Valuing Oil & Gas Properties

Robert M. McGowen

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Valuing Oil and Gas Properties

39th Annual Natural Resources Law Institute
Hot Springs, Arkansas
February 23-26, 2000
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Valuing Oil and Gas Properties

Introduction

The purpose of this paper is to review procedures to value oil and gas properties. It is important to know not only how to determine the value of oil and gas properties but the methods used in arriving at property values. This paper will provide a quick look at property valuation to enable Natural Resources Law Institute participants to discern the reasonableness of oil and gas property values as presented from prospective buyers and sellers alike. Per the October 1992 Uniform Appraisal Standards - Section A “Under established law the criterion for just compensation is the fair market value of the property at the time of the taking. Fair Market Value is defined as the amount in cash, or on terms reasonably equivalent to cash, for which in all probability the property would be sold by a knowledgeable owner willing but not obligated to sell to a knowledgeable purchaser who desired but is not obligated to buy.” Valuation methods will be discussed and reviewed. A review of reserve definitions, methodology, and economic factors will follow the valuation method discussion. The property sale results of 1998 will be summarized and oil and gas valuation examples will be presented.

Valuation Methods

We can make several approaches to place a value on oil and gas properties. Most of the methods require that reserves be determined and scheduled annually with resultant annual net cash flow streams after expenses. All of the valuation methods require, at the least, oil and gas reserves to be determined. Reserve classification and categories will be discussed later in this paper. The reserve classification does affect value as reserves with more risk are discounted accordingly. The valuation methods are as follows:

1. Rate of return or present worth at a specified discount rate (15 - 25%)
2. Payout time (2-5 years with 1/3 of the remaining life being the maximum payout time)
3. Income to investment ratio (2-1 or a 3-1 ratio)
4. Specified fraction of present worth of future net income (2/3)
5. Price per barrel of reserves in ground (1/3 of well head price)
Rate of Return Method

This method calculates Fair Market Value as that purchase that provides for an acceptable rate-of-return on investment. The remaining reserves of the properties in question need to be determined and scheduled annually. Using reasonable product prices and cost, annual net cash flows are calculated. The yearly net cash flow amounts are discounted at a present worth rate that yields an acceptable rate of return. Present worth is by definition the value of future cash projected income applied to the present. The normal discount rate used for oil and gas properties is the cost of money. The present worth equation is $PW = CF(1+i)^n$ where $CF$ is annual net cash flow, $i$ is annual decimal interest rate and $n$ is number of years. Depending on the evaluating entity, the discount rate will range from fifteen to twenty five percent and be closer to the higher rate. This method is the most used, most reliable, and most accurate. It also requires the longest time to determine as compared to some of the other methods.

Payout Time Method

Using the payout time method, the Fair Market Value would be equal to the cumulative undiscounted future net cash flow for the first two to five years after the property is purchased. A rule of thumb for the maximum time length considered in this type of valuation method would usually be no more than one-third of the remaining life. The cash flow needs to be calculated based on projected oil and gas production. Another variation of this approach is the monthly multiplier technique. An example of this is some number of months times current monthly net income. The number of months used range from 12 to 54 depending on the property type. This method provides a quick way to determine a Fair Market Value range for further review.

Income to Investment Ratio Method

This method calculates Fair Market Value by dividing the expected income by the purchase price of the property. Purchasers would typically seek a ratio of two or three to one or better. This technique requires reserves to determined and scheduled annually and resultant net cash flow to be calculated. The income to investment ratio method should be used in conjunction with other methods to fine tune Fair Market Value.
Specified Fraction of Present Worth of Future Net Income

Fair Market Value is estimated by use of a specified percent of present worth. A common rule of thumb approach in using this method is two-thirds of present worth. The remaining reserves of the properties in question need to be determined and scheduled on an annual basis. Using reasonable product prices and costs annual net cash flows are calculated. The yearly net cash flow amounts are discounted at a present worth rate that represents the current cost of money and ranges from seven to ten percent. This method should also be used in conjunction with other methods to fine tune Fair Market Value.

Price Per Barrel of Reserves in Ground (1/3 of Well head Price)

For this method, gas volumes are converted to equivalent barrels of oil on either a heating value (1 Bbl = 6 MCF) or price ratio basis. The oldest and truest rule of thumb in the oil industry is that oil reserves in the ground are worth one-third the current market value. This method, in my opinion, is one that is after the fact. By that I mean that after Fair Market Value is determined then the price per barrel of in ground reserves can be calculated. If reserves are known, then this is a quick way to estimate Fair Market Value.

