revenue) for Program	($4,607,913,746)

Statement of Net Cost – Other Federal Entities – Not Applicable (all on SCNP)

Statement of Changes in Net Position

Collecting Entity Statement of Changes in Net Position

Beginning Net Position	$0
Adjustment: Change in Accounting Principle	1,123,802,312
Beginning Balance, As Adjusted	1,123,802,312
Net Revenue for Program	4,607,913,746
Transfers In/(Out)	(4,553,702,996)
Ending Net Position	$1,178,013,062
	0

Other Federal Entities Statement of Changes in Net Position

Beginning Net Position	$0
Adjustment: Change in Accounting Principle	94,399,394,234
Beginning Balance, As Adjusted	94,399,394,234
Transfers In/(Out)	4,553,702,996
Ending Net Position	$98,953,097,230
	0

Disclosure Information

3. Please prepare a pro forma disclosure of rights to future royalty streams identified for sale in accordance with:

   a. the proposed standards;

Please Note: Key subject matter experts have indicated that this scenario is very highly unlikely. Because such extensive analysis and work was required to satisfy other aspects of the field study, this valuation and entry #10 were not revised from the original proposal in the ED. There is no disagreement with the proposed disclosure and accounting treatment. However, if the fair value method is selected, then valuation based upon the known quantities would be developed using that method.

Time and Expense Information

4. Describe the system changes that would be necessary to implement:

   a. the proposed standards;

- The ED currently only addresses the accounting treatment for oil and gas, and not other commodities. This means that there would be different accounting treatment and models required for oil and gas compared to solids and other commodities, as well as other activity currently classified as custodial. MMS strongly recommends that implementation be delayed until all commodities and related business activities are addressed.
- The Standard does not address the treatment of interest, either payable or receivable, whether related to oil and gas, or otherwise. However, it does rescind the provisions in existing Standards that provide for custodial accounting for royalty activity. This is significant, because currently interest related to royalty payments is treated as custodial. Clarification is needed to ascertain the Board's intent regarding other such business activities. Nonetheless, system changes will

ensue for differing accounting models related to these types of related financial events.

- Implementation will require revising all, or almost all of the existing accounting models in MRMSS; a significant effort and expense.
- Currently, MMS/MRM appropriately records royalty and related activity flowing through clearing account F3875. Amounts are received from the public and distributed to other federal entities. To capture and report on the capital asset and associated depletion expense, a new fund would be required, or an exception granted to report this activity, including equity, in the clearing account. While Treasury is in the midst of prohibiting or limiting use of the F3875 clearing account, a waiver request is in process for MRM royalty activity and Treasury has indicated that it will likely be granted. Historically, Treasury and OMB mandated that MRM use this clearing account for their royalty and related activity, and it is hard-coded throughout the MRMSS.
- Manual workarounds and journal vouchers can help mitigate some of the impacts, but not all of them.

Below are some key points, provided to illustrate more specifically how system issues pose significant implementation challenges for MMS/MRM.

- In MRMSS, a royalty report (2014) that contains multiple lines of royalty data creates just one receivable, with one standard custodial accounting model.
- The same custodial model is applied to all activity, regardless of its nature. For example, a bonus, a rental, an interest invoice and a royalty document all post to the same custodial accounting model.
- In the SCA, the amounts are aggregated into the ‘Rents and Royalties’ line, which includes virtually everything except for first year rents and bonuses on new onshore and offshore leases, and the value of commodity transferred to DOE to fill the SPR.
- Under the new Standard, the individual lines of royalty data, or individual transactions would give rise to different accounting models, depending on product code, transaction code and other criteria. They would also be reported separately in the Statements and require more detailed disclosures.
- For example, a rental amount, bonus amount or interest amount would receive a different accounting model from an oil and gas royalty amount, regardless if they were submitted on the same royalty document.
- This would need to be ascertained by the MRMSS upon receipt of the transaction, based upon the transaction code, product code, lease, etc., and recorded to the differing models as appropriate.
- Discussions with MRM subject matter experts indicate that the existing system is not capable of performing these types of up front breakouts, given the massive amount of data and current processing volume and time constraints.
- Extensive customization of the COTS software would be required to accomplish this.
- If no longer custodial, different SGL accounts would also be required for interest, either receivable or payable, and amounts aggregated and reported separately.

- Required disclosures include detailed breakouts, by commodity, for onshore and offshore.

The issues discussed above are not all-inclusive, but are presented to give an overview of the significant system related challenges inherent in implementing this Standard. Some issues can be mitigated with manual workarounds and journal vouchers. However, sophisticated reports would be required that would capture and report monthly on the detail needed to support the manual journals and the required disclosures.

One potential solution to mitigate the large expense and ongoing effort of converting accounting treatments is to continue overall custodial royalty accounting, simply capitalize the asset as custodial, and revalue it annually with the gain or loss on revaluation being recorded on the Statement of Custodial Activity. This could be done much more readily, would not require massive overhauls of current Bureau and system processes, and still accomplish the Board's objective to capitalize the oil & gas asset.

5. Estimate staff time and costs to complete the field test and to implement:

   a. the proposed standards;

Costs should include expenditures for system changes, consultants, and hardware and software acquisitions, and should **not** include a calculated value for staff time. Implementation estimates should distinguish between initial **implementation** and **ongoing** staff time and costs. All estimates should be **additional** time and cost incurred as a direct result of the proposed standards and the alternative view.

MMS obtained a fairly comprehensive estimate from the contract system integrator, which included an estimate if the Statement were delayed until all commodities were included, and if oil and gas were implemented before resolving all other commodities and business processes. Cost estimates of system changes, assuming simplistic changes to SGL accounts only, range from $5M if done for all commodities at once, to $7M if other commodities are implemented later.

Also, it is likely that at least one or possibly more additional FTE would be required to perform ongoing accounting and reconciliation functions, depending upon the resolution of issues discussed in this document.

6. How did you estimate the value of estimated petroleum royalties:

   a. based on the proposed standards;

Please refer to the detail provided in entries #1 and 11, above.

7. Describe any problems experienced valuing estimated petroleum royalties:

   a. using the proposed standards;
      i. How were they resolved?
      ii. How would you resolve them in actual implementation of the final Statement?

Please refer to the discussion provided with the requested entries above. Also:

Availability of EIA Data: The first step in obtaining quantity was to determine **what portion of all proved reserves fall under federal domain**, before the federal royalty share of those proved reserves could be estimated. **This information is presently not published by EIA,** so an estimation methodology had to be developed. **The MMS/OMM/BLM Team reached agreement on the estimation methodology described herein, and ascertained that in the absence of better information, this would be an acceptable method to use for implementation as well.** Please refer to entry #1 above, for more discussion.

Timing of EIA Published Data – Adjustment Factors: As developed by MMS OMM in the alternative view, there is an inherent problem with any method of booking the value of oil and gas reserves. The problem occurs because an estimate of proved reserves is a dynamic quantity as long as there is production from an area and continued development in the area. Proved reserves estimates are a "snapshot" of the oil and gas quantities as of a given date. For example, the FASAB Exposure Draft proposes to base its values on Energy Information Administration (EIA) estimates of proved reserves. For example, if the first such estimated value were to be booked at the start of fiscal year 2009 (October 1, 2008), the EIA reserve estimates available to calculate the value would be effective on December 31, 2006. This is a full 21 months prior to the effective date of the estimate of value.

This raises several concerns. **First, in the months that will transpire between the effective date of the reserves estimates and the effective date of the value estimate, the reserves estimate will have been reduced by any depletion of the reserves through production. Second, over the same time period, the reserves estimate will have been increased through any additions to reserves that naturally occur as accumulations are explored and developed.**

The decreases due to intermediate production and the increases due to new proved reserves additions that occur between the effective date of the reserve estimates and the effective date of the booked asset value represent true and measurable variations in the final proved reserves estimate that must be factored into the final asset value. The MMS proposes incorporating a factor for this variation in the final estimated quantity, such as has been developed by the MMS OMM subject matter experts and described in the OMM alternative view field test response.

This adjustment factor is not included in the current ED view, nor was it performed in the field study of the ED view, and highlights a significant issue requiring resolution before implementing any valuation methodology.

ED pp. 38, Published EIA Data: The FASAB Exposure Draft view proposes to base values on, "...the most recent survey conducted by the EIA, issued no more than twelve (12) months before the end of the reporting period..." However, if the first such estimated value were to be booked at the start of fiscal year 2009 (October 1, 2008), the EIA reserve estimates available to calculate the value would be effective on December 31, 2006. This is a full 21 months prior to the effective date of the estimate of value. Accordingly, we recommend the ED be worded to base valuation simply on the most recent survey available from EIA.

Obtaining, Classifying and Stratifying the Royalty Reported Data: Initially, it took quite a while to perform and re-perform numerous queries, and to reach agreement on the commodity 'buckets' to be included in the various 'royalty' categories. This was necessary to obtain royalty reported production data which could be compared to EIA estimated production data nationwide, to then compute the estimated proved reserves under federal domain. MRM has developed a statistical reporting tool which is structured around certain decisions related to the placement of each element of activity, and a fairly thorough understanding of those elements was necessary before data could be compared on the same footing with EIA data. Certain assumptions had to be made, such as excluding certain volumes for royalty relief and estimating values for the SPR. Also, it took time initially for CRB to perform the calculations by commodity and for onshore vs. offshore, of the federal domain estimated proved reserves, and to perform quality checks and validations of each formula and each step, as well as variance analysis. The BLM Team members had to suspend their portion of the onshore study until this data was available, which added to the length of time it took to complete the study. It should be noted that this is a time-consuming effort that will require refinement and if the ED view is implemented, will be laborious to complete and subject to a high degree of audit review. Adequate numbers of knowledgeable staff will be crucial and careful reviews and quality control will be key to success, because the slightest error could have material repercussions, and could impact all downstream recipients as well.

ED pp. 9 – 14; Calculating average prices and average rates. When the annual calculations are performed, the timing of available reported royalty data is such that a 2 month lag may exist from the month of production (the sales month) to the month of required royalty reporting. So for example, if calculating annual averages at September 30, the 12 month average based on "the preceding 12 months" would have to be computed on royalty reporting received for sales months July to June. In this example, if a paid estimate was in place for June production, royalty reporting could be deferred for 2 months from the month of production, and not be received until August – the month immediately preceding the month when calculations would be performed. **This is the method that was used for calculating asset value using the ED view.**

Accordingly, the text in these paragraphs (and elsewhere in the Statement) should provide for this by inserting, **"...that royalty data for corresponding production (sales) months is available..."**

For example, pp. #14. "The effective regional average royalty rate for gas is calculated by dividing the royalty value (royalties) earned on the dry gas reserves produced for each associated region for the preceding twelve (12) sales months that royalty data for corresponding production is available by the total sales value of that production for the preceding twelve (12) sales months that royalty data for corresponding production is available."

Calculations of Asset Value; Appendix C, Entry #1; We recommend that if using the ED view, the Statement and Appendices clarify that the major commodity categories in common between EIA and MMS be disaggregated, the averages computed separately, and then summed to derive the asset value. Please refer to the discussion in entry #1 above.

Wet Gas vs. Dry Gas – ED View:
Royalty information reported to MMS/MRM is reported as the commodity was sold or removed from the lease. This is important to note, as some assumptions had to be made in conducting the study of the ED view, and will exist at implementation. As regards wet vs. dry gas, MMS can only retrieve it as it was reported. Where reported and paid separately, dry gas had to be analyzed separately from wet gas, and NGL's were also analyzed separately, averages computed and the totals then summed, in order to derive a more accurate estimate.

Settlement Amounts: Each year, MMS receives payments as settlement on compliance or enforcement cases that are reported generically as custodial 'Rents and Royalties'. The settlement payments are generally matched to a royalty report that does not break out what portion may possibly be estimated to be related to commodity royalties, or interest, or civil penalties. The royalty report simply contains an amount with no product code, so can not be broken out. As a result, these amounts were excluded from the values used to compute the capital asset and from amounts used to compute depletion expense. This will more often than not, be correct, as the compliance 3-year cycle produces settlements generally related to prior periods, appropriately falling outside of the relevant periods for capitalizing or depleting. However, internal process would need to be changed to capture more detail in the event that royalty or other amounts were compliance amounts brought current. This highlights a potential pitfall in the ED view for valuation. Currently, performing a 12 sales month 'look back' of royalty reports would by definition exclude potentially large royalty amounts not captured at the degree of detail necessary to identify them.

Invoiced Amounts: Periodically, MMS receives royalty related payments against invoices that are reported generically as custodial 'Rents and Royalties'. The invoice does not provide for a product code or other detail related to the nature of the obligation, but simply contains an amount due with no product code, so can not be broken out further. As a result, these amounts were excluded from the values used to compute the capital asset and from amounts used to compute depletion expense. Internal system process would need to be changed to capture more detail in the event that royalty or other amounts were invoiced. This highlights a potential pitfall in the ED view for valuation. Currently, performing a 12 sales month 'look back' of royalty reports would by definition exclude potentially large royalty amounts not captured at the degree of detail necessary to identify them.

ED, pp. 23; Royalties and Depletion Expense on Statement of Net Cost (SNC):
Please refer to the extensive discussion in entry #6 above.

Paragraph 23 states,
"Royalties from the production of proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources shall be recognized as exchange revenue on the Statement of Net Cost by the component entity that is responsible for collecting the royalty revenue. At the same time, an amount equal to the royalty revenue shall be recognized as depletion expense on the Statement of Net Cost of the component entity that is responsible for collecting the royalty revenue; and, the value of estimated petroleum royalties shall be reduced by the depletion expense amount."

Appendix C, entry 6, page 54 states,
"Earned royalty revenue should be recognized as exchange revenue by the component entity that is responsible for collecting the royalties. At the same time, an amount equal to the royalty collections should be recognized as depletion expense; and, the value of estimated petroleum reserves should be reduced by the depletion expense amount. Sales value and royalty payment information are due on or before the last of the month following the month the oil or gas product from Federal oil and gas resources was sold or removed from the lease. For example, oil or gas sold in June must be reported by July 31, the end of the following month. For illustrative purposes, the total amount of royalty revenue earned for the fiscal year for offshore and onshore rental leases was used in this calculation."

In order to exclude adjustments to prior period reporting not attributable to depletion in the current year, and to exclude potentially unrelated estimates from the depletion calculations, t**he recommended method is to record depletion based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end; July through June (received through August, fully available in September). Revenue earned would not be a perfect match in the fiscal year, but in this case *it should not*, because depletion in the current year should not be linked to prior adjustments not related to the current year.** To do otherwise would *include* prior period adjustments not related to depletion in the year, and would involve complex and extensive inclusion of current year estimates that are potentially unrelated to depletion and also include prior period adjustments. **This method would likely yield a more accurate picture of current asset depletion over a year span. This method would also provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, onshore vs. offshore and other necessary details.**

8. Did any issues arise that should be included in the final Statement or a forthcoming Implementation Guide?

In addition to the issues presented and discussed above,

New Accounting Treatment, SGL Accounts and Accounting Models Required: In discussions with Treasury SGL experts, new Standard General Ledger (SGL) accounts, reciprocal pairs and posting models will need to be developed, approved, and incorporated into Treasury financial statement crosswalks. For example, some transfer pairs will involve transfers from a clearing to a special fund, some with and some without budget authority. Also, currently there is not a precedent for recording equity in a general fund or a clearing account. Treasury has indicated however, that it is their policy that until a FASAB Statement is finalized they do not develop or implement new sgl accounts, reciprocal pairs, or models. Accordingly, the final details of implementation remain to be developed. Until formal Treasury approved accounts and models are in place, MMS can not engage with the system contractor to build and modify the required accounts and models needed for implementation. Adequate time is requested for Statement implementation, to facilitate this significant and costly effort.

New Fund or Reporting Exception Required: Currently, MMS/MRM appropriately records royalty and related activity flowing through clearing account F3875. Amounts are received from the public and distributed to other federal entities. To capture and report on the capital asset and associated depletion expense, a new fund would be required, or an exception granted to report this activity, including equity, in the clearing account. While Treasury is in the midst of prohibiting or limiting use of the F3875 clearing account, a waiver request is in process for MRM royalty activity and Treasury has indicated that it will likely be granted. Historically, Treasury and OMB mandated that MRM use this clearing account for their royalty and related activity, and it is hard-coded throughout the MRMSS.

ED pp. 21, 23, 46, 47; Exchange revenue recognition based on SFFAS 7 pp. #34 and reported on SNC; Payments to States and Counties. Royalty payments are made to States and Counties through permanent indefinite appropriations, and reflect the budgetary authority both derived and expended based on actual receipts and disbursements. Payments to States and Counties are made from MMS's royalty clearing account F3875 into permanent indefinite appropriated funds, from which they are ultimately expended. Since MMS is the final entity to receive the cash before it leaves Government custody, it is recorded as a transfer to a special fund, where it is then treated as an obligation and outlay. Accordingly, the custodial transfer account shows the current trading partner, G.1417 (MMS), in accordance with specific FASAB guidance. These special funds are presently reported as 'earmarked'. There are unique and detailed implementation issues associated with ensuring the proper accounting for this activity, based upon the new proposed treatment in the ED. In discussions with Treasury SGL experts, at the least, a new transfer account reciprocal pair would need to be developed. They have indicated however, that it is their policy that until a FASAB Statement becomes finalized they do not develop or implement new sgl accounts, pairs, or models. Accordingly, the final details of implementation remain to be developed, and adequate time is requested for Statement implementation, to facilitate this effort.

ED pp. 21; Exchange revenue recognition based on SFFAS 7 pp. #34. The Statement proscribes that, "Revenue from exchange transactions should be recognized when goods or services are provided to the public or another Government entity at a price."

MMS/MRM records as revenue in the current period, both positive and negative amounts resulting from adjustments to prior royalty reporting, for sales (production) months other than just the current months. This is a routine business process in oil and gas industry reporting, resulting from numerous events where subsequent information is received related to previous reporting periods that was unknown when compulsory reporting was legally due, such as pipeline reallocations, revised gas plant statements, unit reallocations, and pricing revisions. The volume of these adjustments to prior period royalty reporting is significant, recurring, and may span multiple years. This practice is foundational to royalty reporting. We request that the Board consider clarifying related provisions in the ED accordingly.

Also, please refer to the additional discussion in entry #6 above.

ED pp. 46-47; Rescission of amendments to SFFAS 7 related to bonus bid, rent, and royalty revenues. The Statement does not address all commodities accounted for by MMS/MRM, such as solid minerals (and related interest). This creates a significant disparity in accounting treatment, and would result in the capitalization and depletion of only oil and gas, while other commodities would not be capitalized, yet would not be covered under any FASAB provisions. We are presuming that all commodities not covered under the ED would continue to be treated as custodial, according to established provisions in SFFAS 7, pp. 45, 275, 276, and 277. We request that the Statement clearly provide for these commodities, and allow current practices related to them to continue as custodial under existing guidance in SFFAS 7.

As mentioned above, the Statement does not address interest derived from royalty related activity, currently also treated as custodial. The interest component bears no relationship to depletion of the asset, but if related to oil or gas, guidance is needed regarding accounting treatment, to determine if it should still be treated as custodial or on the SNC.

It is strongly recommended that all other commodities and related business activity be addressed in this Oil & Gas Standard before implementation, due to the significant issues and costs related to differing treatment.

Long term vs. short term liabilities: The Exposure Draft and accompanying Appendix C do not break out or distinguish between long or short term liabilities, nor does the pro forma balance sheet present them separately, in relation to the nature of the offsetting assets. While it is understood that the Appendix C entries and statements are illustrative and not meant to present all associated detail, the break out and disclosure of long term vs. short term liabilities is a financial reporting requirement, and poses some issues around implementation. In order to comply with reporting requirements of OMB Circular A-136 and FASAB SFFAS 1, current liabilities must be reported separately from non-current (long term) liabilities.

Clearly, the royalty reports and cash received that remain unmatched at the end of a reporting period are current, as they are generally remitted on the legal due date, and payable in the subsequent month. We request that this be clarified in the Statement and Appendices. However for the new asset 'Estimated Petroleum Royalties', no mention is made that any portion of the associated liability might be short term or 'current'.

FASAB SFFAS 1, pp 83 states that, "Other current liabilities may include unpaid expenses that are accrued for the fiscal year for which the financial statements are prepared and are expected to be paid within the fiscal year following the reporting date." Further, pp. 86 requires, "The reporting entity should disclose the amount of current liabilities not covered by budgetary resources." And the Glossary defines current liabilities as, "Amounts owed by a federal entity for which the financial statements are prepared, and which need to be paid within the fiscal year following the reporting date."

For the liability related to 'Estimated Petroleum Royalties', some amount will be liquidated and transferred to recipients in the subsequent year, and should therefore be reported as current.

The entries demonstrated in Appendix C for the recipient 'Other Federal Component Entity' would likewise be affected. We request this be discussed in the Standard and associated Appendices.

The methodology for computing what this current portion might be is subject to debate, but must at least be fairly readily computed, in order to meet short timelines for annual financial statement preparation. It could be based upon the same value reported as depletion expense in the current year. This would be perhaps the best method, as the value would already be computed, reconciled, and audited, and would be most representative of current market conditions that could be expected to occur in the immediately subsequent year.

However, its complexity is greatly increased if it must only relate to oil and gas, as the current ED only includes oil & gas.

If, FASAB determines that the liability related to 'Estimated Petroleum Royalties' should be all classified as long-term (non-current), we request that the Statement clarify this point for implementation.

ED pp. 34; Fiduciary Reporting Requirements:
Currently, EIA does not publish numbers related to proved reserves on Indian lands. Further, MMS only receives a small portion of royalties related to Indian leases, which

are distributed to OST for subsequent funds management and distribution to Tribes. Accordingly, there is presently not a means for MMS to know how to estimate an asset value, nor how to present estimated depletion. While estimates could always be developed, the validity of the data could later be proved to be incorrect, and would be a very broad estimate at best.

Potential Impacts to BLM Accounting and Custodial Statement: BLM receives some royalty amounts that are transmitted 2 or 3 times per month to MMS/MRM, where they are then matched to the lease and distributed according to lease terms. The BLM receipts and distributions to MMS are captured as custodial activity and reported on the Statement of Custodial Activity (SCA). For purposes of the Statement, we do not currently think this would pose a problem, as MMS would still be the 'collecting entity' who bears the responsibility for reporting on the satisfaction of the lease obligation and would record the depletion expense. BLM also receives 'Rights of Way' payments on leases for which the Bureau of Reclamation, the General Fund of the Treasury and States are designated recipients. These payments do not relate to commodity depletion, nor do they flow through MMS at any time. They are also recorded on the SCA. At this time, it does not appear that the Statement would impact this activity, or result in the elimination of the BLM SCA. However, we ask that the Board consider this when finalizing the Statement.

ED pp. 31 d, Component Entity Disclosures: As discussed previously in this document, earned revenue includes numerous components including estimates, which can not be readily broken out into categories such as onshore vs. offshore, etc. We request that the Statement clarify the disclosure requirement, such that the disclosure relate specifically to the royalty data linked with depletion expense, and indicate that it is not all-inclusive of total revenue recorded in the financial statements for the period.

ED pp. 32 a & c, Component Entity Required Supplementary Information (RSI): The information required to be provided in the ED is not available, and so **could not be provided by the MMS. This is information that can only be gathered and provided by the EIA.** As discussed in the valuation process above, MMS had to obtain EIA nationwide data and develop a rough estimation methodology to attempt to arrive at an estimate of the estimated proved reserves under federal domain. The additional information required in the ED for RSI disclosure, such as federal domain technically recoverable resources, onshore and offshore, and historical 10-year information on federal domain estimated proved reserves could only be provided by EIA. If the Board intends that estimated calculations be produced, we request that be clarified. However, such things as net revisions, extensions, new field discoveries, etc. could not be reasonably ascertained.

