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Division of Property Valuation

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2004 Year
Oil & Gas
Appraisal Guide

January 2004
PV-PP-18

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Please note the 2004 Crude Oil Price Schedule will be available at a later date as an addendum to this guide.

2004 Oil and Gas Guide Changes

The following are notable changes in the 2004 guide:

Oil Section, Existing Leases, Paragraph 3, added language to recognize historic decline
Oil Section, Excess Expense Allowance, added language to allowable operating expenses

Gas Section, All Other Kansas, Table B, updated Prescribed Operator's Expense Allowance
Gas Section, All Other Kansas, Table B, Prescribed Water Credit Adjustment, added note

Itemized Equipment Section, Rotary Drilling Rigs, added note

Other changes consist of dates, formatting, and additional language for clarification.

Oil Rendition—dates
Section VI, Line 6 and Line 7b

Gas Rendition—dates
Coalbed Methane and Vacuum Operations checkboxes
Section IV and V, Total Average Production
Section VI, Line 2 and Line 4b

F O R E W O R D

1. KSA 79-329: For the purpose of valuation and taxation, all oil and gas leases and all oil and gas wells, producing or capable of producing oil or gas in paying quantities, together with all casing, tubing or other material therein, and all other equipment and material, used in operating the oil or gas wells are hereby declared to be personal property and shall be assessed and taxed as such.

2. KSA 75-5105a provides for the Director of the Division of Property Valuation (a division of the Kansas Department of Revenue) to prescribe guides to assist the county appraiser in establishing market value for personal property and to confer with representatives of the county appraisers and seek counsel from official representatives of organized groups interested in and familiar with the value of classes of property with which they are concerned. The oil and gas guide is prepared per authority of this statute.

3. KSA 79-332a provides for any person, corporation or association owning oil and gas leases or engaged in operating for oil or gas who fails to make and file the oil/gas tax statement rendition **on or before APRIL 1** in the office of the county appraiser in and for the county which has jurisdiction of the lease, shall be subject to penalties for late filing and/or for failure to file. The statute also notes that the lease operator may request an extension of the filing time, but it must be in writing, and it must be filed prior to the **APRIL 1** deadline. **Penalties are assessed to the operator based on the total value of the royalty interest plus the working interest.** The Kansas State Board of Tax Appeals is the sole authority for relief of the assessed penalty. KSA 79-2017 and 79-2101 provides for collection of delinquent taxes by the county sheriff.

4. KSA 79-1456 requires the county appraiser to follow the policies, procedures, and guidelines issued by the Director of the Division of Property Valuation. ***The county appraiser may deviate from such guidelines on individual properties for just cause and in a manner consistent with establishing market value in accordance with the state statutes.***

5. ***The county appraiser must use the oil and gas guide prescribed by the Director of Property Valuation. If the lease valuation estimated by use of the oil and gas guide does not reflect market value, in the judgment of the appraiser or the taxpayer, the appraiser has the authority to review and adjust the valuation to market value for just cause and proper documentation.*** Any change made in the appraisal must be supported by proper documentation and a copy of the valuation change must be furnished to the taxpayer in a timely manner sufficient to allow the taxpayer the right to appeal the valuation. If the county appraiser increases the valuation of the lease/well from that indicated by the guide application, the reason and documentation justifying the change must be provided to the taxpayer in a timely manner to allow for notice of appeal. **Lease operator/taxpayer/tax representative requests for reduction from the guide value estimate must be documented.**

6. Assessment Rendition: **Column A (Schedule Value) of the oil or gas rendition is to be completed by using the oil and gas guide without departure, adjustment, or change.** Column B (Owner) is reserved for the lease operator/taxpayer/tax representative's use for requested adjustments to Column A. Column C (Appraiser) is reserved for use by the county appraiser to make adjustments to Column A and/or finalize the valuation of the well/lease.

7. The county appraiser may adjust the valuation in Column A of the oil or gas rendition if an adjustment is necessary for the appraiser to comply with the constitutional law of equality and the statutory requirement of market value. If the county appraiser makes an adjustment, the appraiser is to use Column C, entitled "Appraiser", on the rendition form. The county appraiser must notify the taxpayer of the adjusted valuation in time for the taxpayer to appeal, and, on request of the taxpayer, provide the reasons for the change in Column A valuation prior to the appeal.

8. The lease operator/taxpayer/tax representative may request an adjustment to the valuation in Column A of the oil or gas rendition as prescribed by use of the oil and gas guide. The taxpayer may use Column B, entitled "Owner", on the rendition form. All such requests for adjustments are to be fully supported and explained in writing.

9. KSA 79-201t: Property exempt from taxation: Oil Leases. The following described property, to the extent herein specified, shall be and is hereby exempt from all property or ad valorem taxes levied under the laws of the state of Kansas:

   (a.) All oil leases, other than royalty interests therein, the average daily production from which is three barrels or less per producing well, or five barrels or less per producing well which has a completion depth of 2,000 feet or more.

   (b.) The provisions of this section shall apply to all taxable years commencing after December 31, 1997.

   This exemption must be considered and granted by the State Board of Tax Appeals (BOTA) to be effective (KSA 79-213). However, in conjunction with his authority under KSA 75-5105a and 79-506, the Director of Property Valuation is providing the following guidelines for exemption of low producing wells:

   Average daily production per well is defined as annual production divided by 365 days divided by the number of producing wells; or, in the case of new leases, actual production divided by the number of days produced divided by the number of producing wells. Abandoned or shut-in wells are not included in the calculation.

   The royalty interest and the production equipment do not qualify for the exemption. The statute is specific as to production and no consideration may be given to well shut down, pumping unit or transportation problems. The annual production is to be used to determine the exemption. Lease production which began during the year will not be annualized, but will be calculated from the date the lease went into production.

   The equipment is not exempt and will be appraised per Table I or Table II according to depth.

   Request for exemption is made by the operator on forms provided by the county appraiser and filed with the State Board of Tax Appeals. Questions concerning exemption rulings or decisions should be directed to the State Board of Tax Appeals @ 785-296-2388.

10. To promote uniform and equal assessments, the Director of Property Valuation is providing the following guidelines for classification which the county is required to follow per KSA 79-1439(2)B: **The assessment rate for mineral leasehold interests is 30%** ***except oil leasehold interests (working interest) that average five barrels or less per day and natural gas leasehold interests that average 100 mcf or less per day, each of which is assessed at 25%, including production equipment***. The assessment rate is determined on a lease basis by dividing the annual production by 365 days to calculate the average daily lease production**.** For new leases that produced only a part of the year, divide the production by the number of days produced. **The royalty interest is assessed on the basis of 30%. All itemized equipment is assessed at 30%.**

11. The administration of the ad valorem property tax is the jurisdiction of the county appraiser's office, in and for the county, in which the oil or gas lease is located. The Kansas Department of Revenue, Division of Property Valuation prescribes the oil and gas guide and rendition forms**.** ***For copies, please contact the county appraiser's office for the county in which the property is located or download from*** http://www.ksrevenue.org/pvdoilgas.htm

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OIL SECTION

Oil Rendition Form Instructions

The lease operator/taxpayer/tax representative is required to provide the information requested in Sections I through IV of the oil rendition form and all other information necessary to fix the valuation of the property as determined by the Director of Property Valuation. Failure to provide this required information will result in a 50% penalty assessed to the operator based on the total value of the royalty interest plus the working interest for failure to file a full and complete statement of assessment according to KSA 79-332a (c). COLUMN A (SCHEDULE VALUE) is to be completed by using the oil and gas guide without departure, adjustment, or change. COLUMN B (OWNER) is reserved for the lease operator/taxpayer/tax representative's use for requested adjustments to Column A. COLUMN C (APPRAISER) is reserved for the county appraiser to finalize the valuation of the well/lease.

NOTE: For copies of the rendition forms and oil and gas guide, please contact the county appraisal office for the county in which the property is located or download from http://www.ksrevenue.org/pvdoilgas.htm.	
Section I: Location of Property	Provide information to the extent available.
Section II: Well and Lease Data	Provide information as requested for the number of producing oil and gas wells, injection wells, shut-in, salt water disposal wells, and temporarily abandoned wells; year first produced and the year of development (spud date). Provide completion depth, oil gravity, % water production, and barrels of water per day. Note changes from prior year well count. To qualify for secondary recovery, KCC permit number must be provided; total fluids injected must exceed total production of oil and water by a minimum of 10%; only leases that have additional recovery through this process are considered secondary production.
Section III: Itemized Equipment	The rendition sheet does not have space for this information. Please attach separate sheet listing equipment located on the lease, but not part of the production equipment, attach to the rendition, and include total in Section VI on Line 9.
Section IV: Production Data	Provide prior year production on a monthly basis; include under "Notation" explanations for zero production months, downtime, or other information necessary to annualize/analyze lease production capability. Provide total annual production for the year preceding the prior year in the adjoining column.
Section V: Gross Reserve Calculation	Annual Production x Net Price (per Crude Oil Price Schedule provided and made a part of this guide) = Estimated Gross Income Stream x Present Worth Factor (from Table I or Table II, see instructions) = Estimated Gross Reserve Value. Transfer Item 5 (Section V) to Section VI, Line 1 and Line 2.
Section VI: Gross Reserve Value:	Section V, Item 5, is multiplied by the decimal royalty interest to calculate the royalty interest on line one. On line two, the decimal working interest is multiplied by the gross reserve value to calculate the working interest from which operating expenses are deducted and production equipment values are added (from Table I or Table II, see instructions) to calculate the working interest value.

Certification: The certification is to be completed and signed by the lease owner or operator who is responsible for filing the tax rendition with the county appraiser. It must also be signed by the rendition preparer.

Division Orders: A list of the current royalty owners, their decimal interest, and their addresses, is to be provided by the operator and is a requirement for filing the tax rendition.

Oil Well Definition

For ad valorem property tax valuation, an oil well is defined as a well producing, or capable of producing, at a gas-oil ratio less than 15,000 cubic feet of gas per barrel of oil. Example: 30,000 mcf of gas = 30,000 x 1,000 cubic feet = 30,000,000 cubic feet divided by oil produced from the same formation, 6,000 barrels, = 5,000 cubic feet per barrel which is less than 15,000 cubic feet per barrel; therefore, the well is considered an oil well for ad valorem tax valuation.

I. Production

Annual Production is to be used in the appraisal process. Annual production is defined as the amount of oil or natural gas produced during the preceding calendar year, prior to the appraisal year, adjusted for down time where appropriate.

Monthly Production is defined as: The amount of oil quoted in barrels (42 gallons per bbl.) received in lease stock tanks corrected to 24 hours per producing day. The total is based on production for the month divided by the number of days produced during the month multiplied by the number of days in the month.

