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Improved USGS Methodology for Assessing Continuous Petroleum Resources

Data Series 547

U.S. Department of the Interior
U.S. Geological Survey

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By Ronald R. Charpentier and Troy A. Cook

Version 2

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By Ronald R. Charpentier and Troy A. Cook

Abstract

This report was originally published in 2010. This edition of the report, version 2, fixes minor bugs relating to correlations and coproducts.

This report presents an improved methodology for estimating volumes of continuous (unconventional) oil and gas resources within the United States and around the world. The methodology is based on previously developed U.S. Geological Survey methodologies that rely on well-scale production data. Improvements were made primarily to how the uncertainty about estimated ultimate recoveries is incorporated in the estimates. This is particularly important when assessing areas with sparse or no production data, because the new methodology allows better use of analog data from areas with significant discovery histories.

Introduction

The currently used U.S. Geological Survey (USGS) methodology for assessing continuous (unconventional) petroleum resources of the United States was developed in the 1990s and last updated in 2003. Rather than the traditional in-place calculation of resources with a poorly understood recovery factor, the USGS methodology was built to use well-production information to better constrain estimates of recoverable volumes. This was a significant improvement, at least for those resource accumulations that already had significant production history available. As the USGS extends its assessments to hypothetical assessment units (AU) both within and outside the United States (U.S.), the methodology requires improvement to better reflect the greater inherent uncertainties.

The 1990s USGS methodology was based on dividing an AU into cells and assessing the number of untested cells with production potential and the distribution of per-cell production potential. Hundreds to thousands of well production histories were analyzed for each AU to estimate a distribution of well-scale estimated ultimate recoveries (EUR). Cells were scaled to be approximately the average drainage area of a well. The number of potentially productive cells was estimated by dividing the AU area by the well drainage areas. The 2003 version only assesses resources within the areas with higher production potential (sweet spots), rather than the entire AU.

The currently used methodology poorly incorporates uncertainty about the mean of the EUR distribution. This is especially problematic for hypothetical continuous assessment units where this may be the largest source of uncertainty that needs to be reflected in the estimates. The improved methodology estimates the uncertainty of mean EUR directly. It will use analog data to be compiled from production histories of many developed U.S. continuous assessment units. The analog databases will provide a way of estimating the variability of not just EURs but other production parameters useful in assessing continuous resources.

In addition to the analog databases, the improved methodology uses a new Monte Carlo program (Appendix 2) for performing the calculations as well as additional tools to aid assessors in better incorporating the available production data. A series of standard graphs will provide summaries of production data in a probabilistic manner. These graphs will aid interpretation and assessment of both hypothetical assessment units and those with significant production histories.

Assessments

Objective

The purpose of this new methodology is to make quantitative, probabilistic estimates of volumes of technically recoverable oil and gas resources from continuous accumulations. A continuous accumulation is "a petroleum accumulation that is pervasive throughout a large area, that is not significantly affected by hydrodynamic influences, and … lack[s] down-dip water contacts." (Klett, Schmoker, and others, 2003) Examples are gas or oil reservoirs in shales, in low-permeability sandstones and carbonates, and in coals.

The USGS oil and gas estimates are of technically recoverable resources, as opposed to in-place resources. Technologic and economic assumptions are conservative and limited, in that the production data used for calculating well EURs are contemporary to the time of the assessment. Production data, however, have spatial and temporal trends. The intent is to make estimates based on contemporary production practice in the area assessed, or in similar areas. Large improvements in technology or increases in petroleum prices could possibly increase recovery factors substantially in the future. Because this new methodology is tied to contemporary well-production data, such improved recovery factors are not used as part of this assessment methodology.

Procedure

The process of making oil and gas resource assessments begins with geologic studies that attempt, using a petroleum system approach, to explain the controls on oil and gas occurrence in the assessed area. The petroleum system approach examines all of the geologic elements of source, reservoir, seal, and overburden rocks, as well as the processes of generation, migration, entrapment, and preservation of oil, gas, and natural gas liquids. The geologic studies may lead to a division of the area into subunits, either geographically or stratigraphically. The actual volume of rock for which each individual quantitative assessment is made is termed an assessment unit (AU).

After the assessor, or team of assessors, has divided the area into a preliminary set of AUs, production data are retrieved and analyzed for each AU. A geologic review meeting is conducted to present the preliminary geologic interpretations and division into AUs to a review committee consisting of experienced assessors. The geologic interpretations are discussed and the subdivision into AUs is revised if deemed appropriate. After revision, an assessment meeting is held. The assessor presents an input form with preliminary input values for discussion with the review committee. Revisions are made and preliminary results examined. Further revisions to the input are made until the results are a reasonable quantitative reflection of the geologic interpretations. After the assessment meeting, more extensive Monte Carlo simulations are run to calculate the official volume estimates.

Changes from Previous Methodology

Focus on Wells Instead of Cells

The first methodology based on well performance (Schmoker, 1995), divided the AU area into cells of constant size. Choice of cell size, however, was based on the expected average drainage area of a well. This would allow the EURs from wells to be used more directly as total recoveries per cell. Later versions (Crovelli, 2000, 2003; Klett and Charpentier, 2003; Klett and Schmoker, 2003; Schmoker, 2003) used a probability distribution for cell sizes based on a distribution of well-drainage areas. The new methodology uses wells directly instead of cells (Appendix 1, page 1). This eliminates the confusion between the two concepts, which were always closely linked. It also reduces the chance of misinterpreting cells as entities that were actually mapped, as opposed to being conceptual.

Assessment of Non-Sweet Spots

The original USGS methodology based on well performance (Schmoker, 1995) gave estimates for the entire AU. In some cases, this gave very large estimates for numbers of wells and included some resources that were not likely to be relevant to supply for the near future (Schmoker, Fouch, and Charpentier, 1996). A revised methodology (Crovelli, 2000, 2003; Klett and Charpentier, 2003; Klett and Schmoker, 2003; Schmoker, 2003) attempted to solve these problems by dividing the AU into sweet spots and non-sweet spots. The non-sweet spots were considered to be of fairly high risk and low EURs and were not quantitatively assessed.

