Improving the Usefulness of Oil & Gas Resources Estimates: A Forecaster's Perspective

James M. Kendell
Energy Information Administration
James.Kendell@eia.doe.gov

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Today I am going to focus on how an energy forecaster uses oil and gas resource assessments. As you'll see, I'll discuss this from a very particular point of view. That is, how EIA uses them. Undoubtedly other forecasters make different use of resource data, but I hope the problems I raise are representative of the difficulties faced by forecasters. Some of the issues or problems that I raise today may already have solutions. And if that's that case, I'd welcome hearing about them.

For those of you who are not familiar with EIA, we're the independent analytical and statistical agency within the U.S. Department of Energy. We have some measure of independence in issuing our forecasts, and thus don't represent the Department or the Administration. In line with our policy-neutral stance, we also don't speak for any particular point of view on energy policy.

It should be noted that the EIA normally uses Federal oil and gas resource estimates in its forecasts and analyses. Although we acknowledge the fine work performed by the Potential Gas Committee and John Curtis keynoted our recent NEMS/AEO conference, we focus on using Federal estimates in our work. Consequently, my presentation will be confined to a discussion of USGS and MMS oil and gas resource data.

Focus of the Presentation

- The EIA Oil and Gas Supply Model (OGSM) design and its use of USGS-MMS resource data.
- Modeling the effects of technological progress on oil and gas resources.
- USGS oil and gas field appreciation and inferred reserves.
- USGS administrative issues (e.g., resource data dissemination)

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Today, I’m going to talk about four things:

The EIA Oil and Gas Supply Model (OGSM) design and its use of USGS-MMS resource data.

Modeling the effects of technological progress on oil and gas resources.

USGS oil and gas field appreciation and inferred reserves, and

USGS administrative issues on resource data dissemination.

USGS-MMS Oil and Gas Resource Data Used In EIA's Oil & Gas Supply Model

- Technically Recoverable Oil & Gas Resources
- Economically Recoverable Oil & Gas Resources
- Oil and Gas Field Size Distributions
- Unconventional Gas Recovery Per Cell

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First, let me go over the primary USGS-MMS data sets used in the oil and gas supply model. These are illustrated in the next few slides.

National Petroleum Reserve – Alaska
Technically Recoverable Oil & Gas Resources
(Entire Assessment Area)

	USGS 95-Percent Probability Estimate	USGS Mean Probability Estimate	USGS 5-Percent Probability Estimate
Crude Oil (Billion Barrels)	6.7	10.6	15.0
Non-Associated Natural Gas (Trillion Cubic Feet)	40.4	61.4	85.3

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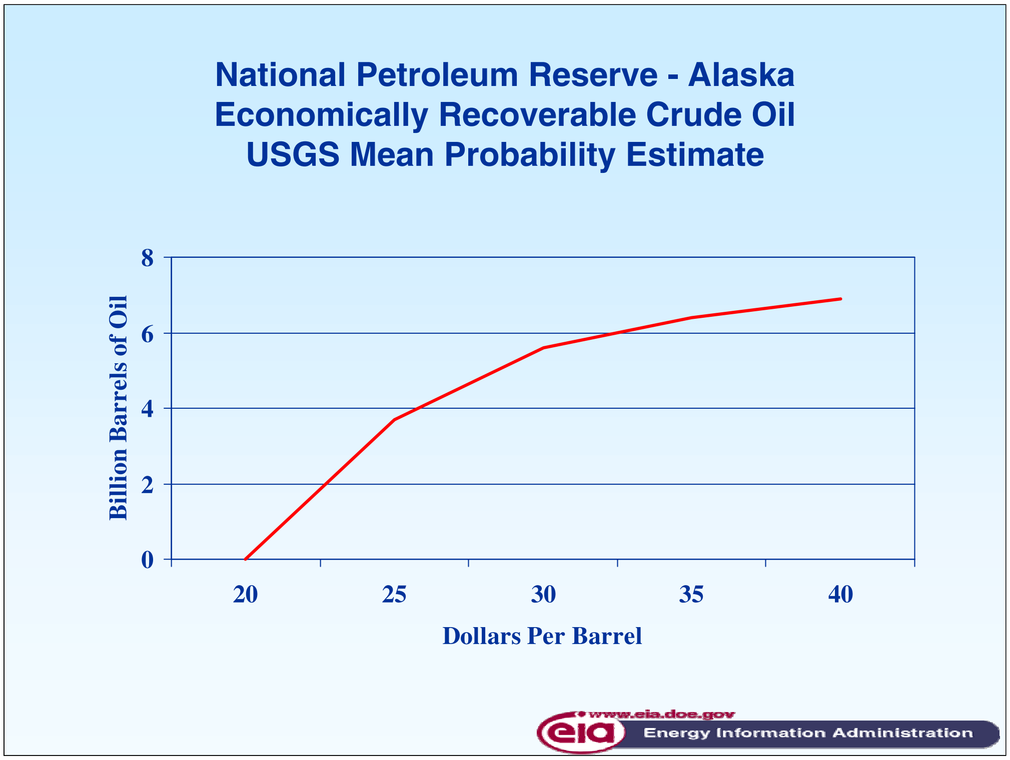
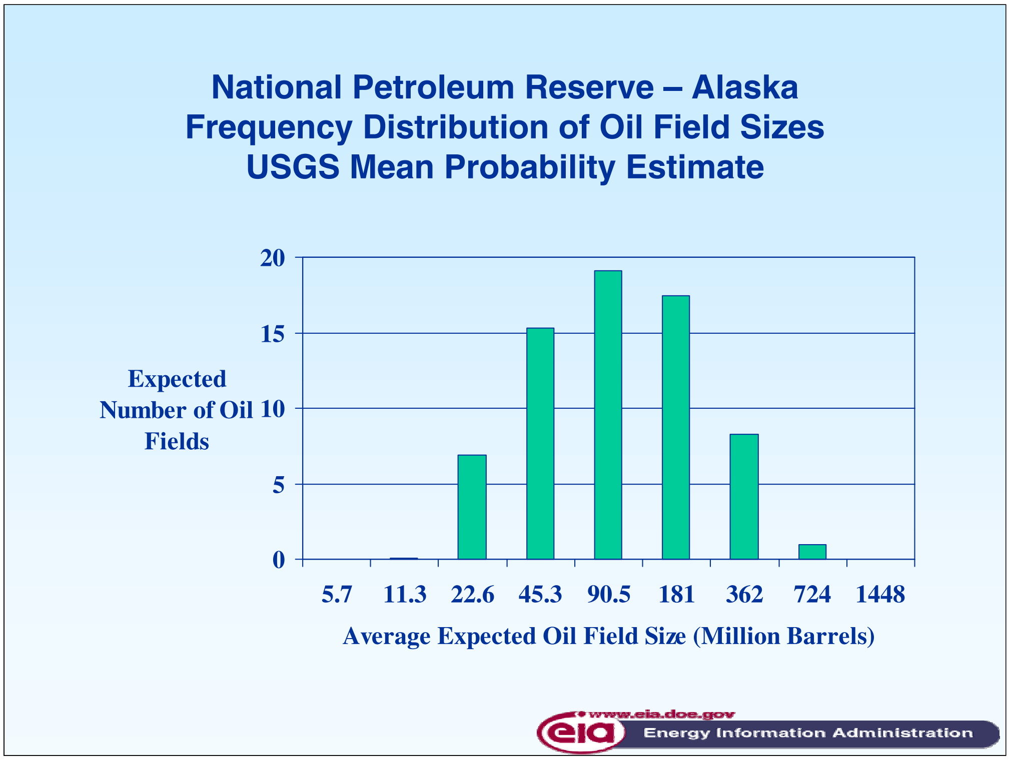
Here’s an example of the kind of technically recoverable resource estimate we use in our *Annual Energy Outlook*. The mean estimate was used in developing our *AEO2004* projections of 510,000 barrels per day of oil production and 2.7 trillion cubic feet per year of natural gas production for Alaska in 2025.