Field Test Questionnaire
Green highlighting marks the differences between this field test response and the ED View field test response.

Accounting for Federal Oil and Gas Resources
Present Value (PV) Method

This field test is intended to assist the Board to:

- Gather information on the effects the valuation methodology proposed in the ED would have on financial statements versus the valuation methodology presented in the Alternative View.
- Discover issues preparers might have in applying each methodology.
- Discover material for a possible Implementation Guide.

Organization Name	Minerals Management Service (MMS)
Contact Name	Kelly West, Chief MMS Custodial Reporting Branch (CRB)
Contact Telephone Number	303-231-3035
Contact E-mail Address	kelly.west@mms.gov

The **Present Value (PV)** method discussed below is the result of a collaborative Team effort. The Team was formed to participate in the FASAB field study and to provide expertise and insight into potential alternative methods of valuing estimated proved reserves under federal domain. The Team was comprised of MMS Offshore Minerals Management (OMM) Economics and Resource Evaluation experts and Petroleum Engineers, Bureau of Land Management (BLM) Petroleum Engineers and Resource Evaluation experts, and MMS Custodial Reporting Branch (CRB) Senior Accountants with expertise in financial reporting. While numerous members participated and provided input, the following are key contacts from each area:

Thomas Farndon
Petroleum Engineer
MMS, OMM, Economics Division
703-787-1502

William Gewecke
Senior Petroleum Engineer
BLM, Inspection and Enforcement
202-452-0337

Kelly West
Chief, MMS CRB
303-231-3035

Pro Forma Transactions

1. Please prepare pro forma transactions in accordance with:

   b. the alternative view presented in paragraphs 114 through 127 of the Basis for Conclusions of the ED for the following accounting events:

      i. recording the initial value of the estimated petroleum royalties;
      ii. recording the one-fifth bid amounts;
      iii. recording the remaining payment by the successful bidder and the annual rental fee and the related liability for revenue distributions to others;
      iv. recording the annual rental fee from pre-existing leases and the related liability for revenue distributions to others;
      v. refunding the unsuccessful bidders' bonus bid deposits;
      vi. recording earned royalty revenue and depletion expense;
      vii. recording the collection of royalty revenue;
      viii. recording the distribution of bonus bid, rent, and royalty collections and the reduction in the liability for the revenue distributed to others;
      ix. recording the sale of future royalty streams identified for sale and the related change in the liability for revenue distributions to others; and,
      x. recording the annual valuation of estimated petroleum royalties and the related change in the liability for revenue distributions to others.

The following pro forma transactions are compressed, simplified, **and reflect only the transactions presented in the Exposure Draft (ED), using the 'Present Value Method' (PV Method)**. They appropriately do not contain all of the detail associated with an event. For example, in transaction number two, the one-fifth bonus is invested until leases are accepted. Any interest accrued is refunded on bids subsequently rejected and returned. The illustration omits transactions internal to the entity. Transfers between sub-component entities are omitted.

Readers should not rely on the pro forma accounting transactions and resulting financial statements as a complete model for agency accounting. **Certain omitted entries may be required in actual practice** but are omitted since they are not required to understand the effect of the proposal on agency financial statements. **Additional nominal account entries would be made by the collecting entity, to track and report on greater detail than is presented in the ED. Also, a greater degree of detail and certain reclassifications would occur in practice, because the asset 'estimated petroleum royalties' would give rise to a long term receivable, while royalty reports and undisbursed cash are current assets.**

At the beginning of the fiscal year for which the accounting standards for oil and gas resources are effective, the following transaction is recorded by the component entity responsible for collecting royalties.

1. Record initial value of estimated petroleum royalties and the related liability for revenue distributions to others.

The initial value of estimated petroleum royalties used in this pro forma transaction is calculated for illustrative purposes only. The value of the Federal government's estimated petroleum royalties was calculated based on the PV method developed by the Team, and described in Question #6 below.

The initial value of estimated petroleum royalties is a hypothetical number used for illustrative purposes only. The hypothetical initial value of estimated petroleum royalties based on the PV methodology described below for offshore is $41,840,410,000, and for onshore is $23,088,640,000, for a total of **$64,929,050,000**. The illustrative pro forma transaction to record the initial value of the Federal government's estimated petroleum royalties and related liability is presented below. The asset's value represents the estimated [ED View states "effective average"] royalty share of the Federal oil and gas resources classified as "proved reserves." The related liability represents the estimated [ED View states "effective average"] royalty share of the Federal oil and gas resources classified as "proved reserves" designated to be distributed to others, i.e., the states, the general fund of the U.S. Treasury and other Federal component entities, **not** including the component entity responsible for collecting royalties. The proposed treatment of distribution of revenue to others creates a Federal and a non-Federal liability for the component entity responsible for collecting royalties.

The cumulative effect of adopting this accounting standard would be reported as a "change in accounting principle" in accordance with SFFAS 21, *Reporting Corrections of Errors and Changes in Accounting Principles*. The adjustment would be made to the beginning net position on the component entity responsible for collecting royalties Statement of Changes in Net Position for the period the change is made **and the other Federal component entities for their allocable share of the related asset**. To obtain the value of the adjustment, the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the component entity responsible for collecting royalties. For this illustration, one percent was used as the average annual share of the revenue distributed to the component entity responsible for collecting royalties based on the average distribution for 2005.[1] To record the related liabilities the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the states. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[2] For this illustration, 84 percent was used as an average annual share of the

[1] The one percent was derived by dividing [Note 21. Custodial Distributions to MMS, Revenues to Fund Operations] by [Total Revenue on the Statement of Custodial Activity] for 2005.

[2] The 15 percent was derived by dividing [Note 21. Payments to States] by [Total Revenue on the Statement of Custodial Activity] for 2005.

revenue distributed to other Federal component entities based on the average distribution for 2005.[3] These calculations are presented below:

$ 64,929,050,000 X .01 = $ 649,290,500

$ 64,929,050,000 X .84 = $54,540,402,000

$ 64,929,050,000 X .15 = $ 9,739,357,000

Dr Estimated Petroleum Royalties	64,929,050,000	
Cr Prior Period Adjustment: Change In Accounting Principle		649,290,500
Cr Liability for Revenue Distribution to Others-Federal		54,540,402,000
Cr Liability for Revenue Distribution to States-Non-Federal		9,739,357,000

To record initial value of estimated petroleum royalties due to change in accounting principle, the related liabilities to state and local governments, and the related liabilities to other Federal component entities. (The 1% expected to be retained by the entity responsible for making royalty collections increases its net position.)

Other Federal component entity entry:

For component entities, amounts must be recognized in a manner that supports elimination of Federal assets and liabilities and flow amounts. Therefore, the receiving Federal component entities would be required to book the asset related to their respective interest in the estimated petroleum royalties.

Dr Long-Term A/R for Oil and Gas-Federal	54,540,402,000	
Cr Prior Period Adjustment: Change In Accounting Principle		54,540,402,000

To book the asset by other Federal entities for their respective interest in the estimated petroleum royalties.

It must be noted that currently when recording the corresponding liabilities for end of period assets, MMS employs an agreed-upon procedure whereby we estimate the percentages allocable to our three largest recipients; U.S. Treasury, Reclamation Fund and the States. In the proposed ED models, due to the magnitude of the asset value, even the estimated 1% that MMS receives in annual appropriations becomes material. This creates a situation where each recipient will require a liability entry based on some estimation method, and each designated federal recipient will be required to record a corresponding receivable and transfer in their statements, with eliminations between entities to prevent double counting government wide. You will see later in the text that any adjustment made to the asset results in an effect upon the recipient which will require an entry. **This becomes especially critical at quarter ends and at fiscal year**

[3] The 84 percent was derived by dividing [Transfers-out to other Federal component entities on the Statement of Custodial Activity] by [Total Revenue on the Statement of Custodial Activity] for 2005.

end, where late adjustments required to accruals that are deemed related to oil and gas revenue (and hence, depletion) will also require late adjustments by all downstream recipients, thus significantly hampering entities ability to meet accelerated financial reporting due dates and potentially giving rise to audit findings.

2. Record payment of the one-fifth bonus bid amounts.

For a competitive lease sale, a notice of lease sale is published in the *Federal Register.* Each lease bid must include a payment for one-fifth of the bonus bid amount unless the bidder is otherwise directed by the Secretary. For purposes of this illustrative accounting event, four bonus bids were received with payment of the one-fifth bonus bid amount. Bonus bid number one was $1,850,000, bonus bid number two was $1,900,000, bonus bid number three was $1,950,000, and bonus number four was $2,000,000. The total payment relating to the four bonus bids was $1,540,000 (bonus bid number one for $370,000, bonus bid number two for $380,000, bonus bid number three for $390,000, and bonus bid number four for $400,000) and was recorded with the following entry by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	1,540,000	
Cr Unearned Revenue		1,540,000

To record collection of the one-fifth bonus bids for the four bonus bids.

3. Record remaining payment by the successful bidder and the annual rental fee and the related liability for revenue distributions to others.

Payment of the unpaid balance of the bonus bid amount and the first year's rental fee are to be received from the successful bidder on the 11th business day after receipt of the lease forms by the successful bidder. The successful bid was bonus bid number four in the amount of $2,000,000. The remaining four-fifths bonus bid of $1,600,000 and the first year rental fee in the amount of $360,000 is received. According to various legislative requirements, rental fees are required to be paid one year in advance and are recorded as revenue from rent when received because there is no obligation to refund unearned portions. The following entries are recorded by the component entity responsible for collecting royalties.

Dr Unearned Revenue	400,000	
Dr Fund Balance with Treasury (1,600,000+360,000)	1,960,000	
Cr Revenue from Rent		360,000
Cr Revenue from Bonus Bid		

To record remaining bonus payment and the annual rental fee by the successful bidder, and associated liability and nominal accounts, less MMS 1% (23,600).

The related increase in the liability for the future revenue distributions to others from the rent and the bonus bid is calculated in two parts. One part is based on revenue designated as payments to the States. The other part is based on designated transfers-out to other Federal component entities. The revenue from rent and bonus bid is multiplied by the average share of the revenue distributed to the States to obtain the value of the rent and bonus bid revenue to be distributed to the States. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005. The revenue from rent and bonus bid is multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent and bonus bid revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other component entities based on the average distribution for 2005. These calculations are presented below:

$$\$2,360,000 \text{ X } .15 = \$354,000$$

$$\$2,360,000 \text{ X } .84 = \$1,982,400$$

Dr Revenue Designated for Others – States – Non-Federal [4]	354,000	
Dr Transfers-Out	1,982,400	
Cr Liability for Revenue Distribution to Others-Federal		1,982,400
Cr Liability for Revenue Distribution to States-Non-Federal		354,000

To record the related increase in the liability for the future revenue distributions to others.

<u>*Other Federal component entity entry:*</u>

Dr Accounts Receivable	1,982,400	
Cr Transfer-In		1,982,400

To record the related accrual of a transfer-in and a reduction in the long-term A/R.

4. Receive the annual rental fee from pre-existing leases and record the related liability for revenue distributions to others.

For illustrative purposes, the total amount of annual rent collected for the year for offshore leases was $193,273,613 and the rental fee for onshore leases was $46,588,068 for a total of $239,861,681. Since $360,000 was received in connection with the new lease, the rental payments remaining are $239,501,681 ($239,861,681 less $360,000). The following entry is recorded by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	239,501,681	
Cr Revenue from Rent		239,501,681

[4] This and certain other titles were selected for illustrative purposes. The entity has the option of selecting another account title that may be more appropriate.

To record rental payments on leases for the year.

The related increase in the liability for the future rent revenue to be distributed to others is calculated in two parts. One part is based on revenue designated as payments to the States. The other part is based on designated transfers-out to other Federal component entities. The revenue from rent is multiplied by the average share of the revenue distributed to the States to obtain the value of the rent revenue to be distributed to the States. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005. The revenue from rent is multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005. These calculations are presented below:

$239,501,681 X .15 = $35,925,252

239,501,681 X .84 = $201,181,412

Dr Revenue Designated for Others – States – Non-Federal	35,925,252	
Dr Transfers-Out	201,181,412	
Cr Liability for Revenue Distribution to Others-Federal		201,181,412
Cr Liability for Revenue Distribution to States-Non-Federal		35,925,252

To record the related increase in the liability for the future revenue distributions to others.

<u>*Other Federal component entity entry:*</u>

Dr Accounts Receivable	201,181,412	
Cr Transfer-In		201,181,412

To record the related accrual of a transfer-in and a reduction in the long-term A/R.

5. Refund unsuccessful bidders' bonus bid deposits.

Bonus bid deposits submitted by unsuccessful bidders are refunded to respective bidders after bids are opened, recorded, and ranked. Bonus bid #1 in the amount of $370,000, bonus bid #2 in the amount of $380,000, and bonus bid #3 in the amount of $390,000 for a total of $1,140,000 are returned to respective bidders. The following entry is recorded by the component entity responsible for collecting royalties.

Dr Unearned Revenue	1,140,000	
Cr Fund Balance with Treasury		1,140,000

To record refund of losing bonus bids.

The remaining pro-forma transactions and financial statements are presented as of the end of the Federal government's fiscal year (FY).

6. Record earned royalty revenue and depletion expense.

The ED states that, *"Earned royalty revenue should be recognized as exchange revenue by the component entity that is responsible for collecting the royalties. At the same time, an amount equal to the royalty collections should be recognized as depletion expense; and, the value of estimated petroleum reserves should be reduced by the depletion expense amount. Sales value and royalty payment information are due on or before the last of the month following the month the oil or gas product from Federal oil and gas resources was sold or removed from the lease. For example, oil or gas sold in June must be reported by July 31, the end of the following month."*

There are extensive issues discussed below around the many components of revenue recognized by the collecting entity, the relationship of that revenue to depletion expense, and the present or future ability to obtain information at the level of detail presented in the ED. This is a significant set of issues that we believe must be addressed before the ED is finalized.

The ED proposes to base depletion expense upon oil & gas 'royalty revenue earned' for the fiscal year (pp. 23, and Appendix C, entry #6), and is silent regarding what components would comprise this value, except that pp. 23 refers to 'royalties from the production' of proved reserves. This introduces many complexities, including whether or how to include estimates such as the 'royalty accrual' (discussed below), and **the relationship between revenue recorded in the current fiscal year for royalty reporting adjustments made to prior years and current year depletion expense**.

Revenue earned by the collecting entity generally consists of amounts reported or billed, cash for which no royalty report has been received (unmatched cash), and amounts accrued as estimates. There is not a simple means at this time to obtain detail which reconciles to the general ledger and financial statements, of all components of earned revenue specifically related to oil and gas and more specifically related to offshore vs. onshore leases.

Earned Revenue Based Upon Royalty Reports; Royalty Adjustments to Prior Periods:

In addition to current royalty amounts, MMS records earned revenue in the current period for the sum of both positive and negative amounts resulting from upward or downward adjustments to prior royalty reporting, related to previous months when the commodity had been either sold or removed from the lease **(sales months).** This is a standard business process in oil and gas industry reporting, resulting from the receipt of subsequent information related to previous reporting periods that was unknown when the compulsory reporting was legally due, such as revised pipeline statements. These adjustments frequently cross monthly, quarterly, and fiscal year boundaries, can be large amounts, and are routine.

If depletion expense is linked across the board with overall revenue earned in the current year, then it must be understood that it would be at least partially based on revenue earned in the current year that is related to adjustments to prior periods falling outside the fiscal year. Therefore, the asset would be depleted in the current year based upon activity that does not actually reflect true depletion in the actual year.

If depletion expense were alternatively based upon revenue earned for oil & gas royalty reports related to current year production only, to most closely reflect the actual asset depletion in the current year, it would be applicable to only the **sales months** falling within the fiscal year. This would exclude prior period adjustments to royalty reporting that would be deemed unrelated to depletion in the current year.

However, complete royalty reporting covering production in the current fiscal year measured at 9/30 can only be ascertained through August, which covers actual reported royalty production through June (for which delayed reporting would not be due until August if a paid estimate were in place). In other words, only 9 months of complete sales month (production) data within a given fiscal year are available at 9/30 if basing ‘revenue earned’ and depletion expense only on current fiscal year sales months; October through June. Clearly, this would not present a complete picture of current year asset depletion, because it would not even include a full 12 months of royalty reporting.

Recommended Depletion Method:

The recommended alternative is to record depletion based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end; July through June (received through August, fully available in September). This would preclude the need to include estimates in the depletion calculations (discussed below), and would represent a realistic value of true asset depletion based on actual royalty reporting. **Revenue earned would not be a perfect match in the fiscal year, but in this case *it should not*, because depletion in the current year should not be linked to prior adjustments not related to the current year.** To do otherwise would *include* prior period adjustments not related to depletion in the year, and would involve complex and extensive inclusion of current year estimates that also include prior period adjustments. **This method would likely yield a more accurate picture of current asset depletion over a year span. This method would also provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, onshore vs. offshore and other necessary details.**

Another alternative would be to record depletion based solely upon all royalty lines received and accepted during the fiscal year, excluding all accruals and regardless of sales month. Again, revenue earned would not be a perfect match in the fiscal year, because accruals would be excluded. But including all lines accepted in a year would eliminate the need to include complex and extensive current year-end estimates for which disclosure detail is not available (see discussion below) because actuals over a 12 month span would be fully included. This method would, however, include all adjustments to prior reporting received in the current fiscal year, and while it may provide a closer tie to actual revenue reported in the financial statements, it would not be as fair a measure of asset depletion in the year. This method, like the recommended method above, would provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, and other necessary details.

Earned Revenue; Document Level Royalty Reporting Accruals vs. Line Level Royalty Detail:
When a royalty document is received, it usually includes numerous individual 'lines' of reporting. Each line contains specific detail about the royalty, such as the individual lease number, sales month and product code. If even one line of the royalty document passes edits and accepts in the royalty accounting system (MRMSS), then revenue is recorded for the full 'document calculated total'. If all lines reject, then a manual accrual is made for the full 'document calculated total'. Priority is placed on clearing rejected lines as quickly as possible, generally in the month following receipt. In subsequent periods, as the previously rejected royalty lines are corrected and accept in the MRMSS, they do not give rise to revenue, as it was already properly accrued when the document was first received.

As you can see, the detail required in the ED for 'earned revenue' by oil or gas and onshore vs. offshore is not readily obtainable for this portion of the population (rejected lines in the last month of the year). For purposes of the field study, CRB undertook an initial effort to ascertain in a 1-month period, the detail related to line level royalty revenue earned by oil or gas and onshore vs. offshore. In instances where the doc calc total giving rise to revenue in the period did not equal the sum of the accepted lines in the system, CRB developed a method to allocate (estimate) earned revenue to detail associated with existing lines. **This identified a significant problem in our ability to report accurately on the detail associated with 'earned revenue' based on current month royalty reporting. In many cases, the revenue was allocated to oil or gas based upon an estimate that may or may not be correct, and which may not prove to be correct in subsequent periods when the rejected lines are corrected and accept in the system. This issue further supports the premise that depletion be based solely upon accepted royalty reporting lines for given sales months, as presented above, and not on accruals and estimates.**

Earned Revenue; Estimates and Manual Accruals: When examining 'earned revenue' and its relationship to asset depletion, CRB performed an extensive analysis for the field study, of estimates and manual accruals related to current period royalty revenue.

MMS records numerous manual accruals to fairly present assets, liabilities and revenue in the financial statements. One such entry is the 'royalty accrual', a large accrual that represents estimated production in the current month for oil, gas and solid minerals, where the royalty reports are not yet received. The royalty accrual is not computed based on sales month (production month), but rather upon when the royalty report was received. It is computed based on a 12-month average of previous royalty reports received. Revenue recognition for royalty is consistent therefore, because **prior period adjustments to previous royalty reporting are treated as current year revenue, upward or downward, and factored into the current period royalty accrual. The royalty accrual is subject to extensive year-end audit review, and a large subsequent adjustment may be required annually, later in the financial reporting process (early November). If included in the revenue matched with depletion expense, this would also then, require that the proved reserves asset be adjusted accordingly, and would impact materially, all allocated downstream recipients as well.**

The royalty accrual is required to be performed fairly quickly, at the high level, to meet accelerated financial reporting objectives. **It includes adjustments to prior reporting periods, and it does not contain the detail required in the ED, to break out oil vs. gas and onshore vs. offshore.** A rough estimation method could always be developed, but its accuracy and validity when compared to subsequent actual information could potentially prove to be incorrect.

Another significant manual accrual involves **unmatched cash** for which no royalty report has been received at the end of the reporting period. This occurs monthly, and this large unmatched cash balance can not accurately be linked to oil or gas, onshore or offshore. In some instances, large compliance settlement amounts may be included in the cash balance, not related to current year royalties. Large amounts could be related to interest payments. It would be incorrect to allocate current year depletion to unmatched amounts that may not be related. **Also, this unmatched cash, when applied to subsequent royalty reports, will likely relate to adjustments to prior reporting, and also not bear a relationship to current year asset depletion.**

Previous discussions with FASAB Staff indicated that in order to provide matching of royalty revenue earned in the fiscal year, the royalty accrual would be included in the 'revenue earned' that would be offset by depletion expense, because the accrual estimates production in the current month for which royalty reports will not be yet be received. Also, it was discussed that revenue recognition overall should remain consistent, and that revenue earned in the fiscal year, regardless of sales (production) month and subsequent adjustments, would still apply. Accordingly, the text in pp. #23 and throughout the Statement was going to be revised to include, "Royalties received and accrued..."

However, upon analysis **as a result of the field test study,** it is apparent that the degree of detail required to be estimated, allocated and reported is very extensive, labor intensive, **includes adjustments to prior period reporting which may not relate to current period asset depletion at all,** and **poses significant risks to meeting audit and accelerated financial reporting objectives.** Again, including these and other estimates, by default, **includes adjustments to prior reporting, or other activity not**

necessarily related to actual current period asset depletion. The degree of detail for disclosure required in the ED would not be readily available from these estimates, and would have to be extensively estimated. And the inclusion of these estimates would likely not yield a better, and perhaps a worse, measure of actual asset depletion in the year, as opposed to the recommended sales month method described above. For the many complex accruals currently performed by MMS, estimation methods would have to be developed to allocate some portion of the earned revenue to oil and gas, and then of that subset, to onshore vs. offshore.

For purposes of this field test study, revenue overall is presented in aggregate, includes estimates and is based upon royalty reporting lines received and accepted in the fiscal year, regardless of sales months, to tie with current practices. This is done to illustrate the many estimates performed, their relationship to earned revenue, and to explain why the detail required in the ED can not currently be provided. However, it is <u>not the recommended method</u> for deriving depletion expense. Also, disclosures were not attempted.

As we have discussed, estimations pose significant challenges to MMS' ability to produce adequate detail in the required disclosures regarding revenue earned by oil and gas and onshore vs. offshore categories. **It currently could not be readily done with existing resources or information.** Each line of each component of earned revenue would have to be carefully analyzed, an allocation method developed for oil and gas and onshore vs. offshore, and would be an extensive and labor intensive process. A sophisticated system report and queries could be developed to help provide some of this degree of detail, but it would not resolve issues around allocations of estimates, and **timing would be crucial, as reconciliations and adjusting entries would need to be made quickly, to meet accelerated financial reporting deadlines, and to pass audit requirements.**

The matrix below presents some of the key components of 'earned royalty revenue' presently recorded by MMS, and demonstrates how the earned royalty revenue value was estimated for the illustrative pro forma entries. It must be noted that in actual practice, the previous year-end estimate would be reversed in the subsequent year, so that actual revenue recorded in any given year related to estimates would essentially reflect the **change** associated with those estimates over the year. In this example, for the study, the full values were presented, to give the reader a general idea of the relative sizes of the estimates under discussion.

