State of Kansas
Laura Kelly, Governor

Department of Revenue
Mark A. Burghart, Secretary

Division of Property Valuation

Bob Kent, Director

2026 Year Oil & Gas Appraisal Guide

January 2026

Zibell Office Bldg, 300 SW 29th St, Topeka, KS 66611
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https://www.ksrevenue.gov/pvdindex.html

2026 Oil and Gas Guide Changes

The following are notable changes in the guide:

Added a new section for Horizontal Oil and Gas (Table III & Table D) that was previously included as an addendum.

Minor guide changes may consist of dates, formatting, and additional language for clarification.

JOAN WAGNON, SECRETARY

KANSAS

DEPARTMENT OF REVENUE
DIVISION OF PROPERTY VALUATION

KATHLEEN SEBELIUS, GOVERNOR

MEMORANDUM

TO: **County Appraisers**

FROM: **Mark S. Beck, Director of Property Valuation**

DATE: **March 6, 2006**

SUBJECT: **Gas Transportation Property**

The Kansas Supreme Court in *In re CIG Field Services Co.*, 279 Kan. 857, 112 P.3d 138 (2005) declared unconstitutional that provision in K.S.A. 79-5a01 which provided for local assessment by the county appraiser of oil or gas production gathering lines located solely within one county.

The director of property valuation is required to value the property of any person or company that is in the "business" of "transporting or distributing to, from, through or in this state gas, oil or other commodities in pipes or pipelines . . . [K.S.A. 79-5a01(a)(4)]." "Business" is any commercial enterprise carried on for profit or gain. *Black's Law Dictionary* 164 (8th ed. abr. 2004). Any person or company, which receives any type of consideration, whether directly or indirectly, for transporting gas, is deemed to be in the "business" of transporting gas. Consideration includes, but is not limited to, any fee, "charge back" to the leasehold interests or any type of transaction that reduces the price of the gas used to value the lease.

Any person or company charging a fee or receiving any type of consideration for transporting gas is required to file a property tax return with the division of property valuation annually on or before March 20th (K.S.A. 79-5a02). In addition, any operator imposing a "charge back" to the leasehold interests is required to file a property tax return with the division. Operator-owned pipe and other equipment used to transport gas from the lease ***where no fee is charged and no "charge back" is taken*** is not required to be included on any return to the division because, in such instances, the value of such pipe and other equipment is included in the value of the lease.

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To: County Appraisers and Industry Representatives

From: Lynn Kent, Oil & Gas Section Mgr.

Date: April 5, 2010

Subject: Gas Gathering Valuation

Gas Gathering systems are valued as a public utility by the Kansas Dept. of Revenue, Division of Property Valuation (PVD) or as an addition to the lease by the county appraiser. There are no longer locally assessed gas gathering lines valued on personal property schedule V per the PVD Gas Transportation Memo dated March 6, 2006, noted in the oil and gas appraisal guide. As described in the referenced memo, lease operators owning their own gathering lines and solely moving their own gas without deducting fees from the rendered lease price should report gathering systems locally, and appropriate value should be added to the lease rendition. If any third party gas is being gathered by the system or the operator is deducting a fee from the lease price, the system must be state assessed.

Value added to the lease may include gathering lines, compressors, dehydrators, amine units, nitrogen units, meters, tanks, etc…. Since this equipment is a necessary addition to the lease to get the gas to a marketable point and there are no deductions for this system in the price, the market value of this equipment is included in the income stream in sec V of the gas assessment rendition. Thus, a salvage value at the end of its economic life is added for recoverable equipment. The value would be added on line 8c, sec VI, of the gas assessment rendition and then discounted by the appropriate guide table equipment factor.

Please be advised that some gathering lines may not be recoverable when made from material such as PVC or Polypipe. No value should be added for non-recoverable lines. Yet, some steel lines, as well as, compressors or other surface equipment on the system will have a salvage value to be added. Also, please be reminded that only equipment owned by the operator and considered as an extension to the lease by NOT deducting gathering/compression charges from the price rendered in sec II of the gas assessment rendition is to be added. If charges are deducted from the price, the property should be assessed as a public utility by the state, and no additional equipment value should be added to the lease rendition. If the surface equipment is leased, it should be added in the lessor's name on personal property schedule V.

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Bob Kent, Director

Laura Kelly, Governor
Mark A. Burghart, Secretary

From: Bob Kent, Director

Date: January 1, 2026

Subject: 2026 General Kansas Crude Oil Price Schedule

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

Gravity	Exempt	Severance
40 and above	$48.00	$45.92
39.99 – 39.00	$47.85	$45.78
38.99 - 38.00	$47.70	$45.63
37.99 - 37.00	$47.55	$45.49
36.99 - 36.00	$47.40	$45.35
35.99 - 35.00	$47.25	$45.20
34.99 - 34.00	$47.10	$45.06
33.99 - 33.00	$46.95	$44.92
32.99 - 32.00	$46.80	$44.77
31.99 - 31.00	$46.65	$44.63
30.99 - 30.00	$46.50	$44.49
29.99 - 29.00	$46.35	$44.34
28.99 - 28.00	$46.20	$44.20
27.99 - 27.00	$46.05	$44.06
26.99 - 26.00	$45.90	$43.91
25.99 - 25.00	$45.75	$43.77
24.99 -24.00	$45.60	$43.63
23.99 - 23.00	$45.45	$43.48
22.99-22.00	$45.30	$43.34
21.99-21.00	$45.15	$43.20
20.99 and lower	$45.00	$43.05

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Bob Kent, Director

Laura Kelly, Governor
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From: Bob Kent, Director

Date: January 1, 2026

Subject: 2026 Eastern Kansas Crude Oil Price Schedule

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

Gravity	Exempt	Severance
40 and above	$46.00	$44.01
39.99 – 39.00	$45.85	$43.86
38.99 - 38.00	$45.70	$43.72
37.99 - 37.00	$45.55	$43.58
36.99 - 36.00	$45.40	$43.43
35.99 - 35.00	$45.25	$43.29
34.99 - 34.00	$45.10	$43.15
33.99 - 33.00	$44.95	$43.00
32.99 - 32.00	$44.80	$42.86
31.99 - 31.00	$44.65	$42.72
30.99 - 30.00	$44.50	$42.57
29.99 - 29.00	$44.35	$42.43
28.99 - 28.00	$44.20	$42.29
27.99 - 27.00	$44.05	$42.14
26.99 - 26.00	$43.90	$42.00
25.99 - 25.00	$43.75	$41.86
24.99 -24.00	$43.60	$41.71
23.99 - 23.00	$43.45	$41.57
22.99-22.00	$43.30	$41.43
21.99-21.00	$43.15	$41.28
20.99 and lower	$43.00	$41.14

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From: Bob Kent, Director

Date: January 1, 2026

Subject: 2026 Gas Market Adjustment Factor (MAF)

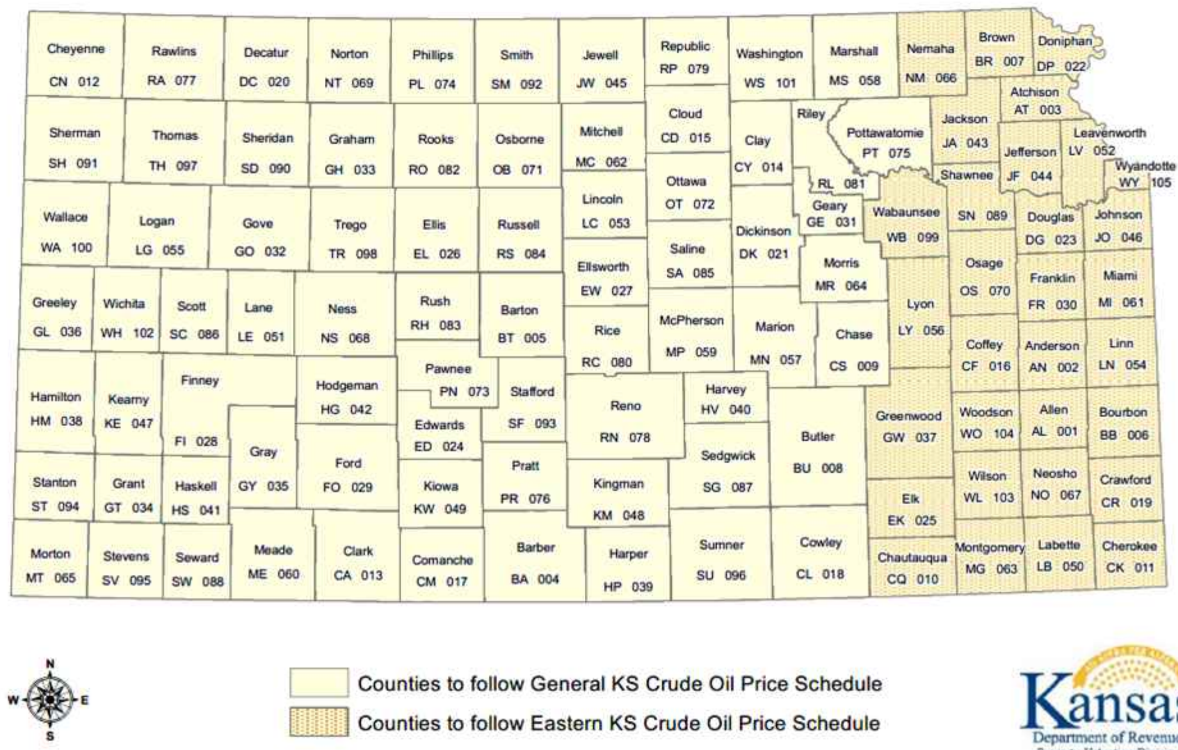
The Market Adjustment Factor to be used for the 2026 Tax Year is

MAF = 0.95

The factor reflects a 5% adjustment for market conditions anticipated over the course of the current tax year.

The MAF is to be multiplied by the prior year's net weighted average price per lease on Line 2, Section V of the Gas Assessment Rendition.

Crude Oil Price Schedule Determination by County



Counties to follow Eastern KS Crude Oil Price Schedule:

Allen	Elk	Montgomery
Anderson	Franklin	Nemaha
Atchison	Greenwood	Neosho
Bourbon	Jackson	Osage
Brown	Jefferson	Shawnee
Chautauqua	Johnson	Wabaunsee
Cherokee	Labette	Wilson
Coffey	Leavenworth	Woodson
Crawford	Linn	Wyandotte
Doniphan	Lyon	
Douglas	Miami	

The above map and county list should be used to determine the use of the Eastern Kansas Crude Price Schedule. **However, please note this pricing is not automatic. This guideline should be used along with the checkbox for the eastern Kansas price designation by the operator in Section IV of the Oil Assessment Rendition.** If the eastern KS posted prices are not received by particular operators in these counties, the General KS Crude Oil Price Schedule should be followed. Documentation from the operator may need to be provided to the county appraiser in order to determine correct price schedule.

Foreword

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

2. Personal property **shall be listed and appraised at its fair market value as of January 1 each year** per KSA 79-301 and KSA 79-501. KSA 75-5105a provides for the Director of the Division of Property Valuation, a division of the Kansas Department of Revenue, to prescribe guides to assist the county appraiser in establishing market value for personal property and to confer with representatives of the county appraisers and seek counsel from official representatives of organized groups interested in and familiar with the value of classes of property with which they are concerned. The oil and gas guide is prepared per authority of this statute.

3. KSA 79-1412a and KSA 79-1456 require the county appraiser to follow the policies, procedures, and guidelines issued by the Director of the Division of Property Valuation. The county appraiser shall first conform to the values for such property as shown in the personal property appraisal guides prescribed by the Director of Property Valuation. ***The county appraiser may then deviate from such guidelines on individual properties for just cause and in a manner consistent with establishing market value in accordance with the state statutes.***

   Thus, the county appraiser shall use the oil and gas guide prescribed by the Director of Property Valuation. If the lease valuation estimated by use of the oil and gas guide does not reflect market value for an individual property in the judgment of the appraiser or the taxpayer, the appraiser has the authority to review and adjust the valuation to market value. Appropriate deviation from the guide requires (i) just cause, (ii) on an individual property, and (iii) proper documentation. Any change made in the appraisal from the guide application must be supported by proper documentation and a copy of the valuation change must be furnished to the taxpayer in a timely manner sufficient to allow the taxpayer the right to appeal the valuation. **Lease operator/taxpayer/tax representative requests for change from the guide value estimate must also be documented.**

4. The Director of Property Valuation, a Division of the KS Department of Revenue, has the authority and responsibility to prescribe forms to be used in the valuation of personal property. KSA 75-5105a(a) states that the Director of Property Valuation "shall devise and prescribe uniform assessment forms…." to be used in the valuation process. The Oil and Gas Assessment Renditions in this guide have been prepared per this authority. The county appraiser is required to use such prescribed forms. Any deviation from the official form and the use of computer generated forms must be approved by the Director of Property Valuation per KSA 79-1457 which states that "the county appraiser shall make available to the general public all necessary blank **forms prescribed or approved by the Director of Property Valuation** which are required to be completed and returned by the public to the county appraiser…..The county appraiser shall utilize those **forms prescribed or approved by the Director of Property Valuation** in making the appraisal of all real and tangible personal property."

5. KSA 79-332a provides for any person, corporation or association owning oil and gas leases or engaged in operating for oil or gas who fails to make and file the oil/gas tax statement rendition **on or before APRIL 1** in the office of the county appraiser in and for the county which has jurisdiction of the lease, shall be subject to penalties for late filing, failure to file, or failure to file a full and complete statement. The statute also notes that the lease operator may request an extension of the filing time, but it must be in writing, and it must be filed prior to the **APRIL 1** deadline. The county appraiser has the sole authority to grant or deny extension requests. The Kansas Attorney General Opinion 76-160 states that a mailing postmarked on or before the deadline shall be accepted without penalty for at least three additional days. **Penalties are assessed to the operator based on the total value of the royalty interest plus the working interest.** The Kansas State Board of Tax Appeals is the sole authority for relief of the assessed penalty. KSA 79-2017 and 79-2101 provides for collection of delinquent taxes by the county sheriff.

6. KSA 79-331 describes the method and contributing factors to be used in the valuation. The Assessment Rendition was created to value the property according to this statute. **Column A (Schedule Value) of the oil or gas rendition is to be completed by using the oil and gas guide without departure, adjustment, or change.** Column B (Owner) is reserved for the lease operator/taxpayer/tax representative's use for requested adjustments to Column A. Column C (Appraiser) is reserved for use by the county appraiser to make adjustments to Column A and/or finalize the valuation of the well/lease.

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

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

9. To promote uniform and equal assessments, the Director of Property Valuation is providing the following guidelines for classification which the county is required to follow per KSA 79-1439(2)B: **The assessment rate for mineral leasehold interests is 30% except *oil leasehold interests (working interest) that average five (5) Bbls or less per day and natural gas leasehold interests that average one hundred (100) Mcf or less per day, each of which is assessed at 25%, including production equipment in use on that lease*.** The assessment rate is determined on a **lease** basis by dividing the annual production by 365 days to calculate the **average daily lease production.** For new leases and existing leases that produced only a part of the year, divide the production by the actual number of days produced. **Shut-In leases with no production do not qualify for the low production assessment; thus, shut-in leases are assessed at 30%. The royalty interest is assessed on the basis of 30%. All itemized equipment is assessed at 30%.**

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

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

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

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

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

The statute is specific as to production and no consideration may be given to well shut down, pumping unit, or transportation problems. In these cases, the annual production divided by the actual producing days is to be used to determine the exemption; normal downtime does not qualify as one of these cases. Lease production that began during the year should not be annualized, but should be calculated from the date the lease went into production. The royalty interest and the production equipment do not qualify for the exemption.

The equipment will be appraised per Table I or Table II according to depth.

Request for exemption is made by the operator on forms provided by the county appraiser and filed with the State Board of Tax Appeals (BOTA). Questions concerning exemption rulings or decisions should be directed to BOTA @ 785-296-2388, or the BOTA website @ *https://www.kansas.gov/bota/*

The exemption status remains in effect for as long as the lease qualifies for the exemption per KSA 79-201t under the ownership granted the exemption for this purpose by the State Board of Tax Appeals. Whenever the lease ownership changes, a request for exemption must be made by the new owner to be granted in his/her name.

11. Pursuant to KSA 75-5105a, the Kansas Department of Revenue, Division of Property Valuation prescribes and furnishes the oil and gas appraisal guide and rendition forms to all county appraisers. ***For copies, please contact the county appraiser's office for the county in which the property is located or download from*** https://www.ksrevenue.gov/pvdoilgas.html

12. The administration of the ad valorem property tax is the jurisdiction of the county appraiser's office, in and for the county, in which the oil or gas lease is located. Any question or specific valuation concern should be directed to the county appraiser. Any equalization or payment under protest appeal should be scheduled with the county appraiser. For appeal information, please contact the county appraiser in which the oil or gas lease is located or download information from https://www.ksrevenue.gov/pvdforms.html.

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Oil Section

Oil Section

Oil Rendition Form Instructions

The lease operator/taxpayer/tax representative is required to provide the information requested in Sections I through IV of the oil rendition form and all other information necessary to fix the valuation of the property as determined by the Director of Property Valuation. Failure to provide this required information will result in a 12.5% penalty assessed to the operator based on the total value of the royalty interest plus the working interest for failure to file a full and complete statement of assessment according to KSA 79-332a (c). COLUMN A (SCHEDULE VALUE) is to be completed by using the oil and gas guide without departure, adjustment, or change. COLUMN B (OWNER) is reserved for the lease operator/taxpayer/tax representative's use for requested adjustments to Column A. COLUMN C (APPRAISER) is reserved for the county appraiser to finalize the valuation of the well/lease.

The Oil Rendition-Schedule Value (Column A) Instructions ***An example of the oil assessment rendition can be found following this explanation.***	
NOTE: For copies of the rendition forms and oil and gas guide, please contact the county appraisal office for the county in which the property is located or download from https://www.ksrevenue.gov/pvdoilgas.html	
Statement of Ownership/ Address/Property Name	Provide information to the extent available. It may be necessary to complete page 2 in order to list all wells on the lease and include location, KDOR ID #s, API #s, etc…
Section I: Location of Property	**THIS IS REQUIRED DATA.** A minimum legal description of Section, Township, and Range is required. Quarter section and/or more detailed location description is preferred.
Section II: Lease Data	**THIS IS REQUIRED DATA.** Provide information as requested for the number of producing oil, submersible, and gas wells. Also provide non-producing well counts for shut-in, salt water disposal, temporarily abandoned, injection, and water supply wells. Provide total number of wells and tank batteries on lease. Provide secondary recovery information if pertains. To qualify for Secondary Recovery, a KCC permit number must be provided. Provide water disposal information as requested. Provide spud and completion dates. Provide average completion depth for the lease, and average SWD, INJ, WS well depth. The total working interest and royalty interest decimal are also required for the correct value split. Include oil gravity, water production (%), and barrels of water per day. It is also necessary to include producing formation, and purchaser name and address. Identification of all wells on lease is to be provided on page 2 of rendition unless there is enough space to accommodate list in notation section on page 1. Identification includes items such as location, well type, KDOR#, API#, and production if not all included on page 1 and/or if not all included under one KDOR#.
Section III: Itemized Equipment	**THIS IS REQUIRED DATA** if it exists. The rendition sheet page 2 has been created for this information. Please attach page 2 with a listing of equipment located on the lease, but not part of the producing "prescribed" equipment. Also, equipment located in storage yards and/or other sites which is considered "itemized equipment" per this guide should be listed using page 2 of the rendition. Once listed on page 2 of the rendition, the total value shall be transferred to the total Itemized Equipment value on Line 8, Section VI, page 1 of the rendition.
Section IV: Production Data	**THIS IS REQUIRED DATA.** Provide two year history, if applicable. The prior year production should be submitted on a monthly basis including explanations for zero production months, downtime, or other information necessary to annualize/analyze lease production capability under the "Notation" section. Casinghead gas production on the lease should be provided in monthly increments in the appropriate column if available. If monthly production for casinghead gas is not available, then an annual total should be submitted. Casinghead gas produced on an oil lease should not be annualized; the actual production should be used. The annual casinghead gas total (Mcf) is required, and it should then be transferred to the conversion calculation box for conversion to barrels (Bbls) of oil to include in total lease production. The second year production total should be submitted in the appropriate column. Monthly increments are not necessary for this second year since that data should exist from the prior year rendition. Severance Tax and Property Tax Exemption numbers are required to value appropriately. Also, the indication of posted prices being received, (eastern KS yes or no) is necessary in determining correct price schedule.

Section V: Gross Reserve Calculation **(Total 8/8ths Interest)**	**Line 1: Annual Production (Bbls)-**Use the prior year total annual production from Sec IV. For new or incomplete year production follow adjustment rules in Oil Section I, pgs 5-9. **Line 2: Effective Jan 1 Net Price $/Bbl-**Use the correct Crude Oil Price Schedule based on gravity and severance tax status, with the consideration of eastern KS pricing **Line 3: Estimated Gross Income Stream**- Multiply Line 1 X Line 2 and enter result on Line 3 **Line 4: Present Worth Factor**-Use factor from Table I or Table II. The Present Worth Factor is based on decline rate. See Oil Section II in guide to determine decline rate. **Line 5**: **Estimated Gross Reserve Value**-Multiply Line 3 X Line 4 and enter result on Line 5 for Estimated Gross Reserve Value (Total 8/8ths Value). The total is then transferred to Lines 1 & 2 in Section VI of rendition.
Section VI: Gross Reserve Value X Decimal Interest **(Calculation of Royalty and Working Interests)**	**Line 1: Royalty Interest Valuation**-Multiply the Estimated Gross Reserve Value (Sec. V, Line 5) X Total Royalty Decimal Interest. Total RI value is then assigned to individual RI and ORRI owners per the division of interest and assessed at 30%. **Line 2: Working Interest Valuation**- Multiply the Estimated Gross Reserve Value (Sec. V, Line 5) X Total Working Decimal Interest. **Line 3**: **a. Deduct Operating Cost Allowance for Producing Wells**-Use expense allowance per well from Table I or Table II, then multiply by number producing wells. **b**. **Deduct Operating Cost Allowance for Injection Wells**-Use expense allowance per well from Table I, then multiply by number injection wells. **c**. **Deduct Operating Cost for Submersible Wells**-Use acceptable actual annual expense for all submersible wells, then multiply by expense factor from Table I or Table II. **Line 4**: **Working Interest Subtotal**-Subtract expenses Sec VI, Lines 3a, 3b, 3c from Line 2 (WI Value). **Line 5**: **Working Interest Minimum Lease Value**-Multiply Sec VI Line 2 X 2%,5%, or 10%, See guide Oil Section IX, Working Interest Valuation. **Line 6**: **Copy Value from Sec VI Line 4 or Line 5**-Use whichever line is greater. **Line 7: a. Add Prescribed Equipment Value for Producing Wells**-Use equipment allowance per well from Table I or Table II, then multiply by number tank batteries per lease from Sec II, Lease Data. (Table values include one producing well and tank battery) **b. Add Prescribed Equipment Value for Multiple Producing Wells**-Use equipment allowance per well from Table I-Multi Table or Table II-Multi Table, then multiply by number of additional producing wells on lease. (Multi Table values include producing well only) **c. Add Prescribed Equipment Value for Non-Producing Wells-**Use equipment allowance per well from Table I or Table II for Shut-In, TA, SWD, INJ, or WS wells, then multiply by number of non-producing wells. **d. Add Prescribed Equipment Value for Submersible Wells**-Use equipment allowance per well from Table I or Table II, then multiply by number of submersible wells. **e**. **Add Prescribed Equipment Value for Additional Equipment**-Use actual salvage equipment value for additional equipment necessary in production that is not already included in the prescribed equipment values noted above, then multiply by equipment factor per Table I or Table II. **Line 8: Add Itemized Equipment**-Use Itemized Equipment Section from back of guide to value attached page 2 listing of equipment not currently being used in well production. **Line 9: Working Interest Total Market Value**-Add Sec VI, Lines 6, 7a, 7b, 7c, 7d, 7e, and 8. **Line 10:Working Interest Total Assessed Value**-Multiply Line 9 X 30%, unless lease qualifies for 25% assessment rate. **Certification:** ***The certification is to be completed and signed by the lease owner or operator who is responsible for filing the tax rendition with the county appraiser. It must also be signed by the rendition preparer***. **Division Orders:** ***A list of the current royalty owners, their decimal interest, and their addresses, is to be provided by the operator and is a requirement for filing the tax rendition.***

OIL ASSESSMENT RENDITION

SHALL BE FILED WITH THE COUNTY APPRAISER BY APRIL 1

Schedule 2 (Class 2B) (Rev. 1/26)

General Kansas **County, Kansas** **Tax Year** **2026**

Statement of	We Produce Oil			**Operator ID#**	257689
P.O. Address	1234 First Street	**City** Big Spring	**State** KS	**Zip**	66795
Name of Property	The Big One	**County ID#** 1879	**KDOR ID#(s)** 115635	**Well API#(s)**	5685295-6

Section I-Location of Property (required)			
Lease Description	SW / 4 SW / 4		
(Well location pg 2)			
Lot Sec.	10	Adn. Twp.	24
Blk Rng.	32	Twp. City	
Tax Unit	32	School Dist	506

Section VII-Abstract Value (for county use only)	Appraised	Assessed	Penalty	Total
Total Working Interest (Sec. VI. Line 9)				
Royalty & ORRI Interest (Sec. VI. Line 1)			XXXXXXXXX	
Itemized Equipment (Sec. VI. Line 8)				
Total				