The new methodology continues to offer the option of dividing the AU into sweet spots and non-sweet spots (Appendix 1, page 2). However, non-sweet spots are now quantitatively assessed in the new methodology. The assessor has the option to treat the area as 100 percent sweet spot if desired. An additional modification is that the future success ratio (probability that a well will have an EUR greater than the minimum size; Appendix 1, page 2) is now explicitly estimated. In the previous version, it had been part of the estimated percent of untested area with potential. The new version requires probability distributions for a future success ratio and for EURs, separately for sweet spots and for non-sweet spots (Appendix 1, page 2).

Uncertainty of Mean EUR

Because of the large numbers of cells involved in the calculations for an AU (thousands to hundreds of thousands), only the mean of the EUR distribution had any relevance to the volumetric estimates in previous methodologies. This made the methodology inappropriate for AUs that had great uncertainty about the EUR distribution, such as hypothetical or very immature AUs. The improved methodology addresses the uncertainty about EURs directly by means of a probability distribution (Appendix 1, page 2).

Input Form

The new input form is included as Appendix 1. The input form is the primary record of quantitative input used in the estimation of volumes of technically recoverable oil and gas resources. The input form also includes additional information, termed ancillary data that is not used in the estimation of technically recoverable oil and gas volumes, but describes characteristics of the petroleum that may be of use in further analysis, such as economic analysis.

Identification Information

The revised input form (Appendix 1) begins with a section labeled “Identification Information.” This section identifies the AU with the standard USGS hierarchical classification of region, province, total petroleum system, and AU names and codes (Klett, Charpentier, and Le, 2003). The date of the assessment meeting and the responsible geologist(s) are also included. Space is given to identify the data sources, such as databases and analogs used, as well as any general comments.

Characteristics of Assessment Unit

The next section of the input form entitled, Characteristics of Assessment Unit, starts with three variables used for classification of assessment units (Appendix 1, page 1). The assessment-unit type is identified as either oil or gas, using a 20,000 cubic foot of gas per barrel of oil cutoff. The well type used for undrilled wells in the assessment is identified as vertical or horizontal. This is important because of the large size differences between drainage areas and EURs of vertical versus horizontal wells. The AU is to be estimated as if all future wells were only one of the two types. The AU is then classified as having one of five types of continuous (unconventional) reservoirs: shale, low-permeability clastics, low-permeability carbonates, coal, or diatomite.

Next, the minimum estimated EUR per well is specified in millions of barrels of oil (MMBO) for an oil AU or in billions of cubic feet of gas (BCFG) for a gas AU. Many of the distributions later in the form depend on this specified minimum. Success ratios are defined as the probability of a well having an EUR at least this large. Drainage areas are estimated only for wells at least this large. EUR distributions have this value as their minimum. The minimum is generally kept low, so as to not exclude significant volumes of marginally economic production.

A historic success ratio is calculated on the number of wells that previously tested the accumulation, and the number of those that had an EUR greater than the minimum value. This calculation, unlike other parts of the form, can include both vertical and horizontal wells.

Finally, the AU probability is the probability that the accumulation has at least one well with EUR of minimum size or larger. If wells already exist with EUR greater or equal than the minimum, the AU probability is equal to 1. Otherwise, the AU probability depends on (1) the existence of the reservoir rock (and the source rock, if separate), and (2) the appropriate thermal (or biogenic) maturation to produce a resource. Reservoirs that are not self-sourced are considered to have little likelihood of significant resources. Thus for shale AUs, the AU probability is the probability of the existence of mature shale with total organic carbon (TOC) of at least 2 weight percent.

Number of Undrilled Wells with Potential for Additions to Reserves

The next section of the input form includes the input used to calculate the number of undrilled wells in sweet spots and non-sweet spots. For convenience, the important input distributions are identified as lines 1 through 4.

The uncertainty about the productive area (in acres) of the continuous accumulation is estimated in line 1. Uncertainty in this distribution can come from uncertainty about the areal extent of the reservoir or source rocks (the extent of the organic-rich [> 2 percent TOC] portion of the shale, the part of the low-permeability reservoir charged with hydrocarbon, or the areal extent of the coal). The uncertainty can also be related to the part of that reservoir that is thermally or biogenically mature.

The uncertainty about the average drainage area of wells is estimated in line 2. This distribution allows a calculation of number of wells that would be needed to drain a particular area. Because the areas being assessed are large, the numbers of wells involved are in the hundreds to hundreds of thousands. With such a large number of wells, only the mean size of the drainage area is relevant, but uncertainty about that mean is also relevant.

The full per-well distribution of drainage areas is estimated as a shifted truncated lognormal distribution in line 2a. This distribution is not used in the calculation of technically recoverable resources; line 2 is used instead. Line 2a is included as ancillary data that may be helpful to users doing further analysis, such as economic analysis.

The portion of the line 1 area that is untested is estimated by the distribution in line 3. A rough calculation of the <u>tested</u> portion can be calculated by multiplying the number of tested wells (in “Characteristics of Assessment Unit”) by the mean of line 2 and dividing by the mean of line 1.

The critical division of the untested area into two parts—the sweet spots and the non-sweet spots—is estimated in line 4. Non-sweet spots are expected to have significantly lower success ratios and lower EUR distributions. In partially developed AUs, most of the drilling will commonly be in sweet spots. If deemed appropriate to the AU, line 4 can make the AU 100 percent sweet spots and no non-sweet spots. If the geologic understanding of the AU is sufficient to actually map the distribution of sweet spots versus non-sweet spots, it is more appropriate to make those separate AUs. The structure implied in line 4 is that the AU is divided geologically into better and poorer areas that cannot be mapped with certainty given current geological knowledge.

