APPENDIX 7

INITIAL ESTIMATES OF REMAINING PROVED ULTIMATE RECOVERY GROWTH

This appendix documents the methodology used by the Energy Information Administration to estimate future reserves growth, also called 'remaining proved ultimate recovery growth,' that will be associated with existing oil and gas fields in the Phase II study areas. A more complete discussion of this phenomenon and its many causes is presented in *The Intricate Puzzle of Oil and Gas "Reserves Growth."*[1] This paper is highly recommended to readers who want to fully understand the development of and rationale for current statistical approaches to estimating the future growth of existing oil and gas fields, as well as the key uncertainties and data limitations of current methods.

The Proved Ultimate Recovery (PUR) of an oil or gas field at a particular point in time is defined as the sum of its estimated proved reserves and its recorded cumulative production at that time.

Proved Ultimate Recovery Growth (PURG) is the increase in proved ultimate recovery over time that is observed for most oil and gas fields. A field's PUR estimate normally increases significantly in the early post-discovery years as a field is developed for production and its areal limits are better discerned. PUR estimates may also be conservative early in a field's life owing to the smaller knowledge base then available regarding its productive performance. A field's later years are usually characterized by slower growth arising from a variety of possible causes including the installation of improved recovery techniques, increased knowledge of the field's performance, the addition of new reservoirs to the field, and infill drilling. Growth factors calculated from most fields' ultimate recovery histories thus usually increase rapidly as initial field development occurs and then asymptotically approach a maximum value as growth slows in later years.

PURG, or *reserves growth*, and the remaining (future) portion thereof, RPURG, can be estimated from the observed historical proved ultimate recovery growth. In a given year for a group of fields of the same vintage (age) the Annual Growth Factor (AGF) is the sum of the estimated proved ultimate recovery of the fields in that year divided by the sum of estimated proved ultimate recovery of the same fields for the prior year. Going one step further, for a basin the average AGF for its multiple fields in multiple vintages is the sum of the estimated proved ultimate recoveries of all fields in all vintages at the same point in time, i.e., the same year after first production (or after field discovery), divided by the sum of estimated proved ultimate recoveries of the same fields for the prior year.

[1] Available online at
http://www.eia.doe.gov/pub/oil_gas/petroleum/feature_articles/1997/intricate_puzzle_reserves_growth/m07fa.pdf .

$$AAGF_n = \frac{\sum_{v=1}^{t}\sum_{f=1}^{i} PUR_n}{\sum_{v=1}^{t}\sum_{f=1}^{i} PUR_{n-1}}$$

where: AAGF = Average Annual Growth Factor
PUR = Proved Ultimate Recovery
n = Years after first production (or discovery)
t = Number of vintages at *n*
i = Number of fields in a vintage at *n*
v = Vintage
f = Field

The Cumulative Growth Factor (CGF) in a particular year is the product of the Average AGF for all fields in all vintages through that year beginning with the first production or discovery year of the first vintage.

$$CGF_n = AAGF_1 * AAGF_2 * ...AAGF_n$$

where: CGF = Cumulative Growth Factor
AAGF = Average Annual Growth Factor
n = Years since first production (or discovery)

The RPURG can be calculated as the product of the ratio of the future CGF to the current CGF and the current PUR.

$$RPURG_{t-n} = \frac{CGF_t}{CGF_n} * PUR_n$$

where: RPURG = Remaining Proved Ultimate Recovery Growth volume at time n
CGF = Cumulative Growth Factor
PUR = Proved Ultimate Recovery volume at current time (n)
n = Current time expressed as years since first production (or discovery)
t = Final time expressed as years since first production (or discovery), i.e., infinity

Equivalently, the estimate of additional ultimate recovery that may be realized in the future based on reserves growth during the future can be stated as:

$$RPURG_{t-n} = PUR_t - PUR_n$$

where: RPURG = Remaining Proved Ultimate Recovery Growth volume at time n

PUR = Proved Ultimate Recovery
n = Current time expressed as years since first production (or discovery)
t = Final time expressed as years since first production (or discovery)