Section II-Lease Data (required)

Producing Wells: Oil 4 Submersible Gas Non-Producing Wells: Shut-In SWD TA INJ WS Total # Wells on Lease 4

Secondary Recovery( ) KCC Permit # n/a Water Disposal: Hauler/System/Well Name Jones Disposal Total # Tank Batteries on Lease 1

Spud Date: Mo/Yr(new prod) 12/1956 Ave Depth 2850' Horizontal ( ) Total WI Decimal 0.875000 Prod Formation Arbuckle

Comp Date: Mo/Yr(new prod) 1/1957 SWD/INJ/WS n/a Horiz Total Depth Total RI&ORRI Dec 0.125000 Purchaser Name Big Guy Purch

Oil Gravity 40* Water Production (%) 48% Bbls Water Per Day 18.5 Purch Address 2020 12th St, Big Spring, KS Purch Phone (785)652-8956

Section IV-Production Data (required)

Month	2025 Oil (Bbls)	2025 Casinghead Gas (Mcf)	2024 Oil (Bbls)
January	593	1256	
February	612	1500	
March	599	1000	
April	623	540	
May	600	305	
June	632	255	
July	618	800	
August	623	652	
September	615	566	
October	621	980	
November	608	800	
December	601	756	
Annual Production	7,345	9,410	7,936
Casinghead Gas (Converted to Bbls)	500	xxxxxx	xxxxxxxxx
Total Annual Production (Bbls + gas conv)	7,845	xxxxxx	xxxxxxxxx
Annual Decline (Bbls)	591	xxxxxx	xxxxxxxxx
Decline Rate (%)	7%	xxxxxx	xxxxxxxxx

Notation

Tx Yr 2026 Decline: 7,936 -7,345 7%

7,936

OIL RENDITION SAMPLE

Lease Receives Eastern KS Posted Price Yes No X

Severance Tax Exempt # B25 Property Tax Exempt # n/a

Casinghead Gas Production Data (conversion calculation)

Prod (Mcf)	X	Net $/Mcf Gas	=	Income	/	Net $/Bbl Oil	=	Total Bbl (Transfer to Sec IV, Casing Gas Conv)
9,410	X	$2.55		23,996		$48.00		500

Gatherer Name PU Inc

Address Big Spring, KS Phone (785)652-5642

Section V-Gross Reserve Calculation (Total 8/8ths Interest)

	1. Annual Production (Bbls) (Total Annual Prod, Sec IV)		2. Effect Jan 1 Net Price $/Bbl (See Crude Oil Price Schedule)		3. Est Gross Income Stream (Multiply Line 1 X Line 2)		4. Present Worth Factor (Based on Decline Rate-See Tbl)		5. Est Gross Reserve Value (Total 8/8ths-Transfer Total to Sec VI, Lines 1&2)
Schedule (A)	7,845	X	$48.00	=	376,560	X	3.332	=	1,254,698
Owner (B)		X		=	0	X		=	0
Appraiser (C)		X		=	0	X		=	0

Section VI-Gross Reserve Value X Decimal Interest				**Schedule (A)**	**Owner (B)**	**Appraiser (C)**
1. Royalty & Overriding Royalty Interest Valuation (Total Sec V, Line 5 X Total RI & ORRI Interest)		X	0.125000	156,837		
2. Working Interest Valuation (Total Sec V, Line 5 X Total WI Interest)		X	0.875000	1,097,861		
3a. Deduct Operating Cost Allowance for Producing Wells (Allowance per Well)	4	X	58245	232,980		
3b. Deduct Operating Cost Allowance for Injection Wells (Allowance per Well)		X		0		
3c. Deduct Operating Cost for Submersible Wells (Annual Submersible Expense)		X		0		
4. Working Interest Subtotal (Sec VI, Line 2 minus Lines 3a, 3b & 3c)				864,881		
5. Working Interest Minimum Lease Value (Sec VI, Line 2) 1,097,861	X	10%	(2%, 5%, 10%)	109,786		
6. Copy Value from Sec VI, Line 4 or Line 5 (Whichever Line is Greater)				864,881		
7a. Add Prescribed Equipment Value for Producing Wells (Allowance per Well)	4400	X	1	4,400		
7b. Add Prescribed Equipment Value for Multiple Producing Wells (Allowance per Well)	1980	X	3	5,940		
7c. Add Prescribed Equipment Value for Non-Producing Wells (Shut-In, TA,SWD,INJ,WS)		X		0		
7d. Add Prescribed Equipment Value for Submersible Wells (Allowance per Well)		X		0		
7e. Add Pres Equip Value for Additional Equipment		X		0		
8. Add Itemized Equipment (Section III - Attached Schedule)				0		
9. Working Interest Total Market Value (Add Sec VI, Lines 6, 7a, 7b, 7c, 7d, 7e & 8)				875,221		
10. Working Interest Total Assessed Value (Multiply Sec VI, Line 9 X 30%, Unless Lease Qualifies for 25% Rate)			30%	262,566		

Current Division Order with Name, Address, Interest of Royalty Owners, and Well/Lease Identifier is a Required Attachment to Rendition

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

Mr. Oil Producer	2026	Oil Guy Rendition Preparer	2026
Owner	**Date**	**Tax Rendition Preparer**	**Date**

Rendition Information: **Contact Phone** (785) 555 - 1212 **Contact Email** oilguy@xyz.com

Lease Code WE1879 **County Code** 1879 **Lease Name** The Big One

Prescribed by Kansas Department of Revenue, Division of Property Valuation

OIL ASSESSMENT RENDITION ADDITIONS PAGE

MUST BE ATTACHED TO OIL ASSESSMENT RENDITION

Schedule 2 (Class 2B) (Rev. 1/26)

General Kansas **County, Kansas** **Tax Year** **2026**

Statement of We Produce Oil **Operator ID#** 257689

Name of Property The Big One **County ID#** 1879 **KDOR ID#(s)** 115635 **Well API#(s)** 5685295-6

Section I-IV Additional Data (required)

Well Names on Lease	Location	Well Type	KDOR ID#	Well API#	Well Production Bbls	Well Production Mcf
The Big One #1	Lat.14.23239,Long.19.74918	Oil	115635	5685295-6		
The Big One #2	Lat.18.23239,Long.29.74919	Oil	115635	5685295-7		
The Big One #3	Lat.10.23239,Long.39.74920	Oil	115635	5685295-8		
The Big One #4	Lat.20.23239,Long.49.74921	Oil	115635	5685295-9		

No need to show separate production for each well if all on same KDOR# and total lease production on pg 1

If separate KDOR# for wells on lease, then show production as assigned to each KDOR#

Notation	Total Lease Production (includes all wells on lease-pg 1 rendition)	Total Bbls	Total Mcf
		7,345	9,410

Tie all wells on lease together to determine assessment rate. Oil wells typically on one rendition with one KDOR# for entire lease

Section III Itemized Equipment (required)

Property Name/Model	Property Description	Location	Condition (New/Used/Salvage)	Year	Series	Mast (ft)	Capacity (lbs)	Guide Value

Notation	Total Item Equip Value (Copy Total Value to Oil Assess Rend Line 8, Sec VI)	

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

This page must be attached to the oil assessment rendition, which must be dated and signed by owner and tax rendition preparer to be valid.

Lease Code WE1879 **County Code** 1879 **Lease Name** The Big One

Oil Well Definition

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

I. Production

The lease production capability for the current valuation year is typically established by the lease history. Annual production is to be used in the appraisal process, and is defined as the amount of oil or natural gas produced during the preceding calendar year, prior to the appraisal year, adjusted for down time where appropriate. However, in some cases, it may be necessary to adjust the prior year production to reflect the lease production capability for the current valuation year. An example might be annualizing six month or quarterly production, and considering the current year first quarter production. Any adjustments made by the appraiser to prior year production must be made with caution in anticipating current year production to establish market value.

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

EXAMPLE

22 days produced with 220 barrels total

220 Bbls divided by 22 days = 10 BOPD

10 BOPD x 31 days month = 310 Bbls / month

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

EXAMPLE

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

Sales shall not be used in the appraisal process:

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

Adjustments

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

a. Well shut down for work-over.

b. Pumping unit problems resulting in less production.

c. Transportation problems.

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

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

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

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

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

EXAMPLES

1) Well shut-down

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

Month	Production (Bbls)	Month	Production (Bbls)	Month	Production (Bbls)
Jan	275	**May**	0	**Sept**	260
Feb	265	**June**	0	**Oct**	240
Mar	285	**July**	294	**Nov**	248
Apr	270	**Aug**	285	**Dec**	0
				Total	**2422**

In this case a well work-over resulted in a 61 day shut-down for May and June. In December no production was reported. Hence, add in for these months of production capability by annualizing the nine months, e.g.,

2,422 Bbls/273 days = 8.87 Bbls/day x 365 days = 3,238 Bbls/yr

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

2) Reserve depletion

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

3) New leases

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

EXAMPLE

Month	Number Days	Production (Bbls)	Month	Number Days	Production (Bbls)
May	31	775	**September**	30	720
June	30	760	**October**	31	735
July	31	777	**November**	30	710
August	31	740	**December**	31	718
			Total	**245**	**5935**
Calculate Daily Production: Bbls / Days = 5935 / 245 = 24.22 Bbls/Day					
Calculate Annualized Production: Bbls X Yr = 24.22 X 365 = 8,840 Bbls/Yr					

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

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

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

The following example demonstrates the calculation adjustment necessary for a lease qualifying for a 40% reduction in income and expenses because of production commencing July 1 or later.

EXAMPLE

Lease production commenced August 16 of the prior year and produced 4,001 barrels in 138 days or 28.99 Bbls/Day or 10,582 barrels annualized. Assume a 30% decline rate, a $48.00 / Bbl crude oil price @ 40 gravity, 3,945 ft depth, and 94% water.

Oil Rendition - Section V - Gross Reserve Calculations										
1. Total Production (Bbls)		2. Net Price Jan 1		3. Est'd Gross Income Stream		4. Present Worth Factor		*KSA 79-331(b)*		5. Est'd Gross Res Value
10,582 Bbls	X	$48.00	=	$507,936	X	1.536	X	***.60***	=	$468,114

Oil Rendition - Section VI - Gross Reserve Value X Decimal Interest					
1. Royalty Interest	$468,114	X	0.125	=	$58,514
2. Working Interest	$468,114	X	0.875	=	$409,600
3. Less Operating Expense	1 @ $95,690	X	***.60*** ***(KSA 79-331(b))***	=	$57,414
7. Plus Equipment Value	1 @ 7,520			=	$7,520
10.Working Interest Total				=	$359,706

4) Change in the Number of Production Wells

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

a. New wells drilled on existing leases

EXAMPLE

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

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

b. Wells plugged or deleted from prior year

EXAMPLE

Month	Number Wells	Production	Month	Number Wells	Production
January	10	1250	**July**	6	474
February	10	1215	**August**	6	460
March	9	900	**September**	6	285
April	9	915	**October**	4	260
May	8	828	**November**	4	275
June	8	580	**December**	4	258
				Total	**7700**
Last Qtr Well Count: 4 Last Qtr Production: 793 Bbls Last Qtr Days: 92 Days					
Calculate Annualized Production: 793 Bbls/ 92 Days = 8.62 Bbls/Day X 365 Days = 3,146 Bbls/Yr					

The example shows the total production for the year to be 7,700 Bbls, with a fluctuating well count. The average number of wells for the year is seven. Yet, the well count is four for the last three months of the year. The last quarter well count of four should be used for the current year valuation providing there are still four producing wells in the first couple of months of the current tax year, which should be verified with the operator. Also, when verifying well count, the appraiser may want to ascertain the most current month's production to assist in establishing total production for the year. The total production for the last quarter, and any additional months in the first quarter of current tax year should be annualized to predict the current year's production. The last quarter in the above example calculates to 3,146 Bbls from the four remaining producing wells. Use 3,146 Bbls and four wells combined with the appropriate price, decline rate, and present worth factor to establish current year value.

II. Decline

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

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

If annualized production is used to estimate value, the annualized production is then used the following year to estimate decline, **supported by the most recent production activity relating to the January 1 appraisal date** for the lease, supported by a decline curve to determine whether the decline is appropriate and continuing. The following guidelines are recommended:

1) New Leases

The first few months of production may be used to establish the decline rate for a new lease. However, it is likely that a reasonable length of time has not passed and a normalized decline cannot be established from this initial production.

If the first few months of production and all data available do not indicate a reasonable rate of decline, it is suggested the appraiser consider the use of an assumed 30% annual decline rate and evaluate the property on this basis. This, however, is not automatic and is to be used only when the actual decline rate cannot be established. Use of a proven neighborhood decline rate may be considered appropriate after proper consideration for flush production, but only when the new well or wells are completed in the same reservoir. Requests for consideration of percentage decline above 30% or adjustments by the appraiser below 30% should be documented by production decline, water cut and/or gas oil ratio curves.

1a) Abnormal Decline for New and Existing Leases

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

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

2) Existing Leases

To estimate the decline rate on an existing lease **having stable production from year to year,** the current year decline is calculated by using the preceding two production years. For the 2026 tax year, use 2024 and 2025 as follows:

EXAMPLE

$$\text{Decline} = \frac{\text{2024 Production} - \text{2025 Production}}{\text{2024 Production}} = \frac{1{,}408 - 1{,}234}{1{,}408} = 12\%$$

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

For leases that have a production history, the production can be plotted to establish a decline curve to indicate the proper decline to be used in the valuation, **supported by the most recent production activity relating to the January 1 appraisal date,** to determine whether the decline is appropriate and continuing at that rate. For leases experiencing work-over periods, lease shutdowns, or other non-producing periods, the appraiser should consider this history along with recent activity since the decline rate prior to these periods typically resumes after production has stabilized if in the same producing zone.

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

QUARTER DECLINE to ANNUALIZED DECLINE TABLE

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

The following example demonstrates the use of the quarter to annualized decline rate table. Please note that **more than a single back to back quarter calculation should be considered when trying to establish an annual rate.**

EXAMPLE

Month	Production (Bbls)	Quarterly Production (Bbls)	Quarterly Decline %
January	812		
February	795		
March	821	2428	
April	780		
May	795		
June	765	2340	3.62%
July	800		
August	750		
September	725	2275	2.78%
October	700		
November	690		
December	695	2,085	8.35%
Calculate Quarterly Decline Rate: Prior Qtr - Current Qtr / Prior Qtr			
Considering Three Quarters, the Average Quarterly Decline is 4.92%			
An Estimate of Annualized Decline Rate Using Table: 19%			

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

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

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

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

III. Casinghead Gas

For wells producing casinghead gas, the revenue derived from the preceding year's total gas production is to be converted to barrels of oil equivalent and added to the annual oil production. Casinghead gas should not be annualized. Actual production should be used to add to the lease total. The conversion is made by multiplying casinghead gas production in Mcf by the net price per Mcf adjusted by the MAF as directed in the Gas Section IV, Price received per Mcf, which is then divided by the net price per Bbl of oil received on the lease.

EXAMPLE

An oil well produced 18,550 Mcf of casinghead gas for which the net price is $2.12 per Mcf, which is then adjusted by the MAF ($2.12/Mcf x 0.95 = $2.01), totaling a gross income of $37,286 (18,550 Mcf x $2.01 Mcf adj). The gross income stream is divided by the net price for oil, $48.00 per Bbl. This answer establishes the gas equivalent of oil in Bbls: $37,286/$48.00 = 777 Bbls. The total Bbls of oil equivalent should be added to the annual production in Sec. IV – Casinghead Gas (Conv Bbls).

Oil Rendition - Casinghead Gas Production Data (conversion calculation)								
Production (Mcf)		**Net $/Mcf Gas**		**Income**		**Net $/Bbl Oil**		**Total Bbls**
18550	X	$2.54	=	$37,286	/	$48.00	=	777
Transfer Converted Mcf Production to Bbls to Sec. IV, Casinghead Gas Conversion								

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

IV. Secondary Recovery

1) To qualify as a secondary recovery operation, the lease must have a permit number issued from the Kansas Corporation Commission specifying it as a secondary or enhanced recovery lease.

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

V. Price Received per Barrel

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

VI. Present Worth Factor

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

The PWF incorporates into the guide the life and performance characteristics based on the percentage rate of decline that is computed for each particular lease as set out under the "Percentage Rate of Decline". The factors to be used are those in the table entitled "Prescribed Present Worth Factor Table." An exception may be in the use of a non-decline factor where a lease has produced for a number of years without a decline from year to year. For example, there are some leases that have produced 15 to 20 years with the production varying only slightly from year to year. In these cases, the appraiser may use a higher factor not to exceed 3.451 for Table I and 4.238 for Table II if it is considered necessary to achieve the fair market value of the lease. These cases are rare and must be properly documented. They are not to be confused with cases where the production has been boosted due to a work-over, a new zone, new well, or new equipment. The production must reflect a non-decline trend that is expected to continue.

EXAMPLE

Year	Production (Bbls)	Production (Bbls)
	Case A	**Case B**
1	10,213	10,213
2	10,411	9,611
3	11,000	9,114
4	11,200	8,410
5	11,350	13,560

Case A would be the type where use of the 3.451(Tbl I) or 4.238 (Tbl II) factor is permitted. The fifth year production for Case B is greater than year 1, but indicates that some factor such as a work-over or acid fracturing or other reason has affected the production. The higher factor is not to be used in this case, since the lease does not represent non-declining production. The use of decline curves will establish the appropriate rate of decline to be used for Case B.

VII. Gross Reserve Value

The "Gross Reserve Value" of the lease, also known as the Total 8/8ths Interest, represents the present value of all reserves to be recovered in the future over the established life of the lease. This value includes all interests and equipment for the determined producing life of the lease. A salvage equipment value is then added back to the working interest to represent any remaining equipment value at the end of the lease's estimated economic life.

The "Estimated Gross Reserve Value", Section V, Line 5, is computed by multiplying Line 1, Annual Production (Bbls) by the Line 2, Effect Jan 1 Net Price $/Bbl to determine Line 3, the Estimated Gross Income Stream. The Estimated Gross Income Stream, Line 3, is then multiplied by the appropriate Present Worth Factor entered on Line 4, which is determined by the decline rate. This product is the Estimated Gross Reserve Value, Line 5.

EXAMPLE

Oil Rendition - Section V - Gross Reserve Calculations								
1. Annual Production (Bbls)		**2. Effect Jan 1 Net Price $/Bbl**		**3. Est'd Gross Income Stream**		**4. Present Worth Factor**		**5. Est'd Gross Res Value**
11,094 Bbls	X	$48.00	=	$532,512	X	1.536	=	$817,938

VIII. Royalty Interest Valuation and Division Orders

The Royalty Interest Valuation, Section VI, Line 1, is computed by multiplying the decimal royalty interest times the Estimated Gross Reserve Value from Section V, Line 5. The total royalty interest decimal figure is to include the royalty and all overriding royalty interests.

Once the total royalty and overriding interest value is established on Line 1, Sec VI of the rendition, it is then divided among all decimal interest owners in a separate attachment using the division order provided by the operator or purchaser on the lease. Each interest owner will be assigned an individual appraised value, their decimal portion of the entire Estimated Gross Reserve Value from Section V, Line 5, which will be assessed at 30%.

The division order, sometimes termed as the division of interest, should be used as the ***only valid document in royalty or overriding royalty ownership changes on a lease***. Thus, a current division order is a must to ensure proper ownership of royalty and overriding royalty interests.

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

The division order shall include the names, addresses and interests owned. If this information is not current or is not furnished with the rendition, the county appraiser will assign value for all of the royalty interests' proportionate share to the respective working interest owner thereof in suspense. The county treasurer will then bill all of the royalty interests' proportionate share of the taxes to the respective working interest owner thereof in suspense for collection from that working interest owner.

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

IX. Working Interest Valuation

The leasehold Working Interest Valuation is computed by multiplying the Estimated Gross Reserve Value from Section V, Line 5 by the total decimal working interest on Line 2, Section VI. An operating cost allowance found in Table I or Table II for particular types of wells is then deducted on Lines 3a, 3b, and 3c from the result on Line 2, Section VI, which is computed on Line 4, Section VI. ***Line 5, Section VI, should be completed by multiplying the Working Interest Value on Line 2, Section VI by 2% for Table I leases, 5% for Table I Secondary Recovery leases, 10% for Table II leases. Line 6, Section VI is then completed by transferring the result of Line 4 or Line 5, whichever is greater, to it.*** The appropriate prescribed equipment values on Lines 7a, 7b, 7c, 7d, and 7e are added to the result on Line 6. Any itemized equipment values are added on Line 8, Section VI from a supplemental listing dubbed Section III. The Working Interest Total Market Value is the result on Line 9, Section VI. The Working Interest Total Assessed Value, Line 10, Section VI, is obtained by multiplying the total from Line 9 by 30% unless the lease qualifies for 25% assessment rate (See Foreword, Paragraph #9, Page ii). **All Working Interest value is assigned to the lease operator.** The lease operator is responsible for dividing the total working interest assigned value to all joint interest partners.

X. Operating Expense

The operating expense allowance is based on experience of the various producing areas of Kansas, and it is supported by the U.S. Dept of Energy's, Energy Information Administration's statistical expense study for the Mid-Continent region. The operating expense allowance provides a sufficient amount per well by depth and water production for typical operating leases. The amount listed represents the discounted expense for the five or seven year term. Use the average depth of all wells associated with the lease to determine the depth to be used for operating expense and equipment value.

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

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

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

4) **Submersible/Centrifugal Pump Well:** Wells equipped with high volume submersible/centrifugal pumps are more expensive to operate than wells equipped with standard pumping equipment. Submersible/centrifugal pumps are commonly referred to by brand names such as "Reda" or comparable. These pumps are used to move large volumes of water.

   Table I: The operator is to submit actual operating costs for the lease to ensure adequate expense is allowed. The lease expenses should be documented on an annual basis excluding non-recurring expenses, and prorating expenses that include costs for more than one year such as a three year insurance premium, which should be allocated at one-third the premium amount for the annual expense. Property tax expense should be excluded (allowance for property tax is made in the PWF). The total allowable annual expense is multiplied by 3.595 to calculate the five year discounted expense allowance for Table I.

   Table II: The operator is to submit actual operating costs for the lease to ensure adequate expense is allowed. The lease expenses should be documented on an annual basis excluding non-recurring expenses, and prorating expenses that include costs for more than one year such as a three year insurance premium, which should be allocated at one-third the premium amount for the annual expense. Property tax expense should be excluded (allowance for property tax is made in the PWF). The total allowable annual expense is multiplied by 4.462 to calculate the seven year discounted expense allowance for Table II.

EXAMPLE

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

Note: *To determine Table II expense, the annual expense of $32,100 above is multiplied by the seven year discount factor of 4.462 to calculate the seven year discounted cost of $143,230 ($32,100 x 4.462).*

5) Excess Expense Allowance

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

The expenses listed in the tables reflect averages; hence, direct comparison to individual wells will not reflect individual experience. If excess operating expenses are requested for an individual lease, lease information for all leases operated within the same field may be requested by the appraiser to ascertain the average expense for the total leases operated. When reviewing operating expense requests, the reason for the request should be explained, and the problems for that lease should be analyzed to determine the cause for the expense and whether it is a short term problem or peculiar to the individual lease. For short term operating problems, no consideration is generally allowed, because the expenses are based on normal re-occurring operating conditions, efficient operating practices, and prudent management, discounted over five or seven years, to reflect typical operating experience. **The appraiser should consider only fully documented requests that are at least 25% greater than the expenses listed in the guide. Provide expense information as attachment.** Total acceptable annual expense is multiplied by 3.595 to develop a five year discounted operating cost for Table I properties, or 4.462 to develop a seven year discounted operating cost for Table II properties.

ALLOWABLE OPERATING EXPENSES:

- **Labor** (including employee benefits) to the district level
- **Utilities**: power, water, fuel or on-site fuel source converted to market price
- **Rental equipment** used to correct recurring problems
- **Supplies**
- **Dehydration and waste water disposal**
- **Corrosion control or other chemical treatment**
- **Lease maintenance and repairs** (including small recurring replacement parts and labor)
- **Lease maintenance and repairs** such as pulling jobs, bailing, parted rods, paraffin scraping, recurring casing leaks or sanding, acidizing and refracturing in the same zone, polymer treatments, and repairs on downhole equipment ***(the appraiser should be certain to consider the frequency of these expenses since they are discounted over 5 or 7 years)***
- **Transportation**
- **Insurance** (lease liability insurance)
- **Overhead through district foreman's level-15% maximum** (***If overhead exceeds maximum, the appraiser may make adjustment by subtracting overhead from total acceptable expenses and dividing the remaining expenses by 85%)***
- **Mechanical Integrity Test (MIT)** amortized over the period qualified by the test

OPERATING EXPENSES NOT ALLOWED:

- **New well drilling**, whether capitalized or expensed
- **New or replaced equipment** (not including small recurring maintenance parts)
- **Re-completion costs into a different producing zone**
- **Property taxes** (already allowed in the PWF)
- **Depreciation**
- **Depletion**
- **Amortization of mortgage payments**
- **Office overhead expense above district level**

EXAMPLE

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

Note: *To determine Table II expense, the annual expense of $20,700 above is multiplied by the seven year discount factor of 4.462 to calculate the seven year discounted cost of $92,363 ($20,700 x 4.462).*

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

XI. Equipment Value

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

A typical lease **Tank Battery** will consist of the following equipment. There will be differences among leases, and equipment and/or equipment count could vary. The appraiser should use discretion and consider the typical setup of his region before adding additional equipment to supplement the Table I or Table II Prescribed Equipment Value which includes equipment for a typical tank battery and one producing well.