Reserve Analysis

Definitions

The above described valuation methods require an understanding and explanation of reserve determination. Reserves are classified as proved, probable, and possible. The lower the category, the less certain are the reserve estimates assigned to the property. Proved reserves are further classified as: proved producing, proved shut-in, proved behind-pipe, and proved undeveloped. An accepted definition of reserves is the Society of Petroleum Engineer’s Definitions of Oil and Gas Reserves which is included in the Appendix as Exhibit A.

Reserve Risk Factors

Reserve risk factors are applied to reserves to account for risk associated with producing the
reserves. The risk factors increase with the uncertainty that the reserves will be produced. The risk factors have been determined from the Society of Petroleum Evaluation Engineers Survey of Economic Parameters Used in Property Evaluation, June 1999 which is in the Appendix as Exhibit B.

Methodology

Decline Analysis

A number of methods are used in determining reserves depending on the producing time and available pressure and production data of the evaluated properties. The methods are decline analysis, volumetric analysis, material balance and analogy. Decline analysis is a method in which future production is estimated based on past performance. This method is best suited for properties that have been producing for some time with production declines that represent true reservoir behavior and not market capacity problems. This method represents the quickest way to evaluate a large number of properties and is very reliable in terms of results.

Volumetric Analysis

Volumetric analysis is a method to determine reserves assuming a reservoir volume to be drained by the well evaluated. This method is used primarily for wells that have been producing for a short time and there is limited well history to predict future production. This method utilizes log and core analyses to estimate productive pore volumes in the vicinity of the evaluated well. The drainage volume also has to be estimated based on well spacing or analogy to offset wells. This method has a greater chance of being incorrect and is usually high.

Material Balance

A third method is material balance. This is an analysis of pressure and production data to determine the original in-place hydrocarbon volumes. As oil or gas is withdrawn from the reservoir there is a change in reservoir pressure. A calculation is performed that examines reservoir withdrawals as compared to reservoir pressure changes to determine original oil or gas in place. This method is the most accurate in determining reserves but requires complete well data. It is not used as often as other methods due the lack of sufficient well data.
Analogy

Analogy is the fourth method used to determine reserves when other methods are not applicable or it is used in conjunction with other methods. This technique compares recoveries from similar producing properties to the properties being examined. The analogy method is not very accurate and is used when other methods do not yield good results. It provides an order of magnitude range of reserves. This method does provide a way to differentiate realistic reserves from pie in the sky reserves.

Economic Factors

One of the more important factors used in valuing oil and gas properties is the economic assumptions. There is considerable risk associated with pricing, costs, and escalations in determining Fair Market Value. This section of the paper will deal with my best guess on how to arrive at economic assumptions that will provide reasonable market values.

Pricing

In an attempt to obtain proper prices to use in valuing properties a number of sources need to be considered. Current prices, an average of the last twelve month prices, and NYMEX future twelve month averages adjusted to spot gas prices and posted oil prices are three sources to review. The NYMEX futures price approach will probably provide the best estimate of the price in the coming year. Depending on the criteria of the evaluator, property values should be considered with different prices to provide a range of values that are price sensitive.

Costs

Operating and capital costs used should be actual average costs over the last six to twelve months. These numbers are not always available but are critical to the accuracy of the evaluation. If cost estimates are necessary, base them an analogy to similar properties. Any liabilities associated with producing properties must also be considered and include plug and abandon costs and environmental clean up costs.

Escalations

Price and cost escalations are moving targets and depend on the economic perception at the time of the analysis to value the oil and gas properties. The commonly used escalation rates track
the consumer price index. An annual escalation rate of between two and three percent is reasonable to use. Price ceilings should also be applied that do not exceed one and one-half times the currently used initial prices. Please see Exhibit B in the Appendix.

**Property Sales Results Summary**

Volume 97, Number 11 of *The Oil and Gas Journal*, reported that the asset sales of 1998 reached a record $82.1 billion. The median reserves value for the 133 deals in 1998 for which transaction values were disclosed was $4.94/boe. Gas dominated transactions accounted for 85.4% of the disclosed transactions in the fourth quarter of 1998 with the median price paid of $0.83/Mcfe. The average prices received in 1998 were $11.72/Bbl for oil and $2.08/MMBTU for gas. The market value price in 1998 represents 42% of the wellhead oil price and 40% of the wellhead gas price. These results are close to the 1/3 wellhead price of the in ground reserves valuation method.