Lines 1 through 4 are all estimated by triangular distributions. Each of the distributions reflects the assessors’ uncertainty about a single value that exists in nature but is unknown. The line 2a distribution, however, represents the distribution of values in a natural population. Greater skewness is needed in this case and thus a shifted truncated lognormal distribution is used.

Most of the geologic information appropriate for estimating the distributions in lines 1 and 4 are best expressed as maps. Therefore, as many of the maps and data sets shown in the following lists should be generated prior to filling out the input form:

Maps and Data Sets Describing Continuous Accumulations in Shale Reservoirs

- Extent of shale reservoir
- Thickness of shale reservoir
- TOC of shale
- Depth of shale reservoir
- Thermal maturity
- Well data on production and shows
- Pressure data
- Estimated ultimate recoveries (EURs)

Maps and Data Sets Describing Continuous Accumulations in Low-Permeability Clastic or Carbonate Reservoirs

- Extent of low-permeability reservoir
- Thickness of low-permeability reservoir
- Porosity of low-permeability reservoir
- Permeability of low-permeability reservoir
- Facies of low-permeability reservoir
- Thermal maturity
- Well data on production and shows
- Pressure data
- Estimated ultimate recoveries (EURs)

Maps and Data Sets Describing Continuous Accumulations in Coal Reservoirs

- Extent of coal
- Thickness of coal
- Rank of coal
- Depth of coal
- Well data on production and shows
- Pressure data
- Estimated ultimate recoveries (EURs)

Estimated Ultimate Recovery per Well

Distributions estimating the productivities of wells in the untested area are entered in lines 5a through 6b. They are in two sets. Lines 5a and 5b are for the sweet spots and lines 6a and 6b are for the non-sweet spots.

The future success ratio within the sweet spots is estimated by the distribution in line 5a. This success ratio is the percent of wells that will produce at least the minimum EUR given in the “Characteristics of Assessment Unit” section of the input form. It may be similar to the historic success ratio given in that section or could vary because of geologic differences in the undrilled area.

The average EUR in the untested sweet spots is estimated by the distribution in line 5b. Because thousands to hundreds of thousands of wells are involved in this calculation, only the average EUR and its uncertainty are relevant.

The future success ratio and average EUR for non-sweet spots are estimated by the distributions in lines 6a and 6b. In some AUs, sufficient production history has delineated sweet spots and non-sweet spots and estimates of future success ratios and average EURs can be supported by drilling and production data from each area. In other AUs, most of the drilling and production has taken place in known sweet spots. In those cases, the distributions in lines 6a and 6b might be based on those wells that were more exploratory (those drilled relatively distant from previously drilled wells).

Triangular distributions are used for lines 5a and 6a because they represent the uncertainty about a single value that exists in nature but is unknown. Triangular distributions allow the distributions to be skewed in either direction. The distributions for lines 5b and 6b are generally expected to be heavily right skewed, so shifted truncated lognormal distributions are used.

For partially developed AUs, the main information source is analysis of production data from wells in that AU. The historical success ratios and EUR distributions may not exactly reflect what is expected for the untested part of the AU, as geological differences may exist between the tested and untested areas. The historical drilling record may also reflect changes in engineering practice with time. To give insight into these factors, a set of standardized plots are developed from the historical data. These plots highlight trends in the production information both temporally and spatially.

Many geologic factors affect the success ratios and EURs. The effects of geology are only partially understood. Nevertheless, geological information can be useful in estimating the changes in success ratios and EURs into the future, as well as estimating what analogs may best be used for hypothetical or poorly explored AUs. The geologic factors that should be considered in the estimation of distributions in lines 5 and 6 are listed below.

Geologic Factors to Consider for Continuous Accumulations in Shale Reservoirs

- Thickness
- TOC
- Pressures
- Mineralogy
- Mechanical stratigraphy (such as existence of frac barriers)
- Organic geochemistry
- Natural fractures

Geologic Factors to Consider for Continuous Accumulations in Low-Permeability Clastic or Carbonate Reservoirs

- Thickness
- Pressures
- Mineralogy
- Organic geochemistry

Geologic Factors to Consider for Continuous Accumulations in Coal Reservoirs

- Thickness
- Rank
- Pressures
- Mineralogy
- Mechanical stratigraphy
- Organic geochemistry
- Gas geochemistry
- Cleating
- Ash content

Uncertainty about Average Coproduct Ratios for Untested Wells

Each AU is classified as having a primary petroleum product, either oil or gas. If the overall gas to oil ratio is 20,000 cubic feet per barrel or more, the primary product is gas; otherwise the primary product is oil. In either case, other products exist in the accumulation. Oil accumulations are considered to have some volume of associated/dissolved gas. Also, some natural gas liquids (NGLs) are considered to be dissolved in the associated/dissolved gas. Some gas accumulations produce volumes of liquids that were dissolved in the gas at reservoir conditions.

In order to estimate the volumes of these other products, coproduct ratios are applied to the estimated volumes of the primary product (Appendix 1, page 2). The distributions represent the uncertainty about the average ratios for the entire AU. Generally, the coproduct ratios based on historic production data are good initial estimates of the coproduct ratios in the remaining untested area of the AU.

Selected Ancillary Data for Untested Wells

Although not used in calculating volumes of resource, ancillary data are provided for the characteristics of the petroleum fluids and reservoirs (Appendix 1, page 2). These data may be useful in any additional analyses, such as economic analyses. Just as in the case of coproduct ratios, historical data generally provide good initial estimates of what the characteristics could be for the untested area of the AU.

Allocations

There are commonly some practical needs to present estimated volumes of resource allocated to particular geographic entities—states, onshore-offshore, by land ownership, and so on. The rough allocations are done with point estimates (of the mean). Distributions of the allocation percents are not given because of the large statistical problems associated with a set of allocations constrained to total 100 percent. Area percents of that geographic entity within the AU are calculated using a GIS (geographic information system). In the absence of any information suggesting that part of the AU has more resource per unit area, the area percent can be used as a default estimated volume percent allocation.

