Chapter 2
Basic Reporting Principles

This chapter covers basic reporting information and instructions for ONRR royalty reporters. You should carefully follow these reporting instructions to avoid delays in acceptance of reports and payments. Additional instructions for reporting geothermal royalties are in the Geothermal Payor Handbook.

If you have questions about these instructions, please contact Reference and Reporting Management. (For contact information, see Appendix A.)

2.1 Sources of Production from which ONRR Expects to Receive Royalties

Lease production: You must report all production produced, removed from, or allocated to the lease premises. We expect royalties on 100 percent of the lease production. If the Federal/Indian mineral ownership percentage is less than 100 percent, we expect royalties on that percentage. Report royalties using the ONRR-converted lease number.

Unitized participating area (PA) production: You must report any production allocated among leases within an established unit PA. We expect to receive royalties for each Federal and Indian lease participating in the PA based on the PA allocation schedule. Report a separate line on Form ONRR-2014 for each lease/agreement combination in the PA.

Communitized production.: A communitization agreement (CA) allows companies to develop and operate separate tracts of land that could not operate independently in conformity with an established State well-spacing program. We expect to receive royalties based on the CA allocation schedule. Report a separate line on Form ONRR-2014 for each lease/agreement combination in the CA.

Compensatory royalty: You must report compensatory royalty from any Federal or Indian lease when directed by the Bureau of Land Management (BLM) or Bureau of Ocean Energy Management (BOEM).

- Unleased Federal or Indian land (**agreements**) — BLM or BOEM requires a compensatory royalty **agreement** for unleased Federal or Indian land when a well located on adjacent land drains the Federal or Indian land. If BLM or BOEM determines that the parcel of land cannot be leased, a compensatory royalty agreement is established. **We account for the compensatory royalty by assigning it an agreement number that is reported on Form ONRR-2014 using the lease number field.**

- Leased Federal or Indian land (**assessments**) — BLM or BOEM assesses compensatory royalties when adjacent land drains a Federal or Indian lease. If the lessee elects not to drill a protective well or enter into a CA with the owner of the lands containing the offending well, BLM or BOEM assesses the royalty on the product drained from the Federal or Indian leases. **You must report this assessment on Form ONRR-2014 using the assessed lease number and transaction code 10.**

Reporting ONRR lease and agreement numbers: Every line that you report on the Form ONRR-2014 must include the ONRR-converted lease number.

You must report:

- The agreement number and the lease number when you report sales related to a lease's allocated production from an agreement, and
- Each lease and agreement number combination on a separate report line if the lease participates in more than one agreement.

For ONRR-converted lease and agreement numbers, see Appendix B. We also post ONRR-converted agreement numbers and corresponding lease numbers on our website listed in Appendix A.

2.2 When Form ONRR-2014 Is Required

Submit a Form ONRR-2014 if you assume responsibility for reporting and paying the following:

- Royalties on production from Federal or Indian leases and agreements
- Rent (Federal non-terminable and Indian producing leases) or minimum royalty
- Royalties on the sale of test production from the initial lease well before the lease is classified as capable of producing
- Fees on a gas storage agreement
- Royalties on compensatory royalty agreements or assessments against Federal or Indian lands
- Well fees if stated in the lease terms

2.3 Leases Reported to ONRR

NOTE

***Do not** combine Federal and Indian leases on the same report. A separate report is required for each land type.*

Federal leases: Report Federal production to ONRR for the following situations:

- Producing mineral leases on public domain, acquired, and military lands, regardless of the Federal agency administering the surface activities
- All Outer Continental Shelf (OCS) leases (after the first year's advance rental and bonus payment are paid to ONRR)
- Leases receiving an allocation from producing units or CAs
- Leases subject to subsurface storage agreements
- Easements for directional drilling agreements
- Lands subject to compensatory royalty agreements or assessments

Indian leases: Indian leases are those leases owned by any individual Indian or Alaska Native, Indian tribe, band, nation, pueblo, community, rancheria, colony, or other tribal group. These persons or individuals own lands or interest in the minerals, and title to these rights is either held in trust or subject to restriction against alienation by the United States.