EXAMPLE

22 days produced with 220 barrels total
220 bbls divided by 22 days = 10 BOPD
10 BOPD x 31 days month = 310 bbls / month

Sales, quoted in stock tank barrels, may only be substituted for production if the sales represent the production capability of the lease excluding curtailed production.

EXAMPLE

180 bbls listed on the rendition for every other month should be noted under "Notation" as total production waiting for full tank to be picked up and would not be subject then to the adjusted production. It is important for the operator to make this distinction to avoid unneeded amendments to the lease valuation; otherwise, the blank months may be annualized in error by the county appraiser.

Sales shall not be used in the appraisal process:

1. When sales are erratic or if sales are not made in each calendar month unless noted as above or,
2. When declines are not constant or down time is present and not accounted for or,
3. When a decline rate is requested by the operator that conflicts with the prior two year production history for the lease.

Adjustments

The prior year production may not represent the production capability of the lease for several reasons, some of which are:

a. Well shut down for work-over.

b. Pumping unit problems resulting in less production.

c. Transportation problems.

d. Reserve depletion, abandonment of lease, no value remaining or taxable for the current year except for equipment.

e. Lease production commenced during the prior year, therefore represents less than a full 12 months production.

f. Lease production began during the year with "gusher" characteristics (flush production) followed by rapid decline to a stabilized level.

g. Increase or decrease in the number of producing wells.

For these reasons and others, it may be necessary to adjust the production to reflect the lease production capability for the near future term.

EXAMPLES

1) **Well shut-down**

Well shut-down or curtailment due to mechanical problems, pumping unit problems, or transportation problems. In these cases, mechanical rather than natural forces are affecting the production capabilities of the property. A representative 12 month production period must be calculated.

Jan	275	May	0	Sept	260
Feb	265	June	0	Oct	240
Mar	285	July	294	Nov	248
Apr	270	Aug	285	Dec	0
					2422

In this case a well work-over resulted in a 60 day shut-down for May and June. In December no production was reported. Hence, add in for these months of production capability by annualizing the nine months, e.g.,

2,422 bbls./273 days = 8.87 bbl/day x 365 days = 3,238 bbls / yr

Use 3,238 bbls for the current year lease valuation instead of the 2,422 barrels.

2) **Reserve depletion**

For leases that are no longer capable of producing oil in commercial quantities, no value is taxable for the current year, other than for the equipment in place on January 1st.

3) **New leases**

a. For leases that have produced less than 12 months during the prior year, the annualized production is calculated by dividing the production for the period of the prior year that the lease did produce by the number of days it produced to ascertain the bbls/day and then multiply the B/D by 365 days to calculate the annualized production.

EXAMPLE

Month / Days / Barrels	Month / Days / Barrels	Month / Days / Barrels
May / 31 / 775	Aug / 31 / 740	Nov / 30 / 710
June / 30 / 760	Sept / 30 / 720	Dec / 31 / 718
July / 31 / 777	Oct / 31 / 735	Totals: 245 days & 5,935 bbls
		Bbls/Day = 5,935/245 = 24.22
		Bbls/Yr = 24.22 x 365 =8,840

b. **K.S.A. 79-331(b) and (c)** provides adjustments for new leases beginning production on July 1 or later.

K.S.A. 79-331 (b) & (c): "(b) The valuation of the working interest and royalty interest, except valuation of equipment, of any original base lease or property producing oil or gas for the first time in economic quantities on and after July 1 of the calendar year preceding the year in which such property is first assessed shall be determined for the year in which such property is first assessed by determining the quantity of oil or gas property would have produced during the entire year preceding the year in which such property is first assessed upon the basis of the actual production in such year and by multiplying the income and expenses that would have been attributable to such property at such production level, excluding equipment valuation thereof, if it had actually produced said entire year preceding the year in which such property is first assessed by sixty percent (60%)."

(c)"The provisions of subsection (b) of this section shall not apply in the case of any production from any direct offset well or any subsequent well on the same lease." (A direct offset well is defined as a well drilled on normal spacing patterns which is completed in the same reservoir as the previous well or wells)

EXAMPLE

Lease production commenced August 16 of the prior year and produced 4,001 barrels in 138 days or 28.99 B/D or 10,582 barrels annualized. Assume a 30% decline rate and $16.00 / bbl crude oil price. Calculate the reserve value:

10,582 bbls	x $16.00 x 1.468	x 0.60	= $149,130
Royalty Interest	$149,130	x 0.125	= $ 18,641
Working Interest	$149,130	x 0.875	= $130,489
Less operating expense	1 @ $45,500	x .60	= ($27,300)
Plus equipment value	1 @ $3,100		= $ 3,100
Working Interest Total			= $106,289

4) **Change in the Number of Production Wells**

The number of wells to be used in the calculation of the reservoir value is the number of wells operating as of January 1 of the tax year. The number may fluctuate from year to year, increasing or decreasing in number. The reservoir valuation is based on future production and the number of operating wells as of January 1 of the current tax year.

a. New wells drilled on existing leases

EXAMPLE

Month	Wells	Production	Bbls./Well
January	3	750	250
February	3	720	240
March	3	699	233
April	4	900	225
May	4	860	215
June	4	840	210
July	4	868	217
August	4	800	200
September	5	1050	210
October	6	1200	200
November	6	1145	190
December	6	1122	187

In this example, the older wells were making about 240 bbl/well/month and the total lease for the last quarter shows about 190 bbl/well/ month. Use 6 wells and the last quarter annualized.

b. Wells plugged or deleted from prior year

EXAMPLE

Month	No. Wells	PRODUCTION	MONTH	No. Wells	PRODUCTION
January	10	1250	July	6	474
February	10	1215	August	6	460
March	9	900	September	6	285
April	9	915	October	4	260
May	8	828	November	4	275
June	8	580	December	4	258
				Total	7700

Note: *The total for the year is 7700 bbls. and the average number of wells is 7 yet the ending three months indicate an annualized production of 3,146 bbls. from four wells. Use 3146 bbls. and four wells and secure the first two or three months of the current year and well count to verify production rate for current tax year valuation, annualize and combine with appropriate decline rate.*

II. Decline

Producing a finite reserve results in a depleting asset. The rate of depletion is known as the decline rate. An oil reserve produced at its potential will theoretically begin to decline immediately. When a lease is new and just commencing its production, the decline rate is not known. The decline rate estimate depends on the age of the lease and cannot be predicted accurately until a reasonable length of time has passed. A history of the lease should be kept for this purpose to plot production over time and to note work-over periods, shut-in periods, additions of new wells, deletion of wells, and other production activity.

The decline curve will reflect changes in operating policy, well work-overs, marketing conditions and other factors, which are not a part of the natural decline. A lease may produce at a constant rate for a long period and then experience a major increase resulting from a well work-over or "fracturing job". Without a record of these activities, production rates and decline rates may be distorted resulting in unrealistic valuations. The appraiser must then consider whether this production rate will continue, decrease, or stabilize; and whether the former decline rate is still applicable. Actual production shall be documented, normalized and adjusted for downtime and a historic decline curve should be submitted with filing in order to estimate the decline rate.

If annualized production is used to estimate value, the annualized production is then used the following year to estimate decline, **supported by the most recent production activity** for the lease, supported by a decline curve to determine whether the decline is appropriate and continuing. The following guidelines are recommended:

1) **New Leases**

Use the first few months of production to establish the decline rate.

If the first few months of production and all data available indicate no decline, it is suggested the appraiser consider the use of an assumed 30% annual decline rate and evaluate the property on this basis. This, however, is not automatic and is to be used only when the actual decline rate cannot be established. Use of a proven neighborhood decline rate may be considered appropriate after proper consideration for flush production, but only when the new well or wells are completed in the same reservoir. Requests for consideration of percentage decline above 30% or adjustments by the appraiser below 30% should be documented by production decline, water cut and/or gas oil ratio curves.

Abnormal sharp decline is usually found with initial production from newly completed wells on new leases, added wells on existing leases, and re-completion or work-over of on existing leases. The appraiser should consider application of historic declines when actual declines are uncertain or are obscured from lease development or work-over. A lease with initial "flush" production will show an abnormal sharp decline followed by change in the decline rate to normal rate of decline. If the property shows a constant rate of decline after the "flush" production, the appropriate present worth factor for that rate should be used with production annualized for the period reflecting the stabilized production period.

A decline curve, with downtime noted, should be submitted with the filing when an adjustment for abnormal decline is requested. No production period less than four to six months should be used to establish an abnormal decline. In addition to decline curves, water cut, and/or gas oil ratio curves may be filed with the filing to document changes in reservoir behavior.

2) **Existing Leases**

To estimate the decline rate on an existing lease **having stable production from year to year,** the current year decline is calculated by using the preceding two production years. For the 2004 tax year, use 2003 and 2002 as follows:

EXAMPLE

$$\text{Decline} = \frac{\text{2002 Production} - \text{2003 Production}}{\text{2002 Production}} = \frac{1{,}408 - 1{,}234}{1{,}408} = 12\%$$

When using prior years' production to estimate the current year decline, the appraiser must be sure that the production figures are for a full year and represent a typical operation with no significant work-over periods, lease shutdowns, or other non-producing periods effecting the lease production capability.

For leases that have a production history, the production can be plotted to establish a decline curve to indicate the proper decline to be used in the valuation, **supported by the most recent production activity,** to determine whether the decline is appropriate and continuing at that rate. For leases experiencing work-over periods, lease shutdowns, or other non-producing periods, the appraiser should consider this history along with recent activity since the decline rate prior to these periods typically resumes after production has stabilized if in the same producing zone.

For abnormal decline, back-to-back quarters, combined with back-to-back quarters of production can be used to estimate the decline if the production is manifesting an accelerated rate of depletion.

QUARTER-DECLINE-ANNUALIZED TABLE

Quarter Decline %		Annual Decline %	Quarter Decline %		Annual Decline
1%		4%	9%		31%
2%		8%	10%		34%
3%		11%	11%		37%
4%		15%	12%		40%
5%		19%	13%		43%
6%		22%	14%		45%
7%		25%	15%		48%
8%		28%	16%		50%

EXAMPLE

2001 first quarter	812/795/821	2,428	
2001 second quarter	780/795/765	2,340	3.62%
2001 third quarter	800/750/725	2,275	2.78%
2001 fourth quarter	700/690/695	2,085	8.35%
Quarterly Decline	**2,275 - 2,085 / 2,275 = 8.35%**		
Annualized Decline	**28% (from table)**		

This table should be used as a guide and the results compared to other estimates of decline for the same lease or the typical decline for the area, since a lease declining 15% in the first quarter may continue at a sharp decline over the next 12 months, but may not decline as great as 48%. When an adjustment is requested for an abnormally sharp decline, it should be supported by an explanation of the known or expected reasons for the decline.