Again, the primary concerns related to recording depletion expense based on revenue which includes estimates revolve around mismatching unrelated portions of estimates with actual asset depletion, potential material audit findings and a potential inability to meet accelerated financial reporting objectives.

As an aside, if using the recommended sales month method described above for ascertaining the amount of depletion to record in a fiscal year, then the actual royalty value for oil and gas reported to MMS was approximately **$9.2** billion for the most recent sales months available when performing the field test, June 2006 through May 2007, obtained in mid-August 2007.

Analysis of Components - Oil & Gas Revenue Earned - Entry #6, FASAB ED

Amounts are representational and illustrative only, to present basic concepts, and are not necessarily based on final or actual numbers

Total Royalty Report Line Level Data Received in Period (Royalty Value Less Allowances - RVLA)	**10,731,532,649**
Royalty line amounts that do not give rise to revenue by collecting entity in period	
Document calculated total equals zero (non-value related adjustments)	246,825,251
No system receivable created, such as for Indian direct pay or Strategic Petroleum Reserve (SPR)	789,559,441
Royalty documents accepted in prior periods where previously rejected lines now accept	17,170,452
Total Royalty Line Amounts That Do Not Give Rise to Revenue by Collecting Entity in Period	**1,053,555,144**
Revenue From Royalty Lines - Other (Currently Reported in 'Rents and Royalties')	**5,333,009**
Remainder - Royalty Lines Giving Rise to Revenue Received in Fiscal Year, Attributable to Oil & Gas	**9,672,644,496**
Accrued Revenue and Estimates - O&G (Illustrative Ending Balances Only - Revenue would be recorded for change in accruals)	
Estimated Portion of Year-End Royalty Accrual Estimating Current Month Production, Oil & Gas	760,179,551
Year-End SPR Accrual Estimating Current Month Production Delivered to DOE, Oil Only	105,216,449
Annual Actual Revenue for Oil Taken In Kind to Fill Strategic Petroleum Reserve (SPR)	200,974,551
Other Invoices In Lieu of Royalty Reports Presumed to be Related to Oil and Gas Royalties	30,000,000
Estimated Royalty Portion of Enforcement Settlements if Related to Current Year - Oil & Gas	50,000,000
Estimated Portion of Numerous Other Revenue Accruals Estimated Allocated to Oil & Gas	200,000,000
Estimated Portion of Unmatched Cash Revenue - No Royalty Report – Allocated to Oil & Gas	500,000,000
Total of Accrued Revenue and Estimates To Be Estimated Allocated to Oil and Gas	**1,846,370,551**
Total Estimated Royalty Related Revenue and Depletion Expense, Oil & Gas, Fiscal Year 20XX	**11,519,015,047**
Other Revenue - Non-CY Oil & Gas Royalty	
Revenue from Onshore lease sale bonus and 1st year rents (does not tie to pro forma entries – informational only)	286,344,000
Revenue from Offshore lease sale bonus and 1st year rents (does not tie to pro forma entries – informational only)	387,689,000
Revenue from PY Settlements including Civil Penalties and Interest (Currently reported in 'Rents and Royalties')	80,000,000
Revenue from Royalties - Other Commodities i.e. Solid Minerals (Currently reported in 'Rents and Royalties')	615,752,400
Revenue from Late Payment Interest (Currently reported in 'Rents and Royalties')	60,000,000
Other Commodity Related Miscellaneous Revenue Including Compliance (Currently reported in 'Rents and Royalties')	12,000,000
Total Other Revenue - Non-CY Oil & Gas Royalty	**1,441,785,400**
Total Revenue Reported on Fiscal Year 20XX Statement of Custodial Activity	**12,960,800,447**

To restate, some of the key concerns around recording depletion expense based upon the sum of current year royalty reports and estimates include:

- Revenue and depletion expense would be mismatched due to prior period adjustments not related to current period depletion captured as revenue in the current year.
- The revenue estimate including accruals would also include estimates of production anticipated through year-end, and estimates of unmatched cash with estimates sub-allocated to oil & gas, and then sub-allocated to onshore vs. offshore. The estimated allocations will likely be later found to be incorrect. Also, the estimates include adjustments to prior periods, not attributable to depletion in the current period.
- Each estimate is already complex to derive, and currently does not include a method for allocating to oil or gas, or onshore vs. offshore.
- Revising each estimate accordingly will decrease the likelihood of meeting accelerated financial reporting objectives, and will increase the likelihood of audit failures, and their severity based on materiality.
- Estimates and subsequent changes to estimates will impact the asset value through depletion expense, and so, all designated downstream recipients.
- Estimates measured against subsequent actuals at fiscal year end will likely result in material adjustments near the close of the annual financial audit process in early November, and also require adjustment by designated downstream recipients.

For illustrative purposes, the hypothetical numbers previously discussed are presented. The **estimated** royalty revenue **earned and accrued** for the fiscal year for offshore and onshore rental leases **estimated allocated to oil and gas only** was used in this calculation. The **estimated** royalty revenue **earned and accrued** during the fiscal year for offshore **and onshore** leases was roughly estimated to be **$11,519,015,047**.

The following entries are recorded by the component entity responsible for collecting royalties.

Dr Accounts Receivable (Billed and Unbilled Accrued)	11,519,015,047	
Cr Revenue from Royalties for Federal Oil and Gas Reserves		11,519,015,047

To record earned royalty revenue.

Dr Oil and Gas Depletion Expense	11,519,015,047	
Cr Estimated Petroleum Royalties		11,519,015,047

To record depletion expense for Federal oil and gas resources.

7. Record collection of royalty revenue.

Royalty payments are due on or before the last of the month following the month the oil or gas product from Federal oil and gas resources are sold or removed from the lease, unless lease terms state that royalties are due otherwise. A year-to-date total estimate of royalty revenue collected is in the amount of $10,048,231,734. The following entry is recorded by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	10,048,231,734	
Cr Accounts Receivable		10,048,231,734

To record collection of royalty revenue.

8. Record distribution of bonus bid, rent, and royalty collections and the reduction in the liability for the revenue distributed to others.

The component entity responsible for collecting royalty revenue is required to distribute the bonus bid, rent, and royalty revenue in accordance with authoritative formulas <u>to recipients designated by law upon matching the revenue collections to specific leases</u>. The component entity distributing bonus bid, rent, and royalty revenue from Federal oil and gas resources should recognize the distribution to component entities in accordance with existing accounting standards. The Federal component entity receiving the distribution should recognize the receipt as a transfer in when calculating its operating results. For purposes of this illustrative accounting event, the bonus bid collected was $2,000,000, the rent collected was $239,861,681 and the royalties collected was $10,048,231,734 for total collections of $10,290,093,415.

The bonus bid, rent, and royalty revenue collections to be distributed and the related reduction in the liability for revenue distribution to others is calculated in two parts. One part is based on revenue collections designated as payments to the States. The other part is based on collections designated as payments to other Federal component entities. The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to the States to obtain the value of the collections to be distributed to the States. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005. The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005. These calculations are presented below:

$10,290,093,415 X .15 = $1,543,514,012

$10,290,093,415 X .84 = $8,643,678,469

Dr Liability for Revenue Distribution to Others-Federal	8,643,678,469	

Dr Liability for Revenue Distribution to States-Non-Federal	1,543,514,012	
Cr Fund Balance with Treasury		10,187,192,481

To record distribution of bonus bid, rent, and royalty revenue collections and the reduction in liabilities for revenue distribution to others.

Other Federal entity entry:

Dr Fund Balance with Treasury	8,643,678,469	
Cr Accounts Receivable		8,643,678,469

To increase the fund balance with treasury and reduce the accounts receivable in relation to distributions received.

Please Note: The illustrative entry above demonstrates that the collecting entity (MMS) retains 1% of all cash received, regardless of its nature or amount. In practice, it is only upon appropriation, dependant upon specific terms and legislated maximums that certain amounts are received.

9. Disclose rights to future royalty streams identified for sale.

Please Note: Key subject matter experts have indicated that this scenario is very highly unlikely. Because such extensive analysis and work was required to satisfy other aspects of the field study, this valuation and item #10 were not revised from the original proposal in the ED. There is no disagreement with the proposed disclosure and accounting treatment. However, if the alternative valuation method is selected, then valuation based upon the known quantities would be developed using that method.

When rights to a future royalty stream are identified to be sold, the value of those rights should be disclosed as future royalty rights held for sale. They should be disclosed rather than reclassified because (1) the point in time for the sale of the future royalty rights may be uncertain or undecided and (2) the identified fields may continue to produce oil and/or gas and generate royalties. These two factors make it difficult to establish and maintain precise valuation information in advance of the sale. Disclosure of the approximate value at the balance sheet date alerts the reader to the pending sale and the potential value of the asset to be sold. The value of the rights identified for sale should be based on the estimated quantity of proved reserves, the first purchase price for oil or the wellhead price for gas, and the royalty rate for each specific field identified for potential sale.

Future royalty streams from two specific oil fields have been identified to be sold.

The estimated value of the future royalty stream identified to be sold from field number one is $5,305,000 based on the following calculation: 1,000,000 barrels to be sold X $42.44 per barrel per field number one first purchase price for oil X the 12.5% royalty rate for field number one.

The estimated value of the future royalty stream identified to be sold from field number two is $3,244,688 based on the following calculation: 750,000 barrels to be sold X $34.61 per barrel per field number two first purchase price for oil X the 12.5% royalty rate for field number two. The future royalty streams are expected to be sold sometime during the next fiscal year.

10. Record sale of future royalty streams identified for sale and the related change in the liability for revenue distributions to others.

At the time the future royalty rights identified for sale are sold, the asset value is calculated based on the quantity of proved oil reserves involved in the sale, the first purchase price or the wellhead price for the field at the time of sale, and the royalty rate for the specific field. Any difference between the asset value of the future royalty rights sold and the sales proceeds results in a net gain or loss. The net gain or loss should be reported on the Statement of Net Cost of the component entity responsible for collecting royalty revenue. For purposes of this illustrative accounting event, the rights to future royalty rights held for sale for field number one had an asset value of $5,375,000 based on the following calculation: 1,000,000 barrels of proved oil reserves involved in the sale multiplied by an arbitrary $43.00 per field number one first purchase price per barrel further multiplied by the arbitrary 12.5 percent royalty rate for field number one. The rights to a future royalty stream from field number one were sold for $3,950,000. As a result, there is a loss of $1,425,000 on the sale of the future royalty stream from field number one, which should be reported on the Statement of Net Cost.

Dr. Fund Balance with Treasury	3,950,000	
Dr. Loss on Sale of Estimated Petroleum Royalties	1,425,000	
Cr. Estimated Petroleum Royalties		5,375,000

To record sale of future royalties.

The loss on the sale of estimated petroleum royalties is multiplied by the average share of the revenue distributed to the States and other Federal component entities to obtain the related reduction in the liabilities for revenue distributions to others. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005. The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005. This calculation is presented below:

$1,425,000 X .15 = $213,750

$1,425,000 X .84 = $1,197,000

Dr Liability for Revenue Distributions to Others- Federal	1,197,000	
Dr Liability for Revenue Distributions to States-Non-Federal	213,750	
Cr Revenue Designated for Others – States – Non-Federal		213,750

Cr Transfers-Out		1,197,000

To record the related reduction in the liabilities for the future revenue distributions to others, revenue designated for the States, and transfers-out as a result of the loss on the sale of estimated petroleum royalties.

Dr Liability for Revenue Distributions to Others- Federal	3,318,000	
Dr Liability for Revenue Distributions to States-Non-Federal	592,500	
Cr Fund Balance with Treasury		3,910,500

To record the distribution of collections from the sale of revenue streams and the related reduction in the liability for revenue distributions to others.

Other Federal entity entry:

Dr Fund Balance with Treasury	3,318,000	
Cr Long-Term A/R for Oil and Gas-Federal		3,318,000

To increase the fund balance with treasury and reduce the long-term accounts receivable for oil and gas in relation to distributions received.

Dr Transfers-In	1,197,000	
Cr Long-Term A/R for Oil and Gas-Federal		1,197,000

To decrease the transfers-in and long-term accounts receivable as a result of the loss on the sale of estimated petroleum royalties.

11. Record annual valuation of estimated petroleum royalties and the related change in the liability for revenue distributions to others.

The calculated value of the Federal government's estimated petroleum royalties for financial statement reporting at year-end should be compared to the book value of estimated petroleum royalties at year-end. If the calculated value of estimated petroleum royalties at year-end is greater than the year-end book value,[5] the book value should be increased to the new estimate and a gain should be recorded on the Statement of Net Cost of the reporting entity responsible for collecting revenue. If the calculated value of estimated petroleum royalties at year-end is less than the year-end book value, the book value should be decreased to the new estimate and a loss should be recorded on the Statement of Net Cost of the reporting entity responsible for collecting royalty revenue. For illustrative purposes, the valuation of estimated petroleum royalties as of as of the year ended September 30 produced a **gain** of **$7,859,210,068** that is based on the following calculations.

To compute the illustrative revaluation of estimated petroleum royalties at fiscal year end, MMS CRB simply computed the percentage decline in asset value

[5] The estimated petroleum royalties beginning balance would have been reduced by the amount expensed on the statement of net cost.

obtained in the ED view calculations, and applied that same percentage decline to the offshore and onshore beginning balance PV method values, to arrive at the end of period PV method balance. There is no direct relationship between the methods or time frames, and this was done simply to provide a hypothetical end of period value.

It is interesting to note that although the overall asset value declined (hypothetically), depletion recorded in the year exceeded the straight difference in the valuation, and required a gain on revaluation to be recorded. This gain may not be reflected in subsequently published EIA data.

The total illustrative revaluation of estimated petroleum royalties for oil and lease condensate, NGPLs, and gas is **$61,263,870,021**. The current value of estimated petroleum royalties less the book value of estimated petroleum royalties (the initial value of estimated petroleum royalties at the beginning of the year (October) less depletion expense for estimated petroleum royalties through the end of the year (September 30), less the asset value of estimated petroleum royalties sold), equals the net **gain** to be recorded:

Dr Estimated Petroleum Royalties	7,859,210,068	
Cr Gain on Revaluation of Estimated Petroleum Royalties		7,859,210,068

To record revaluation of estimated petroleum royalties.

To record the related increase in the liability for the future revenue distributions to others, the amount that the total estimated petroleum royalties was increased due to revaluation is multiplied by the average share of the revenue distributed to the states. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005. These calculations are presented below:

$7,859,210,068 X .15 = $1,178,881,510

$7,859,210,068 X .84 = $6,601,736,457

Dr Revenue Designated for Others – States – Non-Federal	1,178,881,510	
Dr Transfers-Out	6,601,736,457	
Cr Liability for Revenue Distributions to Others-Federal		6,601,736,457
Cr Liability for Revenue Distributions to States-Non-Federal		1,178,881,510

To record the related year-end increase in the liabilities for the future revenue distributions to others.

Other Federal component entity entry:

For component entities, amounts must be recognized in a manner that supports elimination of Federal assets and liabilities and flow amounts. Therefore, the receiving Federal component entities would be required to book the revaluation amount related to their respective interest in the estimated petroleum royalties.

Dr Long-Term A/R for Oil and Gas-Federal	6,601,736,457	
Cr Transfers-In		6,601,736,457

To book the revalued asset amount by other Federal entities for their respective interest in the estimated petroleum royalties.

The pro forma trial balances, closing entries, and financial statements following are illustrative of the bureau entries presented in this document. The “other Federal component entity” entries and statements are also illustrated. Some of the ‘other Federal component entities’ are within the same Department (Interior), and some, without. The consolidated financial statements of the United States Government are not illustrated. Small rounding differences may be present.

Pro Forma Statements

2. Please prepare a pro forma pre-closing trial balance, closing entries, a post-closing trial balance, a balance sheet, a statement of net cost, and a statement of changes in net position for the component entity responsible for collecting royalties based on the following:

b. the pro forma transactions developed in accordance with the alternative view.

Pre-closing trial balance after pro forma transactions:

Collecting Entity

Pre-closing trial balance after pro forma transactions:

Fund Balance with Treasury	102,940,434
Accounts Receivable	1,470,783,313
Estimated Petroleum Royalties	61,263,870,021
Liability for Revenue Distributions to Others - Federal	(52,697,108,801)
Liability for Revenue Distributions to States - Non-Federal	(9,410,198,000)
Revenue from Bonus Bids and Rents	(241,861,681)
Revenue from Royalties	(11,519,015,047)
Transfers-Out	6,803,703,269
Oil & Gas Depletion Expense	11,519,015,047
Revenue Designated for the States	1,214,947,012
Gain on Revaluation of Estimated Petroleum Royalties	(7,859,210,068)
Loss on Sale of Future Royalty Rights	1,425,000
Prior Period Adjustment: Change in Accounting Principle	(649,290,500)

Total	(0)

Other Federal Entities
Pre-closing trial balance after pro forma transactions:

Fund Balance	8,646,996,469
Accounts Receivable	52,697,108,801
Transfers-In	(6,803,703,269)
Prior Period Adjustment: Change in Accounting Principle	(54,540,402,000)
Total	0

Closing Entries:

Collecting Entity
Closing Entries:

Revenue from Bonus Bid and Rents	241,861,681	
Revenue from Royalties	11,519,015,047	
Gain on Revaluation of Estimated Petroleum Royalties	7,859,210,068	
Prior Period Adjustment: Change in Accounting Principle	649,290,500	
Cumulative Results of Operations		730,286,968
Transfers-Out		6,803,703,269
Oil and Gas Depletion Expense		11,519,015,047
Revenue Designated for the States		1,214,947,012
Loss on Sale of Future Royalty Rights		1,425,000

Other Federal Entities
Closing Entries:

Transfers-In	6,803,703,269	
Prior Period Adjustment: Change in Accounting Principle	54,540,402,000	
Cumulative Results of Operations		61,344,105,269

Post-closing trial balance:

Collecting Entity
Post-closing trial balance:

Fund Balance with Treasury	102,940,434
Accounts Receivable	1,470,783,313
Estimated Petroleum Royalties	61,263,870,021
Liability for Revenue Distributions to Others - Federal	(52,697,108,801)
Liability for Revenue Distributions to States - Non-Federal	(9,410,198,000)
Cumulative Results of Operations	(730,286,968)
Total	(0)

Other Federal Entities
Post-closing trial balance:

Fund Balance	8,646,996,469
Accounts Receivable	52,697,108,801
Cumulative Results of Operations	(61,344,105,269)
Total	0

Pro Forma Financial Statements – for fiscal year ended 9/30/20XX

Balance Sheet

<u>Collecting Entity Balance Sheet</u>

Assets	
Fund Balance with Treasury	102,940,434
Accounts Receivable	1,470,783,313
Estimated Petroleum Royalties	61,263,870,021
Total Assets	$62,837,593,768
Liabilities	
Liability for Revenue Distribution to Others - Federal	52,697,108,801
Liability for Revenue Distribution to States - Non-Federal	9,410,198,000
Total Liabilities	62,107,306,801
Net Position	
Cumulative Results of Operations	730,286,968
Total Liabilities and Net Position	$62,837,593,768
	0

Other Federal Entities Balance Sheet

Assets	
Fund Balance	8,646,996,469
Accounts Receivable - MMS	52,697,108,801
Total Assets	$61,344,105,269
Net Position	
Cumulative Results of Operations	61,344,105,269
Total Net Position	$61,344,105,269
	0

Statement of Net Cost

Collecting Entity Statement of Net Cost

Oil & Gas Resources Program	
Leasing Activities:	
Costs (Oil & Gas Depletion Expense)	$11,519,015,047
Less Earned Revenue	(11,760,876,728)
Net Cost/(Revenue) from Leasing Operations	(241,861,681)
Loss/(Gain) on Revaluation of Estimated Petroleum Royalties	(7,859,210,068)
Less: Revenue Designated for States - Non-Federal	1,214,947,012
Less: Loss on Sale of Future Royalty Rights	1,425,000
Net Cost/(Revenue) for Program	($6,884,699,737)

Statement of Net Cost – Other Federal Entities – Not Applicable (all on SCNP)

Statement of Changes in Net Position

Collecting Entity Statement of Changes in Net Position

Beginning Net Position	$0
Adjustment: Change in Accounting Principle	649,290,500
Beginning Balance, As Adjusted	649,290,500
Net Revenue for Program	6,884,699,737
Transfers In/(Out)	(6,803,703,269)
Ending Net Position	$730,286,968
	0

Other Federal Entities Statement of Changes in Net Position

Beginning Net Position	$0
Adjustment: Change in Accounting Principle	54,540,402,000
Beginning Balance, As Adjusted	54,540,402,000
Transfers In/(Out)	6,803,703,269
Ending Net Position	$61,344,105,269
	0

Disclosure Information

3. Please prepare a pro forma disclosure of rights to future royalty streams identified for sale in accordance with:

b. the alternative view;

Please Note: Key subject matter experts have indicated that this scenario is very highly unlikely. Because such extensive analysis and work was required to satisfy other aspects of the field study, this valuation and entry #10 were not revised from the original proposal in the ED. There is no disagreement with the proposed disclosure and accounting treatment. However, if the present value method is selected, then valuation based upon the known quantities would be developed using that method.

Time and Expense Information

4. Describe the system changes that would be necessary to implement:

b. the alternative view;

- Regardless of valuation method, the ED currently only addresses the accounting treatment for oil and gas, and not other commodities. This means that there would be different accounting treatment and models required for oil and gas compared to solids and other commodities, as well as other activity currently classified as custodial. MMS strongly recommends that implementation be delayed until all commodities and related business activities are addressed.
- The Statement does not address the treatment of interest, either payable or receivable, whether related to oil and gas, or otherwise. However, it does rescind the provisions in existing Standards that provide for custodial accounting for royalty activity. This is significant, because currently interest related to royalty payments is treated as custodial. Clarification is needed to ascertain the Board's intent regarding other such business activities. Nonetheless, system changes will ensue for differing accounting models related to these types of related financial events.
- Implementation will require revising all, or almost all of the existing accounting models in MRMSS; a significant effort and expense.
- Currently, MMS/MRM appropriately records royalty and related activity flowing through clearing account F3875. Amounts are received from the public and distributed to other federal entities. To capture and report on the capital asset and associated depletion expense, a new fund would be required, or an exception granted to report this activity, including equity, in the clearing account. While Treasury is in the midst of prohibiting or limiting use of the F3875 clearing account, a waiver request is in process for MRM royalty activity and Treasury has indicated that it will likely be granted. Historically, Treasury and OMB mandated that MRM use this clearing account for their royalty and related activity, and it is hard-coded throughout the MRMSS.
- Manual workarounds and journal vouchers can help mitigate some of the impacts, but not all of them.

Below are some key points, provided to illustrate more specifically how system issues pose significant implementation challenges for MMS/MRM.