You must report to ONRR for the following situations:

- All producing leases, permits, or contracts on Indian tribal and allotted lands
- Leases receiving an allocation from producing units or CAs
- Lands subject to compensatory royalty agreements or assessments

Cook Inlet Region, Incorporated (CIRI): CIRI leases are jointly owned by CIRI and the Federal Government. Report CIRI and Federal portions of the lease to ONRR on separate Form ONRR-2014s. Use payment method (PM) code 2 (PM2) to report the CIRI portion, and enter **I** in field 3, Federal/Indian Report Indicator. Use PM1 or PM3 to report the Federal share and enter **F** in field 3.

2.4 Indian Leases Not Reported to ONRR

The following Indian leases are not reported to ONRR:

- Rentals on nonproducing Indian leases not committed to producing units
- The 27.16186 percent Ute Distribution Corporation (UDC) portion of any lease held jointly by UDC and the Northern Ute Tribe
- Leases, or portions of leases, in which the Bureau of Indian Affairs (BIA) has relinquished supervision

2.5 Authorized Reporting Formats

We now require most reporters to submit data electronically. (See Electronic Reporting, Final Rule, 64 FR 38116, July 15, 1999, at our website listed in Appendix A.)

For instructions on electronic reporting, see Chapter 3.

If you are not required to report electronically, you can print copies of Form ONRR-2014 from our website listed in Appendix A. Photocopies must be 8 1/2 inches long by 14 inches wide.

2.6 Record Retention Requirement

You are required to report to ONRR electronically. This does not change the requirements under 30 CFR, Part 1212.50, which states that all Federal and Indian Records must be retained for a period of 6 years after the records are generated, unless the record holder is notified in writing that records must be maintained for a longer period.

2.7 Payment Requirements

Payments are authorized by 30 CFR 1218.50.

We do not accept cash payments.

NOTE *Include your five-digit ONRR-assigned payor code and an eight-digit PAD number on all payments and reports. Assign a unique PAD number to each separate Form ONRR-2014. Your payor code and PAD number must match on your report and corresponding payment.*

NOTE *Electronic payments are cost effective and practical. ONRR will send Notice of Potential Enforcement Action letters to reporters/payors who do not pay electronically. Failure to make payments electronically may subject you to civil penalties as authorized by 30 CFR Part 1241.*

Electronic payments: Our regulations require the use of electronic funds transfer (EFT), such as Automated Clearing House (ACH) or Fedwire or Pay.gov, to the extent it is cost-effective and practical for payment of **any** royalty liability. For information or assistance with electronic payments, see Appendix A for contact information.

Before using any of the ONRR pay.gov payment types, please provide your bank the appropriate agency identification number(s) to authorize ACH debits. This will ensure payments you submit are not rejected by your bank. A rejected payment is the same as a returned payment or non-payment.

Agency Identification No.	Pay.gov ACH Payment Type
1417000101	Online Rental Payments (eCommerce “Rental Information”)
1417000102	ONRR Renewable Energy Non-Competitive Leasing Acquisition fees
1417000103	ONRR Royalty and Invoice Payments
1417000104	ONRR Renewable Energy Initial Rental Payments
1417000105	ONRR Oil and Gas Initial ROW/RUE Rental Payments

Detailed instructions, including examples, for all EFT payment types are on the ONRR website “Payments” page at www.onrr.gov/reportpay/payments.htm. If you have questions about how to make an EFT payment after reading the instructions on that page, please call the appropriate points of contact, all of whom are identified by topic.

If you are not required to use EFT, use one of the payment documents outlined in 30 CFR 1218.51.

2.8 Due Dates for Reports and Payments

Royalties: Form ONRR-2014s and related payments are due to ONRR by 4:00 p.m. Mountain Time on or before the last day of the month following the month the product was sold or removed from the lease unless lease terms state that royalties are due otherwise. For example, the report(s) and payment(s) for products sold or removed during November 2014 are due by 4:00 p.m. on December 31, 2014. If you receive your royalty information late, you can set up an estimate. Royalties will then be due the last day of the second month following the month you sold or removed the product from the lease. For more information on estimates, see Chapter 4.

Royalty Overrides: Any override submitted later than 11:00 a.m. Mountain Time may not process until the next business day.

Rentals: Online rentals, reports (if applicable) and payments for rents are due to ONRR by 4:00 p.m. Mountain Time on or before the lease anniversary date.