**Valuation of Oil and Gas Property Example**

Reserves and resultant economic analyses were prepared for oil and gas producing properties for the purpose of finding the Fair Market Value by the various methods discussed in this paper. Cash flow projections have been prepared by reserve classification and category and are shown on the following pages.
## Total Composite Projection of Future Revenue

### Proved Developed, Producing

**Evaluation of the Interest in Oil and Gas Properties**

**Effective Date:** November 1, 1999

COUTRET & ASSOCIATES, INC.
 PETROLEUM RESERVOIR ENGINEERS
 810 LOUISIANA TOWER
 401 EDWARDS STREET
 SHREVEPORT, LOUISIANA

### Table: 12 Mons. Gross Production vs Net Production

<table>
<thead>
<tr>
<th>Year</th>
<th>12 / 31</th>
<th>Gross Production</th>
<th>Net Production</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Oil Bbl</td>
<td>Gas Mcf</td>
<td>Oil Bbl</td>
</tr>
<tr>
<td>2001</td>
<td>145,840</td>
<td>1,391,300</td>
<td>5,172</td>
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<tr>
<td>2002</td>
<td>504,640</td>
<td>6,687,350</td>
<td>21,974</td>
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<tr>
<td>2003</td>
<td>376,490</td>
<td>5,386,100</td>
<td>13,632</td>
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<tr>
<td>2004</td>
<td>240,510</td>
<td>4,110,250</td>
<td>8,574</td>
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<tr>
<td>2005</td>
<td>148,140</td>
<td>2,813,400</td>
<td>5,152</td>
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<tr>
<td>2006</td>
<td>99,230</td>
<td>1,926,150</td>
<td>3,420</td>
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<tr>
<td>2007</td>
<td>56,170</td>
<td>1,663,250</td>
<td>1,024</td>
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<tr>
<td>2008</td>
<td>37,780</td>
<td>1,186,800</td>
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<tr>
<td>2009</td>
<td>17,240</td>
<td>859,900</td>
<td>547</td>
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</tbody>
</table>

**Thereafter:** 10,480 918,200 468 41,823 25.00 3.41 11,701 142,749 154,450

**Total:** 1,739,380 27,165,500 62,539 997,547 22.33 2.70 1,396,665 2,692,693 4,089,358

### Table: Net Income vs Total Operating Expense

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Production Income</th>
<th>Operating Expenses</th>
<th>Total Operating Income</th>
<th>Capital Costs</th>
<th>Net Cash Flow</th>
<th>Present Worth @ 10 %</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>1,239,239</td>
<td>16,920</td>
<td>150,811</td>
<td>167,730</td>
<td>63,508</td>
<td>0</td>
</tr>
<tr>
<td>2001</td>
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<td>75,782</td>
<td>151,502</td>
<td>227,284</td>
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<tr>
<td>2002</td>
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<td>51,455</td>
<td>133,568</td>
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<td>617,001</td>
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<td>2003</td>
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<td>151,290</td>
<td>320,947</td>
<td>448,031</td>
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<td>2004</td>
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<td>109,824</td>
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<td>2005</td>
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<td>72,502</td>
<td>189,210</td>
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<tr>
<td>2006</td>
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<td>9,916</td>
<td>55,881</td>
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<tr>
<td>2007</td>
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<td>7,384</td>
<td>51,871</td>
<td>102,875</td>
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<td>2008</td>
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<td>40,622</td>
<td>67,584</td>
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<tr>
<td>2009</td>
<td>59,854</td>
<td>2,133</td>
<td>21,653</td>
<td>36,068</td>
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</tr>
</tbody>
</table>

**Thereafter:** 154,450 5,248 77,455 82,704 71,746 0 71,746 22,967 2,102,960

**Total:** 4,089,358 246,814 958,500 1,205,314 2,884,044 0 2,884,044 2,102,960

### Recovery Summary

**Gross Production:**
- **Oil, Bbl:** 2,507,050
- **Gas, Mcf:** 26,220,400

**Cumulative:** 2,507,050 26,220,400

**Ultimate:** 4,246,430 53,385,900

**Years in Thereafter:** 8.00
TOTAL COMPOSITE PROJECTION OF FUTURE REVENUE
PROVED
DEVELOPED - NONPRODUCING - BEHIND PIPE
EVALUATION OF THE INTEREST IN OIL AND GAS PROPERTIES

EFFECTIVE DATE: NOVEMBER 1, 1999

P. R. REPORT & ASSOCIATES, INC.
PETROLEUM RESERVOIR ENGINEERS
810 LOUISIANA TOWER
401 EDWARDS STREET
SHREVEPORT, LOUISIANA