- In MRMSS, a royalty report (2014) that contains multiple lines of royalty data creates just one receivable, with one standard custodial accounting model.
- The same custodial model is applied to all activity, regardless of its nature. For example, a bonus, a rental, an interest invoice and a royalty document all post to the same custodial accounting model.
- In the SCA, the amounts are aggregated into the 'Rents and Royalties' line, which includes virtually everything except for first year rents and bonuses on new

onshore and offshore leases, and the value of commodity transferred to DOE to fill the SPR.
- Under the new Standard, the individual lines of royalty data, or individual transactions would give rise to different accounting models, depending on product code, transaction code and other criteria. They would also be reported separately in the Statements and require more detailed disclosures.
- For example, a rental amount, bonus amount or interest amount would receive a different accounting model from an oil and gas royalty amount, regardless if they were submitted on the same royalty document.
- This would need to be ascertained by the MRMSS upon receipt of the transaction, based upon the transaction code, product code, lease, etc., and recorded to the differing models as appropriate.
- Discussions with MRM subject matter experts indicate that the existing system is not capable of performing these types of up front breakouts, given the massive amount of data and current processing volume and time constraints.
- Extensive customization of the COTS software would be required to accomplish this.
- If no longer custodial, different SGL accounts would also be required for interest, either receivable or payable, and amounts aggregated and reported separately.
- Required disclosures include detailed breakouts, by commodity, for onshore and offshore.

The issues discussed above are not all-inclusive, but are presented to give an overview of the significant system related challenges inherent in implementing this Statement, regardless of the valuation method selected. Some issues can be mitigated with manual workarounds and journal vouchers. However, sophisticated reports would be required that would capture and report monthly on the detail needed to support the manual journals and the required disclosures.

One potential solution to mitigate the large expense and ongoing effort of converting accounting treatments is to continue overall custodial royalty accounting, simply capitalize the asset as custodial, and revalue it annually with the gain or loss on revaluation being recorded on the Statement of Custodial Activity. This could be done much more readily, would not require massive overhauls of current Bureau and system processes, and still accomplish the Board's objective to capitalize the oil & gas asset.

5. Estimate staff time and costs to complete the field test and to implement:

d. the alternative view;

Costs should include expenditures for system changes, consultants, and hardware and software acquisitions, and should **not** include a calculated value for staff time. Implementation estimates should distinguish between initial **implementation** and **ongoing** staff time and costs. All estimates should be **additional** time and cost incurred as a direct result of the proposed standards and the alternative view.

MMS obtained a fairly comprehensive estimate from the contract system integrator, which included an estimate if the Statement were delayed until all commodities were included, and if oil and gas were implemented before resolving all other commodities and business processes. Cost estimates of system changes, assuming simplistic changes to SGL accounts only, range from $5M if done for all commodities at once, to $7M if other commodities are implemented later.

Also, it is likely that at least one or possibly more additional FTE would be required to perform ongoing accounting and reconciliation functions, depending upon the resolution of issues discussed in this document.

6. How did you estimate the value of estimated petroleum royalties:

b. based on the alternative view;

Methodology for Estimating the Present Value of the Federal Royalties from Federal Proved Reserves (Present Value Method)

Offshore

The following methodology is offered as a workable solution to the Alternative View proposal that a "Fair Value" method be used to value future Federal royalty receipts from proved oil and gas reserves on Federal lands. This methodology has been proposed by the MMS Offshore Minerals Management (MMS-OMM). A model has been constructed and tested, though the results only apply to Federal offshore royalties which fall under the MMS-OMM domain. Federal Agencies responsible for management of Federal onshore oil and gas proved reserves concurred with this proposal, and also applied a similar methodology for valuing Federal onshore proved reserves for the FASAB study.

Responsibility for estimating the present value of the Federal share of Federal OCS proved reserves would reside primarily within the OMM Resource Evaluation (OMM-RE) umbrella with assistance from the Department of Energy – Energy Information Administration (EIA), MMS – Minerals Revenue Management (MMS-MRM), and the MMS - OMM Economics Division (OMM-ED).

Proved Reserves Estimates

The basis for these calculations would be the same as is the Majority Proposal. That is, the present value of the future Federal royalties revenue steam would be calculated using the Department of Energy, Energy Information Administration (EIA) estimated volumes of proved reserves.

Ideally, such estimates of proved reserves would need to be divided according to commodity (crude oil, lease condensate, and natural gas – wet after lease separation), and, in the Gulf of Mexico (GOM), further for each commodity by the water depth category of the field. For example, the proved reserves estimates for oil and lease condensate would further have to be divided into proved reserves from fields in water depths less than 400 meters and proved reserves from fields in water deeper than 400 meters. The water depth subdivision at 400 meters is to facilitate the calculations using the appropriate royalty rate as typically, for pre-2007 GOM leases, those in water shallower than 400 meters have a one-sixth royalty rate and those in deeper than 400 meters have a one-eighth royalty rate. Beginning with GOM leases sold in 2007, all have a one-sixth royalty rate, regardless of water depth. Proved reserves from other Federal OCS Regions would not need to be divided according to water depth as those regions, as typically they have a single royalty rate per Region.

In reality, the DOI has had difficulty communicating with the EIA to determine if they can comply with the proved reserves data needs expressed above. The MMS/OMM strongly recommends that an agreement be reached with the DOE/EIA to provide the necessary proved reserves data in the appropriate form and format for this or any method adopted for the reserves valuation. Alternatively, the MMS has devised a means for estimating the proportions of EIA proved reserves for the GOM applicable to royalty rates of one-sixth and one-eighth. This has been accomplished by applying the water depth proportions from the most recent MMS proved reserves estimates to the published proved reserve estimates from EIA.

Production Profiles

In order to effectively calculate the present value of Federal royalties, it needs to be estimated how those royalties will be received over time. To determine this, one needs to project how the proved reserves estimates will be produced over time. EIA proved reserve estimates include reserves from which Federal royalties will be received, as well as, reserves from which royalties will not be received due to various royalty relief policies.

The model that MMS has created can be used to project the future production of the EIA proved reserve estimates assuming an exponential decline at a rate of the modeler's choice. The model also receives, as inputs, annual estimates of royalty free production from royalty relief. The annual production estimates of the proved reserves calculated by the model are then reduced by the royalty free annual volumes prior to the royalty calculations.

Natural Gas Plant Liquids

The Exposure Draft calls for the estimation of royalties from proved reserves of natural gas plant liquids (NGPL) along with royalties from proved reserve estimates of crude oil, lease condensate, and presumably dry natural gas. The EIA reports estimates of natural gas reserves in two different forms. One form is Dry Natural Gas which is the volume of natural gas after the natural gas liquids have been removed. The other form is Natural Gas, Wet After Lease Separation which is the volume of natural gas prior to the natural gas liquids being removed. Should dry gas proved reserves be used for the royalty estimates, NGPL proved reserve estimates should also be used to capture the entire hydrocarbon value. However, wet gas volumes and values are greater than dry gas volumes and values because of the additional content of NGPL in the wet gas. MMS prefers the use of the wet gas estimates because they replicate the form and the point in time when the royalty valuations are made. Further, MMS/OMM reservoir engineers and geoscientists are very experienced in dealing with and estimating reserves and production in terms of wet gas as all MMS/OMM datasets are in terms of wet gas. Finally, the use of dry gas and NGPL creates possibly insurmountable problems in properly allocating reserves back to their source fields, affecting value estimations at the proper royalty rates, and in constructing production profiles. Adding values for NGPL to this would amount to a double counting of the values of NGPL. MMS has used only wet gas proved reserves estimates (and no estimated of NGPL) in its trial analysis and highly recommends this procedure for these calculations.

Product Prices

Of equal importance in the estimation of the present value of royalties to the production estimates are the estimates of future oil and gas prices. MMS-OMM recommends that independently generated and commonly available price estimates be used. The MMS-OMM already uses and is familiar with the OMB economic assumptions that are generated semi-annually for the President’s Budget. For the purpose of the trial analysis performed, the oil and gas prices from the OMB’s “Economic Assumptions for the 2008 Mid-Session Review” were employed.

A minor limitation to those parameters is that the projections are only for 10 years into the future. An extrapolation of out-year trends in the projections has been made to extend the price profiles as long as necessary.

Depending on the locations associated with the price parameters, the prices will have to be adjusted to approximate average wellhead prices for each OCS Region (GOM, Pacific, Alaska North Slope). Such an adjustment has two components, an adjustment to a regional landed average price, then a transportation allowance to a regional wellhead average price. The first adjustment to a regional landed average price will be conducted by observing the historical average relationship of the price series being considered (e.g., United States average wellhead natural gas price) to the average regional landed natural gas price (e.g., Henry Hub). From these observations, factors and/or trends in these price relationships can be deduced and applied to the price projections to result in projections of regional landed prices. Such relationships need to be studied in detail prior to “going live” with the present value estimates. For the purpose of the trial analysis performed, it was assumed that the OMB’s average imported and domestic refiner’s acquisition cost for oil and the average wellhead price for imported, inter-, and intra-State natural gas estimates would be equivalent to the average landed prices of oil and gas for each Region. The OMB’s price projections are expressed in nominal terms.

Transportation Allowances

The second component of the price adjustment is the transportation allowances. Lessees pay royalties based on the value of their production at the wellhead. Since the price adjustment above resulted in a regional average landed price, these need to be converted to regional average wellhead prices by subtracting a regional average transportation allowance.

One approach would be for MMS-MRM to determine the necessary average historical transportation allowances claimed by lessees on royalty bearing production for the previous 12 sales months. Such averages would be weighted by the volume of production using that allowance, would be by commodity, and for the GOM, would be by the royalty rate of the contributing leases. The assumption would then be that the resulting previous 12-month average transportation allowances would also apply to all future production within the same category. Because the price projections used are nominal values, the transportation allowances would be increased in the future with inflation.

This method was employed in the trial analysis, though further study of the accuracy of this approach would be necessary prior to any official calculations.

Discount and Inflation Rates

As for product prices, MMS-OMM recommends that independently generated and commonly available discount and inflation rates be used in calculating the royalty present value. A public sector discount rate for the Federal government should be readily available and applicable for this purpose. For the purpose of the trial analysis, MMS assumed a discount rate equal to the Federal government's interest rate paid on its long-term borrowing as the discount rate. OMB's projection of the 30-year Treasury Bill rate was used. For inflation, MMS assumed OMB's projection of the GDP Price Index for the trial analysis.

As was the case for OMB's oil and gas price projections, projections of these parameters by OMB are also only for 10 years into the future. An extrapolation of out-year trends in the projections has been made to extend the price profiles as long as necessary.

Present Value Calculations

For all Federal offshore areas, MMS proposes the use of the following method to estimate the present value of future Federal royalties from proved reserves:

1) By Federal OCS Region, project production of DOE-EIA proved oil/condensate, and wet natural gas reserves estimates over time until depleted,
2) In GOM, also project separately for one-sixth and one eighth royalty rate leases (use water depth subsets of >400m and <400m as proxy),

3) Where applicable, determine adjustments needed to reflect projected royalty free production from royalty relief leases and modify as appropriate the total projections above,
4) Calculate future regional landed prices from price projection (OMB or other) assigned by FASAB using historical price relationships to make further adjustments,
5) Calculate future wellhead landed prices from regional landed prices using average actual transportation allowances claimed for the previous 12-month period.
6) For production for each Regional commodity by royalty rate, calculate annual royalties as follows:

*(Annual Production less adjustments for Annual Royalty Free Production) * (Annual Regional Landed Price – Average Transportation Allowance) * Royalty Rate*

7) For a given vector of calculated future annual royalty estimates, determine the present value of the royalty revenue stream assuming the discount rate (OMB 30-year Treasury Bill or other) assigned by FASAB.

Trial Analysis

Using the above methodology, MMS constructed a model and completed a trial calculation for the Federal offshore areas assuming that the effective date of the royalty valuation would be October 1, 2007. MMS used its model and made separate calculations of the present value of proved reserves for the relevant categories pertaining to the Federal Outer Continental Shelf. Presented below are the categories and resulting present value estimates:

Present Value of Future Federal OCS Royalty Receipts - Effective 10/1/2007 ($MM)	
GOM One-Sixth Royalty Oil/Condensate	$ 5,702.35
GOM One-Eighth Royalty Oil/Condensate	$20,737.99
GOM One-Sixth Royalty Wet Gas	$ 8,923.55
GOM One-Eighth Royalty Wet Gas	$ 4,198.31
Pacific Region Oil/Condensate	$ 1,868.62
Pacific Region Wet Gas	$ 409.59
Total	$41,840.41

MMS used future oil and gas price, discount, and inflation rates from the OMB "Economic Assumptions for the 2008 Mid Session Review." The following are those values used in the analysis:

Fiscal Year	Oil Price[1] ($/bbl)	Gas Price[2] ($/mcf)	Discount Rate[3] (%/Year)	Inflation Rate[4] (% Change Yr/Yr)
2006	59.94	7.45	4.85	3.1
2007	56.57	6.59	4.87	2.7
2008	63.26	7.70	5.18	2.4

2009	64.09	7.64	5.33	2.2
2010	63.12	7.40	5.48	2.0
2011	62.29	7.18	5.60	2.0
2012	61.80	7.09	5.61	2.0
2013	61.59	7.23	5.61	2.0
2014	61.97	7.38	5.61	2.0
2015	63.21	7.52	5.61	2.0
2016	64.47	7.68	5.61	2.0
2017	65.76	7.83	5.61	2.0
Annual Rate of Increase Thereafter	2.0%	2.0%	0.0%	2.0%
[1]Average Imported and Domestic Refiner's Acquisition Cost				
[2]Average Wellhead Price for Imported, Inter-, and Intra-State Natural Gas				
[3]30-Year Treasury Bills, Notes, and Bond, Bond Equivalent Rate				
[4]Gross Domestic Product Price Index				

<u>Onshore</u>

The first step in obtaining onshore quantity was to determine **what portion of all proved reserves fall under federal domain**, before the federal royalty share of those proved reserves could be estimated. **This information is presently not published by EIA,** so an estimation methodology had to be developed. **The MMS/OMM/BLM Team reached agreement on the estimation methodology described herein, and ascertained that in the absence of better information, this would be an acceptable method to use for implementation as well.**

For onshore quantities, MMS Custodial Reporting Branch (CRB) obtained the published EIA 2005 Annual Report of total nationwide estimated proved reserves, both Federal and non-Federal. MMS CRB then estimated the Federal portion of onshore proved reserves by using a ratio of 2005 onshore estimated production nationwide published by EIA, compared to 2005 total production volumes from Federal leases reported to MRM on royalty reports. The ratios of Federal to total 2005 production then became a proxy for the ratio of Federal proved reserves to total proved reserves reported by EIA. Offshore quantities are under Federal domain by definition, so were excluded from the estimation process. This differs from the computation method developed in the ED.

Royalty reported data was used for volumes sold or extracted from the lease, rather than straight production data, because production (OGOR) data is not broken out in the required detail, and it is not as up to date as royalty reported data.

It is important to consider that many assumptions had to be made in developing this model. As regards wet vs. dry gas, MMS can only retrieve the data as it is reported by industry, as it is sold or removed from the lease. Below describes the stratification of data that was retrieved by MRM for our field study, and how each commodity was categorized.

The Oil and Lease Condensate category contains product codes of:

01	Oil	(Oil)
02	Condensate	(Lease Condensate)
05	Drip or Scrubber Condensate	(Lease Condensate)
06	Inlet Scrubber	(Lease Condensate)
13	Fuel Oil	(Oil)
14	Oil Lost	(Oil)
20	Other Liquid Hydrocarbons	(Oil)

The Gas Category contains product codes of:

03	Processed (Residue) Gas	(Dry Gas)
04	Unprocessed (Wet) Gas	(Wet Gas)
09	Nitrogen	(Wet Gas)
12	Flash Gas	(Wet Gas)
15	Fuel Gas	(Wet Gas)
16	Gas Lost - Flared or Vented	(Wet Gas)
39	Coal Bed Methane	(Dry Gas)

The NGL Category contains the product code of:
07 Gas Plant Products

Where reported and paid separately, dry gas had to be analyzed separately from wet gas, and NGL's were also analyzed separately, averages computed and the totals then summed, in order to derive a more accurate estimate. This differs somewhat from the Exposure Draft, which reports only dry gas and NGL's. However, as a result of the field test, it is apparent that not only is this the reported information that is available, analyzing and computing each commodity category separately also produces a more accurate overall estimate. However, this is limited to the commodity categories reported in common between EIA and MRM. For purposes of the field study only, coal bed methane was added to onshore dry gas, as the rate and price were fairly comparable. But in practice, since proved reserve and estimated production data are available from EIA, this commodity could be computed and reported separately.

Commodity categories and units were at the common level between EIA and MMS:

Dry Gas	(mcf)
Wet Gas	(mcf)
NGL's	(bbl 42 us gal)
Oil	(bbl)
Lease Condensate	(bbl)

Since the Federal proved reserves derived from EIA published data were for FY 2005, the amount of production from FY 2006 was subtracted from Federal proved reserves before starting additional calculations. Using prior years' production data and estimates on new wells permitted and drilled each year, an estimated yearly production was estimated for each year. The estimates in new permits approved and wells drilled were based on the following parameters:

- 5% of APDs processed are Indian
- 84% of the Federal APDs processed are approved
- 85% of the Federal Approved APDs are drilled
- 90% of the wells drilled are productive
- 10% of the productive wells are oil
- 90% of the prodcutive wells are gas
- 85% of the productive wells begin production in the first year
- 10% of the productive wells begin production in the second year
- 4% of the productive wells begin production in the third year
- 1% of the productive wells begin production in the fourth year
- Average oil well produces 7,300 barrels per year or 20 barrels per day
- Decrease of 10% per year for oil production
- Decrease of 10% per year for gas production
- Average gas well produces 80,000 MCF per year or 219 MCF per day
- APDs processed in 2008 - 2011 are set at 11,500 and then start a slow decline of 500 APDs per year.

Once yearly production estimates were established they were subtracted from the Federal proved reserves until the proved reserves were zero. A similar present value method was applied to onshore quantities. A yearly estimated price for oil, natural gas and natural gas liquids was used based on OMB estimates. Since the OMB estimates only went out for ten years, prices were estimated based on the trend of the OMB estimates after that. A royalty rate based on historic data from MMS was used to estimate the royalty rate. The data from MMS on the royalty rate appeared to be constant, so no change in the royalty rate was made for each year. A standard discount rate was used to bring future dollars back to today dollars.

The estimated yearly production was multiplied by estimated average yearly price, the royalty rate and the discount rate for that year. All of these totals were added together to come up with the estimated value of each commodity (oil, natural gas and natural gas liquids). These total were added together to come up with a estimated total value of the Federal onshore oil and gas proved reserves, which was $23,088.64.

7. Describe any problems experienced valuing estimated petroleum royalties:

b. using the alternative view;
   i. How were they resolved?
   ii. How would you resolve them in actual implementation of the final Statement?

<u>Timing of DOE Proved Reserves Estimates Issue:</u>
There is an inherent problem with any method of booking the value of oil and gas reserves. The problem occurs because an estimate of proved reserves is a dynamic quantity as long as there is production from an area and continued development in the

area. Proved reserves estimates are a “snapshot” of the oil and gas quantities as of a given date. For example, the FASAB Exposure Draft proposes to base its values on Energy Information Administration (EIA) estimates of proved reserves. If the first such estimated value were to be booked at the start of fiscal year 2009 (October 1, 2008), the EIA reserve estimates available to calculate the value would be effective on December 31, 2006. This is a full 21 months prior to the effective date of the estimate of value.

This raises several concerns. First, in the 21 months that will transpire between the effective date of the reserves estimates and the effective date of the value estimate, the reserves estimate will have been reduced by any depletion of the reserves through production. Second, over the same time period, the reserves estimate will have been increased through any additions to reserves that naturally occur as accumulations are explored and developed.

The intermediate production that occurs between the effective date of the reserve estimates and the effective date of the booked value represents a true and measurable reduction in the proved reserves estimate for which the royalty value will have been received and accounted for elsewhere. Booking the value of this production as proved reserves would amount to an overstatement of this asset. The MMS proposes reducing the proved reserves by the volume of the intermediate production. At the time for calculating the book value of the proved reserves for FASAB, the MMS will have production volume estimates for approximately 18 of the 21 months of intermediate production and proposes to use production projections for the remaining months.

MMS believes it would be inconsistent to reduce the value of the royalty stream by the value of the intermediate production without also including a corresponding increase from proved reserves that would be almost certainly added between the effective date of the proved reserve estimates and the effective date of the booked value. Unlike the intermediate production, however, which can be mostly measured, intermediate increases of the EIA proved reserve estimates are not available for these calculations. The MMS proposes that estimates of the reserves additions be employed and offers the following methodology for estimating revised reserves estimates that are based on the EIA estimates but are effective the date of the booked asset value.

The methodology employs the historical relationship between the volume of production of proved reserves and the volume of reserves additions to proved reserves. The EIA has estimated and reported the proved reserves of the Federal OCS areas for many years. In its annual presentation of its reserves estimates, EIA reports the previous year’s reserve estimate, all additions to that previous year’s estimate, and all reductions to that previous year’s estimate (including production). The following are EIA data that track the reserves estimate and corresponding revision categories for crude oil proved reserves of the Pacific Federal OCS for 2005.

Proved Reserves as of 12/31/2004	547 MMbbl
Changes in Reserves During Year	
Adjustments (+,-)	-1 MMbbl

Revision Increases (+)	3 MMbbl
Revision Decreases (-)	81 MMbbl
Sales (-)	0 MMbbl
Acquisitions (+)	0 MMbbl
Extensions (+)	0 MMbbl
New Field Discoveries (+)	0 MMbbl
New Reservoir Discoveries in Old Fields (+)	0 MMbbl
Estimated Production (-)	27 MMbbl
Proved Reserves as of 12/31/2005	441 MMbbl

Since the MMS will have a reliable estimate of the intermediate production, a method was devised to determine the EIA historical average proved reserves change expressed in proportion to historical average production of proved reserves. For example, between 1992 and 2005, EIA's proved oil and lease condensate reserve estimates for the deep water Gulf of Mexico increased by 2.771 billion barrels. Correspondingly, over that same 14-year period, EIA reports that 2.833 billion barrels of oil and lease condensate were produced from the same area. This indicates over that time period, for every barrel of production that occurred, the oil reserves estimate increased by 97.81% of a barrel (2.771/2.833 = 0.9781).

Potentially, this concept can be confusing because of the varying terminology used in the above description. It is important to realize that the reserves estimate adjustment methodology suggested above accounts for reserves additions as well as reserves reductions, including production. This is because the reserves estimate adjustment factor proposed is the determination of the change in the reserves estimate expressed in proportion to the volume of production over the same time period. The important concept to remember is that the volume of production is also a component of the change in reserves estimate.

Using these calculated averages for each appropriate area, and the volumes of intermediate production, MMS proposes that the EIA proved reserves estimates, effective 21 months prior to the effective date of the booked value, be adjusted to a value that is reflective of the effective date of the booked asset value. Continuing with the same example of Gulf of Mexico deep water proved reserves of oil and lease condensate, the proved reserve estimate was 3.626 billion barrels as of December 31, 2005. The MMS estimates 592 million barrels of intermediate deep water GOM oil and lease condensate production over the 21 months between December 31, 2005 and October 1, 2007. Applying the average reserves change to production ratio, the December 31, 2005 GOM oil and lease condensate proved reserve estimate of 3.626 billion barrels would increase by 579 million barrels (592 million barrels produced * 97.81% = 579 million barrels reserves change) to 4.205 billion barrels by October 1, 2008. These data along with the similar data elements for the other Federal OCS areas are shown in the table below.