Minimum royalties: Reports and payments for minimum royalties are due to ONRR by 4:00 p.m. Mountain Time on or before the last day of the month and year of the lease year, regardless of whether there is an estimate established on the lease.

NOTE *If the last day of the month falls on a weekend or Federal holiday, send us the report and payment by 4:00 p.m. Mountain Time the next business day.*

NOTE *We credit Form ONRR-2014 reports and payments when we actually receive them at one of the appropriate addresses listed in Appendix A. The receipt date is the date we receive the document; the postmark does not apply.*

2.9 Report Acceptance

ONRR accepts the financial information contained on reports and payments as correct, subject to a compliance review. Do not send supporting documentation with your reports and payments unless we specifically request it. If requested, indicate the contact person who asked for the information on all supporting documentation.

2.10 Reporting Royalties on Leases within the State of Oklahoma

If you report Federal and Indian oil and gas leases committed to units or CAs within the State of Oklahoma, you do not use special procedures in reporting and paying royalties. Follow the standard procedures as outlined in this handbook to report royalties due on production allocated to each lease under a pooling agreement.

2.11 Takes or Entitlements—Definitions and Examples

Two methods exist to report sales for Federal and Indian leases and agreements: Takes or Entitlements.

- **Takes:** Report and pay royalties based on the portion of the total production that you sold or removed from the lease or from the lease/agreement combination.

  Lease-basis production

  To calculate the takes sales volume, multiply the total production sold or removed from the lease by the Federal and/or Indian mineral ownership interest in the lease.

total takes volume	x	Federal and/or Indian mineral ownership interest	=	takes sales volume

  Agreement-basis production (See 100-percent Federal Agreements under “Federal leases and agreements.”)

  Report your takes volume in the sales volume field for your lease(s) in the agreement.

total Agreement takes volume	=	takes sales volume

- **Entitlements:** Report and pay royalties based on your ownership share of the volume of production sold or removed from the agreement allocated to your lease under the approved allocation schedule.

Agreement-basis production

To calculate the entitled sales volume, multiply the total agreement production sold or removed from the agreement by:

— The tract allocation of the lease,

— the Federal and/or Indian mineral ownership interest in the lease, and

— your company's working interest in the lease.

total agreement production volume	x	tract allocation	x	Federal and/or Indian mineral ownership interest	x	company working interest	=	entitled sales volume

Federal leases and agreements: The Federal Oil and Gas Royalty Simplification and Fairness Act (RSFA) of 1996 clarified and standardized volume reporting requirements on Federal leases and agreements as explained below. The following volume reporting requirements are effective as of sales month September 1996.

- Report **Takes** for:

  — Lease-basis production — production occurring on the lease that is not allocated to an agreement.

  — 100-percent Federal agreements — contain only Federal leases having the same fixed royalty rate and royalty distribution; that is, all revenue is distributed to the same State or surface management agency.

- Report **Entitlements** for a mixed agreement; that is, any agreement that does not qualify as a 100-percent Federal agreement as defined above.

For 100-percent Federal agreements, you may obtain permission to report and pay using an alternative method of reporting and payment if:

- All lessees contractually agree to an alternative method of royalty reporting and payment,

- the lessees submit such alternative method to the Secretary or the delegated State for approval, and
- the lessees make payments in accordance with such approved alternative method so long as such method does not reduce the amount of the royalty obligation.

Indian leases and agreements:

- **Takes**: All lease-basis production is reported as takes.
- **Entitlements**: All agreement production is reported as entitlements. This is true for agreements having allotted, tribal, or a mixture of Federal and Indian leases.

For Indian leases and agreements, you may obtain permission to report and pay by using other methods if:

- You submit your request to us in writing, and
- the method is acceptable to us and all parties involved in reporting and paying royalties on a particular lease or on a lease/agreement combination, and
- we receive 100 percent of the royalties due, properly reported each month.

We reserve the right to review all arrangements and to require retroactive adjustments and reporting based on Entitlements, if appropriate.