12 MOS. GROSS PRODUCTION NET PRODUCTION EFFECTIVE PRICES NET REVENUE
ENDING OIL GAS OIL GAS OIL GAS OIL GAS TOTAL
12 / 31 BBL MCF BBL MCF $/BBL $/MCF $ $ $
2002 54,000 41,000 1,469 1,116 22.15 2.58 32.54 2.88 35,427
2003 105,200 372,400 2,717 7,963 22.81 2.66 61,971 21,195 83,167
2004 74,825 1,095,100 1,896 29,065 23.50 2.74 44,557 79,677 124,234
2005 84,275 577,900 2,210 20,270 24.20 2.82 53,479 57,255 110,734
2006 70,080 1,601,200 1,632 36,054 24.93 2.91 40,684 104,860 145,543
2007 67,360 1,221,400 1,682 27,916 25.00 3.00 42,049 83,627 125,676
2008 121,540 776,200 4,299 19,378 25.00 3.09 107,473 59,790 167,263
2009 81,520 1,095,100 2,881 49,508 25.00 3.18 72,023 157,340 229,364
2010 71,300 1,152,200 1,709 29,579 25.00 3.27 42,728 99,729 142,457
2011 47,600 1,125,200 1,709 29,579 25.00 3.37 42,728 99,729 142,457

THEREAFTER 68,700 5,077,500 2,057 164,267 25.00 3.50 51,430 574,181 625,612
TOTAL 846,400 15,172,300 24,971 428,000 24.40 3.23 609,399 1,380,902 1,990,301

RECOVERY SUMMARY
GROSS OIL, BBL. GROSS GAS, MCF
CUMULATIVE 400 26,300
ULTIMATE 846,800 15,198,600
YEARS IN THEREAFTER 13.00
TOTAL COMPOSITE PROJECTION OF FUTURE REVENUE
PROVED UNDEVELOPED - UNDRILLED

EVALUATION OF THE INTEREST IN OIL AND GAS PROPERTIES

EFFECTIVE DATE: NOVEMBER 1, 1999

COUTRET & ASSOCIATES, INC.
PETROLEUM RESERVOIR ENGINEERS
810 LOUISIANA TOWER
401 EDWARDS STREET
SHREVEPORT, LOUISIANA

GROSS OIL, BBL.  GROSS GAS, MCF
---  ---
12 Mons. Ending 12/31 ---  ---

<table>
<thead>
<tr>
<th>Year</th>
<th>Production</th>
<th>Ultimate</th>
<th>Net Revenue</th>
<th>Effective Prices</th>
<th>Present Worth @ 10%</th>
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</thead>
<tbody>
<tr>
<td>2001</td>
<td>132,000</td>
<td>116,500</td>
<td>5,587</td>
<td>4,931</td>
<td>21.50</td>
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<tr>
<td>2002</td>
<td>269,000</td>
<td>197,000</td>
<td>11,386</td>
<td>8,339</td>
<td>22.15</td>
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<tr>
<td>2003</td>
<td>260,000</td>
<td>209,000</td>
<td>11,386</td>
<td>8,847</td>
<td>22.81</td>
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<tr>
<td>2004</td>
<td>237,000</td>
<td>176,000</td>
<td>10,032</td>
<td>7,450</td>
<td>23.50</td>
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<td>2005</td>
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<td>163,500</td>
<td>8,212</td>
<td>6,074</td>
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<td>2006</td>
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<td>109,000</td>
<td>5,926</td>
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<td>90,000</td>
<td>5,356</td>
<td>3,810</td>
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<tr>
<td>2008</td>
<td>74,000</td>
<td>398,000</td>
<td>3,132</td>
<td>16,847</td>
<td>25.00</td>
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<td>2009</td>
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<td>336,000</td>
<td>2,286</td>
<td>14,307</td>
<td>25.00</td>
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<tr>
<td>2010</td>
<td>25,000</td>
<td>16,000</td>
<td>1,058</td>
<td>677</td>
<td>25.00</td>
</tr>
</tbody>
</table>

Thereafter 21,000 17,500 889 741 25.00 3.41 22,222 2,525 24,748

Total 1,541,531 1,810,500 65,250 76,635 23.48 2.90 1,532,251 222,061 1,754,313

Recovery Summary

Gross Oil, BBL. Gross Gas, MCF
---  ---
Cumulative 0 0
Ultimate 1,541,531 1,810,500

Years in Thereafter 1.00
TOTAL COMPOSITE PROJECTION OF FUTURE REVENUE
PROVED ALL CATEGORIES
EVALUATION OF THE INTEREST IN OIL AND GAS PROPERTIES
EFFECTIVE DATE: NOVEMBER 1, 1999

COUTRET & ASSOCIATES, INC.
PETROLEUM RESERVOIR ENGINEERS
810 LOUISIANA TOWER
401 EDWARDS STREET
SHREVEPORT, LOUISIANA

12 MONS.  GROSS PRODUCTION  NET PRODUCTION  EFFECTIVE PRICES  NET REVENUE
ENDING  OIL  GAS  OIL  GAS  $/BBL.  $/MCF  $.-  $.-  $.-  $.-  $.-  $.-
12 / 31  BBL.  MCF.  BBL.  MCF.