Table I Prescribed Equipment = Tank Battery + Producing Well

Production equipment for one well includes all surface and subsurface equipment necessary in production such as a meter, casing, tubing, rods, down-hole pumps, pumping equipment, engines, etc….

Tank Battery equipment includes flowlines, manifold, separator, heater treater, accessory equipment, disposal system, stock and saltwater tanks. The typical tank battery volume is 600 Bbls, which could exist in various forms such as four 100 Bbl stock tanks and two 100 Bbl water tanks on a site, which might be seen in eastern Kansas. Another combination likely seen in central Kansas would be two 200 Bbl stock tanks and one 200 Bbl water tank.

Table II Prescribed Equipment = Tank Battery + Producing Well

Production equipment for one well includes all surface and subsurface equipment necessary in production such as a meter, casing, tubing, rods, down-hole pumps, pumping equipment, engines, etc….

Tank Battery equipment includes flowlines, manifold, separator, heater treater, accessory equipment, disposal system, stock and saltwater tanks. The typical tank battery volume is 600 Bbls, which could exist in various forms, but the combination likely seen in central and western Kansas would be two 200 Bbl stock tanks and one 200 Bbl water tank.

***If tank battery volume exceeds 600 Bbls, it is then necessary to add tanks as additional prescribed equipment by using tank salvage value multiplied by equipment factor in table on Line 7e, Section VI.*

1) Use Table I for leases 2,000 feet and less deep, and all Secondary Recovery operations. Use Table II for leases 2,001 feet and deeper.

2) **A temporarily abandoned well (TA)** is defined for tax purposes as a well that has had the equipment removed in anticipation of plugging the well bore prior to abandonment of the lease. **If the well qualifies as a "TA" well, the reserves are appraised at zero value. Only the equipment remaining in place as of the January 1 appraisal date should be considered.** If all equipment remains, use values in Table I or Table II equipment value for T/A'd wells. If removal has begun, use Itemized Equipment listing at the end of the guide for remaining equipment.

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

   <u>Shut-in Wells on Shut-in Leases:</u> If there is no production due to economics or only minimal production to maintain lease terms and/or to protect the reserve, the lease is appraised per shut-in equipment values based on depth listed on Table I or Table II in the Shut-In/TA on Shut-In Lease column for the first shut-in well on a shut-in lease. Each additional shut-in well on the same shut-in lease should be valued using the Table I or Table II Shut-In/TA on Producing Lease column. For example, a shut-in well on a shut-in lease at 1800 ft should be valued using Table I @ $2,810. The two additional shut-in wells on this shut-in lease at the same depth should be valued using Table I @ $1,930 ($965 X 2) for a total lease market value of $4,740. *Note: For leases that have a multitude of shut-in wells, less value may apply for the conglomeration of wells. The appraiser must have just cause and proper documentation to deviate from the guide value.*

   ***<u>Shut-in Wells on Producing Leases</u>*:** Appraise the lease as of January 1 based on the number of producing wells using equipment values from Table I or Table II, and appraise all shut-in wells on this same producing lease using Table I or Table II Shut-In/TA on Producing Lease column. For example, a lease has one producing well with a depth of 3400 ft and 55% water cut. The same lease has a shut-in well with the same average depth. The producing well should be appraised using Table II @ $6,540. The shut-in well should be appraised using Table II @ $5,840 for a total lease equipment value of $12,380. *Note: For leases that have a multitude of shut-in wells, less value may apply for the conglomeration of wells. The appraiser must have just cause and proper documentation to deviate from the guide value.*

4) **Equipment for Multiple Producing Wells on Producing Leases** should be valued using the tables below. Equipment for the first producing well on a producing lease, whose value includes a tank battery, should be valued per Table I or Table II. An equipment value for each additional producing well should be added from the Multiple Equipment Tables below with regard to depth and water cut. For example, a lease that has five producing wells going to one tank battery with an average depth of 900 ft and 87% water cut should value the first well using Table I @ $450. The remaining four producing wells on this lease should be valued using the Multiple Well Table I below @ $820 ($205 X 4) for a total lease equipment value of $1,270.

   If there is more than one tank battery on a lease, the values for the additional sites, inclusive of a well, should be added from Table I or Table II. For example, a lease that has 15 producing wells going to three tank batteries with an average depth of 1300 ft and 89% water cut would be valued with three wells including tank batteries from Table I @ $2,385 ($795 X 3), and the remaining 12 wells, exclusive of tank batteries, being valued using the Multiple Well Table I below @ $4,320 ($360 X 12) for a total lease equipment value of $6,705.
5) **A salt water disposal (SWD) well or system** is considered non-commercial if owned/operated by and used in conjunction with and/or connected to an operating lease(s) of the same owner/operator. This also includes those SWD wells/systems owned/operated by and primarily used in conjunction with and/or connected to an operating lease(s) of the same owner/operator that receive additional water from outside lease(s), possibly not owned/operated by the owner/operator of the SWD well/system, within close proximity to the SWD well/system only receiving income in an amount for reimbursement of the actual expense of disposal. The SWD well is appraised by depth

per Table I or II, SWD column. The SWD System value is to be appraised by adding a SWD value from Table I or II, SWD column for each producing lease it services. Operation costs for the salt water disposal well are considered as part of the producing lease's expense (note water %) unless the salt water disposal system qualifies as commercial.

6) **A salt water disposal (SWD) well or system** utilized for commercial dumping is appraised on the basis of net income multiplied by 3.595. Gross income and expenses should be reported for commercial dumping wells/systems. Then acceptable expenses are determined using the same allowable operating expense guidelines used for producing wells on pgs 15-17. The difference from income and acceptable expense (net income) is then discounted using the Table I five year expense factor of 3.595 in order to calculate value. Example: $18,000 gross income less $9,348 acceptable expenses = $8,652 x 3.595 = $31,104 value for the salt water disposal well. If expenses exceed income on a commercial dumping well, the appraiser may value the SWD equipment in place at $.75/ft depth.

7) If the **salt water disposal (SWD) well or system** is considered commercial, but is solely used in conjunction with and connected to producing leases, especially high water volume lease(s), controlled by a single operator, the average decline of the producing lease(s) dumping into system should be considered. Gross income and expenses should be reported for commercial dumping systems, then acceptable expenses are determined using the same allowable operating expense guidelines used for producing wells on pgs 15-17. The difference from income and acceptable expense (net income) is then discounted using the Table I PWF determined from the average decline for producing lease(s) on system in order to calculate value Example: $18,000 gross income less $9,348 acceptable expenses = $8,652 net income; average decline of producing high water volume lease(s) dumping into system by single operator is 15%, so use Tbl I PWF 2.273; $8,652 X 2.273 = $19,666 value for the salt water disposal system. If expenses exceed income on a commercial dumping well, the appraiser may value the SWD equipment in place at $1.05/ft depth

8) **Surface and subsurface equipment** stored on the lease or in a storage area elsewhere is to be itemized on a separate sheet, titled Section III, totaled, and the results transferred to Section VI, line 8. Such equipment is to be appraised in accordance with the equipment values from the table entitled "Oil and Gas Itemized Equipment Value Section".

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

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

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

XII. Tertiary Recovery

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

XIII. Oil Wells Capable of Producing But Never Produced

A well that has been drilled and completed, but has not been produced and/or had production sold in commercial quantities as of the appraisal date, is appraised pursuant to this table. This type of well is not to be classified as a TA or SI well. Do not use for wells that are capable of producing only one or two barrels per day. **Amounts listed indicate minimum reserve valuations.** The appraiser may also take first quarter production, plot decline, and extrapolate production to estimate value.

Depth	Working Interest Value	Royalty Interest Value
0 - 500 Ft	$5,000	None
501 - 1,000 Ft	$15,000	None
1,001 - 2,000 Ft	$25,000	None
2,001 - 4,000 Ft	$50,000	None
4,001 + Ft	$75,000	None

TABLE I

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

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

Prescribed Present Worth Factor

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

*The Present Worth Factor is necessary in the Gross Reserve Calculation on the Oil Assessment Rendition, Section V, Line 4

Prescribed Operator's Expense/Cost Allowance Per Well

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

Well Depth	< 90% Water	90% - 95% Water	> 95% Water	Centrifugal / Submersible	Injection
< = 500 Ft	$13,385	$15,390	$17,700	See Oper.Exp.Sec X,4	$10,240
501 - 1000 Ft	$19,120	$21,990	$25,285	See Oper.Exp.Sec X,4	$15,285
1001 - 1500 Ft	$21,620	$24,860	$28,590	See Oper.Exp.Sec X,4	$16,930
1501 - 2000 Ft	$24,120	$27,740	$31,900	See Oper.Exp.Sec X,4	$18,570
2001 - 3000 Ft	$46,930	$53,970	$62,065	See Oper.Exp.Sec X,4	$21,080
3001 - 4000 Ft	$67,045	$77,100	$88,665	See Oper.Exp.Sec X,4	$30,115
4001 - 6000 Ft	$77,470	$89,090	$102,455	See Oper.Exp.Sec X,4	$32,145
6001+ Ft	$112,680	$129,585	$149,020	See Oper.Exp.Sec X,4	$32,565

*The Operator's Expense/Cost Allowance is deducted from the Working Interest Value on the Oil Assessment Rendition, Section VI, Lines 3a, 3b, & 3c

TABLE I

(continued)

Prescribed Equipment Value Per Well

Equipment Factor 0.5332

Well Depth	< 90% Water	90% - 95% Water	> 95% Water	Centrifugal / Submersible	SWD/ INJ/ WS	Shut-In/TA Well on Shut-In Lease	Shut-In/TA Well on Prod Lease
< = 500 Ft	$315	$365	$415	$520	$60	$1,255	$265
501 - 1000 Ft	$450	$520	$595	$745	$180	$1,795	$380
1001 - 1500 Ft	$795	$915	$1,050	$1,310	$300	$2,305	$670
1501 - 2000 Ft	$1,140	$1,315	$1,510	$1,885	$420	$2,810	$965
2001 - 3000 Ft	$5,820	$6,695	$7,700	$9,605	$600	$11,295	$4,915
3001 - 4000 Ft	$8,650	$9,945	$11,440	$14,270	$840	$14,225	$7,300
4001 - 6000 Ft	$13,715	$15,770	$18,135	$22,625	$1,200	$22,535	$11,575
6001+ Ft	$17,445	$20,065	$23,075	$28,790	$1,680	$27,870	$14,725

- The Prescribed Equipment Value is added to the Working Interest Value on the Oil Assessment Rendition, Section VI, Lines 7a, 7b, 7c, 7d, & 7e.
- Prescribed Equipment Values defined Oil Section XI, Equipment Value. (Well and Tank Battery)
- Shut-In Leases use SI on SI Lease column for first well, additional shut-in wells on SI lease use SI on Producing Lease column. See instructions in Oil Section XI, Equipment Value, Paragraph #3.
- Shut-In Wells on Producing Leases use SI on Producing Lease column. See instructions in Oil Section XI, Equipment Value, Paragraph #3.
- Multiple Producing Wells on Producing Leases use Table I for first well, then Multi Table for additional wells. See example in Oil Section XI, Equipment Value, Paragraph #4.

See Oil Section XI, Equipment Value, for all Prescribed Equipment instructions.

Multiple Well Equipment Values for Producing Wells on Producing Leases

Equipment Factor 0.5332

Well Depth	< 90% Water	90% - 95% Water	> 95% Water
< = 500 Ft	$140	$165	$190
501 - 1000 Ft	$205	$235	$270
1001 - 1500 Ft	$360	$410	$475
1501 - 2000 Ft	$515	$590	$680
2001 - 3000 Ft	$2,620	$3,015	$3,465
3001 - 4000 Ft	$3,890	$4,475	$5,145
4001 - 6000 Ft	$6,170	$7,095	$8,160
> 6000 Ft	$7,850	$9,030	$10,385

*Multiple Well values are exclusive of tank battery. If more than one tank battery exists on a lease, Table I values should be used for total number tank batteries inclusive of a producing well. The remaining producing wells on the lease are to be valued per this table. See example in Oil Section XI, Equipment Value, Paragraph #4.

TABLE II

Primary Production Oil Wells > 2,000 Feet

15% Discount Rate; Seven Year Economic Life; 5% Property Tax Credit

Prescribed Present Worth Factor

Decline Rate (%)	PWF	Decline Rate (%)	PWF	Decline Rate (%)	PWF	Decline Rate (%)	PWF
0-5	3.569	**17**	2.373	**29**	1.588	**41**	1.063
6	3.448	**18**	2.294	**30**	1.536	**42**	1.028
7	3.332	**19**	2.218	**31**	1.485	**43**	0.994
8	3.220	**20**	2.145	**32**	1.437	**44**	0.961
9	3.112	**21**	2.074	**33**	1.390	**45**	0.929
10	3.008	**22**	2.006	**34**	1.344	**46**	0.897
11	2.907	**23**	1.940	**35**	1.300	**47**	0.867
12	2.810	**24**	1.876	**36**	1.257	**48**	0.838
13	2.717	**25**	1.814	**37**	1.216	**49**	0.809
14	2.626	**26**	1.755	**38**	1.176	**50-100**	0.781
15	2.539	**27**	1.697	**39**	1.137		
16	2.454	**28**	1.642	**40**	1.100		

*The Present Worth Factor is necessary in the Gross Reserve Calculation on the Oil Assessment Rendition, Section V, Line 4

Prescribed Operator's Expense/Cost Allowance Per Well

Based on Average Depth of All Wells Associated With the Lease
Expense Factor 4.462

Well Depth	< 90% Water	90% - 95% Water	> 95% Water	Centrifugal / Submersible
2000 - 3000 Ft	$58,245	$66,980	$77,030	See Oper.Exp.Sec X,4
3001 - 4000 Ft	$83,210	$95,690	$110,045	See Oper.Exp.Sec X,4
4001 - 6000 Ft	$96,150	$110,575	$127,160	See Oper.Exp.Sec X,4
6001+ Ft	$139,850	$160,830	$184,955	See Oper.Exp.Sec X,4

*The Operator's Expense/Cost Allowance is deducted from the Working Interest Value on the Oil Assessment Rendition, Section VI, Lines 3a, 3b, & 3c

TABLE II

(continued)

Prescribed Equipment Value Per Well

Equipment Factor 0.4031

Well Depth	< 90% Water	90% - 95% Water	> 95% Water	Centrifugal / Submersible	Shut-In/TA Well on Shut-In Lease	Shut-In/TA Well on Producing Lease
2000 - 3000 Ft	$4,400	$5,060	$5,820	$7,265	$8,540	$3,930
3001 - 4000 Ft	$6,540	$7,520	$8,650	$10,790	$10,760	$5,840
4001 - 6000 Ft	$10,370	$11,925	$13,715	$17,110	$17,040	$9,260
6001+ Ft	$13,195	$15,170	$17,445	$21,770	$21,075	$11,780

- The Prescribed Equipment Value is added to the Working Interest Value on the Oil Assessment Rendition, Section VI, Lines 7a, 7b, 7c, 7d, & 7e.
- Prescribed Equipment Value is defined Oil Section XI, Equipment Value. (Well and Tank Battery)
- Shut-In Leases use SI on SI Lease column for first well, additional shut-in wells on SI lease use SI on Producing Lease column. See instructions in Oil Section XI, Equipment Value, Paragraph #3.
- Shut-In Wells on Producing Leases use SI on Producing Lease column. See instructions in Oil Section XI, Equipment Value, Paragraph #3.
- Multiple Producing Wells on Producing Leases use Table II for first well, then Multi Table for additional wells. See example in Oil Section XI, Equipment Value, Paragraph #4.

See Oil Section XI, Equipment Value for all Prescribed Equipment instructions.

SWD/ INJ/ WS	
< = 500 Ft	$45
501 - 1000 Ft	$135
1001 - 1500 Ft	$225
1501 - 2000 Ft	$315
2001 - 3000 Ft	$455
3001 - 4000 Ft	$635
4001 - 6000 Ft	$905
6001+ Ft	$1,270

Multiple Well Equipment Values for Producing Wells on Producing Leases

Equipment Factor 0.4031

Well Depth	< 90% Water	90% - 95% Water	> 95% Water
2000 - 3000 Ft	$1,980	$2,280	$2,620
3001 - 4000 Ft	$2,945	$3,385	$3,890
4001 - 6000 Ft	$4,665	$5,365	$6,170
> 6000 Ft	$5,935	$6,825	$7,850

*Multiple Well values are exclusive of tank battery. If more than one tank battery exists on a lease, Table II values should be used for total number tank batteries inclusive of a producing well. The remaining producing wells on the lease are to be valued per this table. See example in Oil Section XI, Equipment Value, Paragraph #4.

OIL ASSESSMENT RENDITION

Schedule 2 (Class 2B) (Rev. 1/26)

SHALL BE FILED WITH THE COUNTY APPRAISER BY APRIL 1

________________ County, Kansas Tax Year 2026

Statement of ________________ **Operator ID#** ________
P.O. Address ________________ **City** ________ **State** ________ **Zip** ________
Name of Property ________________ **County ID#** ________ **KDOR ID#(s)** ________ **Well API#(s)** ________

Section I-Location of Property (required)								
Lease Description								
(Well location pg 2)								
Lot Sec.		Adn. Twp.						
Blk Rng.		Twp. City						
Tax Unit		School Dist						

Section VII-Abstract Value (for county use only)	Appraised	Assessed	Penalty	Total
Total Working Interest (Sec. VI. Line 9)				
Royalty & ORRI Interest (Sec. VI. Line 1)			XXXXXXXXX	
Itemized Equipment (Sec. VI. Line 8)				
Total				

Section II-Lease Data (required)

Producing Wells: Oil Submersible Gas	Non-Producing Wells: Shut-In SWD TA INJ WS			Total # Wells on Lease	
Secondary Recovery( ) KCC Permit #	Water Disposal: Hauler/System/Well Name			Total # Tank Batteries on Lease	
Spud Date: Mo/Yr (new prod)	Ave Prod Depth	Horizontal ( )	Total WI Decimal	Prod Formation	
Comp Date: Mo/Yr (new prod)	SWD/INJ/WS	Horiz Total Depth	Total RI&ORRI Dec	Purchaser Name	
Oil Gravity	Water Prod	BWPD	Purch Address	Purch Phone	

Section IV-Production Data (required)

Month	2025 Oil (Bbls)	2025 Casinghead Gas (Mcf)	2024 Oil (Bbls)
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
Annual Production			
Casinghead Gas (Converted to Bbls)		XXXXXX	XXXXXXXXX
Total Annual Production (Bbls + gas conv)		XXXXXX	XXXXXXXXX
Annual Decline (Bbls)		XXXXXX	XXXXXXXXX
Decline Rate (%)		XXXXXX	XXXXXXXXX

Notation

Lease Receives Eastern KS Posted Price Yes No
Severance Tax Exempt # Property Tax Exempt #

Casinghead Gas Production Data (conversion calculation)

X = / =
Prod (Mcf) X Net $/Mcf Gas = Income / Net $/Bbl Oil = Total Bbl (Transfer to Sec IV, Casing Gas Conv)

Gatherer Name
Address Phone

Section V-Gross Reserve Calculation (Total 8/8ths Interest)

	1. Annual Production (Bbls) (Total Annual Prod, Sec IV)		2. Effect Jan 1 Net Price $/Bbl (See Crude Oil Price Schedule)		3. Est Gross Income Stream (Multiply Line 1 X Line 2)		4. Present Worth Factor (Based on Decline Rate-See Tbl)		5. Est Gross Reserve Value (Total 8/8ths-Transfer Total to Sec VI, Lines 1&2)
Schedule (A)		X		=		X		=	
Owner (B)		X		=		X		=	
Appraiser (C)		X		=		X		=	

Section VI-Gross Reserve Value X Decimal Interest

			Schedule (A)	Owner (B)	Appraiser (C)
1. Royalty & Overriding Royalty Interest Valuation (Total Sec V, Line 5 X Total RI & ORRI Interest)	X	(Interest)			
2. Working Interest Valuation (Total Sec V, Line 5 X Total WI Interest)	X	(Interest)			
3a. Deduct Operating Cost Allowance for Producing Wells (Allowance per Well)	X	(Number Wells)			
3b. Deduct Operating Cost Allowance for Injection Wells (Allowance per Well)	X	(Number Wells)			
3c. Deduct Operating Cost for Submersible Wells (Annual Submersible Expense)	X	(Exp Fact-Tbl)			
4. Working Interest Subtotal (Sec VI, Line 2 minus Lines 3a, 3b & 3c)					
5. Working Interest Minimum Lease Value (Sec VI, Line 2)	X	(2%,5%,10% Min Lse)			
6. Copy Value from Sec VI, Line 4 or Line 5 (Whichever Line is Greater)					
7a. Add Prescribed Equipment Value for Producing Wells (Allowance per Well)	X	(Number Wells)			
7b. Add Prescribed Equipment Value for Multiple Producing Wells (Allowance per Well)	X	(Number Wells)			
7c. Add Prescribed Equipment Value for Non-Producing Wells (Shut-In, TA,SWD,INJ,WS)	X	(Number Wells)			
7d. Add Prescribed Equipment Value for Submersible Wells (Allowance per Well)	X	(Number Wells)			
7e. Add Pres Equip Value for Additional Equipment	X	(Equip Fact-Tbl)			
8. Add Itemized Equipment (Section III - Attached Schedule)					
9. Working Interest Total Market Value (Add Sec VI, Lines 6, 7a, 7b, 7c, 7d, 7e & 8)					
10. Working Interest Total Assessed Value (Multiply Sec VI, Line 9 X 30%, Unless Lease Qualifies for 25% Rate)		(Rate)			

Current Division Order with Name, Address, Interest of Royalty Owners, and Well/Lease Identifier is a Required Attachment to Rendition

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

________________ ________ ________________ ________
Owner **Date** **Tax Rendition Preparer** **Date**

Rendition Information: **Contact Phone** ( ) - **Contact Email** @

Lease Code ________ **County Code** ________ **Lease Name** ________

Prescribed by Kansas Department of Revenue, Division of Property Valuation

Gas Section

Gas Section

Gas Rendition Form Instructions

The lease operator/taxpayer/tax representative is required to provide the information requested in Sections I through IV of the gas rendition form and all other information necessary to fix the valuation of the property as determined by the Director of Property Valuation. Failure to provide this required information will result in a 12.5% penalty assessed to the operator based on the total value of the royalty interest plus the working interest for failure to file a full and complete statement of assessment according to KSA 79-332a (c). COLUMN A (SCHEDULE VALUE) is to be completed by using the oil and gas guide without departure, adjustment, or change. COLUMN B (OWNER) is reserved for the lease operator/taxpayer/tax representative's use for requested adjustments to Column A. COLUMN C (APPRAISER) is reserved for the county appraiser to finalize the valuation of the well/lease.

The Gas Rendition-Schedule Value (Column A) Instructions

An example of the gas assessment rendition can be found following this explanation.

NOTE: For copies of the rendition forms and oil and gas guide, please contact the county appraisal office for the county in which the property is located or download from https://www.ksrevenue.gov/pvdoilgas.html.

Statement of Ownership/ Address/Property Name	Provide information to the extent available. It may be necessary to complete page 2 in order to list all wells on the lease and include location, KDOR ID #s, API #s, etc…
Section I: Location of Property	**THIS IS REQUIRED DATA.** A minimum legal description of Section, Township, and Range is required. Quarter section and/or more detailed location description is preferred.
Section II: Well Data	**THIS IS REQUIRED DATA.** A single gas well per rendition is preferred; however, if a lease's production cannot be separated by well, then the entire lease should be rendered on one form. Provide information as requested for the number of producing gas wells, pumping or flowing. Also provide non-producing well counts for shut-in wells, salt water disposal wells, and temporarily abandoned wells. Water production per day, average completion depth and SWD depth should also be provided. Provide producing field name, BTU content, spud and completion dates. Note infill, vacuum, or coalbed methane wells with checkmark. The total working interest and royalty interest decimal must also be provided for the correct value split. Provide water disposal information as requested, as well as, gas gatherer names and address. The prior year gross weighted average $/Mcf should be provided inclusive of BTU adjustments. Any allowable deductions should be noted to arrive at the Effective Jan 1 Net Price $/Mcf. The royalty owner Effective Jan 1 Net Price $/Mcf. Provide all wells, KDOR #s, and API #s for lease in lease name/number tie field. Identification of all wells on lease is to be provided on page 2 of rendition unless there is enough space to accommodate list in Sec II or notation section on page 1. Identification includes items such as location, well type, KDOR#, API#, and production if not all included on page 1 and/or if not all included under one KDOR#.
Section III: Itemized Equipment	**THIS IS REQUIRED DATA** if it exists. The rendition sheet page 2 has been created for this information. Please attach page 2 with a listing of equipment located on the lease, but not part of the producing "prescribed" equipment. Also, equipment located in storage yards and/or other sites which is considered "itemized equipment" per this guide should be listed using page 2 of the rendition. Once listed on page 2 of the rendition, the total value shall be transferred to the total Itemized Equipment value on Line 9, Section VI, page 1 of the rendition.
Section IV: Production Data	**THIS IS REQUIRED DATA.** Provide five years of history, if applicable. The production should be submitted on an annual basis including explanations for zero production months, downtime, or other information necessary to annualize/analyze lease production capability under the "Notation" section. Condensate production on the well/lease should be provided in annual increments in the appropriate column. The condensate amount should be actual production and should not be annualized. The annual condensate total (Bbls) should then be transferred to the conversion calculation box for conversion to Mcf of gas to include in total well/lease annual production.

