Approved 2-26-85
Date

MINUTES OF THE SENATE COMMITTEE ON ENERGY & NATURAL RESOURCES.

The meeting was called to order by SENATOR MERRILL WERTS at
Chairperson

8:00 a.m./~~p.m.~~ on FEBRUARY 21, 1985 in room 123-S of the Capitol.

All members were present except:

Committee staff present:
Ramon Powers - Research Department
Don Hayward - Revisor's Office
Nancy Jones - Committee Secretary

Conferees appearing before the committee:
George Sims - Mobil Oil Corporation
Vic Miller - Director, Property Valuation Division

SB 193 - Concerning oil and gas

Senator Martin presented additional testimony on SB 193 with special attention being given to the 1985 Kansas Appraisal Guide from the Kansas Department of Revenue (Attachment A) which provides an income approach to determining fair market value. Another method for determining value might be comparable sales which could be used to verify accuracy of the appraisal guide approach. This bill is needed to assure that oil and gas industry assessed valuations are at 30% of market value.

In response to a question by Senator Thiessen, Senator Martin said in some other states information on sale prices of oil and gas leases is public knowledge so the problem faced in Kansas does not exist. Where several types of property are involved in a lease sale, county appraisers and field people analyze the transaction in order to allocate value among the different types of property. There is no estimate as to the cost of such analysis.

George Sims briefly summarized a written statement in which he opposes SB 193. This bill would result in difficulty of compliance due to the volume of certificates to be filed. It would cause a heavy burden on purchasers of producing properties (ATTAchment B). He further stated that valuations would be so variable, due to oil price fluctuations, that a certificate of value system would reflect value accurately only at the time the certificate was filed.

Vic Miller spoke as a proponent for the bill stating that the oil and gas guide is not sufficiently accurate for valuation purposes although its use should continue as a valuation tool. SB 193 could provide additional valuable information.

A motion to recommend SB 193 favorably was made by Senator Feleciano and seconded by Senator Martin. The motion failed on a voice vote.

A motion to report SB 193 adversely was made by Senator Yost and seconded by Senator Langworthy. The motion carried on a show of hands (6-4).

A motion to report SB 41 favorably was made by Senator Hayden and seconded by Senator Vidricksen. Discussion followed during which Senator Hayden stated the severance tax does not apply to municipally owned production. He further stated that a precedent would not be set for exemption requests from other cities as the bill is structured to apply only to second class cities which use the well's total production only for the city's needs. There are no other cities which fall into this category.

Senator Feleciano expressed the view that this bill would set a bad precedent in that it undermines the power vested in the KCC. He questioned the wisdom of such a policy being set. Senator Kerr inquired as to the logic for confining the application of this bill to one city. Senator Hayden again stated that Hugoton is the only city of which he is aware that has this particular situation.

The motion to report SB 41 favorably carried on a voice vote.

The meeting adjourned at 9:00 a.m. The next meeting is February 26, 1985.

2-21-85

Guest List

Chip Wheelen	Topeka	Legis. Policy Group
Walter Dunn	" ✓	" EKOGA "
George A. Harris	Hugoton	Mobil
Vic Miller		
Don Schnacke		KIOGA

2-21-85

1985

KANSAS APPRAISAL GUIDE

KANSAS DEPARTMENT OF REVENUE

DIVISION OF PROPERTY VALUATION

OIL & GAS

APPRAISAL GUIDE

PV-PP-18
(Rev. 12/84)

S. E&NR 2/21/85
Attachment A

FOREWORD

1. The Constitution of the State of Kansas requires the legislature to provide for a uniform and equal rate of assessment and taxation, etc... The legislature has created the office of county appraiser, designated the Board of County Commissioners to sit as a County Board of Equalization; created a Division of Property Valuation and a State Board of Equalization. To each of these the legislature has delegated certain duties and responsibilities relative to the appraisal, assessment, and equalization of property for ad valorem tax purposes.

2. The legislature has determined that oil and gas property shall be assessed and taxed as personal property. It has determined that personal property is to be appraised at its fair market value in money where the same may be held, and assessed at 30% thereof. (K.S.A. 79-329, K.S.A. 79-501 and K.S.A. 79-1439.)

3. Working interest fair market value refers to one portion of the present worth of recoverable oil and gas over a reasonable length of time deducting only lease operating expenses and adding to the resultant value the present worth value of all lease equipment.

4. Royalty interest fair market value shall be the other portion of the present worth of recoverable oil and gas reserves over a reasonable length of time not including lease expenses or equipment.

5. The legislature has required the Director of the Division of Property Valuation to devise, prescribe, and furnish personal property guides and also has required the local appraisers, when applicable, to conform to the values as shown in the personal property assessment guides prescribed and furnished by the director. This personal property guide is issued in accordance with the provisions of K.S.A. 75-5105a.

6. The oil and gas guide devised by the Director of the Division of Property Valuation when applied, may in certain instances produce either an underassessment or an overassessment of the particular property involved yet statutory law requires the local appraiser to conform to the state guide. On the other hand, constitutional law requires equality, therefore, statutes should be construed so as to uphold their constitutionality.

7. The oil and gas guide prescribed by the Division of Property Valuation must be used by the local appraisers particularly in respect to the appraisal principles and theories involved. Further, if the valuation produced by use of this guide is in error (in the judgment of the appraiser) then the appraiser has the duty to adjust said valuation either up or down. Any change made in the appraisal must be supported by proper documentation at the time the appraiser makes the change and a copy of the changes must be furnished to the taxpayer at this time.

8. It must be kept in mind that the guide is compiled with averages of high and low operating costs. Wells with low operating costs will benefit from the published values; wells with high operating costs may be penalized. Care must be exercised when deviating from the published values.

9. All oil and gas rendition forms are to be computed on them the valuation as determined by application of the state prescribed oil and gas guide without any deviations or adjustments. Said computations and values to be in the sections and column on the rendition form entitled "SCHEDULE".

10. K.S.A. 79-312 states that it shall be the duty of the appraiser and he is empowered and authorized to increase or diminish the value of any or all items of personal property as listed by any person, company or corporation, if he is satisfied that said property has been returned below or above its true value in money; but said change in value shall be made at the time the return is made to the appraiser.

11. The County Appraiser must adjust either up or down the valuation produced by applying the state guide if in his judgment such an adjustment is necessary in order for him to comply with the constitutional law of equality and the statutory requirement of assessing said property at thirty per cent of its fair market value in money. If an adjustment is made by the County Appraiser, then the appraiser is to use the column entitled "Appraiser" on the rendition form. He is to notify the taxpayer of the adjusted valuation in time for the taxpayer to appeal to the County Board of Equalization. If a taxpayer appeals to the County Board of Equalization, the appraiser, at the time of the hearing before the board, is to furnish to the taxpayer in writing the reasons for his adjustment to the valuation produced by application of the state guide. At the same time a copy of the information is furnished to the taxpayer, a copy of said information and a copy of the rendition form are to be mailed to the Division of Property Valuation by the appraiser.

12. The taxpayer may request consideration for an adjustment to the valuation produced by the application of the state guide. All such requests are to be fully supported and explained in writing. The taxpayer is to use the lines and column entitled "Owner" after supporting and explaining in writing his reasons for the adjustment. A copy of the rendition form and the information supporting the request shall be filed by the taxpayer with the Division of Property Valuation when said information is filed with the County.

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FEBRUARY

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DECEMBER

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OIL SECTION

OIL WELL DEFINITION:

For ad valorem tax purposes, an oil well is defined as a well producing or capable of producing at a gas oil ratio less than 15,000 CF per barrel of oil.

I. PRODUCTION

For the current tax year appraisal, the prior twelve months' production is used. (Sales may be substituted for production.) Production for the prior year is a fact. It is a number, however, that may not reflect the true production capability of the lease; this will in turn distort the true decline rate (See Section II following).

The prior year production may not represent the productive capability of the lease for a number of reasons:

(a) Well shut-down for work-over.
(b) Pumping unit problems resulting in less production.
(c) Transportation problems.
(d) Reserve depletion resulting in dry hole, abandonment of lease, hence, no value remaining or taxable for the current tax year.
(e) Lease production began during the year and 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 minimal level.
(g) Increase or decrease in the number of producing wells.

For these reasons and others, it is necessary to adjust the production number to reflect a realistic lease productive capability that an efficient operator maximizing the potential the lease could expect to produce.

1. (a) Well shut-down,
   (b) Pumping unit problems,
   (c) Transportation problems resulting in production slowdown.

   In these cases, mechanical rather than natural forces are affecting the production capabilities of the property. A representative 12 month production must be calculated.

   Example:

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 Bbls.

   In this case a well work-over resulted in a 60 day shut-down for May and June. In December no sales were reported due to a holdover for the following tax year. Hence, add in for these three months of production by annualizing the nine months, e.g.,

$$\frac{2{,}422 \text{ bbls.}}{273 \text{ days}} = 8.87 \text{ bbl./day} \times 365 \text{ days} = 3{,}238 \text{ bbls.}$$

   Use 3,238 bbls. for the current year lease production capability.

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 abandoned equipment.

3. New leases

   (a) For leases which have produced less than 12 months during the prior year, the computation in arriving at the annualized production is to be made by dividing the production for the period of the prior year that the lease did produce by the number of days it produced, then multiplying that figure by 365.

   Example:

	Days	Bbls.	Days	Bbls.	Days	Bbls.
(a)	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)	5935

   (b) $\frac{5935 \text{ bbls}}{245 \text{ days}} = 24.22$ bbl./day

   (c) Annualized Production = 24.22 Bbl./day
   x 365 days
   8,840 Bbls.

   (b) For leases that began production July 1 or later K.S.A. 79-331 (b) & (c) provide for the following:

   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, it 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."

Example:

Aug. (31)	189	Nov. (30)	192
Sept. (30)	212	Dec. (31)	181
Oct. (31)	174	Totals (153)	948 bbls.

(1) Annualized Production = $\frac{948 \text{ bbls.}}{153 \text{ days}}$ x 365 days = 2,263 bbls.

(2) 2,263 bbls. x .60 = 1,358 bbls.
(3) Net Price (RI & WI) x $23
$31,234
(4) Present Worth Factor x 2.203
(assume 20% decline)
(5) Estimated Gross Reserve Value = $68,809
(6) RI = $68,809 x .125 = = $ 8,601
WI = $68,809 x .875 = $60,208
Expenses 1 well @ $27,424 x .60 = −16,454
Sub-total $43,754
Add equip. value + 8,115
Working Interest = $51,869

4. Increase or decrease in producing wells

(a) There are occasionally new wells drilled on existing leases. In these cases a computation should be made to calculate the production per well:

Example:

Month	No. Wells	Production	Bbls./Well
January	3	750	250
February	3	740	247
March	3	760	253
April	4	1270	318
May	4	1120	280
June	4	1080	270
July	4	1050	263
August	4	1070	267
September	5	1770	354
October	6	2380	397
November	6	2140	357
December	6	2000	333

In the above instance, the older wells were making about 250/month and the total lease for the last quarter shows about 360 bbls./well/month. The decline has accelerated, as is shown, to 16% between October and December. Secure January and February to verify.

6 wells x 333 bbls./well x 12 mos. x price x proper PWF Factor.

(b) There are occasionally some wells plugged on a multiple well lease. In these cases a proper period should be annualized.

Example:

Month	No. Wells	Prod.	Month	No. Wells	Prod.
January	10	1,000	July	6	750
February	10	1,000	August	6	700
March	9	950	September	6	700
April	9	930	October	4	550
May	8	900	November	4	550
June	8	900	December	4	550

Note the actual total for the year is 9,480 and the average number of wells is 7 yet the ending two months indicate an annual average of 6,600 out of 4 wells. This 6,600 and 4 wells is the proper approach.

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 it's potential will theoretically begin to decline immediately. When a lease is new and just beginning 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.

The decline curve will reflect changes in operating policy, well workovers, marketing conditions and other factors which are not a part of the natural decline. A lease could be declining at a constant rate, then a "fracturing job" is completed and production increases. The appraiser must then consider whether this production rate will continue, decrease, or stabilize; and whether the former decline rate is still applicable.