Category	GOM 1/6th Royalty Oil (MMbbl)	GOM 1/8th Royalty Oil (MMbbl)	GOM 1/6th Royalty Gas (Bcf)	GOM 1/8th Royalty Gas (Bcf)	Pacific Oil (MMbbl)	Pacific Gas (Bcf)
Proved Reserves on 12/31/05	688	3,626	10,014	7,412	449	825
Production 1/1/06 – 9/30/07	221	592	2,958	1,914	43	80
Average Reserves Change to Production Ratio	-22.16%	97.81%	-29.66%	40.95%	-70.32%	-111.56%
Proved Reserves on 9/30/07	639	4,205	9,136	8,196	419	736

The MMS/OMM acknowledges improvements over this method include the receipt of EIA's proved reserves estimates sooner. That is, receiving estimates that are only 9 months out of date, instead of 21 months. This would involve the receipt of the necessary estimated prior to EIA publishing the values. Another improvement is if EIA could provide all of the above data in exactly the form and format needed which would mean by water depth category in the Federal offshore Gulf of Mexico, and perhaps for Federal only proved reserves for the Federal onshore.

This adjustment factor is included in the offshore calculations. A production decline factor is included in the onshore calculations, but no factor was included for potential increases or additions. This highlights a significant issue requiring resolution before implementing any valuation methodology, regardless of the valuation method selected.

ED pp. 38, Published EIA Data: The FASAB Exposure Draft view proposes to base values on, "...the most recent survey conducted by the EIA, issued no more than twelve (12) months before the end of the reporting period..." However, if the first such estimated value were to be booked at the start of fiscal year 2009 (October 1, 2008), the EIA reserve estimates available to calculate the value would be effective on December 31, 2006. This is a full 21 months prior to the effective date of the estimate of value. Accordingly, we recommend the ED be worded to base valuation simply on the most recent survey available from EIA.

Availability of EIA Data – Estimating Federal Onshore Quantities: As discussed above, the first step in obtaining onshore quantity was to determine **what portion of all proved reserves fall under federal domain**, before the federal royalty share of those proved reserves could be estimated. **This information is presently not published by EIA,** so an estimation methodology had to be developed. **The MMS/OMM/BLM Team reached agreement on the estimation methodology described herein, and ascertained that in the absence of better information, this would be an acceptable method to use for implementation as well.**

For onshore quantities, MMS Custodial Reporting Branch (CRB) obtained the published EIA 2005 Annual Report of total nationwide estimated proved reserves, both Federal and non-Federal. MMS CRB then estimated the Federal portion of onshore proved reserves by using a ratio of 2005 onshore estimated production nationwide published by EIA, compared to 2005 total production volumes from Federal leases reported to MRM on royalty reports. The ratios of Federal to total 2005 production then became a proxy for the ratio of Federal proved reserves to total proved reserves reported by EIA. Offshore quantities are under Federal domain by definition, so were excluded from the estimation process. This differs from the computation method developed in the ED. Where reported and paid separately, dry gas had to be analyzed separately from wet gas, and NGL's were also analyzed separately

Obtaining, Classifying and Stratifying the Royalty Reported Data: Initially, it took quite a while to perform and re-perform numerous queries, and to reach agreement on the commodity 'buckets' to be included in the various 'royalty' categories. This was necessary to obtain royalty reported production data which could be compared to EIA estimated production data nationwide, to then compute the onshore estimated proved reserves under federal domain. MRM has developed a statistical reporting tool which is structured around certain decisions related to the placement of each element of activity, and a fairly thorough understanding of those elements was necessary before data could be compared on the same footing with EIA data. [ED View contained the sentence "Certain assumptions had to be made, such as excluding certain volumes for royalty relief and estimating values for the SPR."] Also, it took time initially for CRB to perform the calculations by commodity for onshore, of the federal domain estimated proved reserves, and to perform quality checks and validations of each formula and each step, as well as variance analysis. The BLM Team members had to suspend their portion of the onshore study until this data was available, which added to the length of time it took to complete the study. It should be noted that this is a time-consuming effort that will require refinement regardless of the valuation method implemented, will be laborious to complete and subject to a high degree of audit review. Adequate numbers of knowledgeable staff will be crucial and careful reviews and quality control will be key to success, because the slightest error could have material repercussions, and could impact all downstream recipients as well.

Wet Gas vs. Dry Gas – Estimating Onshore Federal Proved Reserves:
Royalty information reported to MMS/MRM is reported as the commodity was sold or removed from the lease. This is important to note, as some assumptions had to be made in conducting the study of the ED view, and will exist at implementation. As regards wet vs. dry gas, MMS can only retrieve it as it was reported. Where reported and paid separately, dry gas had to be analyzed separately from wet gas, and NGL's were also analyzed separately to estimate quantities..

Settlement Amounts: Each year, MMS receives payments as settlement on compliance or enforcement cases that are reported generically as custodial 'Rents and Royalties'. The settlement payments are generally matched to a royalty report that does not break out what portion may possibly be estimated to be related to commodity royalties, or interest, or civil penalties. The royalty report simply contains an amount with no product code, so can not be broken out. As a result, these amounts were excluded from the values used to compute the [ED View included "capital asset and from amounts used to compute"] depletion expense. This will more often than not, be correct, as the compliance 3-year cycle produces settlements generally related to prior periods, appropriately falling outside of the relevant periods for capitalizing or depleting. However, internal process would need to be changed to capture more detail in the event that royalty or other amounts were compliance amounts brought current. This highlights a potential pitfall in the ED view for [ED View: "valuation"] depletion until processes can be changed. Currently, performing a 12 sales month 'look back' of royalty reports would by definition exclude potentially large royalty amounts not captured at the degree of detail necessary to identify them.

Invoiced Amounts: Periodically, MMS receives royalty related payments against invoices that are reported generically as custodial 'Rents and Royalties'. The invoice does not provide for a product code or other detail related to the nature of the obligation, but simply contains an amount due with no product code, so can not be broken out further. As a result, these amounts were excluded from the values used to compute the [ED View included "capital asset and from amounts used to compute"] depletion expense. Internal system process would need to be changed to capture more detail in the event that royalty or other amounts were invoiced. This highlights a potential pitfall in the ED view for [ED View: "valuation"] depletion until processes can be changed. Currently, performing a 12 sales month 'look back' of royalty reports would by definition exclude potentially large royalty amounts not captured at the degree of detail necessary to identify them.

ED, pp. 23; Royalties and Depletion Expense on Statement of Net Cost (SNC):
Please refer to the extensive discussion in entry #6 above.

Paragraph 23 states,
"Royalties from the production of proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources shall be recognized as exchange revenue on the Statement of Net Cost by the component entity that is responsible for collecting the royalty revenue. At the same time, an amount equal to the royalty revenue shall be recognized as depletion expense on the Statement of Net Cost of the component entity that is responsible for collecting the royalty revenue; and, the value of estimated petroleum royalties shall be reduced by the depletion expense amount."

Appendix C, entry 6, page 54 states,
"Earned royalty revenue should be recognized as exchange revenue by the component entity that is responsible for collecting the royalties. At the same time, an amount equal to the royalty collections should be recognized as depletion expense; and, the value of estimated petroleum reserves should be reduced by the depletion expense amount. Sales value and royalty payment information are due on or before the last of the month following the month the oil or gas product from Federal oil and gas resources was sold or removed from the lease. For example, oil or gas sold in June must be reported by July 31, the end of the following month. For illustrative purposes, the total amount of

royalty revenue earned for the fiscal year for offshore and onshore rental leases was used in this calculation."

In order to exclude adjustments to prior period reporting not attributable to depletion in the current year, and to exclude potentially unrelated estimates from the depletion calculations, t**he recommended method is to record depletion based upon royalty reporting lines received and accepted for the preceding 12 <u>sales months</u> available at fiscal year end; July through June (received through August, fully available in September). Revenue earned would not be a perfect match in the fiscal year, but in this case *it should not*, because depletion in the current year should not be linked to prior adjustments not related to the current year.** To do otherwise would *include* prior period adjustments not related to depletion in the year, and would involve complex and extensive inclusion of current year estimates that are potentially unrelated to depletion and also include prior period adjustments. **This method would likely yield a more accurate picture of current asset depletion over a year span. This method would also provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, onshore vs. offshore and other necessary details.**

8. Did any issues arise that should be included in the final Statement or a forthcoming Implementation Guide?

In addition to the issues presented and discussed above,

<u>**New Accounting Treatment, SGL Accounts and Accounting Models Required:**</u> In discussions with Treasury SGL experts, new Standard General Ledger (SGL) accounts, reciprocal pairs and posting models will need to be developed, approved, and incorporated into Treasury financial statement crosswalks. For example, some transfer pairs will involve transfers from a clearing to a special fund, some with and some without budget authority. Also, currently there is not a precedent for recording equity in a general fund or a clearing account. Treasury has indicated however, that it is their policy that until a FASAB Statement is finalized they do not develop or implement new sgl accounts, reciprocal pairs, or models. Accordingly, the final details of implementation remain to be developed. Until formal Treasury approved accounts and models are in place, MMS can not engage with the system contractor to build and modify the required accounts and models needed for implementation. Adequate time is requested for Statement implementation, to facilitate this significant and costly effort.

<u>**New Fund or Reporting Exception Required:**</u> Currently, MMS/MRM appropriately records royalty and related activity flowing through clearing account F3875. Amounts are received from the public and distributed to other federal entities. To capture and report on the capital asset and associated depletion expense, a new fund would be required, or an exception granted to report this activity, including equity, in the clearing account. While Treasury is in the midst of prohibiting or limiting use of the F3875 clearing account, a waiver request is in process for MRM royalty activity and Treasury has indicated that it will likely be granted. Historically, Treasury and OMB mandated that

MRM use this clearing account for their royalty and related activity, and it is hard-coded throughout the MRMSS.

<u>ED pp. 21, 23, 46, 47; Exchange revenue recognition based on SFFAS 7 pp. #34 and reported on SNC; Payments to States and Counties.</u> Royalty payments are made to States and Counties through permanent indefinite appropriations, and reflect the budgetary authority both derived and expended based on actual receipts and disbursements. Payments to States and Counties are made from MMS's royalty clearing account F3875 into permanent indefinite appropriated funds, from which they are ultimately expended. Since MMS is the final entity to receive the cash before it leaves Government custody, it is recorded as a transfer to a special fund, where it is then treated as an obligation and outlay. Accordingly, the custodial transfer account shows the current trading partner, G.1417 (MMS), in accordance with specific FASAB guidance. These special funds are presently reported as 'earmarked'. There are unique and detailed implementation issues associated with ensuring the proper accounting for this activity, based upon the new proposed treatment in the ED. In discussions with Treasury SGL experts, at the least, a new transfer account reciprocal pair would need to be developed. They have indicated however, that it is their policy that until a FASAB Statement becomes finalized they do not develop or implement new sgl accounts, pairs, or models. Accordingly, the final details of implementation remain to be developed, and adequate time is requested for Statement implementation, to facilitate this effort.

<u>ED pp. 21; Exchange revenue recognition based on SFFAS 7 pp. #34.</u> The Statement proscribes that, "Revenue from exchange transactions should be recognized when goods or services are provided to the public or another Government entity at a price."

MMS/MRM records as revenue in the current period, both positive and negative amounts resulting from adjustments to prior royalty reporting, for sales (production) months other than just the current months. This is a routine business process in oil and gas industry reporting, resulting from numerous events where subsequent information is received related to previous reporting periods that was unknown when compulsory reporting was legally due, such as pipeline reallocations, revised gas plant statements, unit reallocations, and pricing revisions. The volume of these adjustments to prior period royalty reporting is significant, recurring, and may span multiple years. This practice is foundational to royalty reporting. We request that the Board consider clarifying related provisions in the ED accordingly.

Also, please refer to the additional discussion in entry #6 above.

<u>ED pp. 46-47; Rescission of amendments to SFFAS 7 related to bonus bid, rent, and royalty revenues.</u> The Statement does not address all commodities accounted for by MMS/MRM, such as solid minerals (and related interest). This creates a significant disparity in accounting treatment, and would result in the capitalization and depletion of only oil and gas, while other commodities would not be capitalized, yet would not be covered under any FASAB provisions. We are presuming that all commodities not covered under the ED would continue to be treated as custodial, according to established provisions in SFFAS 7, pp. 45, 275, 276, and 277. We request that the Statement clearly provide for these commodities, and allow current practices related to them to continue as custodial under existing guidance in SFFAS 7.

As mentioned above, the Statement does not address interest derived from royalty related activity, currently also treated as custodial. The interest component bears no relationship to depletion of the asset, but if related to oil or gas, guidance is needed regarding accounting treatment, to determine if it should still be treated as custodial or on the SNC.

It is strongly recommended that all other commodities and related business activity be addressed in this Oil & Gas Standard before implementation, due to the significant issues and costs related to differing treatment.

Long term vs. short term liabilities: The Exposure Draft and accompanying Appendix C do not break out or distinguish between long or short term liabilities, nor does the pro forma balance sheet present them separately, in relation to the nature of the offsetting assets. While it is understood that the Appendix C entries and statements are illustrative and not meant to present all associated detail, the break out and disclosure of long term vs. short term liabilities is a financial reporting requirement, and poses some issues around implementation. In order to comply with reporting requirements of OMB Circular A-136 and FASAB SFFAS 1, current liabilities must be reported separately from non-current (long term) liabilities.

Clearly, the royalty reports and cash received that remain unmatched at the end of a reporting period are current, as they are generally remitted on the legal due date, and payable in the subsequent month. We request that this be clarified in the Statement and Appendices. However for the new asset ‘Estimated Petroleum Royalties’, no mention is made that any portion of the associated liability might be short term or ‘current’.

FASAB SFFAS 1, pp 83 states that, “Other current liabilities may include unpaid expenses that are accrued for the fiscal year for which the financial statements are prepared and are expected to be paid within the fiscal year following the reporting date.” Further, pp. 86 requires, “The reporting entity should disclose the amount of current liabilities not covered by budgetary resources.” And the Glossary defines current liabilities as, “Amounts owed by a federal entity for which the financial statements are prepared, and which need to be paid within the fiscal year following the reporting date.”

For the liability related to ‘Estimated Petroleum Royalties’, some amount will be liquidated and transferred to recipients in the subsequent year, and should therefore be reported as current. The entries demonstrated in Appendix C for the recipient ‘Other Federal Component Entity’ would likewise be affected. We request this be discussed in the Standard and associated Appendices.

The methodology for computing what this current portion might be is subject to debate, but must at least be fairly readily computed, in order to meet short timelines for annual financial statement preparation. It could be based upon the same value reported as depletion expense in the current year. This would be perhaps the best method, as the value would already be computed, reconciled, and audited, and would be most representative of current market conditions that could be expected to occur in the immediately subsequent year.

However, its complexity is greatly increased if it must only relate to oil and gas, as the current ED only includes oil & gas.

If, FASAB determines that the liability related to 'Estimated Petroleum Royalties' should be all classified as long-term (non-current), we request that the Statement clarify this point for implementation.

ED pp. 34; Fiduciary Reporting Requirements:
Currently, EIA does not publish numbers related to proved reserves on Indian lands. Further, MMS only receives a small portion of royalties related to Indian leases, which are distributed to OST for subsequent funds management and distribution to Tribes. Accordingly, there is presently not a means for MMS to know how to estimate an asset value, nor how to present estimated depletion. While estimates could always be developed, the validity of the data could later be proved to be incorrect, and would be a very broad estimate at best.

Potential Impacts to BLM Accounting and Custodial Statement: BLM receives some royalty amounts that are transmitted 2 or 3 times per month to MMS/MRM, where they are then matched to the lease and distributed according to lease terms. The BLM receipts and distributions to MMS are captured as custodial activity and reported on the Statement of Custodial Activity (SCA). For purposes of the Statement, we do not currently think this would pose a problem, as MMS would still be the 'collecting entity' who bears the responsibility for reporting on the satisfaction of the lease obligation and would record the depletion expense. BLM also receives 'Rights of Way' payments on leases for which the Bureau of Reclamation, the General Fund of the Treasury and States are designated recipients. These payments do not relate to commodity depletion, nor do they flow through MMS at any time. They are also recorded on the SCA. At this time, it does not appear that the Statement would impact this activity, or result in the elimination of the BLM SCA. However, we ask that the Board consider this when finalizing the Statement.

ED pp. 31 d, Component Entity Disclosures: As discussed previously in this document, earned revenue includes numerous components including estimates, which can not be readily broken out into categories such as onshore vs. offshore, etc. We request that the Statement clarify the disclosure requirement, such that the disclosure relate specifically to the royalty data linked with depletion expense, and indicate that it is not all-inclusive of total revenue recorded in the financial statements for the period.

<u>ED pp. 32 a & c, Component Entity Required Supplementary Information (RSI):</u>
The information required to be provided in the ED is not available, and so **could not be provided by the MMS. This is information that can only be gathered and provided by the EIA.** As discussed in the valuation process above, MMS had to obtain EIA nationwide data and develop a rough estimation methodology to attempt to arrive at an estimate of the estimated proved reserves under federal domain. The additional information required in the ED for RSI disclosure, such as federal domain technically recoverable resources, onshore and offshore, and historical 10-year information on federal domain estimated proved reserves could only be provided by EIA. If the Board intends that estimated calculations be produced, we request that be clarified. However, such things as net revisions, extensions, new field discoveries, etc. could not be reasonably ascertained.

Summary Comparison of ED to ED View and PV View Field Test Questionnaires

Key
ED = May 2007 Exposure Draft (ED), *Accounting for Federal Oil and Gas Resources*
ED View = ED View field test questionnaire provided by DOI
PV View = Present Value (PV) View field test questionnaire provided by DOI

This comparison is a summary of the detailed comparison of the field test questionnaires at Tab 6.

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
Reliance on Data Provided by EIA	Reliant on proved reserves data provided by EIA.	Reliant on proved reserves data provided by EIA.	Reliant on proved reserves data provided by EIA.
Components Separately Computed	Group oil and lease condensate together.	Compute oil and lease condensate separately and then sum.	Recommends that estimates of proved reserves be divided according to commodity (crude oil, lease condensate, and natural gas – wet after lease separation), and, in the Gulf of Mexico (GOM), further for each commodity by the water depth category of the field. (DOI acknowledges that they have had difficulty communicating with EIA to determine if EIA can provide such a breakdown of proved reserves.)
Wet vs. Dry Gas	Base calculation on dry (pipeline quality) gas.	Compute wet and dry gas separately and then sum.	The Exposure Draft calls for the estimation of royalties from proved reserves of natural gas plant liquids (NGPL) along with royalties from proved reserve estimates of crude oil, lease condensate, and presumably dry natural gas. The EIA reports estimates of natural gas reserves in two different forms. One form is Dry Natural Gas which is the volume of natural gas after the natural gas liquids have been removed. The other form is Natural Gas, Wet After Lease Separation which is the volume of natural gas prior to the natural gas liquids being removed. Should dry gas proved reserves be used for the royalty estimates, NGPL proved reserve estimates should also be used to capture the entire hydrocarbon value. However, wet gas volumes and values are greater than dry gas volumes and values because of the

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
			additional content of NGPL in the wet gas. MMS prefers the use of the wet gas estimates because they replicate the form and the point in time when the royalty valuations are made. Further, MMS/OMM reservoir engineers and geoscientists are very experienced in dealing with and estimating reserves and production in terms of wet gas as all MMS/OMM datasets are in terms of wet gas. Finally, the use of dry gas and NGPL creates possibly insurmountable problems in properly allocating reserves back to their source fields, affecting value estimations at the proper royalty rates, and in constructing production profiles. Adding values for NGPL to this would amount to a double counting of the values of NGPL. MMS has used only wet gas proved reserves estimates (and no estimates of NGPL) in its trial analysis and highly recommends this procedure for these calculations.
Present Value Of Royalties Received Over Time	N/A	N/A	In order to effectively calculate the present value of federal royalties, it needs to be estimated how those royalties will be received over time. To determine this, one needs to project how the proved reserves estimates will be produced over time. EIA proved reserve estimates include reserves from which federal royalties will be received, as well as, reserves from which royalties will not be received due to various royalty relief policies. The model that MMS has created can be used to project the future production of the EIA proved reserve estimates assuming an exponential decline at a rate of the modeler's choice. The model also receives, as inputs, annual estimates of royalty free production from royalty relief. The annual production estimates of the proved reserves calculated by the model are then reduced by the royalty free annual volumes prior to the royalty calculations.

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
Estimate of Future Gas Prices	N/A	N/A	Of equal importance in the estimation of the present value of royalties to the production estimates are the estimates of future oil and gas prices. MMS-OMM recommends that independently generated and commonly available price estimates be used. The MMS-OMM already uses and is familiar with the OMB economic assumptions that are generated semi-annually for the President's Budget. For the purpose of the trial analysis performed, the oil and gas prices from the OMB's "Economic Assumptions for the 2008 Mid-Session Review" were employed. A minor limitation to those parameters is that the projections are only for 10 years into the future. An extrapolation of out-year trends in the projections has been made to extend the price profiles as long as necessary. Depending on the locations associated with the price parameters, the prices will have to be adjusted to approximate average wellhead prices for each OCS Region (GOM, Pacific, Alaska North Slope). Such an adjustment has two components, an adjustment to a regional landed average price, then a transportation allowance to a regional wellhead average price. The first adjustment to a regional landed average price will be conducted by observing the historical average relationship of the price series being considered (e.g., United States average wellhead natural gas price) to the average regional landed natural gas price (e.g., Henry Hub). From these observations, factors and/or trends in these price relationships can be deduced and applied to the price projections to result in projections of regional landed prices. Such relationships need to be studied in detail prior to "going live" with the present value estimates. For the purpose of the trial analysis performed, it was assumed that the OMB's average

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
			imported and domestic refiner's acquisition cost for oil and the average wellhead price for imported, inter-, and intra-State natural gas estimates would be equivalent to the average landed prices of oil and gas for each Region. The OMB's price projections are expressed in nominal terms.
Transportation Allowances	N/A	N/A	The second component of the price adjustment is the transportation allowances. Lessees pay royalties based on the value of their production at the wellhead. Since the price adjustment above resulted in a regional average landed price, these need to be converted to regional average wellhead prices by subtracting a regional average transportation allowance. One approach would be for MMS-MRM to determine the necessary average historical transportation allowances claimed by lessees on royalty bearing production for the previous 12 sales months. Such averages would be weighted by the volume of production using that allowance, would be by commodity, and for the GOM, would be by the royalty rate of the contributing leases. The assumption would then be that the resulting previous 12-month average transportation allowances would also apply to all future production within the same category. Because the price projections used are nominal values, the transportation allowances would be increased in the future with inflation. This method was employed in the trial analysis, though further study of the accuracy of this approach would be necessary prior to any official calculations.
Discount and Inflation Rates	N/A	N/A	As for product prices, MMS-OMM recommends that independently generated and commonly available discount and inflation rates be used in calculating the royalty present value. A public sector discount rate for the federal government should be readily available and applicable for this purpose. For the purpose of the trial

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
			analysis, MMS assumed a discount rate equal to the federal government's interest rate paid on its long-term borrowing as the discount rate. OMB's projection of the 30-year Treasury Bill rate was used. For inflation, MMS assumed OMB's projection of the GDP Price Index for the trial analysis. As was the case for OMB's oil and gas price projections, projections of these parameters by OMB are also only for 10 years into the future. An extrapolation of out-year trends in the projections has been made to extend the price profiles as long as necessary.
Present Value Calculations	N/A	N/A	For all federal offshore areas, MMS proposes the use of the following method to estimate the present value of future federal royalties from proved reserves: 1) By federal OCS Region, project production of DOE-EIA proved oil/condensate, and wet natural gas reserves estimates over time until depleted, 2) In GOM, also project separately for one-sixth and one eighth royalty rate leases (use water depth subsets of >400m and <400m as proxy), 3) Where applicable, determine adjustments needed to reflect projected royalty free production from royalty relief leases and modify as appropriate the total projections above, 4) Calculate future regional landed prices from price projection (OMB or other) assigned by FASAB using historical price relationships to make further adjustments, 5) Calculate future wellhead landed prices from regional landed prices using average actual transportation allowances claimed for the previous 12-month period.

