

Commingling Guidance

Definitions

For the purpose of this Instruction Memorandum (IM), the following terms are defined:

Beneficial use means, subject to specific exceptions, the use of oil or gas that is produced from a:

1. Lease or CA for operations and production purposes (including placing oil or gas in marketable condition) on the same lease or CA without being removed from the lease or CA; or
2. Unit PA for operations and production purposes (including placing oil or gas in marketable condition) on the unit for the same unit PA without being removed from the unit.

BLM means the Bureau of Land Management.

Btu means British thermal unit

Central Delivery Point (CDP) means a point of royalty measurement measuring commingled production on which royalty is based and from which the allocation to each lease, unit Participating Area (PA), or Communitized Area (CA) is applied.

Indian lease means an oil and gas lease on Indian tribal lands (Indian tribal lease) or on Indian allotted lands (Indian allotted lease) that is administered by the Secretary of the Interior.

Low-volume property means a lease, unit PA, or CA that does not produce sufficient volumes for the operator to realize from continued production a sufficient rate of return on the investment required to achieve non-commingled measurement of volumes produced from that lease, unit PA, or CA, such that a prudent operator would opt to plug a well or shut-in the lease, unit PA, or CA if the commingling request were not approved. In the absence of information demonstrating a different rate, a rate of return less than 10 percent (before Federal, State, and local taxes) will be regarded as not sufficient. A lease, unit PA, or CA may also be regarded as a low-volume property if the operator demonstrates that the cost of the capital expenditures required to achieve measurement of non-commingled production from that property is more than the net present value (NPV) of projected royalty from continued production from the lease, unit PA, or CA proposed for commingling over the life of the equipment.

Mcf means thousands of standard cubic feet.

Point of Royalty Measurement (PRM) means the meter(s) or measurement facility(ies) used to measure the volume and quality of oil and gas on which royalty is reported as due. The PRM must be on the lease, unit PA, or CA from which the production originates unless otherwise approved by the BLM. The PRM is not necessarily the same as the sales or custody transfer point established in a sales contract. The BLM will not approve a PRM located at the tailgate of a gas processing plant that is not located on a Federal or Indian lease, unit, or CA.

Royalty factor means the portion of oil and gas produced from a stand-alone lease, a CA, or a unit PA that represents the royalty interest of the Federal Government or Indian tribal lessor.¹ (See example at attachment 1-4 and 1-5 for further explanation of the significance of the royalty factor). It is the royalty rate for stand-alone leases not committed to a unit or CA; it is the sum of the product of the royalty rate and the allocation factor for each of the Federal (or Indian tribal) leases included in a unit PA or CA. In equation form, the royalty factor is summarized below:

For stand-alone leases:

$$F_r = RR$$

where:

F_r = royalty factor

RR = lease royalty rate (expressed as a fraction)

For PAs and CAs:

$$F_r = \sum_{i=1}^{i=n} RR_i \times F_{a,i} \quad \text{Eq. 1}$$

where:

Subscript i represents an individual lease or portion of a lease

n = the number of Federal or Indian leases or portions of leases within a unit PA or CA

RR_i = royalty rate for lease i (expressed as a fraction)

$F_{a,i}$ = allocation factor for lease i in a unit PA or CA²

For PAs and CAs with only one Federal or Indian lease, Equation 1 simplifies to:

$$F_r = RR \times F_a \quad \text{Eq. 2}$$

where:

F_a = allocation factor for the Federal or Indian lease within the unit PA or CA²

Unit PA means the participating area if one is in effect, the exploratory unit if there is no associated participating area, or an enhanced recovery unit.

Documentation

Every commingling application must contain the following documentation:

¹ Because a commingling approval under Category 1 likely would not be granted for allotted Indian leases, the royalty factor equations apply only to Federal and tribal Indian leases.

² The allocation factor for a lease committed to a CA or unit PA is normally based on surface acreage and can usually be found in LR2000 using the CA or PA case number. The allocation factor is used to determine the percent of production from a CA or unit PA that is allocated to a Federal or Indian lease within the CA or unit PA. For example, if 10,000 Mcf are removed or sold from a CA, and the CA allocation factor is 60.000% for a Federal lease within the CA, then 6,000 Mcf will be allocated to that lease for royalty purposes.

- A list of each lease, unit PA, or CA proposed for commingling, including any non-Federal (State or fee) parcels and unleased tracts;
- For each unit PA and CA proposed for commingling:³
 - The ownership (Federal, tribal Indian [specify tribe], or allotted Indian) of each lease within the unit PA or CA;
 - The royalty rate of each Federal or Indian lease within the unit PA or CA; and
 - The allocation factor for each Federal or Indian lease within the unit PA or CA;
- For each lease proposed for commingling that is not included in a unit PA or CA³
 - The ownership (Federal, tribal Indian [specify tribe], or allotted Indian) of the lease; and
 - The royalty rate of the lease.
- If the commingling proposal includes allotted Indian leases, evidence that all Indian allottee mineral owners of leases included in the commingling request have been notified of the request. An affidavit from the operator stating that a notice was mailed to each allottee mineral owner of record for whom the superintendent or area director has an address will satisfy this notice requirement;
- If the commingling proposal includes tribal Indian leases, evidence that each of the affected tribes has given its consent for commingling;
- The commodities proposed for commingling (oil/condensate, gas, or both);
- Evidence showing that each lease, unit PA, or CA proposed for commingling is either in production or (for Federal leases) is capable of production;
- A map or schematic showing the leases, unit PAs, and CAs whose production is proposed for commingling, along with wells, pipelines, treatment facilities (separators, dehydrators, compressors, etc.), storage facilities, and the CDP;
- If wells are directional or horizontal and produce from a well pad not located on the lease, unit PA, or CA from which the production originates, the map should include the approximate wellbore path and the location of the producing interval(s);
- A list of all equipment for which the applicant seeks approval of off-lease royalty-free beneficial use of gas or oil, and a schematic showing where fuel is to be taken in relation to the CDP;
- The gas heating value (Btu) and oil gravity of the oil and gas proposed for commingling;
- A detailed description of the proposed allocation method for both volume and quality (American Petroleum Institute (API) gravity and heating value (Btu) content) along with an example of how it is applied; and
- If downhole commingling is proposed, pertinent reservoir information such as the presence of hydrogen sulfide, formation pressures, water cut, decline characteristics, drive mechanism, and existing or anticipated enhanced recovery projects.

Initial review

After calculating the royalty factors for each lease, unit PA, or CA proposed for commingling, the initial review should be conducted by answering the following questions:

³ This information should be available on LR2000 for Federal leases and, therefore, does not have to be submitted by the operator.

1. Are the royalty factors of any of the leases, unit PAs, or CAs proposed for commingling different?
2. If tribal Indian leases are proposed for commingling, are any of the leases owned by different tribes?
3. Is any of the production going to the CDP originating from outside of the leases, unit PAs, and CAs proposed for commingling?
4. Are any of the leases proposed for commingling an allotted Indian lease?

If the answer to all of the above questions is “no” (or not applicable for question 2), then this application would have no impacts to Federal or Indian royalty and the AO may approve the application under Category 1 below. If the answer to any of the questions is “yes,” then commingling could have impacts to Federal or Indian royalty and the AO must not approve the application unless the applicant can demonstrate that the leases, unit PAs, or CAs proposed for commingling are low-volume (see Category 2 below) or there are other overriding considerations (see Category 3 below).

Potential Royalty and Production Accounting Impacts of Commingling

The commingling of Federal or Indian leases, unit PAs, or CAs in which there are potential impacts to royalty or royalty distribution is generally not in the public interest or the interest of Indian lessors because it may be inconsistent with Onshore Orders 4 and 5, and could have adverse impacts on royalty income and production accounting. The AO should not approve commingling requests with royalty impacts unless there is supporting documentation that all the properties proposed for commingling are low-volume or that there are overriding considerations (see example 5 regarding downhole commingling).

Royalty impacts

The commingling of Federal or Indian leases with State or fee properties and commingling leases, unit PAs, and CAs with different royalty factors can affect Federal and Indian royalty due to inaccuracies involved in the allocation method.

The following example demonstrates why commingling two CAs with different royalty factors affects royalty income and should not be approved unless both properties are low-volume or there are overriding considerations:

Consider an application proposing to commingle gas production from two CAs as shown in Figure 1. The CA on the left is 8 percent Federal and 92 percent fee and the CA on the

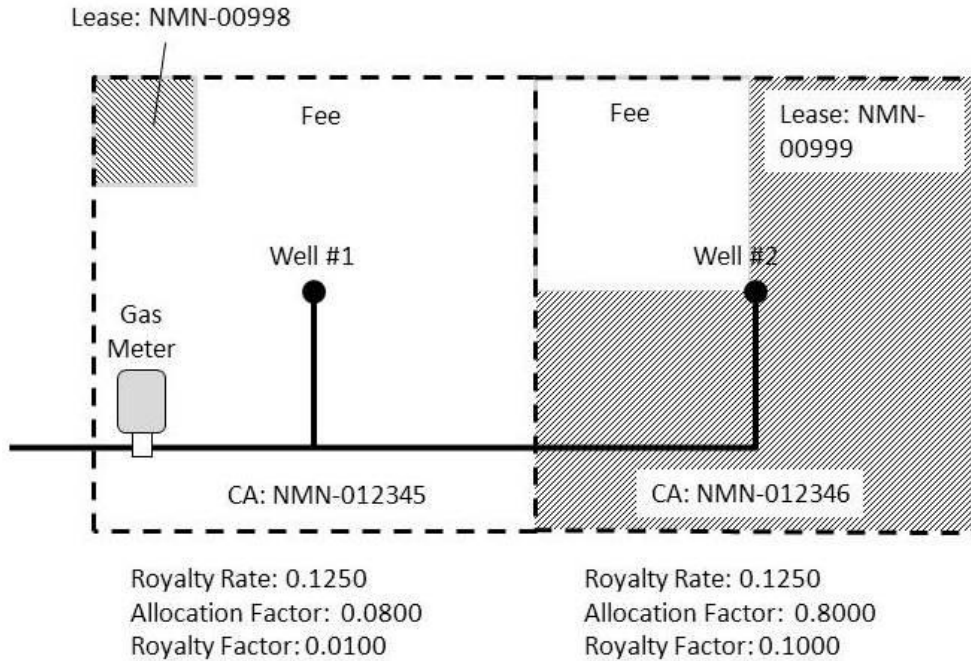


Figure 1 – Allocation by Well Test

right is 80 percent Federal and 20 percent fee. The proposal is to allocate the monthly volume measured by the gas meter to each CA on the basis of a quarterly 24-hour well test. The total amount of Federal royalty due from these two CAs will depend on the results of the well test. Referring to Table 1, “Case 1” shows the Federal royalty volume if the quarterly well test determined that 60 percent of the production was coming from CA NMN-012345 and 40 percent of the production was coming from CA NMN-012346. “Case 2” shows the Federal royalty volume if the well test determined that 30 percent of the production was coming from CA NMN-012345 and 70 percent of the production was coming from CA NMN-012346. From Table 1, it is apparent that Federal royalty volume and, therefore, Federal royalty will be affected by the well test.

	Total Gas (Mcf)	NMN-012345			NMN-012346			Federal Royalty Volume (Mcf)
		Well-test Alloc.	Royalty factor	Alloc. Volume (Mcf)	Well-test Alloc.	Royalty factor	Alloc. Volume (Mcf)	
Case 1	100,000	60%	0.0100	600	40%	0.1000	4,000	4,600
Case 2	100,000	30%	0.0100	300	70%	0.1000	7,000	7,300

Table 1 – Impact of Well Test on Royalty Allocation Between CAs

Commingling gas or oil of different qualities in this situation may also result in a decrease in value, thereby diminishing royalty. For example, if the gas heating value is 900 Btu/scf on the CA NMN-012345 and 1200 Btu/scf on CA NMN-012346, and the allocation is based strictly on volume, Federal royalty would be underpaid. The commingling approval should not be

approved if the commingling would degrade the value of the Federal or Indian gas or oil produced.

Production accounting impacts

The allocation method used when commingling is approved affects production accounting by inhibiting our ability to verify the reported royalty-bearing volumes and qualities on the Oil and Gas Operations Report (OGOR)⁴ Parts B and C and increasing the uncertainty of those values.

Commingling affects verifiability in a number of ways. If production from Federal or Indian leases is commingled with production from State leases or fee leases, the BLM has no jurisdiction to inspect the non-Federal properties, require that meters on non-Federal properties comply with the standards of Onshore Order 4 or Order 5, or request records from the lessees, operators, or owners of the non-Federal properties. If the BLM cannot ensure that all meters in the allocation system meet Onshore Order 4 and 5 standards, then it is impossible to ensure that the approved allocation method is accurate and equitable. Additionally, without the ability to obtain records from the State and fee leases, it is impossible in audit to re-construct the volumes allocated to each property even if we assume that the reported volume and quality from the meters on the State and fee leases are accurate. Including a condition of approval stating that the meters on the State and fee leases must comply with Onshore Orders 4 and 5 does not resolve this problem because the BLM has no legal authority to inspect measurement equipment on State and fee properties to determine if the equipment is out of compliance. Nor would the BLM have an enforcement mechanism to remedy discovered violations.

