COPAS National Fall 2019 Emerging Issues Sub-Committee Meeting
Tulsa, Oklahoma, September 18, 2019

Case Study 1

Central Tank Battery Chargeability

The Operator, with 90% working interest, drilled five wells, with slight variations in Non-Operator ownership across the wells. Each well has a signed AFE, which includes typical costs to drill and complete a well. The wells were drilled and completed separately and put on production as they were completed.

A small tank battery was constructed to serve these wells, which was eventually expanded significantly to serve these wells and five more wells that were expected to be drilled. The total cost to build the tank battery was $3.5 million. The costs for this tank battery were not included on the original well AFE. However, the costs for the initial tank battery construction and expansion were charged to the Joint Accounts of the initial five wells drilled.

During a joint venture audit, the Non-Operator took exception to all tank battery costs, with the reasoning that the costs were not included on the original well AFE and a new AFE covering the costs was not issued. Article VI.D of the operating agreement requires an AFE to be written and approved by the majority for any projects with a total cost greater than $50,000. The Non-Operator claims they would have chosen to go Non-consent in the tank battery expansion had they been given the option. Additionally, the Non-Operator indicated that the project was too expensive, and they could have completed the project for approximately $1 million.

Discussion Questions

1) Is this a valid exception?

2) If the Operator accepts the Non-Operator's Non-Consent election now, would the Non-Operator be subject to Non-Consent penalties related to the tank battery expansion and be required to refund any revenues paid until the Non-Consent penalties are recovered?

3) Since the Operator is the majority WI owner, and the AFE only needs to be approved by a majority to be binding, is it valid to say no AFE was necessary since the Operator would have approved it anyway as the majority?

Case Study 2

Third-Party Provided Transportation Management Services

An Operator uses a transportation and logistics management company, called Move It or Lose It, Inc. (“MILI”), to manage all of its transportation related to equipment and water movements. MILI acts as an intermediary between the Operator and the transportation companies and does not provide any of the actual transportation itself. When the Operator needs equipment moved, MILI contacts a trucking company to move the equipment and then pays the invoice on behalf of the Operator. MILI then invoices the Operator for these costs plus management and processing fees added to each transaction. MILI’s invoice to the Operator consists of a listing of all transactions and fees but does not include copies of the transportation invoices.

During a joint venture audit, the Operator provides MILI’s invoice and spreadsheet as support for the charges from MILI and does not provide any of the invoices from the actual transportation companies contracted by MILI. The Non-Operator takes exception to the management and processing fees as costs covered by the overhead rates. The Non-Operator quotes Section III, Paragraph 1.i. of the 1984 COPAS Accounting Procedure which states, “As compensation for administrative…costs, Operator shall charge (overhead on) drilling and producing operations…”. The Non-Operator also points out the concept of an Operator outsourcing its way to chargeability.

The Operator MILI’s fees are allowed as a direct charge to the Joint Account per the interpretative section of COPAS MFI-17, *COPAS 1984 Model Form Accounting Procedure Interpretation* which states, “Transportation shall include all costs incurred in the transportation of employees, equipment, Material and supplies necessary for the development, maintenance and operation of the Joint Property.” The Operator argues its chargeable field employees (wellsite supervisor, rig clerk, etc.) would be responsible for performing the “management” and “processing” function had MILI not been used. The Operator further points out that Section II, Paragraph 6, *Transportation*, of the 1984 Accounting Procedure does not identify any components of overall transportation costs that are to be excluded. The Operator also states other forms of contractor “profits” not specifically identified on an invoice are allowed as a direct charge to the Joint Account.

The Operator also states it has reviewed COPAS AG-23, *Overhead Rate Negotiation and Calculation*, and finds no reference to these types of fees in the document. The Operator claims these types of costs are prevalent in the industry and had they been intended to be considered when developing the initial overhead rates, COPAS would have included it in COPAS AG-23.

COPAS Guidance

MFI-17, COPAS 1984 Model Form Accounting Procedure Interpretation
AG-23 Overhead Rate Negotiation and Calculation

Discussion Questions

1) Is the invoice and spreadsheet received from MILI (the transportation management company) considered adequate documentation to support the charges to the Joint Account?

2) Is the Operator required to provide copies of the source documents from the actual transportation companies to substantiate the charges to the Joint Account and/or comply with COPAS MFI-43?

3) Are the management and processing fees allowed as a direct charge under Paragraph 6 (Transportation)? Under paragraph 7 (Services)? Is this solely contractor profit and should even be allowed as a direct charge?

4) Does your answer differ depending upon what is being transported? In other words, would you be more likely to agree with the Operator's response if these costs solely related to equipment transportation or if the costs solely related to water transportation?

5) Does the Operator's argument that these types of costs were not contemplated under COPAS AG-23 strengthen the Operator's argument these costs should be allowed as a direct charge to the Joint Account?