This is an example of the kind of economic information we receive on oil and gas resources from the USGS.



This is an oil field size distribution for the National Petroleum Reserve Alaska, showing that the mode of oil field size is around 90 million barrels.

USGS Estimated Total Gas Recovery Per Cell
Uinta Basin, Blackhawk Coalbed Gas

	Minimum	Median	Maximum
Billion Cubic Feet Of Gas	0.05	0.25	10

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This slide shows an example of the USGS unconventional gas resource data that is translated into a gas volume representing the estimated ultimate recovery (or "EUR") per well, which is then used as a data input within the unconventional gas module.

EIA Oil and Gas Supply Model (OGSM) Domestic Modules

- Lower-48 Onshore Conventional Oil and Gas
- Lower-48 Onshore Unconventional Gas
- Lower-48 Offshore Conventional Oil and Gas
- Alaska Onshore and Offshore Conventional Oil and Gas

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So now let's move to the first major topic, which is the design of the Oil and Gas Supply Model and its use of USGS-MMS data.

The EIA Oil and Gas Supply Model or OGSM is composed of four distinct modules:

•Lower-48 Onshore Conventional Oil and Gas module

•Lower-48 Onshore Unconventional Gas module

•Lower-48 Offshore Conventional Oil and Gas module, and

•Alaska Onshore and Offshore Conventional Oil and Gas module.

USGS-MMS Oil and Gas Resource Data Sets Used In EIA's Four Domestic OGSM Modules

OGSM Module	USGS-MMS Oil and Gas Resource Data Sets			
	Technically Recoverable Resources	**Economically Recoverable Resources**	**Oil and Gas Field Size Distribution**	**Estimated Ultimate Recovery Per Well**
Onshore Lower-48 Conventional Oil and Gas	Starting point for annually-adjusted accessible resources.	Used in post processing to gauge the reasonableness of resource development, given projected prices.	Not directly applicable.	Not directly applicable.
Onshore Lower-48 Unconventional Natural Gas	Starting point for annually-adjusted accessible resources.	Ditto.	Not directly applicable.	Used in determining the reserve additions of unconventional gas drilling.
Offshore Lower-48 Conventional Oil and Gas	Consistent with field size distribution information.	Ditto.	Specifically used in determining field development.	Not directly applicable.
Onshore & Offshore Alaska Conventional Oil & Gas	Consistent with field size distribution information.	Ditto.	Specifically used in determining field development.	Not directly applicable.

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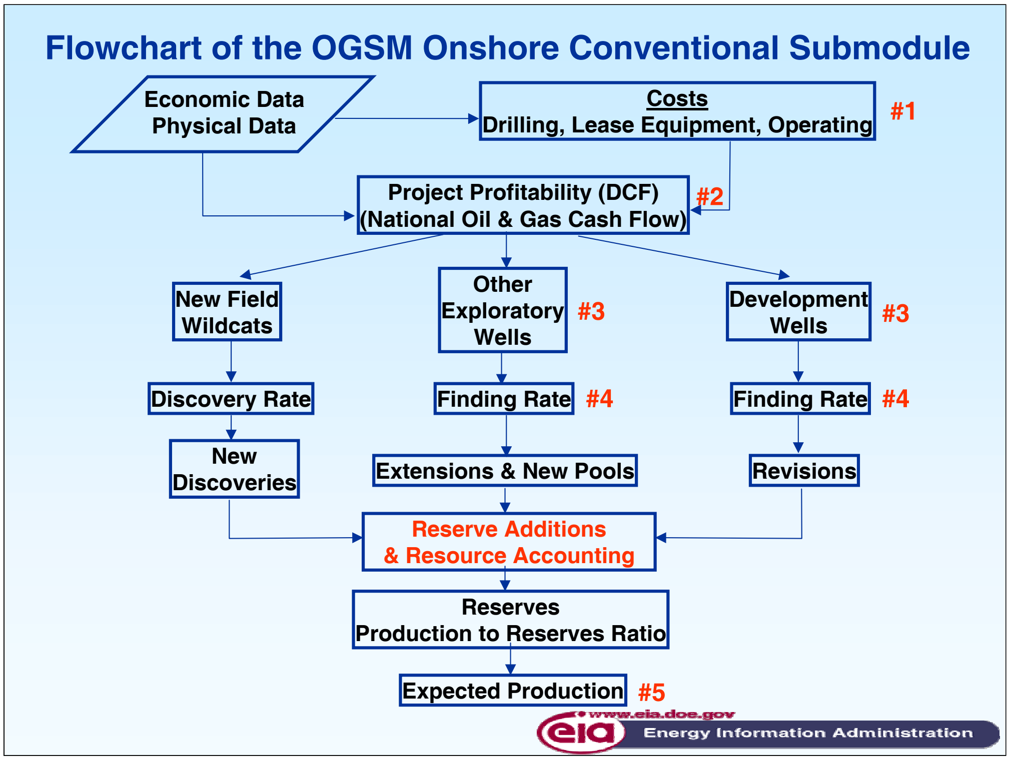
The primary resource data used in the OGSM model is technically recoverable oil and gas resources. The technically recoverable resource base is used as a starting point for setting an upper limit on the volume of oil and gas resources that can be extracted over the forecast period.

The economically recoverable resource cost curves are compared to projected oil and gas production levels at given prices to ensure that projected cumulative oil and gas production does not exceed what's on the curves.

The oil and gas field size distributions are used directly within the Offshore and Alaska modules to determine whether these fields are developed.

The estimated ultimate recovery per well is used in the unconventional gas module both to estimate whether the development and production of that gas would be economic, and to determine the reserve additions resulting from unconventional drilling.