Examples: The following examples show how to allocate sales for these situations:

- One lease with multiple payors (Takes)
- One 100-percent Federal agreement with multiple leases and multiple payors (Takes)
- One mixed agreement (not a 100-percent Federal agreement) with multiple leases and multiple payors (Entitlements)

EXAMPLE

One lease with multiple payors (Takes). This example shows how to report sales based on the actual volume of production sold or removed from a Federal onshore lease with multiple payors.

Assumptions:

Lease 048-111111-0 is a Federal onshore lease. During the month, 80 barrels (bbl) of oil were sold or removed from the lease. The following companies have assumed reporting and payment responsibilities.

Payor	Lease Number	Lease Type	Volume removed or sold (bbl)	Tract allocation percentage	Federal and/or Indian mineral ownership interest percentage	Company working interest percentage	Price $/bbl	Royalty rate percentage
Able Oil Company	048-111111-0	Federal	50	NA	100	50	18.00	12 1/2
David Oil Company	048-111111-0	Federal	30	NA	100	25	18.00	12 1/2
Zebra Oil Company	048-111111-0	Federal	0	NA	100	25	NA	12 1/2
Total volume produced			80					

Because this is lease-basis production, each company reports and pays royalties based on the actual volume of production sold or removed from the lease. Because Zebra Oil Company took no production, a Form ONRR-2014 is not required.

Royalty value calculation:

sales volume × price × royalty rate = royalty value

Able Oil Company

50 bbl × $18.00/bbl × 0.125 = $112.50

David Oil Company

30 bbl × $18.00/bbl × 0.125 = $67.50

The information reported on Form ONRR-2014 is shown on the following fact sheets.

Form ONRR-2014
Fact Sheet

Identification/Authorization Information

Payor Name: Able Oil Company

Detail Line

Line Number	1
API Well Number	
ONRR Lease Number	0481111110
ONRR Agreement Number	
Product Code	01
Sales Type Code	ARMS
Sales MO/YR	102019
Transaction Code	01
Adjustment Reason Code	
Sales Volume	50.00
Gas MMBtu	
Sales Value	900.00
Royalty Value Prior to Allowances	112.50
Transportation Allowance Deduction	
Processing Allowance Deduction	
Royalty Value Less Allowances	112.50
Payment Method Code	03

Form ONRR-2014
Fact Sheet

Identification/Authorization Information

Payor Name: David Oil Company

Detail Line

Line Number	1
API Well Number	
ONRR Lease Number	0481111110
ONRR Agreement Number	
Product Code	01
Sales Type Code	ARMS
Sales MO/YR	102019
Transaction Code	01
Adjustment Reason Code	
Sales Volume	30.00
Gas MMBtu	
Sales Value	540.00
Royalty Value Prior to Allowances	67.50
Transportation Allowance Deduction	
Processing Allowance Deduction	
Royalty Value Less Allowances	67.50
Payment Method Code	03

EXAMPLE

100-percent Federal agreement with multiple leases and multiple payors (Takes). This example shows how to report sales based on the actual volume of production sold or removed from an agreement with multiple Federal onshore leases and multiple payors.

Assumptions:

Leases 049-111111-0, 049-222222-0, and 049-333333-0 are Federal onshore leases within a 100-percent Federal unit, agreement number 892-111111-0; and each lease shares in the unitized production. During the month, 375 bbl of oil were sold or removed from the unit. The following companies have assumed reporting and payment responsibilities.

Payor	Lease Number	Lease Type	Volume removed or sold (bbl)	Tract allocation percentage	Federal and/or Indian mineral ownership interest percentage	Company working interest percentage	Price $/bbl	Royalty rate percentage
Able Oil Company	049-333333-0	Federal	0	10	100	25	NA	12 1/2
David Oil Company	049-111111-0	Federal	250	60	100	25	22.00	12 1/2
Zebra Oil Company	049-222222-0	Federal	125	30	100	50	22.00	12 1/2
Total volume produced			375					

Because the production is attributable to a 100-percent Federal agreement, each company reports and pays royalties based on what they took of the production sold or removed from the lease. Lease 049-333333-0 did not take any production; therefore, Able Oil Company will not report on the Form ONRR-2014.

Royalty value calculation:

sales volume × price × royalty rate = royalty value

David Oil Company

250 bb × $22.00/bbl × 0.125 = $687.50

Zebra Oil Company

125 bbl × $22.00/bbl × 0.125 = $343.75

The information reported on Form ONRR-2014 is shown on the following fact sheets.