6) Should the Operator provide a copy of the contract with MILI, the logistics management company?

7) If the well was covered under a 2005 COPAS Accounting Procedure, would your answer be different considering the interpretative section of the 2005 Accounting Procedure does not contain the "All costs incurred…" language referenced in the interpretive section of the 1984 COPAS Accounting Procedure?

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Case Study 3

Water Facilities

Well A is entering the hydraulic fracturing stage of the well completion process. Some water used in the fracturing process may stay in the target formation, and some water will return to the surface as produced water along with oil, natural gas, or natural gas liquids. Some of the produced water is trucked to a disposal site and some of the produced water is trucked to an operator-owned recycling facility. The recycled water was then used by the operator in frac operations on Well B.

Additional Information:

- Well A was charged a fee of $2.95/bbl for water recycled at the recycling facility
- Well A was charged a fee of $1.50/bbl for water disposed at a disposal facility
- Fresh water cost is $2.60/bbl
- All of the above are the service rates only and do not include transportation, but the trucking rate is the same for each service
- Charges to Well B for recycled water are unknown, if any

Discussion Questions

1) Who owns and has rights to the produced water:
    a. Before it is sent to the recycling center or disposal site?
    b. After it is processed at the recycling center?
    c. That is disposed at the disposal site?

2) Is the recycling cost considered a benefit to Well A as disposal cost or as a benefit to Well B as frac water cost?

3) What portion of the recycling charge should Well A (disposing well) bear? Just the trucking? A composite rate including trucking and disposal?

4) What amount of the recycling charge should Well B (fracing well) bear? Just the disposal fee?

5) If the recycling facility was a third party (and not operator-owned), who would own the recycled water and what fees should be charged to Well A and Well B?

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Water Facilities Part 2: An operator-owned water facility is fairly complex and contains both temporary and permanent disposal lines, which have different costs (installation costs vs. costs to move the lines).

Discussion Questions

1) Should the Operator track which lines are used (temporary vs fixed), or is it acceptable to create a blended rate that captures all aspects of the water facility operations, regardless of which lines service a particular property?

2) If the facility Operator uses the water lines to transport both produced and recycled fresh water, is it acceptable to evenly allocate the cost of the lines to all properties served (producing wells vs. fracing wells), or does some other allocation need to be created?

3) With very few third parties operating recycling facilities, how should the Operator justify/support the rates used vs. market rates?

4) If one Operator has a 60,000-barrel facility and another Operator nearby has a 30,000-barrel facility, the costs to build and operate the facilities will be different. Does that justify having a higher rate for the larger facility than the smaller facility?

Case Study 4

Offset Frac Costs or Offset Remediation Work

In 2014, the Colorado Oil and Gas Conservation Commission (COGC) issued a policy requiring all existing offset wellbores ("Nearby Wells") within 1,500 feet of a proposed horizontal wellbore ("Proposed Well") would be evaluated for adequate zonal isolation from hydraulic fracturing. An Operator's Application for Permit to Drill a Proposed Well shall include an evaluation of all Offset Wells within 1,500 feet of the Proposed Well to determine adequate zonal isolation. If the COGC identifies certain Nearby Wells that do not have adequate isolation, then the Proposed Well operator will be required to submit mitigation plans to address the concerns of the Nearby Well. The Proposed Well Operator shall provide notice to all Nearby Well operators 90-days prior to the anticipated commencement of stimulation. The COGC explicitly intends this Policy to protect Public Health, Safety and Welfare.

Discussion Questions

1) Are these mitigation (same as wellbore integrity or safety prepping) costs directly chargeable to the Joint Account, and if so, under which COPAS provisions?

2) Are there any model forms that may exclude these mitigation costs from being directly chargeable?

Situation 1 – Colorado Jurisdiction

Proposed O&G, as Operator of the planned Proposed well, submitted an Application for Permit to Drill to the COGC. During the Application review process, COGC staff determined a Nearby well (within 1,500 feet) did not have adequate isolation from any potential fracking of the Proposed well. After receiving the required notification from Proposed O&G, Nearby O&G, as Operator of the Nearby well, begins the process of mitigating its well and paying the related costs. Total costs to adequately mitigate the Nearby well are $50,000.

Questions for Situation 1

1) Which well should bear the ultimate cost of mitigating the Nearby well – the Nearby or the Proposed well?
    a. How would your opinion change if Nearby O&G spent $125,000 mitigating the Nearby well, an amount the management of Proposed O&G considers excessive?

2) What if Nearby O&G took this opportunity to perform a previously scheduled recompletion on the Nearby well? Are the related mitigation charges, or a portion of, still billable to the Proposed well?

Situation 2 – Wellbore Compromised

Same fact pattern as situation #1 above. As the Proposed well is being fracked, the wellbore of the Nearby well is compromised, and a workover of the Nearby well become necessary.