Commingling also inhibits verifiability by significantly increasing the complexity and workload of performing a production audit. To verify the reported royalty-bearing volume and quality of oil and gas produced from a particular lease, unit PA, or CA that is commingled with other production, BLM staff must inspect not only the meters on the lease, unit PA, or CA being audited, but also the CDP measurement facilities as well as every allocation meter or measurement facility that is part of the commingling approval. In large commingling approvals, this can greatly increase the time and workload of performing an audit. Complexity also increases the chances of mistakes by both the operator and the BLM.

Onshore Orders 4 and 5 contain detailed requirements for ensuring the accuracy and verifiability of royalty-bearing volumes and qualities of oil and gas removed or sold from Federal and Indian leases. These requirements result in an implicit uncertainty of ± 0.32 percent for oil volume measured by LACT meter, ± 0.5 percent to ± 1 percent for oil volume measured by tank gauging, and ± 3 percent for gas meters measuring more than 100 Mcf/day. However, when commingling is approved, the allocation method will typically use allocation meters or well testing to allocate the oil and gas measured at the CDP back to the leases, unit PAs, and CAs that are commingled (see Figure 2). In the case of allocation by allocation meter, the volume measured by the allocation meter is adjusted based on the readings from all the other meters in the allocation system. Therefore, the uncertainty of the measurement used for royalty determination is the

⁴ The OGOR is the form that operators use to report oil and gas production to the Office of Natural Resources Revenue. OGOR Part B is used to report production removed or sold from a lease, unit PA, or CA when it is not put into inventory (i.e. tanks); OGOR Part C is used to report production removed or sold from inventory.

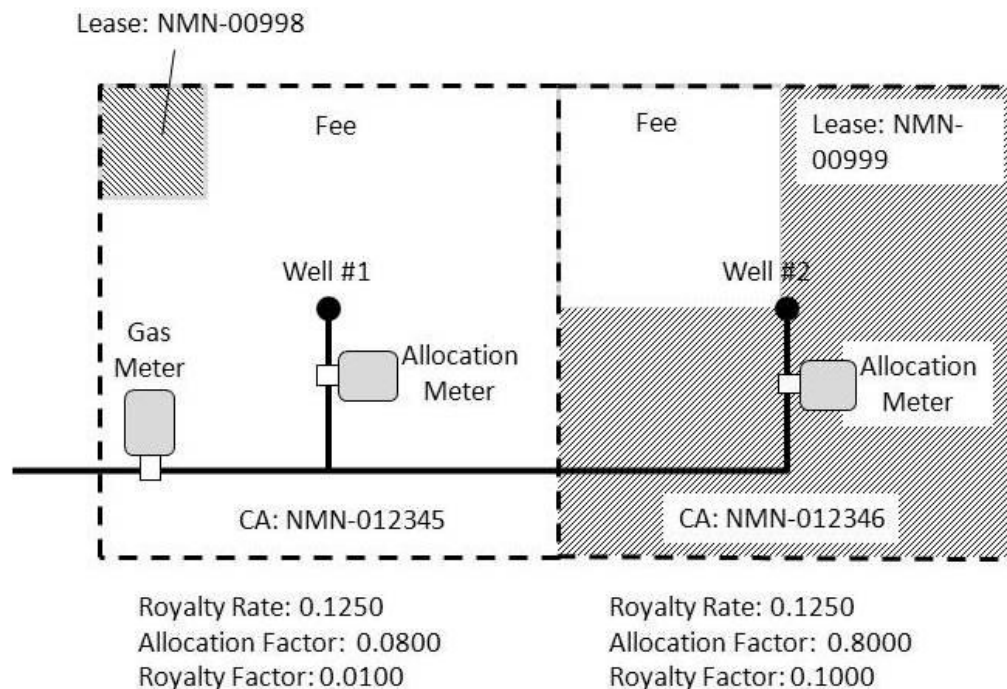


Figure 2 – Example of Allocation using Allocation Meters

statistical summation of the uncertainty from each meter in the allocation system. By approving the allocation, the BLM is tacitly accepting a much higher uncertainty than that envisioned by Onshore Orders 4 and 5, or what is required for production from a lease, unit PA, or CA that is not commingled.

Allocation meters meeting the minimum standards of Onshore Orders 4 and 5 should be used as the PRM for each lease, unit PA, or CA in lieu of using them for allocation. This would not require any approvals and would alleviate the jurisdictional, verifiability, and uncertainty problems associated with commingling.

Allocation by well testing is even more problematic. Even if the well test itself was done in accordance with Onshore Order 4 or 5 standards, verifiability would not be achievable because the production from each lease, unit PA, or CA remains unmeasured for all days other than well test days (for example, 89 out of 90 days in the case of quarterly well testing). A well test conducted for only 1 day out of every 90 days could result in production being inaccurately allocated, and the Federal Government being deprived of significant royalties, particularly if the flow from the Federal or Indian wells were reduced on the well test day. (Reducing the flow from the well on the test day would yield the same substantive result with respect to allocation error as if an allocation meter were installed but partly bypassed on that day.) In addition, the BLM would have no record of changes in flow from any of the wells as a result of manipulation of surface equipment or from natural variations in flow due to changing reservoir and wellbore conditions during the days that production from the wells was not measured. The uncertainty caused by well-test allocation is difficult to quantify but would be far higher than the uncertainties required by Onshore Orders 4 and 5.

Downhole commingling has its own unique issues. The percentage used to allocate production in downhole commingling is typically derived from spinner logs or by flow testing. Spinner logs run while the well is flowing can detect the contribution of each of the commingled zones to total production, thereby providing an allocation percentage. Allocation by flow testing is conducted by flowing the well with the lower zone isolated with a packer, and then flowing the well with both zones producing. The difference in flow rates establishes the allocation percentage. Both of these techniques result in high degrees of uncertainty under the best of conditions, with increased uncertainty due to multi-phase flow and the complexity of wellbore and reservoir fluid dynamics. It is also likely that the allocation percentages obtained by these test methods are only valid for the conditions under which the test was run.

The BLM regulations at 43 CFR 3162.7-2 (oil) and 3162.7-3 (gas) require that all oil and gas production be measured on the lease (or unit PA or CA) unless the BLM approves off-lease measurement. A request for commingling approval will involve a request for approval of off-lease measurement for at least one of the leases, unit PAs, or CAs involved in the proposed commingling, unless the commingling involves only different PAs within the same unit and the measurement point for the commingled production is on the unit. In the situation shown in Figure 1, approval of commingling and off-lease measurement should not be granted unless the properties are low-volume properties or there are overriding considerations.

Situations in which Commingling May Be Approved

1. Commingling with no royalty impacts

The commingling of Federal or Indian leases, unit PAs, or CAs where there are no potential adverse impacts to royalty or production accounting should be approved when it is otherwise in the public interest or the interest of the Indian lessor.

Benefits that may result from these types of approval include:

- Simplified production accounting because production reviews would primarily focus on the measurement facilities at the CDP;
- Potentially better measurement because the combining of production from multiple wells may help alleviate low and erratic flows which are often difficult to measure accurately;
- Reduced environmental impacts because less separation, treatment, and storage equipment is needed onsite, resulting in less surface disturbance and fewer emissions; and
- Helping to achieve maximum ultimate recovery from the leases by lowering operating costs.

Commingling in these situations can be approved for oil (including condensate), gas, or both. The most common situation would be the commingling of Federal leases or tribal Indian leases owned by the same tribe, that are uncommitted to a unit or CA and which have the same royalty rate. There may be some less common situations as well, such as the commingling of CAs where the percent of Federal or tribal Indian ownership in each CA is the same. In all these

cases, the allocation method will not affect total royalty payments because the total amount of royalty due to the Federal Government or Indian tribe is the same regardless of the allocation method. In addition, commingling oil or gas of different quality will not reduce the overall value of the oil or gas when the royalty factors are the same. In other words, there are no royalty impacts from this commingling approval.

Because of the complex and varied mineral ownership of allotted Indian leases, it would be very rare to have two allotted leases with the same allotted lessor royalty interests. Thus, commingling almost invariably would affect the ultimate distribution of royalty payments. Therefore, allotted Indian leases would not typically qualify for commingling approval under this category. A commingling request involving allotted leases may be approved if the leases, unit PAs, and CAs proposed for commingling are deemed to be low-volume (see Category 2) or there are other overriding considerations (see Category 3).

In addition to answering the questions that are part of the initial review, the commingling approval should document the following:

- All stand-alone leases (i.e., those not committed to a unit or CA), unit PAs, and CAs included in the commingling application are in production or (in the case of Federal leases) are capable of production. Unlike a unit or CA, a commingling approval will not hold a stand-alone lease, unit PA, or CA by production. Production must not be allocated to stand-alone leases, unit PAs, or CAs that are not in production or that (in the case of Federal leases) are not capable of production.
- The royalty-bearing volume of oil and gas reported on the OGOR Parts B and C for each lease, unit PA, or CA is determined by taking the oil or gas volume determined at the CDP and multiplying it by the percentage attributable to that lease, unit PA, or CA based on the allocation method described in the commingling application.
- The allocation method for reporting quality (API gravity or Btu content) on OGOR Parts B and C will result in a volume-weighted average or combined quality for all the leases, unit PAs, and CAs that is equal to the measured quality at the CDP.
- None of the leases approved for commingling have sliding-scale royalty rates, or provisions for sliding-scale royalty leases have been made in the conditions of approval. For example, a sliding-scale royalty lease may have the same royalty rate as other standard leases at the time the commingling application was received. If the royalty rate were to change, however, commingling production from that lease with production from standard-royalty leases would no longer meet the intent of this IM unless it was a low-volume property or there were overriding considerations.
- None of the leases approved for commingling have different royalty distribution percentages (see attachment 2 of this IM).

Off-lease Measurement and Off-lease Beneficial Use

Commingling applications will usually involve a request for approval of off-lease measurement because the CDP will be located off all or some of the leases, units, or CAs proposed for commingling (accept in situations where the comingling involves only PAs within the same unit and the measurement point for the commingled production is on the unit).

Generally, the lessee may claim royalty-free beneficial use only for the proportionate share of the fuel used at a CDP that corresponds to the proportionate share of the gas flowing through the CDP that is produced from the lease, unit, or CA on which the CDP is located. If the CDP is not located on any of the leases, units, or CAs from which the production originated, the operator generally may not claim royalty-free beneficial use unless the BLM expressly approves off-lease beneficial use.

For directionally drilled wells where the wellhead is not located on the lease, unit, or CA from which the oil or gas is produced, fuel used for beneficial purposes at the well site is recognized as royalty-free. Off-lease beneficial use may be approved when it is not possible to locate production or treatment equipment on the lease, unit, or CA due to physical constraints, lease stipulations, or environmental mitigation measures, and such equipment otherwise would have been located on the lease, unit, or CA. Off-lease beneficial use may also be approved when economic data demonstrates that the lease, unit, or CA would be shut in absent such approval. Off-lease beneficial use should not be granted routinely in connection with a commingling request; approval of off-lease beneficial use must be independently justified.

Production Accounting

Production accounting for leases, unit PAs, and CAs included in this type of commingling approval would be accomplished by comparing the total volume of commingled products reported as sold or transferred on OGOR B (disposition codes '01' or '11') and 'Sales' on OGOR C with the volume of oil and gas as measured at the CDP plus any fuel used at the CDP that does not qualify or is not approved for beneficial use. In addition, the average reported quality of the oil and gas reported on OGOR B and C would be compared with the qualities measured at the CDP.

Volumes determined from allocation meters or facilities used for commingling approved under Category 1 of this IM will not affect the total Federal or Indian royalty received from the commingled leases, unit PAs, or CAs. Therefore, whether these meters comply with Onshore Order 4 or 5 standards will not affect the royalty owed, and these meters or facilities do not have to be verified as part of a production review. However, in order to use allocation meters or facilities that do not meet Onshore Order 4 or 5 standards, the operator must submit and receive approval of a variance from Onshore Orders 4 or 5. For the reasons just explained, the variance request ordinarily should be approved. Because the allocation method may be used to determine allowable beneficial use deductions attributable to each of the commingled properties and for Office of Natural Resources Revenue (ONRR) royalty enforcement against the proper parties, the allocation method must be thoroughly described in the application.

Example 1 is a commingling application that meets the criteria outlined in this section.

2. Commingling of Low-volume Properties with Potential Royalty Impacts

In the case of low-volume properties, it is generally in the public interest or the interest of Indian lessors to approve commingling to achieve the maximum ultimate recovery, notwithstanding

potential royalty impacts. While this does entail some risk of inaccurate or unverifiable volumes on which royalty is based, the greater risk would be to receive no royalty if the lease, unit PA, or CA were to be shut in as a result of overly burdensome requirements.

To ensure that the BLM only approves commingling of properties under this category that truly qualify as low-volume, the operator must demonstrate that the lease(s), unit PA(s) or CA(s) involved meet the definition given in attachment 1-1. Proposals to commingle production from one or more low-volume properties with production from one or more non-low-volume properties are addressed in example 4 at attachment 1-35.

If the operator proposes to use allocation meters or methods that do not meet the standards of Onshore Orders 4 and 5, the operator must include a request for a variance because Onshore Orders 4 and 5 apply to allocation meters. Commingling under this category can be approved only if the BLM determines that the economic considerations of continued production outweigh the inaccuracies of the allocation method. Therefore, in conjunction with commingling approvals under this category, the BLM should approve variances requesting that allocation meters or methods be exempt from the standards of Onshore Orders 4 and 5.