The next few slides will illustrate how the resource data are used within a couple of the OGSM modules.



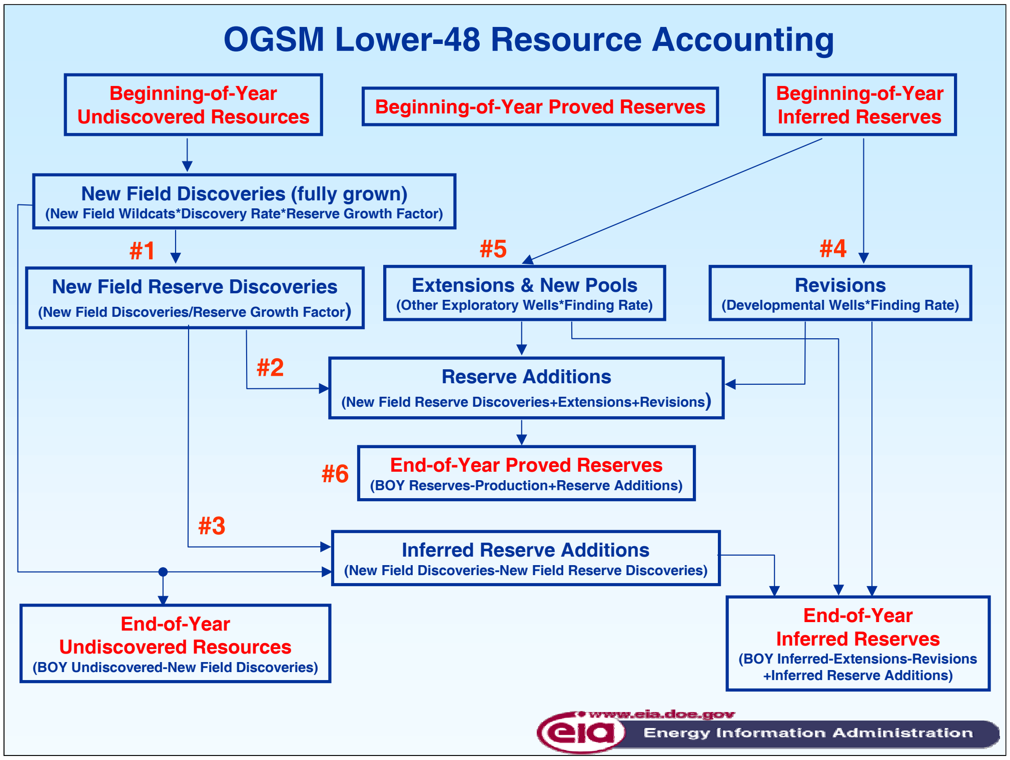
• Starting with the conventional onshore submodule, at point #1, the prospective costs of a representative drilling project for a given fuel category and well class within a given region are computed. Costs are a function of the levels of drilling activity, average well depth, rig availability, and the effects of technological progress.

• At point #2, the present value of the discounted cash flows (DCF) associated with the representative project is computed. These cash flows include both the capital and operating costs of the project, including royalties and taxes, and the revenues derived from a declining well production profile, computed after taking into account the progressive effects of resource depletion and valued at constant real prices as of the year of initial valuation.

• At point #3, drilling levels are calculated as a function of projected profitability as measured by the projected DCF levels for each project and national level cash flow.

• At point #4, regional finding rate equations are used to forecast new field discoveries from new field wildcats, new pools and extensions from other exploratory drilling, and reserve revisions from developmental drilling.

• At point #5, production is determined on the basis of reserves, including new reserve additions, previous productive capacity, flow from new wells, and, in the case of natural gas, fuel demands. This occurs within the market equilibration of the natural gas transmission and distribution module (NGTDM) for natural gas and within OGSM for oil.

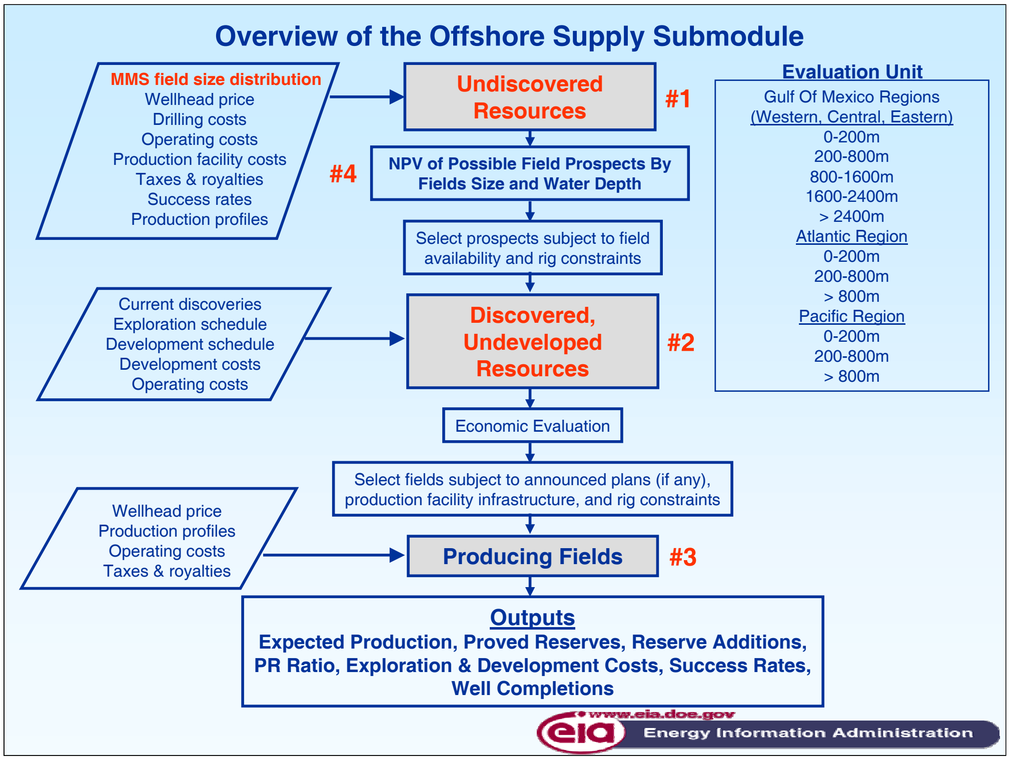


Lower 48 oil and natural gas resources are carefully tracked through the discovery to production process as shown is this chart.

At point #1, the volume of new field reserve discoveries is determined by the number of new field wildcats drilled in a given year and the estimated discovery rate per well. Fully grown resource volume (calculated based on an assumed growth factor) is subtracted from the undiscovered resource base. Some of this volume is added directly to proved reserves (#2) and the remaining volume is added to the inferred reserves category (#3).