3) **Increase or decrease in producing wells**

a. There are occasionally new wells drilled on existing leases. In order to accurately evaluate the decline rate, the guidelines in Decline, Section 1, "New Leases", should be used to determine the post drilling decline rate. Comparison of well averages before and after drilling will lead to a false decline as most new wells will have more oil production than the average existing well. This gives the false appearance of a flatter than actual decline.

b. The same guidelines in Decline, Section 1 should be used for leases with wells that are abandoned or shut-in. Since wells that are abandoned or shut in usually produce below the lease well average, plugging these wells results in an increase in the per well average production. Again, comparison of the per well average before and after the plugging will result in the false appearance of flatter than actual decline.

III. Casinghead Gas

For wells producing casinghead gas, the revenue derived from the preceding year's total gas production is to be converted to barrels of oil equivalent and added to the annual oil production. The conversion is made by multiplying casinghead gas in mcf by the net price per mcf, which is then divided by the net price per barrel of oil received on the lease.

EXAMPLE

An oil well produced 18,550 mcf of casinghead gas for which the net price is $.50 per mcf totaling a gross annual revenue of $9,275 (18,550 mcf x $0.50 mcf); the net price for oil is $11.00 per barrel; then the revenue from the casinghead gas of $9,275 is divided by $11.00 per bbl to establish the gas equivalent in barrels: $9,275/$11.00 = 843 barrels to be added to the annual production in Sec. IV - Item 2, Casinghead Gas.

Note: *This additional production is not to be included in determining the annual decline or the exemption for low production or the assessment rate. However, the taxpayer should file a separate rendition showing gas production when oil rates are declining at rates greater than the natural gas rates or when gas oil ratios (GOR) are above 15,000 mcf to 1.00 bbl of oil.*

IV. Secondary Recovery

1) To qualify as a secondary recovery operation, the lease must:
   a. Have a secondary recovery permit number from the Kansas Corporation Commission.
   b. Be actually injecting a foreign substance into the producing formation of the reservoir on the lease or project for which allowance is claimed. The injection of only produced water does not classify a well for the secondary recovery allowance. To be classified as a secondary recovery project the total injected fluids (produced plus foreign substances) must exceed total produced oil and water by at least 10%.
   c. Only when the additional oil recovery can be clearly attributed to the injection of a foreign substance should dump floods be considered as evidence of secondary recovery.

2) Leases that qualify as secondary recovery operations use Table I for PWF, expenses, and equipment values.

V. Net Price

The net price to be used is the price which corresponds to the crude oil price schedule issued by the Division of Property Valuation, effective January 1 of the current tax year, and made a part of the oil and gas guide by reference. For leases that are exempt from the severance tax, use the column designated **"EXEMPT"** for the appropriate degree of gravity. Leases subject to the severance tax, use column designated **"SEVERANCE"**.

VI. Present Worth Factor

The present worth factor (PWF) is based on a 15% discount rate and three years of income (Table I) or five years of income (Table II). Its purpose is to discount future income to present value combined with a depleting income stream (reservoir decline).

The PWF incorporates into the guide the life and performance characteristics based on the percentage rate of decline that is computed for each particular lease as set out under the "Percentage Rate of Decline". The factors to be used are those in the table entitled "Prescribed Present Worth Factor Table." An exception may be in the use of a non-decline factor where a lease has produced for a number of years without a decline from year to year. For example, there are some leases that have produced 15 to 20 years with the production varying only slightly from year to year. In these cases, the appraiser may use a higher factor not to exceed 3.451 (Table II) for depths greater than 2000 ft. if it is considered necessary to achieve the fair market value of the lease. These cases are rare and must be properly documented. They are not to be confused with cases where the production has been boosted due to a work-over, a new zone, new well, or new equipment. The production must reflect a non-decline trend that is expected to continue.

EXAMPLE

YEAR	PRODUCTION	PRODUCTION
	Case A	Case B
1	10,213	10,213
2	10,411	9,611
3	11,000	9,114
4	10,500	8,410
5	10,300	10,560

Case A would be the type where use of the 3.451 factor is permitted. The fifth year production for Case B is level with year 1, but indicates that some factor such as a work-over or acid fracturing or other reason has affected the production. The 3.451 factor is not to be used in this case, since the lease does not represent non-declining production. The use of decline curves will establish the appropriate rate of decline to be used for Case B.

VII. Gross Reserve Value

The "Gross Reserve Calculations", Section V, is computed by multiplying the "Total Amount (Bbls.) Production", Item 1, by the "Net Price as of January 1", Item 2, to determine an "Estimated Gross Income Stream", Item 3. The "Estimated Gross Income Stream" is then multiplied by the appropriate "Present Worth Factor", Item 4. This product is the "Estimated Gross Reserve Value", Item 5.

SECTION V--GROSS RESERVE CALCULATIONS

4,118	x $17.25	= $71,035	x 1.914	= $135,961
1. Production	**2. Net Price**	**3.Gross Income**	**4. PWF**	**5.Gross Reserve**

VIII. Royalty Interest and Division Orders

The "Royalty Interest", Section VI, line 1, is computed by multiplying the decimal royalty interest times the "Est. Gross Reserve Value" from Section V, Item 5. The total royalty interest decimal figure is to include the royalty reserve in the lease and all over-riding royalty interests.

A current division order must be provided by the operator, unless arrangements have been made to have the oil purchaser provide the information to the county appraiser. A copy of the letter requesting the purchaser to supply the division orders must be filed with the rendition. **The operator is required to file current division orders, including interests and addresses, with each rendition, unless they are filed by the purchaser.** If the operator of a jointly owned lease does not disburse revenues to all of the royalty owners under the lease, each of the remaining working interest owners must provide current listings of their royalty owners to the operator for the purpose of filing the oil assessment rendition.

The list shall include the names, addresses and interests owned. If this information is not furnished with the rendition, the county appraiser will bill all of the royalty interests proportionate share of the taxes to the respective working interest owner thereof.

In the past some operators have filed division of interest lists that do not represent current ownership. In this case the appraiser may bill all Royalty Interests as "suspense item" and bill the interests to the operator or purchaser.

KSA 79-2017 and 79-2101 provides for the collection of delinquent oil and gas property taxes by the county sheriff from the purchaser.

IX. Working Interest

The leasehold working interest is computed by applying the appropriate decimal working interest to *Section V, Item 5* completing line 2. Subtracting the appropriate operator's cost allowance (lines 3a, b, & c) from line 2 results in the line 4 sub-total. If line 4 is greater than zero, transfer answer to line 6***. If line 4 is zero or a negative number (less than zero), complete line 5 by multiplying line 2a by 10% for Table II properties (primary production 2001 ft and deeper) or 5% for secondary recovery of 2001 ft and greater, or 2% for production from 2000 ft and less shallow (Table I).*** Transfer answer to line 6, add the appropriate equipment values (lines 7a, b, c) to produce the working interest valuation on line 8. Add itemized equipment (from supplemental listing as Section III) to line 9 to complete the total working interest market value on line 10. For new leases, KSA 79-331b provides for a 40% reduction in income and expenses for the working interest. See Oil Production, Section I, New Leases, paragraph 3b.

X. Operating Expense

The operating expense allowance is based on experience of the various producing areas of the State and provides a sufficient amount per well by depth and water production for typical operating leases. The amount listed represents the discounted expense for the three or five year term. Use the average depth of all wells associated with the lease to determine the depth to be used for operating expense and equipment value.

1) **Primary Production Wells:** 2000 ft. & less shallow: Use Table I.
   2001 ft. & deeper: Use Table II.

2) **Secondary Recovery Wells:** Use Table I.

3) **Injection Wells (secondary production):** Use the expense per injection well shown in Table I at the appropriate depth.

4) **Centrifugal Pump Well:** Wells equipped with high volume centrifugal pumps are more expensive to operate than wells equipped with standard pumping equipment. Centrifugal pumps are commonly referred to as submersible or by brand name such as "Reda" or comparable.

   Table I: A cost allowance has been incorporated into the "Prescribed Operator's Cost Allowance Per Well" table for wells so equipped for Table I properties to a depth of 3,500 feet. For wells deeper than 3,500 feet, the operator is to submit operating costs for the lease to ensure adequate expense is allowed, excluding non-recurring expenses and prorating other expenses over the lifetime of the expense, e.g., three year insurance premium is allocated at one-third the premium amount. The allowable annual expense total is then multiplied by 2.449 to calculate the three year discounted expense allowance. See example following.

Table II: Actual expenses (as defined above) should be used for leases that have centrifugal pump equipment in place to move large volumes of water. The lease expenses should be documented on an annual basis excluding non-recurring expenses, prorating expenses that include costs for more than one year, and excluding property tax expense (allowance for property tax is made in the PWF). The total annual expense is multiplied by 3.595 to calculate the five year expense allowance for Table II.

EXAMPLE

Centrifugal Well/Lease Expense Calculation Average Monthly Expense	
Expense Item	Average Monthly Expense
Pumping	$425
Overhead	$225
Lease Supervision	$100
Propane	$700
Supplies	$125
Salt Water Disposal	$950
Insurance/36 mo	$150
Total Monthly	**$2,675**
Annual	**$32,100**
Table II – Five Year Factor	**x 3.595**
Five year Discount Expense	**$115,400**

Note: *To determine Table I expense, the annual expense of $32,100 above is multiplied by the three year discount factor of 2.449 to calculate the three year discounted cost of $78,613 ($32,100 x 2.449).*

5) **Excess Expense Allowance**

Expenses are direct re-occurring expenses for specified depths discounted over a three year period for Table I and a five year period for Table II. Work-over expense is not included in the table expense.

The expenses listed in the tables reflect averages; hence, direct comparison to individual wells will not reflect individual experience. If excess operating expenses are requested for an individual lease, lease information for all leases operated within the same field may be requested by the appraiser to ascertain the average expense for the total leases operated. When reviewing operating expense requests, the reason for the request should be explained, and the problems for that lease should be analyzed to determine the cause for the expense and whether it is a short term problem or peculiar to the individual lease. For short term operating problems, no consideration is generally allowed, because the expenses are based on normal re-occurring operating conditions, efficient operating practices, and prudent management, discounted over three / five years, to reflect typical operating experience. **The appraiser should consider only fully documented requests that are at least 25% greater than the expenses listed in the guide. Provide expense information as attachment.** Total annual expense is multiplied by 2.449 to develop a three year discounted operating cost for Table I properties, or 3.595 to develop a five year discounted operating cost for Table II properties.