A7.1 DATABASE PREPARATION

A database was created containing annual oil and gas production, estimates of cumulative production for that production which occurred prior to the keeping of annual production records, annual oil and gas proved reserves, field name, and field discovery date for fields located in selected Phase II study areas (Uinta-Piceance Basin, Paradox/San Juan Basins, Montana Thrust Belt, Powder River Basin, Wyoming Thrust Belt, Greater Green River Basin, Denver Basin and Black Warrior Basin). The available data for the Appalachian Basin were insufficient for PURG analysis. Data sources included the EIA Reserves and Production Division's Oil and Gas Integrated Field File (RPD OGIFF), the EIA Field Code Master List (FCML), the EIA-23 Reserves Survey, various state web sites, and commercial sources (mainly IHS Energy Group).

Each field in a basin was assigned to a vintage year according to its date of first production or its date of discovery depending on which date was available, or which date was deemed the most reliable indicator of initial production. While the earliest field vintage was 1901, the annual proved reserves estimates and therefore the proved ultimate recovery estimates were usually available only from 1977 to present. The resulting files contained vintage year, number of fields in each vintage, annual proved ultimate recovery for each vintage (expressed in barrels of oil equivalent, BOEULT), annual natural gas proved ultimate recovery for each vintage, and annual liquid proved ultimate recovery for each vintage.

Significant effort went into quality control of the data. Many field names and codes had to be altered, corrected, and matched across the multiple data sources and time in order to properly accumulate the field data. *Quality control beyond that point was, however, deliberately conservative.* While obvious major errors had to be corrected, the desire to seek "correction" of things that were merely suspicious had to be resisted for two reasons: first they might well be correct, and second the available task resources and time frames were limited. Therefore, the reserves data were used as reported by the field operators unless very obvious errors were found. Data discontinuities and variations within vintages were for the most part accepted "as-is." Specific vintages that did not fit the trend of most of the data of a basin were excluded from the history matching and forecasting. Attempts to divide the data within a basin into conventional reservoirs, tight formation gas, and coalbed natural gas sources were largely unsuccessful because of the limited number of vintages, the short histories available for some of the fields, and frequent inability to separate the data by reservoir type within a field.

A7.2 ESTIMATION OF REMAINING PROVED ULTIMATE RECOVERY GROWTH

The remainder of this appendix describes two models that were independently used to estimate RPURG by basin and hydrocarbon type within a basin and then details the modeling results. The first model implements an exponential function having two fit parameters while the second model implements a hyperbolic function having four fit parameters. The exponential model is dependent on the annual average cumulative growth factors for the basin, whereas the hyperbolic model is dependent on incremental growth factors by vintage. Both are asymptotic functions that use time as the sole driver. Even though other potential drivers such as drilling rates or wellhead prices of oil and gas are not directly used, they have affected the historical data that feed into the models.

A7.3 EXPONENTIAL CUMULATIVE GROWTH FACTOR MODEL

To estimate a CGF at some time in the future a least squares fit of the historical data can be made using an exponential function. Knowing that the CGF is equal to 1.0 at discovery and that the growth rate should decrease to an asymptote of the CGF, an exponential function beginning at 1.0 at time equals zero (the time of discovery) and thereafter remaining positive as time since discovery increases was found to provide an adequate fit of the historical data, i.e.:

$$CGF = a\left(1 - e^{-bn}\right) + c$$

where: CGF = Cumulative Growth Factor
b = exponent
n = time since first production (or discovery)
c = 1.0 (constant)
a = fit parameter equal to the asymptotic CGF minus 1

Data from the Uinta/Piceance, Paradox/San Juan, Powder River, Wyoming Thrust Belt, Greater Green River, Denver, and Black Warrior basins were evaluated. Sufficient data were not available to evaluate the Montana Thrust Belt and the available coal bed natural gas data were deemed not to be analytically dependable for separate analysis.