<table>
<thead>
<tr>
<th>YEAR</th>
<th>TOTAL INCOME</th>
<th>PRODUCTION TAXES</th>
<th>OPERATING EXPENSE</th>
<th>TOTAL OPERATING EXPENSE</th>
<th>INCOME</th>
<th>CAPITAL EXPENSES</th>
<th>NET CASH</th>
<th>PRESENT WORTH @ 10 %</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>231,239</td>
<td>16,920</td>
<td>150,811</td>
<td>167,730</td>
<td>63,508</td>
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<td>63,508</td>
<td>60,553</td>
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<td>161,363</td>
<td>252,547</td>
<td>950,004</td>
<td>115,991</td>
<td>843,013</td>
<td>730,711</td>
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<tr>
<td>2002</td>
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<td>155,288</td>
<td>243,071</td>
<td>868,107</td>
<td>2,930</td>
<td>865,177</td>
<td>681,747</td>
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<td>2003</td>
<td>965,788</td>
<td>77,121</td>
<td>137,252</td>
<td>221,066</td>
<td>744,722</td>
<td>4,194</td>
<td>740,528</td>
<td>630,478</td>
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<tr>
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<td>778,308</td>
<td>60,871</td>
<td>125,527</td>
<td>186,397</td>
<td>591,911</td>
<td>6,869</td>
<td>580,042</td>
<td>530,488</td>
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<tr>
<td>2005</td>
<td>603,409</td>
<td>48,957</td>
<td>109,207</td>
<td>158,163</td>
<td>445,246</td>
<td>8,165</td>
<td>437,081</td>
<td>298,779</td>
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<td>2006</td>
<td>515,650</td>
<td>37,161</td>
<td>95,852</td>
<td>133,013</td>
<td>380,617</td>
<td>2,174</td>
<td>378,443</td>
<td>203,684</td>
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<td>2007</td>
<td>439,913</td>
<td>32,041</td>
<td>86,632</td>
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<td>319,240</td>
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<td>155,981</td>
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<td>2008</td>
<td>410,344</td>
<td>30,728</td>
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<td>15,548</td>
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<tr>
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<td>93,924</td>
<td>297,905</td>
<td>15,089</td>
<td>282,816</td>
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</table>

THERE-AFTER 1,176,782 51,804 343,988 395,792 780,990 52,252 728,738 211,411 3,455,102

TOTAL 7,833,972 558,469 1,520,063 2,078,533 5,755,439 227,741 5,527,698 3,455,102

RECOVERY SUMMARY

GROSS OIL, BBL.  GROSS GAS, MCF
CUMULATIVE 2,507,450 26,246,700
ULTIMATE 6,634,761 70,395,000

YEARS IN THEREAFTER 15.00

PRESENT WORTH PROFILE

PRESENT WORTH @ 5% $4,284,854
PRESENT WORTH @ 10% $3,455,103
PRESENT WORTH @ 15% $2,868,911
PRESENT WORTH @ 20% $2,436,403
PRESENT WORTH @ 25% $2,106,174
PRESENT WORTH @ 30% $1,846,984
PRESENT WORTH @ 35% $1,638,694
A summary of the Fair Market Value results for the different valuation methods is shown below:

1) **Rate of Return Method - 20%**

<table>
<thead>
<tr>
<th>Reserve Classification-Category</th>
<th>$M</th>
<th>Risk</th>
<th>$M</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PW@20%</td>
<td>Factor</td>
<td>Risk Adjusted</td>
</tr>
<tr>
<td>Proved Dev Producing</td>
<td>1,630</td>
<td>.97</td>
<td>1,581</td>
</tr>
<tr>
<td>Proved Dev Non Prod Behind Pipe</td>
<td>301</td>
<td>.75</td>
<td>226</td>
</tr>
<tr>
<td>Proved Undrilled</td>
<td>506</td>
<td>.56</td>
<td>283</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>2,090</strong></td>
</tr>
</tbody>
</table>

2) **Payout Time Method**

By examining the composite revenue projection on page P-4, it will take 32 months to recover $2,090,000. So the payout time to recover the rate of return market value is 32 months. This is between the stated 2-5 year estimate in the text.