No rules can be established to cover every facet. Decisions based on logical judgement and factual situations with similar leases in the general locale must prevail.

The following guidelines are recommended:

1. New Leases

   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 20% annual decline rate and evaluate the property on this basis. This, however, is not automatic and is to be used only when other data is inconclusive. Use of a proven neighborhood decline rate is considered appropriate after proper consideration for flush production.

2. Abnormal Decline

   Abnormal sharp decline is usually found with initial production from newly completed wells on new leases or added wells on existing leases.

   A lease with initial "flush" production will show an abnormal sharp decline followed by a change in the decline rate to a 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.

   When adjustment is requested by the operator for obvious abnormal sharp decline, it should be supported by data not only for the prior year demonstrating this decline, but production for the year of assessment. A misapplication of the decline factor could result in extreme under or over-appraisal of the lease.

   If the appraiser needs assistance in estimating the decline rate, refer the lease rendition to the Property Valuation Division.

3. Existing Leases

   Historically, Kansas production has declined on an average basis at 8%. The Primary Production Table II has a built in 8% decline for this reason, i.e., wells or leases having primary production (Table II, 2001 ft. and greater) and declining less than 8%, receive an automatic 8% rate of decline and a PWF of 3.378.

   To estimate the decline rate on an existing lease having stable production from year to year, the current year decline is figured by using the prior two production years. For the 1984 tax year, use 1983 and 1982. as follows:

$$\% \text{ Decline} = \frac{1983 \text{ Production} - 1984 \text{ Production}}{1983 \text{ Production}}$$

$$\text{Ex.} \quad \frac{1408 \text{ Bbls.} - 1234 \text{ Bbls.}}{1408 \text{ Bbls.}} = 12\%$$

   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 workover periods or lease shut-downs or other non-producing periods effecting the lease producing capability.

III. CASINGHEAD GAS

For wells producing casinghead gas, the revenue derived from the previous year's total gas production MCF is to be converted to barrels 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 for oil.

EXAMPLE

Assume that 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. Further assume that net price for oil is $23.00 per barrel. The revenue from the casinghead gas of $9,275 would be divided by $23.00 to establish the equivalent in barrels: $9,275/$23 = 403 bbls. to be added to the annual production in Sec. IV — Item 2, Casinghead Gas (Converted to bbls).

Note: This additional production is not to be considered in determining the annual decline.

IV. SECONDARY RECOVERY

1. To qualify as a secondary recovery operation, the lease or leases 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 are classified as secondary recovery operations are to continue using the decline factors under "Shallow and Secondary", Table I, page 8, 11% decline and 2.528 PWF for 2000 ft. and less; 8% decline and 2.748 PWF for 2001 ft. and deeper, until such time as the decline exceeds these rates.

3. When the secondary production starts on its decline in excess of 8% or 11% then start using the "Decline Factors" opposite the appropriate "Percentage Rate of Decline" for "Declining Production" from the Shallow and Secondary Present Worth Factor Table.

V. NET PRICE

The net price to be rendered is that price which is actually paid to the producer January 1 of the assessment year less state and federal wellhead taxes levied on value and/or volumes of oil produced, and less applicable transportation charges. The transportation charges applicable are limited to those charges incurred to a transporter wherein the oil producer neither gains nor retains any interest in the transportation facility itself.

VI. PRESENT WORTH FACTOR

The present worth factor (PWF) is dependent on the discount rate and the duration of income. The value of money (income) varies with the time necessary for its return, the cost of using it, its current and future purchasing power, and its availability. Money to be received in the future is not worth as much as money to be received today.

Eight years of income are discounted for Table II. Five years of income are discounted for Table I.

The PWF incorporates into the manual the life and performance characteristics based on the percentage rate of decline which 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 made 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 leases which have produced 15 or 20 years where the production has not varied more than a few percentage points. In these cases, the appraiser may use a higher factor not to exceed 4.538 (Table II) for depths greater than 2001 ft. if, in his judgment, it is 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 some factor such as a new zone, new well, or re-equipping, but the production must reflect a non-decline trend that is expected to continue.

EXAMPLE:

Year	Production Case A	Production 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 rare type where use of the 4.538 factor is permitted. The fifth year production for Case B is level with year 1, but indicates some factor such as re-equipping, new zone, etc., has affected the production and the year 5 production is only a new starting point for the previous decline experience. The 4.538 factor is not to be used in this case.

VII. ESTIMATED GROSS RESERVE VALUE

The "Gross Reserve Calculations", Section V, will be 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.

*The price for royalty and working interest may vary. Therefore, separate calculation for the royalty interest may be required. Property with joint interest (major and independent) shall follow operator's status under the windfall profit tax.

SECTION V – GROSS RESERVE CALCULATIONS

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

VIII. ROYALTY INTEREST

The "Royalty Interest", Section VI, line 1, will be 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 overriding royalties. Division Order Must Be Provided To County Appraiser By The Operator.

SECTION VI

	Gross Reserve Value X Decimal Interest	a. Schedule	b. Owner	c. Appraiser
1. Royalty Interest Valuation:	X			

IX. WORKING INTEREST

The "Working Interest" will be computed by applying the appropriate decimal working interest to the Section V, Item 5, completing line 2. Subtracting the appropriate operator's cost allowance (Lines 3a, b, c) from line 2 results in the subtotal, line 4. The minimum leasehold appraisal, line 5, is an assumption that there is a value as long as the lease is producing. This value can be potentially great and should be ~~no~~ less than 10% of the gross total working interest. There could be cases where the value is less and the appraiser should examine each case carefully. The figure on line 6, is therefore, the greater of the two figures appearing on line 4 or line 5. To line 6 is added the appropriate equipment values, lines 7a, b, c, to produce a new subtotal, line 8. Line 8 is then multiplied by the low production credit factor found in the table entitled "Low Production Credit Factor" applicable to the rendition under consideration. For new leases KSA 79-331 b provides for a 40% deduction of income & expenses for the WI. See Sec. I preceding.

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 Operating Cost Allowances				
a. Producing Well: $ per well X wells				
b. Injection Well: $ per well X wells				
c. Submersible: $ per well X wells				
4. Sub-total (Line 2 minus lines 3a, b, c)				
5. Minimum Lease Value 0.100 X (Line 2, Col. a)				
6. Line 4 or 5 (Whichever is greater)				
7. Add Prescribed Equipment Value				
a. Producing Well $ per well X wells				
b. T.A.–S.I., SWD, Injection Well $ per well X wells				
c. Submersible $ per well X wells				
8. Sub-total (Line 6 plus lines 7a, b, c)				
9. Low Production Credit Factor: Bbls. Per Day ______				
10. Working Interest Valuation				
11. Itemized Equipment (Section III)				
12. Total Working Interest Market Value				
13. Working Interest Assessed Value (30% of Line 12)				

Property Tax Expense Is Included In Present Worth Factor For 1985

X. OPERATING COST ALLOWANCE

The operating cost allowance is based on the actual experience of the various producing areas of the State and normally provides a sufficient average per well amount by depths for operating the properties.

a. For primary production wells: 2000 ft & less shallow: Use Table I, Page 8
2001 ft & deeper: Use Table, II, Page 9
at the appropriate producing depth and % water cut.

b. For shallow production and secondary recovery use Table I entitled "Prescribed Operator's Cost Allowance Per Well" under the subclass "Shallow Production and All Secondary Recovery" at the appropriate producing depth and % water, page 8.

c. For injection wells (secondary production) use the value per injection well shown in Table I entitled "Prescribed Operator's Cost Allowance Per Well" Subclass title "Injection" at the appropriate depth.

d. High Volume Centrifugal Pump Wells

It is recognized that wells equipped with high volume centrifugal pumps are much more expensive to operate than wells equipped with standard pumping equipment. Said centrifugal pumps are commonly referred to as submersible or Reda pumps or comparable. A cost allowance has been incorporated into the "Prescribed Operator's Cost Allowance Per Well" table for wells so equipped. However, special treatment is recommended when requested and properly documented.

e. Excessive Cost Allowance

The costs shown on pages 8 and 9 are direct costs for specified depths, including workover costs, discounted over a five year period for Table I and eight years for Table II.

The appraiser will likely encounter costs both above and below the median. In this case it is imperative that the appraiser analyze and document costs of comparable properties to determine what costs will be encountered during the 5 or 8 year producing period. In order for the appraiser to make a proper market value determination, any change in operating costs shown in the guide shall be fully documented.

However, where the results of the appraiser's analysis indicate that the operator's costs are consistently higher or lower than the median costs shown in the guide, these costs shall be properly considered and should be utilized.

If such excess costs are not at least 20% greater than the expenses allowed by the guide, no adjustment for excessive costs will be made.

Direct Costs That Should Be Considered

Labor (including employee benefits)
Utilities: power, water, fuel
Rental equipment used to correct recurring problems
Dehydration and waste water disposal
Corrosion control or other chemical treatment
Pulling jobs, bailing, parted rods, paraffin scraping, etc., recurring casing leaks or sanding
Transportation
Insurance
Overhead through district foreman's level.
Workover costs divided by the workover period, e.g., eight year average workover period, divide by 8 year.

Other Costs That Shall Not Be Considered

New well drilling, whether capitalized or expenses
New or replaced equipment
Recompletion costs into a different producing zone
Property taxes
Depreciation
Depletion
Amortization
General office overhead above district level

The determined one year's costs shall be multiplied by 4.678 to develop an eight year discounted operating cost.

The determined one year's costs shall be multiplied by 3.527 to develop a five year discounted operating cost for secondary/shallow operations.

Remember: Costs are a drain on net income and should be given proper consideration. Any prospective purchaser will pay less for a high recurring cost operation, conversely, the same purchaser will pay more for a low cost operation. However, the appraiser must be careful when analyzing costs.

f. The number of wells to be used for computing the operating cost allowance are the number of wells in existence as of January 1. In determining the number of producing wells for the well count, a comingled 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 (1 oil and 1 gas). SWD, TA, and SI wells are not to be considered.

XI. EQUIPMENT VALUE

The prescribed equipment values incorporated into the manual for specified depths are for actual in use oil well producing equipment (surface and subsurface), such as casing, tubing, rods, pumps, units, engines, tanks, separators, heater-treaters, heaters and/or gunbarrels and lease lines.

a. For the equipment value for the producing wells, use the table entitled "Prescribed Equipment Value" at the appropriate producing depth and under the appropriate column of % water or "Centrifugal Equipment (Table I — Shallow Production & All Secondary Recovery or Table II — Primary Production).

b. A temporarily abandoned well is defined as a well that has had production ceased for at least 90 days prior to January 1 and the status has been reported to the Kansas Corporation Commission with proof of notification available on request. Use table entitled "Prescribed Equipment Value" subclass "TA-SI-SWD Injection Wells" for casing equipment. Surface equipment and tubing added separately.

c. The number of wells to be used for computing the equipment value are the number of wells in existence as of January 1. In determining the number of producing wells for the well count, a comingled 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).

d. Separately Itemized Oil Equipment

Surface and subsurface equipment stored either on the lease or in a storage area is to be itemized in Section III or by attached itemized list, totaled, and the results transferred to Section VI, line 11. Such equipment is to be assessed in accordance with the equipment values from the table entitled "Oil and Gas Itemized Equipment Value Section".

Surface and subsurface equipment which has been pulled for repair and/or maintenance to the well is not to be itemized.

Note: When a temporarily abandoned and/or shut-in well is located with producing wells, the tank battery equipment is included with the producing well equipment and should not be separately itemized.

Note: The presence of cemented top to bottom and/or squeezed casing in a functioning well is a sufficient reason for deviating from the "Prescribed Equipment Value" and the appraiser should consider reducing the value of such equipment by up to 10%.

XII. TERTIARY

There are some experimental projects in the state which are called Tertiary Recovery as differentiated from Primary and Secondary Recovery. These, at this time, are entirely experimental and at least one is subsidized. They require highly specialized oil recovery equipment which 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 these projects require special treatment.