ALLOWABLE OPERATING EXPENSES:

- Labor (including employee benefits) to the district level
- Utilities: power, water, fuel or on-site fuel source converted to market price
- Rental equipment used to correct recurring problems
- Dehydration and waste water disposal
- Corrosion control or other chemical treatment
- Lease maintenance and repairs such as pulling jobs, bailing, parted rods, paraffin scraping, recurring casing leaks or sanding, acidizing and refracturing in the same zone, and repairs on downhole equipment (the appraiser should be certain to consider the frequency of these expenses since they are discounted over 3 or 5 years)
- Transportation
- Insurance (lease liability insurance)
- Overhead through district foreman's level (15% maximum) If overhead exceeds maximum, the appraiser may make adjustment by subtracting overhead from total acceptable expenses and dividing the remaining expenses by 85%.
- Mechanical Integrity Test (MIT) amortized over the period qualified by the test

OPERATING EXPENSES NOT CONSIDERED:

- New well drilling, whether capitalized or expensed
- New or replaced equipment
- Re-completion costs into a different producing zone
- Property taxes (already allowed in the PWF)
- Depreciation
- Depletion
- Amortization of mortgage payments
- Office overhead expense above district level

EXAMPLE

Lease Expense Calculation	
Expense Item	Average Monthly Expense
Pumping	$415
Overhead	$180
Lease Supervision	$ 45
Electricity	$495
Supplies	$120
Salt Water Disposal	$295
Insurance/36 mo	$175
Total Monthly	**$1,725**
Annual	**$20,700**
Table II – Five Year Factor	**x 3.595**
Five year Discount Expense	**$74,417**

Note: *To determine Table I expense, the annual expense of $20,700 above is multiplied by the three year discount factor of 2.449 to calculate the three year discounted cost of $50,694 ($20,700 x 2.449).*

6) **Number of wells**

The number of wells to be used for computing the operating cost allowance is the number of wells in existence as of January 1. In determining the number of producing wells for the well count, a commingled multi-zone well is to be counted as one (1) well; dual completions as two (2) wells; triple completions as three (3) wells, etc. A dual completed well with one string producing oil and one string producing gas is to be counted as 2 wells (one oil and one gas). SWD, TA, and SI wells are not included.

XI. Equipment Value

Table I and Table II equipment value sections are used for appraising the producing equipment, surface and subsurface, including casing, tubing, rods, pumping units, engines, tanks, separators, heater treaters, gun-barrel tank, and lease lines.

1) Use Table I for leases 2,000 feet and less deep, and all secondary recovery operations. Use Table II for leases 2001 feet and deeper.

2) A temporarily abandoned well (TA) is defined for tax purposes as a well that has had the equipment removed in anticipation of plugging the well bore prior to abandonment of the lease. If the well qualifies as a "TA" well, it has no market value and the reserves are appraised at zero value. Only the equipment remaining in place as of the January 1 appraisal date should be considered. If all equipment remains, use values in Table I or Table II. If removal has begun, use Itemized Equipment listing at the end of the guide for remaining equipment.

3) Shut-in well (SI) is defined for tax purposes as a lease which has well equipment in place, but production has been stopped or curtailed due to economic reasons unassociated with the mechanical operation of the lease, such as a lack of market demand, rather than reserve depletion.

   Shut-in Wells on Shut-in Leases: i.e., no production due to economics or only minimal production to maintain lease terms and/or to protect the reserve, are appraised per equipment values listed on Table I or Table II, per depth and water cut as established in prior valuation years. Example: Two SI wells, 2950 ft., 93% water: Table II, $2,250 x 2 = $4,500.

   Shut-in Wells on Producing Leases**:** appraise the lease as of January 1 based on the number of producing wells as of January 1 (see Section I, Production, paragraph 4, parts a & b; and Section X, Operating Cost Allowance, paragraph 6) and appraise all shut-in wells using Table I to a maximum value of $0.50 per ft of depth per well; or, Table II to a maximum value of $0.60 per ft of depth per well. *Note: For leases that have a multitude of shut-in wells, less value may apply for the conglomeration of wells.*

4) Salt water disposal well (SWD) used in conjunction with an operating lease is appraised by depth per Table I or II, SWD column. A salt-water disposal well utilized for commercial dumping is appraised on the basis of net income multiplied by 3.595. Example: $18,000 gross income less $9,348 expenses = $8,652 x 3.595 = $31,104 value for the salt-water disposal system.

5) Surface and subsurface equipment stored on the lease or in a storage area elsewhere is to be itemized on a separate sheet, titled Section III, totaled, and the results transferred to Section VI, line 9. Such equipment is to be appraised in accordance with the equipment values from the table entitled "Oil and Gas Itemized Equipment Value Section".

6) Surface and subsurface equipment that has been pulled for repair, and/or maintenance to the well, is included the table value and is not to be separately itemized.

7) Number of wells to be used for computing the equipment value is the number of wells in existence as of January 1. In determining the number of producing wells for the well count, a commingled multi-zone well is to be counted as one (1) well; dual completions as two (2) wells; triple completions as three (3) wells, etc. A dual completed well with one string producing oil and the other string producing gas is to be counted as 2 wells (1 oil and 1 gas).

8) Injection wells, water disposal wells, water supply wells, centrifugal pumps

   a. Injection well - A well used to inject water into a water-flood operation.
   b. Disposal well - A well used to dispose water produced from oil or gas wells
   c. Water supply well - A well used in secondary recovery to provide a water source
   d. Centrifugal pump - A submersible pump or by brand name (Reda, etc.) used to lift high volumes of water: appraised per Table I or Table II. Table values include surface and subsurface equipment.

XII. Tertiary Recovery

There are experimental projects known as tertiary recovery, as distinguished from primary recovery or secondary recovery. These are experimental operations and may also be subsidized. They require specialized oil recovery equipment that is likely to have little value should the experiment prove unsuccessful. The cost of operating the project usually equals or exceeds the net value of the production. All of these projects require special treatment and are appraised on an individual basis.

XIII. Oil (and AOK Gas) Wells Capable of Producing But Never Produced

A well that has been drilled, but not completed (and has discovered reserves existing on the appraisal date), but has not been produced as of the appraisal date, is appraised pursuant to this table. This type of well is not to be classified as a TA or SI well even though it is not equipped with rods, tubing or surface equipment. Do not use for wells that are capable of producing only one or two barrels per day. Amounts listed indicate minimum valuations. Appraiser may take first quarter production, plot decline, and extrapolate production to estimate value.

Depth	Working Interest Amount	Royalty Interest
0-500 ft	$5,000	None
501-1,000 ft	$15,000	None
1,001-2,000 ft	$25,000	None
2,001-4,000 ft	$50,000	None
4,001 & deeper	$75,000	None

TABLE I

Primary Production Oil Wells </= 2,000 Feet and All Secondary Recovery Production

15% Discount Rate; Three Year Economic Life; 4% Property Tax Credit

Prescribed Present Worth Factor

% DECLINE PWF	% DECLINE PWF	% DECLINE PWF	% DECLINE PWF
0-8% = 2.010	19% = 1.596	30% = 1.240	41% = 0.938
9% = 1.969	20% = 1.561	31% = 1.211	42% = 0.913
10% =1.930	21% = 1.527	32% = 1.182	43% = 0.888
11% =1.891	22% = 1.493	33% = 1.153	44% = 0.864
12% = 1.852	23% = 1.460	34% = 1.125	45% = 0.840
13% = 1.814	24% = 1.427	35% = 1.097	46% = 0.817
14% = 1.776	25% = 1.395	36% = 1.069	47% = 0.794
15% = 1.739	26% = 1.363	37% = 1.042	48% = 0.771
16% =1.702	27% = 1.332	38% = 1.016	49% = 0.749
17% = 1.666	28% = 1.301	39% = 0.989	50% = 0.727
18% = 1.631	29% = 1.270	40% = 0.964	100% = 0.727

Prescribed Operator's Expense Allowance Per Well

Based on Average Depth of All Wells Associated With the Lease
Expense Factor 2.449

WELL DEPTH	LESS THAN 90% WATER	90 TO 95 % WATER	ABOVE 95% WATER	CENTRIFUGAL	INJECTION
0 to 500 FT	$7,800	$9,100	$10,150	$15,900	$5,635
501 to 1,000	$10,150	$11,900	$12,000	$17,750	$8,435
1,001-1,500	$11,900	$12,300	$15,600	$22,200	$8,900
1,501-2,000	$12,800	$13,700	$20,200	$35,950	$10,250
2,001-2,500	$16,000	$22,500	$29,400	$66,400	$10,300
2,501-3,000	$23,600	$33,850	$33,950	$70,000	$15,450
3,001-3,500	$28,600	$35,200	$40,000	$79,350	$16,000
3,501-4,000	$32,100	$36,400	$40,150	See Oper.Exp.Sec X,4	$16,622
4,001-4,500	$33,500	$37,100	$44,850	See Oper.Exp.Sec X,4	$17,040
4,501-5,000	$34,000	$37,650	$45,350	See Oper.Exp.Sec X,4	$17,270
5,001-5,500	$34,550	$38,200	$45,550	See Oper.Exp.Sec X,4	$17,523
5,501-6,000	$35,100	$38,700	$45,850	See Oper.Exp.Sec X,4	$17,741
6,001 +	$36,600	$39,200	$46,250	See Oper.Exp.Sec X,4	$17,975

Prescribed Equipment Value Per Well

Equipment Factor 0.7051

Well Depth	Less than 90% Water	90% TO 95 % Water	Above 95% Water	Centrifugal	SWD*/INJ* Water Supply
0 to 500 ft	$100	$120	$125	$600	$30
501 to 1,000 ft	$250	$300	$350	$900	$100
1,001 to 1,500 ft	$300	$400	$450	$1,200	$125
1,501 to 2,000 ft	$700	$800	$950	$1,500	$150
2,001 to 2,500 ft	$2,000	$2,750	$3,100	$3,100	$200
2,501 to 3,000 ft	$2,700	$3,400	$3,750	$3,800	$250
3,001 to 4,500 ft	$4,250	$4,650	$5,100	$6,200	$300
4,501 to 6,000 ft	$5,600	$6,500	$7,150	$8,600	$450
6,001 ft +	$6,650	$7,400	$8,150	$11,000	$500

Includes surface and subsurface equipment. Does not apply to commercial salt water dump disposal wells. See instructions.