A. Rate of Return

A before-tax rate of return of less than 10 percent from continued production (or other threshold justified by the operator) indicates that a prudent operator likely would opt to cease production instead of making the necessary capital expenditures to achieve measurement of non-commingled production. The BLM should approve commingling only if a discounted cash flow analysis (DCFA) of the capital investment required to comply with measurement requirements without commingling shows that the return on investment would be too low for a prudent operator to proceed with the investment, and as a result the lease, unit PA, or CA would be shut in (see examples 3 and 4).

An operator seeking to obtain commingling approval for low-volume properties must include a DCFA showing all capital expenditures needed to comply with measurement requirements without commingling and all assumption made in the DCFA. The assumptions should include the capital expenditure required, operation and maintenance costs, and projected oil and gas price. The field office must review the DCFA to ensure that the assumptions and analysis are reasonable.

For surface commingling applications, the rate of return (before tax) should be 10 percent or less to justify the commingling based on economics. While higher rates of return may be appropriate for new exploration or development projects, the installation of equipment on an existing lease with known production decline characteristics is relatively low risk. If the operator wishes to use a higher threshold, the operator must justify the reason for the threshold it proposes.

Because review of DCFAs can be time-consuming, figures 3 (gas) and 4 (oil), and equations 3 and 4 were developed based on a generic DCFA. Figures 3 and 4 can be used as a quick check of the operator's DCFA. If there is significant disparity between the results using figures 3 and 4

and the operator's conclusion, further analysis should be done to identify the source of the disparity.

These generic DCFAs are intended for surface commingling, because downhole commingling expenditures to comply with measurement requirements without commingling (such as drilling an additional well or dual-completing a well) could have significantly different inputs. For example, drilling an additional well in lieu of downhole commingling could require a higher rate of return, since there is more risk involved than there is in investing in additional measurement equipment for surface commingling. Offices are encouraged to develop DCFAs based on typical operating costs and conditions in their respective areas in order to streamline the review process.

DCFA for gas

The DCFA for gas is based on the following assumptions:

- Flow rate decline: 10 percent/year (exponential)
- Operating cost (not including measurement-related costs): \$1,000/month/well
- Cost of verification and calibrations: \$300/year
- Cost of gas sampling and analysis: \$200/year
- Royalty rate: 12.5 percent
- Rate of Return: 10 percent, before Federal or State income taxes
- Equipment life: 10 years

Based on these assumptions, the minimum initial flow rate needed to achieve a 10 percent rate of return for a given level of investment and natural gas price is shown in figure 3.

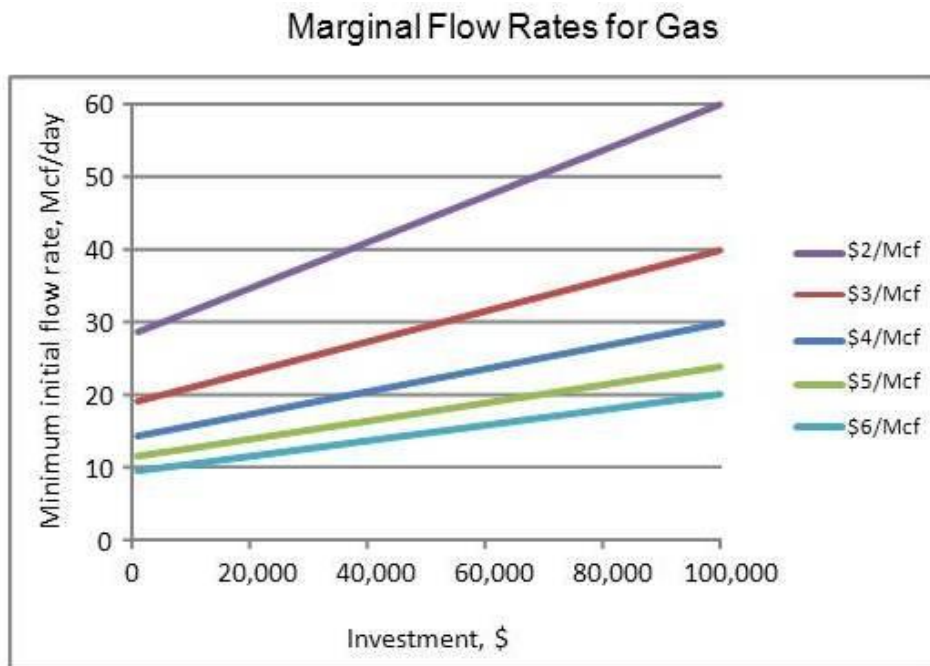


Figure 3

The following equation approximates the results of figure 3:

$$Q_i = \frac{1}{P_g} \left(\frac{I}{1590} + 57 \right) \quad \text{Eq. 3}$$

where:

Q_i = minimum initial flow rate needed to achieve a 10% ROR, Mcf/day

P_g = gas price over the analysis period, \$/Mcf

I = investment required to achieve measurement of non-commingled production, \$

DCFA for oil

The DCFA for oil is based on the following assumptions:

Flow rate decline: 10 percent/year (exponential)

Fixed operating cost (not including measurement-related costs): \$2,000/month/well

Per-barrel operating cost: \$8/barrel⁵

Royalty rate: 12.5 percent

Rate of Return: 10 percent, before Federal or State income taxes

Equipment life: 10 years

Based on these assumptions, the minimum initial production rate needed to achieve a 10 percent rate of return for a given level of investment and oil price is shown in figure 4:

⁵ If the actual operating costs are significantly higher than \$8/bbl (such as for water disposal), the additional costs can be subtracted from the oil price. For example, if the oil price is \$100/bbl, and the actual per-barrel cost is \$33/bbl, an oil price of \$75/bbl (\$100/bbl - (\$33/bbl - \$8/bbl)) can be used in Figure 4 or Equation 4, to determine the minimum required initial flow rate.

Marginal Flow Rates for Oil

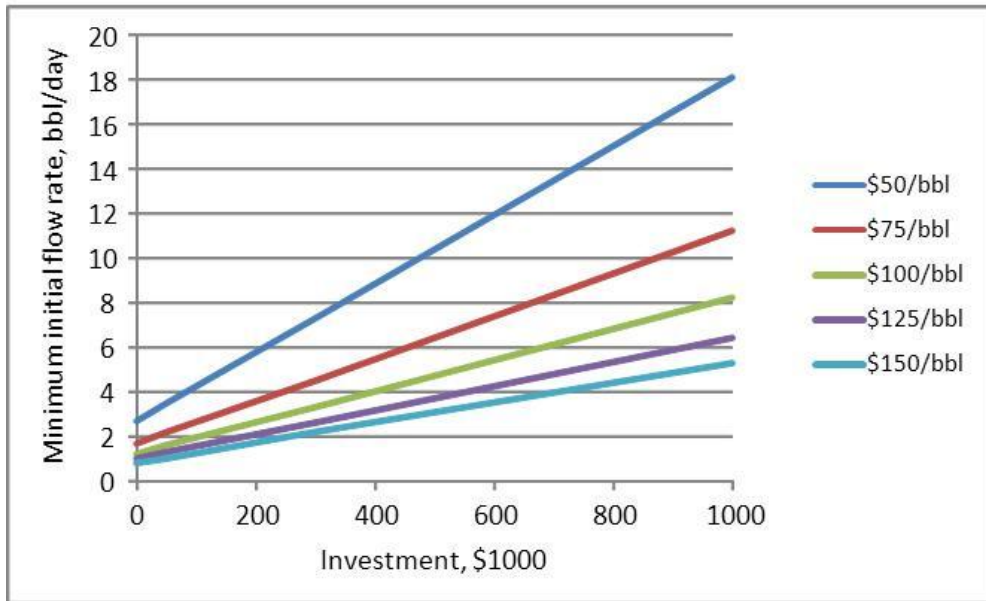


Figure 4

The following equation approximates the results of figure 4:

$$Q_i = \frac{I}{1578P_o - 14475} + \frac{1}{0.008684P_o - 0.05261} \tag{Eq. 4}$$

where:

Q_i = minimum initial flow rate needed to achieve a 10% ROR, bbl/day

P_o = oil price over the analysis period, \$/bbl

I = investment required to achieve measurement of non-commingled production, \$

The selection of an oil or gas price should be based on projections made over the life of the analysis, rather than on current prices. Pricing projections can be obtained from several sources including the Energy Information Agency (www.eia.gov). Operators will typically use current pricing for economic decisions. If there is a wide disparity between current and long-term projected prices, first choose the lower of the two. If a project is economical based on the lower price then it will be economical based on the higher price. If the price chosen makes the difference between economic and non-economic, you may consider a temporary approval with a rescission or modification of the approval when current prices increase.

B. Total Royalty

Even if an operator could receive an adequate rate of return on the capital expenditure needed to achieve non-commingled production, it is unreasonable to expect an operator to make such an

expenditure if it exceeds the total amount of royalty that would be collected from the lease, unit PA, or CA. Therefore, the field office can compare the NPV of projected royalty over the life of the capital equipment with the total cost of the capital equipment and other needed expenditures. If the total cost needed to achieve non-commingled production is greater than the NPV of the projected royalty, the lease, unit PA, or CA is considered a low-volume property and may be approved for commingling under Category 2 (see example 3).

You should use the 30-year Treasury bond rate⁶ for the discount rate in the NPV calculation unless a different discount rate is justified.

3. Commingling based on overriding considerations

It is virtually impossible to anticipate all the variations in factual situations involved in commingling applications that the BLM will receive. Therefore, there may be commingling applications that cannot be approved under Category 1 or 2, but may still be in the public interest for other reasons. If those reasons are analyzed and documented, the commingling application may be approved under Category 3. Field offices should rigorously examine alternatives to approving commingling requests under this Category. Two of the more common overriding considerations are environmental considerations and downhole commingling.

If the operator proposes to use allocation meters or methods that do not meet the standards of Onshore Orders 4 and 5, it must include a request for a variance because Onshore Orders 4 and 5 apply to allocation meters. Commingling under this category can be approved only if the BLM determines that the overriding considerations of continued production outweigh the inaccuracies of the allocation method. Therefore, in conjunction with commingling approvals under this category, the BLM should approve variances requesting that allocation meters or methods be exempt from the standards of Onshore Orders 4 and 5.

⁶ <http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield>

Environmental Considerations

One of the potential benefits of commingling is that it can reduce environmental impacts by centralizing separation, treatment, storage, and measurement facilities at one location, thereby reducing truck traffic, vapor emissions, surface disturbance, and visual impacts. Locating such equipment or facilities at one location also may be compelled by unfavorable topography. (The site may be on one of the leases from which the production is commingled, or not on any of the leases. Whether the BLM should approve off-lease beneficial use is a related but separate question.) While the BLM is committed to employing best management practices and reducing environmental impacts to the extent possible on Federal leases, production accountability is also vitally important. As discussed above, commingling that has potential royalty impacts makes accurate production accounting difficult and, in some cases, impossible.

Environmental protection and production accountability are not mutually exclusive and, in almost every case, both can be accomplished. While there will be a wide variety of situations and proposals, one example is presented here (see example 2 at attachment 1-22). BLM staff should work closely with the applicant to achieve commingled production only where there are no potential royalty impacts while minimizing surface impacts, particularly at the well sites. Ideally, this should be done at the project planning stage before any infrastructure is in place. For example, the running of parallel production pipelines to the central measurement facility, one for Federal or Indian production and one for State and fee production, to avoid multiple facilities at different well sites, would be much easier to implement early in the project. However, it is often possible to make relatively minor changes to plumbing to achieve non-commingled measurement on leases that are already in production.

Downhole Commingling Considerations

This IM sets policy for both surface and downhole commingling, since the same basic principles of public interest and the interest of Indian lessors, royalty income, production accounting, and economics apply to both situations. However, downhole commingling may include additional factors that could warrant approval under Category 3 of this IM.

Downhole commingling may have benefits to the public interest or the interest of Indian lessors in the form of maximum ultimate recovery that are not directly tied to low-volume production and economics. For example, the reservoir energy in one formation may help lift fluids from another formation (see example 5), thereby increasing the maximum ultimate recovery. While economics are still the reason an operator would propose such an operation, an economic analysis may be complex or highly speculative.

As discussed previously (page Attachment 1-7), downhole commingling approvals have the potential to adversely affect royalty income and production accounting.