XIII. LOW PRODUCTION CREDIT FACTOR (Pages 8 & 9)

This credit is to be allowed on leases which produce an average daily oil production (Lease average) per well as set out by depth. Average daily oil production shall be the total daily lease production as used for the appraisal divided by the number of wells[1.] on the lease as of January 1. The number of TA, SI and SWD wells are not to be considered in this calculation.

Note 1: To arrive at the number of wells:

Depth Range

0-2000 ft.: One credit for each producing well and one credit for each injection well. Use table on pg. 8.

2001 ft. and deeper: One credit for each producing well and one-half credit for each injection well.

For primary production: Maximum credit is three (3) Bbl/day per well.

For secondary production: credit allowed for up to 6.00 Bbl/day per well.
Use table on page 9.

TABLE 1

OIL WELLS 2,000 FT. AND LESS SHALLOW
ALL SECONDARY RECOVERY
PRESCRIBED PRESENT WORTH FACTOR TABLE
16% DISCOUNT RATE; 5 YR.; 3% PROPERTY TAX CREDIT

	Percentage Rate of Decline	Present Worth Factor	Secondary** Recovery 2,001 Ft. & Greater	Percentage Rate of Decline	Present Worth Factor
*2,000 Ft. and Less:	0	2.528*	2.748**		
Shallow Production and	1	2.528	2.748	26	1.646
Secondary Recovery Use	2	2.528	2.748	27	1.599
11% Decline (2.528)	3	2.528	2.748	28	1.552
**Secondary Recovery 2,001 Ft.	4	2.528	2.748	29	1.507
and Greater Use 8% (2.748)	5	2.528	2.748	30	1.463
	6	2.528	2.748	31	1.420
	7	2.528	2.748	32	1.378
	8	2.528	2.748	33	1.337
	9	2.528	2.673	34	1.297
	10	2.528	2.600	35	1.258
	11	2.528	2.528	36	1.220
	12	2.458	2.458	37	1.183
	13	2.390	2.390	38	1.147
	14	2.324	2.324	39	1.112
	15	2.259	2.259	40	1.078
	16	2.196	2.196	41	1.045
	17	2.135	2.135	42	1.012
	18	2.075	2.075	43	0.980
	19	2.016	2.016	44	0.950
	20	1.959	1.959	45	0.919
	21	1.904	1.904	46	0.890
	22	1.850	1.850	47	0.861
	23	1.797	1.797	48	0.833
	24	1.745	1.745	49	0.806
	25	1.695	1.695	50	0.780

PRESCRIBED OPERATORS COST ALLOWANCE PER WELL

Well Depth	SHALLOW PRODUCTION (0—2,000') & ALL SECONDARY RECOVERY: Under 90% Water	90 — 95% Water	Above 95% Water	Centrifugal (Reda)	Injection Wells
0 — 500'	5,695	7,025	8,352	19,800	7,025
501 — 1,000'	9,360	10,494	10,620	22,079	10,494
1,001 — 1,500'	10,978	10,950	15,184	27,598	10,950
1,501 — 2,000'	11,648	12,774	20,878	44,710	12,774
2,001 — 2,500'	20,061	28,104	36,719	90,823	14,052
2,501 — 3,000'	29,517	42,282	42,391	95,807	21,141
3,001 — 3,500'	35,713	43,943	49,982	108,581	21,972
3,501 — 4,000'	40,124	45,476	50,172	146,904	22,738
4,001 — 4,500'	42,064	46,626	56,309	159,678	23,313
4,501 — 5,000'	42,712	47,262	56,942	166,066	23,631
5,001 — 5,500'	43,360	47,904	57,195	178,840	23,952
5,501 — 6,000'	44,006	48,543	57,574	185,355	24,272
6,001 +	45,948	49,180	58,071	192,104	24,590

PRESCRIBED EQUIPMENT VALUE — SHALLOW PRODUCTION AND ALL SECONDARY RECOVERY

Depth	Under 90% Water	90 — 95% Water	Above 95% Water	Centrifugal (Reda)	TA - SI - SWD Injection Wells
0 — 500'	145	175	185	2,525	45
501 — 1,000'	430	520	610	3,795	110
1,001 — 1,500'	1,190	1,640	1,805	5,055	175
1,501 — 2,000'	2,990	3,225	3,885	6,320	350
2,001 — 2,500'	8,320	11,555	12,745	12,855	775
2,501 — 3,000'	11,355	14,150	15,600	15,890	950
3,001 — 4,500'	17,765	19,350	21,235	25,780	1,300
4,501 — 6,000'	23,340	27,150	29,755	35,675	1,825
6,001 +	27,800	30,910	34,000	45,495	2,075

LOWPRODUCTION CREDIT FACTOR TABLE (One Credit Each Producing Well — One Credit Each Injection Well)

Average Daily Production	0 — 2000 FT.*** % Adjustment	— Credit Factor
0.01 — 0.49	30%	.70
0.50 — 0.99	20%	.80
1.00 — 1.49	15%	.85
1.50 — Up	0%	1.00

** *2001 ft. & deeper, use table on page 9.

TABLE II

PRIMARY PRODUCTION: OIL WELLS DEEPER THAN 2,000 FT.
PRESCRIBED PRESENT WORTH FACTOR TABLE
16% DISCOUNT RATE; 8 YR.; 3% PROPERTY TAX CREDIT

	Percentage Rate of Decline	Present Worth Factors	Percentage Rate of Decline	Present Worth Factors
Primary Production	0	3.378		
	1	3.378	26	1.790
	2	3.378	27	1.730
	3	3.378	28	1.672
	4	3.378	29	1.616
	5	3.378	30	1.562
	6	3.378	31	1.510
	7	3.378	32	1.459
	8	3.378	33	1.411
	9	3.257	34	1.364
	10	3.142	35	1.319
	11	3.030	36	1.275
	12	2.923	37	1.232
	13	2.820	38	1.192
	14	2.722	39	1.152
	15	2.626	40	1.114
	16	2.535	41	1.077
	17	2.447	42	1.041
	18	2.363	43	1.006
	19	2.281	44	0.972
	20	2.203	45	0.940
	21	2.127	46	0.908
	22	2.055	47	0.877
	23	1.985	48	0.847
	24	1.918	49	0.819
	25	1.853	50 to 100	0.791

PRESCRIBED OPERATORS COST ALLOWANCE PER WELL				
	PRIMARY PRODUCTION			
Depth	Under 90% Water	90 — 95% Water	Above 95% Water	Centrifugal (Reda)
2,001 — 2,500'	29,453	43,604	50,616	118,226
2,501 — 3,000'	45,364	56,818	58,608	128,478
3,001 — 3,500'	51,580	57,278	65,772	142,753
3,501 — 4,000'	53,313	57,373	68,328	197,260
4,001 — 4,500'	55,895	57,611	70,154	208,350
4,501 — 5,000'	57,569	58,160	72,246	214,130
5,001 — 5,500'	60,915	60,783	74,607	216,725
5,501 — 6,000'	62,934	63,425	75,915	227,108
6,001 +	66,940	67,390	76,570	240,086

	PRESCRIBED EQUIPMENT VALUE				
	PRIMARY PRODUCING WELLS				
Depth	Under 90% Water	90 — 95% Water	Above 95% Water	Centrifugal (Reda)	TA-SI-SWD Injection Wells
2,001 — 2,500'	6,050	6,700	7,380	7,500	450
2,501 — 3,000'	7,380	8,200	9,000	9,200	550
3,001 — 4,500'	10,100	11,190	12,285	14,900	750
4,501 — 6,000'	14,100	15,750	17,225	20,650	1,055
6,001 +	16,100	17,900	19,680	26,260	1,200

LOW PRODUCTION CREDIT FACTOR TABLE (One Credit Each Producing Well, One-Half Credit Each Injection Well)				
Average Daily Production	2,001 — 4,000 FT. % Adjustment	Credit Factor	4,001 FT. + % Adjustment	Credit Factor
0.01 — 0.99	25%	.75	30%	.70
1.00 — 1.99	20%	.80	25%	.75
2.00 — 3.00	15%	.85	20%	.80
3.01 +	0%	1.00	0%	1.00
	2,001 —4,000 FT.	SECONDARY RECOVERY USE ONLY	4,000 FT. +	
3.01 — 3.99	10%	.90	15%	.85
4.00 — 4.99	5%	.95	10%	.90
5.00 — 5.99	0	1.00	5%	.95
6.00 — Up	0	1.00	0	1.00

PRESCRIBED VALUE FOR AN OIL WELL THAT HAS NEVER PRODUCED BUT IS CAPABLE OF PRODUCING*				
Depth	Working Interest	Amount	Royalty Interest	Amount
0 — 500'	7/8	$ 12,500	1/8	$ 2,500
501 — 1,000'	7/8	25,000	1/8	5,000
1,001 — 2,000'	7/8	50,000	1/8	10,000
2,001 — 4,000'	7/8	100,000	1/8	20,000
4,001 — Over	7/8	150,000	1/8	30,000

*A well that has been drilled (and discovered reserves exist on the appraisal date), but has not produced will be appraised according to this table. This type of well is not to be classified as a TA 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. If appraiser and taxpayer are unable to arrive at a fair valuation, refer to Property Valuation Division.

OIL ASSESSMENT RENDITION

SHALL BE F... WITH COUNTY APPRAISER ...IL 1

EXAMPLE COUNTY, KANSAS ______, 19____

OPERATOR I.D. NO. ______

TAXPAYER I.D. NO. ______

STATEMENT OF ______

P.O. ADDRESS ______ CITY ______ STATE ______ ZIP CODE ______

NAME OF PROPERTY ______ LEASE NO. ______

SECTION I — LOCATION OF PROPERTY ASSESSED

DESCR ______

Lot Sec. ______ Adn. Twp. ______ Blk. Rng. ______ Twp. City ______

UD ______ SD HS ______ JC ______ FIRE ______

Cem. ______ Water-shed ______ Library ______

Irrig. Hosp. Drain Taxing Dist.

SECTION VII — ABSTRACT VALUE (For Appraisers Use Only)

	Market Value	Assessed Value	Amount of Tax
Working Interest			
Royalty Interest			
Penalty			
TOTAL			

SECTION II — WELL AND LEASE DATA

No. of Wells Oil 3 Gas ______ Inj. ______ WS ______

Shut In ______ SWD ______ TA ______ Total 3

Age of Well or Average Age of Lease 13 yr.

Average Depth Of Wells 2,700 ft.

Oil Gravity 40^0

Water Production Percent 92% B.P.D.

Secondary Recovery ( ) Permit No.

Producing Formation

Market Price Received (Producer) $ 23.00

Less Oil Transportation Charge $ —

NET PRICE $ 23.00 WI; $21.00 RI

Oil Purchaser

Address

SECTION III — ITEMIZED EQUIPMENT

Type Property	Quantity	Description	Schedule	Owner	Appraiser
		TOTAL			

SECTION IV — OIL PRODUCTION DATA

MONTH	MONTHLY PRODUCTION 1983	1982
January	767	
February	717	
March	847	
April	917	
May	787	
June	827	
July	947	
August	837	
September	887	
October	1,047	
November	688	
December	618	
(1) Annual Production	9,886	11,070
(2) Casinghead Gas (Convt. Bbls.)	403	XXXXXXXXXX
(3) Total Annual Production Bbls. (To Sec. V, Item 1)	10,289	XXXXXXXXXX
(4) Annual Decline Bbls.	1,184	XXXXXXXXXX
(5) Percentage Rate of Decline	11%	XXXXXXXXXX

NOTATION:

CASINGHEAD GAS PRODUCTION

18550MCF Production x $.50 Price Per MCF = $9,275 Income ÷ $23 $ Bbl. Oil = 403 Bbl. Oil

(Transfer To Section IV, Line 2)

SECTION V — GROSS RESERVE CALCULATIONS

10,289 x RI $21 = $ 216,069 x 3.030 = $ RI $654,689

WI $23 = $ 236,647 = $ WI $717,040

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

SECTION VI

	Gross Reserve Value	X Decimal Interest	a. Schedule	b. Owner	c. Appraiser
1. Royalty Interest Valuation*:	$654,689	x .125	$ 81,836		
2. Working Interest Valuation:	$717,040	x .875	627,410		
3. Deduct Operating Cost Allowances					
a. Producing Well:	$ 56,818 per well	X 3 wells	–170,454		
b. Injection Well:	$ per well	X wells			
c. Submersible:	$ per well	X wells			
4. Sub-total (Line 2 minus lines 3 a, b, c)			456,956		
5. Minimum Lease Value 0.100 X	$627,410	(Line 2, Col. a)	62,741		
6. Line 4 or 5 (Whichever is greater)			$456,956		
7. Add Prescribed Equipment Value					
a. Producing Well	$ 8,200 per well X	3 wells	$ 24,600		
b. T.A.—S.I., SWD, Injection Well	$ per well X	wells			
c. Submersible	$ per well X	wells			
8. Sub-total (Line 6 plus lines 7 a, b, c)			$481,556		
9. Low Production Credit Factor: Bbls. Per Day	10,280 ÷ 365 ÷ 3=9.39		1.00		
10. Working Interest Valuation					
11. Itemized Equipment (Section III)					
12. Total Working Interest Market Value			$481,556		
13. Working Interest Assessed Value (30% of Line 12)			$144,467		

*ATTACH NAME, ADDRESS, AND INTEREST OF ROYALTY OWNERS.