TABLE II

Primary Production Oil Wells > 2,000 Feet

15% Discount Rate; Five Year Economic Life; 4% Property Tax Credit

Prescribed Present Worth Factor

% DECLINE PWF	% DECLINE PWF	% DECLINE PWF	% DECLINE PWF
0-5% = 3.009	17% = 2.147	29% = 1.512	41% = 1.046
6% = 2.927	18% = 2.087	30% = 1.468	42% = 1.013
7% =2.847	19% = 2.027	31% = 1.424	43% = 0.981
8% = 2.769	20% = 1.970	32% = 1.382	44% = 0.950
9% = 2.692	21% = 1.914	33% = 1.341	45% = 0.920
10% = 2.618	22% = 1.859	34% = 1.300	46% = 0.891
11% = 2.546	23% = 1.805	35% = 1.261	47% = 0.862
12% = 2.475	24% = 1.753	36% = 1.223	48% = 0.834
13% = 2.406	25% = 1.703	37% = 1.186	49% = 0.806
14% = 2.339	26% = 1.653	38% = 1.149	50% = 0.780
15% = 2.273	27% = 1.605	39% = 1.114	100% = 0.780
16% = 2.210	28% = 1.558	40% = 1.080	

Prescribed Operator's Expense Allowance Per Well

Based on Average Depth of All Wells Associated With the Lease
Expense Factor 3.595

WELL DEPTH	LESS THAN 90% WATER	90 TO 95 % WATER	ABOVE 95% WATER	CENTRIFUGAL
2,001-2,500	$23,850	$34,925	$37,750	See Oper.Exp.Sec X,4
2,501-3,000	$35,200	$41,100	$44,400	See Oper.Exp.Sec X,4
3,001-3,500	$40,000	$45,000	$50,500	See Oper.Exp.Sec X,4
3,501-4,000	$42,700	$45,500	$53,200	See Oper.Exp.Sec X,4
4,001-4,500	$44,800	$45,800	$56,250	See Oper.Exp.Sec X,4
4,501-5,000	$46,100	$46,400	$57,350	See Oper.Exp.Sec X,4
5,001-5,500	$48,450	$48,800	$59,200	See Oper.Exp.Sec X,4
5,501-6,000	$50,300	$50,400	$60,200	See Oper.Exp.Sec X,4
6,001 +	$51,400	$51,700	$60,650	See Oper.Exp.Sec X,4

Prescribed Equipment Value Per Well

Equipment Factor 0.5332

WELL DEPTH	UNDER 90% WATER	90% TO 95 % WATER	ABOVE 95% WATER	CENTRIFUGAL	SWD*/INJ* Water Supply
2,001 to 2,500 ft	$1,700	$1,750	$2,000	$2,100	$240
2,501 to 3,000 ft	$2,050	$2,250	$2,500	$2,550	$300
3,001 to 4,500 ft	$2,800	$3,100	$3,400	$4,100	$400
4,501 to 6,000 ft	$3,900	$4,350	$4,750	$5,700	$550
6,001 ft +	$4,450	$4,950	$5,450	$7,200	$650

**Includes surface and sub-surface equipment. Does not apply to commercial salt water dump disposal wells. See instructions.*

OIL ASSESSMENT RENDITION

SHALL BE FILED WITH COUNTY APPRAISER BY APRIL 1

Schedule 2 (Class 2B) (Rev. 11/03)

____________ COUNTY, KANSAS

STATEMENT OF ____________ OPERATOR I.D. NO. ____________

P.O. ADDRESS ____________ CITY ____________ STATE ____ ZIP ____________

NAME OF PROPERTY ____________ Property ID: Company ID: ____________ County ID: ____________ 1st Well API #: ____________

SECTION I - LOCATION OF PROPERTY ASSESSED	SECTION VII - ABSTRACT VALUE (FOR APPRAISER'S USE ONLY)				
DESCR		Appraised Value	Assessed	Penalty	TOTAL
	Total Working Interest (Sec. VI, Line 8)				
	Royalty Interest (Sec. VI, Line 1)			XXXXXXXXXX	
Lot Sec Adn. Twp Blk Rng	Itemized Equipment (Sec. VI, Line 9)				
Twp. City	Total				
Tax Unit: School Dist:					

SECTION II - WELL AND LEASE DATA

No of Wells - Oil: Gas: Inj: Ws:	Secondary Recovery ( ) Permit No:
Shut In: SWD: TA: Total:	Producing Formation:
Year First Produced: Spud Date:	Market Price Received (Producer):
Average Depth of Well: Producing: SWD:	Less Oil Transportation Charges:
Oil Gravity: Water Production (Percent): B.P.D.: 0.0	Net Price: Oil Purchaser:

SECTION IV- PRODUCTION DATA

MONTH	MONTHLY PRODUCTION 2003	2002	Notation
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
1) Annual Production			Casinghead Gas Production
2) Casinghead Gas (Conv. Bbls)		XXXXXX XXXXXX	______ X ______ = ______ / ______ = ______
3) Total Annual Production Bbls. (to Sec. V. Item 1)		XXXXXX XXXXXX	Production Price Per MCF Income $ Bbl. Oil Bbl. Oil
4) Annual Decline Bbls.		XXXXXX XXXXXX	
5) Percentage Rate of Decline		XXXXXX XXXXXX	(Transfer to Sec. IV, Line 2)

SECTION V - GROSS RESERVE CALCULATIONS

______ X ______ = ______ X ______ = ______

______ X ______ = ______ X ______ = ______

1. Total Amount (Bbls.) Production 2. Net Price as of Jan. 1 3. Est'd Gross Income Stream 4. Present Worth Factor 5. Est'd Gross Reserve Value

SECTION VI GROSS RESERVE VALUE X DECIMAL INTEREST	A. Schedule	B. Owner	C. Appraiser
1. Royalty Interest Valuation: $ X			
2. Working Interest Valuation: $ X			
3. Deduct Operation Cost Allowance:			
A. Producing Well: $ Per Well X Wells			
B. Injection Well: $ Per Well X Wells			
C. Submersible: $ Per Well X Wells			
4. SUBTOTAL (Line 2 minus Lines 3A. B. C.)			
5. Line 2, Col. A: $ X			
6. Line 4 or Line 5 (Whichever is Greater)			
7. Add Prescribed Equipment Value			
A. Producing Well: $ Per Well X Wells			
B. TA,SI,SWD, INJ,WS $ Per Well X Wells			
C. Submersible: $ Per Well X Wells			
8. TOTAL Working Interest Value (Add Lines 6-7A. B. C.) Appraised Value			
9. Itemized Equipment (Section III - Attach Schedule)			
10. TOTAL Working Interest Market Value			
11. Working Interest Assessed Value X			

* Attach Name, Address, And Interest of Royalty Owners

CERTIFICATION: I do hereby certify that this schedule contains a full and true list of all personal property owned or held by me subject to personal property taxation under the laws of the state of Kansas pursuant to K.S.A. 79-329 through 79-333

______ OWNER ______ DATE ______ TAX RENDITION PREPARER ______ DATE

Lease Code ____________ County Code ____ Lease Name ____________

PRESCRIBED BY KANSAS DEPARTMENT OF REVENUE, DIVISION OF PROPERTY VALUATION

GAS SECTION

Gas Rendition Form Instructions

The lease operator/taxpayer/tax representative is required to provide the information requested in Sections I through IV of the gas rendition form and all other information necessary to fix the valuation of the property as determined by the Director of Property Valuation. Failure to provide this required information will result in a 50% penalty assessed to the operator based on the total value of the royalty interest plus the working interest for failure to file a full and complete statement of assessment according to KSA 79-332a (c). COLUMN A (SCHEDULE VALUE) is to be completed by using the oil and gas guide without departure, adjustment, or change. COLUMN B (OWNER) is reserved for the lease operator/taxpayer/tax representative's use for requested adjustments to Column A. COLUMN C (APPRAISER) is reserved for the county appraiser to finalize the valuation of the well/lease.

NOTE: For copies of the rendition forms and oil and gas guide, please contact the county appraisal office for the county in which the property is located or download from http://www.ksrevenue.org/pvdoilgas.htm.	
Section I: Location of Property	Provide information to the extent available.
Section II: Well and Lease Data	Provide information as requested for the number of producing gas wells(pumping or flowing), shut-in wells, salt water disposal wells, and temporarily abandoned wells; year first produced and the year of development (spud date). Provide completion depth, water production, and producing field. Note changes from prior year well count. Provide the weighted average spot price received per mcf for the prior year(see Gas Section, II) If the unit has been infill drilled, place an "X" where indicated for "Infill Unit" Additionally, the names and API numbers of the original well and infill well(s) should be entered in the spaces provided. Provide any other requested information necessary to ascertain the value of property.
Section III: Itemized Equipment	The rendition sheet does not have space for this information. Please attach separate sheet listing equipment located on the lease, but not part of the production equipment, attach to the rendition, and include total in Section VI on Line 9.
Section IV: Production Data	Provide five year history for the Hugoton Chase and Panoma Council Grove fields in Table A and for all AOK fields in Table B. Provide at least three year history for all other fields listed in Table A.
Section V: Valuation of the 8/8ths Interest	Line 1: **Average Production**: Column A: All fields listed in Table A: Use prior year production. All Other KS fields in Table B: Use prior year production. Columns B & C: see Major Fields Section, I, and AOK Section, II. Line 2: **Net Price**: Column A: Use weighted average spot price received for prior year as explained in Gas Section, II. Line 3: **Estimated Gross Income Stream**: Multiply Line 1 x Line 2 and enter result on Line 3 in Column A. Line 4: **Present Worth Factor**: Column A: Use factor in Table A for major fields. Use factors in Table B for All Other KS fields. See AOK Section III, Decline Rate, to determine decline rate for factor. Line 5: **Total**: Column A: Multiply Line 3 x Line 4 and enter result on line 5 and transfer to Section VI, Line 1 and Line 2.

Section VI: Calculation of Royalty and Working Interests	**Line 1:** Column A: From Line 5, Section V, multiply gross reserve value by the royalty decimal interest to calculate the royalty interest. **Line 2:** Column A: From Line 5, Section V, multiply the gross reserve value by the working decimal interest to calculate the gross working interest before expenses. Column A: Water Credit adjustment for Table B wells is also made on this line. Multiply gross reserve value x working interest x gas well/combination factor from Table B, Water Credit Table. **Line 3:** Deduct Operating Cost Allowance: Column A: For major fields refer to Table A for expense allowance, or complete Column B with actual expenses, including water and compression, multiplied by the appropriate expense factor from Table A. Provide expense information as attachment. See Gas Section V, Operating Expenses. Column A: For AOK fields refer to Table B for expense allowance, or complete Column B with actual expenses, including compression and **deducting** water (see water credit adjustment line 2), multiplied by the 3.595 expense factor from Table B. Provide expense information as attachment. See Gas Section V, Operating Expenses. **Line 4:** Column A: Deduct wellhead compression expense, actual expense multiplied by the appropriate Table A or Table B expense factor, on line 4a. See Gas Section V, Operating Expenses. Column A: Deduct water expense for Table A wells, actual expense multiplied by the appropriate Table A expense factor, on line 4b.(Table B water expense adjustment in line 2 above. See Gas Section, V). **Line 5:** Column A: Sub-total of Line 2 less Line 3 and Line 4a and 4b, if applicable. **Line 6:** Column A: Minimum lease calculation: Line 2 x 10% (.10). **Line 7:** Column A: Enter Line 5 or Line 6, whichever is greater. **Line 8:** Column A: Enter equipment value from Table A for major fields or Table B for AOK. **Line 9:** Column A: Add Itemized Equipment (attach schedule) **Line 10:** Column A: Total of lines 7, 8a, 8b, and 9.