Use of Analogs

The methodology described in this report can be used for maturely developed AUs. In these cases, the data can be used to estimate the input distributions in a relatively direct manner. Some AUs, however, are immaturely developed or even hypothetical. In these cases, the input distributions must be derived by comparison with the geologic and production data in analog areas. Construction of analog databases makes this easier.

Summary

The new USGS methodology for assessing continuous (unconventional) oil and gas resources offers significant improvements over the previous version. Most importantly, uncertainty about the average EUR is directly assessed and incorporated into the calculations. An option is added to treat the success ratio and EUR distribution as either representing one population or a mixture of two populations. Also, the theoretical concept of cells has been eliminated, and well results are used more directly. These changes are especially important for improving assessments of continuous resources in frontier or near-frontier deposits.

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Appendix 1. Input data form for continuous accumulations

INPUT DATA FORM FOR CONTINUOUS ACCUMULATIONS
(version 1.0, November 5, 2010)

IDENTIFICATION INFORMATION

Assessment Geologist: ______ Date: ______
Region: ______ Number: ______
Province: ______ Number: ______
Total Petroleum System: ______ Number: ______
Assessment Unit: ______ Number: ______
Based on Data as of: ______

Notes from Assessor: ______

CHARACTERISTICS OF ASSESSMENT UNIT

Assessment-unit type: oil (<20,000 cfg/bo) ______ gas (>20,000 cfg/bo) ______
heavy oil (<10 API) ______

Well type: vertical ______ horizontal ______
Major reservoir type (Choose one.):
shale ______ low-permeability clastics ______
coal ______ low-permeability carbonates ______
diatomite ______

Minimum EUR per well ______ (mmbo for oil AU; bcfg for gas AU)

Number of tested wells: ______
Number of tested wells with EUR > minimum: ______
Historic success ratio, tested wells (%) ______

Assessment-Unit Probability:
What is the probability that an accumulation with producible resources exists? ______

NUMBER OF UNDRILLED WELLS WITH POTENTIAL FOR ADDITIONS TO RESERVES

1. Productive area of accumulation (acres): (triangular)

   calculated mean ______ minimum ______ mode ______ maximum ______

2. Uncertainty about average drainage area of wells (acres): (triangular)

   calculated mean ______ minimum ______ mode ______ maximum ______

   2a. Distribution of drainage areas of individual wells (acres): (shifted truncated lognormal)

   calculated mean ______ *minimum* ______ *median* ______ *maximum* ______

3. Percentage of total assessment-unit area that is untested (%): (triangular)

   calculated mean ______ minimum ______ mode ______ maximum ______

Assessment Unit (name, no.) ____________________

NUMBER OF UNDRILLED WELLS WITH POTENTIAL FOR ADDITIONS TO RESERVES (Continued)

4. Percentage of untested assessment-unit area in sweet spots (%): (triangular)

calculated mean ______ minimum ______ mode ______ maximum ______

ESTIMATED ULTIMATE RECOVERY (EUR) PER WELL

SWEET SPOTS

5a. Future success ratio (%): (triangular)

calculated mean ______ minimum ______ mode ______ maximum ______

5b. Uncertainty about average EUR (mmbo for oil; bcfg for gas): (shifted truncated lognormal)

calculated mean ______ minimum ______ median ______ maximum ______

NON-SWEET SPOTS

6a. Future success ratio (%): (triangular)

calculated mean ______ minimum ______ mode ______ maximum ______

6b. Uncertainty about average EUR (mmbo for oil; bcfg for gas): (shifted truncated lognormal)

calculated mean ______ minimum ______ median ______ maximum ______

UNCERTAINTY ABOUT AVERAGE COPRODUCT RATIOS FOR UNTESTED WELLS
(triangular)

Oil assessment unit:	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	______	______	______
NGL/gas ratio (bngl/mmcfg)	______	______	______
Gas assessment unit:			
Liquids/gas ratio (bliq/mmcfg)	______	______	______

Assessment Unit (name, no.) ____________________

SELECTED ANCILLARY DATA FOR UNTESTED WELLS
(no specified distribution type)

Oil assessment unit:	minimum		median		maximum
API gravity of oil (degrees)	____		____		____
Sulfur content of oil (%)	____		____		____
Depth (m) of water (if applicable)	____		____		____
Drilling depth (m)	minimum	F75	median	F25	maximum
	____	____	____	____	____

Gas assessment unit:	minimum		median		maximum
Inert-gas content (%)	____		____		____
CO_2 content (%)	____		____		____
Hydrogen sulfide content (%)	____		____		____
Heating value (BTU)	____		____		____
Depth (m) of water (if applicable)	____		____		____
Drilling depth (m)	minimum	F75	median	F25	maximum
	____	____	____	____	____

Completion practices:

1. Typical well-completion practices (conventional, open hole, open cavity, other) ____
2. Fraction of wells drilled that are typically stimulated ____
3. Predominant type of stimulation (none, frac, acid, other) ____
4. Historic fraction of wells drilled that are horizontal ____

Assessment Unit (name, no.) ______________________________

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO STATES
Surface Allocations (uncertainty of a fixed value)

1. ______________________ is ________ % of the AREA of the AU

   mean VOLUME % in entity ________

2. ______________________ is ________ % of the AREA of the AU

   mean VOLUME % in entity ________

3. ______________________ is ________ % of the AREA of the AU

   mean VOLUME % in entity ________

4. ______________________ is ________ % of the AREA of the AU

   mean VOLUME % in entity ________

5. ______________________ is ________ % of the AREA of the AU

   mean VOLUME % in entity ________

6. ______________________ is ________ % of the AREA of the AU

   mean VOLUME % in entity ________

7. ______________________ is ________ % of the AREA of the AU

   mean VOLUME % in entity ________

8. ______________________ is ________ % of the AREA of the AU

   mean VOLUME % in entity ________

9. ______________________ is ________ % of the AREA of the AU

   mean VOLUME % in entity ________

10. ______________________ is ________ % of the AREA of the AU

    mean VOLUME % in entity ________

Assessment Unit (name, no.) ________________________

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO GENERAL LAND OWNERSHIPS
Surface Allocations (uncertainty of a fixed value)