STATE OF ______ COUNTY, SS.

I do swear and affirm that I have fully completed and truthfully answered all questions required on this form under the pains and penalties of perjury.

Subscribed and sworn to before me this ____ day of ______, 19____ Title ______

______ Signature ______

County Appraiser or Notary Public

Lease Code ______ County Code ______ Lease Name ______

PV-PP-25 (Rev. 12-83)

Prescribed by Kansas Department of Revenue, Division of Property Valuation

'85 O/G

OIL ASSESSMEN~ ~ENDITION

SHALL BE F~ ~ITH
COUNTY APPRAISER ~ ~L 1

EXAMPLE ______ COUNTY, KANSAS ______, 19____

STATEMENT OF ______ TAXPAYER I.D. NO. ______
P.O. ADDRESS ______ CITY ______ STATE ______ ZIP CODE ______
NAME OF PROPERTY ______ LEASE NO. ______

SECTION I — LOCATION OF PROPERTY ASSESSED

DESCR ______

Lot Sec. ______ Adn. Twp. ______ Blk. Rng. ______ Twp. City ______
UD ______ SD HS ______ JC ______ FIRE ______
Cem. ______ Water-shed ______ Library ______
Irrig. Hosp. Drain Taxing Dist.

SECTION VII — ABSTRACT VALUE (For Appraisers Use Only)

	Market Value	Assessed Value	Amount of Tax
Working Interest			
Royalty Interest			
Penalty			
TOTAL			

SECTION II — WELL AND LEASE DATA

No. of Wells Oil 1 Gas ______ Inj. ______ WS ______
Shut In ______ SWD ______ TA ______ Total ______
Age of Well or Average Age of Lease Aug. 83
Average Depth Of Wells 3200 ft.
Oil Gravity 40
Water Production Percent 80% B.P.D.

Secondary Recovery ( ) Permit No.
Producing Formation
Market Price Received (Producer) $
Less Oil Transportation Charge $
NET PRICE $
Oil Purchaser
Address

SECTION III — ITEMIZED EQUIPMENT

Type Property	Quantity	Description	Schedule	Owner	Appraiser
		TOTAL			

SECTION IV — OIL PRODUCTION DATA

MONTH	MONTHLY PRODUCTION 1983	19
January		
February		
March		
April		
May		
June		
July		
August 31 days	400	
September 30	850	
October 31	300	
November 30	620	
December 31	510	
(1) Annual Production 153 days	2,680	
(2) Casinghead Gas (Convt. Bbls.)		XXXXXXXXXX
(3) Total Annual Production Bbls. (To Sec. V, Item 1)		XXXXXXXXXX
(4) Annual Decline Bbls.		XXXXXXXXXX
(5) Percentage Rate of Decline		XXXXXXXXXX

NOTATION:

(a) & (b) KSA 79-331: For new lease beginning production July 1 or later of prior year, 60% of annualized production and 60% of authorized expenses are to be used. See pg. 1, Sec. 1 — 3b.

2680 bbls ÷ 153 days x 365 days = 6393
x .60
3836 bbls.

(c) 20% decline. See pg. 3, Sec. II, 1.

CASINGHEAD GAS PRODUCTION

Production ______ X Price Per MCF ______ = Income ______ ÷ $ Bbl. Oil ______ = Bbl. Oil ______
(Transfer To Section IV, Line 2)

SECTION V — GROSS RESERVE CALCULATIONS

1. Total Amount (Bbls.) Production		2. Net Price as of Jan. 1		3. Est'd. Gross Income Stream		4. Present Worth Factor		5. Estimated Gross Reserve Value
3,836 (a)	X	RI $23	=	$ 88,228	X	2.203 (c)	= $	RI $194,366
		WI $23	=	$ 88,228				WI $194,366

SECTION VI

	Gross Reserve Value	X Decimal Interest	a. Schedule	b. Owner	c. Appraiser
1. Royalty Interest Valuation*:	194,366	x .125	$ 24,295		
2. Working Interest Valuation:	194,366	x .875	170,070		
3. Deduct Operating Cost Allowances					
a. Producing Well: $ 51,580 per well		x 1 x .60 (b) wells	— 30,948		
b. Injection Well: $ per well		X wells	—		
c. Submersible: $ per well		X wells	—		
4. Sub-total (Line 2 minus lines 3 a, b, c)			$139,122		
5. Minimum Lease Value 0.100 X 170,070		(Line 2, Col. a)	17,007		
6. Line 4 or 5 (Whichever is greater)			$139,122		
7. Add Prescribed Equipment Value					
a. Producing Well	$ 10,100	per well X 1 wells	+ 10,100		
b. T.A.—S.I., SWD, Injection Well	$	per well X wells			
c. Submersible	$	per well X wells			
8. Sub-total (Line 6 plus lines 7 a, b, c)			$149,222		
9. Low Production Credit Factor: Bbls. Per Day ______			1.00		
10. Working Interest Valuation			$149,222		
11. Itemized Equipment (Section III)			—		
12. Total Working Interest Market Value			$149,222		
13. Working Interest Assessed Value (30% of Line 12)			$ 44,767		

*ATTACH NAME, ADDRESS, AND INTEREST OF ROYALTY OWNERS.

STATE OF ______ COUNTY, SS.

I do swear and affirm that I have fully completed and truthfully answered all questions required on this form under the pains and penalties of perjury.

Subscribed and sworn to before me this ____ day of ______, 19____ Title ______

______ Signature ______
County Appraiser or Notary Public

Lease Code ______ County Code ______ Lease Name ______

PV-PP-25
(Rev. 12-83)

Prescribed by Kansas Department of Revenue, Division of Property Valuation

GAS SECTION

MAJOR GAS FIELDS

GAS WELL DEFINITION AND PRODUCTION FACTORS

For ad valorem tax purposes, a natural gas well is to be defined as a well producing or capable of producing at a gas-oil ratio (G.O.R.) equal or greater than 15,000 cubic feet per barrel of oil (15,000 ft.^{3} to 1 barrel).

Example: (30,000 Mcf x 1,000) $\div$ (2,000 Bbls.) = 15,000 ft.^{3} to 1 Bbl.

Production history to be shown by the taxpayer for initial filings shall be an average of the past 5 years, except Hugoton and Panoma Field wells flowing to the intrastate market and connected to Kansas Power and Light (K.P.L.), 4 years. All of Spivey Grabs wells regardless of pipeline connection, 3 years.

TABLE A

MAJOR PROVEN GAS AREAS AND FIELDS

Ad Valorem Tax Credit is Included as an Expense
in the Calculation of the Present Value Factor

Producing Field	Present Worth Factor	Expenses Allowance (Per Well)	Equipment Value (Per Well)
	1985	1985	
Bradshaw-Byerly (Note 3)	3.83	$24,000	$ 500
Glick	2.50	35,000	4,900
Greenwood (Note 3)	4.85	26,260	500
Hugoton Chase Group (Note 3) Above 3,000 ft. Permian System	5.87	26,335	500
Hugoton Area Deep (Note 3 & 5) Zones below 3,000 ft. Pennsylvania & Mississippian	4.24	30,640	6,500
Interstate Redcave (Note 3)	4.85	9,610	500
Panoma Council Grove (Note 3) Lower Permian System	5.87	26,335	500
Spivey Grabs (Note 2)	3.07	25,000 FL 35,000 PU	5,000 5,000
McKinney (Note 2)	3.83	30,640	500

Notes

(1) The number of wells to be used for computing operating expenses and equipment values are the number of wells in existence as of January 1. In determining the number of producing wells for the well count, a comingled multizone well is to be counted as one (1) well; dual completions as two (2) 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 2 wells (1 oil and 1 gas).

(2) WATER CREDIT TABLE FOR:

Glick, Spivey Grabs and McKinney

Bbl/Water/Day	% Adjustment	Gas Well Factor*	Combination Oil-Gas Well Factor**
0.00 - 4.9	0	1.00	1.00
5.00 - 9.9	10	.90	.95
10.0 - 14.9	15	.85	.90
15.0 - 19.9	20	.80	.85
20.0 - Over	25	.75	.80

*Make adjustment on Line 4, Section 5, Gas Rendition

**There are certain fields throughout the State of Kansas which produce a combination of Crude Oil and Natural Gas from the same well bore. In these instances, where the well is producing in excess of 5.00 BOPD, the combination Oil & Gas Well reservoir damage water credit factor is to be used.

(3) *SALT WATER PUMPING CREDIT FOR:

An adequate allowance has been provided for 10 Bbls. of water or less per day in the base operating expense. For wells producing more than 10 Bbls. of water per day use the schedule set out below for each Bbl. over 10 Bbls.

Producing Field	Lump Sum Pumping Credit	Per Bbl. Credit
Bradshaw-Byerly	$ 8,700	$335
Greenwood	14,265	490
Hugoton-Chase Group above 3,000 ft.	10,535	669
Hugoton Deep Penn-Miss. Zones below 3,000 ft.	11,885	610
Interstate Redcave	7,245	225
Panoma Council Grove	10,535	669

*Make adjustment on Line 4, Section 6 of Gas Rendition.

Note: In order to qualify for water credits the operator must file either an affidavit showing test date, water production and type of test taken, or may include the information under a cover affidavit showing lease description, name, date of test and water production. In order to qualify for pumping credits the operator must state in the affidavit that a pumping unit exists on the assessment date.

Water lifting expenses covering 10 barrels or less per day has been allowed in the basic operating allowance. Only those wells that are supported by sworn affidavits, either singular or grouped under one affidavit, will be allowed the additional credits.

(4) Severance Tax Multiplier

Under Kansas law an 8% gross severance tax is imposed on all natural gas leases when lease gross income is $81.00 or greater per day. The law allows a 1% credit for local production taxes resulting in a 7% "net" gross severance tax. Both the state severance and local production taxes have been allowed as an expense in calculation of the field present value factors (7% severance and 10% local production).

Most "interstate gas" purchase contracts allow a direct pass-thru of state severance taxes, and many contracts also allow a pass-thru of local taxes, however, this is not the normal procedure for gas leases dedicated to the "intrastate market". In order to treat all situations equally it is necessary to increase the gross reserve value by the percentage of taxes built into the present value factors. To achieve an estimate of market value, the taxpayer shall add 7 percent to the estimated gross reserve when the state severance tax is being reimbursed by the pipeline purchaser. This adjustment is made on Line 6, Section V. If the gas is flowing to the intrastate market and all or any portion of the state severance tax is passed through multiply by 1 plus the percentage of pass-through. Example: (1.05) = 5% pass-through.

(5) The Hugoton Deep Factor is to be used for calculating present worth on wells deeper than 3,000 feet and located in the nine southwestern counties. However, the appraiser should consider using the A.O.K. Table B when the wells estimated life drops below 5 years.

(6) A shut-in gas well that has never been produced or sold gas, and is located in a major proven area may be appraised at 87.5% working interest value of $20 per foot of depth. Royalty interest is to be appraised at 12.5% of $20 per foot of depth. If the working interest is different than 87.5%, adjust royalty interest and working interest according to that ratio, e.g., WI 82.5%, RI = 17.5% x $20 ft. x depth. This rate should only be applied if the well has been shut in less than two years. If the well has been shut in for more than two years, appraise at equipment value only using equipment values from Table B, Page 15.