Questions for Situation 2

1) Which well should incur the workover-related costs?

2) Is responsibility changed by the Damages and Losses to Joint Property provisions of the 1962, 1968, 1974, 1984, 1995 and 2005 Accounting Procedures?

Situation 3 – Wyoming / Texas Jurisdiction

Same fact pattern as situation #1 above. However, the Proposed well and Nearby well are located in Wyoming or Texas (or any state) where the relevant oil and gas regulatory commission hasn't issued such a policy.

Questions for Situation 3

1) Does the absence of such a regulatory policy change chargeability of the mitigation costs?

2) Is Proposed O&G acting as a "reasonable and prudent Operator" in requesting the Nearby wells be mitigated?

3) Which well should bear responsibility for the mitigation costs?

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Case Study 5

Seismic Costs in an RTC

An Operator incurs costs for seismic testing and analysis to determine the placement of Well A. The operator also incurs costs related to geo-steering services provided through its Operator-owned RTC facility.

Do the working interest owners of Well A have an ownership stake in the seismic data and do they have a right to review the data:

1) If the seismic testing and analysis costs are directly charged to the Joint Account (either at 100% of the costs or a portion of the costs if the seismic data is related to multiple wells).

2) If the seismic testing and analysis costs are borne by the Operator, but the seismic analysis is completed in the RTC, and the RTC rate is directly charged to the Joint Account?

3) If the seismic testing and analysis is completed in the RTC and the seismic costs are directly charged to the Joint Account through the RTC facility rate?

Case Study 6

Incidental Supplies

An operator maintains a supply shop near a field office. To avoid downtime and delays, the operator maintains a four-week supply of commonly used supplies in the supply shop. Inventory is maintained consistently at a 4 to 6-week supply level. Supplies are purchased at less than $100 per item and have an expected life of less than 12 months. Pumpers routinely access the supply shop for rags, soapsticks, batteries, solar panels, and other supplies to be used on wells and facilities. Generally, a pumper keeps a small stock on hand in his or her truck for immediate use as needed. The supplies are typically not removed from the supply shop for use on specific wells.

COPAS Guidance

MFI-38, Materials Manual
Section II.B Controllable/Non-Controllable Materials

COPAS classifies materials as Controllable Material or Non-Controllable Material. The purpose of the controllable material designation is to provide a uniform classification of material utilized in joint interest operations, which, under terms of the accounting procedures, is subject to record and inventory control. The classification of material as controllable or non-controllable has no correlation to the capitalization or expensing of material cost for tax or financial reporting purposes. The classification of material as controllable and non-controllable is to facilitate the preparation of joint interest billings and the reconciliation of joint account material inventories as specified in the accounting procedures. Refer to the governing accounting procedure for the applicable provisions that require the detailed listing of controllable materials on the Joint Interest Bill (JIB).

Appendix C lists materials classified as controllable. The materials listed are those materials that COPAS has classified as controllable as of the date of this publication. The classification of material as non-controllable does not, however, eliminate the operator's responsibility for properly accounting for material purchases, transfers and dispositions. The terms controllable and non-controllable are used synonymously with the terms detailable and non-detailable.

MFI-38, Materials Manual
Appendix C

The material listings are generally complete, as of the date of this document, and items omitted can generally be considered non-controllable. When items utilized in joint operations are not listed in this publication, the operator may classify such material as controllable or non-controllable based on the standards and guidelines listed below:

1) Original cost of item versus record maintenance cost
2) Salvage value

3) Identity as a complete unit or part of a unit
4) Probability of movement and/or replacement and/or usability
5) Practical or impractical to control
6) Useful life.

The guidelines represent the most current practices in the industry and supersede all prior material classification publications. The information contained in this publication may be reviewed and revised periodically.

Discussion Questions

1) Are these incidental supplies considered non-controllable material?

2) Is the maintenance of a supply shop appropriate? Is the supply shop considered a warehouse? Is a physical inventory required?

3) Are any of the following acceptable accounting methods for charging the supplies?
   a. Individual items are charged as used. The pumper should assess the price and condition of supplies before use, and a material transfer should be performed for each item.
   b. An inventory of the shop should be performed at the beginning and end of every month, and usage (change in inventories plus purchases) should be allocated to producing wells in the area.
   c. Purchases which occur each month should be allocated across the producing wells for that month.
   d. Purchases which occur each month should be allocated across the producing wells for the subsequent month (on a one-month lag).
   e. Supply purchases are included in the field-wide allocation and are allocated through field operations expense.
   f. Supply purchases are included in pumper costs and are allocated based on the pumper's allocation? (either as extra $/hr added to pumper rate, or allocated as separate charge or fee?)
   g. Other accounting methods?

4) Should the costs to operate the supply shop be allocated out to the field or properties served?

5) Do the answers change if the ownership does <u>not</u> vary between wells?