A7.4 HYPERBOLIC INCREMENTAL GROWTH FACTOR MODEL

The RPURG for each basin can also be estimated by sorting the data by vintage within that basin and predicting the achievable PURG for the basin over time using a hyperbolic incremental model. The solely time-based model function excludes direct consideration of other factors such as drilling levels, prices, and costs. The historical estimated data were, however, subject to these factors and more. The initial dataset was limited to PUR estimates from 1977 to 2003 and there were significant data gaps in the some of the data series.

The methodology for fitting and using the hyperbolic model involves the following sequential steps:

A. Sort the field-level PUR estimates by hydrocarbon type and vintage year
B. Calculate the relative field growth factor by dividing successive PUR estimates by the “starting” 1977 estimate
C. Determine the incremental percentage increase from year to year for all vintages
D. Create a time-based hyperbolic model curve using the following formula:

$$CGF_{TBHM} = \left[1 + Tbeta1 \times \left(1 - \frac{1}{1 + Tbeta2 \times (n)}\right)\right] \times \left[1 + Tbeta4 \times \left(1 - e^{Tbeta3 \times \frac{n}{10}}\right)\right]$$

where: CGF_{TBHM} = Cumulative Growth Factor of the time-based hyperbolic model.

n = Years after first production (or discovery), a time difference factor that is the number of years between the current year and the vintage year (i.e., 1995-1901).

E. Perform a least squares fit of the incremental percentage increase per vintage year of the model with the actual incremental data, solving for Tbeta1 through Tbeta4, using the following constraints on the variables:

$$1 \le Tbeta1 \le 10$$
$$0.1 \le Tbeta2 \le 1$$
$$-1 \le Tbeta3 \le -0.5$$
$$0 \le Tbeta4 \le 5$$

F. Obtain the asymptotic limit of the model by multiplying (1+Tbeta1) x (1+Tbeta4) (note that as the time difference approaches infinity the Tbeta2 and Tbeta3 factors cancel out of the model)
G. Plot the results by basin and fuel using 50 years and 300 years as x-axis lengths to allow for quality control inspection of the results on both short and long time scales
H. Using the known PUR estimate for the basin, and the actual years after first production (or discovery) time difference, use the performance of the model curve fit to predict the RPURG volume

The results obtained using this model are presented by basin and hydrocarbon type in the “Details of Each Methodology” section of this appendix. The Montana Thrust Belt study area had just three vintages, insufficient for modeling purposes.

A7.5 RESULTS

While at first inspection the concepts and implementations of RPURG estimation may appear to be fairly straight-forward, that's rarely the case when the mathematics meet real-world data. Each of the models described above was independently used to estimate the remaining proved ultimate recovery growth volumes for each basin and hydrocarbon type. The available data were sometimes culled differently for the two model fits, i.e., for a given basin and hydrocarbon type the exact same data may or may not have been used for both models. This was because one of the models gave reasonable results with a specific data set, whereas the other model yielded reasonable results only after certain data or vintages were eliminated. Results of the two model fits were compared for each basin and hydrocarbon type and a preferred model result was selected based on the modeling team's expert judgment and experience. The exponential model was selected the majority of the time. When selection of the preferred model fit was a toss up the exponential model was the default selection. Table A7-1 shows the results of the selection process. The preferred model associated with it is listed along with the PUR volumes by basin and hydrocarbon type for the preferred model results.

Table A7-1. Phase II Selected Models and Results

The Energy Information Administration methodology used for the Phase II study areas and the methodology used by the U.S. Geological Survey to estimate reserves growth for the most recent National Assessment are both statistical extrapolations of historical reserves growth and are subject to the same inherent limitations,[2] although the methodologies differ in detail. These limitations introduce substantial uncertainty into the final results, which the USGS is currently addressing in an on-going review of their reserves growth estimation methodology (see below). In a recent test, the USGS found that two different statistical extrapolation methodologies produce reserves growth estimates that differed by approximately 25 percent and were as much as 60 percent higher than actual volumetric data.[3] The results shown in Table A7-1 should be interpreted with these limitations in mind:

- Inherent uncertainty in the underlying data (for example, ‘reserves’ are defined differently by different operators and different commercial/ private databases; fields and reservoirs are inconsistently defined)
- Current statistical methodologies rely on field age (since field discovery) as a surrogate for field development effort. Other factors such as reserves recognition practices, differential application of new technology and production monitoring practices, different operating environments and access to markets may not be adequately represented by field age alone.
- Large fields have more weight in the analysis, which may bias the results towards the development histories of the largest fields in a basin or study area. Large fields may be more likely than smaller fields to receive consistently applied development efforts and new technology applications, and be less sensitive to economic factors.
- Uncertainties are not addressed directly such as variance of the input data and uncertainties in the underlying assumed field development scenarios.