Approval of downhole commingling based on factors other than low-volume property economics must include thorough documentation demonstrating that the benefits to the public interest or the interest of Indian lessors from commingling outweigh the potential adverse impacts on royalty income and production accountability. Alternatives to downhole commingling such as dual

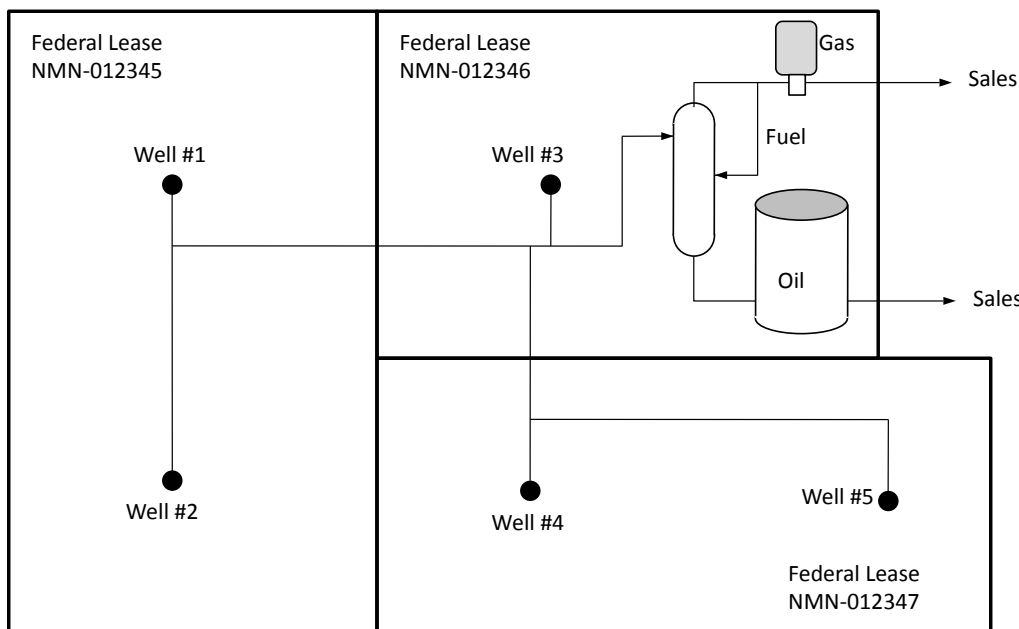
completion should be considered when reviewing downhole commingling applications under this category. Field offices are encouraged to develop guidelines specific to their areas in order to implement this IM while minimizing permitting delays that could result from the additional analysis required.

Example 1: Commingling Request with No Potential to Affect Federal or Indian Royalty

The BLM receives the following application to commingle oil and gas production from three leases:

We are requesting approval for off-lease measurement, off-lease beneficial use, and the commingling of oil and gas production from the following three Federal leases (see the figure below):

Lease No.	Ownership	Royalty Rate (%)
NMN-012345	Federal	12.5
NMN-012346	Federal	12.5
NMN-012347	Federal	12.5



The allocation method will be by a 24-hour monthly well test. The percentage of oil allocated to each lease will be the total oil rate from all well tests on the lease divided by the total oil rate from all well tests. The percentage of gas allocated to each lease will be the total gas rate from all well tests on the lease divided by the total gas rate from all well tests.

The quantity of oil to be reported as sales on OGOR C for each lease will be the total oil sales from the central delivery point multiplied by the oil percentage determined from the well tests. The quantity of gas to be reported as sold on OGOR B will be the total gas measured at the central delivery point multiplied by the gas percentage determined from the well tests.

The API Gravity and heating value to be reported on OGOR C and B for all three leases will be the values determined from the central delivery point.

All measurement at the central delivery point will comply with the requirements of Onshore Orders 4 and 5. A separator will be located at the central delivery point which will use gas removed from the line before the gas sales meter.

The following Table shows an example of the allocation method:

Lease Number	Well #	Date	Gas rate (Mcf/day)	Lease gas rate (Mcf/day)	Gas (%)	Oil rate (bbl/day)	Lease Oil rate (bbl/day)	Oil (%)
NMN-012345	1	7/6/11	133.6	189.4	19.98	20.1	33.0	31.16
	2	7/8/11	55.8			12.9		
NMN-012346	3	7/9/11	254.0	254.0	26.79	25.3	25.3	23.89
NMN-012347	4	7/11/11	392.4	504.6	53.23	28.6	47.6	44.95
	5	7/13/11	112.2			19.0		
Totals:				948.0	100.0		105.9	100.0

BLM Review

First, the submittal should be reviewed to ensure that sufficient information was submitted:

- A list of each lease, unit PA, or CA proposed for commingling: **Yes**
- The royalty rate and ownership (Federal/tribal Indian [specify tribe], or allotted Indian) of each lease to be included: **Yes**
- For unit PAs and CAs, the Federal or Indian allocation factor: **Not Applicable**
- If the commingling proposal includes allotted Indian leases, evidence that all Indian allottee mineral owners of leases included in the commingling request have been notified of the request. An affidavit from the operator stating that a notice was mailed to each mineral owner of record for whom the superintendent or area director has an address will satisfy this notice requirement: **Not Applicable**
- If the commingling proposal includes tribal Indian leases, evidence that each of the affected tribes has given its consent for commingling: **Not Applicable**
- The commodities proposed for commingling (oil/condensate, gas, or both): **Yes**
- Evidence showing that each lease, unit PA, or CA proposed for commingling is either in production or (for Federal leases) is capable of production: **Yes, the well tests shown in the example allocation method indicate that all leases are capable of production.**
- A map or schematic showing the proposed leases, unit PAs, and CAs, along with wells, pipelines, processing facilities (separators, dehydrators, compressors, etc.), storage facilities, and the point of royalty measurement: **Yes**

- If wells are directional or horizontal and the well pad is not located on the lease, unit PA, or CA from which the production originates, the map should include the approximate wellbore path and the location of the producing interval(s): **Not applicable**
- A list of all equipment proposed for royalty-free use of gas and oil (beneficial use) and a schematic showing where fuel is to be taken in relation to the royalty measurement point: **Yes**
- The gas heating value (Btu) and oil gravity of the oil and gas proposed for commingling: **No – this should be requested**
- A detailed description of the proposed allocation method for both volume and quality along with an example of how it is applied: **Yes**
- If downhole commingling is proposed, pertinent reservoir information such as the presence of hydrogen sulfide, formation pressures, water cut, decline characteristics, drive mechanism, and existing or anticipated enhanced recovery projects: **Not applicable**

Initial Questions

Based on the information submitted, the following questions can be answered:

1. Are the royalty factors of any of the leases, unit PAs, or CAs proposed for commingling different? **No, all are 0.125**

Lease	Royalty Rate	Royalty Factor
NMN-012345	0.125	0.125
NMN-012346	0.125	0.125
NMN-012347	0.125	0.125

2. If tribal Indian leases are proposed for commingling, are any of the leases owned by different tribes? **Not applicable**
3. Is any of the production going to the CDP originating from outside of the leases, unit PAs, and CAs proposed for commingling? **No**
4. Are any of the leases proposed for commingling an allotted Indian lease? **No**

Approve the request?

Because the answer to all these questions is “no,” and the proposal appears to be in the public interest, this commingling request should be approved under Category 1 of this IM. In this situation, the allocation method will not affect Federal royalty income because the total amount of Federal royalty generated from these leases will be the same regardless of the allocation method or percentages. Although the operator provided neither the historic heating value of the gas nor the gravity of the oil, the commingling of oil and gas of different qualities will generally not have a negative impact on the total value of the oil or gas as long as all the commingled

properties are 100 percent Federal or 100 percent owned by the same Indian tribe and have the same royalty rate.

Related Approvals and Off-lease Beneficial Use

Off-lease measurement approval will be required for leases NMN-012345 and NMN-012347 because production from those leases is removed from the lease prior to measurement. Because commingling would be approved in this situation, off-lease measurement would also be approved.

A variance to the requirements of Onshore Orders 4 and 5 will also be required because the proposed well test methodology for allocation does not meet the standards required by the Onshore Orders for sales and allocation facilities.

Because the CDP is located on lease NMN-012346, the only beneficial use that can be claimed (absent approval of off-lease beneficial use) is the share of the fuel used to run the separator that is apportioned to lease NMN-012346. The method of apportionment should be the same as the method used to determine the allocation percentages, which should be specified as a condition of the commingling approval. The request for off-lease beneficial use should be denied because the operator did not include any economic justification for approving it.

OGOR Reporting and Production Accounting

The approval should also specify how volumes and qualities of oil and gas are to be reported on OGOR B and C. Production accounting will focus on the oil tank and the gas meter at the CDP and the fuel usage by the separator, as these are the only measurements that need to be verified. However, because the production volumes and qualities allocated to each lease will be reported separately on the OGORS, the sum of the OGOR volumes and the volume-weighted average of the OGOR qualities must match the volumes and qualities obtained from the CDP. The easiest way to ensure the OGOR qualities match the qualities at the CDP is to report the same quality for each lease on the OGORS.

For example, assume that the following quantities and qualities were measured at the CDP for the month of April 2012:

	Volume	Quality
Oil	966 bbls	33.5 ⁰
Gas	56,442 Mcf	1112 Btu/scf
Fuel	2,258 Mcf	1112 Btu/scf

First, the oil, gas, and fuel volumes should be allocated using the allocation percentages as determined by the method included in the commingling application. Using the example provided:

Commodity	Total Volume	NMN-012345		NMN-012346		NMN-012347	
		Alloc. Factor	Alloc. Volume	Alloc. Factor	Alloc. Volume	Alloc. Factor	Alloc. Volume
Oil	966 bbls	0.3116	301	0.2389	231	0.4495	434
Meas. Gas	56,442 Mcf	0.1998	11,277	0.2679	15,121	0.5323	30,044
Fuel	2,258 Mcf	0.1998	451	0.2679	605	0.5323	1,202
'01' Gas*			11,728		15,121		31,246
'20' Gas*			0		605		0

Because leases NMN-012345 and NMN-012347 are not eligible for beneficial use (the CDP is not located on them) and because the fuel used at the CDP is taken prior to the meter, the fuel allocated to these leases must be added to the allocated measured gas. Neither lease should be reporting anything under OGOR Code '20' (Used on Lease). On the other hand, lease NMN-012346 is eligible for beneficial use because the CDP is physically located on this lease. Therefore, the allocated measured gas should be reported under OGOR Code '01', and the allocated fuel usage should be reported under OGOR Code '20'.

The OGOR reporting for the three commingled leases should be as follows:

Lease	OGOR B*			OGOR C	
	01		20	Oil	Oil
	BTU	MCF	MCF	Gravity	Sales
NMN-012345	1112	11,728	0	33.5	301
NMN-012346	1112	15,121	605	33.5	231
NMN-012347	1112	31,246	0	33.5	434

*OGOR B Disposition Code '01' is for oil or gas sold, Code '20' is oil or gas used on lease.

Example 2: Commingling Request of Non-Low-Volume Properties with Potential Royalty Impacts

The BLM receives the following application to commingle oil and gas production from three leases:

We are requesting approval to commingle oil and gas production from the following three leases (see the attached Figure):

Lease No.	Ownership	Federal Royalty Rate (%)
WYW-667788	Federal	12.5
WYW-334455	Federal	12.5
Fee #1	Fee	n/a

In addition, we are requesting off-lease measurement approval and approval to claim beneficial use at the separator. Beneficial use would be allocated back to each lease at the same percentage as the gas produced (see $F_{g,i}$ below). We do not believe that lease "Fee #2" is productive and are not requesting commingling of production from this lease at this time.

The combined production from these leases would be carried to an off-lease central delivery point which includes separation, storage, and measurement facilities. Allocation of production would be done by a 24-hour monthly well test of both oil and gas rates using a permanently installed well test separator and measurement system. The gas meter on the test separator meets all Onshore Order 5 requirements, and oil measurement on the test separator is by Coriolis meter, which meets or exceeds the accuracy requirements of Onshore Order 4. Initial well tests indicate gas production rates to be between 1,000 and 5,000 Mcf/day and oil rates to be between 50 and 200 barrels per day.

All measurement done at the central delivery point would be in accordance with Onshore Order 5 and Onshore Order 4.