Certification: The certification is to be completed and signed by the lease owner or operator who is responsible for filing the tax rendition with the county appraiser. It must also be signed by the rendition preparer.

Division Orders: A list of the current royalty owners, their decimal interest, and their addresses, is to be provided by the operator and is a requirement for filing the tax rendition.

Gas Well Definition

For ad valorem tax purposes, a natural gas well is defined as a well producing or capable of producing at a gas-oil ratio equal or greater than 15,000 cubic feet per barrel of oil. Example: 30,000 mcf = 30,000 x 1,000 cubic feet = 30,000,000 cubic feet divided by oil produced from the same formation, 2,000 barrels = 15,000 cubic feet gas per barrel of oil, which is equal or greater than 15,000 cubic feet gas per barrel of oil; therefore, the well is considered a gas well for ad valorem tax valuation.

I. Production

Use prior year production for all fields in Table A and Table B. If prior year production is not indicative of future well capabilities, please refer to alternative production options in Section I, Major Proven Gas Areas and Fields for Table A and Section II, All Other Kansas for Table B.

New Leases

For a new lease that has produced for less than 12 months during the prior year, annualize the production by dividing the production by the number of days produced and multiplying the result by 365 (days per year) or a representative period for which the lease may be expected to be produced in the future as documented by evidence provided to substantiate that the pipeline will not purchase production from the well for a full year. See Oil Section I, Production, paragraph 3a for example.

K.S.A. 79-331(b) & (c) provides adjustments for new leases beginning production on July 1 or later.

K.S.A. 79-331 (b) & (c): "(b) The valuation of the working interest and royalty interest, except valuation of equipment, of any original base lease or property producing oil or gas for the first time in economic quantities on and after July 1 of the calendar year preceding the year in which such property is first assessed shall be determined for the year in which such property is first assessed by determining the quantity of oil or gas property would have produced during the entire year preceding the year in which such property is first assessed upon the basis of the actual production in such year and by multiplying the income and expenses that would have been attributable to such property at such production level, excluding equipment valuation thereof, if it had actually produced said entire year preceding the year in which such property is first assessed by sixty percent (60%)."

(c)"The provisions of subsection (b) of this section shall not apply in the case of any production from any direct offset well or any subsequent well on the same lease." (A direct offset well is defined as a well drilled on normal spacing patterns which is completed in the same reservoir as the previous well or wells)

II. Price Received per MCF

The price used in the valuation is the average monthly price received during the prior year.

The method to be used in calculating the average price per mcf shall be the volumes sold in each month times the price or prices received per one million BTU before any reductions for taxes or levies of any kind, but after quality adjustments, upward or downward, from a base of one million BTU per one thousand cubic feet. The BTU content shall be measured at the wellhead prior to any processing or extraction of natural gas liquids.

Each month's average price shall be added to each succeeding month's average price then divided by the months produced and sold to arrive at a weighted average price. The weighted average price calculation shall be supported by written documentation supplied to the appraiser either on a per-lease basis or by pipeline or system basis, whichever is appropriate.

Allowable Deductions from Price Received:

a. Gathering charges
b. Transportation charges
c. Any charge borne by the producer necessary to condition low quality wellhead natural gas to marketable condition.

NOTE: *Deductions must be documented on either a lease basis or by pipeline or system basis. In the case of off lease sales, the price to be used is that paid to the Royalty Interest, including any amount paid in to escrow. All such information will be treated as confidential if so designated when the rendition is filed.*

III. Present Worth Factor

Please refer to Table A, Major Proven Gas Areas and Fields, or Table B, All Other Kansas, for appropriate factor. Prescribed present worth factor descriptions are located in their respective sections, Major Proven Gas Areas and Fields or All Other Kansas.

IV. 8/8ths Gas Production

The total average gas production (MCF) computed in Section IV - Gas Assessment Rendition, is transferred to Section V, line 1, multiplied by line 2, net price, resulting in line 3, estimated gross income. Line 3 is then multiplied by line 4, present worth factor, resulting in the line 5 total valuation. Any adjustments are multiplied on line 6, resulting in the line 7, gross value.

V. Operating Expenses

Please refer to Table A, Major Proven Gas Areas and Fields, or Table B, All Other Kansas, for appropriate expense allowance or complete Column B with actual expenses multiplied by the appropriate expense factor from Table A or Table B. Compression expenses should be included for both Table A and Table B total expenses. Water should be included in Table A total expenses, see water credit adjustment factor for Table B. Only direct re-occurring expenses based on normal operating conditions, efficient operating practices, and prudent management should be considered. **The appraiser should consider only fully documented requests that are at least 25% greater than the expenses listed in the guide. Provide expense information as attachment.** See Oil Section X, Operating Expenses, for allowable expenses.

Example: $6,959 per year x 7.9049 = $55,010 (for the Hugoton-Chase Group).

Expense for wellhead compression is deducted in Section VI, on Line 4a if not included in total actual expenses (see above). The annual wellhead compression expense is multiplied by the appropriate expense factor from Table A or Table B. **Provide supporting expense information.**

Example: $800 per year x 3.595 = $2,876 (for All Other Kansas)

Expense for water is deducted in Section VI, on line 4b if not included in total actual expenses (see above) for Table A wells. The annual water expense is multiplied by the appropriate expense factor from Table A. Table B expense allowance for water is made using a water credit adjustment factor in Section VI, line 2. (see Table B, AOK, for factor) **Provide supporting expense information.**

The number of wells to be used for computing operating expenses and equipment value is the number of wells in existence as of January 1. In determining the number of producing wells for the well count, a commingled multi-zone well is to be counted as one (1) well; dual completion as two wells, triple completion as three (3) wells, etc. A dual completed well with one string of pipe producing oil and the other string of pipe producing gas is to be counted as two (2) wells (one oil and one gas). Well depth should reflect the average for all wells located on the lease. See Oil Section X for additional expense information.

VI. TA & SWD Wells

1) A "temporarily abandoned" (TA) well is defined for tax purposes as a well that has had the equipment removed in anticipation of plugging the well bore prior to abandonment of the lease. If the well qualifies as a "TA" well, it has no market value and the reserves are appraised at zero value. Only the equipment remaining in place as of the January 1 appraisal date should be considered. If all equipment remains, use values in Table B, AOK. If removal has begun, use Itemized Equipment listing at the end of the guide for remaining equipment.

2) A salt water disposal well (SWD) used in conjunction with an operating lease is valued at $0.10 per foot of depth.

3) A salt water disposal system utilized for commercial dumping is appraised on the basis of net income multiplied by 3.595. Example: $18,000 gross income less $9,348 expenses = $8,652 x 3.595 = $31,104 value for the system.

VII. Severance Tax Multiplier

KSA 79-4217 provides for an 8% gross severance tax on all natural gas severed from a well having an average daily production during a calendar month having a gross value of more than $87 per day.

KSA 79-4219 provides for a 3.67% credit for local production taxes resulting in a 4.33% "net" severance tax. Both the state severance and local production taxes have been allowed as an expense in calculation of the present value factors. When any natural gas purchase contract allows reimbursement for both ad valorem and 4.33% state severance taxes, multiply Line 5, Section V (Total Value) by a factor of 1.15 for Hugoton Chase and Panoma Council Grove, or 1.17 for all other fields.

If not all taxes are reimbursed, use a factor equal to 1 + the percentage of tax reimbursement: e.g. (0% ad valorem tax, 50% of state severance tax = 1 + (.50 x .0433) = 1.022.

VII. Royalty Interest and Division Orders

The "Royalty Interest", Section VI, line 1, is computed by multiplying the decimal royalty interest times the "Est. Gross Reserve Value" from Section V, Item 5. The total royalty interest decimal figure is to include the royalty reserve in the lease and all over-riding royalty interests.

A current division order must be provided by the operator, unless arrangements have been made to have the oil purchaser provide the information to the county appraiser. A copy of the letter requesting the purchaser to supply the division orders must be filed with the rendition. **The operator is required to file current division orders, including interests and addresses, with each rendition, unless they are filed by the purchaser.** If the operator of a jointly owned lease does not disburse revenues to all of the royalty owners under the lease, each of the remaining working interest owners must provide current listings of their royalty owners to the operator for the purpose of filing the oil assessment rendition.

The list shall include the names, addresses and interests owned. If this information is not furnished with the rendition, the county appraiser will bill all of the royalty interests proportionate share of the taxes to the respective working interest owner thereof.

In the past some operators have filed division of interest lists that do not represent current ownership. In this case the appraiser may bill all Royalty Interests as "suspense item" and bill the interests to the operator or purchaser.

KSA 79-2017 and 79-2101 provides for the collection of delinquent oil and gas property taxes by the county sheriff from the purchaser.

MAJOR PROVEN GAS AREAS AND FIELDS
Table A Section

I. Production

A well's historic production may or may not be indicative of the well's future volumes. Due to over-production or under-production of allowable, significant decreases or increases in allowable or the accumulation or production of available underage. Any combination of up to five years' production or other level of production supported by **Rate-Time** analysis or other engineering information may be utilized provided such consideration results in the fair market value of the lease as determined by the appraiser.

For Hugoton in-fill wells that have sufficient production history to estimate initial recoverable reserves (IRR), typically three to five years minimum, estimate the IRR by preparing either a single Rate-Time curve for both wells or separate curves for both the parent and infill wells in the unit.

For Hugoton in-fill wells that do not have sufficient production history to estimate initial recoverable reserves by using Rate-Time analysis, the following procedure may be used to estimate the IRR of the infill well, as well as, remaining recoverable reserves (RRR) of the unit:

1) Determine the initial recoverable reserves (IRR) of the original well by using an economic limit (abandonment rate) of 15 MCF / day per well in the Rate-Time curve calculation.

2) To estimate the total unit IRR, multiply the IRR of the original well by a factor of 1.06 to recognize incremental increase in reserves attributable to the infill well.

3) Determine the remaining recoverable reserves (RRR) for the unit by subtracting the cumulative production of both wells from the total unit IRR estimate derived in #2 above.

4) Determine the in-place value of the reserves by dividing the working interest appraised value by the estimate of net remaining recoverable reserves (NRR = RRR multiplied by the working interest from rendition Section VI, Line 2).

Note: *For all Hugoton units, please note that additional information should be entered in the spaces provided at the end of Section II. If the unit has been infill drilled, place an "X" where indicated for "Infill Unit" Additionally, the names and API numbers of the original well and infill well(s) should be entered in the spaces provided.*

II. Present Worth Factor

The present worth factors listed in Table A, Major Proven Gas Areas and Fields, are based on recommendations by the Guide Committee and approved by the Director of the Property Valuation Division, Kansas Department of Revenue. The factors were developed by discounting income and expenses over the estimated producing life of the individual field. An expense allowance of 4.33% of gross income for severance tax and 10.67% for local ad valorem tax and State Corporation Commission levies is included in the present worth factor for the Hugoton Chase Group and the Panoma Council Grove fields; all other fields include 4.33% + 12.67% or total 17% tax expense. No escalation for expenses or price is included in the factor.