Table A7-2 compares the EIA proved ultimate recovery growth estimates shown in Table A7-1 with recent estimates of reserves growth published by the National Petroleum Council[4] and the Potential Gas Committee (PGC).[5] Table A7-2 shows that

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[2] From Klett, Timothy, *One-Year Reserve-Growth Scoping Project, Fiscal Year 2006*, presentation to American Association of Petroleum Geologists, Committee on Resource Evaluation, February 9, 2006.
[3] Ibid; slide titled “Test of Modified Arrington and USGS Least Squares/Monotonic Methods”
[4] National Petroleum Council, 2003, *Balancing Natural Gas Policy*, Supply Task Group Report.

for most study areas, the reserves growth volumes estimated are significantly lower than reserves growth estimates published by other organizations. It is unlikely that there's a single cause of these differences. Most certainly there are some significant differences in methodology and input data. For example, the PGC uses a non-statistical, reservoir-specific approach that relies on expert judgment to estimate the probable resources associated with the additional development of an already discovered reservoir. Historically, in fact, the most successful estimates of reserves growth have relied on the use of reservoir level data rather than the more aggregate field level data on which the EPCA estimates are based. That is not particularly surprising since most factors that affect the reserves growth phenomenon are reservoir-specific and will not necessarily apply to an entire field when it consists of multiple reservoirs as many fields do.[6] Unfortunately, reservoir level proved reserves data are only rarely available for onshore United States fields and the EPCA RPURG estimation must therefore be done using the field level data that are available. It should also be noted that this is, insofar as we know, the first time that field level RPURG analysis has been attempted on a scale comparable to that of the EPCA project.

Table A7-2. Comparison of Estimates of Reserves Growth-Natural Gas

Recognizing that the oil and gas constraints analysis is cumulative and ongoing, subsequent phases in the inventory may provide opportunities to use new input data or an improved methodology to investigate and adjust the estimates of proved ultimate recovery growth.

Recognizing the inherent uncertainties and limitations of recent USGS reserves growth estimation methods, the USGS has undertaken a scoping project to review current extrapolation methods and develop feasible improvements to the existing reserve growth methodologies..[6] The USGS “FY 2006 Reserves Growth Scoping Project” will result in various products which could potentially inform and improve the estimates of remaining proved ultimate recovery growth for future inventory releases. These include USGS recommendations for reserves growth estimation methodologies, updates to the USGS database, an evaluation of the use of field “age” or field development effort to estimate reserves growth, and evaluation of “cell-based” estimation approaches.

EIA is investigating whether it will be possible to develop improved, less labor-intensive means of cleansing the field level data of its apparent anomalies and errors. Another EIA goal is improvement of the RPURG estimation methodology via multi-parameter modeling.

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[5] Potential Gas Committee, 2005, *Potential Supply of Natural Gas in the United States as of December 31, 2004*, September 2005

[6] U.S. Geological Survey, Energy Resources Team, *Reserves Growth Scoping Project*, Project No. 8930C1K, October 1, 2005 to September 30, 2006, Timothy Klett, project chief. Also, Klett, Timothy, *One-Year Reserve-Growth Scoping Project, Fiscal Year 2006*, presentation to American Association of Petroleum Geologists, Committee on Resource Evaluation, February 9, 2006.

A7.6 DETAILED RESULTS BY MODEL TYPE

The detailed results of each model are presented in this section. The preferred results previously shown in Table A7-1 were selected after comparing the model results described in this section.