The allocation of production would be done using the following equations (see attached example):

$$V_{g,i} = F_{g,i} \times S_g \quad \text{and} \quad V_{o,i} = F_{o,i} \times S_o$$

$$F_{g,i} = \frac{R_{g,i}}{\sum_{i=1}^{i=6} R_{g,i}} \quad \text{and} \quad F_{o,i} = \frac{R_{o,i}}{\sum_{i=1}^{i=6} R_{o,i}}$$

where:

Subscript i denotes an individual well (total of 6 wells to be commingled)

Subscript g denotes gas

Subscript o denotes oil

V = gas or oil volume attributed to well i

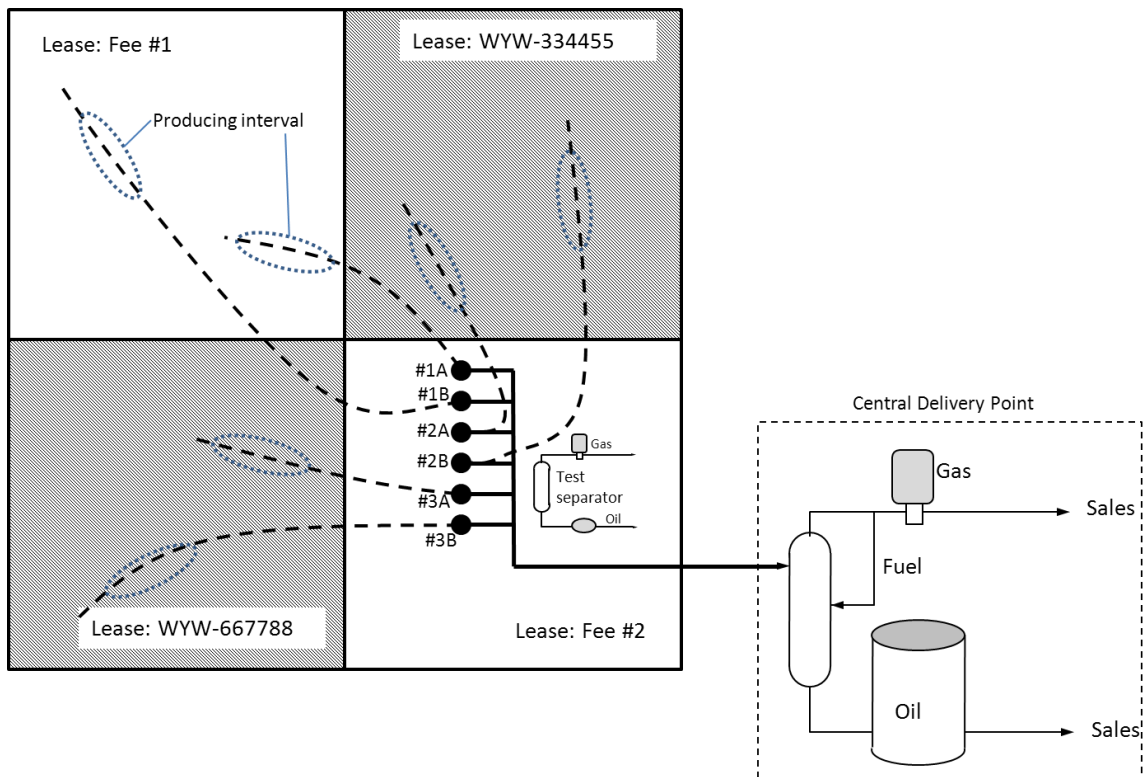
F = fraction of oil or gas production attributed to well i , through the well test

S = gas or oil sales volume from the central delivery point

R = 24-hour oil or gas rate for well i

Justification:

The Resource Management Plan (RMP) requires oil and gas operators to mitigate air quality and surface impacts by eliminating onsite oil storage tanks. Without the commingling approval, we would need to measure oil and gas from each of the three leases separately. This would require three separators, three gas meters, and three oil storage tanks to be located on-lease. By granting the commingling request, the only surface equipment needed on the leases proposed for commingling would be the test separator.



The following Table shows an example of the allocation method:

Lease Number	Well #	Date	Gas rate (Mcf/day)	Lease gas rate (Mcf/day)	Gas (%)	Oil rate (bbl/day)	Lease Oil rate (bbl/day)	Oil (%)
Fee #1	1A	4/18/12	1556.8	3741.1	24.72	166.3	338.9	36.17
	1B	4/20/12	2184.3			172.6		
WYW-334455	2A	4/23/12	1109.0	4237.6	28.00	95.0	295.4	31.52
	2B	4/24/12	3128.6			200.4		
WYW-667788	3A	4/26/12	2276.4	7153.9	47.28	121.5	302.8	32.31
	3B	4/27/12	4877.5			181.3		
Totals:				15,132.6	100.0		937.1	100.0

Historic gas heating values (Btu/scf) are as follows:

Date	Well Number					
	1A	1B	2A	2B	3A	3B
April 2012	1025	1050	902	920	1002	1066
Mar. 2012	1036	1060	910	908	988	1089
Feb. 2012	1031	1066	900	906	996	1075
Jan 2012	1020	1051	929	919	1024	1051
Dec 2012	1009	1049	931	928	1019	1074
Nov . 2011	1030	1059	905	906	1018	1060

Historic oil gravities (^oAPI) are as follows

Date	Well Number					
	1A	1B	2A	2B	3A	3B
April 2012	33.6	32.1	41.0	42.8	44.4	43.2
Mar. 2012	33.4	33.1	40.4	43.4	44.3	43.8
Feb. 2012	33.0	32.8	41.1	43.1	44.0	43.8
Jan 2012	34.5	32.7	41.5	42.9	44.3	43.6
Dec 2012	34.1	31.9	41.5	43.6	44.6	43.0
Nov . 2011	33.9	32.4	42.1	43.0	44.2	43.1

BLM Review

First, the submittal should be reviewed to ensure that sufficient information was submitted:

- A list of each lease, unit PA, or CA proposed for commingling: **Yes**
- The royalty rate and ownership (Federal, tribal Indian [specify tribe], or allotted Indian) of each lease to be included: **Yes**
- For unit PAs and CAs, the Federal or Indian allocation factor: **Not Applicable**
- If the commingling proposal includes allotted Indian leases, evidence that all Indian allottee mineral owners of leases included in the commingling request have been notified

of the request. An affidavit from the operator stating that a notice was mailed to each mineral owner of record for whom the superintendent or area director has an address will satisfy this notice requirement: **Not Applicable**

- If the commingling proposal includes tribal Indian leases, evidence that each of the affected tribes has given its consent for commingling: **Not Applicable**
- The commodities proposed for commingling (oil/condensate, gas, or both): **Yes**
- Evidence showing that each lease, unit PA, or CA proposed for commingling is either in production or (for Federal leases) is capable of production: **Yes, the initial well tests indicate that all leases are capable of production**
- A map or schematic showing the proposed leases, unit PAs, and CAs, along with wells, pipelines, processing facilities (separators, dehydrators, compressors, etc.), storage facilities, and the point of royalty measurement: **Yes**
- If wells are directional or horizontal and the well pad is not located on the lease, unit PA, or CA from which the production originates, the map should include the approximate wellbore path and the location of the producing interval(s): **Yes**
- A list of all equipment proposed for royalty-free use of gas and oil (beneficial use) and a schematic showing where fuel is to be taken in relation to the royalty measurement point: **Yes**
- The gas heating value (Btu) and oil gravity of the oil and gas proposed for commingling: **Yes**
- A detailed description of the proposed allocation method for both volume and quality along with an example of how it is applied: **Yes, but only for volume**
- If downhole commingling is proposed, pertinent reservoir information such as the presence of hydrogen sulfide, formation pressures, water cut, decline characteristics, drive mechanism, and existing or anticipated enhanced recovery projects: **Not Applicable**

Initial Questions

Based on the information submitted, the following questions can be answered:

1. Are the royalty factors of any of the leases, unit PAs, or CAs proposed for commingling different? **Yes**

Lease	Federal Royalty Rate	Royalty Factor
WYW-667788	0.125	0.125
WYW-334455	0.125	0.125
Fee #1	0	0.000

2. If tribal Indian leases are proposed for commingling, are any of the leases owned by different tribes? **Not applicable**

3. Is any of the production going to the CDP originating from outside of the leases, unit PAs, and CAs proposed for commingling? **No**
4. Are any of the leases proposed for commingling an allotted Indian lease? **No, none of the leases are allotted.**

Approve the request?

Because the royalty factors are not the same (one of the leases proposed for commingling is fee), this commingling request should not be approved under Category 1 because there are potential royalty impacts resulting from the allocation methodology. In addition, the proposed well testing allocation methodology cannot meet Onshore Order 4 or 5 requirements. Verification of the allocation method would be difficult because the BLM would have no authority over the fee wells, which affect the allocation percentages and, therefore, royalty. Because of the high production rates, it is unlikely that these leases could be considered low-volume. Therefore, the application should not be approved under Category 2. Although the operator has presented environmental factors as an overriding consideration, the field office should only approve this request under Category 3 if alternatives have been rigorously explored, documented, and rejected.

In addition, the variation in oil gravity is a concern that could result in reduced royalty if production were commingled under the circumstances described in this example. Unlike example 1, where all the commingled leases are 100 percent Federal and have the same royalty rate, in this example the operator proposes to commingle both Federal and non-Federal production. Most oil sales contracts give a premium price for oil in the 40 to 45° API gravity range, with values reduced for gravities over or under this range. Because the oil produced from the fee lease has gravities that are well below the gravities of the oil produced from the Federal leases, commingling this oil could result in boosting the value of the fee oil at the expense of the Federal oil.

To achieve non-commingled production and to overcome the environmental concerns raised by the RMP, other options should be explored with the operator. One of those options could be as follows (see figure 2):

- The operator would commingle the two Federal leases;
- The Federal leases would require their own separator and meters for gas and oil;
- Presumably, the fee lease would also require a separator and gas and oil meters; however, the BLM has no jurisdiction over the fee lease;
- Once measured, the Federal and fee gas could be re-combined in a single pipeline and shipped elsewhere for final re-separation and sales. Likewise, the Federal and fee oil could be combined and shipped elsewhere for sales;
- The BLM point-of-royalty measurement would be the gas and oil meters at the separator outlet for the Federal leases;
- Coriolis meters may work directly off a separator without the need for a storage tank. In addition, Coriolis meters may be capable of meeting or exceeding Onshore Order 4 standards for bias and uncertainty; and

- The gas and oil measured at the Federal separator would be reported directly on OGOR B (OGOR C would not be used because there is no inventory on lease). The operator would have to submit an allocation methodology as part of its commingling request for the Federal leases.

This alternative would require a variance to use Coriolis meters and a commingling approval for the two Federal leases. Because the fuel usage in the separator would take place on the well pad of the directionally drilled wells, it would be considered “on-lease,” and approval of off-lease beneficial use would not be required. Similarly, because the measurement would take place on the well pad, off-lease measurement approval would not be required either.

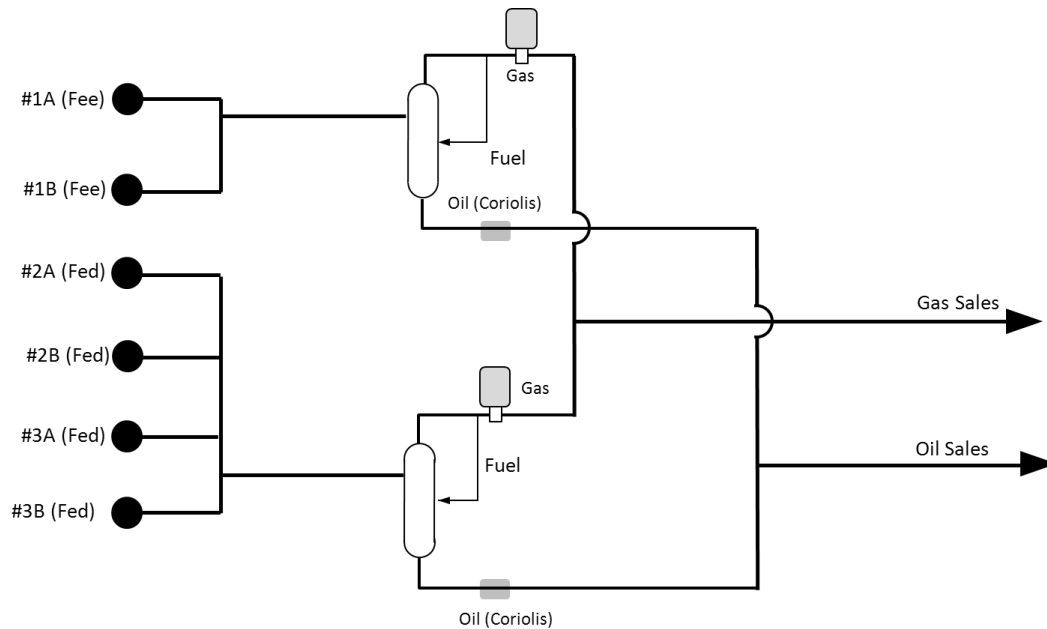


Figure 2 – Alternative to proposed commingling

Example 3: Commingling Request for Low-Volume Properties

The BLM receives the following application to commingle oil production from four CAs:

We are requesting approval to commingle oil production from four CAs as listed below and shown on the attached figure. This request is in response to INC No. 123-RME-12-1, which was issued for unapproved commingling. We just purchased these properties and were not aware that the commingling had not been approved by the BLM. The corrective action on the INC is “install oil measurement facilities on each CA in accordance with Onshore Order 4 or request commingling approval.”