Developmental and other exploratory drilling move inferred reserves to proved reserves in the form of reserve revisions (#4), extensions, and new reservoir discoveries in old fields (or new pools) (#5).

End-of-year proved reserves (#6) are then calculated by taking the beginning-of-year reserves, subtracting production, and adding new field reserve discoveries, revisions, and extensions and new pools.

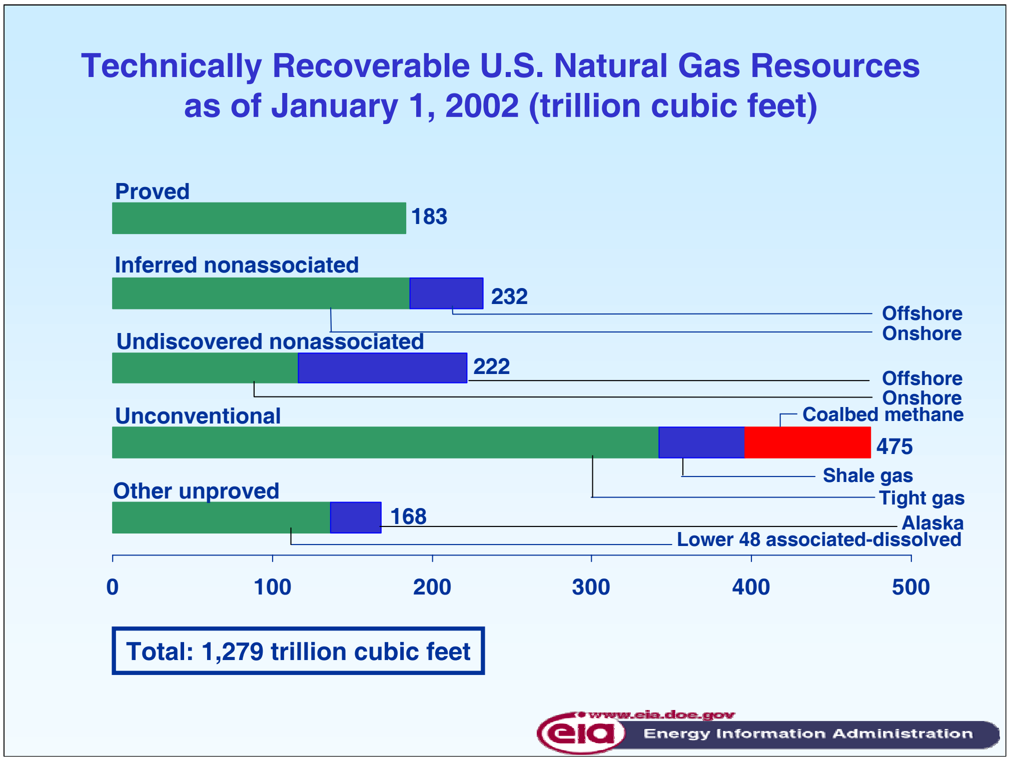


Both the offshore and Alaska modules explicitly use the USGS-MMS expected oil and gas field sizes to determine whether the expected discounted cash flow is sufficient to warrant field development. Fields with positive net present values undergo drilling, and resources are moved from being undiscovered to proven. OGSM accounting tracks reserve depletion resulting from production.

The offshore module, as shown in this chart, simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore resources are divided into three categories: #1) undiscovered (based on the MMS's field size distribution), #2) discovered/undeveloped, and #3) producing fields.

The net present value of prospects are calculated and then ranked (#4). The best prospects are then selected for exploration and development, subject to field availability and rig constraints.

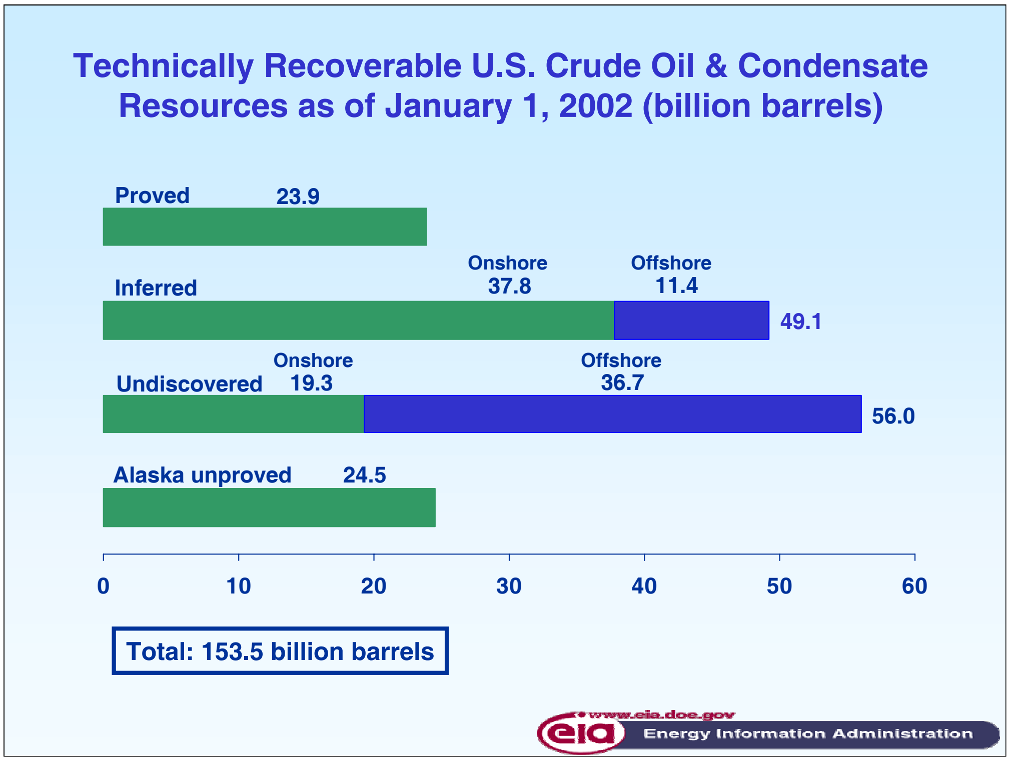
Now let's look at how the model uses resource data.