Form ONRR-2014
Fact Sheet

Identification/Authorization Information

Payor Name: David Oil Company

Detail Line

Line Number	1
API Well Number	
ONRR Lease Number	0491111110
ONRR Agreement Number	8921111110
Product Code	01
Sales Type Code	ARMS
Sales MO/YR	102019
Transaction Code	01
Adjustment Reason Code	
Sales Volume	250.00
Gas MMBtu	
Sales Value	5500.00
Royalty Value Prior to Allowances	687.50
Transportation Allowance Deduction	
Processing Allowance Deduction	
Royalty Value Less Allowances	687.50
Payment Method Code	03

Form ONRR-2014
Fact Sheet

Identification/Authorization Information

Payor Name: Zebra Oil Company

Detail Line

Line Number	1
API Well Number	
ONRR Lease Number	0492222220
ONRR Agreement Number	8921111110
Product Code	01
Sales Type Code	ARMS
Sales MO/YR	102019
Transaction Code	01
Adjustment Reason Code	
Sales Volume	125.00
Gas MMBtu	
Sales Value	2750.00
Royalty Value Prior to Allowances	343.75
Transportation Allowance Deduction	
Processing Allowance Deduction	
Royalty Value Less Allowances	343.75
Payment Method Code	03

EXAMPLE

Mixed agreement (not a 100-percent Federal agreement) with multiple leases and multiple payors (Entitlements). This example shows how to report sales based on the percentage of working interest or operating rights ownership with an approved agreement allocation schedule for a mixed agreement with multiple leases and multiple payors.

Assumptions:

Leases 048-000123-0, 607-012900-0, and 048-000178-0 are within the Dover CA, agreement number 894-000001-0. During the month, 200 bbl of oil were sold or removed from the CA. The following companies have assumed reporting and payment responsibilities.

Payor	Lease Number	Lease Type	Volume removed or sold (bbl)	Tract allocation percentage	Federal and/or Indian mineral ownership interest percentage	Company working interest percentage	Price $/bbl	Royalty rate percentage
Baker Oil Company	048-000123-0	Federal	60	50	100	100	22.00	12 1/2
Charlie, Inc.	607-012900-0	Indian	30	40	100	100	22.00	20
Delta Ltd.	048-000178-0	Federal	110	10	100	100	22.00	16 2/3
Total volume produced			200					

Because the CA is a mixed agreement with Federal and Indian leases, each company will report and pay royalties based on the volume of production sold or removed from the agreement allocated to the company's lease under the approved allocation schedule, no matter who takes the production.

Royalty value calculation:

sales volume	×	tract allocation	×	price	×	royalty rate	=	royalty value

Baker Oil Company

200 bbl	×	0.50	×	$22.00/bbl	×	0.125	=	$275.00

Charlie, Inc.

200 bbl	×	0.40	×	$22.00/bbl	×	0.20	=	$352.00

Delta Ltd.

200 bbl	×	0.10	×	$22.00/bbl	×	0.166667	=	$73.33

The information reported on Form ONRR-2014 is shown on the following fact sheets.

Form ONRR-2014
Fact Sheet

Identification/Authorization Information

Payor Name: Baker Oil Company

Detail Line

Line Number	1
API Well Number	
ONRR Lease Number	0480001230
ONRR Agreement Number	8940000010
Product Code	01
Sales Type Code	ARMS
Sales MO/YR	102019
Transaction Code	01
Adjustment Reason Code	
Sales Volume	100.00
Gas MMBtu	
Sales Value	2200.00
Royalty Value Prior to Allowances	275.0
Transportation Allowance Deduction	
Processing Allowance Deduction	
Royalty Value Less Allowances	275.00
Payment Method Code	03

Form ONRR-2014
Fact Sheet

Identification/Authorization Information

Payor Name: Charlie, Inc.