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
			6) For production for each Regional commodity by royalty rate, calculate annual royalties as follows: (Annual Production less adjustments for Annual Royalty Free Production) * (Annual Regional Landed Price – Average Transportation Allowance) * Royalty Rate 7) For a given vector of calculated future annual royalty estimates, determine the present value of the royalty revenue stream assuming the discount rate (OMB 30-year Treasury Bill or other) assigned by FASAB.
Selection of Regions	Par. 17 states that "the regions used in determining and reporting regional amounts or factors shall be collaboratively developed by all the component entities involved in oil and gas resource activities."	Regions were divided simply into onshore and offshore. However, for implementation of the Statement, we would recommend a greater degree of division, to better reflect price differentials in different basins and regions.	Not specifically discussed.
Data Provided by EIA	Par. 38 states that "based on quantity information from an annual survey conducted by the EIA, the estimated quantities of proved oil and lease condensate reserves from Federal oil and gas resources are to be added together in each region, the estimated quantities of proved NGPLs reserves from Federal gas resources are to be added together in each region, and the	The first step was to determine what portion of all proved reserves fall under federal domain, before the federal royalty share of those proved reserves could be estimated. This information is presently not published by EIA, so an estimation methodology had to be developed. Step 1: MRM performed queries from its published statistics module of royalties reported for the 12 sales (production) months in calendar year 2005, which would include any adjustments for sales months in that time frame made up through September, 2007, when the final refined queries were run.	Substantially the same as ED View Field Test Questionnaire; however, offshore quantities are under federal domain by definition, so were excluded from the estimation process. This differs from the computation method developed in the ED.

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
	estimated quantities of proved gas reserves from Federal gas resources are to be added together in each region.”	Step 2: MMS Custodial Reporting Branch (CRB) obtained the published EIA 2005 Annual Report of total nationwide estimated proved reserves, both federal and non-federal. Step 3: MMS CRB then estimated the federal portion of onshore proved reserves by using a ratio of 2005 onshore estimated production nationwide published by EIA, compared to 2005 total production volumes from federal leases reported to MRM on royalty reports. Step 4: The ratios of federal to total 2005 production then became a proxy for the ratio of federal proved reserves to total proved reserves reported by EIA.	
Asset Value	Par. 18 states that “The values of estimated petroleum royalties calculated for oil and lease condensate on a regional basis, NGPLs calculated on a regional basis, and gas calculated on a regional basis shall be added together to provide the total value of estimated petroleum royalties for the Federal government.”	Step 5: To compute the estimated beginning balance of the federal royalty share of the asset to capitalize, MMS CRB utilized the existing royalty reported data for sales months in calendar year 2005 which had been provided by MRM to aid in computing the estimated quantity, as it had already been refined and was available. This was done solely for illustrative purposes to obtain a beginning balance. In actual practice this unique scenario would not exist, where the EIA published data and the MRM reported royalty data would cover the exact same time frame for computing the averages. In practice, the MRM reported data used to compute the averages would be more current, and reflect more current volumes, prices and rates. It would be based upon the preceding 12 sales months royalties reported for which royalty	Since the federal proved reserves derived from EIA published data were for FY 2005, the amount of production from FY 2006 was subtracted from federal proved reserves before starting additional calculations. Using prior years’ production data and estimates on new wells permitted and drilled each year, an estimated yearly production was estimated for each year. The estimates in new permits approved and wells drilled were based on the following parameters: • 5% of Applications for Permit to Drill (APDs) processed are Indian • 84% of the federal APDs processed are approved • 85% of the federal Approved APDs are drilled • 90% of the wells drilled are productive • 10% of the productive wells are oil • 90% of the productive wells are gas

Issue Area	ED	Field Test Questionnaires: ED View	Field Test Questionnaires: PV View
		production data is available, or July through June when measured at September 30. Step 6: Average royalty rates were computed by dividing the total regional royalty value by the total regional sales value by commodity categories for sales months in calendar year 2005. Step 7: Average unit prices were similarly derived by dividing the total regional sales value by the total regional sales volume. Step 8: The asset value was computed by simply multiplying average rate X average unit price X estimated quantity for each region and commodity category. The totals were then summed to arrive at the total asset estimated value to capitalize. In deriving the averages, numerous factors had to be included, such as excluding royalty relief volumes and estimating the value of commodity received in kind and delivered to DOE to fill the Strategic Petroleum Reserve (SPR). For purposes of the study, since SPR royalty reports contain volumes but no value, the average rate and unit price computed for Gulf oil were imputed to the SPR volumes, and the value computed from these averages. In practice, this method could be used, or alternatively the volumes could be obtained from royalty reports, the value from the manual journals used to record the activity in the period, and the average rate and average unit price then computed. The summary calculations are presented in Illustration 1.	• 85% of the productive wells begin production in the first year • 10% of the productive wells begin production in the second year • 4% of the productive wells begin production in the third year • 1% of the productive wells begin production in the fourth year • Average oil well produces 7,300 barrels per year or 20 barrels per day • Decrease of 10% per year for oil production • Decrease of 10% per year for gas production • Average gas well produces 80,000 MCF per year or 219 MCF per day • APDs processed in 2008 - 2011 are set at 11,500 and then start a slow decline of 500 APDs per year. Once yearly production estimates were established they were subtracted from the federal proved reserves until the proved reserves were zero. A similar present value method was applied to onshore quantities. A yearly estimated price for oil, natural gas and natural gas liquids was used based on OMB estimates. Since the OMB estimates only went out for ten years, prices were estimated based on the trend of the OMB estimates after that. A royalty rate based on historic data from MMS was used to estimate the royalty rate. The data from MMS on the royalty rate appeared to be constant, so no change in the royalty rate was made for each year. A standard discount rate was used to bring future dollars back to today dollars. The estimated yearly production was multiplied by estimated average yearly price, the royalty rate and the

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
			discount rate for that year. All of these totals were added together to come up with the estimated value of each commodity (oil, natural gas and natural gas liquids). These total were added together to come up with a estimated total value of the federal onshore oil and gas proved reserves.
Effect of Intermediate Production Between the Effective Date of the Reserves Estimate and the Effective Date of the Booked Value	N/A	Discussed in comment section.	In the 21 months that will transpire between the effective date of the reserves estimates and the effective date of the value estimate, the reserves estimate will have been reduced by any depletion of the reserves through production. In addition, over the same time period, the reserves estimate will have been increased through any additions to reserves that naturally occur as accumulations are explored and developed. The intermediate production that occurs between the effective date of the reserve estimates and the effective date of the booked value represents a true and measurable reduction in the proved reserves estimate for which the royalty value will have been received and accounted for elsewhere. Booking the value of this production as proved reserves would amount to an overstatement of this asset. The MMS proposes reducing the proved reserves by the volume of the intermediate production. At the time for calculating the book value of the proved reserves for FASAB, the MMS will have production volume estimates for approximately 18 of the 21 months of intermediate production and proposes to use production projections for the remaining months. MMS believes it would be inconsistent to reduce the value of the royalty stream by the value of the intermediate production without also including a corresponding increase from proved reserves that would be almost certainly added between the effective date of the proved reserve estimates and the effective date of

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
			the booked value. Unlike the intermediate production, however, which can be mostly measured, intermediate increases of the EIA proved reserve estimates are not available for these calculations. The MMS proposes that estimates of the reserves additions be employed and offers the following methodology for estimating revised reserves estimates based on the EIA estimates but are effective the date of the booked asset value. The methodology employs the historical relationship between the volume of production of proved reserves and the volume of reserves additions to proved reserves. The EIA has estimated and reported the proved reserves of the federal OCS areas for many years. In its annual presentation of its reserves estimates, EIA reports the previous year's reserve estimate, all additions to that previous year's estimate, and all reductions to that previous year's estimate (including production). The following are EIA data that track the reserves estimate and corresponding revision categories for crude oil proved reserves of the Pacific federal OCS for 2005. Proved Reserves as of 12/31/2004 547 MMbbl Changes in Reserves During Year Adjustments (+,-) -1 MMbbl Revision Increases (+) 3 MMbbl Revision Decreases (-) 81 MMbbl Sales (-) 0 MMbbl Acquisitions (+) 0 MMbbl Extensions (+) 0 MMbbl New Field Discoveries (+) 0 MMbbl New Reservoir Discov in Old Fields (+) 0 MMbbl

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
			Estimated Production (-) 27 MMbbl Proved Reserves as of 12/31/2005 441 MMbbl Since the MMS will have a reliable estimate of the intermediate production, a method was devised to determine the EIA historical average proved reserves change expressed in proportion to historical average production of proved reserves. For example, between 1992 and 2005, EIA's proved oil and lease condensate reserve estimates for the deep water Gulf of Mexico increased by 2.771 billion barrels. Correspondingly, over that same 14-year period, EIA reports that 2.833 billion barrels of oil and lease condensate were produced from the same area. This indicates over that time period, for every barrel of production that occurred, the oil reserves estimate increased by 97.81% of a barrel (2.771/2.833 = 0.9781). Potentially, this concept can be confusing because of the varying terminology used in the above description. It is important to realize that the reserves estimate adjustment methodology suggested above accounts for reserves additions as well as reserves reductions, including production. This is because the reserves estimate adjustment factor proposed is the determination of the change in the reserves estimate expressed in proportion to the volume of production over the same time period. The important concept to remember is that the volume of production is also a component of the change in reserves estimate. Using these calculated averages for each appropriate area, and the volumes of intermediate production, MMS proposes that the EIA proved reserves estimates, effective 21 months prior to the effective date of the booked value, be adjusted to a value that is reflective of the effective date of the booked asset value. Continuing

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
			with the same example of Gulf of Mexico deep water proved reserves of oil and lease condensate, the proved reserve estimate was 3.626 billion barrels as of December 31, 2005. The MMS estimates 592 million barrels of intermediate deep water GOM oil and lease condensate production over the 21 months between December 31, 2005 and October 1, 2007. Applying the average reserves change to production ratio, the December 31, 2005 GOM oil and lease condensate proved reserve estimate of 3.626 billion barrels would increase by 579 million barrels (592 million barrels produced * 97.81% = 579 million barrels reserves change) to 4.205 billion barrels by October 1, 2008. The MMS/OMM acknowledges improvements over this method include the receipt of EIA's proved reserves estimates sooner. That is, receiving estimates that are only 9 months out of date, instead of 21 months. This would involve the receipt of the necessary estimated prior to EIA publishing the values. Another improvement is if EIA could provide all of the above data in exactly the form and format needed which would mean by water depth category in the federal offshore Gulf of Mexico, and perhaps for federal only proved reserves for the federal onshore. This adjustment factor is included in the offshore calculations. A production decline factor is included in the onshore calculations, but no factor was included for potential increases or additions. This highlights a significant issue requiring resolution before implementing any valuation methodology, regardless of the valuation method selected
'Earned Revenue' and Depletion Expense	Par. 23 states that "Royalties from the production of proved oil and lease condensate, NGPLs,	This introduces many complexities, including whether or how to include estimates such as the 'royalty accrual' and the relationship between revenue recorded in the current fiscal	Substantively the same as discussion in ED View Field Test Questionnaire.

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
	and gas reserves from Federal oil and gas resources shall be recognized as exchange revenue on the Statement of Net Cost by the component entity that is responsible for collecting the royalty revenue. At the same time, an amount equal to the royalty revenue shall be recognized as depletion expense on the Statement of Net Cost of the component entity that is responsible for collecting the royalty revenue; and, the value of estimated petroleum royalties shall be reduced by the depletion expense amount."	year for royalty reporting adjustments made to prior years and current year depletion expense. Revenue earned by the collecting entity generally consists of amounts reported or billed, cash for which no royalty report has been received (unmatched cash), and amounts accrued as estimates. There is not a simple means at this time to obtain detail which reconciles to the general ledger and financial statements, of all components of earned revenue specifically related to oil and gas and more specifically related to offshore vs. onshore leases. The recommended alternative is to record depletion based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end; July through June (received through August, fully available in September). This would preclude the need to include estimates in the depletion calculations (discussed below), and would represent a realistic value of true asset depletion based on actual royalty reporting. Revenue earned would not be a perfect match in the fiscal year, but in this case it should not, because depletion in the current year should not be linked to prior adjustments not related to the current year. To do otherwise would include prior period adjustments not related to depletion in the year, and would involve complex and extensive inclusion of current year estimates that also include prior period adjustments. This method would likely yield a more accurate picture of current asset depletion over a year span. This method would also provide the ability, with sophisticated	

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
		queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, onshore vs. offshore and other necessary details. Another alternative would be to record depletion based solely upon all royalty lines received and accepted during the fiscal year, excluding all accruals and regardless of sales month. Again, revenue earned would not be a perfect match in the fiscal year, because accruals would be excluded. But including all lines accepted in a year would eliminate the need to include complex and extensive current year-end estimates for which disclosure detail is not available (see discussion below) because actuals over a 12 month span would be fully included. This method would, however, include all adjustments to prior reporting received in the current fiscal year, and while it may provide a closer tie to actual revenue reported in the financial statements, it would not be as fair a measure of asset depletion in the year. This method, like the recommended method above, would provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, and other necessary details. The matrix in Illustration 3 presents some of the key components of 'earned royalty revenue' presently recorded by MMS, and demonstrates how the earned royalty revenue value was estimated for the illustrative pro forma entries. It must be noted that in actual practice, the previous year-end estimate would	

		Field Test Questionnaires	
Issue Area	**ED**	**ED View**	**PV View**
		be reversed in the subsequent year, so that actual revenue recorded in any given year related to estimates would essentially reflect the change associated with those estimates over the year. In this example, for the study, the full values were presented, to give the reader a general idea of the relative sizes of the estimates under discussion.	

Detailed Comparison of ED View and PV View Field Test Questionnaires

The field tests prepared by the Department of Interior (DOI) provided pro forma transactions for the following ten accounting events for both the (a) proposed standards presented in the exposure draft (ED) as well as (b) the alternative view presented in paragraphs 114 through 127 of the Basis for Conclusion in the ED. The alternative view is being referred to as the present value (PV) view.

1. recording the initial value of the estimated petroleum royalties;
2. recording the one-fifth bid amounts;
3. recording the remaining payment by the successful bidder and the annual rental fee and the related liability for revenue distributions to others;
4. recording the annual rental fee from pre-existing leases and the related liability for revenue distributions to others;
5. refunding the unsuccessful bidders' bonus bid deposits;
6. recording earned royalty revenue and depletion expense;
7. recording the collection of royalty revenue;
8. recording the distribution of bonus bid, rent, and royalty collections and the reduction in the liability for the revenue distributed to others;
9. recording the sale of future royalty streams identified for sale and the related change in the liability for revenue distributions to others; and,
10. recording the annual valuation of estimated petroleum royalties and the related change in the liability for revenue distributions to others.

Key
(yellow) - Text in ED View field test questionnaire differs from the ED
(green) - Text in PV View field test questionnaire differs from the ED View field test questionnaire

ED	PV
1. Record the initial value of the estimated petroleum royalties and the related liability for revenue distributions to others. (There is a material difference between the field test views; read narrative that follows for more information.)	
The initial value of estimated petroleum royalties used in this pro forma transaction is calculated for illustrative purposes only. The value of the federal government's estimated petroleum royalties was calculated based on the valuation of oil and lease condensate estimated petroleum royalties, natural gas plant liquids (NGPLs) estimated petroleum royalties, and gas estimated petroleum royalties on a regional basis. Formulas to be used to calculate the	The initial value of estimated petroleum royalties used in this pro forma transaction is calculated for illustrative purposes only. The value of the federal government's estimated petroleum royalties was calculated based on the PV method developed by the Team, and described in detail below. **Methodology for Estimating the Present Value**

ED	PV
estimated petroleum royalties for oil and lease condensate, NGPLs, and gas on a regional basis are as follows: For oil and lease condensate **(Computed Separately and then Summed)**: **Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves X Regional Average First Purchase Price for Oil and Lease Condensate X Effective Regional Average Royalty Rate for Oil and Lease Condensate = Regional Estimated Petroleum Royalties for Oil and Lease Condensate** For NGPLs: **Regional Estimated Quantity of Proved NGPLs Reserves X Regional Average First Purchase Price for NGPLs X Effective Regional Average Royalty Rate for NGPLs = Regional Estimated Petroleum Royalties for NGPLs** For **wet and** dry gas **(Computed Separately and then Summed)**: **Regional Estimated Quantity of Proved Gas Reserves X Regional Average Wellhead Price for Gas X Effective Regional Average Royalty Rate for Gas = Regional Estimated Petroleum Royalties for Gas** When computing regional average unit prices and regional average royalty rates by commodity, each component in common between EIA and MMS should be averaged separately and then summed. For example, when computing averages for oil and lease condensate, they should be computed separately, as their average unit price and rate are different. In order to have a more accurate estimate, they should not be folded together and then averaged, or	**of the Federal Royalties from Federal Proved Reserves (Present Value Method)** **Offshore** The following methodology is offered as a workable solution to the Alternative View proposal that a "Fair Value" method be used to value future federal royalty receipts from proved oil and gas reserves on federal lands. This methodology has been proposed by the MMS Offshore Minerals Management (MMS-OMM). A model has been constructed and tested, though the results only apply to federal offshore royalties which fall under the MMS-OMM domain. Federal agencies responsible for management of federal onshore oil and gas proved reserves concurred with this proposal, and also applied a similar methodology for valuing federal onshore proved reserves for the FASAB study. Responsibility for estimating the present value of the federal share of federal OCS proved reserves would reside primarily within the OMM Resource Evaluation (OMM-RE) umbrella with assistance from the Department of Energy – Energy Information Administration (EIA), MMS – Minerals Revenue Management (MMS-MRM), and the MMS - OMM Economics Division (OMM-ED). **Proved Reserves Estimates** The basis for these calculations would be the same as is the Majority Proposal. That is, the present value of the future federal royalties revenue steam would be calculated using the Department of Energy, Energy Information Administration (EIA) estimated volumes of proved reserves. Ideally, such estimates of proved reserves would need to be divided

[1] The one percent was derived by dividing [Note 21. Custodial Distributions to MMS, Revenues to Fund Operations] by [Total Revenue on the Statement of Custodial Activity] for 2005.
[2] The 15 percent was derived by dividing [Note 21. Payments to States] by [Total Revenue on the Statement of Custodial Activity] for 2005.
[3] The 84 percent was derived by dividing [Transfers-out to other Federal component entities on the Statement of Custodial Activity] by [Total Revenue on the Statement of Custodial Activity] for 2005.

ED	PV
the results may be notably different than if averaged separately and then summed. In the field study, folding just oil & lease condensate together and then computing the average made a $500M difference in the overall asset value. We recommend that the Statement and Appendices **clarify that the major commodity categories in common between EIA and MMS be disaggregated, the averages computed separately, and then summed to derive the asset value.** Royalty information reported to MMS/MRM is reported as the commodity was sold or removed from the lease. This is important to note, as some assumptions had to be made in conducting the study of the ED view, and will exist at implementation. As regards wet vs. dry gas, MMS can only retrieve it as it was reported. For purposes of the field test of the ED view, regions were divided simply into Onshore and Offshore. However, for implementation of the Statement, we would recommend a greater degree of division, to better reflect price differentials in different basins and regions. The first step was to determine what portion of all proved reserves fall under federal domain, before the federal royalty share of those proved reserves could be estimated. This information is presently not published by EIA, so an estimation methodology had to be developed. The MMS/OMM/BLM Team reached agreement on the estimation methodology described herein, and ascertained that **in the absence of better information, this would be an acceptable method to use for implementation as well.** In order to maintain some consistency and comparability with the most recent available EIA data published for calendar year 2005, MRM performed queries from their published statistics module of	according to commodity (crude oil, lease condensate, and natural gas – wet after lease separation), and, in the Gulf of Mexico (GOM), further for each commodity by the water depth category of the field. For example, the proved reserves estimates for oil and lease condensate would further have to be divided into proved reserves from fields in water depths less than 400 meters and proved reserves from fields in water deeper than 400 meters. The water depth subdivision at 400 meters is to facilitate the calculations using the appropriate royalty rate as typically, for pre-2007 GOM leases, those in water shallower than 400 meters have a one-sixth royalty rate and those in deeper than 400 meters have a one-eighth royalty rate. Beginning with GOM leases sold in 2007, all have a one-sixth royalty rate, regardless of water depth. Proved reserves from other federal OCS Regions would not need to be divided according to water depth as those regions, as typically they have a single royalty rate per Region. In reality, the DOI has had difficulty communicating with the EIA to determine if they can comply with the proved reserves data needs expressed above. The MMS/OMM strongly recommends that an agreement be reached with the DOE/EIA to provide the necessary proved reserves data in the appropriate form and format for this or any method adopted for the reserves valuation. Alternatively, the MMS has devised a means for estimating the proportions of EIA proved reserves for the GOM applicable to royalty rates of one-sixth and one-eighth. This has been accomplished by applying the water depth proportions from the most recent MMS proved reserves estimates to the published proved reserve estimates from EIA. **Production Profiles** In order to effectively calculate the present value of federal royalties, it needs to be estimated how those royalties will be received over time.

[4] The one percent was derived by dividing [Note 21. Custodial Distributions to MMS, Revenues to Fund Operations] by [Total Revenue on the Statement of Custodial Activity] for 2005.
[5] The 15 percent was derived by dividing [Note 21. Payments to States] by [Total Revenue on the Statement of Custodial Activity] for 2005.
[6] The 84 percent was derived by dividing [Transfers-out to other Federal component entities on the Statement of Custodial Activity] by [Total Revenue on the Statement of Custodial Activity] for 2005.