CA No.	Lease Ownership	Federal Royalty Rate (%)	CA Allocation Factor
COC-98766	Federal	12.5	0.2500
COC-98755	Federal	12.5	0.5000
COC-98744	Federal	12.5	0.3750
COC-98733	Federal	12.5	0.5000

After some research, we have determined that the cost to install an oil measurement facility on each CA would be as shown in the following table:

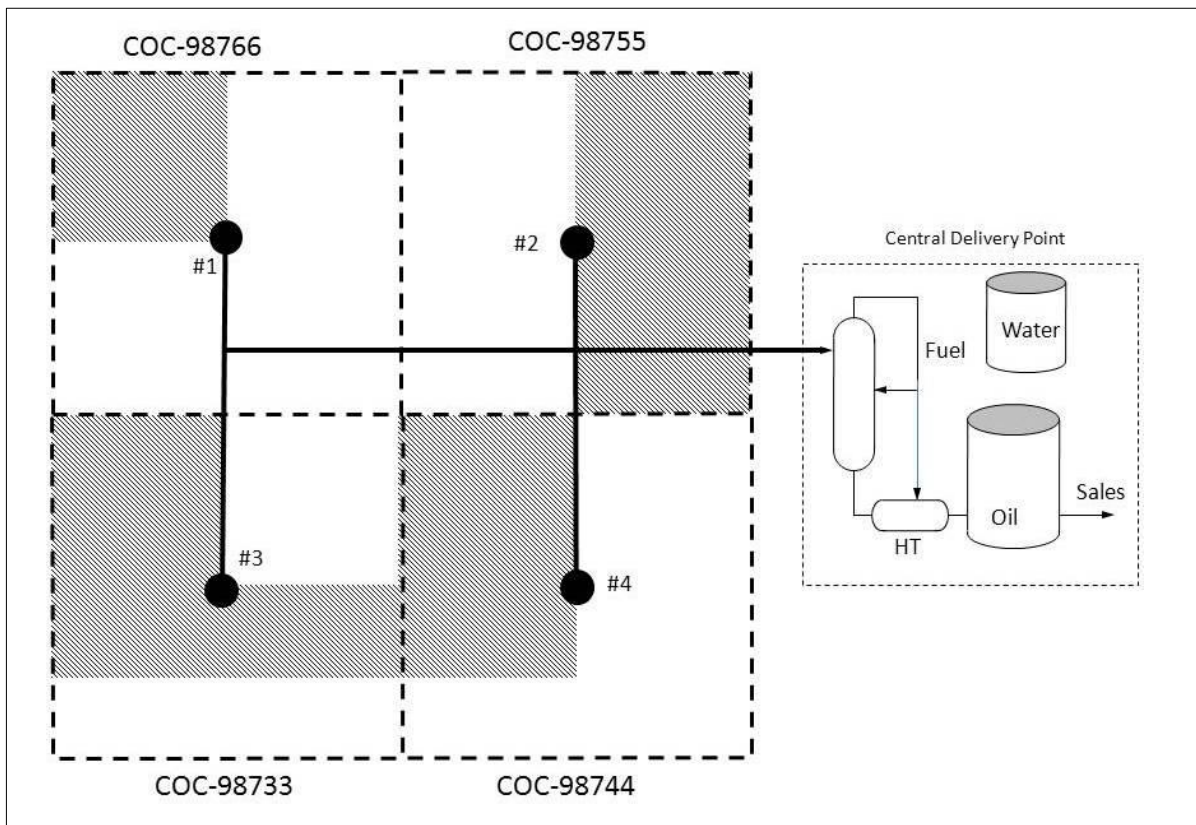
Equipment/Labor	Cost
250 bbl oil sales tank	\$60,000
250 bbl water tank	\$25,000
Separator	\$20,000
Heater-treater	\$50,000
Misc piping and installation	\$70,000
Total	\$225,000

The total cost to bring all four CAs into compliance would be \$900,000.

Our Discounted Cash Flow analysis shows that we could not achieve an acceptable rate of return on this expenditure since these wells were first completed in the early 1970s and now produce between 3 and 6 bbls/day each, declining at about 5 percent per year. Therefore, if we are required to install the necessary measurement equipment on each CA, we will plug and abandon these wells instead.

Our proposed allocation method is to use a fixed percentage based on historical well test data. These tests show that the percentage split between wells has remained nearly constant for the past 10 years as follows:

Well #	Rate (bbl/day)	Percent	Gravity
1	4	22.2	22.3
2	6	33.3	24.0
3	5	27.8	21.0
4	3	16.7	22.0
Total	18	100.0	



BLM Review

First, you should review the submittal to ensure that sufficient information was submitted:

- A list of each lease, unit PA, or CA proposed for commingling: **Yes**
- The royalty rate and ownership (Federal, tribal Indian [specify tribe], or allotted Indian) of each lease to be included: **Yes**
- For unit PAs and CAs, the Federal or Indian allocation factor: **Yes**
- If the commingling proposal includes allotted Indian leases, evidence that all Indian allottee mineral owners of any leases included in the commingling request have been notified of the request. An affidavit from the operator stating that a notice was mailed to each mineral owner of record for whom the superintendent or area director has an address will satisfy this notice requirement: **Not Applicable**
- If the commingling proposal includes tribal Indian leases, evidence that each of the affected tribes has given its consent for commingling: **Not Applicable**
- The commodities proposed for commingling (oil/condensate, gas, or both): **Yes**
- Evidence showing that each lease, unit PA, or CA proposed for commingling is either in production or (for Federal leases) is capable of production: **Yes, the well tests shown in the example allocation method indicate that all leases are capable of production**
- A map or schematic showing the proposed leases, unit PAs, and CAs, along with wells, pipelines, processing facilities (separators, dehydrators, compressors, etc.), storage facilities, and the point of royalty measurement: **Yes**

- If wells are directional or horizontal and produce from a well pad not located on the lease, unit PA, or CA from which the production originates, the map should include the approximate wellbore path and the location of the producing interval(s): **Not applicable**
- A list of all equipment proposed for royalty-free use of gas and oil (beneficial use) and a schematic showing where fuel is to be taken in relation to the royalty measurement point: **Yes**
- The gas heating value (Btu) and oil gravity of the oil and gas proposed for commingling: **Yes**
- A detailed description of the proposed allocation method for both volume and quality along with an example of how it is applied: **Yes**
- If downhole commingling is proposed, pertinent reservoir information such as the presence of hydrogen sulfide, formation pressures, water cut, decline characteristics, drive mechanism, and existing or anticipated enhanced recovery projects: **Not Applicable**

Initial Questions

Based on the information submitted, the following questions can be answered:

1. Are the royalty factors of any of the leases, unit PAs, or CAs proposed for commingling different? **Yes**

Lease	Royalty Rate	Allocation Factor	Royalty Factor
COC-98766	0.125	0.2500	0.03125
COC-98755	0.125	0.5000	0.06250
COC-98744	0.125	0.3750	0.04688
COC-98733	0.125	0.5000	0.06250

2. If tribal Indian leases are proposed for commingling, are any of the leases owned by different tribes? **Not applicable**
3. Is any of the production going to the CDP originating from outside of the leases, unit PAs, and CAs proposed for commingling? **No**
4. Are any of the leases proposed for commingling an allotted Indian lease? **No**

Approve the request?

Because the royalty factors for three of the four CAs are different, the allocation method will have royalty implications. Therefore, this request does not meet applicable criteria for measurement or accountability to be eligible for commingling approval under Category 1. However, given the low oil production rates, the operator may be making a legitimate claim regarding the economics of installing the necessary production and measurement equipment for compliance with Onshore Order 4 and to achieve measurement on each CA.

To verify the economics of installing the necessary equipment, equation 4 can be used as a default case:

$$Q_i = \frac{I}{1578P_o - 14475} + \frac{1}{0.008684P_o - 0.05261}$$

Assuming an oil price of \$80/bbl (“Colorado D-J Basin”), the equation can be solved for Q_i :

$$Q_i = \frac{225,000}{1578 \times 80 - 14475} + \frac{1}{0.008684 \times 80 - 0.05261} = 3.57 \frac{\text{bbl}}{\text{day}}$$

In other words, in order to achieve a rate of return of at least 10 percent (before taxes) on the \$225,000 investment required for individual measurement on each CA, the production from each well would have to have a minimum initial flow rate of 3.57 bbl/day. Only the production from well #4 (CA COC-98744) is below that level and would qualify as a low-volume property under the first prong of the definition (the rate-of-return calculation). The operator did not include an alternate NPV of royalty analysis with the application.

Although CA COC-98733, COC-98755, and COC-98766 do not meet the requirements of a low-volume property under the first definition, an analysis should be run to determine if the required investment is greater than the NPV of the royalty income estimated over the equipment life (assume 20 years). Using a 30-year treasury rate of 3 percent and an oil price of \$80/bbl, the NPV calculations are summarized below:

	COC-98733	COC-98755	COC-98766
NPV Gross Revenue	1,563,483	1,876,307	1,250,871
Royalty Factor	0.0625	0.0625	0.03125
NPV Royalty	97,718	117,269	39,090

For each of these CAs, the royalty value is less than the required investment of \$225,000. Therefore, all three of these CAs would qualify as low-volume properties under the second prong of the definition (the royalty NPV calculation).

Because all four CAs are considered low-volume properties, this commingling request should be approved under Category 2 of the IM because the public interest in achieving maximum ultimate recovery from the reservoir outweighs the potential for mis-measurement due to the allocation methodology. Royalty on production from these wells, even if it is inaccurate, is better than no royalty at all, which would be the result if the wells were plugged. Proposals to commingle production from one or more low-volume properties with production from one or more non-low-volume properties are addressed below in example 4.

Related Approvals and Off-lease Beneficial Use

This approval will require approval of off-lease measurement for all four CAs. A variance to the requirements of Onshore Order 4 will also be required because the proposed well test

methodology for allocation does not meet the standards required by the Onshore Orders for sales and allocation facilities.

Because the CDP is not on any of the CAs proposed for commingling, none of the fuel used by the heater-treater at the CDP can be claimed as beneficially used (absent approval of off-lease beneficial use in unusual circumstances). That fuel, therefore, is royalty bearing. The amount of fuel should be measured (or estimated if the cost of installing a fuel meter is shown by the operator to be uneconomic) and reported on OGOR B under disposition code '01'. The total amount of fuel used each month should be allocated to each CA using the allocation percentages proposed by the operator. If the operator had requested approval of off-lease beneficial use, the BLM would only approve the request if a separate economic analysis showed that the approval was necessary to allow continued production of the CAs.

OGOR Reporting and Production Accounting

The approval should also specify how volumes and qualities of oil and gas are to be reported on OGOR B and C. Production accounting will focus on the oil sales tank at the CDP, and the fuel use meter, if required, or the estimation of fuel usage if a meter is not required. However, because the production volumes and qualities allocated to each lease will be reported separately on the OGORs, the sum of the OGOR volumes and the volume weighted average of the OGOR qualities must match the volumes and qualities obtained from the CDP. Reporting the same quality for each lease (matching the measured quality at the CDP) is acceptable for royalty reporting purposes.

For example, suppose the following quantities and qualities were measured at the CDP for the month of April 2012:

	Volume	Quality
Oil	300 bbls	23.0
Gas	0 Mcf	n/a
Fuel	150 Mcf	1200 Btu/scf

(The facts here assume that all the gas collected at the separator was used as fuel.) The OGOR reporting for the four commingled CAs should be as follows (the allocation percentages shown in the example allocation method will be assumed):

Lease	OGOR B			OGOR C	
	01		20	Oil Gravity	Oil Sales
	BTU	MCF	MCF		
COC-98766	1200	33	0	23.0	67
COC-98755	1200	50	0	23.0	100
COC-98744	1200	42	0	23.0	83
COC-98733	1200	25	0	23.0	50
Total		150	0		300

Example 4: Commingling a Low-Volume Property with a Non-Low-Volume Property

The BLM receives the following application to commingle oil and gas production from a low-volume Federal lease with a unit PA:

We are requesting approval to commingle oil and gas production from our Federal lease with a PA as listed below and shown on the attached figure. This request is made to allow the economic production of well "GDC #1," which was recently drilled but does not produce at sufficient rates to justify the investment in the necessary separation and metering equipment given current gas prices (\$2/Mcf). Our only options are to commingle production with the PA or plug and abandon this well. We believe that production of this gas is in the public interest. The initial well test indicated a gas flow rate of 45 Mcfd with a negligible amount of oil production. Heating value of the gas was 1190 Btu/scf. If approved, a 300-foot pipeline would be constructed from the wellhead to the gathering system near the Mesa #5 well (see Figure). We estimate the cost of the tie-in line to be \$15,000.