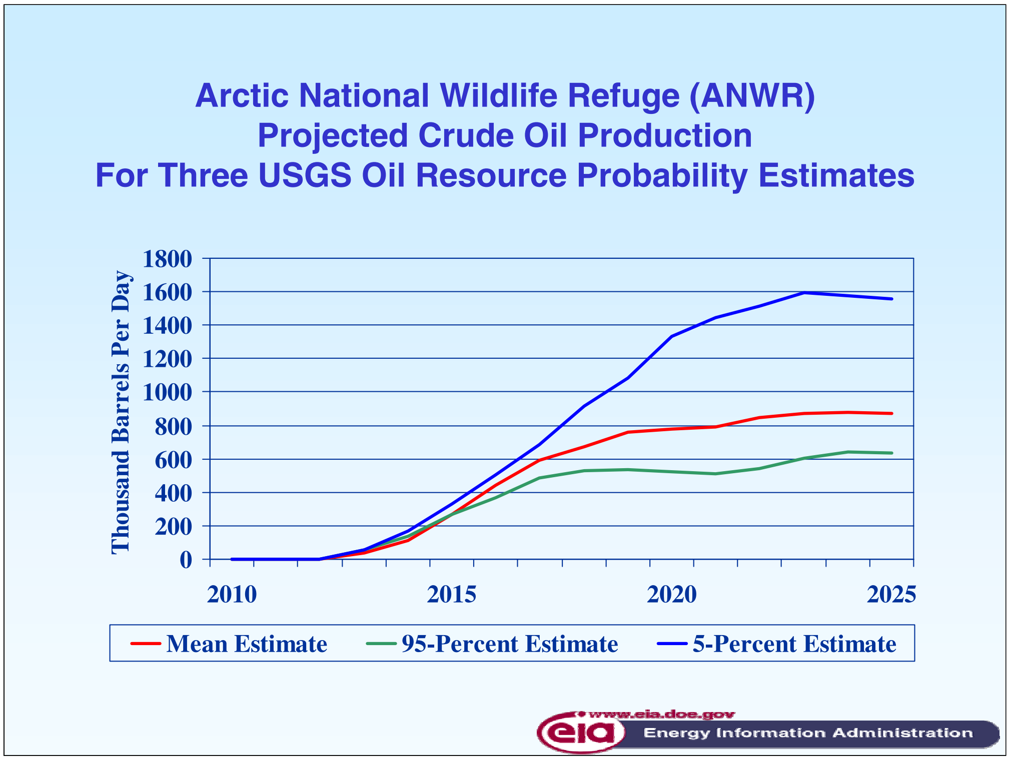
Each year, EIA adjusts the OGSM oil and gas resource base to incorporate new USGS-MMS regional resource assessments, and changes in annual oil and gas reserves and production. EIA also adjusts the USGS-MMS oil and gas resource data to reflect the lack of access to certain Federal and State onshore and offshore regions. Because of the accessibility adjustments, the OGSM technically recoverable oil and gas resource base is less than the totals reported by the USGS and MMS.

The estimate of total technically recoverable natural gas resources as of January 1, 2002 is 1,279 tcf. Production occurs from proved reserves (183 tcf) in known reservoirs, where wells have been drilled and production rates have been demonstrated. Inferred reserves (232 Tcf) are also in known reservoirs, but there is some uncertainty about recovery. Inferred reserves move into the proved category with developmental or other exploratory drilling. Undiscovered conventional resources (222 tcf) are the least certain and are located in areas that have not been drilled. About a third of these are in the deep waters of the Gulf of Mexico. The largest category is unconventional resources (475 tcf) with most of it residing in tight sandstones (72 percent). Shale gas and coalbed methane comprise the rest of the unconventional resource base. Other unproved natural gas resources include gas in Alaska (32 tcf) and associated-dissolved natural gas in lower 48 crude oil reservoirs (136 tcf).

The volume of unconventional gas resources shown on this slide exceeds the current USGS estimate because 1) some unconventional plays have been updated to reflect new data, 2) other plays previously lacking data have been included as data became available, and 3) new unconventional plays have been identified and incorporated into OGSM. For example, in the 1995 USGS assessment, the Barnett Shale in the Fort Worth Basin had not been assessed by the USGS due to a lack of sufficient data.



This figure shows 153.5 billion barrels of technically recoverable crude oil resources, as of January 1, 2002. The largest OGSM oil resource is in the undiscovered category at 56.0 billion barrels, followed by the inferred category at 49.1 billion barrels. It is also worth noting that one of the largest crude oil resource categories is the offshore, undiscovered category at 36.7 billion barrels.



When EIA runs the OGSM model for the *Annual Energy Outlook* reference case, it uses the USGS-MMS mean probability estimate for oil and gas resources. However, the OGSM model could be run using the 5-percent and 95-percent probability resource estimates.

For example, this chart illustrates the results from a March 2004 EIA analysis, which looked at potential future ANWR oil production rates, based on the oil resource estimated by the USGS for the technically recoverable resource base estimated at three different probability levels.

We are currently thinking of extending this type of production analysis, which incorporates the USGS-MMS resource probability distribution, to the entire oil and gas model. This would permit us, for example, to project the potential range of future natural gas prices, based on the uncertainty of the domestic oil and gas resource base.

To conduct this analysis, the EIA energy model would be run for each of the three resource probability estimates. The price probability distribution would then result from the price spread exhibited across three model runs.

Now let me turn to my second topic, which relates to how we and others might model the effect of technological progress on both the technically recoverable and economically recoverable oil and gas resource base.

The effects of technological progress are two-fold. First, new technologies serve to reduce the cost of developing technically recoverable resources. Second, they serve to expand the resource base that is "technically recoverable." For example, in the early 1980s, some oil and gas producers referred to the Gulf of Mexico as the "Dead Sea" because the shelf discoveries were rapidly falling in size. However, the technological development of the tension leg platform opened up a whole new play in the deep water that has been "booming" ever since.

Understanding technological progress is crucial to oil and gas forecasting, because it has a significant impact on price. For example, the 2025 natural gas wellhead price in our current forecast in constant 2002 dollars is $4.40 per thousand cubic feet, but in the high technology case it's $3.80.

OGSM Modeling of Technological Progress in Relation to Technically Recoverable Oil & Gas Resources

- OGSM captures the impact of technological progress by reducing the cost of developing and producing technically recoverable oil and gas resources.
- With the exception of the unconventional gas module, OGSM does not model the impact of technological progress in expanding the size of the technically recoverable resource base.
- The OGSM resource base, however, is frequently updated to incorporate new USGS-MMS resource assessments, which implicitly capture the impact of technology in expanding the resource base.

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OGSM incorporates the effects of technological progress on the cost of developing and producing domestic oil and gas resources, but that largely does not capture the effect of technological progress on expanding the recoverable resource base. However, because we incorporate new USGS-MMS assessments, as they become available, we indirectly capture the second effect.

We do, however, expand the resource base in the unconventional gas module by increasing the estimated ultimate recovery per well over time.

The following three slides give you some sense of the variables that incorporate changes in technological progress and the rates of change associated with these variables.

Technology Improvement Factors for the Conventional Lower-48 Onshore Module

Category	Improvement Rate
Drilling costs	1.87 %/year
Lease equipment costs	1.20 %/year
Operating costs	0.54 %/year
Finding rates	2.84 %/year
Success rates	0.5 %/year

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For the *Annual Energy Outlook* reference case, OGSM uses historical rates of cost reductions due to technological progress. This slide along with the following two slides provide the rates of technological improvement that were used in the 2004 edition of the *Annual Energy Outlook*.