(7) A well's historic production may or may not be indicative of the well's future volumes. Therefore, the accumulation of large overages or underages, for a gas well capable of producing its assigned allowable, should be considered, provided such consideration results in a fair market value determination by the appraiser.

(8) The appraiser must use individual judgement when considering wells that have been produced irratically due to market conditions, and should consider past as well as future purchaser takes, i.e., as relates to gas leases only, the appraiser may use any combination of production history years that may be representative and will result in the best indication of market value.

(9) Net Price Received The net price as of the assessment date is that price received by the lessee producer and lessor royalty owner prior to any reduction for taxes, i.e., (state severance, local production, K.D.H.E. and K.C.C. levies). An adequate allowance has been built into the calculation of the present value factors to compensate for all tax burden. In addition, net price is that price paid per MCF after quality adjustments for BTU content and after any transportation, compression and producer carried costs, relating to the required removal of any materials in order to bring the gas up to pipeline quality.

(9a) Operators are cautioned that joint interest properties may well have different contract provisions for each lessee producer involved in the production unit. Operators are also cautioned that recent court settlements have recognized that many leases are considered "Market Value Leases". Under this settlement the royalty or fractional portions of the royalty deemed to be market value leases will receive prices per MCF, above the F.E.R.C. or contract rate received by the lessee producers. In the event that any part of the leasehold is entitled to a different rate per MCF the operator filing the return is required to furnish this information on the rendition and calculate each interest separately.

(9b) Elimination of Certain Price Ceilings Under Section 121 of the N.G.P.A. On January 1, 1985, price controls on certain categories of natural gas will expire. The effect on producers and royalty owners is not known, however, the schedule of price expirations is set out under the N.G.P.A.

Section 121 of the N.G.P.A. governs the elimination of price regulation. Not all gas is price-decontrolled on January 1, 1985. The categories which will expire are:

1. Section 102 gas: This is gas defined as new natural gas.

2. Section 103 gas which is produced from depths below 5,000 ft.

3. Natural gas subject to any existing intrastate contract (or successor or rollover thereof) if the price paid (or which would have been paid) for deliveries on December 31, 1984, exceeds $1.00 per MMBTU, and, any existing and successor contract if that price is not attributable to the operation of an indefinite price escalator clause.

On July 1, 1987, additional price controls will be eliminated pursuant to Section 121 of the N.G.P.A. Section 103 Gas (new on shore gas) being produced from depths above 5,000 feet will be price decontrolled.

There are certain important factors to bear in mind in evaluating the N.G.P.A. deregulation schedule. First, not all gas is deregulated, even within the same category. While Section 103 gas produced from a completion more than 5,000 feet deep, and not committed or dedicated to interstate commerce on April 20, 1977, is price-decontrolled on January 1, 1985. Gas that otherwise qualifies for Section 103, but which was committed or dedicated before April 20, 1977, is never deregulated regardless of the depth of completion.

Finally under Section 122 of the N.G.P.A., the President and Congress may reimpose price controls for an 18 month period following January 1, 1985. The reimposition under this Section may not take effect earlier than July 1, 1985, nor later than June 30, 1987.

Extreme caution is required when evaluating natural gas prices under Section 121 of the N.G.P.A. Some pipeline purchasers are amending contracts to actually reduce the price being paid per MCF. Other prices will increase under incentive rules in the gas purchase contracts or under provision of the N.G.P.A. Operators should make every attempt to check with their gas sales department before filing 1985 returns. If different price structures do prevail as of the assessment date the lease operator or tax representative should file documentation with the rendition in order that the appraiser is aware of these changes.

(10) Total 8/8ths Gas Production Valuation The total average gas production (MCF) computed as outlined under Total Average Gas Production (Column 1) is multiplied by the net price received to determine the estimated previous year's revenue. The estimated previous year's revenue is then multiplied by the 100% value factor to determine the 100% value of production. Then any prescribed and/or determined adjustments to be made are applied to the 100% value of production to arrive at the appraised value of gas production.

(11) KSA 79-331 provides special treatment for new leases beginning production on July 1 or later. See Oil Section, Paragraph I.

(12) New Leases For leases which have produced less than 12 months during the prior year, the computation in arriving at the annualized production is to be made by dividing the production for a representative period of the prior year that the lease did produce by the number of days it produced, then multiplying that figure by 365.

(13) Refer to Table II of the Oil Schedule for treatment of SWD, SI, TA gas wells.

(14) **Operators and purchasers are cautioned that a new up to date list of royalty owners including interests and addresses is a required portion of the rendition. Caution is also required in order that a full 100% list of royalty owners is filed with each rendition. The operator or representative is required under most lease operation agreements to timely file all governmental reports and documents that may be required in any jurisdiction.**

It is the operator/purchaser's duty to see that the County Appraiser is supplied with an up to date list of interest owners in order that tax billings will be correct. In lieu of correct listings the operator/purchaser will be liable for the taxes if lists are received after September 1st of the taxable year.

TABLE B

ALL OTHER KANSAS GAS FIELDS
10% Ad Valorem Tax Credit and 7% Severance Tax Credit included in P.V. Factor

Percentage Rate of Decline	Present Value Factor 5 yr. life	Present Value Factor 8 yr. life	Percentage Rate of Decline	Present Value Factor 5 yr. life	Present Value Factor 8 yr. life
0	2.952	3.915	26	1.420	1.545
1	2.873	3.772	27	1.379	1.493
2	2.796	3.634	28	1.339	1.443
3	2.721	3.502	29	1.300	1.394
4	2.647	3.375	30	1.262	1.348
5	2.576	3.253	31	1.225	1.303
6	2.506	3.135	32	1.189	1.259
7	2.438	3.023	33	1.153	1.217
8	2.371	2.914	34	1.119	1.177
9	2.306	2.811	35	1.085	1.138
10	2.243	2.711	36	1.053	1.100
11	2.182	2.615	37	1.021	1.063
12	2.121	2.522	38	.990	1.028
13	2.063	2.434	39	.960	.994
14	2.005	2.348	40	.930	.961
15	1.950	2.266	41	.901	.929
16	1.895	2.187	42	.873	.898
17	1.842	2.111	43	.846	.868
18	1.790	2.038	44	.819	.839
19	1.740	1.968	45	.793	.811
20	1.691	1.901	46	.768	.783
21	1.643	1.836	47	.743	.757
22	1.596	1.773	48	.719	.731
23	1.550	1.713	49	.695	.706
24	1.506	1.655	50	.673	.682
25	1.463	1.599			

PRESCRIBED OPERATORS COST ALLOWANCE AND EQUIP. VALUE

	PER WELL/PER FT. OF DEPTH			
	OPERATORS COST		EQUIP. VALUE	
	5 Yr. Life	8 Yr. Life	5 Yr. Life	8 Yr. Life
Flowing Wells	$4.25 Per Ft.	$5.55 Per Ft.	$1.55 Per Ft.	$ .95 Per Ft.
Pumping Wells	$7.65 Per Ft.	$9.95 Per Ft.	$3.95 Per Ft.	$2.40 Per Ft.

WATER CREDIT TABLE

Bbl/Water/Day	% Adjustment	Gas Well Factor*	Combination Oil - Gas Well Factor**
0.0 - 4.9	0	1.0	1.0
5.0 - 9.9	10	.90	.95
10.0 - 14.9	15	.85	.90
15.0 - 19.9	20	.80	.85
20.0 - Over	25	.75	.80

*Make Adjustment on Line 4, Section 5, Gas Rendition.

**There are certain fields throughout the State of Kansas which produce a combination of Crude Oil and Natural Gas from the same well bore. In these instances, where the well is producing in excess of 5.00 BOPD, the combination Oil & Gas Well reservoir damage water credit factor is to be used.

Notes

A. The number of wells to be used for computing operating expenses and equipment values are the number of wells in existence as of January 1. In determining the number of producing wells for the well count, a comingled multi-zone well is to be counted as one (1) well; dual completions as two (2) 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 2 wells (1 oil and 1 gas).

B. Only the last two years of the well's producing history is to be shown for All Other Kansas leases (AOK).

All Other Kansas gas fields (A.O.K.) includes all fields other than shown in Table A, Page 12. The All Other Kansas classification does not include wells deeper than 3,000 ft. located in the Hugoton Embayment of Southwest Kansas (The nine southwest counties).

For wells qualifying under the A.O.K. classification, use Table B "All Other Kansas Gas Field Present Worth Factors" Page 15.

Most wells qualifying as A.O.K. are producing from limited life reservoirs, therefore, the actual decline rate must be calculated. The appraiser's task becomes more difficult when dealing with wells producing from small reservoirs and non-prorated fields. The following procedure is recommended for all wells qualifying as A.O.K.:

1. For new wells, use a minimum 20% decline rate until the well has produced three years unless the lease operator can demonstrate that the well is declining at an annual rate in excess of 20%. The appraiser should require the operator to file justifying data when requesting an adjustment.

2. New Leases For leases which have produced less than 12 months during the prior year, the computation in arriving at the annualized production is to be made by dividing the production for a representative period of the prior year that the lease did produce by the number of days it produced, then multiplying that figure by 365.

3. The decline rate shall be calculated by using a two point curve. (The last two years prior to the appraisal year.)

Example:

Year 1	130,000 MCF	(Year 1 shown for reference only)
Year 2	84,500 MCF	1st point
Year 3	54,925 MCF	2nd point

$$\text{Decline Rate} = \frac{\text{Year 2 - Year 3}}{\text{Year 2}}$$

$$\text{Substituting: Decline Rate} = \frac{\text{84,500 MCF - 54,925 MCF}}{\text{84,500 MCF}} = 35\%$$

Even though the last two producing years are used to calculate the annual decline, the appropriate decline factor should be applied to the prior year's volume. The appraiser must recognize and the appraiser must be aware of the decline behavior that occurs in their area.

Example:

Year 1983	84,500 MCF	
Year 1984	54,925 MCF	Two year's volumes prior to appraisal date.
Year 1985	37,701 MCF	
Year 1986	23,205 MCF)	Estimates
Year 1987	15,083 MCF)	

As can be seen, if one applied the appropriate decline factor to the average of the last two years (84,500 MCF + 54,925 MCF/ 2 or 69,713 MCF) one would be forecasting the well's 3rd year (1985) production at 69,713 MCF when actually the well is only capable of producing 54,925 declining at 35% or 35,701 MCF. The appraiser must remember that most limited life reservoirs decline at a compound rate.

C. There are many small gas fields of 1 to 3 well gas pools located in Kansas. Most have economic life spans of five years or less. However, there are fields and pools that have been producing for many years, therefore, the A.O.K. Tables are based upon a 5 year life and an 8 year life. The appraiser should use the 5 year Present Worth Factor Tables, unless the appraiser can document that the well has produced longer than 5 years and has a remaining life in excess of 8 years.

D. The decline rate is to be calculated in the same manner as the 5 year life properties. Equipment values will be lower for 8 year leases. (Based on "The Present Worth of 1", the farther in the future the equipment is salvaged, the less present value the equipment has today.) The operating allowance will be higher due to the longer period of time required to recover reserves.

E. All Other Kansas Present Worth Factors include a 7% credit for STATE SEVERANCE TAXES.

See comments under Item No. 4 under Table A.

F. For All Other Kansas gas fields (A.O.K.) use the operating cost shown in Table B, unless the operator can show that the operating costs are consistently above the operating costs shown. If operating costs are consistently above the cost allowance shown, the appraiser must multiply the appropriate one year's operating costs by 3.526 for 5 years life and 4.678 for 8 year life wells.

G. New Leases (Shut-In Wells) $1.50/ft. of depth should be used to estimate the value of new leases where reserves have been discovered but not yet produced. See instruction on Page 13 , Item No. 6 for Working Interest/Royalty Interest proration.