Detail Line

Line Number	1
API Well Number	
ONRR Lease Number	6070129000
ONRR Agreement Number	8940000010
Product Code	01
Sales Type Code	ARMS
Sales MO/YR	102019
Transaction Code	01
Adjustment Reason Code	
Sales Volume	80.00
Gas MMBtu	
Sales Value	1760.00
Royalty Value Prior to Allowances	352.00
Transportation Allowance Deduction	
Processing Allowance Deduction	
Royalty Value Less Allowances	352.00
Payment Method Code	05

Form ONRR-2014
Fact Sheet

Identification/Authorization Information

Payor Name: Delta Ltd.

Detail Line

Line Number	1
API Well Number	
ONRR Lease Number	0480001780
ONRR Agreement Number	8940000010
Product Code	01
Sales Type Code	ARMS
Sales MO/YR	102019
Transaction Code	01
Adjustment Reason Code	
Sales Volume	20.00
Gas MMBtu	
Sales Value	440.00
Royalty Value Prior to Allowances	73.33
Transportation Allowance Deduction	
Processing Allowance Deduction	
Royalty Value Less Allowances	73.33
Payment Method Code	03

12.12 Step-Scale and Sliding-Scale Royalty Rates

Some Federal onshore leases have step-scale (Schedule B and C) or sliding-scale (Schedule D) variable royalty rate schedules. This document includes the variable royalty rate schedules and instructions for determining well counts and the royalty rate on sales from inventory.

General:

Step-scale schedules for both **oil** and **gas** royalties, and the sliding-scale schedule for **oil** royalties are based on the average daily production per well per month on a given property; i.e., lease, communitization agreement (CA), or unit participating area (PA). The average daily production per well for a property is computed based on a 28-, 29-, 30-, or 31-day month; the number of wells on the property counted as producing; and the gross production (this includes production from wells not considered countable). The term "gross production" is interpreted to mean all production from the lease or agreement, excluding any production used on the lease or agreement and/or unavoidably lost volumes. In other words, volumes that are not subject to royalty (i.e., production used on the lease or agreement and/or unavoidably lost as shown on the production report) are not included in the determination of royalty rates. Gas production sold in the same month it is produced is synonymous with sales from a lease. Since sales from oil inventory often includes production from a previous production month, more than one royalty rate could apply to oil sales during the month.

The sliding-scale Schedule D for **gas** royalties is based on the total gas produced or allocated to the lease from all sources per month. If a lease has lease-basis production and participates in one or more agreements, allocated production for the lease is totaled from all agreements in which the lease receives an allocation, and that total allocated production is added to the lease-basis production. The average daily production rate yields a royalty rate of either 12 1/2 percent or 16 2/3 percent - see tables. The royalty rate is based on the average daily production and is calculated based on the days of the month and is not based on well counts or on days of actual production.

Well Counts:

Countable wells include:

1. Commercially productive wells:
   - Existing (producing in a previous month) oil wells must produce at least 15 days during the month
   - New oil wells must produce at least 10 days during the month
   - Gas wells - any wells that produce gas during the month are counted

2. Injection wells (includes all injection wells; gas, water, steam, etc.) must be operated at least 15 days during the month and the total days operated includes production and injection days added together. Injection wells count for gas and oil. Water and gas injection wells can be included in the well count for oil if the wells are used in secondary and tertiary recovery operations.

3. On previously producing properties, if no wells produce 15 days or more during the month, the average daily production rate is computed based on actual producing well days.

   Countable wells are considered producing for the entire month. Oil and gas wells are counted separately based on the production from each well. In other words, a producing oil well (POW well status, as classified by the Bureau of Land Management) would be counted in the well counts for the oil royalty rate calculation. Producing gas wells (PGW well status, as classified by the Bureau of Land Management) that have condensate production would be counted in the well counts for the condensate royalty rate calculation. The average daily condensate production should be determined separately from oil, and the wells that produce condensate should be counted in the same manner as oil wells are counted.

   Example: The following property has a Schedule B (step-scale) royalty rate and has 8 producing oil wells. For the month of June, the summary of operations is:

Well No. and Record	**Count**	**Production per well**
Produced full time for 30 days	Y	200 bbl
Produced for 26 days; down 4 days for repairs	Y	200 bbl
Produced for 28 days; down June 5 for 12 hours, down June 14 for 6 hours, and down June 26 for 24 hours	Y	200 bbl
Produced for 12 days; down June 13-30	N	75 bbl
Produced for 8 hours every day (head well)	Y	75 bbl
Not operated	N	
New well, completed June 17; produced for 14 days	Y	150 bbl
New well, completed June 22; produced for 9 days	N	100 bbl
		Total Production: 1,000 bbl

In this example, 5 of the 8 wells are counted as producing for 30 days. The average production per well per day is determined by dividing the total production of the property for the month (including the production from the wells not counted) by 5 (the number of wells counted as producing), then by the number of days in the month.