Section V: Gross Reserve Calculation **(Total 8/8ths Interest)**	**Line 1: Annual Production (Mcf)**-Use the prior year total annual production from Sec IV For new or incomplete year production follow adjustment rules in Gas Section I, pg 29 **Line 2: Effective Jan 1 Net Price $/Mcf multiplied by Market Adjustment Factor (MAF)**-Use current yr MAF. See Gas Section IV, pg 31. See rendition Section II for price info. **Line 3: Estimated Gross Income Stream**- Multiply Line 1 X Line 2 and enter result on Line 3 **Line 4: Present Worth Factor**-Use factor from Table A, B, or C. The Present Worth Factor is based on decline rate. See Gas Section II, Major Fields Sec II, AOK Sec III, or CBM Sec III in guide to determine decline rate. **Line 5**: **Estimated Gross Reserve Value**-Multiply Line 3 X Line 4 and enter result on Line 5 for Estimated Gross Reserve Value (Total 8/8ths Value). The total is then transferred to Lines 1 & 2 in Section VI of rendition.
Section VI: Gross Reserve Value X Decimal Interest **(Calculation of Royalty and Working Interests)**	**Line 1: Royalty Interest Valuation**-Multiply the Estimated Gross Reserve Value (Sec. V, Line 5) X Total Royalty Decimal Interest. Total RI value is then assigned to individual RI and ORRI owners per the division of interest and assessed at 30%. **Line 2: Working Interest Valuation**- Multiply the Estimated Gross Reserve Value (Sec. V, Line 5) X Total Working Decimal Interest. **Water Credit Adjustment for Table B** wells is also made on Line 2. Multiply the Estimated Gross Reserve Value (Sec. V, Line 5) X Total Working Decimal Interest as noted above. This total is then multiplied X Gas Well or Combination Factor from Table B, Prescribed Water Credit Adjustment. **Line 3**: **Deduct Operating Cost Allowance for Producing Well**-Use expense allowance per well from Table A, B, or C, then multiply by number producing wells if more than one well reported on rendition. **Line 4: a. Deduct Wellhead Compression**-Use acceptable actual annual expense for wellhead compression, then multiply by expense factor from Table A, B, or C. a. **Deduct Water Expense Allowance-** Use acceptable actual annual expense for water, then multiply by expense factor from Table A wells. Table B water expense adjustment is made on Line 2 above. If Table B does not use adjust factor, actual expense may be deducted on this line by multiplying times Table B expense factor. Table C hauling expenses may be deducted on this line by multiplying times Table C expense factor. **b. Deduct Water Expense Allowance**-Use SWD expense allowance per SWD well from Table C. Use SWD expense allowance per gas producing well for SWD system expenses. **Line 5**: **Working Interest Subtotal**-Subtract expenses Sec VI, Lines 3, 4a, 4b, & 4c from Line 2 (WI Value). **Line 6**: **Working Interest Minimum Lease Value**-Multiply Sec VI Line 2 X 10% for Table A and B gas wells/leases, and 5% for Table C gas wells/leases. **Line 7**: **Copy Value from Sec VI Line 5 or Line 6**-Use whichever line is greater. **Line 8: a. Add Prescribed Equipment Value for Producing Wells**-Use equipment allowance per well from Table A and Table C. Determine whether Pumping or Flowing well for Table B allowance. **b. Add Prescribed Equipment Value for Non-Producing Wells-**Use equipment allowance per well from Table B and Table C for Shut-In, TA, & SWD wells. Add SWD equipment value per gas producing well for SWD system values. Table A see Gas Section, Major Proven Fields, Section IV, Equipment Value. **c**. **Add Prescribed Equipment Value for Additional Equipment**-Use actual salvage equipment value for additional equipment necessary in production that is not already included in the prescribed equipment values noted above, then multiply by equipment factor per Table A, B, or C. **Line 9: Add Itemized Equipment**-Use Itemized Equipment Section from back of guide to value attached listing of equipment not currently being used in well production. **Line 10:Working Interest Total Market Value**-Add Sec VI, Lines 7, 8a, 8b, 8c & 9 **Line 11:Working Interest Total Assessed Value**-Multiply Line 10 X 30%, unless lease qualifies for 25% assessment rate. **Certification:** ***The certification is to be completed and signed by the lease owner or operator who is responsible for filing the tax rendition with the county appraiser. It must also be signed by the rendition preparer.*** **Division Orders***:* ***A list of the current royalty owners, their decimal interest, and their addresses, is to be provided by the operator and is a requirement for filing the tax rendition.***

GAS ASSESSMENT RENDITION

SHALL BE FILED WITH THE COUNTY APPRAISER BY APRIL 1

Schedule 2 (Class 2B) (Rev. 1/26)

General Kansas **County, Kansas** **Tax Year** 2026

Statement of	We Have Gas			**Operator ID#**	4365298
P.O. Address	8953 North Ave.	**City** Riverdale	**State** KS	**Zip**	66953
Name of Property	Gusher	**County ID#** 4869	**KDOR ID#(s)** 245873	**Well API#(s)**	8542975-1

Section I-Location of Property (required)			
Lease Description	NE / 4		
(Well location pg 2)			
Lot Sec.	26	Adn. Twp.	32
Blk Rng.	32	Twp. City	
Tax Unit	42	School Dist	364

Section VII-Abstract Value (for county use only)	Appraised	Assessed	Penalty	Total
Total Working Interest (Sec. VI. Line 10)				
Royalty & ORRI Interest (Sec. VI. Line 1)			xxxxxxxxx	
Itemized Equipment (Sec. VI. Line 9)				
Total				

Section II-Well Data (required)

Producing Well: Pump Flow 1 Non-Producing Well: Shut-In SWD TA Bbls Water per Day 6 Ave Depth 3250' SWD Depth

Producing Field Name Jones-AOK BTU Content 1000 Spud Date: Mo/Yr(new prod) 6/1994 Comp Date: Mo/Yr(new prod) 8/1994 Total WI 0.875000

( )Infill ( )Commingled ( )CBM ( )Horizontal Total Depth Horizontal Lease Name/Number Tie (List All Wells KDOR#s & Total RI 0.125000

Water Disposal: Hauler/System/Well Name John's Disposal ( ) SWD System		Prior Yr Gross Weighted Ave $/Mcf (Adjusted for BTU Content)	$2.65
Address Riverdale, KS	Phone (785)225-7856	Less Allowable Deductions $/Mcf (Gathering, Transportation, etc…)	$0.15
Gatherer Name Gas Pipeline		Effective Jan 1 Net Price $/Mcf (Prior Yr Net Weighted Ave Price $/Mcf)	**$2.50**
Address Riverdale, KS	Phone (785)225-3285	Effective Jan 1 Net Price $/Mcf to Royalty Owner	**$2.50**

Section IV-Production Data (required)

Year		Cond(Bbls)	Gas(Mcf)
2021	Annual Production	0	40,875
2022	Annual Production	0	38,446
2023	Annual Production	0	32,194
2024	Annual Production	0	29,843
2025	Annual Production	0	27,792
Total Production (5 yr cumulative)		0	169,150
Annual Production (Prior Yr)		0	27,792
Condensate (Converted to Mcf)		xxxxxxxxx	0
Total Annual Production (Mcf + condensate conversion)			27,792

Condensate Production Data (conversion calculation)

0	X	0	$2.38	0

Prod (Bbls) X Net $/Bbl Oil = Income / Net $/Mcf Gas = Total Mcf (cond conv)

Notation

Decline Rate: 7%

Tx Yr 2026 Decline: **29,843 -27,792** / **29,843** **7%**

GAS RENDITION SAMPLE

Assessment Rate--see page 2

Section V-Gross Reserve Calculation (Total 8/8ths Interest)	**Schedule (A)**	**Owner (B)**	**Appraiser (C)**
1. Annual Production - Mcf (Total Annual Prod Sec IV)	27,792		
2. Effective Jan 1 Net Price $/Mcf (Sec II) **$2.50** X market adjust factor **0.95** adj inc/dec	2.38		
3. Estimated Gross Income Stream (Multiply Line 1 X Line 2)	66,145		
4. Present Worth Factor (Based on Decline Rate-Apply Appropriate Table PWF)	3.157		
5. Estimated Gross Reserve Value (Total 8/8ths - Multiply Line 3 X Line 4 - Transfer Total to Section VI, Lines 1 & 2)	208,820		

Section VI-Gross Reserve Value X Decimal Interest	**Schedule (A)**	**Owner (B)**	**Appraiser (C)**
1. Royalty & Overriding Royalty Interest Valuation (Total Sec V, Line 5 X Total RI & ORRI Interest) X 0.125000	26,103		
2. Working Interest Valuation (Total Sec V, Line 5 X Total WI Interest) 0.875000 X 0.98 Tbl B Water Credit Adj	179,063		
3. Deduct Operating Cost Allowance for Producing Well (Allowance per Tbl) 1 X 69600	69,600		
4a. Deduct Wellhead Compression (Annual Compression Expense) X (Expense Factor-Tbl)	0		
4b. Deduct Water Expense Allowance (Tbl A Yr Exp; Tbl B Yr Exp if Actual) X (Expense Factor-Tbl)	0		
4c. Deduct Water Exp Allow Tbl C per SWD Well (SWD Exp per Prod Well if SWD System) X	0		
5. Working Interest Subtotal (Sec VI, Line 2 minus Lines 3, 4a, 4b & 4c)	109,463		
6. Working Interest Minimum Lease Value (Sec VI, Line 2) 179,063 X 10%	17,906		
7. Copy Value from Sec VI, Line 5 or Line 6 (Whichever Line is Greater)	109,463		
8a. Add Prescribed Equip Value for Producing Well Flow 2610 Pump 1	2,610		
8b. Add Prescribed Equip Value for Non-Prod Well (SI, TA,SWD) X	0		
8c. Add Pres Equip Value for Add Equip(Compressors,Gthrg Lines,etc…) X (Equip Fact-Tbl)	0		
9. Add Itemized Equipment (Section III - Attached Schedule)	0		
10. Working Interest Total Market Value (Add Sec VI, Lines 7, 8a, 8b, 8c, & 9)	112,073		
11. Working Interest Total Assessed Value (Multiply Sec VI, Line 10 X 30%, Unless Lease Qualifies for 25% Rate) **30%**	33,622		

Current Division Order with Name, Address, Interest of Royalty Owners, and Well/Lease Identifier is a Required Attachment to Rendition

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

Mr. Gas Producer	2026		
Owner	**Date**	**Tax Rendition Preparer**	**Date**

Rendition Information: Contact Phone (813) 444 - 8989 **Contact Email** wehavegas@xyz.com

Lease Code H-78967 **County Code** 4869 **Lease Name** Gusher

Prescribed by Kansas Department of Revenue, Division of Property Valuation

GAS ASSESSMENT RENDITION ADDITIONS PAGE

MUST BE ATTACHED TO GAS ASSESSMENT RENDITION

Schedule 2 (Class 2B) (Rev. 1/26) General Kansas **County, Kansas** **Tax Year** **2026**

Statement of We Have Gas **Operator ID#** 4365298

Name of Property Gusher **County ID#** 4869 **KDOR ID#(s)** **245873** **Well API#(s)** 8542975-1

Section I-IV Additional Data (required)

Well Names on Lease	Location	Well Type	KDOR ID#	Well API#	Well Production	
					Bbls	Mcf
Gusher (Base well on pg 1)	Lat. -19.68998 Long 12.359	Gas-AOK	**245873**	8542975-1		**27,792**
Gusher A	Lat. -29.87998 Long 11.339	Gas-AOK	**216754**	85459454-1		**15,253**
Gusher B-1	Lat. -59.87998 Long 9.340	Gas-AOK	**298345**	7864684-1		**11,485**
Notation			**Total Lease Production** (includes all wells on lease-pg 1 rendition)		0 Total Bbls	**54,530** Total Mcf

Tie all wells on lease together to determine assessment rate. Gas wells typically on separate renditions.

Section III Itemized Equipment (required)

Property Name/Model	Property Description	Location	Condition (New/Used/Salvage)	Year	Series	Mast (ft)	Capacity (lbs)	Guide Value
Notation					**Total Item Equip Value** (Copy Total Value to Gas Assess Rend Line 9, Sec VI)			

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

This page must be attached to the gas assessment rendition, which must be dated and signed by owner and tax rendition preparer to be valid.

Lease Code H-78967 **County Code** 4869 **Lease Name** Gusher

Prescribed by Kansas Department of Revenue, Division of Property Valuation

Gas Well Definition

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

I. Production

The lease production capability for the current valuation year is typically established by the lease history. Use prior year production for all fields in Table A, Table B, and Table C. Adjustments may be necessary to production if prior year production is not indicative of future well capabilities. Any adjustments made by the appraiser to prior year production must be made with caution in anticipating current year production to establish market value.

Adjustments

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

a. Well shut down for work-over.

b. Pumping unit problems resulting in less production.

c. Transportation problems.

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

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

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

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

For these reasons and others, it may be necessary to adjust the production to reflect the lease production capability for the near future term. Adjustments may be made using examples in the Oil Section I, Production, Adjustments, pages 4-7. For specific adjustment options by gas table, please refer to alternative production options in Section I, Major Proven Gas Areas and Fields for Table A, Section II, All Other Kansas for Table B, and Section II, Coalbed Methane Gas Fields for Table C for existing leases.

New Leases

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

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

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

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

II. Decline

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

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

If annualized production is used to estimate value, the annualized production is then used the following year to estimate decline, **supported by the most recent production activity relating to the January 1 appraisal date** for the lease, supported by a decline curve to determine whether the decline is appropriate and continuing.

Specific decline information for each group of gas fields is located in the respective section. Table A decline information can be found in Section II, Major Proven Gas Areas and Fields. Table B decline information may be found in Section III, All Other Kansas, while Table C decline notes may be found in Section III, Coalbed Methane Gas Fields.

III. Condensate Production

For wells producing condensate, the revenue derived from the preceding year's total oil production is to be converted to Mcf of gas and added to the annual gas production. Condensate production should not be annualized. Actual production should be used. The conversion is made by multiplying condensate production in Bbls by the net price per Bbl, which is then divided by the net price per Mcf of gas adjusted by MAF received on the lease.

EXAMPLE

A gas well produced 2,000 Bbls of condensate oil for which the net price is $48.00 per Bbl based on the Crude Oil Price Schedule's 40* gravity price. The total gross income would be $96,000 (2,000 Bbls X $48.00/ Bbl). The gross income stream is divided by the net price for gas adjusted by the MAF as directed in Gas Section IV ($2.43/mcf X 0.95 = $2.31), $2.31 per Mcf. This answer establishes the oil equivalent of gas in Mcf: $96,000/$2.31 = 41,558 Mcf. The total Mcf of gas equivalent should be added to the annual production in Sec. IV – Condensate (Conv Mcf).

Gas Rendition - Condensate Production Data (conversion calculation)								
Production (Bbls)		**Net $/Bbl Oil**		**Income**		**Net $/Mcf Gas**		**Total Mcf**
2,000	X	$48.00	=	$96,000	/	$2.31	=	41,558
Transfer Converted Bbl Production to Mcf to Sec. IV, Condensate Conversion								

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

IV. Price Received per Mcf

The price to be used is the prior year's net weighted average price adjusted for the current year market conditions by multiplying it by a factor issued by the Director of Property Valuation. The factor will be considered the **"Market Adjustment Factor" (MAF)**, and it will be effective January 1 of the current tax year and made a part of the oil and gas guide by reference. The MAF will be applied in Section V, Line 2 of the Gas Assessment Rendition.

The net weighted average price per Mcf shall be calculated by multiplying the volumes sold in each month times the price or prices received per one million BTU before any reductions for taxes or levies of any kind, but after quality adjustments, upward or downward, from a base of one million BTU per one thousand cubic feet. The BTU content shall be measured at the wellhead prior to any processing or extraction of natural gas liquids. Each month's average price shall be added to each succeeding month's average price then divided by the months produced and sold to arrive at a weighted average price. Allowable deductions may be taken from the weighted average price resulting in a "net" weighted average. Deductions are to be displayed in Section II of the Gas Assessment Rendition. **The net weighted average price calculation shall be supported by written documentation supplied to the appraiser either on a per-lease basis or by pipeline or system basis, whichever is appropriate.**

Allowable Deductions from Price Received:

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

Note: *The recoupment of initial costs/expenses for pipeline is **NOT** a valid deduction. If these charges are being applied to either the working or royalty interest payments, then the price used must be adjusted upward to eliminate these deductions from the price rendered for valuation purposes. Deductions must be documented on either a lease basis or by pipeline or system basis. In the case of off lease sales, the price to be used is that paid to the Royalty Interest, including any amount paid in to escrow. All such information will be treated as confidential if so designated when the rendition is filed.*

V. Severance Tax Multiplier

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

KSA 79-4219 provides for a 3.67% credit for local production taxes resulting in a 4.33% "net" severance tax. Both the state severance and local production taxes have been allowed as an expense in calculation of the present value factors. When any natural gas purchase contract allows reimbursement for both ad valorem and 4.33% state severance taxes, multiply Line 5, Section V (Total Value) by a factor of 1.12 for Table A properties, or 1.10 for Table B and Table C properties.

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

VI. Present Worth Factor

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

VII. Gross Reserve Value

The “Gross Reserve Value” of the lease, also known as the Total 8/8ths Interest, represents the present value of all reserves to be recovered in the future over the established life of the lease. This value includes all interests and equipment for the determined producing life of the lease. A salvage equipment value is then added back to the working interest to represent any remaining equipment value at the end of the lease’s estimated economic life.

The “Estimated Gross Reserve Value", Section V, Line 5, is computed by multiplying Line 1, Annual Production (Mcf) by the Line 2, Effect Jan 1 Net Price $/Mcf x Market Adjustment Factor (MAF) to determine Line 3, the Estimated Gross Income Stream. The Estimated Gross Income Stream, Line 3, is then multiplied by the appropriate Present Worth Factor entered on Line 4, which is determined by the decline rate. This product is the Estimated Gross Reserve Value, Line 5.

EXAMPLE

Gas Rendition - Section V – Gross Reserve Calculation	
1. Annual Production - Mcf	50,000
2. Effect Jan 1 Net Price / Mcf X MAF ($2.16X0.95)	$2.05
3. Est'd Gross Income Stream	$102,500
4. Present Worth Factor	2.994
5. Est'd Gross Reserve Value	$306,885

VIII. Royalty Interest Valuation and Division Orders

The Royalty Interest Valuation, Section VI, Line 1, is computed by multiplying the decimal royalty interest times the Estimated Gross Reserve Value from Section V, Line 5. The total royalty interest decimal figure is to include the royalty and all overriding royalty interests.

Once the total royalty and overriding interest value is established on Line 1, Sec VI of the rendition, it is then divided among all decimal interest owners in a separate attachment using the division order provided by the operator or purchaser on the lease. Each interest owner will be assigned an individual appraised value, their decimal portion of the entire Estimated Gross Reserve Value from Section V, Line 5, which will be assessed at 30%.

The division order, sometimes termed as the division of interest, should be used as the ***only valid document in royalty or overriding royalty ownership changes on a lease***. Thus, a current division order is a must to ensure proper ownership of royalty and overriding royalty interests.

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

The division order shall include the names, addresses and interests owned. If this information is not current or is not furnished with the rendition, the county appraiser will assign value for all of the royalty interests' proportionate share to the respective working interest owner thereof in suspense. The county treasurer will then bill all of the royalty interests' proportionate share of the taxes to the respective working interest owner thereof in suspense for collection from that working interest owner.

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

IX. Working Interest Valuation

The leasehold Working Interest Valuation is computed by multiplying the Estimated Gross Reserve Value from Section V, Line 5 by the total decimal working interest on Line 2, Section VI. An operating cost allowance found in Table A, B, or C for particular types of wells is then accounted for on Line 3. Wellhead compression expenses and water expenses are considered on Lines 4a, 4b, and 4c, as well. Lines 3, 4a, 4b, and 4c are deducted from the result on Line 2, Section VI, which is computed on Line 5, Section VI. ***Line 6, Section VI, should be completed by multiplying the Working Interest Value on Line 2, Section VI by 10% for Table A and Table B gas leases, and 5% for Table C gas leases. Line 7, Section VI is then completed by transferring the result of Line 5 or Line 6, whichever is greater, to it.*** The appropriate prescribed equipment values on Lines 8a, 8b, and 8c are added to the result on Line 7. Any itemized equipment values are added on Line 9, Section VI from a supplemental listing dubbed Section III. The Working Interest Total Market Value is the result on Line 10, Section VI. The Working Interest Total Assessed Value, Line 11, Section VI, is obtained by multiplying the total from Line 10 by 30% unless the lease qualifies for 25% assessment rate (See Foreword, Paragraph #9, Page ii). **All Working Interest value is assigned to the lease operator.** The lease operator is responsible for dividing the total working interest assigned value to all joint interest partners.

X. Operating Expenses

Please refer to Table A, Major Proven Gas Areas and Fields, Table B, All Other Kansas, or Table C, Coalbed Methane Gas Fields, for appropriate expense allowance.

Excess Expense Allowance

Guide allowed expenses are direct re-occurring expenses for specified depths discounted over a three to twenty five year period for Table A, a seven year period for Table B, and a seven year period for Table C. Work-over expense is not included in the table expense.

The expenses listed in the tables reflect averages; hence, direct comparison to individual wells will not reflect individual experience. If excess operating expenses are requested for an individual lease, lease information for all leases operated within the same field may be requested by the appraiser to ascertain the average expense for the total leases operated. When reviewing operating expense requests, the reason for the request should be explained, and the problems for that lease should be analyzed to determine the cause for the expense and whether it is a short term problem or peculiar to the individual lease. For short term operating problems, no consideration is generally allowed, because the expenses are based on normal re-occurring operating conditions, efficient operating practices, and prudent management, discounted over the table economic lives, to reflect typical operating experience. **The appraiser should consider only fully documented requests that are at least 25% greater than the expenses listed in the guide. Provide expense information as attachment.** Total acceptable annual expense is multiplied by Table A expense factor dependent upon decline to develop a three to twenty five year discounted operating cost, or 4.462 to develop a seven year discounted operating cost for Table B and Table C properties.

ALLOWABLE OPERATING EXPENSES:

- **Labor** (including employee benefits) to the district level
- **Utilities**: power, water, fuel or on-site fuel source converted to market price
- **Rental equipment** used to correct recurring problems
- **Supplies**
- **Dehydration and waste water disposal**
- **Corrosion control or other chemical treatment**
- **Lease maintenance and repairs** (including small recurring replacement parts and labor)
- **Lease maintenance and repairs** such as pulling jobs, bailing, parted rods, paraffin scraping, recurring casing leaks or sanding, acidizing and refracturing in the same zone, polymer treatments, and repairs on downhole equipment ***(the appraiser should be certain to consider the frequency of these expenses since they are discounted over 5 or 7 years)***
- **Transportation**
- **Insurance** (lease liability insurance)
- **Overhead through district foreman's level-15% maximum** (***If overhead exceeds maximum, the appraiser may make adjustment by subtracting overhead from total acceptable expenses and dividing the remaining expenses by 85%)***
- **Mechanical Integrity Test (MIT)** amortized over the period qualified by the test

OPERATING EXPENSES NOT ALLOWED:

- **New well drilling**, whether capitalized or expensed
- **New or replaced equipment** (not including small recurring maintenance parts)
- **Re-completion costs into a different producing zone**
- **Property taxes** (already allowed in the PWF)
- **Depreciation**
- **Depletion**
- **Amortization of mortgage payments**
- **Office overhead expense above district level**

Complete Column B with actual expenses multiplied by the appropriate expense factor from Table A, Table B, Table C if requesting excess expenses.

Compression expenses should be included for Table A, Table B, and Table C total expenses. Water should be included in Table A total expenses, see Water Credit Adjustment Factor for Table B. The appraiser should be certain to either use Table B Water Credit Adjustment or actual water expense, but not both. Table C water expense is provided in table by depth.

Example: $18,500 per year x 5.768 = $106,708 (for a Hugoton-Chase well at 15% decline rate).

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

Example: $800 per year x 4.462 = $3,570 (for an All Other Kansas well)

Expense for water is deducted in Section VI, on line 4b if not included in total actual expenses (see above) for Table A wells. The annual water expense is multiplied by the appropriate expense factor from Table A. Table B expense allowance for water is made using a Water Credit Adjustment Factor in Section VI, Line 2. (see Table B, AOK, for Water Credit Factor) Table B actual annual water expense may be multiplied by the 4.462 expense factor and deducted on Line 4b if the appraiser chooses **NOT** to use the Water Credit Adjustment Factor on Line 2, typically due to high volumes of water. Table C water expense allowance may be determined per SWD well and depth from Table C. It is applied in Section VI, Line 4c. For those SWD systems, a SWD well expense should be allowed for each gas producing well on the rendition to account for system expenses. **Provide supporting expense information for actual expenses.**

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

XI. Equipment Value

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

1) **A "temporarily abandoned" (TA)** well is defined for tax purposes as a well that has had the equipment removed in anticipation of plugging the well bore prior to abandonment of the lease**. If the well qualifies as a "TA" well, the reserves are appraised at zero value. Only the equipment remaining in place as of the January 1 appraisal date should be considered.** If all equipment remains for a Table A well, use $.80 / ft of depth to value the property. If all equipment remains for a Table B or Table C well, use values in Table B, AOK, or Table C, CBM, equipment value for T/A'd wells. If removal has begun, use Itemized Equipment listing at the end of the guide for remaining equipment.