1. Federal Lands ________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

2. Private Lands ________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

3. Tribal Lands ________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

4. Other Lands ________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

5. State 1 Lands ________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

6. ________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

7. ________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

8. ________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

9. ________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

10. ________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

Assessment Unit (name, no.) ____________________

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO FEDERAL LAND SUBDIVISIONS
Surface Allocations (uncertainty of a fixed value)

1. Bureau of Land Management (BLM) is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

2. BLM Wilderness Areas (BLMW) is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

3. BLM Roadless Areas (BLMR) is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

4. National Park Service (NPS) is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

5. NPS Wilderness Areas (NPSW) is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

6. NPS Protected Withdrawals (NPSP) is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

7. US Forest Service (FS) is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

8. USFS Wilderness Areas (FSW) is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

9. USFS Roadless Areas (FSR) is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

10. USFS Protected Withdrawals (FSP) is ________ % of the AREA of the AU
    mean VOLUME % in entity ________

Assessment Unit (name, no.) ______________________________

11. US Fish and Wildlife Service (FWS) is ________ % of the AREA of the AU

mean VOLUME % in entity ________

12. USFWS Wilderness Areas (FWSW) is ________ % of the AREA of the AU

mean VOLUME % in entity ________

13. USFWS Protected Withdrawals (FWSP) is ________ % of the AREA of the AU

mean VOLUME % in entity ________

14. Wilderness Study Areas (WS) is ________ % of the AREA of the AU

mean VOLUME % in entity ________

15. Department of Energy (DOE) is ________ % of the AREA of the AU

mean VOLUME % in entity ________

16. Department of Defense (DOD) is ________ % of the AREA of the AU

mean VOLUME % in entity ________

17. Bureau of Reclamation (BOR) is ________ % of the AREA of the AU

mean VOLUME % in entity ________

18. Tennessee Valley Authority (TVA) is ________ % of the AREA of the AU

mean VOLUME % in entity ________

19. Other Federal is ________ % of the AREA of the AU

mean VOLUME % in entity ________

20. ______________________ is ________ % of the AREA of the AU

mean VOLUME % in entity ________

Assessment Unit (name, no.) ____________________

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO ECOSYSTEMS
Surface Allocations (uncertainty of a fixed value)

1. ____________________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

2. ____________________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

3. ____________________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

4. ____________________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

5. ____________________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

6. ____________________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

7. ____________________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

8. ____________________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

9. ____________________ is ________ % of the AREA of the AU
   mean VOLUME % in entity ________

10. ____________________ is ________ % of the AREA of the AU
    mean VOLUME % in entity ________

Appendix 2. Monte Carlo program for assessment of continuous accumulations

The attached program, Continuous2010v2, is a Monte Carlo program that uses @Risk software (Palisade, 2010) to run within Microsoft Excel (Microsoft, 2007). Before using the program, the user must purchase and install both of these commercially available software packages. Once installed, the Continuous2010v2 program runs normally like any other @Risk program. The user is referred to the documentation for those software programs for general instructions on running the program.

Continuous2010v2 includes several spreadsheets. All the input is to be entered on the "Input" spreadsheet in the yellow boxes. The spreadsheet "RiskTemplate_Input" is provided to the user who wishes to add a record of the input data to reports generated by @Risk.

> "Although this program has been used by the USGS, no warranty, expressed or implied, is made by the USGS or the United States Government as to the accuracy and functioning of the program and related program material nor shall the fact of distribution constitute any such warranty, and no responsibility is assumed by the USGS in connection therewith."

USGS 2010 Continuous Methodology

version 2.0 - August 29, 2011

Province Geologist(s):   **Date:**

	Number	Name
Region:		
Province:		
Total Petroleum System:		
Assessment Unit:		

Oil or Gas?

Line #		Distribution	Minimum	Mode	Median	Maximum	Functions
1	Productive area of accumulation (acres)	Triangular					#NAME?
2	Uncertainty about mean drainage area of wells (acres)	Triangular					#NAME?
3	Percentage of total AU area that is untested (%)	Triangular					#NAME?
4	Percentage of untested AU area in sweet spots (%)	Triangular					0.0%
	Sweet Spots						
5a	Future Success Ratio (%)	Triangular					#NAME?
5b	Uncertainty about mean EUR (mmbo or bcfg)	Lognormal					#NAME?
	Non-Sweet Spots						
6a	Future Success Ratio (%)	Triangular					#NAME?
6b	Uncertainty about mean EUR (mmbo or bcfg)	Lognormal					#NAME?
	Coproduct Ratios						
For Oil Accumulation	Gas/oil ratio (cfg/bo)	Triangular					#NAME?
	NGL/gas ratio (bngl/mmcfg)	Triangular					#NAME?
For Gas Accumulation	Liquids/gas ratio (bliq/mmcfg)	Triangular					#NAME?

AU Probability

Correlation 0.50

Untested Area (acres)	#NAME?	
Sweet Spot Area (acres)	#NAME?	
Non-Sweet Spot Area (acres)	#NAME?	
Sweet Spot Well Count (with Success Ratio)	**#NAME?**	
Non-Sweet Spot Well Count (with Success Ratio)	**#NAME?**	
	Unrisked	**Risked**
Gas in Sweet Spot Gas Accumulation (bcfg)	**#NAME?**	**#NAME?**
Gas in Non-Sweet Spot Gas Accumulation (bcfg)	**#NAME?**	**#NAME?**
Total Gas in Gas Accumulation (bcfg)	**#NAME?**	**#NAME?**