Lease/ Agreement No.	Ownership	Royalty Rate (%)	Allocation Factor
UTU-98765A (PA)	Mixed – see attached figure		
UTU-889966 (Lease)	Federal	12.5	n/a

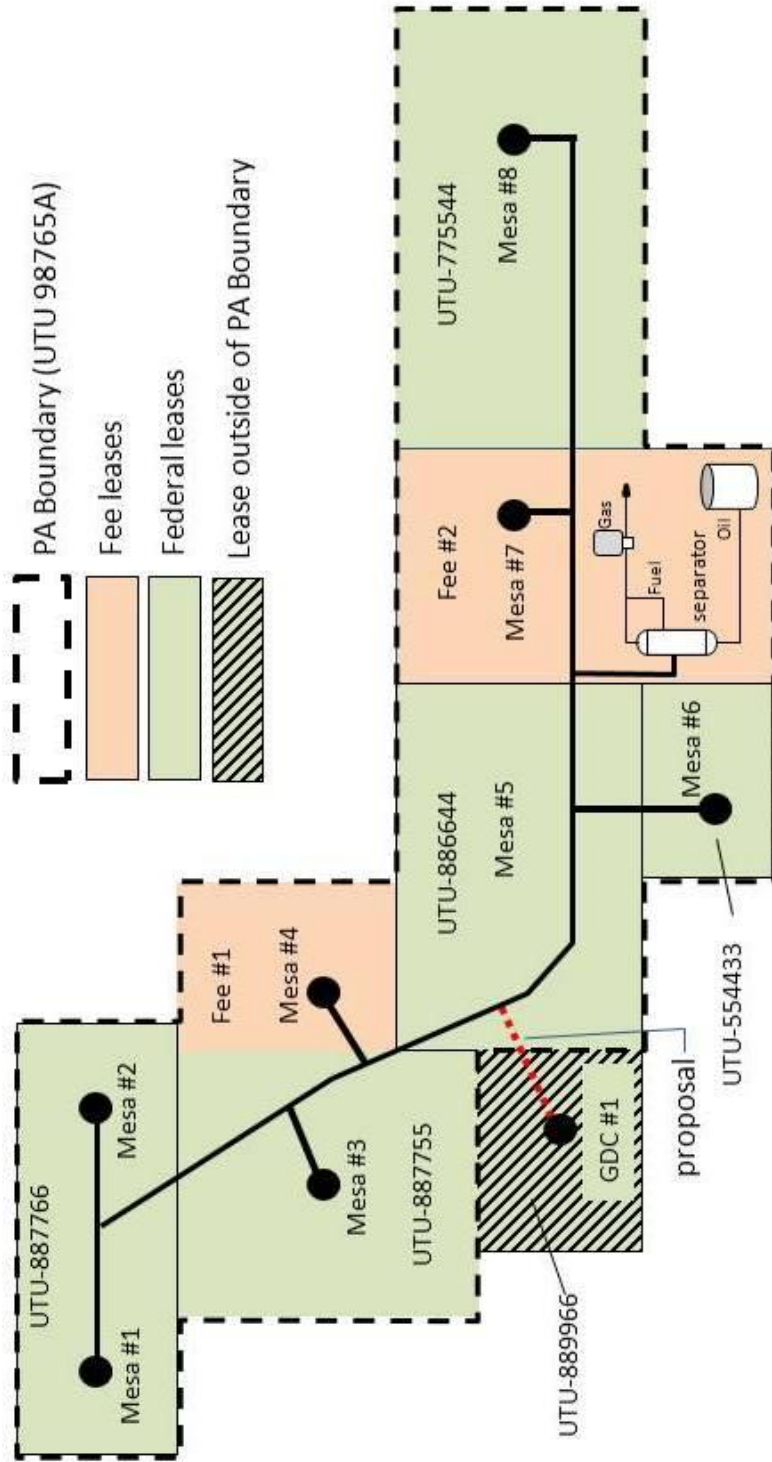
After some research, we have determined that the cost to install a separate pipeline to tie directly into the trunk line after the CDP and to purchase measurement equipment on the lease is as shown in the following table:

Equipment/Labor	Cost
Meter	\$8,000
Additional piping and installation to tie into gas transmission line near well Mesa #7	\$115,000
Total	\$123,000

Our Discounted Cash Flow analysis shows that we could not recover these costs at a reasonable rate of return; therefore, we would plug and abandon this well if we do not receive approval. We propose to allocate production to lease UTU-889966 based on semi-annual well tests of all wells involved in the commingling approval. The percentage of oil and gas production attributable to lease UTU-889966 would be determined by dividing the gas rate from the semi-annual test of well GDC#1 by the total of the oil and gas rates from the tests of the other nine wells within the PA. This percentage would be applied to the total oil and gas sales as measured at the gas meter and oil tank on the Fee #2 lease.

Production from the PA over the past 3 months is as follows:

Month	Oil (bbl)	Gravity (°API)	Gas (Mcf)	Heat. Value (Btu/scf)
May	698	33.6	110,197	1010.3
April	664	32.5	98,008	1010.3
March	755	33.3	144,530	1031.0



Ownership within PA UTU-98765A

Lease	Ownership	Royalty Rate (%)	Allocation Factor
UTU-887766	Federal	12.5	13.5900
UTU-887755	Federal	12.5	16.4517
UTU-886644	Federal	12.5	18.7048
UTU-775544	Federal	12.5	18.2058
UTU-554433	Federal	12.5	7.4457
Fee #1	Fee	n/a	7.5750
Fee #2	Fee	n/a	18.0270

BLM Review

First, you should review the submittal to ensure that sufficient information was submitted:

- A list of each lease, unit PA, or CA proposed for commingling: **Yes**
- The royalty rate and ownership (Federal, tribal Indian [specify tribe], or allotted Indian) of each lease to be included: **Yes**
- For unit PAs and CAs, the Federal or Indian allocation factor: **Yes**
- If the commingling proposal includes allotted Indian leases, evidence that all Indian allottee mineral owners of any leases included in the commingling request have been notified of the request. An affidavit from the operator stating that a notice was mailed to each mineral owner of record for whom the superintendent or area director has an address will satisfy this notice requirement: **Not Applicable**
- If the commingling proposal includes tribal Indian leases, evidence that each of the affected tribes has given its consent for commingling: **Not applicable**
- The commodities proposed for commingling (oil/condensate, gas, or both): **Yes**
- Evidence showing that each lease, unit PA, or CA proposed for commingling is either in production or (for Federal leases) is capable of production: **Yes, the well tests shown in the example allocation method indicate that all leases are capable of production**
- A map or schematic showing the proposed leases, unit PAs, and CAs, along with wells, pipelines, processing facilities (separators, dehydrators, compressors, etc.), storage facilities, and the point of royalty measurement: **Yes**
- If wells are directional or horizontal and produce from a well pad not located on the lease, unit PA, or CA from which the production originates, the map should include the approximate wellbore path and the location of the producing interval(s): **Not applicable**
- A list of all equipment proposed for royalty-free use of gas and oil (beneficial use) and a schematic showing where fuel is to be taken in relation to the royalty measurement point: **Yes**
- The gas heating value (Btu) and oil gravity of the oil and gas proposed for commingling: **Yes**
- A detailed description of the proposed allocation method for both volume and quality along with an example of how it is applied: **Yes, but no example**
- If downhole commingling is proposed, pertinent reservoir information such as the presence of hydrogen sulfide, formation pressures, water cut, decline characteristics, drive mechanism, and existing or anticipated enhanced recovery projects: **Not Applicable**

Initial Questions

Based on the information submitted, the following questions can be answered:

1. Are the royalty factors of any of the leases, unit PAs, or CAs proposed for commingling different? **Yes**

Lease	Royalty Rate	Allocation Factor	Royalty Factor
UTU-889966	0.1250	n/a	0.125000
UTU-98765A	See Table below		0.049676

Federal royalty factor for PA UTU-98765A (per Equation 1)

Lease	Federal Royalty Rate	Alloc. Factor	Royalty Factor
UTU-887766	0.12500	0.135900	0.016988
UTU-886644	0.12500	0.187048	0.023381
UTU-554433	0.12500	0.074457	0.009307
Total Royalty Factor:			0.049676

2. If tribal Indian leases are proposed for commingling, are any of the leases owned by different tribes? **Not applicable**
3. Is any of the production going to the CDP originating from outside of the leases, unit PAs, and CAs proposed for commingling? **No**
4. Are any of the leases proposed for commingling an allotted Indian lease? **No**

Approve the request?

Because the royalty factors for the lease and the unit PA proposed to be commingled are different, the allocation method will have royalty implications. The production from the unit PA is high enough that commingling cannot be justified from an economic standpoint with respect to that unit PA; however, production from the lease may be low enough that the operator's arguments about plugging the well if commingling is not approved may be legitimate. To determine if it is economic to measure the GDC # 1 well on Lease UTU-889966 without the commingling, equation 3 can be used as a default case:

$$Q_i = \frac{1}{P_g} \left(\frac{I}{1590} + 57 \right)$$

Using the current gas price of \$2/Mcf, the following initial gas production rate would be required to justify the necessary investment:

$$Q_i = \frac{1}{2} \left(\frac{123,000}{1590} + 57 \right) = 67 \text{ Mcfd}$$

However, using long-term projected gas prices of \$4/Mcf:

$$Q_i = \frac{1}{4} \left(\frac{123,000}{1590} + 57 \right) = 34 \text{Mcf/d}$$

With an initial flow rate of 45 Mcf/day, the investment required for non-commingled measurement would not be economic at \$2/Mcf, but it would be economic at \$4/Mcf. The operator will likely make the economic decision based on current prices.

This proposal presents a dilemma because it is clearly in the public interest to produce the gas from lease UTU-889966. However, a commingling approval using the proposed allocation method would compromise the production accountability of the unit PA because of the proposed well test methodology.

One alternative would be to require a simpler and more verifiable allocation methodology. For example, if the operator were to tie into the unit PA gathering system as proposed and install a meter, the measured gas could be reported as gas sold on OGOR B. This amount could then be subtracted from the gas measured by the gas meter at the POM. The total cost of this alternative would be \$23,000. With an initial flow rate of 45 Mcf/day, this investment would be economically prudent for the operator, even at \$2/Mcf:

$$Q_i = \frac{1}{2} \left(\frac{23,000}{1590} + 57 \right) = 36 \text{Mcf/d}$$

The NPV of royalty from this lease would be \$32,000 with a \$2/Mcf gas price; therefore, the lease would not qualify as a low-volume property based on this criterion.

The field office should work with the operator to develop an allocation methodology similar to that described above, or dictate the allocation methodology with conditions of approval. In that event, this application then would be approved under Category 2 of the IM. However, the approval could be re-examined if current gas prices increased significantly.

In general, approval of requests to commingle production from one or more low-volume properties with production from one or more non-low-volume properties will depend on establishing an allocation method that both is sufficiently accurate and verifiable to reduce the risk to production accountability for the non-low-volume property(ies) and is economical for the low-volume property(ies).

Related Approvals and Off-lease Beneficial Use

Approval of the alternative described above would not require off-lease measurement approval because the operator would measure production from lease UTU-889966 on the lease and the production from the unit PA is measured on the unit PA. If the field office approves or requires the simplified allocation method discussed above, a variance request from Onshore Order 5 is not required because the operator's gas meter would comply with the standards of Onshore Order 5.

Because the CDP is physically located on the unit PA, the proportionate share of fuel used to separate the oil and gas produced from the unit PA qualifies as royalty-free beneficial use. However, the proportionate share of the fuel that corresponds to the proportion of total production from lease UTU-889966 is not royalty-free both because the CDP is not physically located on that lease and because that lease contributes only a negligible amount of oil to the production stream. Effectively, all the oil separated from the production stream is produced from the unit PA. Thus, the gas used as fuel should come only from the gas produced from the unit PA, and the total gas used as fuel therefore must be allocated. The operator did not request approval of off-lease beneficial use.

OGOR Reporting and Production Accounting

The approval should also specify how volumes and qualities of oil and gas are to be reported on OGOR B and C. Production accounting will focus on the oil sales tank and gas meter at the CDP and the meter installed for gas production from lease UTU-889966.

For example, assume that the following quantities and qualities were measured at the CDP for the month of June 2012:

	Volume	Quality
Oil	655 bbls	33.2 ⁰
Gas	103,846 Mcf	1020 Btu/scf
Fuel	1,150 Mcf	

And, the following was measured by the meter for UTU-889966:

	Volume	Quality
Oil	0	n/a
Gas	1,250 Mcf	1188 Btu/scf

The proportion of gas production attributable to the unit PA is:

$$\frac{(103,846Mcf - 1,250Mcf)}{103,846Mcf} = 0.9880$$

This fraction would be applied to both the total gas volume and the fuel usage for OGOR B (PA UTU-98765A):

Gas volume (code 01): 103,846 Mcf x 0.9880 = 102,600 Mcf
 Beneficial use (code 20): 1,150 Mcf x 0.9880 = 1,136 Mcf

The OGOR reporting for the commingled lease and unit PA should be as follows:

Lease	OGOR B			OGOR C	
	01		20	Oil	Oil
	BTU	MCF	MCF	Gravity	Sales
UTU-98765A	1.020	102,600	1136	33.2	655
UTU-889966	1.188	1,250	0		0

Note that the allocation could also be done on a heating value (MMBtu) basis rather than a volume basis:

Total heating value at the CDP:

$$103,846 \text{ Mcf} \times 1.020 \text{ MMBtu/Mcf} = 105,923 \text{ MMBtu}$$

Total heating value from lease UTU-889966:

$$1,250 \text{ Mcf} \times 1.188 \text{ MMBtu/Mcf} = 1,485 \text{ MMBtu}$$

Proportion of gas attributable to the PA:

$$\frac{(105,923 \text{ MMBtu} - 1,485 \text{ MMBtu})}{105,923 \text{ MMBtu}} = 0.9860$$

Using the ratios based on heating value would result in the following OGOR B values:

$$\text{Gas volume (code 01): } 103,846 \times 0.986 = 102,392 \text{ Mcf}$$

$$\text{Beneficial use (code 20): } 1,150 \times 0.986 = 1,134 \text{ Mcf}$$

The difference in royalty-bearing volume (code 01) is -208 Mcf.

Although more complex, allocation based on heating value (MMBtu) rather than volume more accurately depicts the value of the gas removed from the respective properties. If the field office determines that the difference in heating value is significant, the conditions of approval should specify that the allocation is to be based on heating value.

Example 5: Downhole Commingling – Overriding Considerations

The BLM receives the following application for the downhole commingling of a PA and a Federal lease:

We are requesting approval to down-hole commingle gas from Federal lease NMN-031245 with Participating Area NMN-73976A (see Figure 1). Well MV#8 is currently dual-completed (see Figure 2a), with one completion in the Pictured Cliffs formation (lease NMN-031245) and the other completion in the Mesa Verde formation (PA NMN-73976A). Both formations produce through 1-¼” tubing. Due to high water production from the Pictured Cliffs formation, production from lease NMN-031245 has been shut in for 4 years. Production from the Mesa Verde (NMN-73976A) continues, although flow is restricted due to the small tubing diameter.