2) **A salt water disposal (SWD) well or system** is considered non-commercial if owned/operated by and used in conjunction with and/or connected to an operating lease(s) of the same owner/operator. This also includes those SWD wells/systems owned/operated by and primarily used in conjunction with and/or connected to an operating lease(s) of the same owner/operator that receive additional water from outside

lease(s), possibly not owned/operated by the owner/operator of the SWD well/system, within close proximity to the SWD well/system only receiving income in an amount for reimbursement of the actual expense of disposal. The SWD well is appraised at $.15 / ft of depth for Table A wells and by depth category for Table B, AOK wells and Table C, CBM wells. The SWD System value is to be appraised by adding a SWD well value for each producing well it services. Operation costs for the SWD well are added separately to each producing gas well's expense unless the salt water disposal system qualifies as commercial.

3) **A salt water disposal (SWD) well or system** utilized for commercial dumping is appraised on the basis of net income multiplied by 3.595. Gross income and expenses should be reported for commercial dumping wells/systems. Then acceptable expenses are determined using the same allowable operating expense guidelines used for producing wells on pgs 34-35. The difference from income and acceptable expense (net income) is then discounted using the Table I five year expense factor of 3.595 in order to calculate value. Example: $18,000 gross income less $9,348 acceptable expenses = $8,652 x 3.595 = $31,104 value for the salt water disposal well. If expenses exceed income on a commercial dumping well, the appraiser may value the SWD equipment in place at $.75/ft depth.

4) If the **salt water disposal (SWD) system** is considered commercial, but is solely used in conjunction with and connected to producing leases, especially high water volume lease(s), controlled by a single operator, the average decline of the producing lease(s) dumping into system should be considered. Gross income and expenses should be reported for commercial dumping systems, then acceptable expenses are determined using the same allowable operating expense guidelines used for producing wells on pgs 34-35. The difference from income and acceptable expense (net income) is then discounted using the appropriate Table PWF determined from the average decline for producing lease(s) on system in order to calculate value Example: Tbl B producing lease, $18,000 gross income less $9,348 acceptable expenses = $8,652 net income; average decline of producing high water volume lease(s) dumping into system by single operator is 15%, so use Tbl B PWF 2.405; $8,652 X 2.405 = $20,808 value for the salt water disposal system. If expenses exceed income on a commercial dumping well, the appraiser may value the SWD equipment in place at $1.05/ft depth

5) **Owned compressors** located on the well/lease site necessary in boosting well/lease production capability should be appraised using the following table. Larger compressors not actually located on a well/lease site, but used to boost several wells/leases also fall into this category, and should be valued using $77.00 per horsepower (hp). **The values should be added to the gas assessment rendition in Section VI, Line 8c, as additional prescribed equipment, then multiplied by the appropriate equipment factor to discount over the well/lease assigned economic life.** If horsepower is not listed for a particular compressor, the appraiser should use $77/hp. All gas sections; Major Fields, AOK, and CBM should use this information to value owned compressors. Leased compressors should not be valued per this table.

Compressors							
Horsepower (HP)	25	35	50	60	75	95	195
Value	$1,925	$2,695	$3,850	$4,620	$5,775	$7,315	$15,015

Major Proven Gas Areas and Fields

Table A Section

I. Production

The prior year's production should be used for Table A wells when calculating the Schedule, Column A, value.

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

New Leases see Gas Section I, Production, and Oil Section I, Production for more information and examples.

II. Decline

1) Existing Leases

To estimate the decline rate for the Schedule, Column A, on a Table A existing lease, the current year decline is calculated by using the preceding two production years. For the 2026 tax year, use 2024 and 2025 as follows:

EXAMPLE

$$\text{Decline} = \frac{\text{2024 Production} - \text{2025 Production}}{\text{2024 Production}} = \frac{56{,}500 - 53{,}200}{56{,}500} = 6\%$$

When using prior years' production to estimate the current year decline, the appraiser must be sure that the production figures are for a full year and represent a typical operation with no significant work-over periods, lease shutdowns, or other non-producing periods affecting the lease production capability. If annualized production is used to estimate value, the annualized production is then used the following year to estimate decline. See Gas Section II, Decline, and Oil Section II, Decline for more information and examples.

For leases that have a production history, the production can be plotted to establish a decline curve to indicate the proper decline to be used in the valuation, **supported by the most recent production activity relating to the January 1 appraisal date,** to determine whether the decline is appropriate and continuing at that rate. For leases experiencing work-over periods, lease shutdowns, or other non-producing periods, the appraiser should consider this history along with recent activity since the decline rate prior to these periods typically resumes after production has stabilized if in the same producing zone.

2) **New Leases**

The appraiser should use an assumed 10% decline rate for new Table A wells in the Schedule, Column A, unless an actual rate can be established with supporting documentation. See Gas Section II, Decline, and Oil Section II, Decline for more information and examples. **The appraiser should be certain to consider "flush" production of a new lease, and apply established 10% decline rate to stabilized production.**

III. Present Worth Factor

The present worth factors listed in Table A, Major Proven Gas Areas and Fields, are based on a 13% discount rate, and variable economic lives with a minimum of three years and a maximum of twenty five years. The factors incorporate the life and performance characteristics based on the percentage rate of decline that is computed for each particular lease. An expense allowance of 4.33% of gross income for severance tax and 7.67% for local ad valorem tax and State Corporation Commission levies is included in the present worth factor. No escalation for expenses or price is included in the factor.

IV. Operating Expenses

The appropriate expense allowance for Table A properties should be determined for the Schedule, Column A value by using the year to year decline rate established and the appropriate producing field. Requests for excessive expenses should use Column B with actual annual expenses multiplied by the Table A prescribed expense factor. See general Gas Section X, Operating Expenses, for additional information.

Expense for wellhead compression is deducted in Section VI, on Line 4a if not included in total actual expenses. **Provide supporting expense information.**

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

V. Equipment Value

1) The Table A prescribed equipment value per well should be used for the Schedule, Column A value. This value is determined by the year to year decline rate.

2) Refer to the general Gas Section XI, Equipment Values, **Temporarily Abandoned (TA)** and **Salt Water Disposal (SWD)** wells for valuation details for this well type for Table A. Use $.80 / ft for Table A T/A'd wells, and use $.15 / ft for Table A SWD wells.

3) A **shut-in well (SI)** is defined for tax purposes as a well that has production equipment in place, but production has been stopped or curtailed (shut-in) due to economic reasons such as lack of market demand, or stopped by the Kansas Corporation Commission (KCC) for excessive over-production, rather than reserve depletion.

   Shut-in gas wells located in a major field are appraised at $1.00 per foot of depth.

4) **Owned compressor** values should be calculated from general Gas Section XI, Equipment Values, Compressors.

VI. Reserve In-Place Value

The "In-Place" value of reserves is one method analysts use to determine market value for petroleum producing properties. It is an industry accepted tool that values the property as a whole, inclusive of reserves remaining in the ground and producing equipment.

The "In-Place" value methodology is an acceptable, alternate valuation tool for the appraiser to ascertain market value if he/she chooses to deviate from the guide value on individual properties. However, the "In-Place" value, a measure of market value, should be determined using the same appraisal standards as any other type of property being valued by the market approach. Comparable sales data is essential to this process, and as with any type property, more than one sale should be analyzed to more accurately determine value. Comparable properties with limited adjustments from similar producing areas should be used when utilizing this "In-Place" approach. If using this method as a "check" to the guide, and then possibly as a final determination of value, the appraiser must be certain to consider all aspects of the subject property, as well as, the comparables used.

The "Reserve In-Place" calculation begins by determining the Initial Recoverable Reserves (IRR) of the "parent" and "child" (in-fill) wells. A single Rate/Time curve for both wells or a separate curve for each well may be used to determine the IRR. An economic limit (abandonment rate) of **8 Mcf per day** should be used in the Rate/Time curve calculation.

The Remaining Recoverable Reserves (RRR) are then determined by subtracting either the cumulative production from the unit IRR if using the Rate/Time curve for both wells combined, or the cumulative production from the individual well's IRR if using the Rate/Time curve for each separate well.

The Net Remaining Recoverable Reserves (NRR) are established by multiplying the RRR by the working interest used on Line 2, Section VI of the gas rendition.

The "In-Place" value of the reserves is calculated by dividing the working interest appraised value by the estimate of net remaining recoverable reserves.

The resulting value should then be analyzed using the comparable sales information gathered to determine the market value of the lease. The appraiser must use the KS Dept of Revenue's Oil and Gas Guide's Schedule, Column A to first determine value, which may be compared to the "In-Place" established market value. If the appraiser determines the guide value to be representative of market, it should be used. If the appraiser deems the guide value does not accurately reflect market value, he/she has the authority and responsibility to deviate from the guide valuation on individual properties with just cause and proper documentation.

TABLE A

Major Proven Gas Areas and Fields

Decline Rate (%)	Remaining Economic Life (Yrs.)	Prescribed PWF (13% Disc Rate, 12 % Tax Credit, Varied Econ Life-3 Yr Min/25 Yr Max, No Price/Expense Esc)	Prescribed Operator's Expense Allowance per Well				Prescribed Equipment Factor (13% Disc Rate, Varied Econ Life-3 Yr Min/25 Yr Max)	Prescribed Equipment Value per Well $8,625 ave
			Prescribed Expense Factor (13% Disc Rate, Varied Econ Life-3 Yr Min/25 Yr Max)	Greenwood, Hugoton Chase, Panoma Council Grove $11,000 ave annual exp	Bradshaw / Byerly $18,000 ave annual exp	Interstate Redcave $13,500 ave annual exp		
0	25	6.857	7.792	$85,700	$140,300	$105,200	0.0501	$400
1	25	6.373	7.792	$85,700	$140,300	$105,200	0.0501	$400
2	25	5.938	7.792	$85,700	$140,300	$105,200	0.0501	$400
3	25	5.546	7.792	$85,700	$140,300	$105,200	0.0501	$400
4	25	5.193	7.792	$85,700	$140,300	$105,200	0.0501	$400
5	25	4.873	7.792	$85,700	$140,300	$105,200	0.0501	$400
6	25	4.582	7.792	$85,700	$140,300	$105,200	0.0501	$400
7	23	4.301	7.685	$84,500	$138,300	$103,800	0.0639	$600
8	20	4.031	7.467	$82,100	$134,400	$100,800	0.0923	$800
9	18	3.791	7.271	$80,000	$130,900	$98,200	0.1178	$1,000
10	16	3.564	7.020	$77,200	$126,400	$94,800	0.1504	$1,300
11	14	3.346	6.700	$73,700	$120,600	$90,400	0.1921	$1,700
12	13	3.165	6.508	$71,600	$117,100	$87,900	0.2170	$1,900
13	12	2.994	6.291	$69,200	$113,200	$84,900	0.2452	$2,100
14	11	2.832	6.045	$66,500	$108,800	$81,600	0.2771	$2,400
15	10	2.675	5.768	$63,400	$103,800	$77,900	0.3132	$2,700
16	9	2.522	5.455	$60,000	$98,200	$73,600	0.3539	$3,100
17	9	2.427	5.455	$60,000	$98,200	$73,600	0.3539	$3,100
18	8	2.284	5.101	$56,100	$91,800	$68,900	0.3999	$3,400
19	8	2.203	5.101	$56,100	$91,800	$68,900	0.3999	$3,400
20	7	2.066	4.701	$51,700	$84,600	$63,500	0.4518	$3,900
21	7	1.996	4.701	$51,700	$84,600	$63,500	0.4518	$3,900
22	6	1.859	4.249	$46,700	$76,500	$57,400	0.5106	$4,400
23	6	1.801	4.249	$46,700	$76,500	$57,400	0.5106	$4,400
24	6	1.744	4.249	$46,700	$76,500	$57,400	0.5106	$4,400
25	5	1.608	3.739	$41,100	$67,300	$50,500	0.5770	$5,000
26	5	1.561	3.739	$41,100	$67,300	$50,500	0.5770	$5,000
27	5	1.515	3.739	$41,100	$67,300	$50,500	0.5770	$5,000
28	5	1.470	3.739	$41,100	$67,300	$50,500	0.5770	$5,000
29	5	1.427	3.739	$41,100	$67,300	$50,500	0.5770	$5,000
30	4	1.299	3.162	$34,800	$56,900	$42,700	0.6520	$5,600
31	4	1.263	3.162	$34,800	$56,900	$42,700	0.6520	$5,600
32	4	1.228	3.162	$34,800	$56,900	$42,700	0.6520	$5,600
33	4	1.194	3.162	$34,800	$56,900	$42,700	0.6520	$5,600
34	4	1.161	3.162	$34,800	$56,900	$42,700	0.6520	$5,600
35	3	1.026	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
36	3	1.000	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
37	3	0.974	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
38	3	0.949	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
39	3	0.925	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
40	3	0.900	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
41	3	0.877	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
42	3	0.853	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
43	3	0.830	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
44	3	0.807	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
45	3	0.785	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
46	3	0.763	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
47	3	0.741	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
48	3	0.720	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
49	3	0.699	2.510	$27,600	$45,200	$33,900	0.7367	$6,400
50-100	3	0.678	2.510	$27,600	$45,200	$33,900	0.7367	$6,400

All Other Kansas Gas Fields
Table B Section

I. All Other Kansas (AOK)

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

II. Production

The prior year's production should be used for Table B wells when calculating the Schedule, Column A, value.

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

New Leases see Gas Section I, Production, and Oil Section I, Production for more information and examples.

III. Decline

Most wells in the AOK produce from limited life reservoirs; therefore, the decline rate must be calculated. Provide five years of production history for use in establishing decline rate. See Gas Section II, Decline, and Oil Section II, Decline for more information and examples.

1) Existing Leases

To estimate the decline rate for the Schedule, Column A, on a Table B existing lease, the current year decline is calculated by using the preceding two production years. For the 2026 tax year, use 2024 and 2025 as follows:

EXAMPLE

$$\text{Decline} = \frac{\text{2024 Production} - \text{2025 Production}}{\text{2024 Production}} = \frac{56{,}500 - 53{,}200}{56{,}500} = 6\%$$

When using prior years' production to estimate the current year decline, the appraiser must be sure that the production figures are for a full year and represent a typical operation with no significant work-over periods, lease shutdowns, or other non-producing periods affecting the lease production capability. If annualized production is used to estimate value, the annualized production is then used the following year to estimate decline. See Gas Section II, Decline, and Oil Section II, Decline for more information and examples.

For leases that have a production history, the production can be plotted to establish a decline curve to indicate the proper decline to be used in the valuation, **supported by the most recent production activity relating to the January 1 appraisal date,** to determine whether the decline is appropriate and continuing at that rate. For leases experiencing work-over periods, lease shutdowns, or other non-producing periods, the appraiser should consider this history along with recent activity since the decline rate prior to these periods typically resumes after production has stabilized if in the same producing zone.

2) New Leases

The appraiser should use an assumed 30% decline rate for new wells in the Schedule, Column A, unless an actual rate can be established with supporting documentation. The assumed 30% rate may be used until the lease has produced three years if an actual rate cannot be established. See Gas Section II, Decline, and Oil Section II, Decline for more information and examples.

IV. Present Worth Factor

The present worth factors listed in Table B, All Other Kansas, are based on a 15% discount rate and seven years of income. The factors incorporate the life and performance characteristics based on the percentage rate of decline that is computed for each particular lease. An expense allowance of 4.33% of gross income for severance tax and 5.67% for local ad valorem tax and State Corporation Commission levies is included in the present worth factor. No escalation for expenses or price is included in the factor.

V. Operating Expenses

Use appropriate expense allowance by depth and well type per Table B for the Schedule, Column A.

Annual **compression expense** should be multiplied by the 4.462 expense factor for AOK, Table B properties. It should then be deducted from the working interest value in the Schedule, Column A, Section VI, Line 4a. See general Gas Section X, Operating Expenses, for additional information. **Provide supporting expense information.**

Expense for water is allowed for AOK wells by using the Water Credit Adjustment Factor found in Table B. The factor is applied to the working interest value on the gas rendition in Section VI, Line 2. If actual annual water expense is used, it should be multiplied by the 4.462 expense factor for Table B, and deducted on the gas rendition from the working interest in Section VI, Line 4b, or included in total excessive expenses. **If using actual water expense, the Water Credit Adjustment Factor should NOT be used on Line 2.** See general Gas Section X, Operating Expenses, for additional information. **Provide supporting expense information if using actual expenses.**

Requests for excessive expenses should use Column B with actual annual expenses multiplied by the 4.462 expense factor for Table B, All Other Kansas. See general Gas Section X, Operating Expenses, for additional information.

VI. Equipment Value

1) The Table B prescribed equipment value per well should be used for the Schedule, Column A value. This value is determined by well depth and well type.

2) Refer to the general Gas Section XI, Equipment Value, **Temporarily Abandoned (TA)** and **Salt Water Disposal (SWD)** wells for valuation details for this well type for Table B. Use appropriate Table B value determined by depth for both well types.

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

5) **Owned Compressor** values should be calculated from general Gas Section XI, Equipment Values, Compressors.

VII. AOK Wells Capable of Producing But Never Produced

A well that has been drilled and completed, but has not been produced and/or had production sold in commercial quantities as of the appraisal date, is appraised pursuant to this table. This type of well is not to be classified as a TA or SI well. Do not use for wells that are capable of producing only one or two barrels per day. **Amounts listed indicate minimum reserve valuations.** The appraiser may also take first quarter production, plot decline, and extrapolate production to estimate value.

Depth	Working Interest Value	Royalty Interest Value
0 - 500 Ft	$5,000	None
501 - 1,000 Ft	$15,000	None
1,001 - 2,000 Ft	$25,000	None
2,001 - 4,000 Ft	$50,000	None
4,001 + Ft	$75,000	None

TABLE B

All Other Kansas (AOK) Gas Fields

15% Discount Rate, Seven Yr. Economic Life, 10% Tax Credit

Prescribed Present Worth Factor

Decline Rate (%)	PWF	Decline Rate (%)	PWF	Decline Rate (%)	PWF	Decline Rate (%)	PWF
0-5	3.381	**17**	2.248	**29**	1.504	**41**	1.007
6	3.267	**18**	2.173	**30**	1.455	**42**	0.974
7	3.157	**19**	2.102	**31**	1.407	**43**	0.942
8	3.051	**20**	2.032	**32**	1.361	**44**	0.910
9	2.949	**21**	1.965	**33**	1.316	**45**	0.880
10	2.850	**22**	1.900	**34**	1.273	**46**	0.850
11	2.754	**23**	1.838	**35**	1.232	**47**	0.821
12	2.662	**24**	1.777	**36**	1.191	**48**	0.794
13	2.574	**25**	1.719	**37**	1.152	**49**	0.767
14	2.488	**26**	1.662	**38**	1.114	**50-100**	0.740
15	2.405	**27**	1.608	**39**	1.077		
16	2.325	**28**	1.555	**40**	1.042		

Prescribed Operator's Expense Allowance Per Well

Expense Factor 4.462

Well Type	Well Depth < = 500'	Well Depth 501 – 1000'	Well Depth 1001 – 1500'	Well Depth 1501 – 2000'	Well Depth 2001 – 4000'	Well Depth 4001 – 6000'	Well Depth 6001+ Ft
Flowing	$41,760	$48,720	$55,680	$62,640	$69,600	$82,540	$87,895
Pumping	$45,935	$53,590	$61,250	$68,905	$76,560	$90,795	$96,680

Prescribed Equipment Value Per Well

Equipment Factor 0.4031

Well Type	Well Depth < = 500'	Well Depth 501 – 1000'	Well Depth 1001 – 1500'	Well Depth 1501 – 2000'	Well Depth 2001 – 4000'	Well Depth 4001 – 6000'	Well Depth 6001+ Ft
Flowing	$1,010	$1,320	$1,450	$1,950	$2,610	$4,065	$5,535
Shut-In/TA	$1,195	$1,500	$1,810	$2,605	$3,340	$4,790	$6,260
Pumping	$1,110	$1,455	$1,595	$2,145	$2,875	$4,470	$6,085
Shut-In/TA	$1,310	$1,650	$1,995	$2,865	$3,670	$5,270	$6,885
SWD	$45	$135	$225	$315	$545	$905	$1,270

Prescribed Water Credit Adjustment

Bbls / Water / Day	% Adjustment	Gas Well Factor*	Combination**
0.00 to 4.99	0%	1	1
5.00 to 9.99	2%	0.98	1
10.00 to 14.99	5%	0.95	0.98
15.00 to 19.99	7%	0.93	0.95
20.00 +	10%	0.90	0.93

Note:** ***Make adjustment on Line 2, Section VI: WI Value Value X decimal interest X gas well factor

The appraiser should consider actual water expenses rather than using factor if amounts greatly exceed 20 Bbls/day. An example may be 100 + Bbls/day. Actual expenses should be deducted on Line 4b, Section VI. Supporting documentation should be provided for actual expenses.

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

Coalbed Methane Gas Fields
Table C Section

I. Coalbed Methane (CBM)

CBM gas fields include those gas fields located in eastern, and specifically southeastern, Kansas coal seams. CBM fields are not included under "Table B – All Other Kansas (AOK)".

II. Production

The prior year's production should be used for Table C wells when calculating the Schedule, Column A, value.

Although typical CBM production increases in the first couple of years of production as water volumes decrease, the prior year production likely best represents the future forecast for the lease for many of the wells considered in CBM. In other cases, a representative period may be used if it represents the production capability of the lease. As much history as is available should be reviewed to estimate production capability, yet historic production may not be indicative of future production capability. For example, if the production is curtailed and is expected to be curtailed for the foreseeable future, use the curtailed production as the typical production for use in the calculation of the reservoir value. Quarterly production may need to be extrapolated to better indicate more current volumes for CBM leases. For example, the last two quarters of the prior year and the first quarter of the current tax year may need to be annualized to better state the current production capability of an increasing CBM gas production rate. The decline rate may need to be adjusted to reflect the production used.

New Leases see Gas Section I, Production, and Oil Section I, Production for more information and examples.

III. Decline

Theoretically, as a gas lease is produced, the reserve begins to decline immediately. This is apparent for conventional gas production; however, it is not as obvious in CBM production. CBM production typically increases in the first couple of years as pressures increase with the removal of mass amounts of water. This "dewatering" process can take anywhere from 6 months to 2 years. Thus, maximum lease production capability may not be attained and an apparent decline shown for three to five years in most cases. Yet, most wells in the CBM produce from limited life reservoirs; therefore, the decline rate must be calculated. Provide five years of production history for consideration in establishing decline rate. See Gas Section II, Decline, and Oil Section II, Decline for more information and examples.

2) Existing Leases

To estimate the decline rate for the Schedule, Column A, on a Table C existing lease, the current year decline is calculated by using the preceding two production years. For the 2026 tax year, use 2024 and 2025 as follows:

EXAMPLE

$$\text{Decline} = \frac{\text{2024 Production} - \text{2025 Production}}{\text{2024 Production}} = \frac{56{,}500 - 53{,}200}{56{,}500} = 6\%$$

When using prior years' production to estimate the current year decline, the appraiser must be sure that the production figures are for a full year and represent a typical operation with no significant work-over periods, lease shutdowns, or other non-producing periods affecting the lease production capability. If annualized production is used to estimate value, the annualized production is then used the following year to estimate decline. See Gas Section II, Decline, and Oil Section II, Decline for more information and examples.

For leases that have a production history, the production can be plotted to establish a decline curve to indicate the proper decline to be used in the valuation, **supported by the most recent production activity relating to the January 1 appraisal date,** to determine whether the decline is appropriate and continuing at that rate. For leases experiencing work-over periods, lease shutdowns, or other non-producing periods, the appraiser should consider this history along with recent activity since the decline rate prior to these periods typically resumes after production has stabilized if in the same producing zone.

3) New Leases

The appraiser should use an assumed 30% decline rate for new wells in the Schedule, Column A, unless an actual rate can be established with supporting documentation. The assumed 30% rate may be used until the lease has produced three years if an actual rate cannot be established. An assumed 15% rate may be used, and is recommended, for two to three additional years if an actual rate still cannot be established. Thus, for the first five to six producing years, the appraiser may use, and is recommended to use, an assumed decline if an actual rate cannot be established due to the nature of the CBM production. See Gas Section II, Decline, and Oil Section II, Decline for more information and examples.

IV. Present Worth Factor

The present worth factors listed in Table C, Coalbed Methane Gas Fields, are based on a 15% discount rate and seven years of income. The factors incorporate the life and performance characteristics based on the percentage rate of decline that is computed for each particular lease. An expense allowance of 4.33% of gross income for severance tax and 5.67% for local ad valorem tax and State Corporation Commission levies is included in the present worth factor. No escalation for expenses or price is included in the factor.

V. Operating Expenses

Use appropriate expense allowance per well by depth per Table C for the Schedule, Column A, Line 3, Section VI.

Annual **compression expense** should be multiplied by the 4.462 expense factor for CBM, Table C properties. It should then be deducted from the working interest value in the Schedule, Column A, Section VI, Line 4a. See general Gas Section X, Operating Expenses, for additional information. **Provide supporting expense information.**

Water expense is allowed by using the SWD expense in Table C for each **SWD well.**

If the lease is utilizing a **SWD system** along with other leases, going to a centralized disposal site, a SWD well expense should be added from Table C for **each gas producing well** on the rendition. For example, if a lease rendition shows two CBM gas producing wells on the same rendition and a SWD System noted at 1100’, then a total SWD expense allowance of $8,830 ($4,415 X 2) should be added to Line 4c in Section VI of the gas rendition.