III. Shut-in Gas Wells

A "shut-in" (SI) well is defined as a well that has production equipment in place, but production has been stopped (shut-in) due to market demand or by the Kansas Corporation Commission (KCC) for excessive over-production.

1) A shut-in gas well that has never been produced or sold gas, and is located in a major proven area, is appraised at working interest equipment value of $20 per foot of depth. For Hugoton wells that have been drilled, but not completed, $20 per foot of total depth shall be used. For Hugoton wells connected to a pipeline, and assigned an allowable, $40 per foot of total depth shall be used.

2) Gas wells shut-in for longer than two years are appraised at $1.50 per foot of depth, except for shut-in wells located in the Bradshaw-Byerly, Greenwood, or Redcave fields. Appraisal of these wells is based on applying the appropriate present worth factor to the three year average production or to a representative production period, multiplied by the prior year average monthly spot price as calculated per note 3, Gas section. However, the operating cost allowance, pumping credits, etc., shall be reduced by 50%. A minimum value of $20 per foot is assigned to the working interest.

TABLE A
MAJOR PROVEN GAS AREAS AND FIELDS

Present worth factors do not include escalation of expense or price; do include a 15% credit for ad valorem tax and severance tax expense for Hugoton Chase Group and Panoma Council Grove; and, 17% for the other fields.

Producing Field	Prescribed PWF	Prescribed Operator's Expense Allowance per Well	Prescribed Equipment Value per Well
Bradshaw/Byerly: 20 year life, 10% decline, 12% discount rate, 7.9049 expense factor, annual expense: $8,795	3.55	$69,520	None
Greenwood: 15 year life, 4% decline, 14% discount rate, 6.558 expense factor, $11,000 annual expense.	4.37	$72,140	None
Hugoton Chase Group: 20 year life, 10% decline, 12% discount rate, 7.9049 expense factor, $7,975 annual expense.	3.63	$63,000	None
Interstate Redcave: 15 year life, 5% decline, 14% discount rate, 6.558 expense factor, $5,750 annual expense.	4.14	$37,700	None
Panoma Council Grove: 20 year life, 10% decline, 12% discount rate, 7.9049 expense factor, $8,415 annual expense.	3.63	$66,529	None
Glick ***Hugoton Area Deep*** **(Zones below 3,500 feet, Pennsylvania & Mississippi)** ***McKinney*** ***McKinney* (Chester Zone)** ***Spivey Grabs***	**Use Table B** **All Other Kansas** **Present worth factor, expenses, and equipment**		

ALL OTHER KANSAS
Table B Section

I. All Other Kansas (AOK)

AOK gas fields include all gas fields *except* those included under "Table A--Major Proven Gas Fields and Areas."

II. Production

Historic production may not be indicative of future production capability. In most cases, use the prior year production if it represents the future forecast for the lease. In other cases, a representative period may be used if it represents the production capability of the lease. For example, if the production is curtailed and is expected to be curtailed for the foreseeable future, use the curtailed production as the typical production for use in the calculation of the reservoir value. As much history as is available should be reviewed to estimate production capability. The decline rate may need to be adjusted to reflect the production used.

III. Decline

Most wells in the AOK produce from limited life reservoirs, therefore, the decline rate must be calculated. See Oil Section II, Decline, for determination of decline rate for AOK gas wells.

1) New Wells: Use 30% decline rate until the well has produced three years, unless the lease operator can establish a rate greater than 30% by use of back-up data.

2) For most leases with a production history, the decline can be plotted as a decline curve or the prior two years production may be used if they are representative of typical production and typical decline. **Provide five years of production history for use in establishing decline rate.**

EXAMPLE

Year 1:	120,000 mcf
Year 2:	84,500 mcf
Year 3:	54,925 mcf

Decline rate = Year 2 - Year 3 divided by Year 2
= 84,500 - 54,925 divided by 84,500 = 35%

IV. Present Worth Factor

The present worth factors listed in Table B, All Other Kansas, are based on a 15% discount rate and five years of income. The factors incorporate the life and performance characteristics based on the percentage rate of decline that is computed for each particular lease. An expense allowance of 4.33% of gross income for severance tax and 12.67% for local ad valorem tax and State Corporation Commission levies is included in the present worth factor. No escalation for expenses or price is included in the factor.

V. Operating Expenses

Use appropriate expense allowance by depth per Table B for Column A. Requests for excessive expenses should use Column B with actual annual expenses multiplied by a factor of 3.595 for Table B, All Other Kansas. See general Gas Section V, Operating Expenses, for additional information.

VI. Shut-in Gas Wells

Shut-in well (SI) is defined for tax purposes as a lease which has well equipment in place, but production has been stopped or curtailed due to economic reasons unassociated with the mechanical operation of the lease, such as a lack of market demand, rather than reserve depletion.

For AOK, all shut-in wells are valued on the basis of $0.50 per ft of depth.

All AOK wells newly developed with reserves in place, waiting for pipeline connection, use minimal reserve value table in Oil Section, topic XIII.

VII. Coalbed Methane Gas Wells

Use Table B, All Other Kansas, for coalbed methane well valuation.

TABLE B

All Other Kansas (AOK) Gas Fields

15% Discount Rate; Five Year Economic Life; 17% Tax Credit

Prescribed Present Worth Factor

% DECLINE / PWF	% DECLINE / PWF	% DECLINE / PWF	% DECLINE / PWF	% DECLINE / PWF
0% = 2.984				
1% = 2.903	11% = 2.201	21% = 1.654	31% = 1.231	41% = 0.904
2% = 2.825	12% = 2.140	22% = 1.607	32% = 1.195	42% = 0.876
3% = 2.749	13% = 2.080	23% = 1.561	33% = 1.159	43% = 0.849
4% = 2.674	14% = 2.022	24% = 1.516	34% = 1.124	44% = 0.822
5% = 2.601	15% = 1.966	25% = 1.472	35% = 1.090	45% = 0.795
6% = 2.530	16% = 1.910	26% = 1.429	36% = 1.057	46% = 0.770
7% = 2.461	17% = 1.857	27% = 1.388	37% = 1.025	47% = 0.745
8% = 2.394	18% = 1.804	28% = 1.347	38% = 0.994	48% = 0.721
9% = 2.328	19% = 1.759	29% = 1.307	39% = 0.963	49% = 0.697
10% = 2.264	20% = 1.703	30% = 1.269	40% = 0.933	50+ = 0.674

Prescribed Operator's Expense Allowance and Equipment Value

Expense Factor 3.595

Expense Allowance and Equipment Value: $ / Ft Per Well					Equipment
Depth	**-1,500 feet**	**1,500 ft to 3,500 ft**	**3,501 ft to 4,500 ft**	**+4,500 ft**	
Flowing	$6.20 per ft	$6.10 per ft	$5.75 per ft	$5.20 per-ft	$0.85 per ft
Pumping	$11.20 per ft	$10.80 per ft	$9.85 per ft	$8.90 per ft	$1.25 per ft
Disposal	-	-	-	-	$0.10 per ft

Prescribed Water Credit Adjustment

Water Credit Table			
Bbls / Water / Day	**% Adjustment**	**Gas Well Factor***	**Combination****
0.00 to 4.99	0%	1.00	1.00
5.00 to 9.99	10%	0.90	0.95
10.00 to 14.99	15%	0.85	0.90
15.00 to 19.99	20%	0.80	0.85
20.00 +	25%	0.75	0.80

Note:** ***Make adjustment on Line 2, Section VI: Working Interest Value: $ X decimal interest X gas well factor. The appraiser should consider actual water expenses rather than using factor if amounts greatly exceed 20 Bbls/day. An example may be 100 + Bbls/day. Coalbed methane wells typically produce large amounts of water during the initial production phase and may require consideration of actual water expenses. Actual expenses should be deducted on Line 4b, Section VI. Supporting documentation should be provided for actual expenses.

****Note:** There are certain fields throughout the state of Kansas that produce a combination of crude oil and natural gas from the same well bore. In cases where the well is producing in excess of 5.00 BOPD, the combination oil and gas well factor is applicable.

GAS ASSESSMENT RENDITION

SHALL BE FILED WITH COUNTY APPRAISER BY APRIL 1

Schedule 2 (Class 2B) (Rev.11/03)

_______ COUNTY, KANSAS

STATEMENT OF ____________________ OPERATOR I.D. NO. ________

P.O. ADDRESS ____________ CITY ____________ STATE ____ ZIP ________

NAME OF PROPERTY ____________ Property ID: Company ID: ________ County ID: ________ 1st Well API #: ________

SECTION I - LOCATION OF PROPERTY ASSESSED	SECTION VII - ABSTRACT VALUE (FOR APPRAISER'S USE ONLY)				
DESCR		Appraised Value	Assessed	Penalty	TOTAL
	Total Working Interest (Sec. VI, Line 8)				
	Royalty Interest (Sec. VI, Line 1)			XXXXXXXXXX	
Lot Sec Adn. Twp Blk Rng	Itemized Equipment (Sec. VI, Line 9)				
Twp. City	Total				
Tax Unit: School Dist:					

SECTION II - WELL AND LEASE DATA			
Wells: Pump Flow S.I. S.W.D.	Bbls Water	Field	Yr. Life Depth
Gatherer (1st Purchaser), Address, Phone Nbr.:			
Market Price (Producer) Jan 1 $/MCF:		Net Price Jan. 1 $/MCF:	
$/MCF Jan 1 to Royalty Owner:	BTU Content:	SPUD Date: Mo. Yr.	
NGPA Category:		Contract Expiration Date:	
Sales Interstate:	Intrastate:	( ) Vacuum Operation	( ) Coalbed Methane Well

SECTION IV- PRODUCTION DATA			
Gas Well Production Data		Condensate - Bbls	Gas - MCF
1999	Annual Production		
2000	Annual Production		
2001	Annual Production		
2002	Annual Production		
2003	Annual Production		
Total Production			
Average Annual Production			
Condensate (Converted to MCF)			
Total Annual / Average Production - MCF			

( ) Infill Unit: Orig. Well: API #:

Infill Well: API #:

Notation

Condensate Production Data

______	X	______	=	______	/	______	=	______
Avg. Prod Bbls		Net Price Per Bbl		Income		Price Per Mcf		Total MCF To Sec. IV

SECTION V- VALUATION OF THE TOTAL 8/8TH INTEREST	A. Schedule	B. Owner	C. Appraiser
1. Annual / Average Production - Mcf			
2. Net Price/Mcf:			
3. Estimated Gross Income Stream			
4. Present Worth Factor			
5. Estimated Gross Reserve Value (Transfer TOTAL to section VI, lines 1 & 2)			