This slide shows the rates of technological improvement used in the conventional onshore module.

As you can see, these rates of technological improvement vary significantly, with drilling costs and finding rates expected to show the greatest year-to-year improvement, at 1.87 and 2.84 percent per year, respectively. The term “finding rates” refers to reserve additions per year divided by the wells drilled per year, while the term “success rates” refers to the probability that a well will find a commercial oil or gas deposit.

Technology Improvement Factors for the Conventional Lower-48 Offshore Module

Category	Improvement Rate
Exploration success rates	0.80 %/year
Delay to commence first exploration and between exploration (years)	0.60 %/year
Drilling costs	1.20 %/year
Operating costs	1.20 %/year
Time to construct production facility (years)	0.60 %/year
Production facility construction costs	1.20 %/year
Initial production rate	0.80 %/year

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This slide shows the rates of technological improvement in the offshore module.

As seen in this slide, technological advances are projected to show the greatest impact on the costs associated with developing and producing offshore oil and gas.

Technology Improvement Factors for the Estimated Ultimate Gas Recovery Per Well in the Unconventional Gas Module

Resource Category	Improvement Rate
Coalbed Methane	0.45 %/year
Tight Gas Sandstones	0.83 %/year
Gas Shales	1.18 %/year

Advances in several major technologies are assumed to improve estimated ultimate recoveries (EUR's) per well for the various types of unconventional gas recovery. One such technology is more effective, lower-damage well completion and stimulation technology, which increases EUR per well by improving fracture length and conductivity.

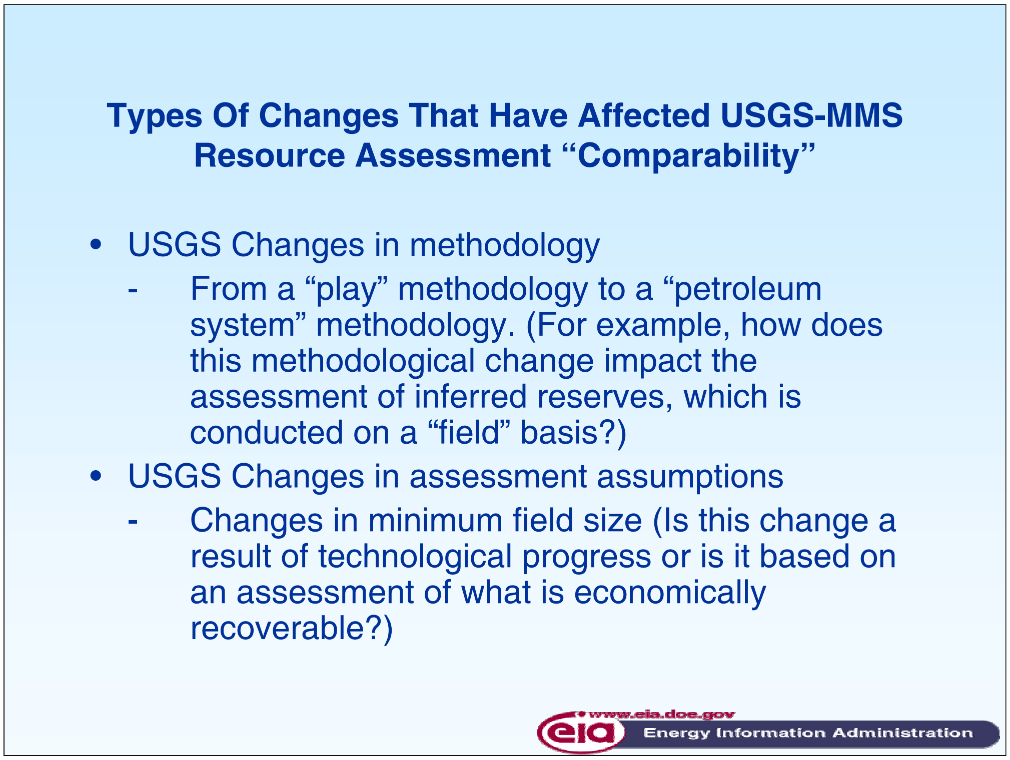
Potential USGS Role in Determining the Impact of Technological Progress in Expanding the Size of the Technically Recoverable Resource Base

- If past, present and future USGS-MMS resource assessments were comparable over time, then one could econometrically estimate the rate at which technology has expanded the technically recoverable resource base.

- But what does assessment "comparability" mean? How would one know if and when two resource estimates are "comparable"? Can prior resource assessments be made comparable?

As mentioned earlier, technological progress both reduces the cost of developing and producing oil and gas resources, and expands the resource base. With the respect to the second effect, it would be valuable both to energy forecasters and the public to have a better understanding of how technological progress has expanded the technically recoverable oil and gas resource base. The USGS would serve both energy forecasters and the Nation by undertaking this work.

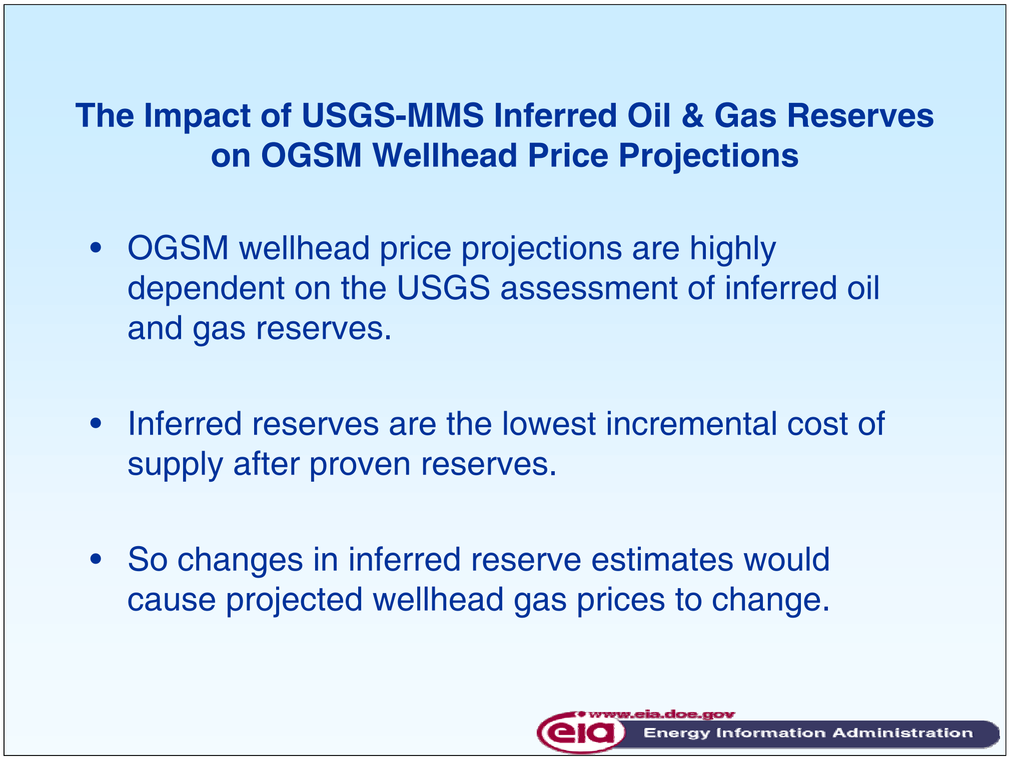
Assessment "comparability" is easy to define, but difficult to determine. In the context of this presentation, assessments are comparable if each assessment's resource estimate <u>solely</u> reflects changes in technology, and does not reflect, for example, changing economic or political paradigms.