ED	PV
royalties reported for the 12 sales (production) months in calendar year 2005, which would include any adjustments for sales months in that time frame made up through September, 2007, when the final refined queries were run. Data obtained included region, product code, commodity description, reported sales volume, reported sales value, and reported royalty value. MMS Custodial Reporting Branch (CRB) obtained the published EIA 2005 Annual Report of total nationwide estimated proved reserves, both federal and non-federal. MMS CRB then estimated the federal portion of onshore proved reserves by using a ratio of 2005 onshore estimated production nationwide published by EIA, compared to 2005 total production volumes from federal leases reported to MRM on royalty reports. The ratios of federal to total 2005 production then became a proxy for the ratio of federal proved reserves to total proved reserves reported by EIA. Offshore quantities are under federal domain by definition, so were excluded from the estimation process. This differs from the computation method developed in the ED. Royalty reported data was used for volumes sold or extracted from the lease, rather than straight production data, because production (OGOR) data is not broken out in the required detail, and it is not as up to date as royalty reported data. It is important to consider that many assumptions had to be made in developing this model. As regards wet vs. dry gas, MMS can only retrieve the data as it is reported by industry, as it is sold or removed from the lease. Below describes the stratification of data that was retrieved by MRM for our field study, and how each commodity was categorized. The Oil and Lease Condensate category contains product codes of: 01 Oil (Oil) 02 Condensate (Lease Condensate) 05 Drip or Scrubber Condensate (Lease Condensate)	To determine this, one needs to project how the proved reserves estimates will be produced over time. EIA proved reserve estimates include reserves from which federal royalties will be received, as well as, reserves from which royalties will not be received due to various royalty relief policies. The model that MMS has created can be used to project the future production of the EIA proved reserve estimates assuming an exponential decline at a rate of the modeler's choice. The model also receives, as inputs, annual estimates of royalty free production from royalty relief. The annual production estimates of the proved reserves calculated by the model are then reduced by the royalty free annual volumes prior to the royalty calculations. **<u>Natural Gas Plant Liquids</u>** The Exposure Draft calls for the estimation of royalties from proved reserves of natural gas plant liquids (NGPL) along with royalties from proved reserve estimates of crude oil, lease condensate, and presumably dry natural gas. The EIA reports estimates of natural gas reserves in two different forms. One form is Dry Natural Gas which is the volume of natural gas after the natural gas liquids have been removed. The other form is Natural Gas, Wet After Lease Separation which is the volume of natural gas prior to the natural gas liquids being removed. Should dry gas proved reserves be used for the royalty estimates, NGPL proved reserve estimates should also be used to capture the entire hydrocarbon value. However, wet gas volumes and values are greater than dry gas volumes and values because of the additional content of NGPL in the wet gas. MMS prefers the use of the wet gas estimates because they replicate the form and the point in time when the royalty valuations are made. Further, MMS/OMM reservoir engineers and geoscientists are very experienced in dealing with and estimating reserves and production in terms of wet gas as all MMS/OMM datasets are in terms of wet gas. Finally, the use of dry gas and NGPL creates possibly insurmountable problems in properly allocating reserves back to their source fields, affecting value estimations at the proper royalty rates, and in constructing production profiles. Adding values for NGPL to this would amount to a double

ED	PV
06 Inlet Scrubber (Lease Condensate) 13 Fuel Oil (Oil) 14 Oil Lost (Oil) 20 Other Liquid Hydrocarbons (Oil) The Gas Category contains product codes of: 03 Processed (Residue) Gas (Dry Gas) 04 Unprocessed (Wet) Gas (Wet Gas) 09 Nitrogen (Wet Gas) 12 Flash Gas (Wet Gas) 15 Fuel Gas (Wet Gas) 16 Gas Lost - Flared or Vented (Wet Gas) 39 Coal Bed Methane (Dry Gas) The NGL Category contains the product code of: 07 Gas Plant Products Where reported and paid separately, <u>dry gas had to be analyzed separately from wet gas</u>, and NGL's were also analyzed separately, averages computed and the totals then summed, in order to derive a more accurate estimate. This differs somewhat from the Exposure Draft, which reports only dry gas and NGL's. However, as a result of the field test, it is apparent that not only is this the reported information that is available, analyzing and computing each commodity category separately also produces a more accurate overall estimate. However, this is limited to the commodity categories reported in common between EIA and MRM. For purposes of the field study only, coal bed methane was added to onshore dry gas, as the rate and price were fairly comparable. But in practice, since proved reserve and estimated production data are available from EIA, this commodity could be computed and reported separately. Commodity categories and units were at the common level between EIA and MMS: Dry Gas (mcf) Wet Gas (mcf)	counting of the values of NGPL. MMS has used only wet gas proved reserves estimates (and no estimated of NGPL) in its trial analysis and highly recommends this procedure for these calculations. **<u>Product Prices</u>** Of equal importance in the estimation of the present value of royalties to the production estimates are the estimates of future oil and gas prices. MMS-OMM recommends that independently generated and commonly available price estimates be used. The MMS-OMM already uses and is familiar with the OMB economic assumptions that are generated semi-annually for the President's Budget. For the purpose of the trial analysis performed, the oil and gas prices from the OMB's "Economic Assumptions for the 2008 Mid-Session Review" were employed. A minor limitation to those parameters is that the projections are only for 10 years into the future. An extrapolation of out-year trends in the projections has been made to extend the price profiles as long as necessary. Depending on the locations associated with the price parameters, the prices will have to be adjusted to approximate average wellhead prices for each OCS Region (GOM, Pacific, Alaska North Slope). Such an adjustment has two components, an adjustment to a regional landed average price, then a transportation allowance to a regional wellhead average price. The first adjustment to a regional landed average price will be conducted by observing the historical average relationship of the price series being considered (e.g., United States average wellhead natural gas price) to the average regional landed natural gas price (e.g., Henry Hub). From these observations, factors and/or trends in these price relationships can be deduced and applied to the price projections to result in projections of regional landed prices. Such relationships need to be studied in detail prior to "going live" with the present value estimates. For the purpose of the trial analysis performed, it was assumed that the OMB's average imported and domestic refiner's acquisition cost for oil and the average wellhead price for imported, inter-, and intra-State natural gas estimates would be equivalent to the

ED	PV
NGL's (bbl 42 us gal) Oil (bbl) Lease Condensate (bbl) Next, to compute the estimated beginning balance of the federal royalty share of the asset to capitalize, MMS CRB utilized the existing royalty reported data for sales months in calendar year 2005 which had been provided by MRM to aid in computing the estimated quantity, as it had already been refined and was available. This was done solely for illustrative purposes to obtain a beginning balance. In actual practice this unique scenario would not exist, where the EIA published data and the MRM reported royalty data would cover the exact same time frame for computing the averages. In practice, the MRM reported data used to compute the averages would be more current, and reflect more current volumes, prices and rates. **It would be based upon the preceding 12 sales months royalties reported for which royalty production data is available, or July through June when measured at September 30 (please refer to pp. 12 in the ED).** Average royalty rates were computed by dividing the total regional royalty value by the total regional sales value by commodity categories for sales months in calendar year 2005. Average unit prices were similarly derived by dividing the total regional sales value by the total regional sales volume. Then, the asset value was computed by simply multiplying average rate X average unit price X estimated quantity for each region and commodity category. The totals were then summed to arrive at the total asset estimated value to capitalize. In deriving the averages, numerous factors had to be included, such as excluding royalty relief volumes and estimating the value of commodity received in kind and delivered to DOE to fill the Strategic Petroleum Reserve (SPR). For purposes of the study, since SPR royalty reports contain volumes but no value, the average rate and unit price computed for Gulf oil were imputed to the SPR volumes, and the value computed from these averages. In	average landed prices of oil and gas for each Region. The OMB's price projections are expressed in nominal terms. **Transportation Allowances** The second component of the price adjustment is the transportation allowances. Lessees pay royalties based on the value of their production at the wellhead. Since the price adjustment above resulted in a regional average landed price, these need to be converted to regional average wellhead prices by subtracting a regional average transportation allowance. One approach would be for MMS-MRM to determine the necessary average historical transportation allowances claimed by lessees on royalty bearing production for the previous 12 sales months. Such averages would be weighted by the volume of production using that allowance, would be by commodity, and for the GOM, would be by the royalty rate of the contributing leases. The assumption would then be that the resulting previous 12-month average transportation allowances would also apply to all future production within the same category. Because the price projections used are nominal values, the transportation allowances would be increased in the future with inflation. This method was employed in the trial analysis, though further study of the accuracy of this approach would be necessary prior to any official calculations. **Discount and Inflation Rates** As for product prices, MMS-OMM recommends that independently generated and commonly available discount and inflation rates be used in calculating the royalty present value. A public sector discount rate for the federal government should be readily available and applicable for this purpose. For the purpose of the trial analysis, MMS assumed a discount rate equal to the federal government's interest rate paid on its long-term borrowing as the discount rate. OMB's projection of the 30-year Treasury Bill rate was used. For inflation, MMS assumed OMB's

ED	PV
practice, this method could be used, or alternatively the volumes could be obtained from royalty reports, the value from the manual journals used to record the activity in the period, and the average rate and average unit price then computed. The summary calculations are presented in Illustration 1.	projection of the GDP Price Index for the trial analysis. As was the case for OMB's oil and gas price projections, projections of these parameters by OMB are also only for 10 years into the future. An extrapolation of out-year trends in the projections has been made to extend the price profiles as long as necessary. **<u>Present Value Calculations</u>** For all federal offshore areas, MMS proposes the use of the following method to estimate the present value of future federal royalties from proved reserves: 1) By federal OCS Region, project production of DOE-EIA proved oil/condensate, and wet natural gas reserves estimates over time until depleted, 2) In GOM, also project separately for one-sixth and one eighth royalty rate leases (use water depth subsets of >400m and <400m as proxy), 3) Where applicable, determine adjustments needed to reflect projected royalty free production from royalty relief leases and modify as appropriate the total projections above, 4) Calculate future regional landed prices from price projection (OMB or other) assigned by FASAB using historical price relationships to make further adjustments, 5) Calculate future wellhead landed prices from regional landed prices using average actual transportation allowances claimed for the previous 12-month period. 6) For production for each Regional commodity by royalty rate, calculate annual royalties as follows: *(Annual Production less adjustments for Annual Royalty Free Production) * (Annual Regional Landed Price – Average Transportation Allowance) * Royalty Rate* 7) For a given vector of calculated future annual royalty estimates, determine the present value of the royalty revenue stream assuming the discount rate (OMB 30-year Treasury Bill or other)

ED	PV
	assigned by FASAB. **Trial Analysis** Using the above methodology, MMS constructed a model and completed a trial calculation for the federal offshore areas assuming that the effective date of the royalty valuation would be October 1, 2007. MMS used its model and made separate calculations of the present value of proved reserves for the relevant categories pertaining to the federal Outer Continental Shelf. Presented below are the categories and resulting present value estimates:

PV of Future Federal OCS Royalty Receipts - Eff 10/1/2007 ($MM)	
GOM One-Sixth Royalty Oil/Condensate	$ 5,702.35
GOM One-Eighth Royalty Oil/Condensate	$20,737.99
GOM One-Sixth Royalty Wet Gas	$ 8,923.55
GOM One-Eighth Royalty Wet Gas	$ 4,198.31
Pacific Region Oil/Condensate	$ 1,868.62
Pacific Region Wet Gas	$ 409.59
Total	$41,840.41

ED	PV
	MMS used future oil and gas price, discount, and inflation rates from the OMB “Economic Assumptions for the 2008 Mid Session Review.” See Illustration 2. **Onshore** The first step in obtaining onshore quantity was to determine **what portion of all proved reserves fall under federal domain**, before the federal royalty share of those proved reserves could be estimated. **This information is presently not published by EIA,** so an estimation methodology had to be developed. **The MMS/OMM/BLM Team reached agreement on the estimation methodology described herein, and ascertained that in the absence of better information, this would be an acceptable method to use for implementation as well.**

<table>
<tr><th>ED</th><th>PV</th></tr>
<tr><td></td><td>For onshore quantities, MMS Custodial Reporting Branch (CRB) obtained the published EIA 2005 Annual Report of total nationwide estimated proved reserves, both federal and non-federal. MMS CRB then estimated the federal portion of onshore proved reserves by using a ratio of 2005 onshore estimated production nationwide published by EIA, compared to 2005 total production volumes from federal leases reported to MRM on royalty reports. The ratios of federal to total 2005 production then became a proxy for the ratio of federal proved reserves to total proved reserves reported by EIA. Offshore quantities are under federal domain by definition, so were excluded from the estimation process. This differs from the computation method developed in the ED.

Royalty reported data was used for volumes sold or extracted from the lease, rather than straight production data, because production (OGOR) data is not broken out in the required detail, and it is not as up to date as royalty reported data.

It is important to consider that many assumptions had to be made in developing this model. As regards wet vs. dry gas, MMS can only retrieve the data as it is reported by industry, as it is sold or removed from the lease. Below describes the stratification of data that was retrieved by MRM for our field study, and how each commodity was categorized.

The Oil and Lease Condensate category contains product codes of:
01 Oil (Oil)
02 Condensate (Lease Condensate)
05 Drip or Scrubber Condensate (Lease Condensate)
06 Inlet Scrubber (Lease Condensate)
13 Fuel Oil (Oil)
14 Oil Lost (Oil)
20 Other Liquid Hydrocarbons (Oil)

The Gas Category contains product codes of:
03 Processed (Residue) Gas (Dry Gas)
04 Unprocessed (Wet) Gas (Wet Gas)</td></tr>
</table>

ED	PV
	09 Nitrogen (Wet Gas) 12 Flash Gas (Wet Gas) 15 Fuel Gas (Wet Gas) 16 Gas Lost - Flared or Vented (Wet Gas) 39 Coal Bed Methane (Dry Gas) The NGL Category contains the product code of: 07 Gas Plant Products Where reported and paid separately, <u>dry gas had to be analyzed separately from wet gas</u>, and NGL's were also analyzed separately, averages computed and the totals then summed, in order to derive a more accurate estimate. This differs somewhat from the Exposure Draft, which reports only dry gas and NGL's. However, as a result of the field test, it is apparent that not only is this the reported information that is available, analyzing and computing each commodity category separately also produces a more accurate overall estimate. However, this is limited to the commodity categories reported in common between EIA and MRM. For purposes of the field study only, coal bed methane was added to onshore dry gas, as the rate and price were fairly comparable. But in practice, since proved reserve and estimated production data are available from EIA, this commodity could be computed and reported separately. Commodity categories and units were at the common level between EIA and MMS: Dry Gas (mcf) Wet Gas (mcf) NGL's (bbl 42 us gal) Oil (bbl) Lease Condensate (bbl) Since the federal proved reserves derived from EIA published data were for FY 2005, the amount of production from FY 2006 was subtracted from federal proved reserves before starting additional calculations. Using prior years' production data and estimates on new wells permitted and drilled each year, an estimated yearly production was estimated for each year. The estimates in new permits approved

ED	PV
	and wells drilled were based on the following parameters: • 5% of APDs processed are Indian • 84% of the federal APDs processed are approved • 85% of the federal Approved APDs are drilled • 90% of the wells drilled are productive • 10% of the productive wells are oil • 90% of the productive wells are gas • 85% of the productive wells begin production in the first year • 10% of the productive wells begin production in the second year • 4% of the productive wells begin production in the third year • 1% of the productive wells begin production in the fourth year • Average oil well produces 7,300 barrels per year or 20 barrels per day • Decrease of 10% per year for oil production • Decrease of 10% per year for gas production • Average gas well produces 80,000 MCF per year or 219 MCF per day • APDs processed in 2008 - 2011 are set at 11,500 and then start a slow decline of 500 APDs per year. Once yearly production estimates were established they were subtracted from the federal proved reserves until the proved reserves were zero. A similar present value method was applied to onshore quantities. A yearly estimated price for oil, natural gas and natural gas liquids was used based on OMB estimates. Since the OMB estimates only went out for ten years, prices were estimated based on the trend of the OMB estimates after that. A royalty rate based on historic data from MMS was used to estimate the royalty rate. The data from MMS on the royalty rate appeared to be constant, so no change in the royalty rate was made for each year. A standard discount rate was used to bring future dollars back to today dollars. The estimated yearly production was multiplied by estimated average yearly price, the royalty rate and the discount rate for that year. All of these totals were added together to come up with the estimated value of each commodity (oil, natural gas and natural gas liquids). These

ED	PV
The initial value of estimated petroleum royalties is a hypothetical number used for illustrative purposes only. The hypothetical initial value of estimated petroleum royalties based on the methodologies described above is $**112,380,231,231**. The illustrative pro forma transaction to record the initial value of the federal government's estimated petroleum royalties and related liability is presented below. The asset's value represents the **effective average** royalty share of the federal oil and gas resources classified as "proved reserves." The related liability represents the **effective average** royalty share of the federal oil and gas resources classified as "proved reserves" designated to be distributed to others, i.e., the states, the general fund of the U.S. Treasury and other federal component entities, **not** including the component entity responsible for collecting royalties. The proposed treatment of distribution of revenue to others creates a federal and a non-federal liability for the component entity responsible for collecting royalties. The cumulative effect of adopting this accounting standard would be reported as a "change in accounting principle" in accordance with SFFAS 21, *Reporting Corrections of Errors and Changes in Accounting Principles*. The adjustment would be made to the beginning net position on the component entity responsible for collecting royalties Statement of Changes in Net Position for the period the change is made **and the other federal component entities for their allocable share of the related asset**. To obtain the value of the adjustment, the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the component entity responsible for collecting royalties. For this illustration, one percent was used as the average annual share of the revenue distributed to the component entity responsible for collecting royalties based on the average distribution for 2005.[1] To record the related liabilities the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the states. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[2] For this illustration, 84 percent was	total were added together to come up with a estimated total value of the federal onshore oil and gas proved reserves, which was $23,088.64. The initial value of estimated petroleum royalties is a hypothetical number used for illustrative purposes only. The hypothetical initial value of estimated petroleum royalties based on the PV methodology described below for offshore is $41,840,410,000, and for onshore is $23,088,640,000, for a total of **$64,929,050,000**. The illustrative pro forma transaction to record the initial value of the federal government's estimated petroleum royalties and related liability is presented below. The asset's value represents the estimated royalty share of the federal oil and gas resources classified as "proved reserves." The related liability represents the estimated royalty share of the federal oil and gas resources classified as "proved reserves" designated to be distributed to others, i.e., the states, the general fund of the U.S. Treasury and other federal component entities, **not** including the component entity responsible for collecting royalties. The proposed treatment of distribution of revenue to others creates a federal and a non-federal liability for the component entity responsible for collecting royalties. The cumulative effect of adopting this accounting standard would be reported as a "change in accounting principle" in accordance with SFFAS 21, *Reporting Corrections of Errors and Changes in Accounting Principles*. The adjustment would be made to the beginning net position on the component entity responsible for collecting royalties Statement of Changes in Net Position for the period the change is made **and the other federal component entities for their allocable share of the related asset**. To obtain the value of the adjustment, the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the component entity responsible for collecting royalties. For this illustration, one percent was used as the average annual share of the revenue distributed to the component entity responsible for collecting royalties based on the average distribution for 2005.[4] To record the related liabilities the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the states. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[5] For this illustration, 84 percent was

<table>
<tr><th>ED</th><th>PV</th></tr>
<tr><td>used as an average annual share of the revenue distributed to other federal component entities based on the average distribution for 2005.[3] These calculations are presented below:

$112,380,231,231 X .01 = $ 1,123,802,312
$112,380,231,231 X .84 = $94,399,394,234
$112,380,231,231 X .15 = $16,857,034,685

Dr Estimated Petroleum Royalties 112,380,231,231
Cr PPA: Change In Acct Principle 1,123,802,312
Cr Liability for Rev Distr to Others-Federal 94,399,394,234
Cr Liability for Rev Distr to States-Non-Fed 16,857,034,685

<i>To record initial value of estimated petroleum royalties due to change in accounting principle, the related liabilities to state and local governments, and the related liabilities to other Federal component entities. (The 1% expected to be retained by the entity responsible for making royalty collections increases its net position.)</i></td><td>used as an average annual share of the revenue distributed to other federal component entities based on the average distribution for 2005.[6] These calculations are presented below:

$ 64,929,050,000 X .01 = $ 649,290,500
$ 64,929,050,000 X .84 = $54,540,402,000
$ 64,929,050,000 X .15 = $ 9,739,357,000

Dr Estimated Petroleum Royalties 64,929,050,000
Cr PPA: Change In Acct Principle 649,290,500
Cr Liability for Rev Distr to Others-Federal 54,540,402,000
Cr Liability for Rev Distr to States-Non-Fed 9,739,357,000

To record initial value of estimated petroleum royalties due to change in accounting principle, the related liabilities to state and local governments, and the related liabilities to other federal component entities. (The 1% expected to be retained by the entity responsible for making royalty collections increases its net position.)</td></tr>
<tr><td colspan="2">2. Record payment of the one-fifth bonus bid amounts.

(same entry in all three – no differences)</td></tr>
<tr><td>Dr Fund Balance with Treasury 1,540,000
Cr Unearned Revenue 1,540,000

To record collection of the one-fifth bonus bids for the four bonus bids.</td><td>same</td></tr>
<tr><td colspan="2">3. Record remaining payment by the successful bidder and the annual rental fee and the related liability for revenue distributions to others.

(same entries in all three – no differences)</td></tr>
</table>

<table>
<tr><th>ED</th><th>PV</th></tr>
<tr><td>Dr Unearned Revenue 400,000
Dr Fund Balance with Treasury 1,960,000
Cr Revenue from Rent 360,000
Cr Revenue from Bonus Bid 2,000,000

To record remaining bonus payment and the annual rental fee by the successful bidder, and associated liability and nominal accounts, less MMS 1% (23,600).

$2,360,000 X .15 = $354,000
$2,360,000 X .84 = $1,982,400

Dr Rev Desgn for Others - Non-Fed [7] 354,000
Dr Transfers-Out 1,982,400
Cr Liability for Rev Distr to Others-Fed 1,982,400
Cr Liability for Rev Distr to States-Non-Fed 354,000

To record the related increase in the liability for the future revenue distributions to others.

<u>Other federal component entity entry:</u>

Dr Accounts Receivable 1,982,400
Cr Transfer-In 1,982,400

To record the related accrual of a transfer-in and a reduction in the long-term A/R.</td><td>same</td></tr>
<tr><td colspan="2">4. Receive the annual rental fee from pre-existing leases and record the related liability for revenue distributions to others.
(same entries in all three – no differences)</td></tr>
<tr><td>Dr Fund Balance with Treasury 239,501,681
Cr Revenue from Rent 239,501,681</td><td>same</td></tr>
</table>

[7] This and certain other titles were selected for illustrative purposes. The entity has the option of selecting another account title that may be more appropriate.

ED	PV
To record rental payments on leases for the year. $239,501,681 X .15 = $35,925,252 239,501,681 X .84 = $201,181,412 Dr Rev Desgn for Others – Non-Fed 35,925,252 Dr Transfers-Out 201,181,412 Cr Liability for Rev Distr to Others-Fed 201,181,412 Cr Liability for Rev Distr to States-Non-Fed 35,925,252 *To record the related increase in the liability for the future revenue distributions to others.* *Other federal component entity entry:* Dr Accounts Receivable 201,181,412 Cr Transfer-In 201,181,412 *To record the related accrual of a transfer-in and a reduction in the long-term A/R.*	
5. Refund unsuccessful bidders' bonus bid deposits. (same entries in all three – no differences)	
Dr Unearned Revenue 1,140,000 Cr Fund Balance with Treasury 1,140,000 *To record refund of losing bonus bids.*	same
6. Record earned royalty revenue and depletion expense. (same entries in both field tests; amount different in ED - $4,416,252,801)	
The ED states that, *"Earned royalty revenue should be recognized as exchange revenue by the component entity that is responsible for collecting the royalties. At the same time, an amount equal to the royalty collections should be recognized as depletion expense;*	same

ED	PV
and, the value of estimated petroleum reserves should be reduced by the depletion expense amount. Sales value and royalty payment information are due on or before the last of the month following the month the oil or gas product from Federal oil and gas resources was sold or removed from the lease. For example, oil or gas sold in June must be reported by July 31, the end of the following month." **There are extensive issues discussed below around the many components of revenue recognized by the collecting entity, the relationship of that revenue to depletion expense, and the present or future ability to obtain information at the level of detail presented in the ED. This is a significant set of issues that we believe must be addressed before the ED is finalized.** The ED proposes to base depletion expense upon oil & gas 'royalty revenue earned' for the fiscal year (pp. 23, and Appendix C, entry #6), and is silent regarding what components would comprise this value, except that pp. 23 refers to 'royalties from the production' of proved reserves. This introduces many complexities, including whether or how to include estimates such as the 'royalty accrual' (discussed below), and **the relationship between revenue recorded in the current fiscal year for royalty reporting adjustments made to prior years and current year depletion expense**. Revenue earned by the collecting entity generally consists of amounts reported or billed, cash for which no royalty report has been received (unmatched cash), and amounts accrued as estimates. There is not a simple means at this time to obtain detail which reconciles to the general ledger and financial statements, of all components of earned revenue specifically related to oil and gas and more specifically related to offshore vs. onshore leases. **<u>Earned Revenue Based Upon Royalty Reports; Royalty Adjustments to Prior Periods:</u>** In addition to current royalty amounts, MMS records earned revenue in the current period for the sum of both positive and	

ED	PV
negative amounts resulting from upward or downward adjustments to prior royalty reporting, related to previous months when the commodity had been either sold or removed from the lease **(sales months).** This is a standard business process in oil and gas industry reporting, resulting from the receipt of subsequent information related to previous reporting periods that was unknown when the compulsory reporting was legally due, such as revised pipeline statements. These adjustments frequently cross monthly, quarterly, and fiscal year boundaries, can be large amounts, and are routine. If depletion expense is linked across the board with overall revenue earned in the current year, then it must be understood that it would be at least partially based on revenue earned in the current year that is related to adjustments to prior periods falling outside the fiscal year. Therefore, the asset would be depleted in the current year based upon activity that does not actually reflect true depletion in the actual year. If depletion expense were alternatively based upon revenue earned for oil & gas royalty reports related to current year production only, to most closely reflect the actual asset depletion in the current year, it would be applicable to only the **sales months** falling within the fiscal year. This would exclude prior period adjustments to royalty reporting that would be deemed unrelated to depletion in the current year. However, complete royalty reporting covering production in the current fiscal year measured at 9/30 can only be ascertained through August, which covers actual reported royalty production through June (for which delayed reporting would not be due until August if a paid estimate were in place). In other words, only 9 months of complete sales month (production) data within a given fiscal year are available at 9/30 if basing 'revenue earned' and depletion expense only on current fiscal year sales months; October through June. Clearly, this would not present a complete picture of current year asset depletion, because it would not even include a full 12 months of royalty reporting.	