If a lease is not connected to a SWD well or system, but incurs expense to **haul water** from the lease, actual annual hauling expenses may be used. The annual expenses should be multiplied by the 4.462 expense factor for Table C and entered on Line 4b, Section VI.

(Same line as Tables A & B actual water expenses) **Documentation must be provided for the actual hauling expenses to be considered.**

Requests for excessive expenses should use Column B with actual annual expenses multiplied by the 4.462 expense factor for Table C. See general Gas Section X, Operating Expenses, for additional information

VI. Equipment Value

1) The Table C prescribed equipment value per well should be used for the Schedule, Column A value. This value is determined by well depth and well type.
2) Refer to the general Gas Section XI, Equipment Value, **Temporarily Abandoned (TA)** and **Salt Water Disposal (SWD)** wells for valuation details for this well type for Table C. Use appropriate Table C value determined by depth for both well types.

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

4) **Owned compressor** values should be calculated from general Gas Section XI, Equipment Values, Compressors.

VII. CBM Wells Capable of Producing But Never Produced

A well that has been drilled and completed, but has not been produced and/or had production sold in commercial quantities as of the appraisal date, is appraised pursuant to this table. This type of well is not to be classified as a TA or SI well. Do not use for wells that are capable of producing only one or two barrels per day. **Amounts listed indicate minimum reserve valuations.** The appraiser may also take first quarter production, plot decline, and extrapolate production to estimate value.

Depth	Working Interest Value	Royalty Interest Value
0 - 500 Ft	$5,000	None
501 - 1,000 Ft	$15,000	None
1,001 - 2,000 Ft	$25,000	None
2,001 - 4,000 Ft	$50,000	None
4,001 + Ft	$75,000	None

TABLE C

Coalbed Methane (CBM) Gas Fields

15% Discount Rate, Seven Yr. Economic Life, 10% Tax Credit

Prescribed Present Worth Factor

Decline Rate (%)	PWF	Decline Rate (%)	PWF	Decline Rate (%)	PWF	Decline Rate (%)	PWF
0-5	3.381	**17**	2.248	**29**	1.504	**41**	1.007
6	3.267	**18**	2.173	**30**	1.455	**42**	0.974
7	3.157	**19**	2.102	**31**	1.407	**43**	0.942
8	3.051	**20**	2.032	**32**	1.361	**44**	0.910
9	2.949	**21**	1.965	**33**	1.316	**45**	0.880
10	2.850	**22**	1.900	**34**	1.273	**46**	0.850
11	2.754	**23**	1.838	**35**	1.232	**47**	0.821
12	2.662	**24**	1.777	**36**	1.191	**48**	0.794
13	2.574	**25**	1.719	**37**	1.152	**49**	0.767
14	2.488	**26**	1.662	**38**	1.114	**50-100**	0.740
15	2.405	**27**	1.608	**39**	1.077		
16	2.325	**28**	1.555	**40**	1.042		

Prescribed Operator's Expense Allowance Per Well

Expense Factor 4.462

Expense Allowance Per Well	Well Depth < =500'	Well Depth 501 – 800'	Well Depth 801 – 1000'	Well Depth 1001 – 1250'	Well Depth 1251 – 1500'	Well Depth 1501 – 2000'	Well Depth 2001 + Ft
CBM	$25,765	$29,445	$33,125	$36,810	$40,490	$44,170	$47,850
SWD	$3,090	$3,535	$3,975	$4,415	$4,860	$5,300	$5,740

*Note: Apply SWD expense allowance per producing gas well for SWD system expenses

**Note: Water Hauling expense- use actual annual multiplied by expense factor, enter Line 4b, Sec VI gas rendition

Prescribed Equipment Value Per Well

Equipment Factor 0.4031

Well Type	Well Depth < =500'	Well Depth 501 – 800'	Well Depth 801 – 1000'	Well Depth 1001 – 1250'	Well Depth 1251 – 1500'	Well Depth 1501 – 2000'	Well Depth 2001 + Ft
CBM	$1,330	$1,520	$1,710	$1,900	$2,090	$2,280	$2,470
Shut-In/TA	$1,630	$1,865	$2,100	$2,330	$2,565	$2,800	$3,030
SWD	$680	$775	$875	$970	$1,065	$1,165	$1,260

*Note: Apply SWD equipment allowance per producing gas well for SWD system values

GAS ASSESSMENT RENDITION

Schedule 2 (Class 2B) (Rev. 1/26)

SHALL BE FILED WITH THE COUNTY APPRAISER BY APRIL 1

______________ **County, Kansas** **Tax Year** 2026

Statement of ______________ **Operator ID#** ______________
P.O. Address ______________ **City** ______________ **State** ______________ **Zip** ______________
Name of Property ______________ **County ID#** ______________ **KDOR ID#(s)** ______________ **Well API#(s)** ______________

Section I-Location of Property (required)				**Section VII-Abstract Value** (for county use only)				
Lease Description					Appraised	Assessed	Penalty	Total
(Well location pg 2)				Total Working Interest (Sec. VI. Line 10)				
Lot Sec.		Adn. Twp.		Royalty & ORRI Interest (Sec. VI. Line 1)			XXXXXXXXX	
Blk Rng.		Twp. City		Itemized Equipment (Sec. VI. Line 9)				
Tax Unit		School Dist		Total				

Section II-Well Data (required)

Producing Well: Pump Flow Non-Producing Well: Shut-In SWD TA	Bbls Water per Day Ave Prod Depth	SWD Depth
Producing Field Name BTU Content Spud Date: Mo/Yr(new prod)	Comp Date: Mo/Yr(new prod)	Total WI Decimal
( )Infill ( )Commingled ( )CBM ( )Horizontal Total Depth Horizontal	Lease Name/Number Tie (See Notation/Pg 2)	Total RI&ORRI Dec
Water Disposal: Hauler/System/Well Name ( ) SWD System	Prior Yr Gross Weighted Ave $/Mcf (Adjusted for BTU Content)	
Address Phone	Less Allowable Deductions $/Mcf (Gathering, Transportation, etc…)	
Gatherer Name	Effective Jan 1 Net Price $/Mcf (Prior Yr Net Weighted Ave Price $/Mcf)	
Address Phone	Effective Jan 1 Net Price $/Mcf to Royalty Owner	

Section IV-Production Data (required)

Year		Cond(Bbls)	Gas(Mcf)
2021	Annual Production		
2022	Annual Production		
2023	Annual Production		
2024	Annual Production		
2025	Annual Production		
Total Production (5 yr cumulative)			
Annual Production (Prior Yr)			
Condensate (Converted to Mcf)		XXXXXXXXX	
Total Annual Production (Mcf + condensate conversion)			

Notation

Decline Rate: %

Condensate Production Data (conversion calculation)

________ X ________ = ________ / ________ = ________

Prod (Bbls) X Net $/Bbl Oil = Income / Net $/Mcf Gas = Total Mcf (cond conv)

Section V-Gross Reserve Calculation (Total 8/8ths Interest)	Schedule (A)	Owner (B)	Appraiser (C)
1. Annual Production - Mcf (Total Annual Prod Sec IV)			
2. Effective Jan 1 Net Price $/Mcf (Sec II) $ X market adjust factor adj inc/dec			
3. Estimated Gross Income Stream (Multiply Line 1 X Line 2)			
4. Present Worth Factor (Based on Decline Rate-Apply Appropriate Table PWF)			
5. Estimated Gross Reserve Value (Total 8/8ths - Multiply Line 3 X Line 4 - Transfer Total to Section VI, Lines 1 & 2)			

Section VI-Gross Reserve Value X Decimal Interest	Schedule (A)	Owner (B)	Appraiser (C)
1. Royalty & Overriding Royalty Interest Valuation (Total Sec V, Line 5 X Total RI & ORRI Interest) X			
2. Working Interest Valuation (Total Sec V, Line 5 X Total WI Interest) X X (Tbl B Water Cr Adj)			
3. Deduct Operating Cost Allowance for Producing Well (Allowance per Tbl)			
4a. Deduct Wellhead Compression (Annual Compression Expense) X (Expense Factor-Tbl)			
4b. Deduct Water Expense Allowance (Tbl A Annual Exp; Tbl B Annual Exp if Actual) X (Expense Factor-Tbl)			
4c. Deduct Water Expense Allowance Table C per SWD Well (Deduct SWD Expense for each Prod Well if SWD System)			
5. Working Interest Subtotal (Sec VI, Line 2 minus Lines 3, 4a,4b & 4c)			
6. Working Interest Minimum Lease Value (Sec VI, Line 2) X 10%			
7. Copy Value from Sec VI, Line 5 or Line 6 (Whichever Line is Greater)			
8a. Add Prescribed Equipment Value for Producing Well (Flowing $/Well) (Pumping $/Well)			
8b. Add Prescribed Equipment Value for Non-Producing Well (Shut-In, TA,SWD-Add SWD Equip Value for each Prod Well if SWD System)			
8c. Add Pres Equip Value for Additional Equipment (Compressors,Gathering Lines,etc…) X (Equip Fact-Tbl)			
9. Add Itemized Equipment (Section III - Attached Schedule)			
10. Working Interest Total Market Value (Add Sec VI, Lines 7, 8a, 8b, 8c, & 9)			
11. Working Interest Total Assessed Value (Multiply Sec VI, Line 10 X 30%, Unless Lease Qualifies for 25% Rate)			

Current Division Order with Name, Address, Interest of Royalty Owners, and Well/Lease Identifier is a Required Attachment to Rendition

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

______________ ______________ ______________ ______________

Owner **Date** **Tax Rendition Preparer** **Date**

Rendition Information: **Contact Phone** ( ) - **Contact Email** @

Lease Code ______________ **County Code** ______________ **Lease Name** ______________

Prescribed by Kansas Department of Revenue, Division of Property Valuation

Horizontal Wells Section

Horizontal Wells Section

Oil Section

Table III, Oil Section, Part I – Table III is for new oil leases producing for their first three years with a secant decline of 70% or greater, which equates to an effective decline rate of 50% or greater. It has been created to accommodate those new leases with high volume water production that are primarily horizontals and/or are producing from the Mississippian Lime. Please see specific details in table columns and secant and effective decline calculations below table. General guide excess expense rules apply and excess expense requests must be fully documented. Please note table expenses are separated for fixed expenses and water. Excess expense requests must be 25% greater than total allowed table expenses. All other general guide rules for oil leases apply.

Table III, Oil Section, Part II – Table III is for qualifying Table III oil leases producing after their first three years with a secant decline less than 70%, which equates to an effective decline rate of less than 50%. It has been created to accommodate those new leases with high volume water production that are primarily horizontals and/or are producing from the Mississippian Lime. Please see specific details in table columns. Also note that secant decline is no longer applicable. Standard guide decline calculations are now resumed and are demonstrated below table. General guide excess expense rules apply and excess expense requests must be fully documented. Please note table expenses are separated for fixed expenses and water. Excess expense requests must be 25% greater than total allowed table expenses. All other general guide rules for oil leases apply.

Gas Section

Table D, Gas Section, Part I – Table D is for new gas leases producing for their first three years with a secant decline of 70% or greater, which equates to an effective decline rate of 50% or greater. It has been created to accommodate those new leases with high volume water production that are primarily horizontals and/or are producing from the Mississippian Lime. Please see specific details in table columns and secant and effective decline calculations below table. General guide excess expense rules apply and excess expense requests must be fully documented. Please note table expenses are separated for fixed expenses and water. Excess expense requests must be 25% greater than total allowed table expenses. All other general guide rules for gas leases apply.

Table D, Gas Section, Part II – Table D is for qualifying Table D gas leases producing after their first three years with a secant decline less than 70%, which equates to an effective decline rate of less than 50%. It has been created to accommodate those new leases with high volume water production that are primarily horizontals and/or are producing from the Mississippian Lime. Please see specific details in table columns. Also note that secant decline is no longer applicable. Standard guide decline calculations are now resumed and are demonstrated below table. General guide excess expense rules apply and excess expense requests must be fully documented. Please note table expenses are separated for fixed expenses and water. Excess expense requests must be 25% greater than total allowed table expenses. All other general guide rules for oil leases apply.

TABLE III

Part I: New Oil Leases Producing for First 3 Yrs with Effective Decline Rate => 50% (Secant Rate => 70%), High Volume Water Production, Primarily Horizontals and/or Mississippian Lime Production

15% Discount Rate; Seven Year Economic Life; 5% Property Tax Credit

Decline and Prescribed PWF			Prescribed Operator's Expense Allowance per Well					Prescribed Equipment Value per Well				
Secant Decline Rate (%)	Effective Decline Rate (%)	Prescribed PWF (15% Disc Rate, 5 % Tax Credit, 7 Yr Econ Life)	Prescribed Fixed Expense Factor (15% Disc Rate, 7 Yr Econ Life)	Prescribed Producing Well Fixed Exp Allow NOT incl Water ave exp	Prescribed Water Expense Factor incl Decline (15% Disc Rate, 7 Yr Econ Life)	Prescribed SWD Expense SWD Well or System Per Oil Prod Well (Sngl Well or Low Volume System <=2000 BWPD) ave exp	Prescribed SWD Expense SWD Well or System Per Oil Prod Well (Sngl Well or High Volume System >2000 BWPD) ave exp	Prescribed Equipment Factor (15% Disc Rate, 7 Yr Econ Life)	Prescribed Producing Well Equip ave	Prescribed SWD Equip SWD Well or System Per Oil Prod Well (Sngl Well or Low Volume System <=2000 BWPD) ave	Prescribed SWD Equip SWD Well or System Per Oil Prod Well (Sngl Well or High Volume System >2000 BWPD) ave	Prescribed Shut In/TA Well Equip ave
70	**50**	0.874	4.462	$490,820	0.536	$21,440	$35,375	0.4031	$27,485	$4,235	$5,550	$31,605
71-74	**51-52**	0.813	4.462	$490,820	0.542	$21,680	$35,770	0.4031	$27,485	$4,235	$5,550	$31,605
75-79	**53-54**	0.750	4.462	$490,820	0.551	$22,040	$36,365	0.4031	$27,485	$4,235	$5,550	$31,605
80	**55**	0.683	4.462	$490,820	0.553	$22,120	$36,500	0.4031	$27,485	$4,235	$5,550	$31,605
81-84	**56-57**	0.648	4.462	$490,820	0.555	$22,200	$36,630	0.4031	$27,485	$4,235	$5,550	$31,605
85-89	**58-59**	0.613	4.462	$490,820	0.558	$22,320	$36,830	0.4031	$27,485	$4,235	$5,550	$31,605
90	**60**	0.588	4.462	$490,820	0.560	$22,400	$36,960	0.4031	$27,485	$4,235	$5,550	$31,605
91-94	**61-64**	0.563	4.462	$490,820	0.561	$22,440	$37,025	0.4031	$27,485	$4,235	$5,550	$31,605
95	**65**	0.539	4.462	$490,820	0.562	$22,480	$37,090	0.4031	$27,485	$4,235	$5,550	$31,605
96-99	**66-69**	0.538	4.462	$490,820	0.563	$22,520	$37,160	0.4031	$27,485	$4,235	$5,550	$31,605
1.00	**70**	0.537	4.462	$490,820	0.564	$22,560	$37,225	0.4031	$27,485	$4,235	$5,550	$31,605
1.01-1.09	**71-74**	0.536	4.462	$490,820	0.565	$22,600	$37,290	0.4031	$27,485	$4,235	$5,550	$31,605
1.10	**75**	0.535	4.462	$490,820	0.566	$22,640	$37,355	0.4031	$27,485	$4,235	$5,550	$31,605
1.11-1.24	**76-79**	0.534	4.462	$490,820	0.567	$22,680	$37,420	0.4031	$27,485	$4,235	$5,550	$31,605
1.25	**80**	0.533	4.462	$490,820	0.593	$23,720	$39,140	0.4031	$27,485	$4,235	$5,550	$31,605
1.26-1.54	**81-84**	0.532	4.462	$490,820	0.619	$24,760	$40,855	0.4031	$27,485	$4,235	$5,550	$31,605
1.55	**85**	0.530	4.462	$490,820	0.645	$25,800	$42,570	0.4031	$27,485	$4,235	$5,550	$31,605
1.56-1.74	**86-89**	0.527	4.462	$490,820	0.682	$27,280	$45,010	0.4031	$27,485	$4,235	$5,550	$31,605
1.75	**90**	0.525	4.462	$490,820	0.719	$28,760	$47,455	0.4031	$27,485	$4,235	$5,550	$31,605
1.76-2.79	**91-94**	0.524	4.462	$490,820	0.789	$31,560	$52,075	0.4031	$27,485	$4,235	$5,550	$31,605
2.80-3.90	**95-97**	0.515	4.462	$490,820	0.856	$34,240	$56,495	0.4031	$27,485	$4,235	$5,550	$31,605
3.91	**98-100**	0.501	4.462	$490,820	0.920	$36,800	$60,720	0.4031	$27,485	$4,235	$5,550	$31,605

Calculate Secant Decline Rate Using Initial Rate and End Rate (monthly or annual), then use table to determine Effective Decline Rate. Example: July 2025 Prod = 3030, Dec 2025 Prod = 789, 5 mos production change (12/5); Secant Decline = (3030-789)/3030*(12/5) = 1.78. Use Table to Determine Effective Decline; Secant = 1.78 = Effective Decline = 91-94% , Use PWF 0.524

TABLE III

Part II: Table III Oil Leases Producing After 3 Yrs , Effective Decline Rate < 50% (Secant Rate < 70%), High Volume Water Production, Primarily Horizontals and/or Mississippian Lime Production

15% Discount Rate; Seven Year Economic Life; 5% Property Tax Credit

Decline and Prescribed PWF		Prescribed Operator's Expense Allowance per Well					Prescribed Equipment Value per Well				
Decline Rate (%)	Prescribed PWF (15% Disc Rate, 5 % Tax Credit, 7 Yr Econ Life)	Prescribed Fixed Expense Factor (15% Disc Rate, 7 Yr Econ Life)	Prescribed Producing Well Fixed Exp Allow NOT incl Water ave exp	Prescribed Water Expense Factor incl Decline (15% Disc Rate, 7 Yr Econ Life)	Prescribed SWD Expense SWD Well or System Per Oil Prod Well (Sngl Well or Low Volume System <=2000 BWPD) ave exp	Prescribed SWD Expense SWD Well or System Per Oil Prod Well (Sngl Well or High Volume System >2000 BWPD) ave exp	Prescribed Equipment Factor (15% Disc Rate, 7 Yr Econ Life)	Prescribed Producing Well Equip ave	Prescribed SWD Equip SWD Well or System Per Oil Prod Well (Sngl Well or Low Volume System <=2000 BWPD) ave	Prescribed SWD Equip SWD Well or System Per Oil Prod Well (Sngl Well or High Volume System >2000 BWPD) ave	Prescribed Shut In/TA Well Equip ave
0-5	3.569	4.462	$220,870	0.822	$3,700	$6,105	0.4031	$19,240	$2,965	$3,885	$22,120
6	3.448	4.462	$220,870	0.852	$3,835	$6,325	0.4031	$19,240	$2,965	$3,885	$22,120
7	3.332	4.462	$220,870	0.882	$3,970	$6,550	0.4031	$19,240	$2,965	$3,885	$22,120
8	3.220	4.462	$220,870	0.913	$4,110	$6,780	0.4031	$19,240	$2,965	$3,885	$22,120
9	3.112	4.462	$220,870	0.945	$4,250	$7,015	0.4031	$19,240	$2,965	$3,885	$22,120
10	3.008	4.462	$220,870	0.977	$4,395	$7,255	0.4031	$19,240	$2,965	$3,885	$22,120
11	2.907	4.462	$220,870	1.011	$4,550	$7,505	0.4031	$19,240	$2,965	$3,885	$22,120
12	2.810	4.462	$220,870	1.046	$4,705	$7,765	0.4031	$19,240	$2,965	$3,885	$22,120
13	2.717	4.462	$220,870	1.082	$4,870	$8,035	0.4031	$19,240	$2,965	$3,885	$22,120
14	2.626	4.462	$220,870	1.119	$5,035	$8,310	0.4031	$19,240	$2,965	$3,885	$22,120
15	2.539	4.462	$220,870	1.158	$5,210	$8,600	0.4031	$19,240	$2,965	$3,885	$22,120
16	2.454	4.462	$220,870	1.197	$5,385	$8,890	0.4031	$19,240	$2,965	$3,885	$22,120
17	2.373	4.462	$220,870	1.238	$5,570	$9,190	0.4031	$19,240	$2,965	$3,885	$22,120
18	2.294	4.462	$220,870	1.280	$5,760	$9,505	0.4031	$19,240	$2,965	$3,885	$22,120
19	2.218	4.462	$220,870	1.323	$5,955	$9,825	0.4031	$19,240	$2,965	$3,885	$22,120
20	2.145	4.462	$220,870	1.368	$6,155	$10,155	0.4031	$19,240	$2,965	$3,885	$22,120
21	2.074	4.462	$220,870	1.415	$6,370	$10,505	0.4031	$19,240	$2,965	$3,885	$22,120
22	2.006	4.462	$220,870	1.463	$6,585	$10,865	0.4031	$19,240	$2,965	$3,885	$22,120
23	1.940	4.462	$220,870	1.512	$6,805	$11,225	0.4031	$19,240	$2,965	$3,885	$22,120
24	1.876	4.462	$220,870	1.564	$7,040	$11,615	0.4031	$19,240	$2,965	$3,885	$22,120
25	1.814	4.462	$220,870	1.617	$7,275	$12,005	0.4031	$19,240	$2,965	$3,885	$22,120
26	1.755	4.462	$220,870	1.671	$7,520	$12,405	0.4031	$19,240	$2,965	$3,885	$22,120
27	1.697	4.462	$220,870	1.728	$7,775	$12,830	0.4031	$19,240	$2,965	$3,885	$22,120
28	1.642	4.462	$220,870	1.786	$8,035	$13,260	0.4031	$19,240	$2,965	$3,885	$22,120
29	1.588	4.462	$220,870	1.847	$8,310	$13,715	0.4031	$19,240	$2,965	$3,885	$22,120
30	1.536	4.462	$220,870	1.910	$8,595	$14,180	0.4031	$19,240	$2,965	$3,885	$22,120
31	1.485	4.462	$220,870	1.975	$8,890	$14,665	0.4031	$19,240	$2,965	$3,885	$22,120
32	1.437	4.462	$220,870	2.042	$9,190	$15,160	0.4031	$19,240	$2,965	$3,885	$22,120
33	1.390	4.462	$220,870	2.111	$9,500	$15,675	0.4031	$19,240	$2,965	$3,885	$22,120
34	1.344	4.462	$220,870	2.183	$9,825	$16,210	0.4031	$19,240	$2,965	$3,885	$22,120
35	1.300	4.462	$220,870	2.258	$10,160	$16,765	0.4031	$19,240	$2,965	$3,885	$22,120
36	1.257	4.462	$220,870	2.335	$10,510	$17,335	0.4031	$19,240	$2,965	$3,885	$22,120
37	1.216	4.462	$220,870	2.415	$10,870	$17,930	0.4031	$19,240	$2,965	$3,885	$22,120
38	1.176	4.462	$220,870	2.498	$11,240	$18,550	0.4031	$19,240	$2,965	$3,885	$22,120
39	1.137	4.462	$220,870	2.583	$11,625	$19,180	0.4031	$19,240	$2,965	$3,885	$22,120
40	1.100	4.462	$220,870	2.672	$12,025	$19,840	0.4031	$19,240	$2,965	$3,885	$22,120
41	1.063	4.462	$220,870	2.764	$12,440	$20,525	0.4031	$19,240	$2,965	$3,885	$22,120
42	1.028	4.462	$220,870	2.859	$12,865	$21,230	0.4031	$19,240	$2,965	$3,885	$22,120
43	0.994	4.462	$220,870	2.958	$13,310	$21,965	0.4031	$19,240	$2,965	$3,885	$22,120
44	0.961	4.462	$220,870	3.060	$13,770	$22,720	0.4031	$19,240	$2,965	$3,885	$22,120
45	0.929	4.462	$220,870	3.166	$14,245	$23,510	0.4031	$19,240	$2,965	$3,885	$22,120
46	0.897	4.462	$220,870	3.276	$14,740	$24,325	0.4031	$19,240	$2,965	$3,885	$22,120
47	0.867	4.462	$220,870	3.390	$15,255	$25,170	0.4031	$19,240	$2,965	$3,885	$22,120
48	0.838	4.462	$220,870	3.508	$15,785	$26,045	0.4031	$19,240	$2,965	$3,885	$22,120
49	0.809	4.462	$220,870	3.630	$16,335	$26,955	0.4031	$19,240	$2,965	$3,885	$22,120
50-100	0.781	4.462	$220,870	3.757	$16,905	$27,895	0.4031	$19,240	$2,965	$3,885	$22,120

Calculate Decline Rate Using the Preceding Two Production Years. For example for the 2026 tax year, use 2025 and 2024 as follows: 2024 Production = 1,408, 2025 Production = 1,234. Decline = (1408 - 1234)/1408 = 12%. Use PWF 2.810.