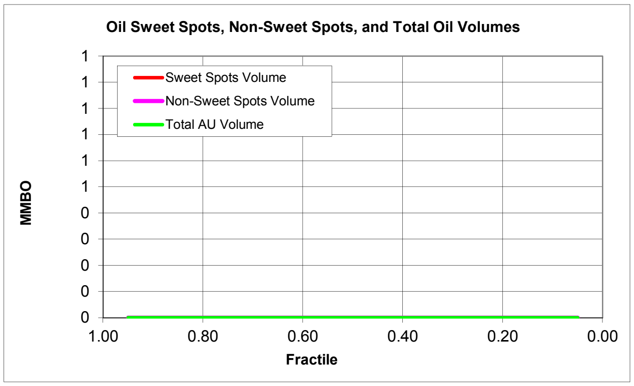
@RISK Correlations			
	1	0.5	0.5
	0.5	1	0
	0.5	0	1

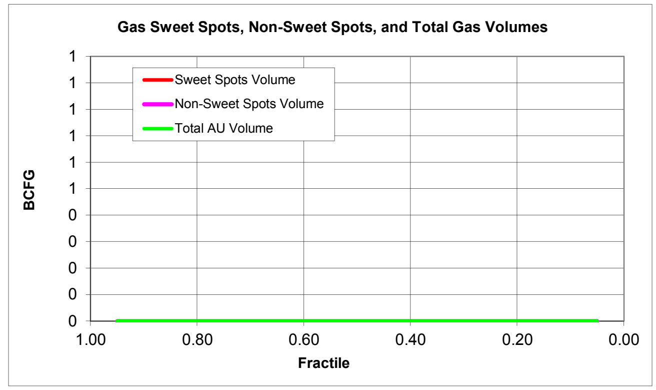
Uniform Probability #NAME?

	Parameters of lognormal				Parameters of associated normal		
mean	#NUM!	s.d.	#NUM!	mu	#NUM!	sigma	#NUM!
mean	#NUM!	s.d.	#NUM!	mu	#NUM!	sigma	#NUM!

Gas in Sweet Spot Gas Accumulation (bcfg)	**#NAME?**	Risked Gas in Sweet Spot Gas Accumulation (bcfg)	**#NAME?**
Gas in Non-Sweet Spot Gas Accumulation (bcfg)	**#NAME?**	Risked Gas in Non-Sweet Spot Gas Accumulation (bcfg)	**#NAME?**
Total Gas in Gas Accumulation (bcfg)	**#NAME?**	Risked Total Gas in Gas Accumulation (bcfg)	**#NAME?**
Oil in Sweet Spot Oil Accumulation (mmbo)	**#NAME?**	Risked Oil in Sweet Spot Oil Accumulation (mmbo)	**#NAME?**
Oil in Non-Sweet Spot Oil Accumulation (mmbo)	**#NAME?**	Risked Oil in Non-Sweet Spot Oil Accumulation (mmbo)	**#NAME?**
Total Oil in Oil Accumulation (mmbo)	**#NAME?**	Risked Total Oil in Oil Accumulation (mmbo)	**#NAME?**
Gas in Sweet Spot Oil Accumulation (bcfg)	**#NAME?**	Risked Gas in Sweet Spot Oil Accumulation (bcfg)	**#NAME?**
Gas in Non-Sweet Spot Oil Accumulation (bcfg)	**#NAME?**	Risked Gas in Non-Sweet Spot Oil Accumulation (bcfg)	**#NAME?**
Total Gas in Oil Accumulation (bcfg)	**#NAME?**	Risked Total Gas in Oil Accumulation (bcfg)	**#NAME?**
NGL in Sweet Spot Oil Accumulation (mmbo)	**#NAME?**	Risked NGL in Sweet Spot Oil Accumulation (mmbo)	**#NAME?**
NGL in Non-Sweet Spot Oil Accumulation (bcfg)	**#NAME?**	Risked NGL in Non-Sweet Spot Oil Accumulation (mmbo)	**#NAME?**
Total NGL in Oil Accumulation (mmbo)	**#NAME?**	Risked Total NGL in Oil Accumulation (mmbo)	**#NAME?**
Liquids in Sweet Spot Gas Accumulation (mmbo)	**#NAME?**	Risked Liquids in Sweet Spot Gas Accumulation (mmbo)	**#NAME?**
Liquids in Non-Sweet Spot Gas Accumulation (mmbo)	**#NAME?**	Risked Liquids in Non-Sweet Spot Gas Accumulation (mmbo)	**#NAME?**
Total Liquids in Gas Accumulation (mmbo)	**#NAME?**	Risked Total Liquids in Gas Accumulation (mmbo)	**#NAME?**

EUR Distribution Sweet Spot	#NAME?
EUR Distribution Non-Sweet Spot	#NAME?





OIL

F05/F95 Ratio	#NAME?	#NAME?	#NAME?

Fractile	Sweet Spots	Non-Sweet Spots	Total AU
0.05	#NAME?	#NAME?	#NAME?
0.10	#NAME?	#NAME?	#NAME?
0.15	#NAME?	#NAME?	#NAME?
0.20	#NAME?	#NAME?	#NAME?
0.25	#NAME?	#NAME?	#NAME?
0.30	#NAME?	#NAME?	#NAME?
0.35	#NAME?	#NAME?	#NAME?
0.40	#NAME?	#NAME?	#NAME?
0.45	#NAME?	#NAME?	#NAME?
0.50	#NAME?	#NAME?	#NAME?
0.55	#NAME?	#NAME?	#NAME?
0.60	#NAME?	#NAME?	#NAME?
0.65	#NAME?	#NAME?	#NAME?
0.70	#NAME?	#NAME?	#NAME?
0.75	#NAME?	#NAME?	#NAME?
0.80	#NAME?	#NAME?	#NAME?
0.85	#NAME?	#NAME?	#NAME?
0.90	#NAME?	#NAME?	#NAME?
0.95	#NAME?	#NAME?	#NAME?