3) **Income to Investment Ratio Method**

The total net cash flow to recover from the evaluated properties is $5,527,698. Using the rate of return FMV of $2,090,000, the income to investment ratio is 2.64-1. This is between the range of 2-1 to 3-1 as listed in the text.

4) **Specified Fraction of Present Worth Method**

<table>
<thead>
<tr>
<th>Reserve Classification-Category</th>
<th>$M</th>
<th>Risk</th>
<th>$M</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>PW@10%</td>
<td>Factor</td>
<td>Risk Adjusted</td>
</tr>
<tr>
<td>Proved Dev Producing</td>
<td>2,130</td>
<td>.97</td>
<td>2,040</td>
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<tr>
<td>Proved Dev Non Prod Behind Pipe</td>
<td>593</td>
<td>.75</td>
<td>445</td>
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<tr>
<td>Proved Undrilled</td>
<td>759</td>
<td>.56</td>
<td>425</td>
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<tr>
<td><strong>Total</strong></td>
<td>3,455</td>
<td></td>
<td><strong>2,910</strong></td>
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<tr>
<td>Specified Fraction</td>
<td></td>
<td></td>
<td>.72</td>
</tr>
<tr>
<td>Total PW @10% multiplied by the specified fraction</td>
<td></td>
<td></td>
<td>2,090</td>
</tr>
</tbody>
</table>

The specified fraction was calculated to be .72 to determine a FMV of $2,090,000. This fraction is similar to the text stated fraction of .667.

5) **Price per Barrel in Ground Method**

Proved net oil reserves - 152,760 Bbl
Proved net gas reserves - 1,502,182 MCF
Oil/Gas price ratio - $20.87/Bbl/2.43/MCF = 8.1 MCF/Bbl
Proved net reserves, BOE = 152,760 Bbl + (1,502,182 MCF/8.1 MCF/Bbl) = 338,215 BOE
FMV = $2,090,000/338,215  BOE = $6.18/Bbl
Fraction of FMV $/Bbl to current price $/Bbl = $6.18/Bbl/$20.87/Bbl = .30
The calculated fraction of the wellhead oil price is 30% which is very close to the rule of thumb of 33.33%.

These various valuation methods point out how each method yields the same approximate answer. The quickest method to determine a Fair Market Value range with some degree of confidence would be the in ground method. This method does require total net remaining reserves. The rate of return method is the most reliable and requires a full evaluation of remaining reserves along with annual production schedules and resultant economic analyses. The remaining methods are used to review the Fair Market Value of a property with certain economic scenarios. It is hoped that this paper will allow the Natural Resources Law Institute participants to have a greater understanding of how to arrive at a Fair Market Value of oil and gas properties and to discern a reasonable value from one that is unrealistic.

References

APPENDIX
Reserves estimates have been classified in accordance with the approved definitions by the Board of Directors of the Society of Petroleum Engineers (SPE), Inc. on March 7, 1997. These definitions have been developed in cooperation with other technical organizations and are widely accepted in the oil and gas industry. While they are not identical, these definitions basically conform to the definitions used by the United States Securities and Exchange Commission.

The definitions, which are provided in their entirety on the following pages, basically require that reserve estimates be classified as proved or unproved. These are defined as follows:

**Proved** Reserves which can be estimated with reasonable certainty to be recoverable under current economic conditions. Current economic conditions include prices and costs prevailing at the time of the estimate.

**Unproved** Reserves which are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. They may be estimated assuming future economic conditions different from those prevailing at the time of the estimate.

There are two subcategories of unproved reserves:

a. **Probable** - Probable reserves are less certain than proved reserves and can be estimated with a degree of certainty sufficient to indicate they are more likely to be recovered than not.

b. **Possible** - Possible reserves are less certain than probable reserves and can be estimated with a low degree of certainty, insufficient to indicate whether they are more likely to be recovered than not.

Reserves are further classified by producing status. The status categories that have been used in this report, if applicable, are as follows:

- Developed - Producing
- Developed - Nonproducing - Shut-in
- Developed - Nonproducing - Behind Pipe
- Developed - Improved Recovery
- Undeveloped - Undrilled
PETROLEUM RESERVES DEFINITIONS

SOCIETY OF PETROLEUM ENGINEERS (SPE)
AND
WORLD PETROLEUM CONGRESSES (WPC)

PREAMBLE

Petroleum is the world's major source of energy and is a key factor in the continued development of world economies. It is essential for future planning that governments and industry have a clear assessment of the quantities of petroleum available for production and quantities which are anticipated to become available within a practical time frame through additional field development, technological advances, or exploration. To achieve such an assessment, it is imperative that the industry adopt a consistent nomenclature for assessing the current and future quantities of petroleum expected to be recovered from naturally occurring underground accumulations. Such quantities are defined as reserves, and their assessment is of considerable importance to governments, international agencies, economists, bankers, and the international energy industry.