GAS ASSE. .NT RENDITION

SHALL BE FILED
COUNTY APPRAISER BY APRIL 1

EXAMPLE COUNTY, KANSAS January 1, 1985

OPERATOR I.D. NO. ____
TAXPAYER I.D. NO. ____

STATEMENT OF ____
P.O. ADDRESS ____ CITY ____ STATE ____ ZIP CODE ____
NAME OF PROPERTY ____ LEASE NO. ____

SECTION I — LOCATION OF PROPERTY ASSESSED

DESCR ____

Lot / Sec. ____ Adn. / Twp. ____ Blk. / Rng. ____ Twp. / City ____

UD ____ SD / HS ____ JC ____ FIRE ____

Cem. ____ Water shed ____ Library ____

Irrig. Hosp. Drain Taxing Dist.

SECTION VII — ABSTRACT VALUE (For Appraisers Use Only)

	Market Value	Assessed Value	Amount of Tax
Working Interest			
Royalty Interest			
Penalty			
TOTAL			

SECTION II — WELL AND LEASE DATA

Wells: No.: Pumping ____ Flowing 1 S.I. ____ S.W.D. 1 Bbls. Water: 30 Field: Barker (AOK) Depth: 5,300

Gas Purchaser and Address

Market Price (Producer) Jan. 1 \$/MCF 2.63 Less Gas Compression Charge \$/MCF .12 Net Price Jan. 1 \$/MCF 2.51

\$/MCF Jan. 1 to Royalty Owners 2.51 BTU Content: 1,052 Spud Date: Mo. 1 Yr. 76

N.G.P.A. CATEGORY: 106 CONTRACT EXPIRATION DATE: 12-31-88

Sales: ____ Interstate ____ Intrastate

SECTION III — ITEMIZED EQUIPMENT

Type Property	Quantity	Description	Age	Schedule	Owner	Appraiser
			TOTAL			

SECTION IV — PRODUCTION DATA

Gas Well Production Data	Condensate — Bbls.	Gas — MCF
19 Annual Production		
19 Annual Production		
19 Annual Production		
1983 Annual Production		25,083
1984 Annual Production		15,465
Total Production		40,548
Average Annual Production		20,274
Condensate (Converted To MCF)*		
Total Average Production — MCF		

CONDENSATE PRODUCTION DATA*

____ X ____ = ____ ÷ ____ = ____

Avg. Prod. Bbls. / Net Price Per Bbl. / Income / Price Per MCF / Total MCF (To Sec. IV, Above)

NOTATION:

$$\text{Decline} = \frac{1983-1984}{1983}$$

$$= \frac{25,083 - 15,465}{25,083}$$

$$= 38\%$$

SECTION V — VALUATION OF THE TOTAL 8/8THS INTEREST

	Owner	Appraiser
1. Average Production - MCF Example shown is for an 8 yr life well	20,274	
2. Net Price: \$/MCF Jan. 1	2.51	
3. Estimated Gross Income Stream	50,887	
4. Present Worth Factor 1.028 x Water Credit Factor .75	.771	
5. Total	39,233	
6. Adjustment (F.E.R.C. Rate ☒ Yes ☐ No) (Water Credit ☐ Yes ☐ No) Other ☐	1.00	
7. Estimated Gross Reserve Value (Transfer Total to Section VI, Lines 1 & 2)	39,233	

SECTION VI

	Gross Reserve Value	X	Decimal Interest		a. Schedule	b. Owner	c. Appraiser
1. Royalty Interest Valuation*:	39,233	X	.125	=	4,904		
2. Working Interest Valuation:	39,233	X	.875	=	34,328		
3. Deduct Operating Cost Allowance \$	5.55x5300 per well	X	1	wells	29,415		
4. Deduct Pumping/Water Credit (\$____ X ____ Bbls.) + (\$____)							
5. Sub Total (Line 2 minus lines 3 and 4)					4,913		
6. Minimum Lease Value 0.100 X			(Line 2, Col. a)		3,432		
7. Line 5 or Line 6 (Whichever is Greater)					4,913		
8. Add Equipment Value							
a. Producing \$	.95 x 5300 well	X	1	wells	5,035		
b. Non-producing \$	1055 well	X	1	wells	1,055		
9. Add Itemized Equipment (Section III)							
10. Total Working Interest Market Value					11,003		
11. Working Interest Assessed Value (30% of Line 10)					3,300		

*ATTACH NAME, ADDRESS, AND INTEREST OF ROYALTY OWNERS.

STATE OF ____ COUNTY, SS.

I do swear and affirm that I have fully completed and truthfully answered all questions required on this form under the pains and penalties of perjury.

Subscribed and sworn to before me this ____ day of ____, 19 ____. Title ____

____ Signature ____

County Appraiser or Notary Public

Lease Code ____ County Code ____ Lease Name ____

PV-PP-26
(Rev. 12/83)

Prescribed by Kansas Department of Revenue, Division of Property Valuation

GAS ASSESSMENT DITION

SHALL BE FILED COUNTY APPRAISER BY APR.

EXAMPLE COUNTY, KANSAS January 1, 1985

OPERATOR I.D. NO.
TAXPAYER I.D. NO.

STATEMENT OF
P.O. ADDRESS CITY STATE ZIP CODE
NAME OF PROPERTY LEASE NO.

SECTION I — LOCATION OF PROPERTY ASSESSED

DESCR

Lot Sec. Adn. Twp. Blk. Rng. Twp. City
UD SD HS JC FIRE
Cem. Water shed Library
Irrig. Hosp. Drain Taxing Dist.

SECTION VII — ABSTRACT VALUE (For Appraisers Use Only)

	Market Value	Assessed Value	Amount of Tax
Working Interest			
Royalty Interest			
Penalty			
TOTAL			

SECTION II — WELL AND LEASE DATA

Wells: No.: Pumping ___ Flowing 1 S.I. ___ S.W.D. 1 Bbls. Water: 10 Field: Hugoton Deep Depth: 5,700

Gas Purchaser and Address Pipeline

Market Price (Producer) Jan. 1 $/MCF .84 Less Gas Compression Charge $/MCF Net Price Jan. 1 $/MCF .84

$/MCF Jan. 1 to Royalty Owners .84 BTU Content: 1000 Spud Date: Mo. 7 Yr. 31

N.G.P.A. CATEGORY: CONTRACT EXPIRATION DATE:

Sales: X Interstate ___ Intrastate

SECTION III — ITEMIZED EQUIPMENT

Type Property	Quantity	Description	Age	Schedule	Owner	Appraiser
			TOTAL			

SECTION IV — PRODUCTION DATA

Gas Well Production Data	Condensate — Bbls.	Gas — MCF
19 80 Annual Production	230	230,000
19 81 Annual Production	210	165,000
19 82 Annual Production	205	195,000
19 83 Annual Production	185	110,000
19 84 Annual Production	175	90,000
Total Production	1005	790,000
Average Annual Production	201	158,000
Condensate (Converted To MCF)*		5,503
Total Average Production — MCF		163,503

NOTATION:

Example shown is less than 10 Bbls of water per day.

CONDENSATE PRODUCTION DATA*

201 (Avg. Prod. Bbls.) X $23 (Net Price Per Bbl.) = $4,623 (Income) ÷ .84 (Price Per MCF) = 5,503 (Total MCF (To Sec. IV, Above))

SECTION V — VALUATION OF THE TOTAL 8/8THS INTEREST

	Owner	Appraiser
1. Average Production - MCF	163,503	
2. Net Price: $/MCF Jan. 1	.84	
3. Estimated Gross Income Stream	137,343	
4. Present Worth Factor 4.24 X Water Credit Factor ___	4.24	
5. Total	582,332	
6. Adjustment (F.E.R.C. Rate ☒ Yes ☐ No) (Water Credit ☐ Yes ☐ No) Other ☐	1.07	
7. Estimated Gross Reserve Value (Transfer Total to Section VI, Lines 1 & 2)	623,095	

SECTION VI

	a. Schedule	b. Owner	c. Appraiser
1. Royalty Interest Valuation*: Gross Reserve Value $623,095 X Decimal Interest .125 =	77,886		
2. Working Interest Valuation: Gross Reserve Value $623,095 X Decimal Interest .875 =	545,208		
3. Deduct Operating Cost Allowance $ 30,640 per well X 1 wells	30,640		
4. Deduct Pumping/Water Credit ($___ X ___ Bbls.) + ($___)			
5. Sub Total (Line 2 minus lines 3 and 4)	514,568		
6. Minimum Lease Value 0.100 X (Line 2, Col. a)	54,520		
7. Line 5 or Line 6 (Whichever is Greater)	514,568		
8. Add Equipment Value			
a. Producing $ 6,500 well X 1 wells	6,500		
b. Non-producing $ 450 well X 1 wells	450		
9. Add Itemized Equipment (Section III)			
10. Total Working Interest Market Value	521,518		
11. Working Interest Assessed Value (30% of Line 10)	156,455		

*ATTACH NAME, ADDRESS, AND INTEREST OF ROYALTY OWNERS.

STATE OF ___ COUNTY, SS.

I do swear and affirm that I have fully completed and truthfully answered all questions required on this form under the pains and penalties of perjury.

Subscribed and sworn to before me this ___ day of ___, 19___ Title ___

Signature ___

County Appraiser or Notary Public

Lease Code ___ County Code ___ Lease Name ___

PV-PP-26
(Rev. 12/83)

Prescribed by Kansas Department of Revenue, Division of Property Valuation

GAS ASSE ENT RENDITION

SHALL BE FILEL
COUNTY APPRAISER BY APRIL 1

EXAMPLE COUNTY, KANSAS January 1, 1985

OPERATOR I.D. NO. ______
TAXPAYER I.D. NO. ______

STATEMENT OF ______
P.O. ADDRESS ______ CITY ______ STATE ______ ZIP CODE ______
NAME OF PROPERTY ______ LEASE NO. ______

SECTION I — LOCATION OF PROPERTY ASSESSED
DESCR
Lot Sec. ___ Adn. Twp. ___ Blk. Rng. ___ Twp. City ___
UD ___ SD HS ___ JC ___ FIRE ___
Cem. ___ Water shed ___ Library ___
Irrig. Hosp. Drain Taxing Dist.

SECTION VII — ABSTRACT VALUE (For Appraisers Use Only)	Market Value	Assessed Value	Amount of Tax
Working Interest			
Royalty Interest			
Penalty			
TOTAL			

SECTION II — WELL AND LEASE DATA

Wells: No.: Pumping 1 Flowing ___ S.I. ___ S.W.D. ___ Bbls. Water: 13 Field: Hugoton Depth: 2,650

Gas Purchaser and Address PEPL KC MO

Market Price (Producer) Jan. 1 $/MCF 1.989 Less Gas Compression Charge $ /MCF Net Price Jan. 1 $ /MCF 1.839

$/MCF Jan. 1 to Royalty Owners 1.839 BTU Content: 925 Spud Date: Mo. Yr.

N.G.P.A. CATEGORY: CONTRACT EXPIRATION DATE: 12-1990

Sales: X Interstate ___ Intrastate

SECTION III — ITEMIZED EQUIPMENT

Type Property	Quantity	Description	Age	Schedule	Owner	Appraiser
			TOTAL			

SECTION IV — PRODUCTION DATA

Gas Well Production Data	Condensate — Bbls.	Gas — MCF
1980 Annual Production	17,786	
1981 Annual Production	21,696	
1982 Annual Production	18,294	
1983 Annual Production	22,047	
1984 Annual Production	23,629	
Total Production	103,452	
Average Annual Production	20,690	
Condensate (Converted To MCF)*	-0-	
Total Average Production — MCF	20,690	

NOTATION:

Example shown is producing more than 10 Bbls of water per day.