Risked Volumes

Fractile	Sweet Spots	Non-Sweet Spots	Total AU
0.05	#NAME?	#NAME?	#NAME?
0.10	#NAME?	#NAME?	#NAME?
0.15	#NAME?	#NAME?	#NAME?
0.20	#NAME?	#NAME?	#NAME?
0.25	#NAME?	#NAME?	#NAME?
0.30	#NAME?	#NAME?	#NAME?
0.35	#NAME?	#NAME?	#NAME?
0.40	#NAME?	#NAME?	#NAME?
0.45	#NAME?	#NAME?	#NAME?
0.50	#NAME?	#NAME?	#NAME?
0.55	#NAME?	#NAME?	#NAME?
0.60	#NAME?	#NAME?	#NAME?
0.65	#NAME?	#NAME?	#NAME?
0.70	#NAME?	#NAME?	#NAME?
0.75	#NAME?	#NAME?	#NAME?
0.80	#NAME?	#NAME?	#NAME?
0.85	#NAME?	#NAME?	#NAME?
0.90	#NAME?	#NAME?	#NAME?
0.95	#NAME?	#NAME?	#NAME?

GAS

	#NAME?	#NAME?	#NAME?

Fractile	Sweet Spots	Non-Sweet Spots	Total AU
0.05	#NAME?	#NAME?	#NAME?
0.10	#NAME?	#NAME?	#NAME?
0.15	#NAME?	#NAME?	#NAME?
0.20	#NAME?	#NAME?	#NAME?
0.25	#NAME?	#NAME?	#NAME?
0.30	#NAME?	#NAME?	#NAME?
0.35	#NAME?	#NAME?	#NAME?
0.40	#NAME?	#NAME?	#NAME?
0.45	#NAME?	#NAME?	#NAME?
0.50	#NAME?	#NAME?	#NAME?
0.55	#NAME?	#NAME?	#NAME?
0.60	#NAME?	#NAME?	#NAME?
0.65	#NAME?	#NAME?	#NAME?
0.70	#NAME?	#NAME?	#NAME?
0.75	#NAME?	#NAME?	#NAME?
0.80	#NAME?	#NAME?	#NAME?
0.85	#NAME?	#NAME?	#NAME?
0.90	#NAME?	#NAME?	#NAME?
0.95	#NAME?	#NAME?	#NAME?

Fractile	Sweet Spots	Non-Sweet Spots	Total AU
0.05	#NAME?	#NAME?	#NAME?
0.10	#NAME?	#NAME?	#NAME?
0.15	#NAME?	#NAME?	#NAME?
0.20	#NAME?	#NAME?	#NAME?
0.25	#NAME?	#NAME?	#NAME?
0.30	#NAME?	#NAME?	#NAME?
0.35	#NAME?	#NAME?	#NAME?
0.40	#NAME?	#NAME?	#NAME?
0.45	#NAME?	#NAME?	#NAME?
0.50	#NAME?	#NAME?	#NAME?
0.55	#NAME?	#NAME?	#NAME?
0.60	#NAME?	#NAME?	#NAME?
0.65	#NAME?	#NAME?	#NAME?
0.70	#NAME?	#NAME?	#NAME?
0.75	#NAME?	#NAME?	#NAME?
0.80	#NAME?	#NAME?	#NAME?
0.85	#NAME?	#NAME?	#NAME?
0.90	#NAME?	#NAME?	#NAME?
0.95	#NAME?	#NAME?	#NAME?

Gas in Oil Accumulation (bcfg) **#NAME?**

F05/F95 Ratio	#NAME?	#NAME?	#NAME?

Fractile	Sweet Spots	Non-Sweet Spots	Total AU
0.05	#NAME?	#NAME?	#NAME?
0.10	#NAME?	#NAME?	#NAME?
0.15	#NAME?	#NAME?	#NAME?
0.20	#NAME?	#NAME?	#NAME?
0.25	#NAME?	#NAME?	#NAME?
0.30	#NAME?	#NAME?	#NAME?
0.35	#NAME?	#NAME?	#NAME?
0.40	#NAME?	#NAME?	#NAME?
0.45	#NAME?	#NAME?	#NAME?
0.50	#NAME?	#NAME?	#NAME?
0.55	#NAME?	#NAME?	#NAME?
0.60	#NAME?	#NAME?	#NAME?
0.65	#NAME?	#NAME?	#NAME?
0.70	#NAME?	#NAME?	#NAME?
0.75	#NAME?	#NAME?	#NAME?
0.80	#NAME?	#NAME?	#NAME?
0.85	#NAME?	#NAME?	#NAME?
0.90	#NAME?	#NAME?	#NAME?
0.95	#NAME?	#NAME?	#NAME?

Risked Gas in Oil Accumulation (bcfg) **#NAME?**

Fractile	Sweet Spots	Non-Sweet Spots	Total AU
0.05	#NAME?	#NAME?	#NAME?
0.10	#NAME?	#NAME?	#NAME?
0.15	#NAME?	#NAME?	#NAME?
0.20	#NAME?	#NAME?	#NAME?
0.25	#NAME?	#NAME?	#NAME?
0.30	#NAME?	#NAME?	#NAME?
0.35	#NAME?	#NAME?	#NAME?
0.40	#NAME?	#NAME?	#NAME?
0.45	#NAME?	#NAME?	#NAME?
0.50	#NAME?	#NAME?	#NAME?
0.55	#NAME?	#NAME?	#NAME?
0.60	#NAME?	#NAME?	#NAME?
0.65	#NAME?	#NAME?	#NAME?
0.70	#NAME?	#NAME?	#NAME?
0.75	#NAME?	#NAME?	#NAME?
0.80	#NAME?	#NAME?	#NAME?
0.85	#NAME?	#NAME?	#NAME?
0.90	#NAME?	#NAME?	#NAME?
0.95	#NAME?	#NAME?	#NAME?

NGL in Oil Accumulation (mmbNGL) **#NAME?**

F05/F95 Ratio	#NAME?	#NAME?	#NAME?