TABLE D

Part I: New Gas Leases Producing for First 3 Yrs with Effective Decline Rate => 50% (Secant Rate => 70%) , High Volume Water Production, Primarily Horizontals and/or Mississippian Lime Production

15% Discount Rate; Seven Year Economic Life; 5% Property Tax Credit

Decline and Prescribed PWF			Prescribed Operator's Expense Allowance per Well					Prescribed Equipment Value per Well				
Secant Decline Rate (%)	Effective Decline Rate (%)	Prescribed PWF (15% Disc Rate, 5 % Tax Credit, 7 Yr Econ Life)	Prescribed Fixed Expense Factor (15% Disc Rate, 7 Yr Econ Life)	Prescribed Producing Well Fixed Exp Allow NOT incl Water ave exp	Prescribed Water Expense Factor incl Decline (15% Disc Rate, 7 Yr Econ Life)	Prescribed SWD Expense SWD Well or System Per Oil Prod Well (Sngl Well or Low Volume System <=2000 BWPD) ave exp	Prescribed SWD Expense SWD Well or System Per Oil Prod Well (Sngl Well or High Volume System >2000 BWPD) ave exp	Prescribed Equipment Factor (15% Disc Rate, 7 Yr Econ Life)	Prescribed Producing Well Equip ave	Prescribed SWD Equip SWD Well or System Per Oil Prod Well (Sngl Well or Low Volume System <=2000 BWPD) ave	Prescribed SWD Equip SWD Well or System Per Oil Prod Well (Sngl Well or High Volume System >2000 BWPD) ave	Prescribed Shut In/TA Well Equip ave
70	**50**	0.930	4.462	$513,130	0.713	$28,520	$47,060	0.4031	$27,485	$4,235	$5,550	$31,605
71-72	**51-52**	0.877	4.462	$513,130	0.717	$28,680	$47,320	0.4031	$27,485	$4,235	$5,550	$31,605
73-74	**53-54**	0.817	4.462	$513,130	0.719	$28,760	$47,455	0.4031	$27,485	$4,235	$5,550	$31,605
75	**55**	0.754	4.462	$513,130	0.721	$28,840	$47,585	0.4031	$27,485	$4,235	$5,550	$31,605
76-79	**56-59**	0.730	4.462	$513,130	0.722	$28,880	$47,650	0.4031	$27,485	$4,235	$5,550	$31,605
80	**60**	0.725	4.462	$513,130	0.723	$28,920	$47,720	0.4031	$27,485	$4,235	$5,550	$31,605
81-1.04	**61-64**	0.700	4.462	$513,130	0.724	$28,960	$47,785	0.4031	$27,485	$4,235	$5,550	$31,605
1.05	**65**	0.690	4.462	$513,130	0.725	$29,000	$47,850	0.4031	$27,485	$4,235	$5,550	$31,605
1.06-1.19	**66-69**	0.689	4.462	$513,130	0.726	$29,040	$47,915	0.4031	$27,485	$4,235	$5,550	$31,605
1.20	**70**	0.688	4.462	$513,130	0.737	$29,480	$48,640	0.4031	$27,485	$4,235	$5,550	$31,605
1.21-1.43	**71-75**	0.687	4.462	$513,130	0.763	$30,520	$50,360	0.4031	$27,485	$4,235	$5,550	$31,605
1.44-1.60	**76-79**	0.686	4.462	$513,130	0.768	$30,720	$50,690	0.4031	$27,485	$4,235	$5,550	$31,605
1.61	**80**	0.685	4.462	$513,130	0.794	$31,760	$52,405	0.4031	$27,485	$4,235	$5,550	$31,605
1.62-2.00	**81-86**	0.683	4.462	$513,130	0.860	$34,400	$56,760	0.4031	$27,485	$4,235	$5,550	$31,605
2.01-2.65	**87-92**	0.681	4.462	$513,130	0.923	$36,920	$60,920	0.4031	$27,485	$4,235	$5,550	$31,605
2.66	**93-100**	0.677	4.462	$513,130	0.979	$39,160	$64,615	0.4031	$27,485	$4,235	$5,550	$31,605

Calculate Secant Decline Rate Using Initial Rate and End Rate (monthly or annual), then use table to determine Effective Decline Rate. Example: Jan 2025 Prod = 55400, Dec 2025 Prod = 16000, 11 months production change (12/11); Secant Decline = (55400-16000)/55400*(12/11)= 78%. Use Table to Determine Effective Decline; Secant = .78 = Effective Decline = 56-59% , Use PWF 0.730

TABLE D

Part II: Table D Gas Leases Producing After 3 Yrs , Effective Decline Rate < 50% (Secant Rate < 70%), High Volume Water Production, Primarily Horizontals and/or Mississippian Lime Production

15% Discount Rate; Seven Year Economic Life; 5% Property Tax Credit

Decline and Prescribed PWF		Prescribed Operator's Expense Allowance per Well					Prescribed Equipment Value per Well				
Decline Rate (%)	**Prescribed PWF** (15% Disc Rate, 5 % Tax Credit, 7 Yr Econ Life)	**Prescribed Fixed Expense Factor** (15% Disc Rate, 7 Yr Econ Life)	**Prescribed Producing Well Fixed Exp Allow** NOT incl Water ave exp	**Prescribed Water Expense Factor** incl Decline (15% Disc Rate, 7 Yr Econ Life)	**Prescribed SWD Expense** SWD Well or System Per Oil Prod Well (Sngl Well or Low Volume System <=2000 BWPD) ave exp	**Prescribed SWD Expense** SWD Well or System Per Oil Prod Well (Sngl Well or High Volume System >2000 BWPD) ave exp	**Prescribed Equipment Factor** (15% Disc Rate, 7 Yr Econ Life)	**Prescribed Producing Well Equip** ave	**Prescribed SWD Equip** SWD Well or System Per Oil Prod Well (Sngl Well or Low Volume System <=2000 BWPD) ave	**Prescribed SWD Equip** SWD Well or System Per Oil Prod Well (Sngl Well or High Volume System >2000 BWPD) ave	**Prescribed Shut In/TA Well Equip** ave
0-5	3.569	4.462	$200,120	0.822	$3,700	$6,105	0.4031	$19,240	$2,965	$3,885	$22,120
6	3.448	4.462	$200,120	0.852	$3,835	$6,325	0.4031	$19,240	$2,965	$3,885	$22,120
7	3.332	4.462	$200,120	0.882	$3,970	$6,550	0.4031	$19,240	$2,965	$3,885	$22,120
8	3.220	4.462	$200,120	0.913	$4,110	$6,780	0.4031	$19,240	$2,965	$3,885	$22,120
9	3.112	4.462	$200,120	0.945	$4,250	$7,015	0.4031	$19,240	$2,965	$3,885	$22,120
10	3.008	4.462	$200,120	0.977	$4,395	$7,255	0.4031	$19,240	$2,965	$3,885	$22,120
11	2.907	4.462	$200,120	1.011	$4,550	$7,505	0.4031	$19,240	$2,965	$3,885	$22,120
12	2.810	4.462	$200,120	1.046	$4,705	$7,765	0.4031	$19,240	$2,965	$3,885	$22,120
13	2.717	4.462	$200,120	1.082	$4,870	$8,035	0.4031	$19,240	$2,965	$3,885	$22,120
14	2.626	4.462	$200,120	1.119	$5,035	$8,310	0.4031	$19,240	$2,965	$3,885	$22,120
15	2.539	4.462	$200,120	1.158	$5,210	$8,600	0.4031	$19,240	$2,965	$3,885	$22,120
16	2.454	4.462	$200,120	1.197	$5,385	$8,890	0.4031	$19,240	$2,965	$3,885	$22,120
17	2.373	4.462	$200,120	1.238	$5,570	$9,190	0.4031	$19,240	$2,965	$3,885	$22,120
18	2.294	4.462	$200,120	1.280	$5,760	$9,505	0.4031	$19,240	$2,965	$3,885	$22,120
19	2.218	4.462	$200,120	1.323	$5,955	$9,825	0.4031	$19,240	$2,965	$3,885	$22,120
20	2.145	4.462	$200,120	1.368	$6,155	$10,155	0.4031	$19,240	$2,965	$3,885	$22,120
21	2.074	4.462	$200,120	1.415	$6,370	$10,505	0.4031	$19,240	$2,965	$3,885	$22,120
22	2.006	4.462	$200,120	1.463	$6,585	$10,865	0.4031	$19,240	$2,965	$3,885	$22,120
23	1.940	4.462	$200,120	1.512	$6,805	$11,225	0.4031	$19,240	$2,965	$3,885	$22,120
24	1.876	4.462	$200,120	1.564	$7,040	$11,615	0.4031	$19,240	$2,965	$3,885	$22,120
25	1.814	4.462	$200,120	1.617	$7,275	$12,005	0.4031	$19,240	$2,965	$3,885	$22,120
26	1.755	4.462	$200,120	1.671	$7,520	$12,405	0.4031	$19,240	$2,965	$3,885	$22,120
27	1.697	4.462	$200,120	1.728	$7,775	$12,830	0.4031	$19,240	$2,965	$3,885	$22,120
28	1.642	4.462	$200,120	1.786	$8,035	$13,260	0.4031	$19,240	$2,965	$3,885	$22,120
29	1.588	4.462	$200,120	1.847	$8,310	$13,715	0.4031	$19,240	$2,965	$3,885	$22,120
30	1.536	4.462	$200,120	1.910	$8,595	$14,180	0.4031	$19,240	$2,965	$3,885	$22,120
31	1.485	4.462	$200,120	1.975	$8,890	$14,665	0.4031	$19,240	$2,965	$3,885	$22,120
32	1.437	4.462	$200,120	2.042	$9,190	$15,160	0.4031	$19,240	$2,965	$3,885	$22,120
33	1.390	4.462	$200,120	2.111	$9,500	$15,675	0.4031	$19,240	$2,965	$3,885	$22,120
34	1.344	4.462	$200,120	2.183	$9,825	$16,210	0.4031	$19,240	$2,965	$3,885	$22,120
35	1.300	4.462	$200,120	2.258	$10,160	$16,765	0.4031	$19,240	$2,965	$3,885	$22,120
36	1.257	4.462	$200,120	2.335	$10,510	$17,335	0.4031	$19,240	$2,965	$3,885	$22,120
37	1.216	4.462	$200,120	2.415	$10,870	$17,930	0.4031	$19,240	$2,965	$3,885	$22,120
38	1.176	4.462	$200,120	2.498	$11,240	$18,550	0.4031	$19,240	$2,965	$3,885	$22,120
39	1.137	4.462	$200,120	2.583	$11,625	$19,180	0.4031	$19,240	$2,965	$3,885	$22,120
40	1.100	4.462	$200,120	2.672	$12,025	$19,840	0.4031	$19,240	$2,965	$3,885	$22,120
41	1.063	4.462	$200,120	2.764	$12,440	$20,525	0.4031	$19,240	$2,965	$3,885	$22,120
42	1.028	4.462	$200,120	2.859	$12,865	$21,230	0.4031	$19,240	$2,965	$3,885	$22,120
43	0.994	4.462	$200,120	2.958	$13,310	$21,965	0.4031	$19,240	$2,965	$3,885	$22,120
44	0.961	4.462	$200,120	3.060	$13,770	$22,720	0.4031	$19,240	$2,965	$3,885	$22,120
45	0.929	4.462	$200,120	3.166	$14,245	$23,510	0.4031	$19,240	$2,965	$3,885	$22,120
46	0.897	4.462	$200,120	3.276	$14,740	$24,325	0.4031	$19,240	$2,965	$3,885	$22,120
47	0.867	4.462	$200,120	3.390	$15,255	$25,170	0.4031	$19,240	$2,965	$3,885	$22,120
48	0.838	4.462	$200,120	3.508	$15,785	$26,045	0.4031	$19,240	$2,965	$3,885	$22,120
49	0.809	4.462	$200,120	3.630	$16,335	$26,955	0.4031	$19,240	$2,965	$3,885	$22,120
50-100	0.781	4.462	$200,120	3.757	$16,905	$27,895	0.4031	$19,240	$2,965	$3,885	$22,120

Calculate Decline Rate Using the Preceding Two Production Years. For example for the 2026 tax year, use 2025 and 2024 as follows: 2024 Production = 1,408, 2025 Production = 1,234. Decline = (1408 - 1234)/1408 = 12%. Use PWF 2.810.

Itemized Equipment Section

Itemized Equipment Section

Rendition Form Instructions

The lease operator/service contractor/taxpayer/tax representative is required to provide the information requested in the rendition header, Section I, Section IV notations, and additional attached list of equipment to be known as Section III of the oil and/or gas rendition form and all other information necessary to fix the valuation of the property as determined by the Director of Property Valuation. Failure to provide this required information will result in a 12.5% penalty for failure to file a full and complete statement of assessment according to KSA 79-332a (c). COLUMN A (SCHEDULE VALUE) is to be completed by using the oil and gas guide without departure, adjustment, or change. COLUMN B (OWNER) is reserved for the lease operator/service contractor/taxpayer/tax representative's use for requested adjustments to Column A. COLUMN C (APPRAISER) is reserved for the county appraiser to finalize the valuation of the equipment.

The Itemized Equipment Rendition-Schedule Value (Column A) Instructions ***An example of an itemized equip assessment rendition can be found following this explanation(may use oil or gas form)***	
NOTE: For copies of the rendition forms and oil and gas guide, please contact the county appraisal office for the county in which the property is located or download from https://www.ksrevenue.gov/pvdoilgas.html.	
Statement of Ownership/ Address/Property Name	Provide information to the extent available. It may be necessary to complete page 2 in order to list all wells on the lease and include location, KDOR ID #s, API #s, etc…
Section I: Location of Property	**THIS IS REQUIRED DATA.** A minimum legal description of Section, Township, and Range is required. Quarter section and/or more detailed location description is preferred.
Section II: Well Data	This is required data if filed with a producing lease. If itemized equipment only, there is no need for this section to be completed.
Section III: Itemized Equipment	**THIS IS REQUIRED DATA** The rendition sheet page 2 has been created for this information. Please attach page 2 with a listing of equipment located on the lease, but not part of the producing "prescribed" equipment. Also, equipment located in storage yards and/or other sites which is considered "itemized equipment" per this guide should be listed using page 2 of the rendition. Once listed on page 2 of the rendition, the total value shall be transferred to the total Itemized Equipment value to the oil rendition Section VI, Line 8, or to the gas rendition Section VI , Line 9.
Section IV: Production Data	This is required data if filed with a producing lease. If itemized equipment only, there is no need for this section to be completed.
Section V: Gross Reserve Calculation (Total 8/8ths Interest)	This section is only calculated if filed with a producing lease. If itemized equipment only, there is no need for this section to be calculated.
Section VI: Gross Reserve Value X Decimal Interest **(Determination of total itemized equipment value)**	The gross reserve value is only calculated if filed with a producing lease. **If itemized equipment only, the total market value of all itemized equipment described in page 2 attachment (Section III) should be the only value shown on either Line 8 (oil rendition) or Line 9 (gas rendition).** **Line 8 (oil)/Line 9 (gas): Add Itemized Equipment**-Use Itemized Equipment Section from back of guide to value attached listing of equipment not currently being used in well production. **Line 9 (oil)/Line 10 (gas):Working Interest Total Market Value**-Repeat Line 8 (oil)/Line 9 (gas) **Line 10 (oil)/Line 11 (gas):Working Interest Total Assessed Value**-Multiply Line 10 X 30% assessment rate. **Certification:** ***The certification is to be completed and signed by the lease owner or operator who is responsible for filing the tax rendition with the county appraiser. It must also be signed by the rendition preparer.***

OIL ASSESSMENT RENDITION

SHALL BE FILED WITH THE COUNTY APPRAISER BY APRIL 1

Schedule 2 (Class 2B) (Rev. 1/26)

Somewhere **County, Kansas** **Tax Year** **2026**

Statement of	We Produce Oil			**Operator ID#**	257689
P.O. Address	1234 First Street	**City**	Big Spring	**State** KS	**Zip** 66795
Name of Property	Itemized Equipment	**County ID#**	3879	**KDOR ID#(s)**	**Well API#(s)**

Section I-Location of Property (required)				**Section VII-Abstract Value** (for county use only)	Appraised	Assessed	Penalty	Total
Lease Description	Yard located in city							
(Well location pg 2)				Total Working Interest (Sec. VI. Line 9)				
Lot Sec.		Adn. Twp.		Royalty & ORRI Interest (Sec. VI. Line 1)			XXXXXXXXX	
Blk Rng.		Twp. City		Itemized Equipment (Sec. VI. Line 8)				
Tax Unit	**28**	School Dist		Total				

Section II-Lease Data (required)

Producing Wells: Oil Submersible Gas	Non-Producing Wells:	Shut-In SWD TA INJ WS			Total # Wells on Lease
Secondary Recovery( ) KCC Permit #	Water Disposal: Hauler/System/Well Name				Total # Tank Batteries on Lease
Spud Date: Mo/Yr (new prod)	Ave Prod Depth	Horizontal ( )	Total WI Decimal		Prod Formation
Comp Date: Mo/Yr (new prod)	SWD/INJ/WS	Horiz Total Depth	Total RI&ORRI Dec		Purchaser Name
Oil Gravity	Water Prod	BWPD	Purch Address		Purch Phone

Section IV-Production Data (required)

Month	2025 Oil (Bbls)	2025 Casinghead Gas (Mcf)	2024 Oil (Bbls)
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
Annual Production			
Casinghead Gas (Converted to Bbls)		XXXXXX	XXXXXXXXX
Total Annual Production (Bbls + gas conv)		XXXXXX	XXXXXXXXX
Annual Decline (Bbls)		XXXXXX	XXXXXXXXX
Decline Rate (%)		XXXXXX	XXXXXXXXX

Notation

ITEMIZED EQUIPMENT RENDITION SAMPLE

***Please see attached list (Section III) of equipment as support for total value**

Lease Receives Eastern KS Posted Price Yes No

Severance Tax Exempt # Property Tax Exempt #

Casinghead Gas Production Data (conversion calculation)

______ X ______ = ______ / ______ = ______

Prod (Mcf) X Net $/Mcf Gas = Income / Net $/Bbl Oil = Total Bbl (Transfer to Sec IV, Casing Gas Conv)

Gatherer Name

Address Phone

Section V-Gross Reserve Calculation (Total 8/8ths Interest)

	1.		2.		3.		4.		5.
Schedule (A)		X		=		X		=	
Owner (B)		X		=		X		=	
Appraiser (C)		X		=		X		=	

1. Annual Production (Bbls) (Total Annual Prod, Sec IV) 2. Effect Jan 1 Net Price $/Bbl (See Crude Oil Price Schedule) 3. Est Gross Income Stream (Multiply Line 1 X Line 2) 4. Present Worth Factor (Based on Decline Rate-See Tbl) 5. Est Gross Reserve Value (Total 8/8ths-Transfer Total to Sec VI, Lines 1&2)

Section VI-Gross Reserve Value X Decimal Interest	**Schedule (A)**	**Owner (B)**	**Appraiser (C)**
1. Royalty & Overriding Royalty Interest Valuation (Total Sec V, Line 5 X Total RI & ORRI Interest) X			
2. Working Interest Valuation (Total Sec V, Line 5 X Total WI Interest) X			
3a. Deduct Operating Cost Allowance for Producing Wells (Allowance per Well) X (Number Wells)			
3b. Deduct Operating Cost Allowance for Injection Wells (Allowance per Well) X (Number Wells)			
3c. Deduct Operating Cost for Submersible Wells (Annual Submersible Expense) X (Expense Factor-Tbl)			
4. Working Interest Subtotal (Sec VI, Line 2 minus Lines 3a, 3b & 3c)			
5. Working Interest Minimum Lease Value (Sec VI, Line 2) X (2%, 5%, 10%)			
6. Copy Value from Sec VI, Line 4 or Line 5 (Whichever Line is Greater)			
7a. Add Prescribed Equipment Value for Producing Wells (Allowance per Well) X (Number Wells)			
7b. Add Prescribed Equipment Value for Multiple Producing Wells (Allowance per Well) X (Number Wells)			
7c. Add Prescribed Equipment Value for Non-Producing Wells (Shut-In, TA,SWD,INJ,WS) X (Number Wells)			
7d. Add Prescribed Equipment Value for Submersible Wells (Allowance per Well) X (Number Wells)			
7e. Add Pres Equip Value for Additional Equipment X (Equip Fact-Tbl)			
8. Add Itemized Equipment (Section III - Attached Schedule)	43,885		
9. Working Interest Total Market Value (Add Sec VI, Lines 6, 7a, 7b, 7c, 7d, 7e & 8)	43,885		
10. Working Interest Total Assessed Value (Multiply Sec VI, Line 9 X 30%, Unless Lease Qualifies for 25% Rate) 30%	13,166		

Current Division Order with Name, Address, Interest of Royalty Owners, and Well/Lease Identifier is a Required Attachment to Rendition

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

Mr. Oil Producer	2026	Oil Guy Rendition Preparer	2026
Owner	**Date**	**Tax Rendition Preparer**	**Date**

Rendition Information: **Contact Phone** (785) 555 - 1212 **Contact Email** oilguy@xyz.com

Lease Code WE-Item **County Code** 3879 **Lease Name** Itemized Equipment

Prescribed by Kansas Department of Revenue, Division of Property Valuation

OIL ASSESSMENT RENDITION ADDITIONS PAGE

MUST BE ATTACHED TO OIL ASSESSMENT RENDITION

Schedule 2 (Class 2B) (Rev. 1/26)

Somewhere **County, Kansas** **Tax Year** **2026**

Statement of We Produce Oil **Operator ID#** 257689

Name of Property Itemized Equipment **County ID#** 3879 **KDOR ID#(s)** 0 **Well API#(s)** 0

Section I-IV Additional Data (required)

Well Names on Lease	Location	Well Type	KDOR ID#	Well API#	Well Production Bbls	Well Production Mcf
Notation				**Total Lease Production** (includes all wells on lease-pg 1 rendition)	Total Bbls	Total Mcf

Section III Itemized Equipment (required)

Property Name/Model	Property Description	Location	Condition (New/Used/Salvage)	Year	Series	Mast (ft)	Capacity (lbs)	Guide Value
RMI	M42-550-42 Dbl Drum Dbl/Trpl Derrick-5 axle carrier	yard	Used	1981	400	96	215000	29,750
Cardwell	KB200 Dbl Drum Dbl/Sgl Derrick-4 axle carrier	yard	Used	1965	200	70	155000	13,125
Bethlehem	Rebuilt GCI 600 Duplex mud pump 8'x18"	yard	Used					1,010
Notation					**Total Item Equip Value** (Copy Total Value to Oil Assess Rend Line 8, Sec VI)			43,885

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

This page must be attached to the oil assessment rendition, which must be dated and signed by owner and tax rendition preparer to be valid.

Lease Code WE-Item **County Code** 3879 **Lease Name** Itemized Equipment

Itemized Equipment Values

Partial list of prevalent items, not intended to be inclusive

Rotary Drilling Rigs

Depth Rating	New	Used		Stacked < = 3 Mos		Stacked >3 Mos< 6 Mos		Stacked >6 Mos< 1 Yr	
		Good Cond	Fair Cond	Good Cond	Fair Cond	Good Cond	Fair Cond	Good Cond	Fair Cond
< = 1250 Ft	$60,960	$11,020	$6,610	$7,165	$4,295	$5,510	$3,305	$3,855	$2,315
1251 - 2500 Ft	$135,470	$16,950	$13,185	$11,020	$8,570	$8,475	$6,595	$5,935	$4,615
2501 - 5000 Ft	$225,780	$56,500	$15,815	$36,725	$10,280	$28,250	$7,910	$19,775	$5,535
5001 - 7500 Ft	$451,565	$72,320	$31,640	$47,010	$20,565	$36,160	$15,820	$25,310	$11,075
7501 - 10,000 Ft	$903,125	$135,600	$52,735	$88,140	$34,280	$67,800	$26,370	$47,460	$18,455
10,001 - 12,500 Ft	$1,445,000	$250,710	$80,155	$162,960	$52,100	$125,355	$40,080	$87,750	$28,055
12,501 - 15,000 Ft	$1,986,875	$389,760	$134,400	$253,345	$87,360	$194,880	$67,200	$136,415	$47,040
15,001 - 17,500 Ft	$2,393,280	$396,480	$141,120	$257,710	$91,730	$198,240	$70,560	$138,770	$49,390

Depth Rating	Stacked > 1 Yr		Salvage
	Good Cond	Fair Cond	
< = 1250 Ft	$2,205	$1,320	$465
1251 - 2500 Ft	$3,390	$2,635	$925
2501 - 5000 Ft	$11,300	$3,165	$1,105
5001 - 7500 Ft	$14,465	$6,330	$2,215
7501 - 10,000 Ft	$27,120	$10,545	$3,690
10,001 - 12,500 Ft	$50,140	$16,030	$5,610
12,501 - 15,000 Ft	$77,950	$26,880	$9,410
15,001 - 17,500 Ft	$79,295	$28,225	$9,880

Note: New column does not include drill pipe or drill collars. Used column does include drill pipe and drill collars. Rotary rig values include truck/carrier value.

Condition Definitions for Rotary Drilling Rigs:

Good – Complete (100%) operating condition. May have just recently been completely overhauled or rebuilt with new or nearly new materials, and/or has had such limited use that no repairs or worn part replacements are necessary. Very low hours of use.

Fair – Very high hours or extended use. Defects are obvious and will require repair or general rebuild soon. Not 100% functional or efficient, and may be operational or functional, but questionable.