The proposed completion (see Figure 2b) would replace the dual 1-¼” tubing strings with a single 2-3/8” tubing string. We believe that the proposed completion would allow the reservoir energy in the Mesa Verde to lift the water produced from the Pictured Cliffs, thereby producing both formations. A plunger lift system would be installed if necessary. Both the Pictured Cliffs and the Mesa Verde have significant gas reserves remaining.

The proposed allocation method would be to use historical production rates from each formation to establish a fixed allocation percentage (see the following table). The allocation percentage would then be applied to the commingled gas volumes as measured at the surface. Both the Pictured Cliffs and the Mesa Verde have similar decline characteristics.

Year	Pictured Cliffs Production (Mcf)	Mesa Verde Production (Mcf)	Pictured Cliffs (%)	Mesa Verde (%)
2002	49,308	36,048	57.767	42.233
2003	43,391	32,083	57.492	42.508
2004	38,184	28,554	57.215	42.785
2005	33,602	25,413	56.938	43.062
2006	29,570	22,617	56.661	43.339
2007	26,021	20,129	56.383	43.617
2008	22,899	17,915	56.105	43.895
Average:			56.937	43.063

Lease/ Agreement No.	Ownership	Royalty Rate (%)	Alloc. Factor
NMN-73976A	Federal/Fee	12.5	0.256
NMN-031245	Federal	12.5	n/a

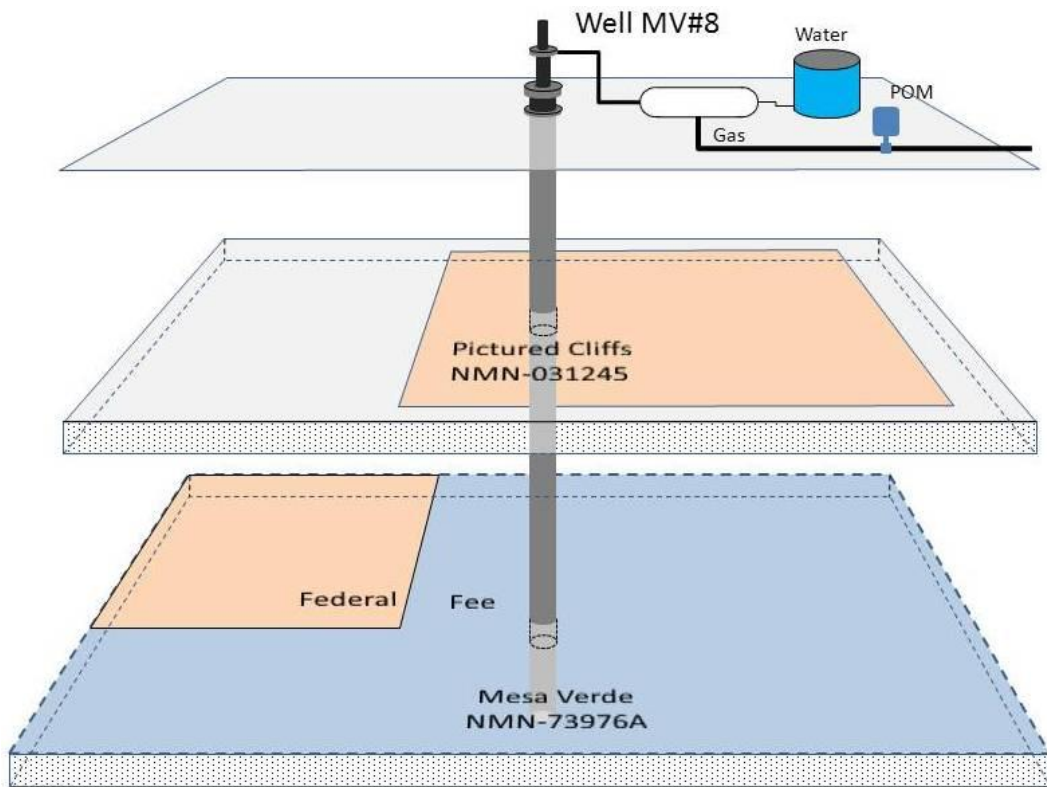
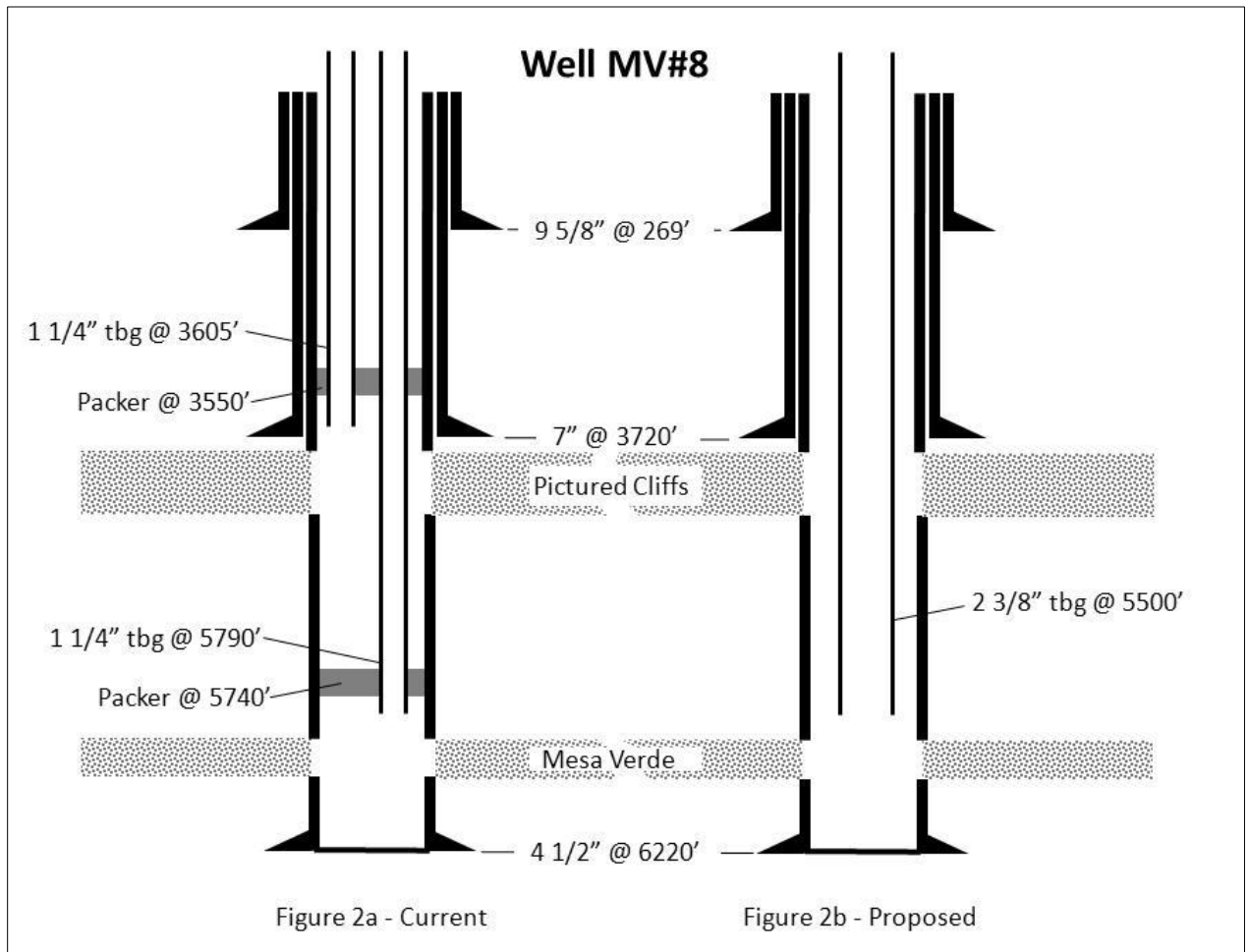


Figure 1



BLM Review

First, you should review the submittal to ensure that sufficient information was submitted:

- A list of each lease, unit PA, or CA proposed for commingling: **Yes**
- The royalty rate and ownership (Federal, tribal Indian [specify tribe], or allotted Indian) of each lease to be included: **Yes**
- For unit PAs and CAs, the Federal or Indian allocation factor: **Yes**
- If the commingling proposal includes allotted Indian leases, evidence that all Indian allottee mineral owners of any leases included in the commingling request have been notified of the request. An affidavit from the operator stating that a notice was mailed to each mineral owner of record for whom the superintendent or area director has an address will satisfy this notice requirement: **Not Applicable**
- If the commingling proposal includes tribal Indian leases, evidence that each of the affected tribes has given its consent for commingling: **Not Applicable**
- The commodities proposed for commingling (oil/condensate, gas, or both): **Yes**
- Evidence showing that each lease, unit PA, or CA proposed for commingling is either in production or (for Federal leases) is capable of production: **Yes, annual volumes are given from 2002-2008**
- A map or schematic showing the proposed leases, unit PAs, and CAs, along with wells, pipelines, processing facilities (separators, dehydrators, compressors, etc.), storage facilities, and the point of royalty measurement: **Yes**
- If wells are directional or horizontal and produce from a well pad not located on the lease, unit PA, or CA from which the production originates, the map should include the approximate wellbore path and the location of the producing interval(s): **Not applicable**
- A list of all equipment proposed for royalty-free use of gas and oil (beneficial use) and a schematic showing where fuel is to be taken in relation to the royalty measurement point: **Yes**
- The gas heating value (Btu) and oil gravity of the oil and gas proposed for commingling: **No – this should be requested**
- A detailed description of the proposed allocation method for both volume and quality along with an example of how it is applied: **Yes, but no example**
- If downhole commingling is proposed, pertinent reservoir information such as the presence of hydrogen sulfide, formation pressures, water cut, decline characteristics, drive mechanism, and existing or anticipated enhanced recovery projects: **No, this information should be requested from the operator.**

Initial Questions

Based on the information submitted, the following questions can be answered:

1. Are the royalty factors of any of the leases, unit PAs, or CAs proposed for commingling different? **Yes**

Lease	Royalty Rate	Fed. Allocation	Royalty Factor
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		Factor	
NMN-031245	0.125	n/a	0.1250
NMN-73976A	0.125	0.256	0.0320

2. If tribal Indian leases are proposed for commingling, are any of the leases owned by different tribes? **Not applicable**
3. Is any of the production going to the CDP originating from outside of the leases, unit PAs, and CAs proposed for commingling? **No**
4. Are any of the leases proposed for commingling an allotted Indian lease? **No**

Approve the request?

Because the royalty factors of the lease and the PA proposed for commingling are different and the properties are not low-volume, approving the request depends on whether there are other overriding considerations. The fact that the operator has not produced the Pictured Cliffs formation for 4 years is an indication that the economics of working over the well and recompleting it in the current configuration are not favorable. However, approving or denying the commingling on a purely economic basis becomes very complex given the speculative nature of both the costs involved and the probable return on investment. In other words, the operator cannot accurately predict what flow rate of gas will result from re-completing the well.

Clearly, it is in the public interest to produce the Pictured Cliffs formation not only for reasons of achieving maximum ultimate recovery but also to prevent potential drainage situations from wells on State or fee leases. On the other hand, the proposed allocation method will affect royalty because the royalty factors are different. With the complexity of multiple zones, multiple fluid phases, and the possible inclusion of a plunger lift, it is likely that there will be a high level of uncertainty in the proposed allocation.

Alternatives to the proposed commingling could include the drilling of a new well that would only produce from the Pictured Cliffs formation or the installation of a pump jack in the shallower tubing string. The operator should provide justification of why these alternatives are not viable. The BLM should verify the operator's analysis and document this finding.

The question is: which alternative better addresses the public interest? Not approving the commingling request and potentially stranding significant gas reserves in the Pictured Cliffs formation, or approving the commingling even though the allocation method could result in significant mis-allocation of Federal gas? Generally, achieving maximum ultimate recovery takes precedence over uncertainty of allocation. Therefore, it presumably would be proper to approve this application under Category 3 of the IM, unless the reservoir and fluid property issues discussed below tip the balance the other way. Had this application involved Indian leases, the input of the tribe or allottees would be important in making the ultimate decision on whether maximum ultimate recovery or certainty of allocation was the higher priority.

Reservoir and Fluid Property Issues

Reservoir and fluid properties were not included in this application but should also be considered before approving this request. For example, if oil and gas produced from the Pictured Cliffs formation was of a significantly different quality than the oil and gas produced from the Mesa Verde formation, then the commingling of these formations could reduce the value of the Federal portion of the oil and gas. Approval of the commingling request should take this into consideration by including the oil and gas qualities in the allocation methodology.

Other considerations should include reservoir pressure, water content, and hydrogen sulfide content. If these are significantly different between the formations, it could not only reduce the value of the oil and gas but could also lead to a drainage situation in these circumstances. For example, if the Pictured Cliffs formation had a higher reservoir pressure than the Mesa Verde formation, oil and gas from lease NMN-031245 could flow into PA NMN-73976A, especially during shut-in periods.

Related Approvals and Off-lease Beneficial Use

There would be no off-lease measurement or beneficial use issues because both the separator and the point-of-royalty measurement are on the footprint of both the lease and the unit PA. A variance to the requirements of Onshore Order 5 will be required because the proposed allocation methodology does not meet the standards required by Onshore Order 5 for sales and allocation facilities.