This slide shows some examples of changes in assessment methodology and assumptions that could affect their comparability over time, without trying to be comprehensive.

The USGS resource assessment methodology and assumptions have changed over time, in ways that make it difficult to compare assessments. For example, the USGS resource assessment methodology has recently transitioned from a "play" methodology to a "petroleum system" methodology.

Given the inherent difficulties in creating comparable historical assessments and the budget limitations faced by Federal agencies, we realize of course, that providing comparable historic resource estimates might not be feasible.



Now let me turn to the third topic, which is oil and gas field appreciation and inferred oil and gas resources.

The "bottom line" of this slide is that significant changes in the USGS assessment regarding gas field appreciation and potential inferred reserves would have a significant impact on projected future natural gas prices. If the conventional gas fields found in the future do not appreciate to the same extent as they had in the past, then the OGSM model could be using USGS inferred gas reserves that are overestimated. Consequently, we ask the USGS (and the MMS) to consider whether the current inferred oil and gas estimation methods and assumptions are appropriate, given the changing characteristics of gas fields.

USGS Inferred Oil and Gas Reserves

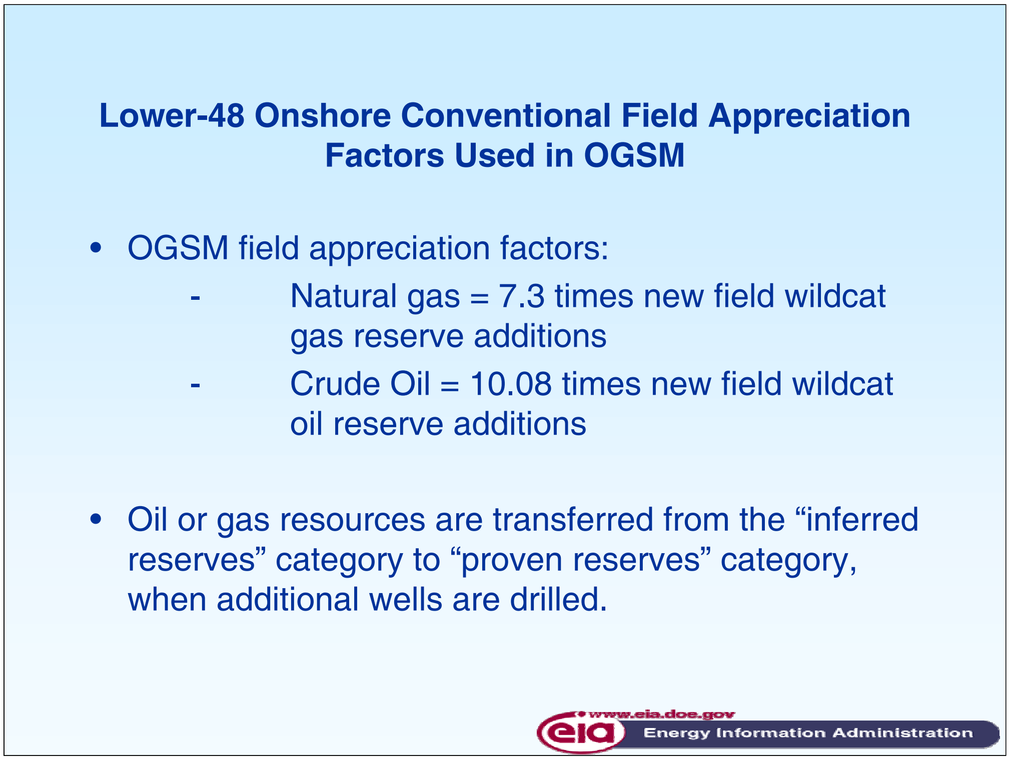
Definition includes:

- Extensions to known fields (developmental drilling)
- New reservoirs in old fields (non-wildcat exploratory drilling)
- Positive net reserve revisions
- Improved recovery of original oil in-place

1995 USGS inferred reserves assessment is based on EIA Oil and Gas Integrated Field File

This slide briefly reviews the four basic definitional categories of USGS inferred oil and gas reserves: extensions, new reservoirs, revisions, and better recovery.

The next slide shows the degree of oil and gas field appreciation currently incorporated into OGSM.



Here you see the national average, 80-year, oil and gas field growth factors—7.3 for gas and 10.1 for oil.

The next four slides discuss why past performance in each of the four definitional areas might not be indicative of future performance.

USGS Inferred Oil & Gas Reserves: Field Extensions

- Today, small, deep high-pressure gas deposits, in conjunction with horizontal drilling, generally require fewer wells to drain the reservoir. For example, some deep gas fields can be efficiently drained (in an economic sense) by one well; so reserve "extensions" in these one-well fields will not occur. So the ratio of reserve extensions to initial field discoveries might be lower now and in the future, than it had been in the past.

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First, extensions. Using horizontal drilling techniques, fewer wells are needed to tap small, deep, high-pressure gas deposits. So, the ratio of reserve extensions to initial field discoveries might be lower now than it had been in the past.

USGS Inferred Oil & Gas Reserves: New Reservoirs In Old Fields

- Technological improvements in seismic data acquisition and processing over the past several decades allows all of a potential field's reservoir "targets" to be identified before the first well is drilled. That seismic knowledge can be used to minimize the number of exploratory wells drilled to test all these potential targets (esp. with multi-laterals).
- Moreover, "intelligent well" technology now permits multiple reservoirs in field to be produced simultaneously rather than the older technique, which completed/re-completed wells sequentially, starting from the deepest reservoir and proceeding up the drill stem to the shallowest reservoir. This older production method meant that each reservoir could be "booked" as "proven, developed" reserves only when it was brought into production, while the new technique potentially allows all the reservoirs to be brought into production and "booked" from the from the very beginning.