Workover / Well Service Units

Rig Series	Main Drum Size	Main Brake Band Width	Derrick/ Pole Capacity	Mast/ Pole/ Derrick (Sgl or Dbl)	New	Used	Stacked < = 3 mos	Stacked > 3 mos < 6 mos	Stacked > 6 mos < 1 yr	Stacked > 1 yr	Salvage
Shallow Truck NOT INCLUDED	< 32"	< 6"	< 85,000	< 65'	$3,570	$685	$445	$345	$240	$135	$50
100 Truck NOT INCLUDED	32"-36"	6"- 8"	85,000 - 100,000	65'-72'	$31,875	$5,375	$3,495	$2,690	$1,880	$1,075	$375
200 Carrier INCLUDED	36"-42"	8"-10"	100,001 - 150,000	65'-72'	$72,500	$13,125	$8,530	$6,565	$4,595	$2,625	$920
300 Carrier INCLUDED	38"-42"	10"-12"	150,001 - 200,000	84'+	$92,500	$17,500	$11,375	$8,750	$6,125	$3,500	$1,225
400 Carrier INCLUDED	42"	10"-12"	200,001 - 250,000	84'+	$112,500	$29,750	$19,340	$14,875	$10,415	$5,950	$2,085
500 Carrier INCLUDED	42"	12"	250,000 +	97'+	$132,500	$39,375	$25,595	$19,690	$13,780	$7,875	$2,755

- ❖ The heaviest rig capacity must be used when determining rig series.
- ❖ The Shallow and 100 Series rig values do not include a truck/carrier value. The rig equipment for these units can typically be separated from the "chassis cab", which is considered a complete vehicle that could be driven on the highways without a bed; thus, it must be classified and valued separately as a motor vehicle per the Kansas Constitution, Article 11. The "truck bed" is reported and valued as C/I or Oil & Gas Itemized equipment.
- ❖ The 200, 300, 400, and 500 Series rig values include a carrier value. Rigs in these categories are vehicles constructed as a machine used exclusively for servicing, cleaning-out, or drilling an oil well and consisting in general of a mast, an engine for power, a draw works, and a chassis permanently constructed or assembled for one or more of those purposes per KSA 8-126, Article 1. The table value is NOT applicable if the workover/well service rig does not qualify as a unit as described in the previous sentence. In this case, the "chassis cab" and/or "truck bed" values must be rendered and valued separately. A market value must then be determined for the rig.
  - Shallow series includes but is not limited to: Pullstar, Semco, and Smeal. Specific models included are: Pullstar 6000, Semco 6000, Smeal 5T - 8T
  - Series 100 includes but is not limited to: Cabot, Cardwell, Cooper, Crane, Franks, Hopper, National Oilwell, RMI, Skytop, Taylor, and Wilson. Specific models included are: 32 Cooper, 33 Franks, 44 Franks, and 844 Franks
  - Series 200 includes but is not limited to: Cabot, Cardwell, Cooper, Crane, Franks, Hopper, National Oilwell, RMI, Skytop, Taylor, and Wilson. Specific models included are: 38" X 10" Cooper, 42" X 8" Cooper, 40" X 10" Cardwell, 65 Franks, 658 Franks, 1058 Franks
  - Series 300 includes but is not limited to: Cabot, Cardwell, Cooper, Crane, Franks, Hopper, National Oilwell, RMI, Skytop, Taylor, and Wilson. Specific models included are: 38" X 10" Cooper, 658 Franks, 1058 Franks
  - Series 400 includes but is not limited to: Cabot, Cardwell, Cooper, Crane, Franks, Hopper, National Oilwell, RMI, Skytop, Taylor, and Wilson.
  - Series 500 includes but is not limited to: Cabot, Cardwell, Cooper, Crane, Franks, Hopper, National Oilwell, RMI, Skytop, Taylor, and Wilson.
  - Cable Tool Rigs such as Cardwell, Franks, Walker-Neer, and Wichtex should be measured and classified as a Series 100, 200, 300, 400, or 500 in the table.

Drill Collars

	New		Used		
Size	Slick	Spiral	Slick	Spiral	Salvage
3 1/8"	$295	$495	$90	$290	$45
3 1/4"	$330	$530	$100	$300	$50
3 1/2"	$590	$790	$175	$375	$90
4 1/8"	$625	$825	$190	$390	$95
4 3/4"	$795	$995	$240	$440	$120
4 7/8"	$1,025	$1,225	$310	$510	$155
5"	$1,230	$1,430	$370	$570	$185
6"	$1,665	$1,865	$500	$700	$250
6 1/4"	$1,840	$2,040	$550	$750	$275
6 1/2"	$1,895	$2,095	$570	$770	$285
6 3/4"	$1,920	$2,120	$575	$775	$290
7"	$2,095	$2,295	$630	$830	$315
7 1/4"	$2,225	$2,425	$670	$870	$335
7 3/4"	$2,355	$2,555	$705	$905	$355
8"	$3,455	$3,655	$1,035	$1,235	$520
8 1/4"	$3,530	$3,730	$1,060	$1,260	$530
8 1/2"	$3,580	$3,780	$1,075	$1,275	$540
9"	$3,840	$4,040	$1,150	$1,350	$575
9 1/2"	$4,065	$4,265	$1,220	$1,420	$610
10"	$4,170	$4,370	$1,250	$1,450	$625
11"	$4,785	$4,985	$1,435	$1,635	$720

Drill Pipe

Size/Wght/Grade	New	Used T&D	Used	Salvage
2 3/8" X 6.65# E	$3.45	$1.38	$1.10	$0.55
2 3/8" X 6.65# X	$3.50	$1.40	$1.12	$0.56
2 3/8" X 6.65# G	$3.70	$1.48	$1.18	$0.59
2 3/8" X 6.65# S	$3.70	$1.48	$1.18	$0.59
2 3/8" X 6.85# E	$4.25	$1.70	$1.36	$0.68
2 3/8" X 6.85# X	$4.30	$1.72	$1.38	$0.69
2 3/8" X 6.85# G	$4.30	$1.72	$1.38	$0.69
2 3/8" X 6.85# S	$4.35	$1.74	$1.39	$0.70

Size/Wght/Grade	New	Used T&D	Used	Salvage
2 7/8" X 10.40# E	$4.35	$1.74	$1.39	$0.70
2 7/8" X 10.40# X	$4.60	$1.84	$1.47	$0.74
2 7/8" X 10.40# G	$4.65	$1.86	$1.49	$0.74
2 7/8" X 10.40# S	$4.80	$1.92	$1.54	$0.77
3 1/2" X 9.50# E	$6.00	$2.40	$1.92	$0.96
3 1/2" X 9.50# X	$6.35	$2.54	$2.03	$1.02
3 1/2" X 9.50# S	$7.20	$2.88	$2.30	$1.15
3 1/2" X 13.30# E	$8.20	$3.28	$2.62	$1.31
3 1/2" X 13.30# X	$8.55	$3.42	$2.74	$1.37
3 1/2" X 13.30# G	$8.60	$3.44	$2.75	$1.38
3 1/2" X 13.30# S	$8.75	$3.50	$2.80	$1.40
3 1/2" X 15.50# E	$8.85	$3.54	$2.83	$1.42
3 1/2" X 15.50# X	$9.25	$3.70	$2.96	$1.48
3 1/2" X 15.50# G	$9.30	$3.72	$2.98	$1.49
3 1/2" X 15.50# S	$9.30	$3.72	$2.98	$1.49
4" X 14.00# E	$9.35	$3.74	$2.99	$1.50
4" X 14.00# X	$9.45	$3.78	$3.02	$1.51
4" X 14.00# G	$9.60	$3.84	$3.07	$1.54
4" X 14.00# S	$9.80	$3.92	$3.14	$1.57
4" X 15.70# E	$10.25	$4.61	$3.69	$1.85
4" X 15.70# X	$10.30	$4.64	$3.71	$1.85
4" X 15.70# G	$10.55	$4.75	$3.80	$1.90
4" X 15.70# S	$10.55	$4.75	$3.80	$1.90
4 1/2" X 16.60# E	$12.25	$7.35	$5.88	$2.94
4 1/2" X 16.60# X	$12.35	$7.41	$5.93	$2.96
4 1/2" X 16.60# G	$13.05	$7.83	$6.26	$3.13
4 1/2" X 16.60# S	$13.05	$7.83	$6.26	$3.13
4 1/2" X 20.00# E	$13.10	$7.86	$6.29	$3.14
4 1/2" X 20.00# X	$13.10	$7.86	$6.29	$3.14
4 1/2" X 20.00# G	$13.15	$7.89	$6.31	$3.16
4 1/2" X 20.00# S	$13.35	$8.01	$6.41	$3.20
5" X 19.50#E	$15.15	$9.09	$7.27	$3.64
5" X 19.50#X	$15.25	$9.15	$7.32	$3.66
5" X 19.50#G	$15.35	$9.21	$7.37	$3.68
5" X 19.50#S	$15.35	$9.21	$7.37	$3.68
5 1/2" X 21.90#E	$16.40	$9.84	$7.87	$3.94
5 1/2" X 21.90#X	$16.50	$9.90	$7.92	$3.96
5 1/2" X 21.90#G	$16.75	$10.05	$8.04	$4.02
5 1/2" X 21.90#S	$16.80	$10.08	$8.06	$4.03
6 5/8" X 25.20#E	$18.00	$10.80	$8.64	$4.32
6 5/8" X 27.20#E	$18.45	$11.07	$8.86	$4.43

Pumps

Mud Pumps - Drilling				
	New	Rebuilt	Used	Salvage
GCI 600 Duplex	$5,040	$3,275	$1,010	$150
G85 Duplex	$10,640	$6,915	$2,130	$320
C-350 Duplex	$9,800	$6,370	$1,960	$295
A-1000P Duplex	$12,600	$8,190	$2,520	$380
F-500 Triplex	$24,500	$15,925	$4,900	$735
F-800 Triplex	$28,420	$18,475	$5,685	$855
F-1300 Triplex	$33,600	$21,840	$6,720	$1,010

Pumps (Continued)

Water Injection Pumps				
	New	Rebuilt	Used	Salvage
PR-10	$190	$125	$40	$5
J-30	$1,020	$665	$205	$30
J-60	$1,645	$1,070	$330	$50
J-100	$2,820	$1,835	$565	$85

Miscellaneous Items

Diesel Engines				
	New	Rebuilt	Used	Salvage
GM - 671 (Twin)	$3,575	$2,325	$715	$105
Cat - 3406	$5,195	$3,375	$1,040	$155
Cat - 3408	$8,050	$5,235	$1,610	$240

Steel Cable – O.D. / ft			
	New	Used	Salvage
7/16"	$0.30	None	None
9/16"	$0.35	None	None
3/4"	$0.50	None	None
7/8"	$0.70	None	None
1.0"	$0.85	None	None
1&1/8"	$0.90	None	None
1&1/4"	$0.95	None	None

Power Tongs			
	New	Used	Salvage
Tubing	$1,370	$275	$40

Torque Converters			
National or equivalent			
	New	Used	Salvage
C-195	$1,960	$390	$60

Power Service Lines (Including poles and wires)			
Two wire $/ft	$0.40	Three wire $/ft	$0.15

Miscellaneous Items (Continued)

Light Plants			
Gasoline Powered			
	New	Used	Salvage
1.00 – 1.50 KW	$520	$105	$15
1.5 - 3.00 KW	$520	$105	$15
+3.0 - 7.5 KW	$590	$120	$20
+7.5 KW	$755	$150	$25

TRANSFORMER 2300/110-220			
Installed price = 1.7 x transformer price.			
KVA Size	New	Used	Salvage
1.5	$20	$5	$0
2	$20	$5	$0
2.5	$25	$5	$0
3	$30	$5	$0
4	$40	$10	$0
5	$50	$10	$0
7.5	$60	$10	$0
10	$70	$15	$0
15	$90	$20	$5
20	$100	$20	$5
25	$110	$20	$5
30	$130	$25	$5
37.5	$140	$30	$5
40	$165	$35	$5
50	$175	$35	$5
75	$195	$40	$5
100	$245	$50	$5
167	$370	$75	$10

Pipe

Line Pipe			
	New	Used	Salvage
1/8"	$0.25	$0.05	$0.00
1/4"	$0.25	$0.05	$0.00
3/8"	$0.30	$0.05	$0.00
1/2"	$0.30	$0.05	$0.00
3/4"	$0.35	$0.05	$0.00
1"	$0.45	$0.10	$0.00
1 1/4"	$0.55	$0.10	$0.00
1 1/2"	$0.70	$0.15	$0.00
2"	$1.00	$0.20	$0.05
3	$2.20	$0.45	$0.05
4"	$2.65	$0.55	$0.10
6"	$3.10	$0.60	$0.10

Pipe (Continued)

Galvanized Pipe			
	New	Used	Salvage
1/2"	$0.35	$0.05	$0.00
3/4"	$0.45	$0.10	$0.00
1"	$0.60	$0.10	$0.00
1 1/4"	$0.80	$0.15	$0.00
1 1/2"	$0.90	$0.20	$0.05
2"	$1.25	$0.25	$0.05

Poly Pipe			
Size/Type/Series/Length	New	Used	Salvage
1" Roll SDR-11 500'	$0.10	None	None
2" Roll SDR-11 500'	$0.15	None	None
2" Roll SDR-11 1500'	$0.15	None	None
2" Roll SDR-7 2000'	$0.25	None	None
3" Roll SDR-11 500'	$0.35	None	None
3" Roll SDR-11 1000'	$0.35	None	None
3" Roll SDR-7 1000'	$0.45	None	None
4" Roll 6500/YL 500'	$0.50	None	None
4" Roll SDR-11 600'	$0.50	None	None
4" Roll SDR-7 600'	$0.75	None	None
6" Joint 6500/YL 50'	$1.25	None	None
6" Roll 6500/YL 500'	$1.30	None	None
6" Joint SDR-11 50'	$1.10	None	None
12" Joint SDR-11 50'	$3.05	None	None
16" Joint SDR-11 50'	$4.70	None	None

PVC Pipe			
	New	Used	Salvage
3/4" Sch 40	$0.10	$0.00	$0.00
1" Sch 40	$0.10	$0.00	$0.00
1" Sch 80	$0.20	$0.05	$0.00
1 1/4" Sch 40 Bell End Pipe	$0.10	$0.00	$0.00
1 1/2" Sch 40 Bell End Pipe	$0.20	$0.05	$0.00
2" Sch 40 Bell End Pipe	$0.20	$0.05	$0.00
2" Sch 80	$0.40	$0.10	$0.00
2 1/2" Sch 40	$0.35	$0.05	$0.00
2 1/2" Sch 160	$0.15	$0.05	$0.00
3" Sch 40	$0.45	$0.10	$0.00
3" Sch 80	$0.70	$0.15	$0.00
3" Sch 160	$0.25	$0.05	$0.00
4" Sch 40	$0.65	$0.15	$0.00
4" Sch 160 Bell End Pipe	$0.50	$0.10	$0.00
6" Sch 40	$1.05	$0.20	$0.05
6" Sch 160	$0.85	$0.15	$0.05

Tubing / Casing / Rods

Tubing - O.D./ ft				
Size/Wght/Grade	**New**	**Used T&D**	**Used**	**Salvage**
1" 1.7# A5L	$0.40	$0.25	$0.10	$0.00
1" Poly Lined A5L	$0.60	$0.40	$0.10	$0.00
1 1/4" R-2	$0.80	$0.50	$0.15	$0.00
2 3/8" J-55	$0.80	$0.50	$0.15	$0.00
2 3/8" Sealtite	$1.10	$0.70	$0.20	$0.05
2 7/8" J-55	$1.05	$0.70	$0.20	$0.05
2 7/8" Lmtd Service	$0.90	$0.60	$0.20	$0.05
2 7/8" Sealtite	$1.40	$0.90	$0.30	$0.05
3 1/2" R-2	$1.45	$0.95	$0.30	$0.05

Steel Casing- API Specs: O.D. / ft				
Size/Wght/Grade	**New**	**Used T&D**	**Used**	**Salvage**
4 1/2" 9.5# R-2	$1.55	$1.00	$0.30	$0.05
4 1/2" 9.5# R-2 & R-3	$1.65	$1.05	$0.35	$0.05
4 1/2" 10.5# R-3 Lmt Ser	$1.35	$0.90	$0.25	$0.05
4 1/2" 10.5# J-55	$1.40	$0.90	$0.30	$0.05
4 1/2" 10.5# R-2 Lmt Ser	$1.50	$1.00	$0.30	$0.05
4 1/2" 10.5# R-3 Lmt Ser	$1.40	$0.90	$0.30	$0.05
4 1/2" 10.24# End Casing	$1.35	$0.90	$0.25	$0.05
5 1/2" 14# J-55	$1.90	$1.25	$0.40	$0.05
5 1/2" 14# R-2	$1.95	$1.25	$0.40	$0.05
5 1/2" 14# R-2 Lmt Ser	$1.35	$0.90	$0.25	$0.05
5 1/2" 14# R-3 Lmt Ser	$1.80	$1.15	$0.35	$0.05
5 1/2" 15.5# J-55	$2.10	$1.35	$0.40	$0.05
5 1/2" 15.5# R-2	$2.05	$1.35	$0.40	$0.05
5 1/2" 15.5# R-2 #2	$1.90	$1.25	$0.40	$0.05
5 1/2" 15.5# R-3 Lmt Ser	$2.05	$1.35	$0.40	$0.05
5 1/2" 15.5# R-3	$2.20	$1.45	$0.45	$0.05
7" 20# J-55	$2.55	$1.65	$0.50	$0.10
7" 20# R-1	$1.45	$0.95	$0.30	$0.05
7" 20# R-3	$1.45	$0.95	$0.30	$0.05
8 5/8" 20# R-1 L/S Surface	$3.30	$2.15	$0.65	$0.10
8 5/8" 20# R-3 L/S Surface	$4.00	$2.60	$0.80	$0.10
8 5/8" 23# R-3 L/S Surface	$3.30	$2.15	$0.65	$0.10
7 5/8" 24# J-55	$3.30	$2.15	$0.65	$0.10
8 5/8" 24# R-1 Surface	$3.95	$2.55	$0.80	$0.10
8 5/8" 24# R-2 L/S Surface	$3.30	$2.15	$0.65	$0.10
8 5/8" 24# R-3 L/S Surface	$3.30	$2.15	$0.65	$0.10
8 5/8" 28# R-3	$3.05	$2.00	$0.60	$0.10

Tubing / Casing / Rods (Continued)

Sucker Rods - O.D. / ft				
	New	Used T&D	Used	Salvage
5/8" Grade C w/cplg	$0.45	$0.30	$0.10	$0.00
5/8" Grade D w/cplg	$0.50	$0.35	$0.10	$0.00
5/8" Type 30 w/cplg	$0.50	$0.35	$0.10	$0.00
3/4" Grade C w/cplg	$0.50	$0.35	$0.10	$0.00
3/4" Grade D w/cplg	$0.50	$0.35	$0.10	$0.00
3/4" Type 30 w/cplg	$0.55	$0.35	$0.10	$0.00
3/4" Type 78 w/cplg	$0.60	$0.40	$0.10	$0.00
3/4" Type 90 w/cplg	$0.70	$0.45	$0.15	$0.00
7/8" Grade C w/cplg	$0.60	$0.40	$0.10	$0.00
7/8" Grade D w/cplg	$0.65	$0.40	$0.15	$0.00
7/8" Type 30 w/cplg	$0.70	$0.45	$0.15	$0.00
7/8" Type 78 w/cplg	$0.75	$0.50	$0.15	$0.00
7/8" Type 90 w/cplg	$0.90	$0.60	$0.20	$0.05
1" Grade D w/cplg	$1.00	$0.65	$0.20	$0.05
1" Type 90 w/cplg	$1.20	$0.80	$0.25	$0.05

Pumping Units

Pumping Units - Chain				
	New	Reconditioned	Used	Salvage
2	$265	$170	$55	$10
3	$265	$170	$55	$10
4	$375	$245	$75	$10
6	$395	$255	$80	$10
10	$420	$275	$85	$15
25	$660	$430	$130	$20
40	$970	$630	$195	$30
50	$2,205	$1,435	$440	$65
57	$1,100	$715	$220	$35
80	$1,765	$1,145	$355	$55
114	$3,530	$2,295	$705	$105
160	$5,510	$3,580	$1,100	$165

Pumping Units - Gear				
	New	Reconditioned	Used	Salvage
2	$265	$170	$55	$10
3	$265	$170	$55	$10
4	$335	$220	$65	$10
6	$395	$255	$80	$10
10	$490	$320	$100	$15
13	$550	$360	$110	$15
16	$785	$510	$155	$25
25	$1,470	$955	$295	$45

Pumping Units - Gear				
	New	Reconditioned	Used	Salvage
40	$2,550	$1,660	$510	$75
57	$3,470	$2,255	$695	$105
80	$3,915	$2,545	$785	$115
90	$5,290	$3,440	$1,060	$160
114 54"	$5,955	$3,870	$1,190	$180
114 64"	$6,670	$4,335	$1,335	$200
160	$7,330	$4,765	$1,465	$220
228	$9,315	$6,055	$1,865	$280
320	$10,825	$7,035	$2,165	$325
330	$10,300	$6,695	$2,060	$310
456	$13,600	$8,840	$2,720	$410
640	$15,820	$10,285	$3,165	$475
912	$18,700	$12,155	$3,740	$560

Down Hole Pumps

Submersible/Centrifugal Pumps				
	New	Rebuilt	Used	Salvage
1 to 10 hp per hp	$85	$55	None	None
11 to 40 hp per hp	$70	$45	None	None
41 & up per hp	$80	$50	None	None

Oil Well Tubing Pumps				
	New	Rebuilt	Used	Salvage
2 x 1 1/2 x 4'	$200	$130	$40	None
2 x 1 1/2 x 6'	$220	$145	$45	None
2 x 1 1/2 x 8'	$240	$155	$50	None
2 x 1 1/2 x 10'	$265	$170	$55	None
2 x 2 1/2 x 10'	$350	$230	$70	None
2 x 1 1/2 x 12'	$310	$200	$60	None

Heater Treaters / Separators / Tanks

Horizontal Heater Treaters				
	New	Reconditioned	Used	Salvage
30" X 7.5 ft	$970	$630	$195	$30
30" x 10 ft	$1,060	$690	$210	$30
48" x 10 ft	$1,270	$825	$255	$40

Emulsion Heater Treaters				
	New	Reconditioned	Used	Salvage
4' x 15 ft	$1,590	$1,035	$320	$50
4' x 20 ft	$1,890	$1,230	$380	$55
6' x 20 ft	$2,260	$1,470	$450	$70
8' x 20 ft	$2,645	$1,720	$530	$80
10' x 20 ft	$3,085	$2,005	$615	$95

Free Water Knock Out				
	New	Reconditioned	Used	Salvage
4' x 10' Knockout	$900	$585	$180	$25

Oil Separators				
	New	Reconditioned	Used	Salvage
12" x 10' 1000 psi	$1,550	$1,010	$310	$45
14" x 8' 1440 psi Horiz Coal Filter	$3,150	$2,050	$630	$95
16" x 5' 1440 psi Horiz Two Phase	$1,420	$925	$285	$45
24" x 5' 125 psi	$695	$450	$140	$20
24" x 12' 500 psi	$1,370	$890	$275	$40
30" x 10' 1440 psi Horiz Three Phase	$5,200	$3,380	$1,040	$155
36" x 10' 125 psi	$1,130	$735	$225	$35
48" x 12' 125 psi	$1,290	$840	$260	$40

Gun Barrel				
	New	Reconditioned	Used	Salvage
10' x 15' Fiberglass	$1,230	$800	$245	$35

Steel Tanks				
	New	Reconditioned	Used	Salvage
12' x 10' Stock Tank	$1,100	$715	$220	$35

Fiberglass Tanks				
	New	Reconditioned	Used	Salvage
12' x 10' Water Tank CT	$815	$530	$165	$25
12' x 15' Water Tank OT	$955	$620	$190	$30

Motors / Engines

Electric Motors				
	New	Rebuilt	Used	Salvage
2 hp Single Phase 1800	$60	$40	$10	$0
2 hp Three Phase 1800	$45	$30	$10	$0
3 hp Three Phase 1200	$75	$50	$15	$0
3 hp Three Phase 1800	$50	$35	$10	$0
5 hp Single Phase 1800	$105	$70	$20	$5
5 hp Three Phase 1200	$85	$55	$15	$5
7 1/2 hp Three Phase 1200	$120	$80	$25	$5
10 hp Single Phase 1800	$145	$95	$30	$5
10 hp Three Phase 1200	$150	$100	$30	$5
15 hp Three Phase 1200	$190	$125	$40	$5

	New	Rebuilt	Used	Salvage
15 hp Single Phase 1200	$220	$145	$45	$5
20 hp Three Phase 1200	$230	$150	$45	$5
25 hp Three Phase 1200	$280	$180	$55	$10
25 hp Single Phase 1200	$320	$210	$65	$10
30 hp Three Phase 1200	$325	$210	$65	$10

Pump Engines				
	New	**Rebuilt**	**Used**	**Salvage**
C-46	$2,360	$1,535	$470	$70
C-66	$2,625	$1,705	$525	$80
C-96	$3,940	$2,560	$790	$120
C-106	$4,460	$2,900	$890	$135
Lister 36 hp	$2,520	$1,640	$505	$75

F & M Engines				
	New	**Rebuilt**	**Used**	**Salvage**
118	$1,125	$730	$225	$35
208	$1,310	$850	$260	$40
346	$1,945	$1,265	$390	$60
503	$2,625	$1,705	$525	$80
739	$3,240	$2,105	$650	$95