SECTION VI- GROSS RESERVE VALUE X DECIMAL INTEREST	A. Schedule	B. Owner	C. Appraiser
1. Royalty Interest Valuation: X			
2. Working Interest Valuation: X X (Table B Water Credit Adj)			
3. Deduct Operating Cost Allowance: Per Well X Wells			
4a. Deduct Wellhead Compression Expense: X			
4b. Deduct Water Expense Allowance (Table A wells;Table B wells if actual): X			
5. SUBTOTAL (Line 2 minus Lines 3 & 4a, 4b)			
6. Minimum Lease Value (Line 2, Col. A) X 0.10			
7. Line 5 or Line 6 (Whichever is Greater)			
8. Add Equipment Value			
A. Producing Per Well X Wells			
B. Non-Producing Per Well X Wells			
9. Add Itemized Equipment (Section III - Attach Schedule)			
10. TOTAL Working Interest Market Value (Add Lines 7 thru 9):			
11. Working Interest Assessed Value (% of line 10) X			

* Attach Name, Address, And Interest of Royalty Owners

CERTIFICATION: I do hereby certify that this schedule contains a full and true list of all personal property owned or held by me subject to personal property taxation under the laws of the state of Kansas pursuant to K.S.A. 79-329 through 79-333

OWNER	DATE	TAX RENDITION PREPARER	DATE

Lease Code ____________ County Code ____ Lease Name ____________

PRESCRIBED BY KANSAS DEPARTMENT OF REVENUE, DIVISION OF PROPERTY VALUATION

Year 2004
OIL and GAS
ITEMIZED EQUIPMENT VALUES
Partial list of prevalent items, not intended to be inclusive.

***ROTARY DRILLING RIGS**	**USED**	**STACKED**	**SALVAGE**	**SCRAP**
Depth to: 1,000 feet	$12,000	$ 5,400	$ 3,000	$1,000
1,001 ft -2,000 feet	$20,000	$ 9,000	$ 4,500	$1,250
2,001 ft -3,500 feet	$28,000	$15,000	$ 7,500	$1,500
3,501 ft-5,900 feet	$40,000	$20,000	$10,000	$1,750
6,000 ft-with sub	$60,000 +	$25,000	$12,500	$2,000

** If the estimated rig value does not reflect market valuation in the opinion of the appraiser, the appraiser has the authority to deviate from the above values and adjust the valuation to market value for just cause and proper documentation.*

Note:
1.) Used column includes drill pipe and drill collars.
2.) Rigs stacked three months or more prior to January 1, of current tax year.
3.) 3,501 - 5,900 feet includes National T-32's, T-20's, United U-34, U-34B, DW 450-T, Bethlehem 250, S-50, Cardwell S-350, and Oilwell 52T.

DRILL PIPE	**NEW**	**USED**	**SALVAGE**	**SCRAP**
2 and 3/8" o.d. per ft	$2.50	$1.50	$0.25	
2 and 7/8"	$3.50	$1.70	$0.30	
3 and 1/2"	$5.50	$2.10	$0.40	
4 and 1/2"	$8.00	$2.95	$0.80	
5"	$10.00	$4.50	$1.00	

DRILL COLLARS				
6 and 1/4"	$800	$440	$100	

SERVICE UNITS	**NEW**	**USED**	**SALVAGE**	**SCRAP**
Under 1,500 ft capacity	$25,000	$3,500	$1,000	$500
(Sgl or dbl drum without truck*)*				
Over 1,500 ft capacity	$50,000	$6,000	$2,000	$750
(Sgl drum unit *without truck)*				
Dbl Drum Unit *without truck*				
1,000 ft to 3,500 ft	$50,000	$7,000	$2,500	$750
3,501 ft +	$80,000	$11,000	$4,000	$1,000

MUD PUMPS Drilling	Duplex: National or equivalent, excluding engine, drive section included			
	NEW	USED	SALVAGE	SCRAP
K-380	$50,000	$15,000	$3,200	$500
K-500	$50,000	$16,000	$3,200	$500
Triplex	$50,000	$17,500	$3,200	$500
7P-50	$60,000	$18,000	$7,500	$500

WATER INJECTION PUMPS	National or equivalent; excluding engine and pump.			
	NEW	USED	SALVAGE	SCRAP
PR-10 "Wheatley"	$600	$250	$100	
J-30	$3,250	$1,500	$250	
J-60	$5,250	$1,800	$400	
J-100	$9,000	$3,000	$750	

POWER TONGS	NEW	USED	SALVAGE	SCRAP
Tubing	$7,000	$1,200	$600	
TORQUE CONVERTERS	National or equivalent			
C-195	$10,000	$4,500	$1,250	
DIESEL ENGINES				
GM - 671 (Twin)	$11,400	$5,100	$1,700	
Cat - 3406	$16,560	$4,900	$1,600	
Cat - 3408	$25,670	$5,400	$2,100	
STEEL CABLE o.d. per ft				
7/16"	$1.50	none	none	
9/16"	$1.85			
3/4"	$2.70			
7/8"	$3.45			
1.0"	$4.30			
1&1/8"	$4.50			
1&1/4"	$4.75			
STEEL CASING - API SPECS: O.D. / ft				
4"	$3.85	$2.75 (9.5#)	$1.65	
		$2.90 (10.5#)	$0.55	
5"	$5.25	$2.25	$0.75	
6"	$6.60	$3.75	$1.00	
8"	$8.60	$6.00 (20#)	$3.70	
		$6.50 (23#)	$1.20	
9&5/8"	$9.20	$7.50	$2.50	
10"	$14.16	$6.00	$2.00	

TUBING: "/o.d. per ft				
1.05"	$0.60	$0.25	$0.10	
1.61"	$0.95	$0.40	$0.15	
1.90"	$1.20	$0.55	$0.20	
2&3/8"	$2.00	$0.85	$0.30	
2&7/8"	$2.65	$1.15	$0.40	
3&1/2"	$3.20	$1.40	$0.45	

LINE PIPING Nominal Sizes C.W. Grade 1-25; per ft	**NEW**	**USED**	**SALVAGE**	**SCRAP**
1.00"	$0.60	$0.25	$0.10	
1.25"	0.80	0.35	0.15	
1.50"	1.00	0.40	0.20	
2.00"	1.30	0.55	0.25	
2.50"	2.00	0.85	0.30	
3.50"	3.20	1.35	0.45	
4.00"	3.80	1.60	0.55	
6.00"	6.50	2.80	0.95	
8.00"	10.00	4.30	1.40	
PUMPING JACKS				
D-2	$600	$240	$100	
D-3	600	240	100	
D-4	850	240	100	
D-6	900	360	100	
D-10	950	380	100	
D-25	1,500	875	200	
D-57	4,800	1,500	600	
D-80	8,000	2,250	850	
D-114	10,600	4,500	1,200	
D-160	11,900	6500	1,200	
D-228	15,300	9,250	1,200	
D-320	21,250	10,750	1,200	
D-330	23,350	12,000	1,200	
D-456	30,400	15,000	4,000	
D-640	36,800	17,500	4,000	
D-912	42,400	20,000	4,000	
ELECTRIC MOTORS				
To 5hp	$170	$50		
6 to 19 hp	425	300		
20 & over	680	350		
PUMP ENGINES				
Continental Engines				
C-46	$7,800	$1,500	$450	
C-66	10,200	$2,400	$500	
C-96	13,700	$4,750	$650	

F & M ENGINES	**NEW**	**RE-BUILT**		
118	$3,650	$550		
208	4,250	900		
346	6,300	1,750		
503	8,500	2,500		
739	10,500	3,150		
REDA-GOULD SUBMERSIBLE PUMPS	**NEW**		**SALVAGE**	
1 to 10 hp per hp	$210		None	
11 to 40 hp per hp	175		None	
41 & up per hp	150		None	

OIL WELL TUBING PUMPS	**NEW**	**USED**	**SALVAGE**	
4-5'	$1,250	$450	None	
6'	$1,800	$650		
8'	$2,500	$1,000		
10'	$3,000	$1,100		
12'	$3,400	$1,200		
SUCKER RODS o.d. per ft				
5/8"	$0.80	$0.35	$0.10	
3/4"	0.90	0.40	0.15	
7/8"	1.00	0.45	0.20	
1.0"	1.50	0.60	0.25	
HORIZONTAL HEATERS				
30" X 7.5 ft	$2,750	$900	$240	
30" x 10 ft	$3,000	1,000	290	
48" x 10 ft	$3,600	1,200	350	
EMULSION HEATERS				
30 lb pressure				
4' x 15 ft	$4,500	$1,125	$450	
4' x 21 ft	$5,700	$1,425	$570	
6' x 21 ft	$6,500	$1,625	$650	
8' x 21 ft	$7,500	$1,875	$750	
10' x 21 ft	$8,750	$2,200	$800	
OIL SEPARATORS				
24" x 5' 125 psi	$1,750	$600	$160	
30" x 10' 125 psi	$2,450	$850	$230	
36" x 10' 125 psi	$2,850	$1,000	$280	
48" x 12' 125 psi	$3,250	$1,150	$320	
24" x 12' 500 psi	$3,450	$1,250	$350	
12" x 10' 1000 psi	$3,900	$1,500	$390	
4" x 10' knockout	$4,500	$1,650	$400	
5" x 12' knockout	$4,750	$1,800	$450	

TANKS	**STEEL**		**FIBERGLASS**	
	NEW	USED	NEW	USED
200 bbl (salt water)	$1,900	$500	$2,200	$500
200 bbl (stock)	$1,600	$500	$2,500	$500
210 (gun barrel)	$2,100	$750	$3,500	$750

TRANSFORMER 2300/110-220 Installed price = 1.7 x transformer price.	**NEW**	**USED**	**SALVAGE**	
KVA Size				
1.5	$100	$50	$10	
2.0	$100	$60	$15	
2.5	$125	$70	$15	
3.0	$150	$100	$20	
4.0	$200	$125	$25	
5.0	$250	$140	$30	
7.5	$295	$175	$35	
10.0	$360	$225	$45	
15.0	$450	$275	$50	
20.0	$525	$350	$60	
25.0	$575	$400	$75	
30.0	$650	$475	$85	
37.5	$700	$500	$95	
40.0	$840	$550	$100	
50.0	$900	$600	$110	
75.0	$1,000	$900	$125	
100	$1,250	$1,000	$160	
167	$1,900	$1,500	$250	
POWER SERVICE LINES (Including poles and wires)				
Two wire $/per ft	$2.00			
Three wire - $ per ft	$2.35			
LIGHT PLANTS GASOLINE POWERED				
1.00 – 1.50 KW	$2,640	$1,200	$240	
1.5 - 3.00 KW	$2,640	$1,200	$240	
+3.0 - 7.5 KW	$3,000	$1,400	$280	
+7.5 KW	$3,850	$1,750	$350	