ED	PV
The recommended alternative is to record depletion based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end; July through June (received through August, fully available in September). This would preclude the need to include estimates in the depletion calculations (discussed below), and would represent a realistic value of true asset depletion based on actual royalty reporting. **Revenue earned would not be a perfect match in the fiscal year, but in this case *it should not*, because depletion in the current year should not be linked to prior adjustments not related to the current year.** To do otherwise would *include* prior period adjustments not related to depletion in the year, and would involve complex and extensive inclusion of current year estimates that also include prior period adjustments. **This method would likely yield a more accurate picture of current asset depletion over a year span. This method would also provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, onshore vs. offshore and other necessary details.** Another alternative would be to record depletion based solely upon all royalty lines received and accepted during the fiscal year, excluding all accruals and regardless of sales month. Again, revenue earned would not be a perfect match in the fiscal year, because accruals would be excluded. But including all lines accepted in a year would eliminate the need to include complex and extensive current year-end estimates for which disclosure detail is not available (see discussion below) because actuals over a 12 month span would be fully included. This method would, however, include all adjustments to prior reporting received in the current fiscal year, and while it may provide a closer tie to actual revenue reported in the financial statements, it would not be as fair a measure of asset depletion in the year. This method, like the recommended method above, would provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as	

ED	PV
commodity type, Region, and other necessary details. **Earned Revenue; Document Level Royalty Reporting Accruals vs. Line Level Royalty Detail:** When a royalty document is received, it usually includes numerous individual 'lines' of reporting. Each line contains specific detail about the royalty, such as the individual lease number, sales month and product code. If even one line of the royalty document passes edits and accepts in the royalty accounting system (MRMSS), then revenue is recorded for the full 'document calculated total'. If all lines reject, then a manual accrual is made for the full 'document calculated total'. Priority is placed on clearing rejected lines as quickly as possible, generally in the month following receipt. In subsequent periods, as the previously rejected royalty lines are corrected and accept in the MRMSS, they do not give rise to revenue, as it was already properly accrued when the document was first received. As you can see, the detail required in the ED for 'earned revenue' by oil or gas and onshore vs. offshore is not readily obtainable for this portion of the population (rejected lines in the last month of the year). For purposes of the field study, CRB undertook an initial effort to ascertain in a 1-month period, the detail related to line level royalty revenue earned by oil or gas and onshore vs. offshore. In instances where the doc calc total giving rise to revenue in the period did not equal the sum of the accepted lines in the system, CRB developed a method to allocate (estimate) earned revenue to detail associated with existing lines. **This identified a significant problem in our ability to report accurately on the detail associated with 'earned revenue' based on current month royalty reporting. In many cases, the revenue was allocated to oil or gas based upon an estimate that may or may not be correct, and which may not prove to be correct in subsequent periods when the rejected lines are corrected and accept in the system. This issue further supports the premise that depletion be based solely upon accepted royalty reporting lines for given sales months, as presented above, and not on accruals and estimates.**	

ED	PV
<u>Earned Revenue; Estimates and Manual Accruals:</u> When examining 'earned revenue' and its relationship to asset depletion, CRB performed an extensive analysis for the field study, of estimates and manual accruals related to current period royalty revenue. MMS records numerous manual accruals to fairly present assets, liabilities and revenue in the financial statements. One such entry is the 'royalty accrual', a large accrual that represents estimated production in the current month for oil, gas and solid minerals, where the royalty reports are not yet received. The royalty accrual is not computed based on sales month (production month), but rather upon when the royalty report was received. It is computed based on a 12-month average of previous royalty reports received. Revenue recognition for royalty is consistent therefore, because **prior period adjustments to previous royalty reporting are treated as current year revenue, upward or downward, and factored into the current period royalty accrual. The royalty accrual is subject to extensive year-end audit review, and a large subsequent adjustment may be required annually, later in the financial reporting process (early November). If included in the revenue matched with depletion expense, this would also then, require that the proved reserves asset be adjusted accordingly, and would impact materially, all allocated downstream recipients as well.** The royalty accrual is required to be performed fairly quickly, at the high level, to meet accelerated financial reporting objectives. **It includes adjustments to prior reporting periods, and it does not contain the detail required in the ED, to break out oil vs. gas and onshore vs. offshore.** Of course, a rough estimation method could always be developed, but its accuracy and validity when compared to subsequent actual information could potentially prove to be incorrect. Another significant manual accrual involves **unmatched cash** for which no royalty report has been received at the end of the	

ED	PV
reporting period. This occurs monthly, and this large unmatched cash balance can not accurately be linked to oil or gas, onshore or offshore. In some instances, large compliance settlement amounts may be included in the cash balance, not related to current year royalties. Large amounts could be related to interest payments. It would be incorrect to allocate current year depletion to unmatched amounts that may not be related. **Also, this unmatched cash, when applied to subsequent royalty reports, will likely relate to adjustments to prior reporting, and also not bear a relationship to current year asset depletion.** Previous discussions with FASAB Staff indicated that in order to provide matching of royalty revenue earned in the fiscal year, the royalty accrual would be included in the 'revenue earned' that would be offset by depletion expense, because the accrual estimates production in the current month for which royalty reports will not be yet be received. Also, it was discussed that revenue recognition overall should remain consistent, and that revenue earned in the fiscal year, regardless of sales (production) month and subsequent adjustments, would still apply. Accordingly, the text in pp. #23 and throughout the Statement was going to be revised to include, "Royalties received and accrued..." However, upon analysis **as a result of the field test study,** it is apparent that the degree of detail required to be estimated, allocated and reported is very extensive, labor intensive, **includes adjustments to prior period reporting which may not relate to current period asset depletion at all,** and **poses significant risks to meeting audit and accelerated financial reporting objectives.** Again, including these and other estimates, by default, **includes adjustments to prior reporting, or other activity not necessarily related to actual current period asset depletion. The degree of detail for disclosure required in the ED would not be readily available from these estimates, and would have to be extensively estimated.** And the inclusion of these estimates would likely not yield a better, and perhaps a worse, measure of actual asset depletion in the year, as opposed to the recommended sales month method described above. For the many	

ED	PV
complex accruals currently performed by MMS, estimation methods would have to be developed to allocate some portion of the earned revenue to oil and gas, and then of that subset, to onshore vs. offshore. **For purposes of this field test study, revenue overall is presented in aggregate, includes estimates and is based upon royalty reporting lines received and accepted in the fiscal year, regardless of sales months, to tie with current practices**. **This is done to illustrate the many estimates performed, their relationship to earned revenue, and to explain why the detail required in the ED can not currently be provided. However, it is <u>not the recommended method</u> for deriving depletion expense. Also, disclosures were not attempted.** As we have discussed, estimations pose significant challenges to MMS' ability to produce adequate detail in the required disclosures regarding revenue earned by oil and gas and onshore vs. offshore categories. **It currently could not be readily done with existing resources or information.** Each line of each component of earned revenue would have to be carefully analyzed, an allocation method developed for oil and gas and onshore vs. offshore, and would be an extensive and labor intensive process. A sophisticated system report and queries could be developed to help provide some of this degree of detail, but it would not resolve issues around allocations of estimates, and **timing would be crucial, as reconciliations and adjusting entries would need to be made quickly, to meet accelerated financial reporting deadlines, and to pass audit requirements.** The matrix in Illustration 3 presents some of the key components of 'earned royalty revenue' presently recorded by MMS, and demonstrates how the earned royalty revenue value was estimated for the illustrative pro forma entries. It must be noted that in actual practice, the previous year-end estimate would be reversed in the subsequent year, so that actual revenue recorded in any given year related to estimates would essentially reflect the **change** associated with those estimates over the year. In this example, for	

ED	PV
the study, the full values were presented, to give the reader a general idea of the relative sizes of the estimates under discussion. **Again, the primary concerns related to recording depletion expense based on revenue which includes estimates revolve around mismatching unrelated portions of estimates with actual asset depletion, potential material audit findings and a potential inability to meet accelerated financial reporting objectives.** As an aside, if using the recommended sales month method described above for ascertaining the amount of depletion to record in a fiscal year, then the actual royalty value for oil and gas reported to MMS was approximately $9.2 billion for the most recent sales months available when performing the field test, June 2006 through May 2007, obtained in mid-August 2007. To restate, some of the key concerns around recording depletion expense based upon the sum of current year royalty reports and estimates include: - Revenue and depletion expense would be mismatched due to prior period adjustments not related to current period depletion captured as revenue in the current year. - The revenue estimate including accruals would also include estimates of production anticipated through year-end, and estimates of unmatched cash with estimates sub-allocated to oil & gas, and then sub-allocated to onshore vs. offshore. The estimated allocations will likely be later found to be incorrect. Also, the estimates include adjustments to prior periods, not attributable to depletion in the current period. - Each estimate is already complex to derive, and currently does not include a method for allocating to oil or gas, or onshore vs. offshore. - Revising each estimate accordingly will decrease the likelihood of meeting accelerated financial reporting objectives, and will increase the likelihood of audit failures, and their severity based on materiality.	

<table>
<tr><th>ED</th><th>PV</th></tr>
<tr><td>

Estimates and subsequent changes to estimates will impact the asset value through depletion expense, and so, all designated downstream recipients.
Estimates measured against subsequent actuals at fiscal year end will likely result in material adjustments near the close of the annual financial audit process in early November, and also require adjustment by designated downstream recipients.

For illustrative purposes, the hypothetical numbers previously discussed are presented. The estimated royalty revenue earned and accrued for the fiscal year for offshore and onshore rental leases estimated allocated to oil and gas only was used in this calculation. The estimated royalty revenue earned and accrued during the fiscal year for offshore and onshore leases was roughly estimated to be $11,519,015,047. [This amount was requested to be separated into offshore and onshore amounts in the ED.]

The following entries are recorded by the component entity responsible for collecting royalties.

Dr AR (Billed and Unbilled Accrued) 11,519,015,047
Cr Rev from Royalties for Fed Reserves 11,519,015,047

To record earned royalty revenue.

Dr Oil and Gas Depletion Expense 11,519,015,047
Cr Estimated Petroleum Royalties 11,519,015,047

To record depletion expense for federal oil and gas resources.
</td><td></td></tr>
<tr><td colspan="2">7. Record collection of royalty revenue.
(same entries in both field tests; amount different in ED - $4,048,231,734)</td></tr>
<tr><td>Dr Fund Balance with Treasury 10,048,231,734
Cr Accounts Receivable 10,048,231,734</td><td>same</td></tr>
</table>

<table>
<tr><th>ED</th><th>PV</th></tr>
<tr><td>To record collection of royalty revenue.</td><td></td></tr>
<tr><td colspan="2">8. Record distribution of bonus bid, rent, and royalty collections and the reduction in the liability for the revenue distributed to others.
(same entries in both field tests; amount different in ED - $4,247,192,481 for first and $3,603,678,469 for second)</td></tr>
<tr><td>$10,290,093,415 X .15 = $1,543,514,012
$10,290,093,415 X .84 = $8,643,678,469

Dr Liability for Rev Distr to Others-Fed 8,643,678,469
Dr Liability for Rev Distr to States-Non-Fed 1,543,514,012
Cr Fund Balance with Treasury 10,187,192,481

To record distribution of bonus bid, rent, and royalty revenue collections and the reduction in liabilities for revenue distribution to others.

<u>Other federal entity entry:</u>

Dr Fund Balance with Treasury 8,643,678,469
Cr Accounts Receivable 8,643,678,469

To increase the fund balance with treasury and reduce the accounts receivable in relation to distributions received.</td><td>same</td></tr>
<tr><td colspan="2">9. Disclose rights to future royalty streams identified for sale.

Key subject matter experts have indicated that this scenario is very highly unlikely. Because such extensive analysis and work was required to satisfy other aspects of the field study, this valuation was not revised from the original proposal in the ED.</td></tr>
<tr><td colspan="2">10. Record sale of future royalty streams identified for sale and the related change in the liability for revenue distributions to others.

Key subject matter experts have indicated that this scenario is very highly unlikely. Because such extensive analysis and work was required to satisfy other aspects of the field study, this valuation was not revised from the original proposal in the ED.</td></tr>
</table>

Illustration 1

Summary; Calculations of Estimated Proved Reserves

Federal Offshore Royalties Reported

Calendar Year 2005 Sales Months as of September 4, 2007

Categories Consolidated - Offshore

		Volume	Value	Royalty Value	Calc Royalty Rate	Calc Unit Price
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	1,634,243,775.24	12,891,342,243.25	1,874,938,867.11	0.145442	7.89
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	1,396,328,369.82	9,594,581,770.75	1,469,886,320.24	0.153200	6.87
	Gas Total	**3,030,572,145.06**	**22,485,924,014.00**	**3,344,825,187.35**	**0.148752**	**7.42**
NGL (gal)	Gas Plant Products (gal)	2,106,307,734.15	1,611,579,527.38	135,731,752.01	0.084223	0.77
NGL (bbl 42 gal)	**Gas Plant Products Total (bbl 42 gal)**	**50,150,184.15**	**1,611,579,527.38**	**135,731,752.01**	**0.084223**	**32.14**
Oil (bbl)		331,872,511.54	15,603,826,996.48	2,133,366,086.08	0.136721	47.02
Condensate (bbl)		39,613,036.74	1,291,839,143.91	195,812,132.70	0.151576	32.61
Oil & Cond (bbl)	**Oil & Condensate Total**	**371,485,548.28**	**16,895,666,140.39**	**2,329,178,218.78**	**0.137857**	**45.48**

Calculated Estimated Proved Reserves Under Federal Domain - Federal Royalty Share, as of 9/4/2007 - Offshore

		Onshore Est Proved Reserves	Offshore Est Proved Reserves	Total Est Proved Reserves	Est Asset Val (Avg Rate X Avg Price X Est Quantity)
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	-	18,604,000,000.00	18,604,000,000.00	**21,344,038,883.42**
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	-	19,040,000,000.00	19,040,000,000.00	**20,043,018,635.35**
	Gas Total	**-**	**37,644,000,000.00**	**37,644,000,000.00**	**41,387,057,518.77**
NGL (gal)	Gas Plant Products (gal)				
NGL (bbl 42 gal)	**Gas Plant Prod Total (bbl 42 gal)**	**-**	**740,000,000.00**	**740,000,000.00**	**2,002,814,111.19**
Oil (bbl)		-	4,758,000,000.00	4,758,000,000.00	**30,585,708,320.54**
Condensate (bbl)		-	293,000,000.00	293,000,000.00	**1,448,335,184.64**
Oil & Cond (bbl)	**Oil & Condensate Total**	**-**	**5,051,000,000.00**	**5,051,000,000.00**	**32,034,043,505.19**

Total Est Proved Reserves, Asset Value - Fed Royalty Share - CY 2005 Sales Months - Offshore **75,423,915,135.15**

Federal Onshore Royalties Reported
Calendar Year 2005 Sales Months as of September 4, 2007
Categories Consolidated - Onshore

		Volume	Value	Royalty Value	Calc Royalty Rate	Calc Unit Price
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	1,146,151,633.04	7,426,469,521.60	838,167,362.52	0.112862	6.48
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	1,467,970,348.00	10,602,363,010.95	1,283,204,061.34	0.121030	7.22
	Gas Total	**2,614,121,981.04**	**18,028,832,532.55**	**2,121,371,423.86**	**0.117665**	**6.90**
NGL (gal)	Gas Plant Products (gal)	1,593,967,707.03	1,286,266,838.18	126,132,310.29	0.098061	0.81
NGL (bbl 42 gal)	**Gas Plant Prod Total (bbl 42 gal)**	**37,951,612.07**	**1,286,266,838.18**	**126,132,310.29**	**0.098061**	**33.89**
Oil (bbl)		86,644,381.56	4,304,809,820.77	379,491,776.77	0.088155	49.68
Condensate (bbl)		10,335,920.75	566,071,089.71	69,487,330.46	0.122754	54.77
Oil & Cond (bbl)	**Oil & Condensate Total**	**96,980,302.31**	**4,870,880,910.48**	**448,979,107.23**	**0.092176**	**50.23**

Calculated Estimated Proved Reserves Under Federal Domain - Federal Royalty Share, as of 9/4/2007 - Onshore

		Onshore Est Proved Reserves	Offshore Est Proved Reserves	Total Est Proved Reserves	Est Asset Val (Avg Rate X Avg Price X Est Quantity)
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	15,227,904,771.19	-	15,227,904,771.19	**11,135,989,698.78**
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	19,425,200,893.36	-	19,425,200,893.36	**16,980,245,352.14**
	Gas Total	**34,653,105,664.55**	**-**	**34,653,105,664.55**	**28,116,235,050.92**
NGL (gal)	Gas Plant Products (gal)				
NGL (bbl 42 gal)	**Gas Plant Prod Total (bbl 42 gal)**	**470,294,072.95**	**-**	**470,294,072.95**	**1,563,023,932.26**
Oil (bbl)		1,480,091,280.44	-	1,480,091,280.44	**6,482,618,488.16**
Condensate (bbl)		118,169,090.91	-	118,169,090.91	**794,438,625.14**
Oil & Cond (bbl)	**Oil & Condensate Total**	**1,598,260,371.35**	**-**	**1,598,260,371.35**	**7,277,057,113.30**

Total Est Proved Reserves, Asset Value Est - Fed Royalty Share - CY 2005 Sales Months - Onshore	**36,956,316,096.47**
Total Estimated Proved Reserves, Asset Value Estimate - CY 2005 Sales Months	**112,380,231,231.63**

Illustration 2

Fiscal Year	Oil Price[1] ($/bbl)	Gas Price[2] ($/mcf)	Discount Rate[3] (%/Year)	Inflation Rate[4] (% Change Yr/Yr)
2006	59.94	7.45	4.85	3.1
2007	56.57	6.59	4.87	2.7
2008	63.26	7.70	5.18	2.4
2009	64.09	7.64	5.33	2.2
2010	63.12	7.40	5.48	2.0
2011	62.29	7.18	5.60	2.0
2012	61.80	7.09	5.61	2.0
2013	61.59	7.23	5.61	2.0
2014	61.97	7.38	5.61	2.0
2015	63.21	7.52	5.61	2.0
2016	64.47	7.68	5.61	2.0
2017	65.76	7.83	5.61	2.0
Annual Rate of Increase Thereafter	2.0%	2.0%	0.0%	2.0%
[1]Average Imported and Domestic Refiner's Acquisition Cost				
[2]Average Wellhead Price for Imported, Inter-, and Intra-State Natural Gas				
[3]30-Year Treasury Bills, Notes, and Bond, Bond Equivalent Rate				
[4]Gross Domestic Product Price Index				

Illustration 3

Analysis of Components - Oil & Gas Revenue Earned - Entry #6, FASAB ED

Amounts are representational and illustrative only, to present basic concepts, and are not necessarily based on final or actual numbers

Total Royalty Report Line Level Data Received in Period (Royalty Value Less Allowances - RVLA)	**10,731,532,649**
Royalty line amounts that do not give rise to revenue by collecting entity in period	
Document calculated total equals zero (non-value related adjustments)	246,825,251
No system receivable created, such as for Indian direct pay or Strategic Petroleum Reserve (SPR)	789,559,441
Royalty documents accepted in prior periods where previously rejected lines now accept	17,170,452
Total Royalty Line Amounts That Do Not Give Rise to Revenue by Collecting Entity in Period	**1,053,555,144**
Revenue From Royalty Lines - Other (Currently Reported in 'Rents and Royalties')	**5,333,009**
Remainder - Royalty Lines Giving Rise to Revenue Received in Fiscal Year, Attributable to Oil & Gas	**9,672,644,496**
Accrued Revenue and Estimates - O&G (Illustrative Ending Balances Only - Revenue would be recorded for change in accruals)	
Estimated Portion of Year-End Royalty Accrual Estimating Current Month Production, Oil & Gas	760,179,551
Year-End SPR Accrual Estimating Current Month Production Delivered to DOE, Oil Only	105,216,449
Annual Actual Revenue for Oil Taken In Kind to Fill Strategic Petroleum Reserve (SPR)	200,974,551
Other Invoices In Lieu of Royalty Reports Presumed to be Related to Oil and Gas Royalties	30,000,000
Estimated Royalty Portion of Enforcement Settlements if Related to Current Year - Oil & Gas	50,000,000
Estimated Portion of Numerous Other Revenue Accruals Estimated Allocated to Oil & Gas	200,000,000
Estimated Portion of Unmatched Cash Revenue - No Royalty Report – Allocated to Oil & Gas	500,000,000
Total of Accrued Revenue and Estimates To Be Estimated Allocated to Oil and Gas	**1,846,370,551**
Total Estimated Royalty Related Revenue and Depletion Expense, Oil & Gas, Fiscal Year 20XX	**11,519,015,047**
Other Revenue - Non-CY Oil & Gas Royalty	
Revenue from Onshore lease sale bonus and 1st year rents (does not tie to pro forma entries – informational only)	286,344,000
Revenue from Offshore lease sale bonus and 1st year rents (does not tie to pro forma entries – informational only)	

	387,689,000
Revenue from PY Settlements including Civil Penalties and Interest (Currently reported in 'Rents and Royalties')	80,000,000
Revenue from Royalties - Other Commodities i.e. Solid Minerals (Currently reported in 'Rents and Royalties')	615,752,400
Revenue from Late Payment Interest (Currently reported in 'Rents and Royalties')	60,000,000
Other Commodity Related Miscellaneous Revenue Including Compliance (Currently reported in 'Rents and Royalties')	12,000,000
Total Other Revenue - Non-CY Oil & Gas Royalty	**1,441,785,400**
Total Revenue Reported on Fiscal Year 20XX Statement of Custodial Activity	**12,960,800,447**