Fractile	Sweet Spots	Non-Sweet Spots	Total AU
0.05	#NAME?	#NAME?	#NAME?
0.10	#NAME?	#NAME?	#NAME?
0.15	#NAME?	#NAME?	#NAME?
0.20	#NAME?	#NAME?	#NAME?
0.25	#NAME?	#NAME?	#NAME?
0.30	#NAME?	#NAME?	#NAME?
0.35	#NAME?	#NAME?	#NAME?
0.40	#NAME?	#NAME?	#NAME?
0.45	#NAME?	#NAME?	#NAME?
0.50	#NAME?	#NAME?	#NAME?
0.55	#NAME?	#NAME?	#NAME?
0.60	#NAME?	#NAME?	#NAME?
0.65	#NAME?	#NAME?	#NAME?
0.70	#NAME?	#NAME?	#NAME?
0.75	#NAME?	#NAME?	#NAME?
0.80	#NAME?	#NAME?	#NAME?
0.85	#NAME?	#NAME?	#NAME?
0.90	#NAME?	#NAME?	#NAME?
0.95	#NAME?	#NAME?	#NAME?

Risked NGL in Oil Accumulation (mmbNGL) **#NAME?**

Fractile	Sweet Spots	Non-Sweet Spots	Total AU
0.05	#NAME?	#NAME?	#NAME?
0.10	#NAME?	#NAME?	#NAME?
0.15	#NAME?	#NAME?	#NAME?
0.20	#NAME?	#NAME?	#NAME?
0.25	#NAME?	#NAME?	#NAME?
0.30	#NAME?	#NAME?	#NAME?
0.35	#NAME?	#NAME?	#NAME?
0.40	#NAME?	#NAME?	#NAME?
0.45	#NAME?	#NAME?	#NAME?
0.50	#NAME?	#NAME?	#NAME?
0.55	#NAME?	#NAME?	#NAME?
0.60	#NAME?	#NAME?	#NAME?
0.65	#NAME?	#NAME?	#NAME?
0.70	#NAME?	#NAME?	#NAME?
0.75	#NAME?	#NAME?	#NAME?
0.80	#NAME?	#NAME?	#NAME?
0.85	#NAME?	#NAME?	#NAME?
0.90	#NAME?	#NAME?	#NAME?
0.95	#NAME?	#NAME?	#NAME?

Liquids in Gas Accumulation **#NAME?**

F05/F95 Ratio	#NAME?	#NAME?	#NAME?

Fractile	Sweet Spots	Non-Sweet Spots	Total AU
0.05	#NAME?	#NAME?	#NAME?
0.10	#NAME?	#NAME?	#NAME?
0.15	#NAME?	#NAME?	#NAME?
0.20	#NAME?	#NAME?	#NAME?
0.25	#NAME?	#NAME?	#NAME?
0.30	#NAME?	#NAME?	#NAME?
0.35	#NAME?	#NAME?	#NAME?
0.40	#NAME?	#NAME?	#NAME?
0.45	#NAME?	#NAME?	#NAME?
0.50	#NAME?	#NAME?	#NAME?
0.55	#NAME?	#NAME?	#NAME?
0.60	#NAME?	#NAME?	#NAME?
0.65	#NAME?	#NAME?	#NAME?
0.70	#NAME?	#NAME?	#NAME?
0.75	#NAME?	#NAME?	#NAME?
0.80	#NAME?	#NAME?	#NAME?
0.85	#NAME?	#NAME?	#NAME?
0.90	#NAME?	#NAME?	#NAME?
0.95	#NAME?	#NAME?	#NAME?

Risked Liquids in Gas Accumulation **#NAME?**

Fractile	Sweet Spots	Non-Sweet Spots	Total AU
0.05	#NAME?	#NAME?	#NAME?
0.10	#NAME?	#NAME?	#NAME?
0.15	#NAME?	#NAME?	#NAME?
0.20	#NAME?	#NAME?	#NAME?
0.25	#NAME?	#NAME?	#NAME?
0.30	#NAME?	#NAME?	#NAME?
0.35	#NAME?	#NAME?	#NAME?
0.40	#NAME?	#NAME?	#NAME?
0.45	#NAME?	#NAME?	#NAME?
0.50	#NAME?	#NAME?	#NAME?
0.55	#NAME?	#NAME?	#NAME?
0.60	#NAME?	#NAME?	#NAME?
0.65	#NAME?	#NAME?	#NAME?
0.70	#NAME?	#NAME?	#NAME?
0.75	#NAME?	#NAME?	#NAME?
0.80	#NAME?	#NAME?	#NAME?
0.85	#NAME?	#NAME?	#NAME?
0.90	#NAME?	#NAME?	#NAME?
0.95	#NAME?	#NAME?	#NAME?

USGS 2010 Continuous Methodology

version 2.0 - August 29, 2011

Province Geologist(s): | **Date:**

	Number	Name
Region:		
Province:		
Total Petroleum System:		
Assessment Unit:		

Oil or Gas?

Line #		Distribution	Minimum	Mode	Median	Maximum	Functions
1	Total AU area (acres)	Triangular					#NAME?
2	Uncertainty about mean drainage area of wells (acres)	Triangular					#NAME?
3	Percentage of total AU area that is untested (%)	Triangular					#NAME?
4	Percentage of untested AU area in sweet spots (%)	Triangular					0.0%
	Sweet Spots						
5a	Future Success Ratio (%)	Triangular					#NAME?
5b	Uncertainty about mean EUR (mmbo or bcfg)	Lognormal					#NAME?
	Non-Sweet Spots						
6a	Future Success Ratio (%)	Triangular					#NAME?
6b	Uncertainty about mean EUR (mmbo or bcfg)	Lognormal					#NAME?
	Coproduct Ratios						
For Oil Accumulation	Gas/oil ratio (cfg/bo)	Triangular					#NAME?
	NGL/gas ratio (bngl/mmcfg)	Triangular					#NAME?
For Gas Accumulation	Liquids/gas ratio (bliq/mmcfg)	Triangular					#NAME?

AU Probability

Correlation 0.50

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