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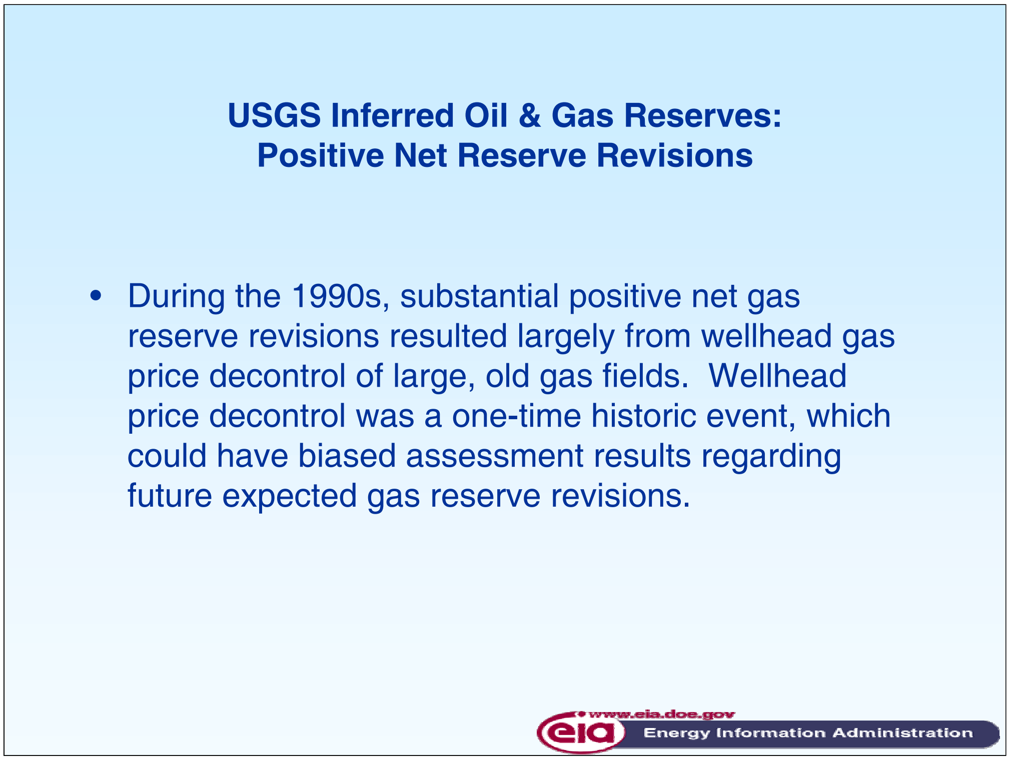
Second, new reservoirs: Previously, if a well was drilled through multiple gas formations, the producer completed the deepest formation first (and booked the reserves as proven, developed), and then when that formation played out cemented it in and then moved up the drill stem to the next deepest stratum, recompleted the well and booked those reserves, exhausted the formation, cemented it, moved up the drill stem, and so on, until all the strata have been produced and the well was abandoned. In this process the booking of proved developed reserves was incremental and over a longer period of time. The reason for this production approach was that if all the strata were producing simultaneously, the high pressure gas from the deepest formation would invade the lower pressure, shallower reservoirs, and get "lost." The new technology separates and isolates each stratum from all the other producing strata, thereby avoiding the problem of "lost" gas.



Third, positive net revisions. During the 1990s, we saw substantial positive net gas reserve revisions, largely because of previous decontrol of wellhead gas prices in large, old gas fields. Wellhead price decontrol was a one-time historic event, which could have biased assessment results regarding future expected gas reserve revisions.

USGS Inferred Oil & Gas Reserves: Improved Recovery

- In the past, improved recovery occurred in large fields, which operated over an extended time period, which permitted multiple generations of technology to be successively applied (e.g., primary, secondary and tertiary oil recovery).
- The new, smaller fields produce over a much shorter period of time, which prevents technology and resource recovery from improving dramatically in this shorter period.

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Finally, improved recovery from old fields. In the past, improved recovery occurred in large fields, which operated over an extended time period, which permitted multiple generations of technology to be successively applied.

But, the new, smaller fields produce over a much shorter period of time, which keeps technology and resource recovery from improving dramatically in this shorter period.

Changing Field Characteristics and Technologies Which Potentially Affect Field Appreciation and Inferred Reserve Estimates

- Field size (smaller),
- Field length of life (shorter),
- Field depth (higher reservoir pressure and lighter oils at greater depth),
- Well drainage area (i.e., horizontal wells, multi-laterals),
- Improved seismic acquisition and processing
- Simultaneous production of multiple reservoirs
- Reservoir drive(?) (i.e.,water, gas, depletion)

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Here are seven field characteristics and technologies that could affect field appreciation and inferred reserves.

The first six elements in this slide have been discussed in prior slides, but the last element – reservoir drive – was added to this list to raise the question as to whether there are also other oil and gas field attributes and technologies that have significantly changed the extent to which field appreciation occurs in the future.

USGS Encouraged to Re-examine Inferred Reserves Methodology & Assumptions

- Are the newer, smaller reservoirs displaying the same degree of field appreciation, as the large fields did in the past?
- Are significantly fewer wells drilled to obtain the same reserve recovery?
- Did gas wellhead price deregulation overstate past field appreciation?
- Are well recovery rates approaching a maximum value that precludes further future technological advances?
- Have technologies been developed which result in the simultaneous discovery and production of all the reservoirs within a field?

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This slide reiterates some of the questions that have been raised regarding current and potential future field appreciation and their implication for inferred oil and gas reserves.

USGS Administrative Issues:
Resource Data Dissemination

- Central USGS web site which links the latest regional USGS assessment <u>to all ancillary open-file reports</u>.
- E-mail list serve for web-casting announcements of new USGS assessments and open-file reports.
- More efficient search engine on the USGS website

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This is my last topic. Aside from the theoretical issues associated with USGS resource data, there are a few administrative issues we urge the USGS to address so that the USGS data and analysis are more readily known and obtainable.

Although the USGS has a central internet web site, which provides access to new USGS oil and gas resource assessments, this site only permits the user to obtain the USGS Fact Sheet, but not the technical, open-file reports, which provide extensive details and which are the basis for the Fact Sheet summary data. We recommend that the open-file reports be referenced on each basin's Fact Sheet web page, with direct internet access also provided on these web pages.

To insure that users of USGS information know of the existence of new data and analysis in a timely manner, we also recommend that the USGS institute an e-mail webcast to outside subscribers, which would notify them of new resource assessments and open-file reports.

Finally, we encourage the USGS to reconsider its internet site search engine, which is currently very inefficient. For example, when a user inputs a specific open file report number, the USGS search engine typically does not reference the document in the first few citations.

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In summary, I've focused on four things today:

1. Giving you a better understanding of the EIA Oil and Gas Supply Model and how it uses USGS-MMS resource data.

2. Making a plea for assistance in understanding technological progress in oil and gas resource development.

3. Making a plea for reexamination of oil and gas field appreciation and inferred reserves.

4. Suggesting improvements in USGS information dissemination.