1,000 ÷ 5 ÷ 30 = 6.67 bbl/well/day (12 1/2 percent royalty rate - see Schedule B for oil)

Inventory:

The applicable royalty rate is determined by the production volume in the month in which that oil or gas is produced, not the month in which it was sold. The first-in first-out method should be used when calculating royalty rates on inventory.

Example:

Lease ABC	Beginning Inventory (bbl)	Oil Produced (bbl)	Oil Sold (bbl)	Ending Inventory (bbl)
June	0	1,000	700	300
July	300	2,000	1,200	1,100

In June, the lease or agreement produced 1,000 barrels and sold 700 barrels, leaving 300 barrels as the ending inventory. The royalty rate for the 700 barrels sold in June was determined to be 12 1/2 percent (see above well count example).

In July, the lease or agreement produced 2,000 barrels and sold 1,200 barrels, leaving 1,100 barrels as the ending inventory. The inventory carried over into July will be the first oil sold in July. The royalty rate on the 300 barrels produced during June and sold in July would be determined based on the royalty rate established for June production (i.e., 12 1/2 percent). The royalty rate for the 900 barrels produced and sold in July is the royalty rate established for July based on the 2,000 barrels produced. The royalties on the 1,100 barrels remaining in inventory at the end of July will be paid using the royalty rate calculated for July when the production is sold.

Schedules:

The following tables and descriptions define what royalty rates should be used based on production.

Schedule B Step-Scale
Royalty Rates

1. Oil - When the average production for the month in barrels per well per day is:

Over	Not Over	Royalty Rate	Over	Not Over	Royalty Rate
	50 bbl	12 1/2%	130 bbl	150 bbl	19%
50 bbl	60 bbl	13%	150 bbl	200 bbl	20%
60 bbl	70 bbl	14%	200 bbl	250 bbl	21%
70 bbl	80 bbl	15%	250 bbl	300 bbl	22%
80 bbl	90 bbl	16%	300 bbl	350 bbl	23%
90 bbl	110 bbl	17%	350 bbl	400 bbl	24%
110 bbl	130 bbl	18%	400 bbl		25%

2. Leases issued between August 21, 1935 and May 3, 1945, have an expanded version of the above oil royalty rate schedule; however, the maximum royalty rate is 32 percent when the production exceeds 2,000 barrels per well per day.

3. Gas – Including inflammable gas, helium, carbon dioxide, and all other natural gases and mixtures thereof, and on natural or casinghead gasoline and other liquid products obtained from gas, when the average production for the month in Mcf of gas per well per day is:

Over	Not Over	Royalty Rate
	5,000 Mcf	12 1/2%
5,000 Mcf		16 2/3%

Schedule C Step-Scale
Royalty Rates

1. Oil - A royalty rate of 12 1/2 percent on the production removed or sold from:

    a. Land determined by the Director, Geological Survey, not to be within the productive limits of any oil or gas deposit on August 8, 1946;

    b. An oil or gas deposit which was discovered after May 27, 1941, by a well or wells drilled on the leased land and which is determined by the Director, Geological Survey, to be a new deposit; or

    c. Allocated to the lease pursuant to an approved unit or cooperative agreement from an oil or gas deposit which was discovered on unitized land after May 27, 1941, and determined by the Director, Geological Survey, to be a new deposit, but only if at the time of discovery the lease was committed to the agreement or was included in a duly executed and filed application for approval of the agreement.