The terminology used in classifying petroleum substances and the various categories of reserves have been the subject of much study and discussion for many years. Attempts to standardize reserves terminology began in the mid 1930's when the American Petroleum Institute considered classification for petroleum and definitions of various reserves categories. Since then, the evolution of technology has yielded more precise engineering methods to determine reserves and has intensified the need for an improved nomenclature to achieve consistency among professionals working with reserves terminology. Working entirely separately, the Society of Petroleum Engineers (SPE) and the World Petroleum Congresses (WPC) produced strikingly similar sets of petroleum reserve definitions for known accumulations which were introduced in early 1987. These have become the preferred standards for reserves classification across the industry. Soon after, it became apparent to both organizations that these could be combined into a single set of definitions which could be used by the industry worldwide. Contacts between representatives of the two organizations started in 1987, shortly after the publication of the initial sets of definitions. During the World Petroleum Congress in June 1994, it was recognized that while any revisions to the current definitions would require the approval of the respective Boards of Directors, the effort to establish a worldwide nomenclature should be increased. A common nomenclature would present an enhanced opportunity for acceptance and would signify a common and unique stance on an essential technical and professional issue facing the international petroleum industry.

As a first step in the process, the organizations issued a joint statement which presented a broad set of principles on which reserves estimations and definitions should be based. A task force was established by the Boards of SPE and WPC to develop a common set of definitions based on this statement of principles. The following joint statement of principles was published in the January 1996 issue of the SPE Journal of Petroleum Technology and in the June 1996 issue of the WPC Newsletter:

There is a growing awareness worldwide of the need for a consistent set of reserves definitions for use by governments and industry in the classification of petroleum reserves. Since their introduction in 1987, the Society of Petroleum Engineers and the World Petroleum Congresses reserves definitions have been standards for reserves classification and evaluation worldwide.

SPE and WPC have begun efforts toward achieving consistency in the classification of reserves. As a first step in this process, SPE and WPC issue the following joint statement of principles.

The SPE and the WPC recognize that both organizations have developed a widely accepted and simple nomenclature of petroleum reserves.

The SPE and the WPC emphasize that the definitions are intended as standard, general guidelines for petroleum reserves classification which should allow for the proper comparison of quantities on a worldwide basis.

The SPE and the WPC emphasize that, although the definition of petroleum reserves should not in any manner be construed to be compulsory or obligatory, countries and organizations should be encouraged to use the core definitions as defined in these principles and also to expand oil these definitions according to special local conditions and circumstances.

The SPE and the WPC recognize that suitable mathematical techniques can be used as required and that it is left to the country to fix the exact criteria for reasonable certainty of existence of petroleum reserves. No methods of calculation are excluded, however, if probabilistic methods are used, the chosen percentages should be unequivocally stated.
The SPE and the WPC agree that the petroleum nomenclature as proposed applies only to known discovered hydrocarbon accumulations and their associated potential deposits.

The SPE and the WPC stress that petroleum proved reserves should be based on current economic conditions, including all factors affecting the viability of oil projects. The SPE and the WPC recognize that the term is general and not restricted to costs and price only. Probable and possible reserves could be based on anticipated developments and/or the extrapolation of current economic conditions.

The SPE and the WPC accept that petroleum reserves definitions are not static and will evolve.

A conscious effort was made to keep the recommended terminology as close to current common usage as possible in order to minimize the impact of previously reported quantities and changes required to bring about wide acceptance. The proposed terminology is not intended as a precise system of definitions and evaluation procedures to satisfy all situations. Due to the many forms of occurrence of petroleum, the wide range of characteristics, the uncertainty associated with the geological environment, and the constant evolution of evaluation technologies, a precise classification system is not practical. Furthermore, the complexity required for a precise system would detract from its understanding by those involved in petroleum matters. As a result, the recommended definitions do not represent a major change from the current SPE and WPC definitions which have become the standards across the industry. It is hoped that the recommended terminology will integrate the two sets of definitions and achieve better consistency in reserves data across the international industry.

Reserves derived under these definitions rely on the integrity, skill, and judgment of the evaluator and are affected by the geological complexity, stage of development, degree of depletion of the reservoirs, and amount of available data. Use of these definitions should sharpen the distinction between the various classifications and provide more consistent reserves reporting.

DEFINITIONS

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further subclassified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

It is the intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of reserves classified as unproved. Public disclosure of the quantities classified as unproved reserves is left to the discretion of the countries or companies involved.