A7.6.1 Exponential Cumulative Growth Factor Model Runs

The exponential cumulative growth factor estimation results for Phase II are reported in Table A7-3. Charts of the exponential model curve fit of the oil equivalent, total liquids, and natural gas are included as Figures A7-1 through A7-26. Separate estimates for gas in tight reservoirs and coal bed methane could not be relied on for most basins owing to a combination of data anomalies and data interpretation concerns. For purposes of consistency, the results for the three instances in which such estimates could be made were not carried forward.

For each type of production any obviously anomalous vintages may not have been used in the analysis and forecast but are nevertheless shown in Figures A7-1 through A7-26. Because some forecasts did not show the expected asymptotic behavior, a CGF calculated for the distant, arbitrarily selected year 2303 was used (t-n = 300) for the CGF in lieu of a model-derived asymptote (as listed in Table A7-3).

Table A7-3. Exponential Method Ultimate Recovery Growth from 2003 to 2303

Figure A7-1. Uinta-Piceance Basin Exponential Curve Fit of Equivalent Oil Cumulative Growth Factor

Figure A7-2. Uinta-Piceance Basin Exponential Curve Fit of Tight Formation Equivalent Oil Cumulative Growth Factor

Figure A7-3. Uinta-Piceance Basin Exponential Curve Fit of Liquids Cumulative Growth Factor

Figure A7-4. Uinta-Piceance Basin Exponential Curve Fit of Gas Cumulative Growth Factor

Figure A7-5. Uinta-Piceance Basin Exponential Curve Fit of Tight Formation Gas Cumulative Growth Factor

Figure A7-6. Paradox/San Juan Basins Exponential Curve Fit of Equivalent Oil Cumulative Growth Factor

Figure A7-7. Paradox/San Juan Basins Exponential Curve Fit of Tight Formation Equivalent Oil Cumulative Growth Factor

Figure A7-8. Paradox/San Juan Basins Exponential Curve Fit of Liquids Cumulative Growth Factor

Figure A7-9. Paradox/San Juan Basins Exponential Curve Fit of Tight Formation Liquids Cumulative Growth Factor

Figure A7-10. Paradox/San Juan Basins Exponential Curve Fit of Gas Cumulative Growth Factor

Figure A7-11. Paradox/San Juan Basins Exponential Curve Fit of Tight Formation Gas Cumulative

Figure A7-12. Powder River Basin Exponential Curve Fit of Equivalent Oil Cumulative Growth Factor

Figure A7-13. Powder River Basin Exponential Curve Fit of Liquids Cumulative Growth Factor

Figure A7-14. Powder River Basin Exponential Curve Fit of Gas Cumulative Growth Factor

Figure A7-15. Wyoming Thrust Belt Exponential Curve Fit of Oil Equivalent Cumulative Growth Factor

Figure A7-16. Wyoming Thrust Belt Exponential Curve Fit of Liquids Cumulative Growth Factor

Figure A7-17. Wyoming Thrust Belt Exponential Curve Fit of Gas Cumulative Growth Factor

Figure A7-18. Greater Green River Basin Exponential Curve Fit of Equivalent Oil Cumulative Growth Factor

Figure A7-19. Greater Green River Basin Exponential Curve Fit of Liquids Cumulative Growth Factor

Figure A7-20. Greater Green River Basin Exponential Curve Fit of Gas Cumulative Growth Factor

Figure A7-21. Denver Basin Exponential Curve Fit of Equivalent Oil Cumulative Growth Factor

Figure A7-22. Denver Basin Exponential Curve Fit of Liquids Cumulative Growth Factor

Figure A7-23. Denver Basin Exponential Curve Fit of Gas Cumulative Growth Factor

Figure A7-24. Black Warrior Basin Exponential Curve Fit of Oil Equivalent Cumulative Growth

Figure A7-25. Black Warrior Basin Exponential Curve Fit of Liquids Cumulative Growth Factor

Figure A7-26. Black Warrior Basin Exponential Curve Fit of Gas Cumulative Growth Factor

A7.6.2 Hyperbolic Incremental Growth Factor Model Runs

The following Table A7-4 and Figures A7-27 through A7-40 show the detailed results of the hyperbolic incremental growth factor model as applied to the Phase II basins.