2. Oil - Leases not subject to the general section above: On production of oil removed or sold, where a flat royalty rate of 5 percent was fixed on the original lease:

    When the average production for the month in barrels per well per day is:

Over	Not Over	Royalty Rate	Over	Not Over	Royalty Rate
	110 bbl	12 1/2%	200 bbl	250 bbl	21%
110 bbl	130 bbl	18%	250 bbl	300 bbl	22%
130 bbl	150 bbl	19%	300 bbl	350 bbl	23%
150 bbl	200 bbl	20%	350 bbl	400 bbl	24%
			400 bbl		25%

3. Gas - Including inflammable gas, helium, carbon dioxide, and all other natural gases and mixtures thereof, and on natural or casinghead gasoline and other liquid products obtained from gas; when the average production for the month in Mcf of gas per well per day:

Over	Not Over	Royalty Rate
	5,000 Mcf	12 1/2%
5,000 Mcf		16 2/3%

Schedule D Sliding-Scale Royalty Rates

1. Oil - A royalty rate of 12 1/2 percent for lands subject to the same provisions shown for Schedule C above, under number 1.

2. Oil - On production of oil removed or sold from lands not subject to the same provisions shown for Schedule C above, under number 1.

On that portion of the average production per well per day for the month:

a. For all oil produced at **30 degrees API or over**:

Over	Not Over	Royalty Rate
	20 bbl	12 1/2%
20 bbl	50 bbl	16 2/3%
50 bbl	100 bbl	20%
100 bbl	200 bbl	25%
200 bbl		33 1/3%

For example, the royalty rate will be 12 1/2% on the portion of the average production per well not exceeding 20 barrels per day for the month; 16 2/3% on the portion of the average production per well of more than 20 barrels and not more than 50 barrels per day for the month, etc.

b. For all oil produced at **less than 30 degrees API**:

Over	Not Over	Royalty Rate
	20 bbl	12 1/2%
20 bbl	50 bbl	14 2/7%
50 bbl	100 bbl	16 2/3%
100 bbl	200 bbl	20%
200 bbl		25%

For example, the royalty rate will be 12 1/2% on the portion of the average production per well not exceeding 20 barrels per day for the month; 14 2/7% on the portion of the average production per well of more than 20 barrels and not more than 50 barrels per day for the month, etc.

3. Gas, **including total gas produced or allocated to the lease from all sources,** when the average production for the month in Mcf of gas per day:

Over	Not Over	Royalty Rate
	3,000 Mcf	12 1/2%
3,000 Mcf		16 2/3%

4. On casinghead gasoline, including NGL plant products, the royalty rate is 16 2/3% of the value of the casinghead gasoline/NGLs extracted from the gas produced and sold.

Note: Additional step- and sliding-scale royalty rate information can be found at 43 CFR, Part 3162.7-4.

Under what circumstances can a Schedule C or D variable royalty rate lease have a royalty rate limitation of 12 1/2 percent?

The 1946 revision of the Mineral Leasing Act provided for a royalty rate limitation of 12 1/2 percent on new discoveries. Specifically, the royalty rate limitation of 12 1/2 percent applies to any production on a lease which was discovered after May 27, 1941, and which the Secretary deemed to be a new deposit. The same royalty rate limitation applies to agreement production on or allocated to a lease within an agreement where that production was discovered after May 27, 1941, and for which the Secretary deemed it to be a new deposit. In addition, the revision allowed the 12 1/2 percent royalty rate limitation on production removed from lands determined to be outside the productive limits of any known oil or gas deposits on August 8, 1946. The Director of the U.S. Geological Survey was charged with making that determination. The determinations issued by the Director under the 1946 Act are rulings as to:

1. whether a discovery on a lease or unit after May 27, 1941, qualifies as a new discovery under the 1946 Act, or
2. whether lands which may constitute all or part of the lease or unit are outside the productive limits of any oil or gas deposits on August 8, 1946.

The charge for the productive limit and new discovery determinations now rests with the Director of the Bureau of Land Management (BLM). Contact the applicable BLM field office for productive limit and new discovery determinations on Schedule C or D variable royalty rate leases.

For information regarding the reporting of oil and gas royalties on step- and sliding-scale royalty rate leases, contact ONRR's Royalty Valuation group at RoyaltyValuation@onrr.gov.

Sources:

- 43 CFR § 3162.7-4 - Royalty rates on oil; sliding and step-scale leases (public land only).
- Federal Register/Vol. 56, No. 234, December 5, 1991, Page 63661- 63662
- Department of the Interior, Geological Survey, Conservation Division Manual/Release CDM 647.13, January 1979.