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range or estimates and their associated probabilities. Identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

Reserves estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced, for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

PROVED RESERVES

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves.

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. In this context, the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir. In certain cases, proved reserves may be assigned on the basis of well logs and/or core analysis that indicate the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

The area of the reservoir considered as proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged, as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data.

Reserves may be classified as proved if facilities to process and transport those reserves to market are operational at the time of the estimate or there is a reasonable expectation that such facilities will be installed. Reserves in undeveloped locations may be classified as proved undeveloped provided (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain such locations are within the known proved productive limits of the objective formation, (3) the locations conform to existing well spacing regulations where applicable, and (4) it is reasonably certain the locations will be developed. Reserves from other locations are categorized as proved undeveloped only where interpretations of geological and engineering data from wells indicate with reasonable certainty that
the objective formation is laterally continuous and contains commercially recoverable petroleum at locations beyond direct offsets.

Reserves which are to be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favorable response of an installed program in the same or an analogous reservoir with similar rock and fluid properties provides support for the analysis on which the project was based, and, (2) it is reasonably certain that the project will proceed. Reserves to be recovered by improved recovery methods that have yet to be established through commercially successful applications are included in the proved classification only (1) after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program where the response provides support for the analysis on which the project is based and (2) it is reasonably certain the project will proceed.

UNPROVED RESERVES
Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

Unproved reserves may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. The effect of possible future improvements in economic conditions and technological developments can be expressed by allocating appropriate quantities of reserves to the probable and possible classifications.

PROBABLE RESERVES
Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where subsurface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time or the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear Favorable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a Future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behavior in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

POSSIBLE RESERVES
Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely than not to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum or estimated proved plus probable plus possible reserves.

In general, possible reserves may include (1) reserves which, based on geological interpretations, could possibly exist beyond areas classified as probable, (2) reserves in formations that appear to be petroleum bearing based on log and core analysis but may not be productive at commercial rates, (3) incremental reserves attributed to infill drilling that are subject to technical uncertainty, (4) reserves attributed to improved recovery methods when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and geological interpretation indicates the subject area is structurally lower than the proved area.

RESERVE STATUS CATEGORIES
Reserve status categories define the development and producing status of wells and reservoirs.

Developed: Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be sub-categorized as producing or nonproducing.

Producing: Reserves subcategorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Non-producing: Reserves subcategorized as non-producing include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

Undeveloped Reserves: Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) reopen an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Approved by the Board of Directors, Society of Petroleum Engineers (SPE), Inc. March 7, 1997
EXHIBIT B
Respondents were asked how they adjusted their evaluations to account for different reserve categories. The respondents were asked to state whether their adjustments factors were used in acquisitions or loans. There was no statistical difference by size or dollar amount of evaluation.

### Adjustment Factors Used for ACQUISITIONS

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<th>Category</th>
<th>Median</th>
<th>Average</th>
<th>Std Dev</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved Producing</td>
<td>100.0%</td>
<td>97.2%</td>
<td>5.3%</td>
</tr>
<tr>
<td>Proved Shut In</td>
<td>90.0%</td>
<td>84.7%</td>
<td>14.0%</td>
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<tr>
<td>Proved Behind Pipe</td>
<td>75.0%</td>
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<td>58.8%</td>
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</tr>
<tr>
<td>Probable Behind Pipe</td>
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<td>22.8%</td>
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### Adjustment Factors Used for LOANS

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<tbody>
<tr>
<td>Proved Producing</td>
<td>100.0%</td>
<td>96.6%</td>
<td>6.1%</td>
</tr>
<tr>
<td>Proved Shut In</td>
<td>77.5%</td>
<td>78.4%</td>
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<td>Proved Behind Pipe</td>
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<td>Proved Undeveloped</td>
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<td>2.3%</td>
<td>5.8%</td>
</tr>
<tr>
<td>Probable Behind Pipe</td>
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<td>2.3%</td>
<td>5.8%</td>
</tr>
<tr>
<td>Probable Undeveloped</td>
<td>0.0%</td>
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<td>Possible Behind Pipe</td>
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<td>0.0%</td>
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<tr>
<td>Possible Undeveloped</td>
<td>0.0%</td>
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</tr>
</tbody>
</table>

For Acquisitions the above risk adjustments are applied mainly to cash flow after discounting (48%) and reserves (41%). For Loans they are applied mainly to cash flow after discounting (53%) and reserves (40%). If reserves are adjusted approximately half of respondents adjust reserves only and leave all other factors unchanged while the other half use professional judgement to adjust other factors.