CONDENSATE PRODUCTION DATA*

-0- X ______ = -0- ÷ ______ = -0-

Avg. Prod. Bbls. | Net Price Per Bbl. | Income | Price Per MCF | Total MCF (To Sec. IV, Above)

SECTION V — VALUATION OF THE TOTAL 8/8THS INTEREST

	Owner	Appraiser
1. Average Production - MCF		20,690
2. Net Price: $ /MCF Jan. 1		1.839
3. Estimated Gross Income Stream		38,048
4. Present Worth Factor ______ X Water Credit Factor ______		5.87
5. Total		223,347
6. Adjustment (F.E.R.C. Rate ☐ Yes ☐ No) (Water Credit ☐ Yes ☐ No) Other☐		1.07
7. Estimated Gross Reserve Value (Transfer Total to Section VI, Lines 1 & 2)		238,981

SECTION VI

Gross Reserve Value X Decimal Interest	a. Schedule	b. Owner	c. Appraiser
1. Royalty Interest Valuation*: 238,981 X .125 =	29,872		
2. Working Interest Valuation: 238,981 X .875 =	209,108		
3. Deduct Operating Cost Allowance $ 26,335 per well X 1 wells	26,335		
4. Deduct Pumping/Water Credit ($ 669 X 3 Bbls.) + ($ 10,595)	12,602		
5. Sub Total (Line 2 minus lines 3 and 4)	170,171		
6. Minimum Lease Value 0.100 X (Line 2, Col. a)	20,910		
7. Line 5 or Line 6 (Whichever is Greater)	170,171		
8. Add Equipment Value			
a. Producing $ 500 well X 1 wells	500		
b. Non-producing $ well X wells			
9. Add Itemized Equipment (Section III)			
10. Total Working Interest Market Value	170,671		
11. Working Interest Assessed Value (30% of Line 10)	51,200		

*ATTACH NAME, ADDRESS, AND INTEREST OF ROYALTY OWNERS.

STATE OF ______ COUNTY, SS.

I do swear and affirm that I have fully completed and truthfully answered all questions required on this form under the pains and penalties of perjury.

Subscribed and sworn to before me this ___ day of ______, 19 ___. Title ______

______ Signature ______

County Appraiser or Notary Public

Lease Code ______ County Code ______ Lease Name ______

PV-PP-26
(Rev. 12/83)

Prescribed by Kansas Department of Revenue, Division of Property Valuation

TABLE I
NATURAL GAS CEILING PRICES
(Other Than 104 and 106(a))

Subpart of Part 271	NGPA Section	Category of Gas	Jan. 1984	Jan. 1985
B	102	New Natural Gas Certain OCS Gas	$3.586	$3.869
C	103(b)1	New Onshore Production Wells	$2.849	$2.960
	103(b)2	Incentive Price	N/A	$3.415
E	105(b)(3)	Intrastate existing contracts	N/A	$3.869
F	106(b)(1)(B)	Alternative Maximum Lawful Price for Certain Intrastate Rollover Gas	$1.628	$1.691
G	107(c)(5)	Gas Produced from Tight Formations	$5.698	$5.920
H	108	Stripper Gas	$3.841	$4.144
I	109	Not Otherwise Covered	$2.359	$2.452

The maximum lawful price for tight formation gas is the lesser of the negotiated contract price or 200% of the price specified in Subpart C of Part 271. The maximum lawful price for tight formation gas applies on or after July 16, 1979. (See 271.703 and 271.204.)

TABLE II
NATURAL GAS CEILING PRICES: 104 and 106(a)

Category of Natural Gas	Type of Sale or Contract	Jan. 1984	Jan. 1985
Post 1974 gas	All producers	$2.359	$2.452
1973-1974 Biennium gas	Small producer	$1.997	$2.075
	Large producer	$1.525	$1.582
Interstate Rollover gas (106(a))	All producers	$ .876	$ .910
Replacement contract gas or recompletion gas	Small producer	$1.120	$1.165
	Large producer	$ .858	$ .891
Flowing gas	Small producer	$ .566	$ .590
	Large producer	$ .478	$ .499
Minimum rate gas*	All producers	$ .292	$ .304

*Prices for minimum rate gas are expressed in terms of dollars per Mcf. rather than MMBtu.

TABLE III
INFLATION ADJUSTMENT

Month of Delivery	Factor by which price in preceding month is multiplied
1984	
November	1.00311
December	1.00311
1985	
January	1.00311

PRODUCER REGULATION BEFORE AND AFTER 1/1/85 Well Category Requirements; NGPA Maximum Lawful Prices on 12/31/84					
NGPA Category	**Type of Natural Gas**	**Well Determinations Required as of 12/31/84**	**NGPA Pricing-Status as of 12/31/84**	**NGPA Pricing-Status as of 1/1/85**	**NGPA MLP on 12/31/84 ($ per MMBtu**
§ 102(c) (1) (B)	*New Natural Gas from New Onshore Well* if 2.5 miles or more from nearest marker well (i.e., well producing commercial quantities before 4/20/77 and after 1/1/70)	Yes	Regulated	Deregulated	$3.845
§ 102 (c) (1) (B)	*New Natural Gas from New Onshore Well* if less than 2.5 miles from nearest marker well and deeper than 1,000 feet of 2.5 mile marker well.	Yes	Regulated	Deregulated	3.845
§ 102(c) (1) (C)	*New Natural Gas from New Onshore Reservoir* (i.e., reservoir not producing commercial quantities before 4/20/77)	Yes	Regulated	Deregulated	3.845
§ 103(c)	*Natural Gas from New Onshore Well* (i.e., surface drilling after 2/18/77) if committed or dedicated to interstate commerce after 4/20/77 and if produced from location deeper than 5,000 feet.	Yes	Regulated	Deregulated	2.951
§ 103(c)	*Natural Gas from New Onshore Well* if gas committed or dedicated to interstate commerce after 4/20/77 and produced from location less than 5,000 feet.	Yes	Regulated	Regulated (Deregulated on 7/1/87)	2.951
§ 103(c)	*Natural Gas from New Onshore Well* if gas committed or dedicated to interstate commerce on or before 4/20/77.	Yes	Regulated	Regulated (Remains regulated indefinitely)	2.951
§ 104	*Natural Gas Committed or Dedicated to Interstate Commerce* before 11/9/78 and with an established NGA rate.	No	Regulated	Regulated	(See Chapter 30) NGPA
§ 105	*Natural Gas Sold Under Existing or Successor Intrastate Contract* (i.e., on or after 11/9/78) if price less than $1.00/MMBtu on 12/31/84.	No	Regulated	Regulated	Lower of $3.845 or Contract Price
§ 105	*Natural Gas Sold Under Existing or Successor Intrastate Contract* (i.e., not committed or dedicated to interstate commerce on 11/8/78) if price exceeds $1.00/MMBtu on 12/31/84 other than by operation of indefinite price escalator.	No	Regulated	Deregulated	Lower of $3.845 or Contract Price
§ 105	*Natural Gas Sold Under Existing or Successor Intrastate Contract* (i.e., not committed or dedicated to interstate commerce on 11/8/78) if price exceeds $1.00/MMBtu on 12/31/84 due to operation of indefinite price escalator.	No	Regulated	Regulated	Lower of $3.845 or Contract Price
§ 106(a)	*Natural Gas Sold Under Interstate Rollover Contracts* (i.e., committed or dedicated on or before 11/8/78).	No	Regulated	Regulated	(See Chapter 30) NGPA
§ 106(b)	*Natural Gas Sold Under Intrastate Rollover Contract* if price equal to or less than $1.00/MMBtu on 12/31/84.	No	Regulated	Regulated	1.686
§ 106(b)	*Natural Gas Sold Under Intrastate Rollover Contract* if price exceeds $1.00/MMBtu on 12/31/84, regardless of operation of indefinite price escalator clauses	No	Regulated	Deregulated	1.686

PRODUCER REGULATION BEFORE AND AFTER 1/1/85 Well Category Requirements; NGPA Maximum Lawful Prices on 12/31/84					
NGPA Category	**Type of Natural Gas**	**Well Determinations Required as of 12/31/84**	**NGPA Pricing-Status as of 12/31/84**	**NGPA Pricing-Status as of 1/1/85**	**NGPA MLP on 12/31/84 ($ per MMBtu)**
§107(c) (1)-(c) (4)	*High-Cost Natural Gas* (i.e., deeper than 15,000 feet; from geopressured brine; from coal seams; or from Devonian shale)	Yes	Deregulated (on 11/1/79)	Deregulated (on 11/1/79)	$–
§107(c) (5)	*High-Cost Natural Gas* resulting in extraordinary risks or costs (i.e., new tight formation gas)	Yes	Regulated	Regulated*	5.902
§107(c) (5)	*High-Cost Natural Gas* resulting in extraordinary risks or costs (i.e., recompletion tight formation gas)	Yes	Regulated	Regulated	5.902
§107(c) (5)	*High-Cost Natural Gas* resulting in extraordinary risks or costs (i.e., production enhancement gas)	Yes	Regulated	Regulated	5.902
§108	*Stripper Well Natural Gas*	Yes	Regulated	Regulated	4.118
§109(a) (1)	*Natural Gas from any New Well* not otherwise qualifying for MLP under NGPA	No	Regulated	Regulated	2.444
§109(a) (2)	*Natural Gas Committed or Dedicated to Interstate Commerce* before 11/9/78 but without established NGA rate	No	Regulated	Regulated	2.444
§109(a) (3)	*Natural Gas Not Committed or Dedicated to Interstate Commerce* before 11/9/78 and not subject to existing contract	No	Regulated	Regulated	2.444

OIL AND GAS

ITEMIZED EQUIPMENT 100% COST SECTION

Rotary Drilling Rigs*	New	Used	Salvage Value
To 1,000 Ft.	$ 45,000	$ 22,500	$ 4,500
1,001 - 2,000 Ft.	75,000	37,500	7,500
2,001 - 3,500 Ft.	147,500	72,500	14,750
3,501 - 6,500 Ft.	225,000	112,500	22,500
6,501 +	625,000	312,500	61,200

*Add for Drill Pipe, Drill Collars. The appraiser must take into consideration the actual condition of the rig and equipment and adjust up or down to achieve fair market value. A rig stacked 90 days prior to assessment date may have a lesser value than an active rig.

Drill Pipe

2 3/8" O.D. Per Ft.	$ 3.40	$ 2.00	$ .35
2 7/8" O.D. Per Ft.	4.25	2.55	.45
3 1/2" O.D. Per Ft.	5.10	3.00	.50
4 1/2" O.D. Per Ft.	8.50	5.10	.85
5" O.D. Per Ft.	13.60	8.15	1.35

Cable Tool Rigs* (Includes Drilling Lines, Sandlines and Cable Tools)

Skid Mounted			
Up to 1,500'	$ 6,000	$ 3,600	$ 600
1,501' to 3,500'	15,000	9,000	1,500
3,501' to 5,000'	26,350	15,750	2,600
Over 5,000'	31,000	18,500	3,100

Drill Collars

6 1/4" O.D.	$ 1,230	$ 750	$ 125

Service Units

1. Under 1,500' Capacity (Sgl. or Dbl. Drum with Truck)	$ 20,000	$ 10,000	$ 2,000
2. Over 1,500' Capacity (Sgl. Drum with Truck)	35,000	23,250	3,500
3. Dbl. Drum Unit with Truck			
1,500' – 3,500'	$ 65,000	$ 43,300	$ 6,500
3,501 – 5,000'	82,500	55,000	8,250
5,001 – 7,500'	95,000	63,500	9,500
7,501 – 10,000'	120,000	80,000	12,000
10,000' +	160,000	107,000	16,000

Steel Cable

7/16" O.D. Per Ft.	$ .45	$ .20	None
9/16" O.D. Per Ft.	.50	.20	None
3/4" O.D. Per Ft.	1.00	.20	None
7/8" O.D. Per Ft.	1.30	.30	None
1" O.D. Per Ft.	1.60	.55	None
1 1/8" O.D. Per Ft.	1.80	.75	None
1 1/4" O.D. Per Ft.	2.25	.85	None

Steel Casing – API Specs

4 1/2" O.D. Per Ft.	$ 2.75	$ 1.50	$ .25
5" O.D. Per Ft.	3.00	1.80	.30
5 1/2" O.D. Per Ft.	3.50	2.10	.35
6 5/8" O.D. Per Ft.	4.00	2.40	.40
7" O.D. Per Ft.	6.00	3.60	.60
8 5/8" O.D. Per Ft.	7.00	4.20	.70
9 5/8" O.D. Per Ft.	8.00	4.80	.80
10 3/4" O.D. Per Ft.	11.00	6.60	1.10

Tubing – API SPECS	New	Used	Salvage Value
1.05" O.D. Per Ft.	$ .70	$ .40	$ .10
1.61" O.D. Per Ft.	1.40	.85	.15
1.9" O.D. Per Ft.	1.80	1.10	.18
2 3/8" O.D. Per Ft.	1.95	1.20	.20
2 7/8" O.D. Per Ft.	2.30	1.40	.25
3 1/2" O. D. Per Ft.	3.40	2.05	.35

Line Pipe (Nominal Sizes) C. W. Grade A-25

1" Per Ft.	$ .85	$ .50	$ .10
1 1/4" Per Ft.	.90	.55	.10
1 1/2" Per Ft.	.95	.60	.10
2" Per Ft.	1.20	.70	.12
2 1/2 " Per Ft.	2.00	1.20	.20
3 1/2" Per Ft.	2.50	1.50	.25
4" Per Ft.	4.00	2.40	.40
6" Per Ft.	6.00	3.60	.60
8" Per Ft.	11.00	6.60	1.10

Electric Motors

1 to 5 H.P. Per H.P.	$78.00	$38.00	$10.00
6 to 19 H.P. Per H. P.	59.00	28.00	7.00
20 & Over H.P. Per H.P.	54.00	25.00	7.00

Pump Engines

Continental Engines			
C-46	$ 4900	$ 3150	$ 750
C-66	5400	3500	1200
C-96	7100	4600	1575
F & M Engines			
118	3500	2150	600
208	4300	2625	750
346	7700	4700	1250
503	9100	5550	1500
739	11400	6950	1850

Reda-Gould Submersible Pumps

1 to 10 H.P. Per H.P.	$ 280		None
11 to 40 H.P. Per H.P	245		None
41 & Over H.P. Per H.P.	200		None

Oil Well Tubing Pumps

4 – 5'	$ 2070	$ 900	None
6'	2990	1300	None
8'	3795	1650	None
10'	4025	1750	None
12'	4600	2000	None

Sucker Rods

5/8" O.D. Per Ft.	$ .75	$ .45	$ .08
3/4" O.D. Per Ft.	.90	.50	.10
7/8" O.D. Per Ft.	1.00	.60	.12
1" O.D. Per Ft.	1.25	.75	.15

Horizontal Heaters

30" x 7 1/2'	$ 5800	$ 2900	$ 600
30" x10'	9500	4750	950
48" x 10'	9500	4750	950

Emulsion Treaters – 30 lb. Pressure

	New	Used	Salvage Value
4′ x 15′	$ 5950	$ 2700	$ 595
4′ x 21′	4335	1950	435
6′ x 21′	7820	2500	800
8′ x 21′	14450	6500	1500
10′ x 21′	17000	7650	1700

Oil Separators

24″ x 5′ 125 psi	$ 1600	$ 565	$ 160
30″ x 10′ 125 psi	1800	640	180
36″ x 10′ 125 psi	2300	800	230
48″ x 12′ 125 psi	2500	865	245
24″ x 12′ 500 psi	3000	1040	295
12″ x 10′ 1000 psi	3400	1190	340
4″ x 10′ knockout	1700	595	170
5″ x 12′ knockout	2200	775	220

Tanks*

	New	Used
Wood Tanks	$ ––	$ 750 (total)
Steel Tanks	$12.00 per bbl.	$ 7.20 per bbl.
Fiberglass Tanks	$11.50 per bbl.	$ 7.00 per bbl.

*Add for Ladder, Platform, Walkway

Transformers 2300/110-220

For Installed Cost of Transformers
Multiply Transformer Value by 1.7.

Size KVA	New	Used	Salvage Value
1.5	$ 85	$ 50	$ 10
2.0	100	60	15
2.5	115	70	15
3.0	150	100	20
4.0	175	125	25
5.0	200	140	30
7.5	275	175	35
10.0	400	225	45
15.0	475	275	50
20.0	550	350	60
25.0	650	400	75
30.0	700	475	85
37.5	750	500	95
40.0	850	550	100
50.0	950	600	110
75.0	1400	900	125
100.0	1500	1000	160
167.0	2350	1500	250

Power Service Lines

Including Poles & Wire Complete

2 Wire Per Ft.	$ 2.00 Per Ft.
3 Wire Per Ft.	2.35 Per Ft.

Light Plants – Gasoline Powered

1.000 – 1.500 KW Complete	$2640	$1200	$ 240
1.5 – 3.00 KW Complete	2640	1200	240
3.0 – 7.5 KW Complete	3080	1400	280
7.5 and Over KW Complete	3850	1750	350

Pumping Jacks	New	Used	Salvage Value
D-2	$ 1000	$ 600	$ 150
D-3	1200	700	180
D-4	1400	850	210
D-6	1500	900	225
D-10	1550	950	235
D-25	3000	2200	450
D-57	8000	5500	1200
D-80	10000	8500	1500
D-114	12000	10000	1800
D-160	18000	15000	2700
D-228	22000	15500	3300
D-320	32000	22400	3500
D-330	33000	23000	4000
D-456	43000	30000	4300
D-640	52000	36400	5200
D-912	60000	42000	6000
Mud Pumps (Drilling)			
Duplex ("National" or Equiv) without Engine or Drive Section			
K-380	$61850	$30000	$ 6000
K-500	88500	45000	8900
C-150			1500
C-250			2000
Triplex			
7P-50	80000	40000	8000
Water Injection Pumps			
("National" or Equiv.) without Engine or Drive Section			
PT-10 "Wheatley"	$ 800	$ 450	$ 100
J-30	4390	3000	400
J-60	7000	4000	700
J-100	12000	7000	1200
Power Tongs			
Tubing	$12000	$ 8000	$ 1000
Torque Converters			
("National" or Equiv.)			
C-195	$ 6000	$ 3000	$ 600
Diesel Engines			
GM-671 (Twin)	$25500	$10000	$ 3750
Cat-3406	23000	9000	3450
Cat-3408	29750	12000	4500

The above table lists the values for New, Used and Salvage of a variety of equipment for oil field use not necessarily included as lease equipment. This table gives guidelines for the appraiser to use in valuing oil field equipment and great care must be exercised by the appraiser to assess the equipment at its fair market value. Actual value will depend upon the age, condition and functional value of the equipment. If the appraiser is unsure of the value he should contact the Division of Property Valuation for advice or other expert advice in these areas.

Kansas

DEPARTMENT OF REVENUE

State Office Building
TOPEKA, KANSAS 66625

January 23, 1985

TO: All County Appraisers

FROM: Victor W. Miller, Director of Property Valuation

RE: Crude Oil Price Schedule: 1985 Tax Year

The policy of the Division of Property Valuation is to issue price memoranda to reflect crude oil prices to assist assessing officials for ad valorem tax purposes. The following schedule reflects the Crude Oil Windfall Profits Tax Act of 1980 and the Kansas severance tax for non-exempt leases. It is to be used in conjunction with the guidelines in the 1985 Oil and Gas Appraisal Guide except whenever the operator is able to verify a different price as of January 1 and whenever the reported price is within a reasonable proximity of the price schedule. In case of a major difference between the oil price schedule and the operator's rendition price, verification is suggested, particularly for oil in the gravity range of 30^{o} and less which may vary substantially. Transportation charges are to be deducted on the rendition sheet and are subject to verification.

The "windfall profits tax" on oil production varies between "Major" and "Independent" producers thereby resulting in two price schedules. For the Royalty Interest Gross Reserve Calculation the Major Producer price schedule must be used for both major and independent royalty owners. Therefore, the Royalty Interest Gross Reserve Calculation for Independent Producers (Tier One and Tier Two) will require separate calculations.

For leases subject to the Kansas severance tax (K.S.A. 79-4217), use column designated "Severance". For leases exempted from the severance tax, use column designated "Exempt".

	Tier One				Tier Two				Tier Three	
	INDEP.		MAJOR*		INDEP.		MAJOR*		All Producers	
Gravity	a. Sev.**	b. Exempt	a. Sev.	b. Exempt	a. Sev.	b. Exempt	a. Sev.	b. Exempt	a. Sev.	b. Exempt
40+	$21.27	$22.23	$19.83	$20.73	$24.86	$25.98	$22.78	$23.81	$24.86	$25.98
39–39.99	21.20	22.16	19.79	20.69	24.71	25.83	22.73	23.75	24.71	25.83
38–38.99	21.12	22.08	19.75	20.64	24.57	25.68	22.67	23.69	24.57	25.68
37–37.99	21.05	22.01	19.70	20.60	24.42	25.53	22.61	23.63	24.42	25.53
36–36.99	20.98	21.93	19.66	20.55	24.28	25.38	22.55	23.57	24.28	25.38
35–35.99	20.91	21.86	19.62	20.51	24.14	25.23	22.50	23.51	24.14	25.23
34–34.99	20.84	21.78	19.57	20.46	23.99	25.08	22.44	23.45	23.99	25.08
33–33.99	20.77	21.71	19.53	20.42	23.85	24.93	22.38	23.39	23.85	24.93
32–32.99	20.69	21.63	19.49	20.37	23.71	24.78	22.32	23.33	23.71	24.78
31–31.99	20.62	21.56	19.45	20.33	23.56	24.63	22.27	23.27	23.56	24.63
30–30.99	20.55	21.48	19.40	20.28	23.42	24.48	22.21	23.21	23.42	24.48
29–29.99	20.48	21.41	19.36	20.24	23.28	24.33	22.15	23.15	23.28	24.33
28–28.99	20.41	21.33	19.32	20.19	23.13	24.18	22.09	23.09	23.13	24.18
27–27.99	20.34	21.26	19.27	20.15	22.99	24.03	22.04	23.03	22.99	24.03
26–26.99	20.26	21.18	19.23	20.10	22.85	23.88	21.98	22.97	22.85	23.88
25–25.99	20.19	21.11	19.19	20.06	22.70	23.73	21.92	22.91	22.70	23.73
24–24.99	20.12	21.03	19.14	20.01	22.56	23.58	21.86	22.85	22.56	23.58
23–23.99	20.05	20.96	19.10	19.97	22.42	23.43	21.81	22.79	22.42	23.43
22–22.99	19.98	20.88	19.06	19.92	22.27	23.28	21.75	22.73	22.27	23.28
21–21.99	19.90	20.81	19.02	19.88	22.13	23.13	21.69	22.67	22.13	23.13
Below 21	19.83	20.73	18.97	19.83	21.98	22.98	21.64	22.61	21.98	22.98

*Use "Major" price for calculation of Royalty Owner reserve value. **For lease subject to severance tax use tax column a. For exempt leases, use column b.

Definitions

Tier One — is a combination of "Upper Tier" and "Lower Tier", that is, oil from wells selling oil for the first time from non-stripper category prior to May 1, 1979.

Tier Two — is defined as oil from a lease incapable of producing ten (10) barrels per well per day based on previous 12 months production and classed as such by the Department of Energy.

Tier Three — is defined as oil sold after May 31, 1979, from property from which no crude oil was produced in calendar year 1978.

2/20/85

SENATE B[illegible] 193

Senate Energy and Natural Resources Committee

Mr. Chairman and Members of the Committee:

Senate bill 193 is a bill which in most instances we would find it very difficult to comply with. In the case of the purchase of a producing company and their assets to place an individual value on each piece of producing property for which a lump sum or stock exchange took place is nearly impossible. In the case of a farmout and a back in after payout it again is very difficult to state the value of a lease which you acquire a working interest in.

With the variation in the price and transportation rate the certificate would have only a short term value to say the least. It would be similar to filing a certificate of value on stock purchased which changes in value daily.

Another related problem would be the volume of certificates which could be required in the event the director did not waive the need for certificates on a purchase such as Mobil purchase of Republic Nat'l. Gas which covered several thousand leases and the purchase of Superior which covered many leases also.

We believe the Oil & Gas manual produced by the Department is the only reasonable manner to arrive at a value which approximates the value of producing property and that the filing of the certificates would only confuse the issue and cause an undue burden on purchasers of producing properties.

Mobil Oil Corp.
George A. Sims

E&NR 2/21/85
Attachment B